# Emission Impossible: Positively Shocking Solutions for Abating Greenhouse Gas Emissions from Canada's Electric Power Industry

**By Justin Domareski**

B. A. (First Class Honours), Simon Fraser University, 2010

RESEARCH PROJECT SUBMITTED IN PARTIAL FULFILLMENT
OF THE REQUIREMENTS FOR THE DEGREE OF
MASTER OF PUBLIC POLICY

in the
School of Public Policy
Faculty of Arts and Social Sciences

**SIMON FRASER UNIVERSITY**

**Spring 2013**

# Approval

**Name:** **Justin Domareski**

**Degree:** **M.P.P.**

**Title of Thesis:** ***Emission Impossible: Positively Shocking Solutions for Abating Greenhouse Gas Emissions from Canada's Electric Power Industry***

**Examining Committee:**

**Chair:** Nancy Olewiler, Director, School of Public Policy

**Nancy Olewiler**
Senior Supervisor
Director, School of Public Policy, SFU

**John Richards**
Professor, School of Public Policy

**Dominique M. Gross**
Internal Examiner
Professor, School of Public Policy

Date Defended/Approved: April 3, 2013

# Partial Copyright License

The author, whose copyright is declared on the title page of this work, has granted to Simon Fraser University the right to lend this thesis, project or extended essay to users of the Simon Fraser University Library, and to make partial or single copies only for such users or in response to a request from the library of any other university, or other educational institution, on its own behalf or for one of its users.

The author has further granted permission to Simon Fraser University to keep or make a digital copy for use in its circulating collection (currently available to the public at the "Institutional Repository" link of the SFU Library website (www.lib.sfu.ca) at http://summit/sfu.ca and, without changing the content, to translate the thesis/project or extended essays, if technically possible, to any medium or format for the purpose of preservation of the digital work.

The author has further agreed that permission for multiple copying of this work for scholarly purposes may be granted by either the author or the Dean of Graduate Studies.

It is understood that copying or publication of this work for financial gain shall not be allowed without the author's written permission.

Permission for public performance, or limited permission for private scholarly use, of any multimedia materials forming part of this work, may have been granted by the author. This information may be found on the separately catalogued multimedia material and in the signed Partial Copyright Licence.

While licensing SFU to permit the above uses, the author retains copyright in the thesis, project or extended essays, including the right to change the work for subsequent purposes, including editing and publishing the work in whole or in part, and licensing other parties, as the author may desire.

The original Partial Copyright Licence attesting to these terms, and signed by this author, may be found in the original bound copy of this work, retained in the Simon Fraser University Archive.

Simon Fraser University Library
Burnaby, British Columbia, Canada

revised Fall 2011

# Abstract

Federal and provincial electricity policies have proven to be inadequate at mitigating greenhouse gas (GHG) emissions from the power industry. Existing abatement policies and electricity markets in Canada do not provide sufficient incentives to shift investment patterns towards low carbon generation technologies. The primary research method used to analyze this incentive problem is an econometric analysis of provincial electricity GHG emissions and abatement policies. This quantitative analysis is supplemented with case studies of Alberta and Texas to control for explanatory factors not addressed directly in the regressions and to explore interactions between subsidy policies and electric system operations. The analysis indicates that a combination of subsidy policies, political barriers, and U.S. trade rules interact to negatively affect electricity system operations. These interactions create technical challenges and negative externalities that minimize the effectiveness of current policies at reducing GHG emissions.

**Keywords**: Electricity policy; Abatement policy; GHG emissions; Renewable Energy Technologies

# Dedication

For my parents, Jane Pickering and Adrian Domareski

# Acknowledgements

I owe everything to my mother and father, thank you for your continuous support.

I would like to thank my supervisor Nancy Olewiler for all of the wise advice she gave me throughout the course of the writing of this thesis, and for reading its various iterations. Nancy's guidance was central to the completion of this thesis. Thank you Nancy. I would like to thank Dominique Gross whose comments and suggestions on several aspects of this thesis improved it, and for helping me to learn about econometrics. As well, I would like to thank Marvin Shaffer, John Richards, and Jonn Axsen for helping to broaden my knowledge of economics, energy and public policy.

I would like to thank Dr. Anil Hira, Dr. Peggy Meyers, and Dr. Dimitris Krallis for supporting my application to the School of Public Policy. Especially, I owe a debt of gratitude to Andy Hira for teaching me the importance of applied social research for policy, and whose counsel has been important to any success I have or will have as an analyst. Thank you Andy, you are a true friend.

For my class mates in the 2011 cohort, School of Public Policy I am glad to have shared two totally excellent, albeit exhausting years with such wonderful people. I am especially grateful for the friendship of Robert Lutener, Pomme Arros, Connor Curson, James Knowles, Toby Stewart, Mallory Crew, Tabrina Clelland, the artist formerly known as Conrad, David Lin, Sandip Basi, Eric Warren, Trisha Subito, James Cousins, Tessa Cheng, Darius Pruss, and Anthony Carricato.

To Robin Downey, I owe a special thank you for taking a chance on me.

Finally, for Sophie, her patience and support for me has been indefatigable through two years of the MPP, and two major research efforts.

# Table of Contents

# List of Tables

# List of Figures

# Glossary

**Baseload capacity** – Generating capacity which runs all the time and provides the ‘base’ supply of electricity to meet electricity demands.

**Bundled vs. unbundled electricity** – Demand for ‘green’ power in the U.S., has created a market for electricity generated from renewable sources. If the electricity source meets certain regulatory criteria, it is eligible to qualify for credits in other jurisdictions. Electricity from this source can then be sold to utilities in the regulated market for compliance purposes with the credits (bundled), or the electricity can be sold separately from the credits (unbundled).

**Capacity factor** – The percentage of a power plant’s total operating capacity that is used. For example, a plant might have a 100 MW capacity with a ten percent capacity factor the facility would produce 10 Mwhs of electricity.

**Carbon leakage or stringency effects** – If regulations in one jurisdiction are more stringent than those in others, investments and facilities may choose not to locate in the jurisdiction with the more stringent regulations. When environmental policies are involved the result may not be the intended reductions in pollution, but merely migration of it to other jurisdictions.

**Congestion** – When the transmission capacity (the maximum ‘amount’ of electricity that can flow through the line) equals the ‘amount’ of electricity flowing on it, a line is said to be congested.

**Dispatch rights** – Certain electricity system rules or financial mechanisms may give a generator a right to send its electricity into system. An example of such rights is Germany’s rules giving rights to renewable electricity generators to have priority access to the grid during peak hours.

**Distributed or nodal or locational markets** – Each generator, industrial facility and distribution point represents a location or node in the electricity market. The market is thus based on the number of and types of nodes and trade between them.

**FERC reciprocity** – A rule requiring that in order for a utility to sell electricity into a market with open access to its transmission system, the jurisdiction of the seller must have the same level of openness, i.e., ‘fair trade’ over ‘free trade’.

**Financial transmission rights** – These are a class of financial mechanisms which distribute compensation between market participants when congestion or other technical constraints create rent seeking opportunities in electric power markets that would unfairly favour one participant over another.

**Independent system operator or regional transmission organization** – A non profit organization with responsibility for balancing the system, coordinating trades, and clearing electricity spot price markets in competitive electricity markets.

**Installed capacity** – The total operating capacity of a given power plant. It is usually measured in megawatts.

**Loads** – The 'load' on the system is the amount of electricity demanded by end-users

**Merchant transmission planning** – A model of transmission planning where the private investors instigate construction of for profit transmission systems.

**Net metering** – A policy allowing consumers, particularly residential and commercial customers, to install small scale generation and sell any power they do not consume back on to the transmission system.

**Open access transmission tariff (OATT) '*pro forma*'** – A price for use of the transmission system which is the same for all participants. Such a tariff is the back bone of FERC order 888. The '*pro forma'* refers to how the rules should be adopted and applied in the same manner in all jurisdictions.

**Operating reserve requirements** – In an electricity system, there is always a concern that a sudden surge in demand could overwhelm the system. To reduce this prospect, regulators require utilities to maintain excess generation on standby in the event of a surge. The standby generation is usually coal or natural gas, as a result the percentage of standby generation can significantly increase emissions; particularly, during peak times.

**Peaking capacity or marginal generator** – A generator which is required to provide extra support to the system in the case of a surge. The electricity is almost always generated from natural gas during peak times. As result of these circumstances, this 'peaking capacity' is said to be the marginal generator, as the generation is sent into the system on the margin of system operations.

**Public contest method** – A method of planning investments in which the construction of additional transmission capacity is placed out to tender, and beneficiaries vote on whether to fund the new project.

**Pooling arrangements** – Multiple utilities may decide to combine certain parts of their operations in order to realize scale economies in their business operations. Thus, they 'pool' their respective resources.

**Power purchase agreements** – Usually, these are auctions that result in contracts between market participants to purchase electricity from a given generator or group of generators.

**Renewable energy credit or tradable renewable energy credit** – A financial compliance mechanism representing the production of electricity from renewable sources. Eligibility of a given source is usually determined by regulatory fiat. These mechanisms are usually used to comply with renewable portfolio standards. There are also voluntary credits that companies can purchase in order to claim they have 'green' electricity.

**Renewable portfolio mandate or standard** – A regulatory policy requiring a certain percentage of a utility's generation mix to contain certain technologies, usually electricity generated from small scale renewable sources.

**Resource shuffling** – This involves a simple arbitrage game where power generators purchase electricity from renewable electricity sources, such as hydroelectricity, and sell it to markets with portfolio standards, while purchasing electricity from emitting sources to balance the system in the arbitrageur's market. The difference between the cost of the renewable electricity and the 'dirty' source represents the rents. The California Air Resources Board (CARB) required any utility meeting regulated import requirements about green power to sign a contract stating they did not 'shuffle resources'.

**System costs** – Actions on the part of market participants or technical operating decisions can inadvertently raise the cost of operating the system. Such costs can be imposed on the responsible participant or generator, or be socialized across all users.

**Transmission reliability margins –** These represent the amount of additional transmission capacity available to the system operator in the event of a sudden need for access to new generation capacity from an uncongested line. In the Alberta case, this presents the amount of transmission capacity shared with Saskatchewan and Alberta.

**Wind ramping rates –** This is the amount of wind electricity that is generated in a given moment. It is usually used to refer to the variation from moment to moment in the production of electricity. A ramping rate can be thought of as the amount of electricity produced in at a given time from a given facility. Higher ramping rates measure how fast the generator can reach the required level of electricity production.

# Executive Summary

Federal and provincial greenhouse gas (hereafter GHG) policies have relied on subsidies for renewable power producers as their primary abatement mechanism to reduce emissions from the electric power industry. These policies are designed and implemented upon the premise that increasing the penetration of their chosen technologies will result in the displacement of Canada’s sizeable coal and natural gas generation fleet. However, these subsidies create price distortions in electricity markets that negatively interact with the efficient functioning of the system. Designing electricity policy is difficult in Canada due to the constitutional division of powers that grants primary responsibility for electricity regulation to the provinces, but international and interprovincial trade powers to the federal government. Simultaneously, as Canada is a large exporter of electricity to the United States (hereafter U.S.), the autonomy of provincial governments is constrained by trade rules set by the Federal Energy Regulatory Commission (hereafter FERC).

The overarching policy problem is that there is a clear deficiency in GHG abatement policies and flawed market designs, which do not create incentives to shift investment towards diversified, low carbon generation portfolios. The study analyzes this problem with two research objectives in mind: assess the effectiveness of provincial and federal government policy at reducing GHGs; and, explore the effects of these policies on electricity markets and system operations. The effectiveness of renewable power support policies is analyzed using an econometric model to ask the research question, *do Canadian renewable electricity policies reduce GHG emissions from the electric power industry?* The second objective is completed by applying a case study analysis to explore the effects of the current regime on electric system operations. The results of these analyses are used to propose policy options to improve efficiency and incentives to mitigate GHG emissions.

The research undertaken in support of this study uses a statistical analysis and case studies to analyze the current basket of renewable policies and discern options to address the incentive problem. An econometric analysis of federal and provincial level renewable electricity policies is used to evaluate their effectiveness at reducing GHG

emissions from the electric power industry. The quantitative analysis is supplemented with case studies to control for explanatory factors not addressed directly in the econometric analysis. Reducing GHG emissions from electric power requires policies that can meet abatement targets, while satisfying complex technical constraints related to system operations. Many of the policies that might seem conceptually to be effective, such as increasing the rate of renewable electricity generation, can interact negatively with system operations and the function of electric power markets. This is a complex area of study, which requires policy designs recognizing the importance of incentives and price signals, technical aspects of system operation, and the goal of meeting abatement targets. As a result, the policy options proposed in this study are related to market design and transmission planning, issues which are often ignored in government discussions about abatement.

Following the example of Prasad and Munch (2012), the econometric analysis uses a panel least squares model with provincial fixed effects to study the effects of provincial and federal renewable energy policies on GHG emissions from electric power in Canada from 1990 to 2010. The data analyzed for this study have a number of problematic statistical issues, such as individual and common unit roots and serial correlation. Nonetheless, the results of the econometric analysis suggest that provincial policies, U.S. regulatory and green power policies, as well as economic and demographic factors have had little effect on GHG emissions. The main federal subsidy programs - *Wind Power Production Credit* and the *ecoEnergy for Renewable Power* – are found to significantly decelerate the rate of GHG emissions from electric power. While, these results are useful for discerning the effects of government policies, statistical analysis of GHG emissions does not provide much insight into how abatement policy interacts with electricity systems.

In order to study the effects of government subsidy programs on electric power systems and competitive electricity markets a case study comparing Alberta and Texas is undertaken. The comparison of Alberta and Texas is useful as both jurisdictions share a number of commonalities including: competitive electricity markets; energy intensive industries; a large fleet of coal and natural gas electricity generators; and, both jurisdictions are the leading emitters of GHGs in their countries. Additionally, both jurisdictions have similar federal subsidies that contribute to high renewable penetration rates, but little impact on GHG emissions. The cases differ in the specifics of the policies: Alberta has a GHG abatement policy, *Specified Gas Emitters Regulation,* while Texas has a renewable portfolio regulation. By examining the differences in these similar jurisdictions it is possible to reach a number of important conclusions with implications for policy. The key findings reveal that though government subsidies may increase the renewable penetration rate, emissions reductions only occur up to a certain penetration threshold. Such subsidies create distortions in electric system operations. The net effect in Texas and Alberta has been that transmission expansion has not kept pace with generation investment, and the result is grid congestion and heightened system costs.

The study concludes with a discussion of the interaction of abatement policy and electrical system operations, and a review of the literature on that subject. It notes the sizable short comings of government subsidy programs for renewable power and energy efficiency, and finds that a carbon pricing mechanism is essential for the success of any abatement efforts. While carbon pricing is a requisite for mitigating GHG emissions, the literature indicates that technology neutrality and minimizing negative electric system externalities are important features of any successful mechanism. On these grounds a number of policy options are proposed to address electricity industry GHGs. These options include: the status quo; encouraging transmission interconnections between provinces; enhanced load management; participant driven transmission planning; and reform of existing tax expenditures. These policy options are analyzed using a range of government and technical criteria including: budgetary cost; stakeholder acceptability; compliance with U.S. FERC trade rules; and technology neutrality. The policies recommended for immediate implementation are enhanced load management, participant driven transmission planning, and reforms to existing or recently eliminated renewable power programs. A longer term policy consideration is exploring the possibilities for increasing transmission capacity between provinces with large thermal generation fleets and those with hydroelectricity dominant generation mixes.

# 1. Introduction

Most of the greenhouse gas (GHG) emissions from Canada's electricity generation originate from burning fossil fuels. Displacing this conventional generation capacity with renewable electricity could allow Canada to diversify its national electricity generation portfolio and reduce greenhouse gas (GHGs) and criteria air contaminant emissions from the electricity industry. Renewable electricity policies are a relatively new phenomenon in Canada, but there is a large body of literature from the U.S. that has suggested provincial or state, not federal action may be the key to advancing successful electricity policy (Carley, 2011). It has been conjectured that Canada's resource potential is capable of achieving "an almost all-renewable Canadian electricity system, which could even export electricity to the United States, [and] appears entirely feasible" (Grubb and Meyer, 1993). This vision of the electric power industry in Canada is disconnected from a reality in which renewable energy expansion faces technical barriers to integration and a clear lack of incentives to invest in low carbon technologies. Deficiencies in such incentives are attributable to the lack of an effective carbon pricing scheme and provincial market designs, which are in essence crown owned, vertically integrated utilities governed by fixed rate regulation. These policy regimes operate under trade rules imposed by the United States (U.S.) Federal Energy Regulatory Commission (FERC) and are influenced by provincial concerns about regulatory autonomy from the Government of Canada (federal government). The result is that Canadian abatement policy in electric power has been ineffectual.

The core problem facing provincial governments in electricity policy is a clear deficiency in GHG abatement policies and flawed market designs, which do not create incentives to shift investment towards diversified, low carbon generation portfolios. This overarching failure is linked to three key failures in market design and electric system operation. First, highly centralized transmission planning does not provide adequate dispersion of costs and benefits amongst system participants, and this creates potential for deadweight loss and operational inefficiencies. Second, price signals in vertically integrated markets are linked to utility costs and regulatory dictums, not the full marginal costs of production including environmental impacts.  The result is inadequate demand management. Finally, the status quo policy approach in most provinces relies on costly renewable subsidies and portfolio mandates, due in large part to the absence of appropriate pricing and incentives. The result is inefficient investments in transmission and generation technologies which create technical issues such as grid congestion.

This study has two research objectives: assess the effectiveness of provincial and federal government policy at reducing GHGs from electric power; and, explore the effects of these policies on electricity markets and system operations. A statistical analysis and case studies are applied to analyze the current basket of renewable policies and discern options to address the incentive problem. An econometric analysis of federal and provincial level renewable electricity policies is used to evaluate their effectiveness at reducing GHG emissions from the electric power industry. The quantitative analysis is supplemented with case studies to control for explanatory factors not addressed directly in the econometric analysis. Reducing GHG emissions from electric power requires policies that can meet abatement targets, while satisfying complex technical constraints related to system operations. Many of the policies that might seem conceptually to be effective, such as policies to increase renewable electricity generation, can interact negatively with system operations and the function of electric power markets. This is a complex area of study, which requires policy designs recognizing the importance of incentives and price signals, technical aspects of system operation, and the goal of meeting abatement targets. As a result, the policy options proposed in this study are related to market design and transmission planning, issues which are often ignored in government discussions about abatement.

# 2. Background: Electricity generation, GHG emissions, and technical complexity

## 2.1. Canada's Electricity Generation Industry, Renewable Energy and Greenhouse Gas Emissions

Canada has a poor reputation as an emitter of GHGs, thanks in large part to inaction by successive federal governments on the implementation of effective abatement policy. Recent events such as the federal government's decision to pull out of the Kyoto Protocol, sends a clear signal that Canada will continue to shirk its climate obligations. This lackadaisical record has made Canada the third highest emitter amongst Organization for Economic Cooperation and Development (hereafter OECD) countries in 2010, and ranks it fifteenth of the seventeen member countries in per capita emissions (Conference Board of Canada, 2013). Further, the average Canadian is responsible for emitting 20.3 tonnes of GHGs in 2010 (Conference Board of Canada, 2013). While Canada has a number of sectors and industries that are large emitters, amongst them the worst is the petroleum extraction industry, but electric power is one of the most persistent. Electricity is also central to the prosperity and success of Canada's economy.

The electricity industry is an important contributor to the Canadian economy, accounting for an average of $25.5 billion[1] per annum between 2004 and 2009, while employing 92,000 people in 2010 (Nyboer and Kamiya, 2012). The Canadian electricity industry includes both industrial cogeneration and public utility segments and has a diverse mix of electricity generation sources including thermal generation, and small

---

[1] Chained 2002 Canadian dollars.

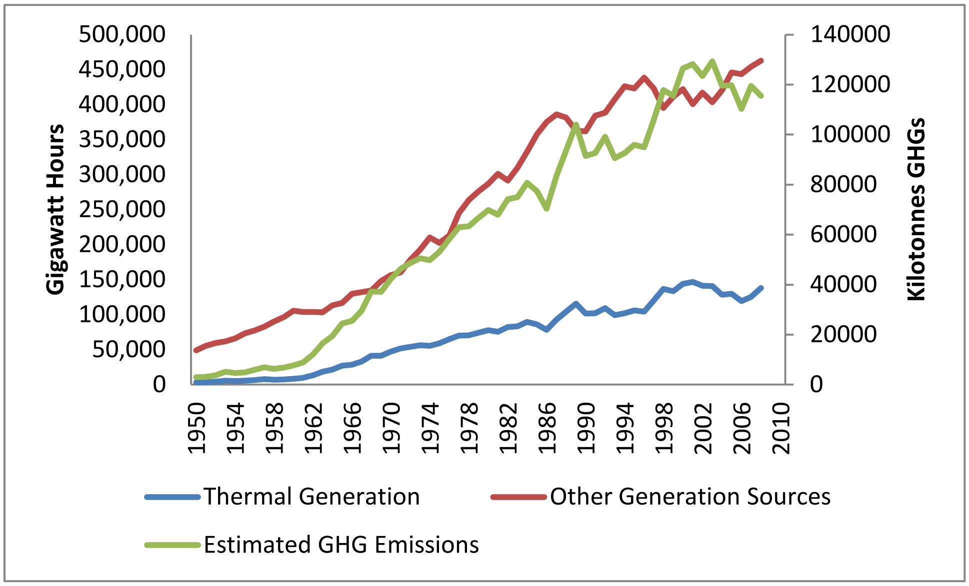
scale renewable facilities (Nyboer and Kamiya, 2012). Overall it is dominated by hydroelectricity (Nyboer and Kamiya, 2012). Between 1990 and 2010, the industrial cogeneration[2] segment of the electricity industry has been a large emitter of GHGs. GHG emissions grew 251 percent and the sector used 43 percent of total fossil fuels consumed in the production of electric power (Nyboer and Kamiya, 2012.).[3] In 2010, natural gas use represented approximately 64 percent of fossil fuels consumed within the electricity industry (Nyboer and Kamiya, 2012.). Overall, the use of fossil fuels in electricity generation has increased compared to hydroelectricity and other forms of generation (Nyboer and Kamiya, 2012.). As well, data presented in Figure 2.1 demonstrate the extensive and accelerating trend in GHG emissions from electricity generation. Despite this trend, data presented in Figure 2.2 demonstrate that installed capacity in renewables has increased slightly, indicating growing capital investment in this segment of the industry to meet rising demand for renewable power, potentially from U.S. markets. Investments in small scale renewable electricity have largely focused on wind and biomass development driven by generous subsidies, as the generation data presented below in Figure 2.3 show.

---

[2] Industrial cogeneration plants are built onsite to provide electric power directly to an industrial facility. Onsite generation is especially common at facilities in the aluminium, pulp and paper, and in petroleum extraction industries. Two excellent sources on this subject in Canada are Nyboer et al. (2011), and LeBlanc and McColl (2006).

[3] Over the period of 1990-2010.

***Figure 2.1 - Electricity Generation by Source and Estimated GHG emissions, 1950-2008*[4]**

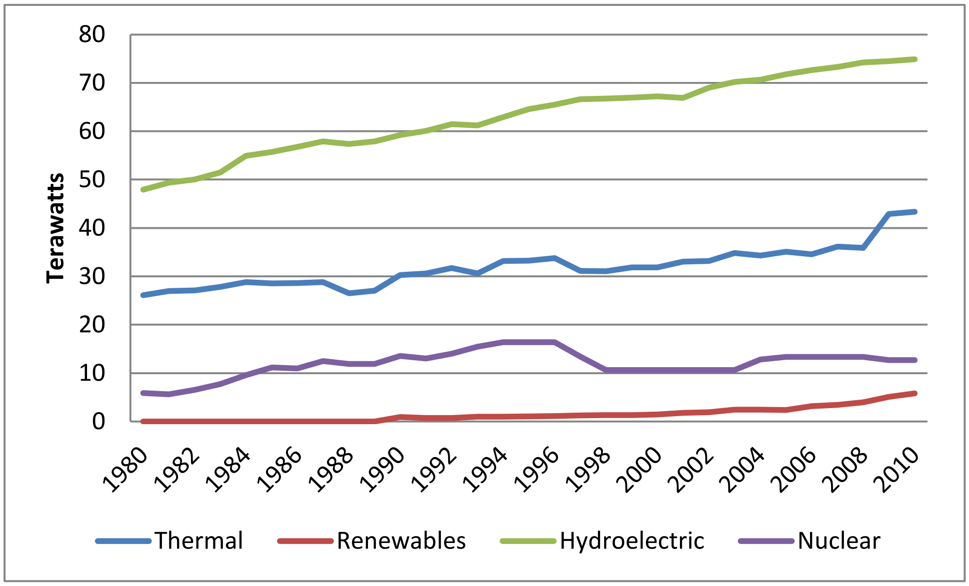


Source: Table 127, Statistics Canada

---

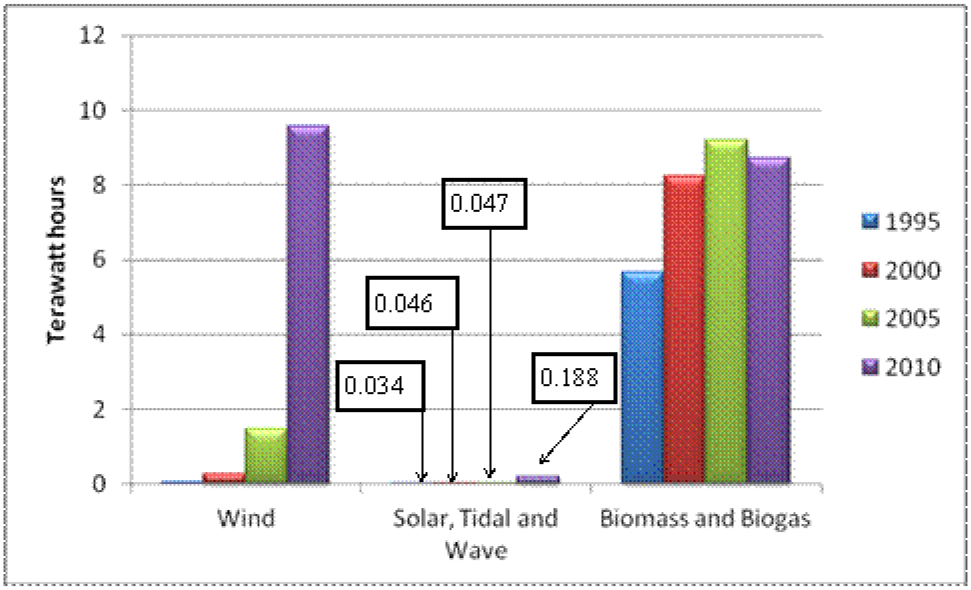
[4] 'Estimated GHG Emissions' is a calculation I performed and that is intended to approximate emissions across the years of 1950-1990 for which there is no publicly reported emissions data. The GHG emissions data for electricity generation from 1990-2008 were divided by the thermal generations data for each year for the same period. This calculation yielded an emissions intensity factor for each year. These were averaged and yielded a factor in kilotonnes per gigawatt hour of approximately 0.898. This factor was then assumed to be constant over the period of 1950-1990, and the factor was multiplied by the thermal generation data for the each given year over the specified period.

***Figure 2.2 - Installed Electric Generation Capacity by type, 1980-2010***



Source: International Energy Statistics Database,
U.S. Energy Information Administration

***Figure 2.3 - Small scale generation, Canada, Snapshots (1995, 2000, 2005, 2010)***



Source: International Energy Statistics Database,
U.S. Energy Information Administration

Though there has been an increase in the penetration rates of small scale renewable electricity capacity and generation, the stark trends in emissions and thermal generation presented in Figure 2.1 pale compared to the alternatives. Indeed, in 2005 electric power produced 121 megatonnes of carbon dioxide equivalent gases ($CO_2e$), accounting for sixteen percent of national emissions (Canada. Environment Canada, 2012). Thermal generation from coal in the baseload generation mix is the central source of GHGs, as it emitted 92 megatonnes or 78 percent of electricity emissions in 2010 (National Energy Board of Canada, 2008; Norton Rose OR LLP, 2011). Though overall electricity emissions declined in 2010 to 99 megatonnes, they persistently represent fourteen percent of national emissions, and on average coal represents about thirteen percent of the generation mix (Norton Rose OR LLP, 2011; National Energy Board of Canada, 2008). The persistent presence of coal is due in large part to the fact that it is a cost-effective and familiar technology that is consistent and reliable at delivering electricity. Despite these favourable characteristics, its continued use represents a marked failure of abatement policy.

Most of the action on abatement policy in North America has been by state and provincial governments whose central strategy to reduce emissions from electricity generation through subsidies and regulations that promote renewable energy sources. The implementation of climate policies in both the United States and Canada has been stalled at the national level because of political gridlock surrounding perceived economic risks and scientific uncertainties. Further, there is a growing body of academic literature and policy analysis in the United States on the effectiveness of state level renewable energy policies. Many of these studies use regression analyses or computational simulation models to assess the impacts and effectiveness of different state-level policy packages. However, a scan of energy and climate policy literature in Canada reveals that there is a dearth of analysis. While, there is a relative lack of academic literature in Canada, there are a number of policy analyses undertaken by non-profit groups, and government agencies examining the role of provincial level climate policies (NRTEE, 2012; Holmes, 2012). Many of the forecast future reductions have been attributed to provincial policies targeting the electricity sector, especially Ontario's pending closure of its coal-fired power plants (Canada. NRTEE, 2012). However, recent reductions have been attributed to the economic downturn since 2008 (Canada. Environment Canada, 2012).

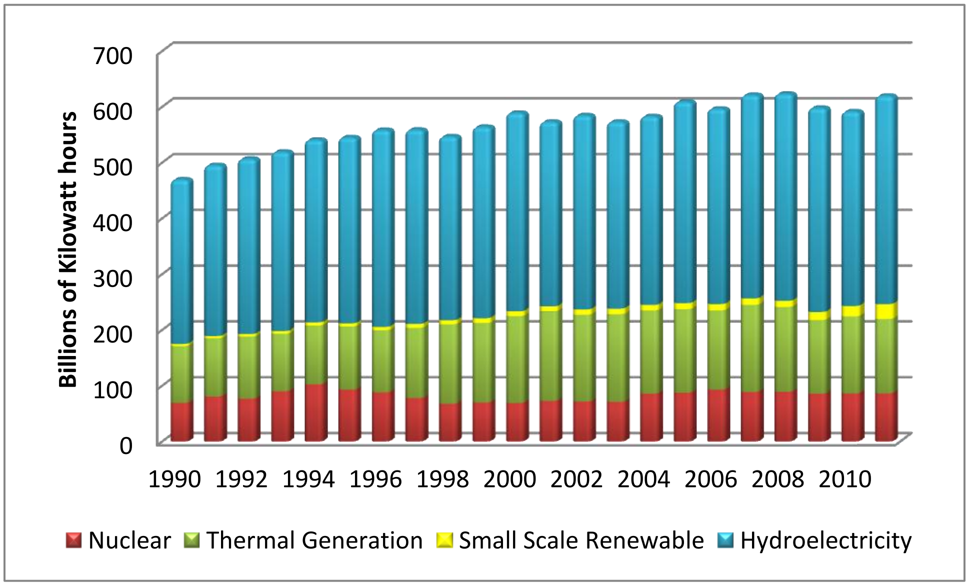
Untwining the effects of provincial policies from economic volatility is empirically difficult, but important for climate change policy. This causal complexity increases uncertainty about whether predictions of future emissions reductions are attributable to the current policy stance in Canada or fluctuations in economic growth. Further, initial assessments of renewable energy programs have focused on the contribution of the policies to broader sustainable economic development and increases in clean electricity capacity, not the ability of the policies to reduce emissions. In part, the lack of focus on emissions is due to the complexities of the electric power industry and difficulties quantifying thermal displacement by renewable sources. As a result, insights from the literature, particularly the economic analyses, tend to focus on penetration rates.[5] The findings suggest that the effectiveness of renewable energy policies has been limited because of the small market share of renewable energy technologies. Notably,

---

[5] A penetration rate is the percentage of market share that a given technology has in the generation mix in a given year.

renewable electricity does not appear to have made a significant historical contribution to reductions. For example, in 2005 it represented only 0.3 percent of the national generation capacity (Canada. Environment Canada, 2012). The lack of penetration is apparent in the trend in Figure 2.4, which presents data from the United States Energy Information Administration (EIA) on generation in Canada. Growth in the penetration rate of renewable energy sources is expected to remain relatively low, as projections indicate it will represent only six percent of the national generation mix in 2020 (Canada. Environment Canada, 2012). This low penetration rate may be the reason current policies have not reduced emissions.

***Figure 2.4 - Electricity Generation by Source, Canada, 1990-2011***



Source: International Energy Statistics Database, U.S. Energy Information Administration

## 2.2. Canada's Renewable Energy Resource Potential

Development of renewable resources for electricity generation could help to reduce emissions from the electricity sector by displacing coal and natural gas capacity. There are six major sources of renewable energy for which established or developmental electricity generation technologies exist and for which provinces in Canada have significant potential resources to develop. These sources include: biomass; geothermal; solar; small scale hydroelectric; tidal; and, wind. Amongst these energy sources, wind, tidal and solar are said to be *partially dispatchable,* and biomass, geothermal, and small scale hydroelectric are said to be *dispatchable* (IPCC, 2011). A dispatchable resource is one that is not intermittent and can be stored before generation occurs and produced as needed. Partially dispatch resources are intermittent and can be more difficult and costly to store.

Canada's potential resources in each of the listed sources are enormous, but there are major challenges facing the viability of each as a renewable electric power source and displacer of thermal base-load capacity. Canada's large forested regions and agriculture landscapes mean there is significant potential to develop biomass energy, but there are technical and economic challenges to effectively reducing GHGs (Manomet Center for Conservation Sciences, 2010; Bates et al., 2009; Stennes et al., 2010). Much of the geothermal resource potential is concentrated in western Canada, but development has been slow due to a lack of attention by regulators.[6] Studies have found that Canada's solar resource potential could help to meet a large swathe of electricity demand, and high physical production potential exists throughout western and central Canada, particularly in Ontario (Pelland et al., 2006; Wiginton et al., 2010). There are approximately 8500 potential small-scale hydro sites in Canada, which represent 31,000 MW of potential installed capacity (CANMET Energy Technology Centre). Tidal and wave energy potential is large, and one study suggests could be as high 183.5 GW of

---

[6] Only British Columbia and the Northwest Territories have permitting processes (Holroyd and Dagg, 2011).

installed capacity, but development has largely focused on demonstration projects (Cornett, 2006). Data presented in Figure 4 shows that development of Canada*'s* abundant wind resources has been increasing, but problems with intermittency have raised concerns about the viability of the resource (Gil et al., 2006). A detailed synopsis of each key renewable energy source in terms of its resource potential and the availability of technology is presented in Appendix D.

A number of provinces have a large renewable resource potential that has gone undeveloped. There are two central reasons for this; first, the estimates above assess total potential capacity and do not consider the amount that is technically feasible, socially acceptable, or economically viable to develop. Second, provincial level policies targeting renewables are a relatively recent event.

## 2.3. Technical Barriers to the Economic Viability of Renewable Electricity

Managing the development of renewable electricity resources is complicated by the technical barriers that shape economic aspects of electricity generation. The key technical-economic barriers to successful renewable resource development relate to: variability of costs; the intermittency of generation, and, limited access to transmission systems. Levelized unit costs of electricity generation[7] vary by project and region due to the quality and type of renewable resources available, electricity market structure, and government regulatory policy. For instance, a study by the United Kingdom's Energy Research Centre found that unit costs were highly variable from country to country due in part to differences between regulatory policies (Heptonstall, 2007). Despite this variability, a review of the unit cost literature by Borenstein (2011) found that the

---

[7] Unit cost for electricity generation, reflects the costs of capital investment, operations and maintenance for a given technology and project over the life of the project, discounting future costs. The sums of these costs are presented on a per unit of production basis, usually as dollars per kilowatt hour or megawatt hour.  These are often called levelized costs by the industry.

production costs of wind, small scale hydropower, and biomass are consistently competitive with natural gas and coal.[8] This suggests that regulatory policy and market regimes are as important for investment decisions as capital cost competitiveness. Further, 'ballpark' cost estimates such as levelized unit costs require more detailed analytical techniques, such as investment analyses to design appropriate decarbonization and renewable investment policies (Gross et al., 2010).

While renewable electricity may be cost competitive when measured by unit costs, this is not the best metric to assess the social efficiency of investment in renewable energy because it is an average cost. Unit costs for electricity build in the capital, operating and maintenance costs of generation, but they do not include important factors such as transmission and distribution costs (IPCC, 2011).[9] Nor do unit costs account for important financial metrics such as internal rates of return or returns on capital (Gross et al., 2010). Indeed, cost estimates for electricity generation investments both from social and financial perspectives are difficult to make accurately and with certainty because of the large number of factors that influence cost. The result is investment decisions influenced by a range of factors, including: "[the] degree of capacity utilization, exercise of market power and the supply/demand balance in the equipment and installation markets, retail price may be above or below long-run marginal cost of production and distribution of a given technology" (Borenstein, 2011). The viability of investment in renewable electricity generation in the long run is then subject to the interactions between intermittency of generation, spot market price fluctuations, and transmission issues. This set of challenges is particularly acute for wind or photovoltaic solar collection. Both technologies are intermittent and may require

---

[8] It should be noted that Borenstein's study only reviewed U.S. studies, and the U.S. has one of the most liberalized electricity markets in the world and the lowest unit costs for renewable electricity generation. This makes U.S. estimates problematic for comparison to Canada because, as the Heptonstall (2007) study notes, renewable generation costs can vary both because of regulation and local resource conditions.

[9] See Annex III of the IPCC report.

storage capacity if the installation is intended to help meet peak electricity demand.[10]

The third key techno-economic barrier to effective renewable electricity policies is access to transmission systems. Most transmissions systems in Canada are focused around load centres or connect to key hydroelectric facilities in remote locations. Transmission systems in most Canadian provinces are in practice vertically integrated and owned by crown corporations, and access to transmission systems can constrain the viability of remote renewable resource sites (Grubb and Meyer, 1993). Indeed, much of the early interest in renewable energy in Canada focused on providing electricity in remote, rural settings, and this is still seen as an important use for it (Grubb and Meyer, 1993; IPCC, 2011). As well, one of the main constraints to renewable electricity development is the underlying capital cost associated with incremental construction of new transmission lines to access the power (Coad et al., 2012). Further, intermittent resources can create uncertainty about aligning investments in generation and transmission capacity (Coad et al., 2012).[11] Indeed, it is well established in the literature that there is a penetration threshold for renewable rates past which risks for system reliability become a concern (Gross and Heptonstall, 2008). The issues of wind penetration and system reliability are discussed at greater length in the sections presenting the case studies.

---

[10] Referring to rooftop solar collection, Wiginton et al. note on page 355 that: “without storage this is only possible if the peak hours of the sun correspond with the instance of peak demand.”

[11] Coad et al. (2012) notes on page 3 that: “the potential for a mismatch between the generation investments assumed and the transmission investments that will be required to integrate long-term future generation projects into the grid. This mismatch would likely be greatest in jurisdictions where a significant portion of future generation investments is in wind and solar and the existing grid is designed primarily around thermal generation sources. The cost of integrating these variable sources is subject to uncertainty...”

## 2.4. Bridging the Gap between Renewable Electricity Policy Design and Decarbonization

Policy supports for renewable electricity generation have not effectively reduced emissions from electric power because they are obliquely designed to increase market penetration rates. The result is that policy has focused on technical solutions, ignoring the need to directly penalize emissions. Indeed, the IPCC report (2011) cited in this study focuses on renewable penetration rates as part of a "transition to a low-GHG economy" in a rhetorical frame of sustainable development. Electricity policies designed to target support for renewable power, but neglecting GHG abatement work upon the presumption that this approach will eventually and miraculously reduce emissions. Advocating for renewable resource development for the vague purpose of transitioning to a sustainable economic system is primarily rhetorical. Such policy mechanisms expressly ignore the real need for concerted action to abate emissions and are second best to an effective carbon pricing scheme. This reality is echoed in the empirical literature on renewables policies in the U.S., which has focused almost exclusively on evaluating policy effects on penetration rates (Adelaja et al., 2010; Carley, 2009; Delmas and Montes-Sancho, 2011; Menz and Vachon, 2006; Prasad and Munch, 2012). A brief review of these articles demonstrates the limited effectiveness of renewable electricity mechanisms at reducing GHG emissions. There are several reasons for the poor performance of the policies, including their failure to address abatement issues directly, lack of technological neutrality,[12] and insufficient incentives to substitute between generation investments. The only empirical study of electric power emissions and renewable policies in the U.S. has found that the sole mechanism effective at reducing

---

[12] This a form of horizontal equity in which a policy does not favour a particular technology. Thus, if a policy is not technologically neutral it does not treat all technologies equally. This point is important for electric power markets where technological neutrality is important for assuring that incentives for investments are not misaligned. It is particularly problematic where technologically specific subsidies are concerned, such production subsidies; there is a large potential for distortionary effects.

GHG emissions are public benefit funds (Prasad and Munch, 2012).[13] Public benefit funds levy a fee on utility customers' bills and then apply the funds raised to finance energy efficiency improvements. This finding demonstrates that mechanisms linking GHG emissions to electricity production can lower emissions.

There are a number of reasons why most governments in North America have not followed the clear lesson that a price on GHGs is the most effective path to mitigate emissions from electricity, but have favoured policies supporting small scale generation technologies. While adoption of renewable electricity policies in the U.S. has been partially motivated by partisan politics, support policies are seen as a way to reduce barriers for renewable technologies (Lyon and Yin, 2010). Policies designed to make renewable electricity economically viable fall into four general classes: financial and fiscal incentives;[14] mandatory rules and regulations;[15] grid access laws;[16] and, generation disclosure and certification (Menz and Vachon, 2006). Table 2.1 presents a classification of renewable energy policy mechanisms. **[17]**

The U.S. body of empirical research indicates that policy mechanisms are designed to provide solutions for specific barriers to project development, and in some cases may be part of a comprehensive renewable energy development plan. The

---

[13] The coefficient for the public benefit fund was large and the sign was negative and indicated that a one increase in the surcharge on the customer's bill resulted in an average decrease in GHG emissions of 2 million tonnes.

[14] Such policies have been mainly production subsidies or tax expenditures, and these have been the favoured choice where the main barrier to renewable electricity development is construction or production costs (Bradley, 2005). However, the application of subsidies and loan products does not discourage GHG emissions (Carley, 2011).

[15] Renewable portfolio standards are the other regulatory mechanism most widely deployed in the United States. Portfolio mandates are explicitly designed to increase renewables electricity generation, but the American literature has found that they do not displace thermal generation (Carley, 2011). Mandate mechanisms pose a number of policy challenges including creation of a stringency effect, where industrial investment migrates to neighbouring jurisdictions in order to avoid compliance (Carley, 2011).

[16] Net metering, grid access and interconnection laws have all been implemented broadly by American states and studies have shown they have the potential to reduce barriers to grid access (Carley.2011).

[17] This material is drawn from Menz and Vachon (2006).

justifications for the implementation of such policies can be broadly categorized into three tranches: “decarbonization, diversification, and decentralization” (Carley, 2011). In the U.S. and increasingly in Canada, jurisdictions have implemented flexibility mechanisms, such as tradable renewable energy credits (Sustainable Prosperity, 2011). However, energy credits in Canada are largely voluntary and the degree to which investment has been driven by U.S. demand is difficult to determine (Sustainable Prosperity, 2011). As well, the selection of policy mechanisms is highly dependent on the barriers faced by renewable electricity developers. However, these policies appear to be designed to reduce the cost of compliance for individual utilities in jurisdictions with portfolio mandates, they do not directly address emissions. Other proposals to address the deficit of climate policies include adapting existing renewable mechanisms.[18] In either case, current renewable energy policies create inefficiencies in energy markets and interfere with electricity system operations (Hogan, 2010). As well, these policies appear to be trendy solutions to climate change, which is reflected in the *ad hoc* nature of their adoption. Preferably, electricity policies should be technology neutral with incentives targeted to shift generation investments to reduce carbon intensity and emissions. Simultaneously, such policies must recognize the importance of system operations.

---

[18] For instance, portfolio mandates could be modified to require utilities to make *quid pro quo* or non proportional reductions in GHG emissions simultaneous with increases in renewable electricity penetration (Carley 2011). Another example comes from Alberta where, qualifying renewable electricity generators can register as offsets under the *Climate Change and Emissions Management Act* (Government of Alberta).

*Table 2.1 - Renewable Electricity Policy Mechanisms*

| Class of Policy Mechanism | Mechanisms |
|---|---|
| Financial and fiscal | Tax exemptions, deductions, grants, subsidies, guaranteed or preferential loans, and production incentives |
| Mandatory rules and regulations | Renewable portfolio standards, and tradable renewable electricity credits to meet portfolio requirements |
| Disclosure and certification | Fuel and emissions generation disclosure agreement, voluntary or mandatory certification of the type and amount of renewable energy in the utility's generation mix, mandatory green power options, |
| Other | Allowing customers to purchase renewable power (only in competitive markets) |

Sources: Menz and Vachon (2006)

## 2.5. Renewable Electricity Policies in Canada and the U.S.

### *2.5.1. Federal Role in Canadian Energy Markets and Renewable Electricity*

The federal and provincial governments have the main responsibilities for energy and electricity policy. The federal government has two primary roles in governing electricity policy in Canada. The first is through its right to regulate interprovincial and international trade under article 91.2 of the *British North America Act of 1867.* The most recent functional legislation consolidating this role is under the *National Energy Board Act of 1985*. The latter legislation gives the primary responsibility for electricity regulatory policy to the National Energy Board of Canada, and the Ministry of Natural Resources has overall responsibility for federal energy policy. The other federal role in energy policy has been enacted through the development of policy supports. Federal support policies have included mechanisms such as: tax expenditures and direct subsidies, funding of technical research, and development of technology demonstration programs (Islam et al., 2004). As well, the federal government has undertaken public information campaigns, streamlining of regulatory policy, and developing standards and training programs (Islam et al., 2004). A list of federal government policies relevant to renewable electricity policy is presented in Appendix E. The federal government's role in the climate change attributes of electricity policy centre on funding direct subsidies and research programs, such as carbon capture and sequestration technology for coal-fired generation.

Most of the major policy efforts by the federal government to encourage the development of renewable electricity capacity are based on recommendations presented in a 1994 report, *Task Force on Economic Instruments and Disincentives to Sound Environmental Practices* (Finance Canada, 1994; Islam et al., 2004). The report recommended that the federal government directly subsidize renewable energy resources in Canada (Islam et al., 2004). The government made direct purchases of power from renewable energy resources from provincial utilities for federal government facilities in certain provinces (Islam et al., 2004).[19] In addition to direct procurement, the federal government has implemented two direct subsidy programs, the *Wind Power Production Incentive* and *ecoENERGY for Renewable Power*. The *Wind Power Production Incentive* program operated from 2002 to 2007 and provided a $0.012 KWh subsidy for electricity generated from onshore wind sources (IEA, 2012). The *ecoENERGY for Renewable Power* program targets most renewable electricity sources and provides a $0.01 KWh subsidy for electricity generated (IEA, 2012).

### 2.5.2. Provincial Role in Canadian Energy Markets and Renewable Electricity

The provincial and territorial governments of Canada are the primary regulators of electricity production, transmission and distribution, mainly through provincial utility boards, and crown utilities. As such, they have primacy in the development of renewable

---

[19] For instance, an ENMAX news release from 2006 states: "[the] agreement calls for ENMAX Energy to supply electricity services to all 938 federal facilities in the province [of Alberta] covering all eleven federal government client departments..." The purchases were made from ENMAX of Alberta, SaskPower of Saskatchewan, amongst others.

generation resources and technology. This means that any increases in renewable electricity generation must occur within the auspices of a provincial jurisdiction. Historically, provincial renewable electricity policy efforts have mirrored and complemented federal government policy initiatives, and have tended to focus on demonstration projects and consumer information programs (Islam et al., 2004). Since 2005, provincial governments have been actively involved in efforts to decarbonize the electricity sector by promoting renewable electricity generation. The policies adopted by provincial governments have increased in complexity and have employed similar approaches as states and utilities in the U.S. A list of provincial policy mechanisms relevant to renewable electricity are presented  in Appendix F.

Provincial government policies vary, employing different combinations of decarbonization regulations and taxes, tax incentives and direct subsidies, mandates, and grid access rules in the form of net metering. Ontario has been the most aggressive in the adoption of renewable energy and decarbonization policies, with a portfolio standard, direct subsidy, and forced closure of its coal fired power plants. British Columbia has imposed a broad based carbon tax and a direct subsidy, the *Standing Offer Program*. Alberta has the only compliance trading market for carbon offsets to date in Canada. As well, it is the only jurisdiction in Canada that allows renewable electricity generators the flexibility of having projects recognized as tradable offsets for compliance with its *Specified Gas Emitters Regulation*. Both Nova Scotia and Prince Edward Island have renewable portfolio standards in place. Amongst all renewable electricity mechanisms, net metering policies[20] are by far the most prevalent with every province in Canada, with the exception of Newfoundland, developing one.

---

[20] Net metering policies allow commercial and residential customers to install small scale generators, less than 1 MW, to provide their own electricity and interconnect to the grid to sell back excess power.

### *2.5.3. The influence of U.S. Electricity Markets and Regulation in Canada*

The formation of electricity policy, specifically transmission policies and market structure, in Canada has been heavily influenced by American interstate and state level regulators. In many cases, the strength of this relationship is such that a number of Canadian regulatory policies are highly limited or made practically irrelevant by American regulatory rulings. Historical context is important to understanding the reasons for the United States Federal Energy Regulatory Commissions' (hereafter FERC) exercise of *de facto* authority over North American electricity trade. Beginning in the 1980s, continent wide moves towards unbundling of provincial and state utility monopolies in natural gas and then electricity converted regulatory agencies from utilities to trade regulators (Saunders, 2001). This shift is particularly important for two groups of actors – FERC and Canadian provincial utility regulators – because in Canada the latter has largely had responsibility for market structure and substantive electricity export policy (Saunders, 2001).[21] Deregulation in the U.S. increased FERC's role in the regulation of interstate and international transmission systems (Saunders, 2001).[22] Both the *Canada-United States Free Trade Agreement* and the *North American Free Trade Agreement* (hereafter NAFTA) were negotiated concomitantly or soon after deregulation became wide spread. However, though NAFTA resulted in changes in energy trade rules with the U.S., trade agreements have exerted little influence over the development of North American regulatory policy of electricity markets (Pineau et al., 2004).

The major North American trade agreements have had limited influence because of the disparate nature of Canadian regulation by provinces and the role of FERC "as gatekeeper to the U.S. market" (Saunders, 2001). FERC has effectively asserted its authority, despite the likelihood that FERC decisions violate international trade law (Saunders, 2001). Three FERC decisions have decisively shaped North American

---

[21] Alberta was the first province to introduce deregulation legislation with its *Electric Utilities Act of 1995,* followed by Ontario with its *Energy Competition Act of 1998.*

[22] In the U.S., deregulation and FERC's role were changed by key legislation including the *Public Utilities Regulatory Act of 1978* and the *Energy Policy Act of 1992*..

market structure: FERC Opinion No. 256;[23] a FERC ruling concerning Energy Alliance Partnership;[24] and, FERC Order No. 888 and 889. In these and similar rulings, FERC effectively overrode NAFTA rules and indirectly imposed regulatory policy in Canada, including issuing rulings in direct contradiction of the National Energy Board of Canada (Saunders, 2001).

The most influential of all FERC rulings are Order Nos.888 and 889 that came into force in 1996.[25] These orders require all jurisdictions engaged in interstate electricity sales to have open access transmission tariffs (OATTs), and encouraged utilities to join grid wide independent system operators (Lusztig etal., 2006).[26] Both orders were decisive in shifting electricity markets towards competition and the development of deregulated wholesale markets across North America (Lusztig etal., 2006). The combined result of FERC's rulings has been efforts by electricity trading provinces to

---

[23] FERC Opinion No. 256 was an inquiry into whether that body could review: "transportation charges imposed on Canadian gas exporters pursuant to their previous approval by Canada's National Energy Board" (Saunders. 2001). FERC found that it could review the charges and make them conform to its principles (Saunders. 2001). This finding resulted in a reduced ability for provincial utilities boards and the National Energy Board to regulate natural gas transport rates (Saunders. 2001).

[24] The ruling was a denial of an application for pricing at market rates, its formal name is *Energy Alliance Partnership, 73 FERC ¶ 61,019.* The case involved an application by Energy Alliance Partnership to sell electricity in the United States at market based rates, a powerful privilege FERC used to speed deregulation of transmissions systems (Saunders. 2001). Hydro Quebec held a one third share in Energy Alliance Partnership, and FERC denied the application because the utility failed to meet two principles: "an absence of generation domination and a lack of transmission market power" (Saunders. 2001). In its ruling, FERC noted that "Energy Alliance must demonstrate that Hydro-Quebec offers non-discriminatory wholesale access to its transmission system than can be used by competitiors..." (Saunders quoting FERC. 2001).

[25] The preamble to FERC Order No. 888 states: "all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service."

[26] In essence FERC Order No. 888, requires that jurisdiction desiring to trade electricity in the U.S. must have transmission tariffs which do not discriminate against different generators and distributors. The rule was created to ensure that utilities with monopoly or oligopolistic market powers could not use the transmission system to discriminate against new entrants to the market. It was part of a broader trend in FERC rulings targeting the elimination of vertically integrated utilities and to force the introduction of competition in the wholesale power markets.

comply with FERC's OATT *pro forma*. Despite, the nominal open access to transmission systems, the effect on Canada's market structure has been negligible, as the Canadian electricity markets are dominated by crown utilities. However, the influence on Canadian interprovincial trade has been large by limiting the development of west-east grids and integration of Canadian electricity markets (Carr, 2010).

### ***2.5.4. The influence of U.S. State Policies***

American state level policies can have a direct influence on Canadian electricity policies because provincial utilities, both public and private, sell to customers in individual states. In recent years, U.S. states have enacted policies which require utilities to produce or purchase a share of their electricity from 'green' sources. Defining 'green' power has proven to be complicated by differences between state rules, and has resulted in trade disputes and difficulties counting emissions (Juisoto, 2006). The American demand for renewable electricity, particularly hydroelectricity, has increased in recent years because of the expansion in the number of state based renewable mandates and other policies. Particularly, there has been a large volume of growth and development in the market for certified, voluntary and compliance based renewable electricity credits (Sustainable Prosperity, 2011). The presence of green power policies has increased demand for Canadian based hydroelectricity when it is deemed renewable. However, there has also been dispute over the validity of this status. A dispute between Powerex, the trading arm of British Columbia Hydro, and the California Air Resources Board (CARB) highlights the latter (Hamilton, 2011). [27]

The influence of American federal and state regulation has directly shaped the structure of Canadian electricity markets, because electricity trade and exports to the U.S. are lucrative for the provinces. Table 2.2 presents provincial data on revenue from

---

[27] In brief, CARB accused Powerex of resource shuffling[27], a practice CARB considered banning, and required it to purchase carbon credits (Hamilton 2011). In response, Powerex invoked a NAFTA clause claiming the regulator's rule violated international trade law (Hamilton 2011). The dispute has been temporarily settled as FERC urged CARB to suspend the rule out of concern for grid stability (Kahn 2012).

electricity trade with the U.S. It is important that any policy options which are proposed recognize the influence of U.S. policy in Canada, and the potential changes which climate change might have on this relationship (Kiani et al, 2013).

*Table 2.1 - Revenue from Provincial Electricity Exports (2002 $ million Canadian)*

| Time Period | Generalized Region | Alberta | British Columbia | Manitoba | New Brunswick | Newfoundland | Nova Scotia | Ontario | Prince Edward Island | Quebec | Saskatchewan | Canada |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1990-1999** | West | $ 4.20 | $ 1,786.91 | $ 1,159.44 | $ 26.83 | $ - | $ - | $ 30.46 | $ - | $ 0.59 | $ 25.93 | $ 3,034.38 |
| **2000-2010** | | $ 265.45 | $ 7,640.31 | $ 4,638.12 | $ - | $ - | $ - | $ 142.08 | $ - | $ - | $ 2,449.76 | $ 15,136.14 |
| **Total Provincial** | | $ 269.66 | $ 9,427.65 | $ 5,797.56 | $ 26.83 | $ - | $ - | $ 172.54 | $ - | $ 0.59 | $ 2,475.70 | $ 18,170.53 |
| **1990-1999** | East | $ - | $ 0.42 | $ - | $ 1,223.48 | $ - | $ - | $ 1,169.87 | $ - | $ 3,139.58 | $ 51.50 | $ 5,584.85 |
| **2000-2010** | | $ 0.67 | $ 2.34 | $ 0.01 | $ 1,610.41 | $ - | $ 39.00 | $ 4,582.78 | $ - | $ 10,082.07 | $ 0.13 | $ 16,317.41 |
| **Total Provincial** | | $ 0.67 | $ 2.76 | $ 0.01 | $ 2,833.89 | $ - | $ 39.00 | $ 5,752.65 | $ - | $ 13,221.65 | $ 51.63 | $ 21,902.26 |
| **1990-1999** | South | $ - | $ 0.59 | $ 32.69 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 33.28 |
| **2000-2010** | | $ 3.05 | $ 2.62 | $ - | $ - | $ - | $ - | $ 109.55 | $ - | $ - | $ 0.00 | $ 111.82 |
| **Total Provincial** | | $ 3.05 | $ 2.85 | $ 32.69 | $ - | $ - | $ - | $ 109.55 | $ - | $ - | $ 0.00 | $ 145.09 |

Source: National Energy Board of Canada

# 3. Econometrics and GHG emissions from Canada's electric power industry

Understanding how effective of Canadian renewable electricity policies are at mitigating GHG emissions from the electric power industry is important for determining the direction of future abatement policy. However, evaluating the effectiveness of renewable energy policies at mitigation is complicated by the difficulties that modelling studies have faced in untwining policy effects from regulatory and trade related influences (NRTEE, 2012; Environment Canada, 2012). Attempting to identify if there is a causal relationship between policy and emissions is one of the core objectives of the study and the main purpose for the application of the econometric analysis. Therefore, the research question the statistical analysis focuses on is: *do Canadian renewable electricity policies reduce GHG emissions from the electric power industry?* It follows a similar approach as Prasad and Munch (2012), in whose research GHG emissions from electricity are regressed on economic, demographic and policy variables.

## 3.1. Theory and Hypotheses

The basic model for estimating GHGs emissions from electricity generation ($GHG^E$) is

$$(1)\quad GHG^E = f(GDP, Pop, Gen, P^E, Temp, Pol)$$

Where *GDP* is a measure of individual economic wealth, *Pop* is the size of the population, *Gen* is a measure of the amount of electricity produced from fossil fuel fired generators, $P^E$ is the price of electricity, *Temp* is the temperature, *Pol* is government abatement policy (Prasad and Munch, 2012; Kaffine et al., 2012; Juisoto, 2006).

Hypotheses about the effects of these explanatory factors is dependent on the amount of thermal capacity in the generation mix of a given jurisdiction, more coal and natural gas means more GHGs. However, other factors directly affect GHG emissions. As electricity is a normal good, it is anticipated that increases in individual economic wealth will increase emissions in jurisdictions with carbon intensive generation. The size of the population in a given jurisdiction should have a direct impact on the volume of emissions as higher population levels should increase consumption of electricity. Electricity prices should send price signals to electricity consumers affecting their consumption, thereby reducing the amount of supporting carbon intensive generation on standby. Higher electricity prices ought to suppress consumption, while lower prices should increase it. Countries and provinces with cold weather climates have greater home heating requirements than jurisdictions in warmer climates; in general, colder climates should have higher emissions due to greater heating needs. Finally, policies designed to abate GHG emissions from electricity generation should reduce emissions.

In estimating GHGs from electricity generation it is important to recognize the basic factors influencing their emission, in Canada other factors play an important role. Canada is a large exporter of electricity to the U.S., and depending on the generation mix of the province and the level of export induced generation, electricity can increase or decrease emissions. In the context of electricity trade and market structure, Canadian electricity exports are thought to be heavily influenced by the role of FERC, which governs electricity trade with the United States (Lusztig etal., 2006). However, the effect on emissions from U.S. regulatory policy is unclear. In addition, to the role of U.S. government regulations, state level policies focused on small scale renewable energy technologies and regulated mandates have created a market for ‘green power’ in Canada (Sustainable Prosperity, 2011). Such policies and their accompanying markets may induce construction of renewable energy projects and help to reduce emissions, or depending on standby generation may increase GHG emissions. A detailed exposition of the hypotheses is presented in Appendix B. As well, a table illustrating the expected signs and source materials for the determination of these hypotheses is presented in Table 3.1.

***Table 3.1 - Expected Signs***

| Variable | Expected Sign | Source |
|---|---|---|
| GDP | + | Prasad and Munch (2012) |
| Pop | + | Prasad and Munch (2012) |
| Gen | + | Kaffine et al. (2012) |
| $P^E$ | +/- | Delmas and Montes-Sancho (2011) |
| Temp | + | Kaffine et al. (2012) |
| Pol | +/- | Prasad and Munch (2012) |
| Exports | +/- | Prasad and Munch (2012) |
| FERC 888 | +/- | Lusztig et al., (2006), Carr (2010) |
| Green Power | +/- | Sustainable Prosperity (2011) |

## 3.2. Measures and Data

GHG emissions from the electricity generation industry are influenced by a number of important basic factors including income and economic wealth, population levels, thermal electricity generation, electricity prices, temperature, and government policies. The data for this study of Canadian emissions are aggregated by province for the years of 1990 through 2010. The GHG emissions data are analyzed using panel least squares with provincial fixed effects. The dependent variable, GHG emissions from electric power ($GHG_{it}$), is measured in kilotonnes $CO_2$e, and the data are drawn from Canada's National Inventory Reports for 2012 and 2006 submitted to the United Nations Framework Convention on Climate Change. Economic wealth is measured in provincial gross domestic product per person ($GDPCAP_{it}$), which is denominated in 2002 Canadian dollars. Population level in a province ($POP_{it}$) is measured by the number of people living in a province based on Statistics Canada data. Generation of electricity from fossil fuel sources ($TGEN_{it}$ ) is measured in megawatt hours (MWhs). Electricity exports are measured on a MWh basis for each province and includes both U.S. and interprovincial trade. All of the data for gross domestic product, population, and generation have been drawn from tables available in Statistics Canada's CANSIM database.

Electricity prices ($ELEC\$_{it}$) are measured on a dollar per kilowatt hour (hereafter KWh) for industrial consumers in the largest city in a given province, and are denominated in 2002 Canadian dollars. This pricing data has been drawn from Quebec

Hydro’s annual *Comparison of Electricity Prices in Major North American Cities* for the years between 1990 and 2010. Temperature ($TEMP_{it}$) is measured in degrees Celsius as the annualized average for each province, and is based on data drawn from Environment Canada’s *National Climate Data and Information Archive.* For certain provinces, temperature data are not reported continuously from one location, this necessitates drawing data from a number of different locations, preferably in close proximity, to make a contiguous dataset. As well, temperature is highly variable within a province and this poses a challenge for effective measurement. Intraprovincial variability in temperature is addressed in the dataset by collecting temperatures measured in the largest city in a province as most of the electricity consumption, and thereby the greatest influence of temperature, is likely to occur.

The electricity policies of the provincial and federal governments have an important influence on the electricity markets and GHG emissions. The federal policies included in the datasets for this analysis are the two primary federal subsidy programs, *Wind Power Production Incentive* and *ecoENERGY for Renewable Power*. The *Wind Power Production Incentive* is represented in the dataset on a dollar per KWh basis at a rate of 0.012. (IEA, 2012). The *ecoENERGY for Renewable Power* program is represented at a rate of $0.01 KWh. Neither subsidy rate is adjusted for inflation, as none of the available documentation states if or how they are to be indexed. Using the subsidy rates is a second best method as data measuring total program expenditure by province and year would be preferred, though no such data are publicly available. As a result, the two subsidies have been combined into a single subsidy variable ($FED_{\mathrm{it}}$) in each provincial cross section from 2002 through 2010, and for the year where the policies overlap in 2007 they are averaged. The data for these subsidies programs have been taken from two sources, the International Energy Agency (2012) and Weis etal. (2009). Provincial subsidy ($SUB_{it}$) programs for renewable electricity are represented on a dollar per KWh in 2002 Canadian dollars for both British Columbia’s *Standing Offer Program* and Ontario’s *Renewable Energy Standard Offer Programme* and *Feed-in-*

*Tariff* in the same variable.[1] A variable representing provincial portfolio mandates ($MAND_{it}$) is included for Nova Scotia and Ontario as the percentage of required renewable generation in the province's generation mix. A net metering policy variable ($NETMET_{it}$) is included for every province except Newfoundland at the rate of the maximum allowed installed generation capacity under the relevant provincial rules. The information for these subsidy programs have been taken from two sources, the International Energy Agency (2012) and Weis etal. (2009).

Finally, the U.S. policy variables are included for FERC order 888 and state level green power policies. A variable for FERC order 888 ($FERC888_{it}$) is represented as a dummy, where 1 equals a year where the rule is in effect starting in 1996. U.S. green power policies that induce green electricity trade are measured by proxy with provincial revenue from electricity trade in 2002 Canadian dollars. The variables are represented as revenue from trade with specific electricity markets in the U.S. ($EAST_{it}$, $SOUTH_{it}$, $WEST_{it}$) and is based on data drawn from the National Energy Board of Canada. Unfortunately, there is a lack of data specific to trade in renewable electricity or renewable energy credits (Sustainable Prosperity, 2011; Juisoto, 2006).[2] As well, there are two regional dummies one for western ($WESTR_{it}$) and eastern Canada ($EASTR_{it}$). Details on all of the data manipulations are reported in greater detail in Appendix C.

---

[1] Documentation for each of these policies state that they are to be adjusted for inflation using the relevant provincial consumer price index.

[2] There may be extensive trade in credits between Canada and the U.S. Many U.S. states mandate that utilities have a certain percentage of 'green' power in their mix of electricity generation. Renewable electricity credits are compliance mechanisms which give those utilities the option to purchase credits from other firms in lieu of producing the electricity from renewable sources themselves As well, with the growth of consumer choice programs in retail electricity in the U.S., there is growing market for voluntary certificates representing power produced from renewable sources. For instance, the U.S. Environmental Protection Agency publishes a number of lists on organizations and governments that consume such 'green' power (http://www.epa.gov/greenpower/communities/gpcrankings.htm). As well, a Sustainable Prosperity paper discusses the growth of renewable energy credit trade in Canada (Sustainable Prosperity 2011). As well, leading expert Ryan Wiser of the U.S. National Renewable Energy Laboratory confirmed the lack of available data for either voluntary or compulsory green energy credits.

## 3.3. Specifications and Analysis

Based on the descriptions of the theory and measures that I have presented, it follows that the empirical specification of the theoretical model is equation 2.

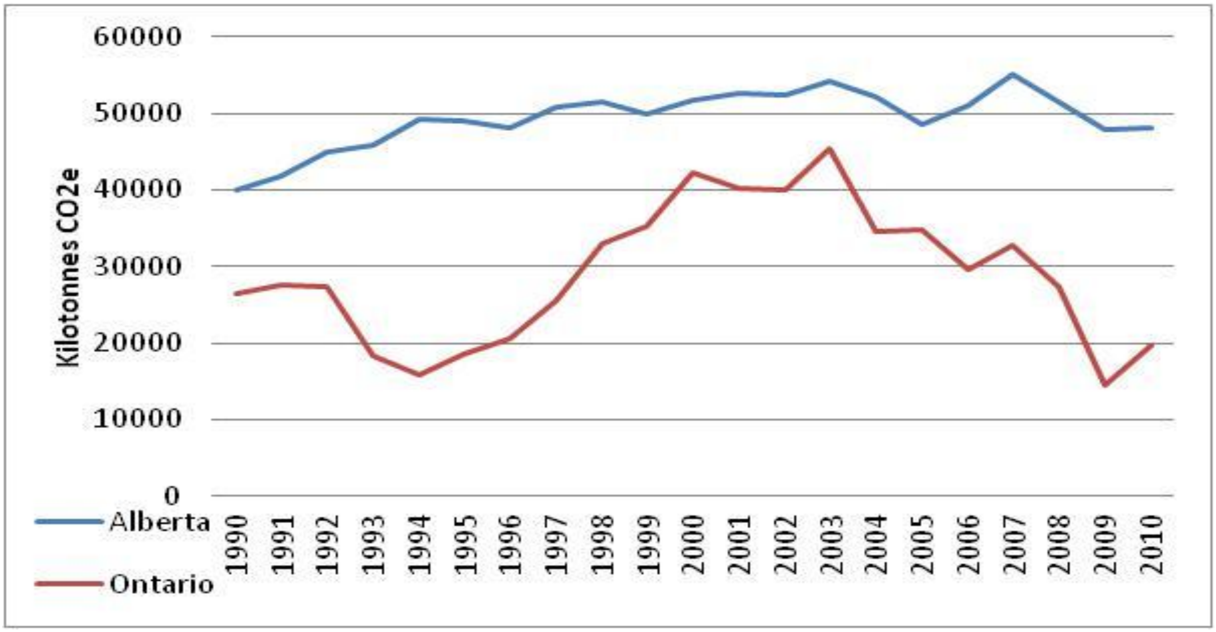
$$
\begin{aligned}
&\log GHG_{it} = \beta_0 + \beta_1 \log GDPCAP_{it} + \beta_2 \log POP_{it} + \beta_3 \log TGEN_{it} + \beta_4 EXPORTS_{it} + \\
(2)\ &\beta_5 \log ELEC\$_{it} + \beta_6 TEMP_{it} + \beta_7 FED_{it} + \beta_8 SUB_{it} + \beta_9 [WESTR_{it} * (\log TGEN_{it})] + \\
&\beta_{10} [EASTR_{it} * (\log TGEN_{it})] + \beta_{11} \log GHG_{i,t-1} + \varepsilon_{it}
\end{aligned}
$$

For each, i= a given province (i=1 to 10); t= a given year (t=1 to 21)

A description of the analysis undertaken using the empirical specification is presented below in the next section.

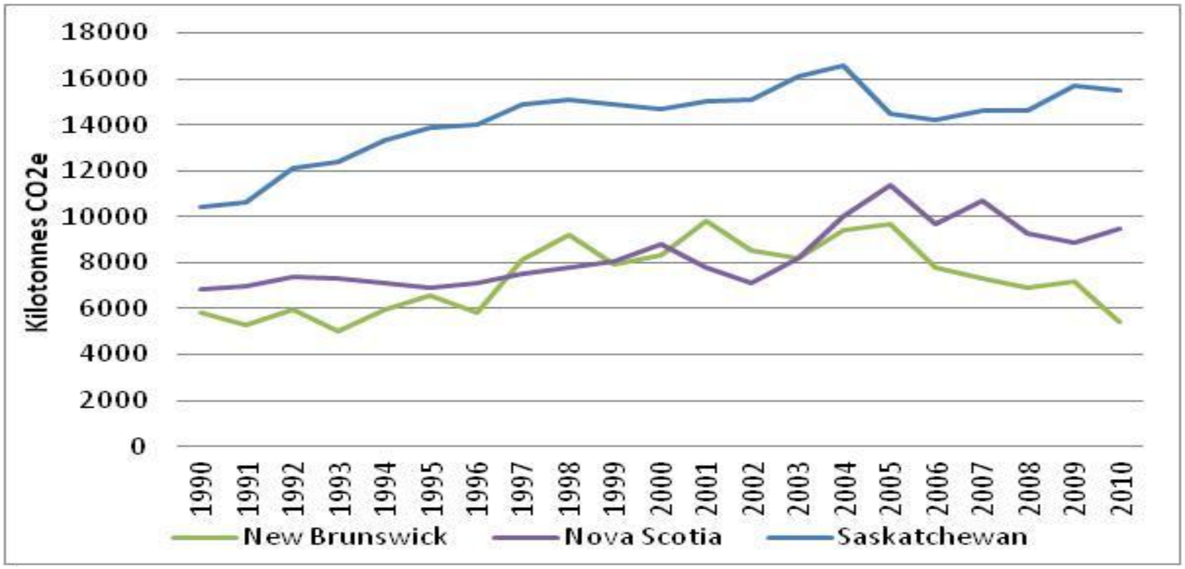
A visual inspection of the GHG data for each province, in figures 3.1 through 3.4, indicates that those provinces with high emissions are highly trended upwards as output increases. This may indicate the presence of a unit root in individual provincial panels, and requires the application of individual and common unit root tests. The results of the unit root tests are presented below in Table A4, Appendix A, and the tests for both individual panel and common unit roots provides strong evidence that the data is non-stationary. This finding means that statistical analysis of the empirical model will have to be undertaken in a first differences transformation, and eliminates the possibility of computing equilibrium changes in GHG emissions.

*Figure 3.1 - GHG Emissions from Electric Power, Alberta and Ontario*



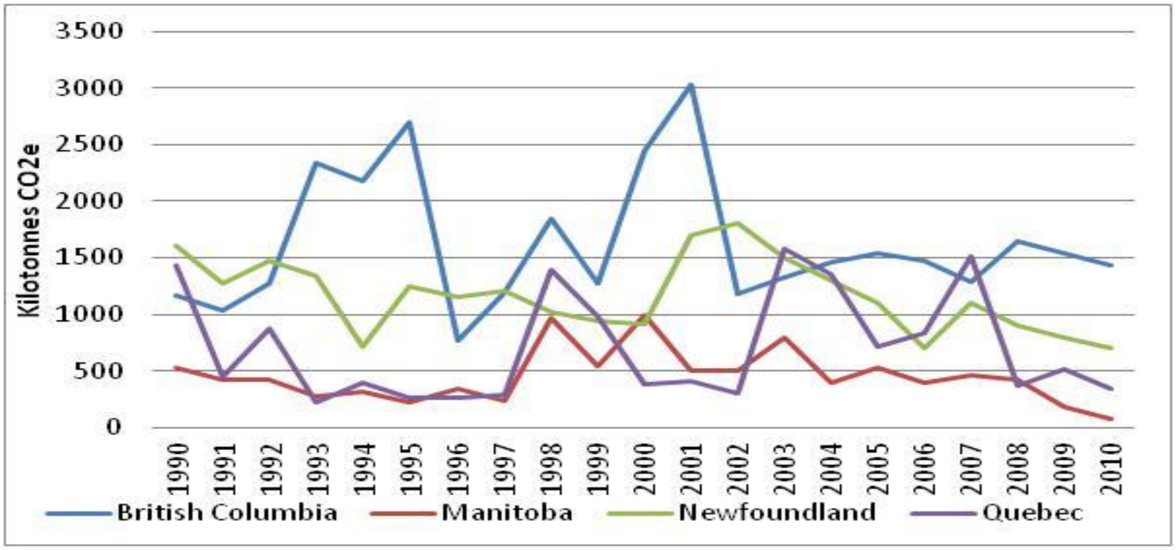
Source: National Inventory Reports, Canada

*Figure 3.2 -GHG emissions from Electric Power - New Brunswick, Nova Scotia, Saskatchewan*



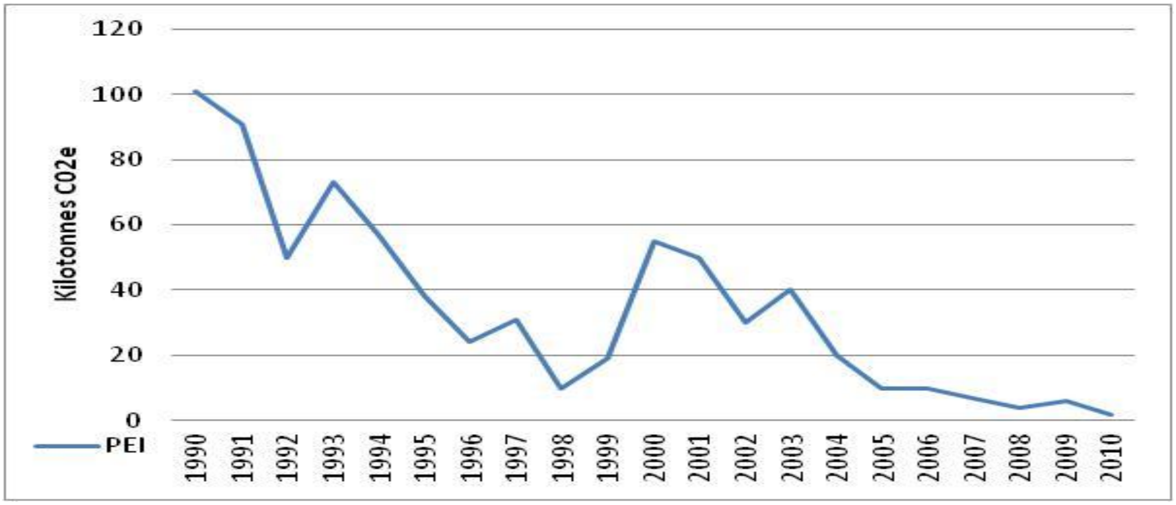
Source: National Inventory Reports, Canada

***Figure 3.3 - GHG emissions from Electric Power - British Columbia, Manitoba, Newfoundland, Quebec***



Source: National Inventory Reports, Canada

***Figure 3.4 - GHG emissions from Electric Power - Prince Edward Island***



Source: National Inventory Reports, Canada

Much the variation in the descriptive statistics, presented in table 4.2, is due to the size disparities and differing regional economic characteristics amongst the provinces. These differences are apparent in the size and wealth of provincial economies as indicated by the GDPCAP. Though the median GDPCAP is approximately $26,677, the approximate maximum and minimum values are $94,743 in Alberta in 2008 and $12,272 in Nova Scotia in 1990. There are similar differences in demographic characteristics such as population and temperature, where moderate mean and median values, approximately 5.6 and 5.7 degrees Celsius mask the underlying size differences. The minimum and maximum temperatures vary quite significantly from approximately -0.6 to11.5 degrees Celsius. However, electricity market characteristics do not vary by region, but based on the effects of resource endowments on generation profiles. For instance, there is wide variation amongst the provinces in the MWhs of electricity generated from fossil fuels. For instance, the maximum value for thermal generation is from Alberta at approximately 64,792,636 MWhs while the minimum value in Prince Edward Island is 680 MWhs. As well, industrial electricity prices reflect differences in provincial regulatory policy and rate setting as the average electricity price is approximately $0.052 KWh, but prices can reach as high as $0.117 KWh in Prince Edward Island or Alberta. The provincial propensity to trade electricity is highly influenced by geographic proximity to U.S. markets, though the Newfoundland’s Churchill Falls facility is an exception as it exports most of that province’s electricity to Quebec. Indeed, the only province that does not engage in extensive electricity is Prince Edward Island as it has limited transmission capacity with the main land, this is apparent in the minimum value of 0 for exports.

*Table 3.2 - Descriptive Statistics*

| | GHG | GDPCAP | POP | TGEN | EXPORTS | ELEC$ | TEMP | FED | FEDPOL |
|---|---|---|---|---|---|---|---|---|---|
| Mean | 11222.03 | 29175.6 | 3069598 | 13568813 | 8587737 | 0.052 | 5.661 | 0.005 | 0.429 |
| Median | 4020 | 26677.3 | 1074892 | 7475587 | 5619108 | 0.049 | 5.7 | 0 | 0 |
| Maximum | 55200 | 94743.8 | 13223789 | 64792636 | 34074438 | 0.117 | 11.4 | 0.012 | 1 |
| Minimum | 1.6 | 12272.2 | 130369 | 680 | 0 | 0.023 | -0.6 | 0 | 0 |
| Std. Dev. | 15673.45 | 13712.1 | 3596641 | 17647682 | 9396877 | 0.019 | 2.686 | 0.006 | 0.496 |
| Skewness | 1.592 | 1.589 | 1.464 | 1.551 | 1.127 | 0.918 | 0.122 | 0.323 | 0.289 |
| Kurtosis | 4.259 | 6.629 | 3.967 | 4.100 | 3.183 | 3.621 | 2.390 | 1.146 | 1.083 |
| Observations | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 |

| | SUB | MAND | NETMET | EAST | SOUTH | WEST | FERC888 | WESTR | EASTR |
|---|---|---|---|---|---|---|---|---|---|
| Mean | 0.00 | 0.55 | 965.00 | 104000000.00 | 690927.10 | 86526315.00 | 0.67 | 0.40 | 0.40 |
| Median | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 0.00 | 0.00 |
| Maximum | 0.15 | 15.00 | 10000.00 | 1720000000.00 | 66810611.00 | 2210000000.00 | 1.00 | 1.00 | 1.00 |
| Minimum | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Std. Dev. | 0.02 | 2.46 | 2863.79 | 249000000.00 | 5457039.00 | 281000000.00 | 0.47 | 0.49 | 0.49 |
| Skewness | 4.92 | 4.85 | 2.83 | 3.41 | 10.05 | 5.54 | -0.71 | 0.41 | 0.41 |
| Kurtosis | 26.40 | 26.43 | 9.06 | 16.37 | 112.47 | 38.38 | 1.50 | 1.17 | 1.17 |
| Observations | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 | 210 |

There are no correlation coefficients presented in Table A2, Appendix A that are high enough to pose a problem of collinearity, though two relationships do warrant mention. $GDPCAP_{it}$ and the federal policy variable $FED_{it}$ have a positive relationship with a correlation coefficient of 0.68. This is an odd finding considering that the policy is set by government at a fixed rate while $GDPCAP_{it}$ moves with changes in the macro-economy. It seems that the correlation between them is incidental of the fact that the first portion of the policy has a higher rate when $GDPCAP_{it}$ increases and a slightly lower rate at the same time GDPCAP decreases in 2008. The second relationship worth mention is the negative correlation of -0.67 between the regional dummies for western and eastern Canada.

## 3.4. Empirical Analysis

The results of the analysis of the provincial GHG emissions data using the specification in equation (2) for the years of 1990 to 2010 is presented in this section. As noted in section 3.3, the GHG data are non-stationary and this necessitates application of the first differences transformation.[3] Initially, a number of base specifications have been run, but when Woolridge's test is applied to each case they provide strong evidence of severe serial correlation.[4] Even after the basic model is re-specified with an interaction between the regional dummies and the thermal generation variable, and a lagged dependent variable model is added the serial correlation problem persists. Serial correlation could be eliminated by lagging all of the explanatory variables several years, but there are an insufficient number of years in each provincial panel to accommodate the application of this solution. Therefore, the only way to analyze the data using the model in equation (2) with panel least squares is a comparison of the same specification, but re-estimated using White's robust standard errors (White's RSE) applied separately to cross sections and time series. Applying the White's RSE for cross sections controls for heteroskedasticity and applying them for time controls for serial correlation. Comparing the significance levels of the two estimates indicates which coefficients are significant.

In addition to the specification in equation (2) additional variables are added to test the robustness of the findings, these cases include: other provincial policies; U.S. green power; and, FERC order 888. The results of the four specifications are presented

---

[3] Use of the first differences transformation is denoted with the '$\Delta$' sign in front of the variables in the regression result tables. The first differences transformation changes the way that the coefficients are interpreted, as they represent the rate of change. When variables are logged it means they represent the rate of change in the rate of change - that is $\Delta\Delta Y_{it}/\Delta\Delta X_{it}$. This means that the coefficients must be interpreted as the influence of each variable on the acceleration or deceleration in the rate of emissions.

[4] According to Woolridge (2010), it is possible to test for serial correlation by regressing the residuals on the lagged residuals of a given regression model. A similar version of the test is recommended in the Eviews 7 manual and in Stata's panel analysis package (Quantitative Micro Software, 2009; Drukker, 2003).

in Table 3.3, and the results of the initial specifications are presented in Table A5, Appendix A. The preferred model is specification 1 or the dynamic model with subsidy policies, and interactions between regional dummies and thermal generation. The dynamic case has a high level of explanatory power as indicated by its adjusted $R^2$ score of 0.62 and F-statistic of 16.4 for overall model significance. As well, specification one is the model which minimizes Schwarz's information criterion, 0.585, and is the most parsimonious. The variables that are significant in the dynamic case are $\Delta \log TGEN_{it}$, $\Delta FED_{it}$, $(EASTR_{it} * \Delta \log TGEN_{it})$, $\Delta \log GHG_{i,t-1}$. The coefficient for $\Delta \log TGEN_{it}$, 0.9, indicates that thermal generation accelerates GHG emissions, and this finding is consistent with expectations. The effect of federal subsidies on GHGs is uncertain in the literature as it depends on the technologies in the generation mix, but the coefficient for $\Delta FED_{it}$ is unambiguous, -10.4 clearly shows a large deceleration in the rate of emissions. The result for thermal generation in eastern Canada is odd, $(EASTR_{it} * \Delta \log TGEN_{it})$ is -0.5. This coefficient indicates that increases in the rate of fossil fuel generated electricity actually decelerate GHGs slightly in the maritime and Atlantic region of Canada. The dynamic term in the model, $\Delta \log GHG_{i,t-1}$, has a small negative coefficient of -0.15 that indicates an increase in the rate of emissions the previous year results in a small deceleration the following year. The size of the coefficients, the signs and the levels of significance are consistent across the other three specifications indicating that they are robust given the serial correlation problem.

While, the coefficients, signs and levels of significance did not vary much across the different specifications there are several notable results from the three alternate models. In specification two, policy variables for net metering and portfolio mandates are added, the latter is not significant, but the $\Delta NETMET_{it}$ coefficient of $-1.05*10^{-5}$ is significant and this indicates that as the rate of the maximum allowable interconnection increases the rate of GHG emissions decelerates. The green power specification has variables for export revenue to the U.S. only one of those is significant, $\Delta WEST_{it}$. It has a slightly positive coefficient of $1.57*10^{-10}$ indicating that there is a slight acceleration in the rate of GHG emissions due to Canadian exports to the western U.S. As well, in specification 3 the variable for population is significant with a strong negative coefficient of -7.693, as is the coefficient for exports, $-2.17E*10^{-08}$. Finally, to test the effect of FERC order 888 the $\Delta FERC888_{it}$ variable is substituted for $\Delta EXPORTS_{it}$, but it is not significant.

## *Table 3.2 - Regression Results*

| **Case** | Dynamic | | | Mandates and Net Metering | | | Green Power | | | FERC888 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Specification** | 1~ | *Cross Section* | *Period* | 2~ | *Cross Section* | *Period* | 3~ | *Cross Section* | *Period* | 4~ | *Cross Section* | *Period* |
| **Variable** | $\Delta logGHG_{it}$ | | | $\Delta logGHG_{it}$ | | | $\Delta logGHG_{it}$ | | | $\Delta logGHG_{it}$ | | |
| | Coefficient | Standard Errors | Standard Errors | Coefficient | Standard Errors | Standard Errors | Coefficient | Standard Errors | Standard Errors | Coefficient | Standard Errors | Standard Errors |
| C | 0.013 | 0.020 | 0.030 | 0.014 | 0.020 | 0.031 | 0.019 | 0.020 | 0.031 | 0.013124 | 0.024 | 0.031023 |
| $\Delta logGDPCAP_{it}$ | 0.038 | 0.097 | 0.133 | 0.032 | 0.097 | 0.134 | 0.005 | 0.106 | 0.139 | -0.005509 | 0.096 | 0.129707 |
| $\Delta logPOP_{it}$ | -6.570 | 4.174 | 4.229**** | -6.688 | 4.149**** | 4.335**** | -7.693 | 4.427*** | 4.336*** | -6.641619 | 4.234**** | 4.233**** |
| $\Delta logTGEN_{it}$ | 0.903 | 0.265* | 0.038* | 0.903 | 0.266* | 0.038* | 0.903 | 0.269* | 0.036* | 0.924939 | 0.283* | 0.039* |
| $\Delta EXPORTS_{it}$ | -1.97E-08 | 1.22E-08**** | 1.02E-08** | -2.02E-08 | 1.25E-08**** | 1.00E-08** | -2.17E-08 | 1.25E-08*** | 9.14E-09* | | | |
| $\Delta logELEC\$_{it}$ | -0.124 | 0.185 | 0.130 | -0.129 | 0.184 | 0.130 | -0.150 | 0.184 | 0.137 | -0.164902 | 0.209 | 0.165846 |
| $\Delta TEMP_{it}$ | -0.022 | 0.018 | 0.013*** | -0.021 | 0.018 | 0.014**** | -0.022 | 0.019 | 0.013*** | -0.018899 | 0.019 | 0.013856 |
| $\Delta FED_{it}$ | -10.367 | 2.739* | 5.067** | -10.255 | 2.748* | 5.074** | -7.426 | 2.634* | 3.804** | -9.639049 | 2.878* | 4.945** |
| $\Delta SUB_{it}$ | -0.950 | 0.585**** | 0.175* | -0.953 | 0.582*** | 0.179* | -1.024 | 0.749 | 0.354* | -0.996118 | 0.792 | 0.587*** |
| $\Delta\ (WESTR_{it} * logTGEN_{it})$ | 0.264 | 0.267 | 0.131** | 0.283 | 0.272 | 0.130** | 0.242 | 0.268 | 0.104* | 0.282769 | 0.3*** | 0.169*** |
| $\Delta(EASTR_{it} * logTGEN_{it})$ | -0.491 | 0.291*** | 0.071* | -0.490 | 0.292*** | 0.071* | -0.489 | 0.293*** | 0.070* | -0.509985 | 0.305*** | 0.074* |
| $\Delta logGHG_{it}(-1)$ | -0.145 | 0.076** | 0.052* | -0.144 | 0.075** | 0.052* | -0.145 | 0.074** | 0.052* | -0.141158 | 0.076** | 0.056* |
| $\Delta MAND_{it}$ | | | | 0.002 | 0.009 | 0.008 | | | | | | |
| $\Delta NETMET_{it}$ | | | | -1.71E-05 | 4.64E-06* | 4.43E-06* | | | | | | |
| $\Delta EAST_{it}$ | | | | | | | 6.34E-11 | 2.70E-10 | 1.28E-10 | | | |
| $\Delta SOUTH_{it}$ | | | | | | | 1.63E-09 | 2.95E-09 | 1.81E-09 | | | |
| $\Delta WEST_{it}$ | | | | | | | 1.57E-10 | 4.18E-11* | 2.99E-11* | | | |
| $\Delta FERC888_{it}$ | | | | | | | | | | -0.004937 | 0.043 | 0.04295 |
| **Obs.** | 200 | | | 200 | | | 200 | | | 200 | | |
| **Adj R^2** | 0.620 | | | 0.620 | | | 0.622 | | | 0.607 | | |
| **F-Statistic** | 16.403 | | | 14.850 | | | 14.548 | | | 15.611 | | |
| **Schwarz** | 0.585 | | | 0.635 | | | 0.642 | | | 0.617 | | |
| **Woolridge's Test - Null Hypothesis: No serial correlation** | | | | | | | | | | | | |
| p-value | 0.007 | | | 0.006 | | | 0.005 | | | 0.007 | | |
| **Notes:** | | | | | | | | | | | | |
| ~White's Robust Standard Errors; **** 10% < X >1 5% ; *** 10% significance level; ** 5% significance level; * 1% significance level | | | | | | | | | | | | |

## 3.5. Implications and Results

The dataset of provincial GHG emissions from electricity generation that has been analyzed for this study is plagued by serial correlation and individual and common unit roots, and the former problem has not been adequately solved. This calls the robustness of the results into question. Nonetheless, the models possess a high degree of explanatory power and the coefficients and significance levels are consistent across several different specifications. With these caveats in mind, the most important finding is that federal production subsidies for renewable power significantly ramp down or decelerate the rate of change in GHG emissions. Increases in the rate of fossil fuel fired electricity generation accelerate the rate of GHG emissions. However, GHG emissions from thermal generation in the Atlantic provinces seem to ramp down slightly in response to increases in the rate of change of thermal generation in that region. This result is strange and difficult to explain, but the coefficient is small indicating that the effect is not large. Another important finding is that the provincial subsidies and regulations for renewable power mandates have no affect on GHG emissions. However, there is some evidence that increases in the rate of installed capacity limits for net metering policies slightly decelerate emissions. The effects of U.S. green power and FERC policies, as measured in this dataset, are not significant with the exception of export revenues to the Western U.S. As well, the variables for temperature, GDPCAP, population and electricity prices are not found to have a direct relationship with GHG emissions from electric power.[1]

While these results provide evidence about the effects of renewable energy policies on GHG emissions and have implications for abatement policy, they do not provide contextual detail about interactions between those policies and electricity systems. It is important to understand the complex nature of the political, geographic,

---

[1] These results are not as it has been observed that overall GHG intensities are declining in Canadian industry (Nyboer and Kamiya 2012b).

and overlapping regulatory powers that influence the functioning of the electricity system. In particular, there are a number of institutional, regulatory and historical trajectories and factors that could not be directly included in the regressions, but which are important for explaining variation in the dependent variable. These complexities are discussed in greater length in the case studies.

# 4. **Case Studies**

Case studies are undertaken to detect variations between jurisdictions with different electricity policy regimes and GHG emissions profiles. By analyzing this variation, the case studies can provide insight into institutional, political and historical factors not readily quantified in the regression analysis. The case studies will help to complete the second research objective of the study which is to *explore the effects of renewable energy policies on electricity markets and system operations*. The sample of case studies – Alberta and Texas – was selected non-randomly on the basis of commonalities and variations between their institutional, political and historical characteristics. Specifically, the case studies focus on the nature of changes over time of electricity market design, historical trajectory of institutions and policies, the impact of renewable electricity, and GHG emissions. The literature indicates that these factors are central to successful decarbonization of the electric power industry.

The case studies undertaken for this section of the analysis are designed to help explain variation in the dependent variable, GHG emissions from the electricity industry, from variables not accounted for explicitly by the regression model. These factors include regulatory policy, electricity market design, institutions, politics, history, and interactions between abatement and renewable energy policy. Two jurisdictions have been selected for inclusion in this analysis, Alberta and Texas. A justification of the cases selected is provided in the next subsection. In addition to a comparison of the aforementioned factors this analysis will examine differences between the two jurisdictions and attempt to explain why Alberta has a high renewable electricity penetration rate, but unlike Texas, no active policies to promote renewables. In essence it is important to understand why these North American jurisdictions have high electricity sector emissions concomitant with a high renewable electricity penetration rates. Understanding the reasons for this difference will help to explain why renewable energy policies may not be having the effects they are designed to have – *why they do not reduce emissions to extent the policies suppose?*

## 4.1. Justification of Cases

Alberta and Texas are unique jurisdictions in Canada and the U.S. because they possess a number of common characteristics, including: high GHG emissions from their electricity industries; high industrial electricity demand; and, high wind penetration rates. Further, they share a number of market commonalities such as similar regulatory cultures, market structures, and transmission planning challenges. Alberta and Texas differ with respect to their approach to promoting renewable electricity production. Alberta has an emissions intensity cap for abatement policy that allows renewable electricity producers to apply as offset providers[2] and Texas has enacted a renewable portfolio mandate (Doluweera et al., 2011; Zarnikau, 2011). Both jurisdictions possess, high renewable penetration rates, but only one has a policy of abatement and the other a regulatory portfolio mandate.

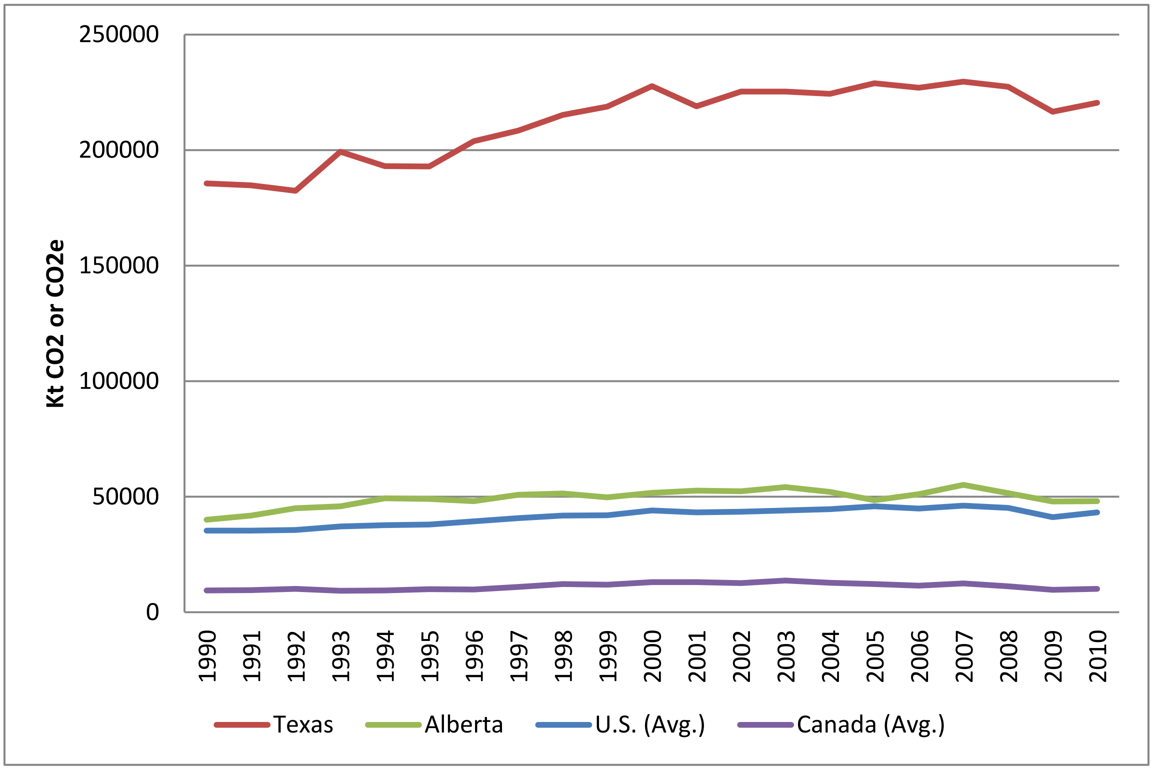
Another commonality between these jurisdictions is their high rate of emissions compared to the means of their respective countries. Respectively, Alberta and Texas have the highest GHG emissions from their electric power industries in Canada and the U.S. For instance, the average annual GHG emissions for Alberta between 1990 and 2010 are approximately 49,339 kt $CO_2$e, far higher than the national average of approximately 11,222 kt $CO_2$e. Texas has the distinction of having the most polluting electricity industry in North America. In 2010 it emitted 220,418 kt $CO_2$ four times higher when compared to the U.S. national average of approximately 43,267 kt $CO_2$. During the period of 1990 through 2010, Texas' average annual emissions were 212,161 kt $CO_2$

---

[2] Doluweera et al. (2011) succinctly describe Alberta's abatement policy: "In 2007 the Alberta provincial legislature enacted the ''Specified Gas Emitters Regulation (SGER)'' to regulate GHG emissions. This regulation uses an intensity- and product-based approach. SGER requires facilities in Alberta that have direct annual GHG emissions larger than 100,000 tonnes of CO 2e to reduce their emissions intensity by 12% of facility's ''baseline emissions intensity (BEI)''...Under SGER, the emissions intensity is defined as the GHG emissions per unit economic output of the facility. Facilities that are regulated by SGER can comply by making improvements to their operations; by purchasing Alberta based ''offset credits''; by using or purchasing ''emissions performance credits (EPC)''; by contributing to the ''Climate Change and Emissions Management Fund (CCEMF)'' at the rate of C$15/tCO..." see page 7965.

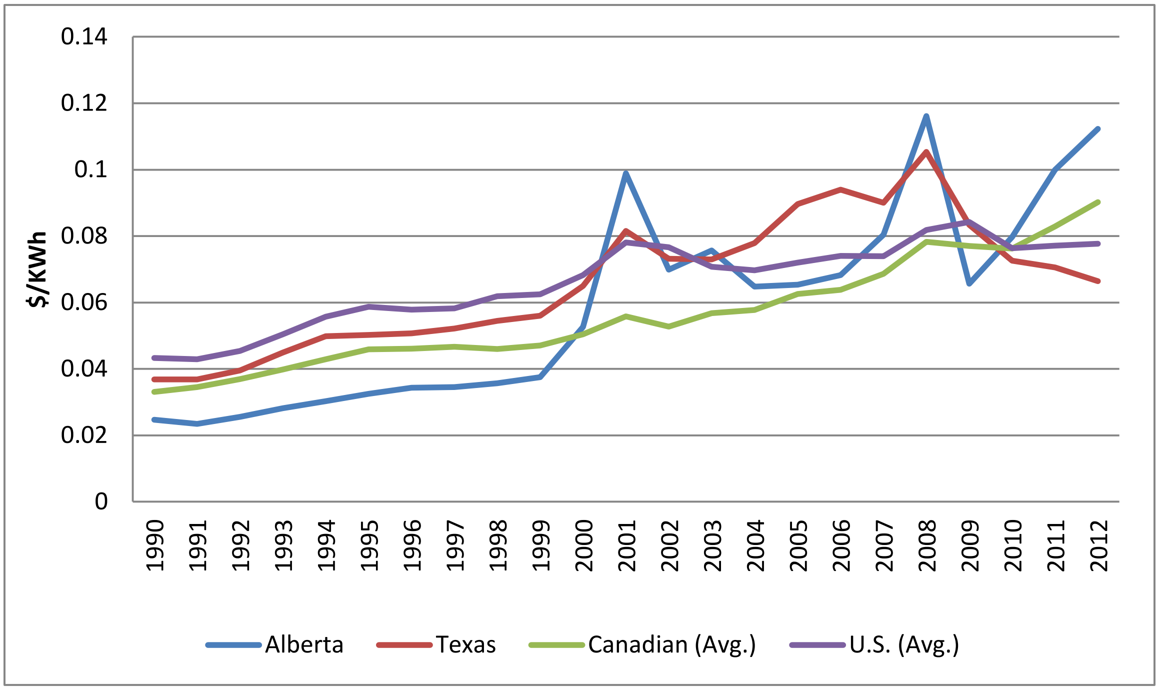
compared to the average of all states over the same period 41,378 kt $CO_2$. The data presented below in Figure 4.1 compares Alberta and Texas emissions to annual national state or province averages, the Canadian data represent all electricity GHG emissions and the American data represent only $CO_2$ emissions. As well, the effects of deregulation, renewable energy and commodity price fluctuations have had similar impacts on the volatility of electricity prices within the respective markets. Data on industrial electricity prices is presented below in Figure 4.2.

***Figure 4.1 – Greenhouse Gas Emissions: Alberta vs. Canadian Average (kt $CO_2$e), and Texas vs. U.S. Average (kt $CO_2$)***



Sources: National Inventory Reports, Canada; State and Local Climate and Energy Program, U.S. Environmental Protection Agency

*Figure 4.2 - Industrial electricity prices (2002 Can $)*



Sources: *Comparison of Electricity Prices in Major North American Cities*, various reports (1990 – 2012), Quebec Hydro; U.S. Energy Information Administration

## 4.2. The Path toward Deregulation

This sub-section briefly describes the historical path each jurisdiction has taken towards its current electricity market structure. A historical description is useful for providing context for analysis of the cases.

### *4.2.1. Alberta*

Alberta's electricity market is unique compared with other provinces because it has never had a crown-owned monopoly over electric power, so its market is typified by several investor owned utilities – principally ENMAX, Transalta, and EPCOR – which were vertically integrated (Dadson et al., 2011). Electricity market reform in Alberta can be divided into three historic phases: 1970s pooling arrangements between the principal utilities[3]; 1982 uniform pricing by provincial legislation[4]; and after 1995, the reform period[5]. Two key reforms characterize the relative success of Alberta's liberalization efforts; first, is the condensation of the Power Pool of Alberta and the Transmission Administrator in 2003 into the Alberta Electric System Operator (AESO) (AESO, 2012). Second is the institution of marginal cost pricing in the wholesale electricity generation market.

Towards the mid-1990s it was recognized that marginal cost pricing in electricity wholesale markets was necessary to induce investments (Dadson et al., 2011). But incumbent generation owners possessed an advantage over new investors due to historical returns from regulated rates (Dadson et al., 2011). The solution to this stranded capital problem was to phase in marginal cost pricing for incumbent generators between 1996 and 2000 (Dadson et al., 2011). Due to this phase in, many of the legacy generation facilities were protected from competition, suppressing wholesale market prices (Dadson et al., 2011). This wrinkle in wholesale pricing led to distorted signals for investment in new generation (Dadson et al., 2011). The result was mismatches between loads and new investments in generation; thus, tightening of the supply of electricity in the market and raising wholesale prices (Dadson et al., 2011).

---

[3] In this period, the principal utilities integrated generation, transmission and distribution operation to enhance efficiency. The result was divergent pricing between the three unique and localized distribution franchises.

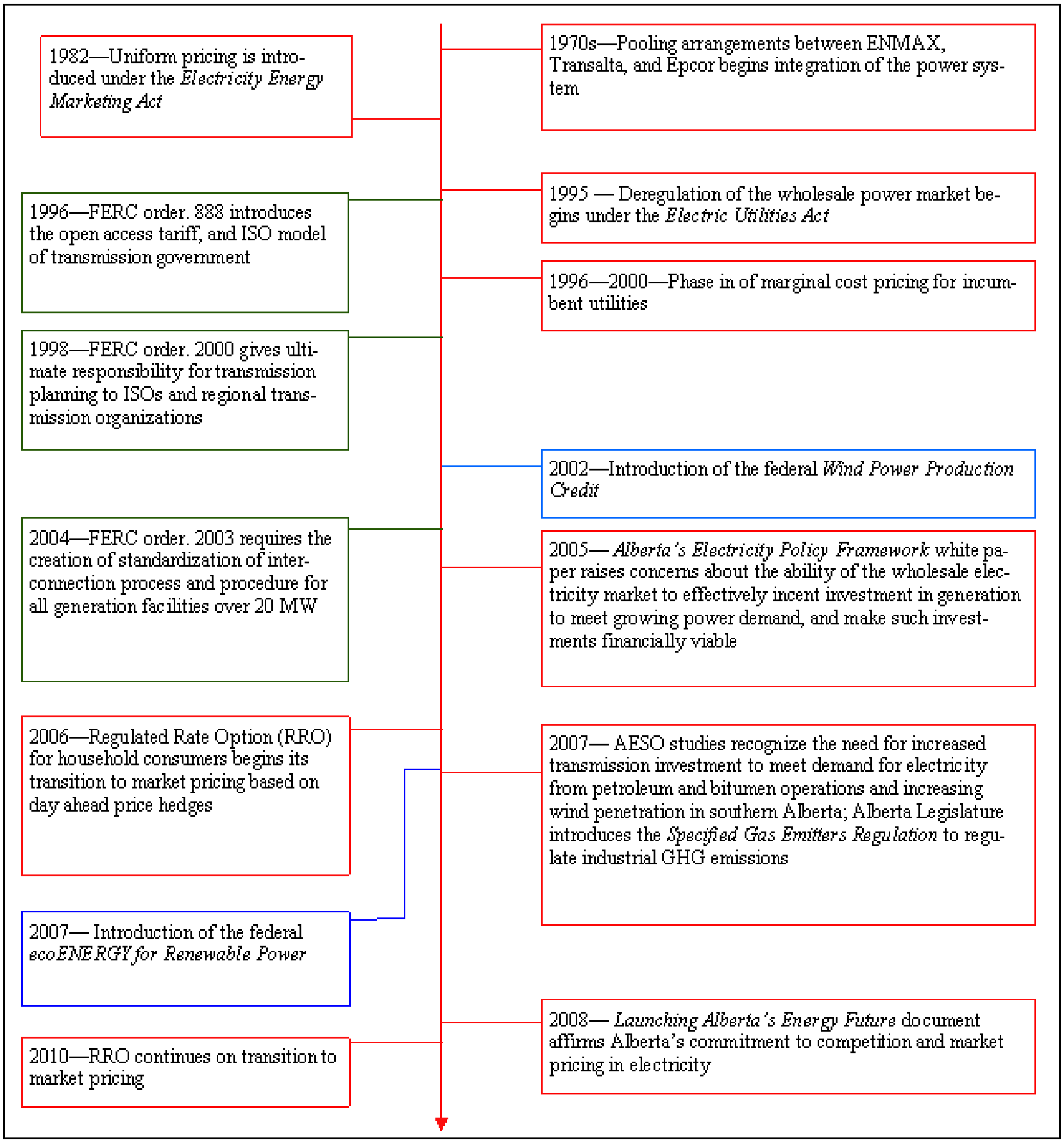
[4] In 1982 the legislature of Alberta passed the *Electric Energy Marketing Act*, which created a provincial agency to purchase and distribute power from the principal utilities. This was undertaken in order to balance electricity costs as they had diverged widely since the pooling period. Pooling agreements are defined by Dadson et al. (2011) on page 318 as "the utilities began dispatching their generation capacity as a single integrated system in order to realize greater operational efficiencies..."

[5] Under Alberta's *Electric Utilities Act of 1995*, competition was introduced and took effect in January of 1996. The main reason for the decision was "deregulating decisions about new generation...[including] on type, timing and amount of generation from the regulator to the market."

In 2001, the delayed opening of retail competition and the lack of effective marginal pricing in wholesale electricity, driven by low initial interest in auctions for power purchases, interfered with market efficiency and incentives. Namely, the goal of competition was to create long term price stability, while inducing the desired generation investments. However, delays and market wrinkles meant that “there was little incentive on the load side for longer term forward contracting” to hedge investment in generation (Dadson et al., 2011). As new investors could not secure stable prices, the decision was made to segregate incumbent generators with prices based on separate power purchase agreements and auctions.

Despite this initial fumbling, by 2005 Alberta’s market had still induced 3500 MW of investment in new generation capacity (Dadson et al., 2011). The effect on the retail market has been a shift of 70 percent of all customers to competitive pricing, including many industrial and commercial customers, though only 7 percent of residences and farms made the switch (Dadson et al., 2011). In light of this success, several policy documents have affirmed Alberta’s dedication to its competitive power market (Dadson et al., 2011). Figure 4.3 presents a detailed chronology of these events, regulatory changes by FERC, and the federal government.

*Figure 4.3 - Alberta Market Timeline*



1970s—Pooling arrangements between ENMAX, Transalta, and Epcor begins integration of the power system

1982—Uniform pricing is introduced under the *Electricity Energy Marketing Act*

1995 — Deregulation of the wholesale power market begins under the *Electric Utilities Act*

1996—FERC order. 888 introduces the open access tariff, and ISO model of transmission government

1996—2000—Phase in of marginal cost pricing for incumbent utilities

1998—FERC order. 2000 gives ultimate responsibility for transmission planning to ISOs and regional transmission organizations

2002—Introduction of the federal *Wind Power Production Credit*

2004—FERC order. 2003 requires the creation of standardization of interconnection process and procedure for all generation facilities over 20 MW

2005— *Alberta's Electricity Policy Framework* white paper raises concerns about the ability of the wholesale electricity market to effectively incent investment in generation to meet growing power demand, and make such investments financially viable

2006—Regulated Rate Option (RRO) for household consumers begins its transition to market pricing based on day ahead price hedges

2007— AESO studies recognize the need for increased transmission investment to meet demand for electricity from petroleum and bitumen operations and increasing wind penetration in southern Alberta; Alberta Legislature introduces the *Specified Gas Emitters Regulation* to regulate industrial GHG emissions

2007— Introduction of the federal *ecoENERGY for Renewable Power*

2008— *Launching Alberta's Energy Future* document affirms Alberta's commitment to competition and market pricing in electricity

2010—RRO continues on transition to market pricing

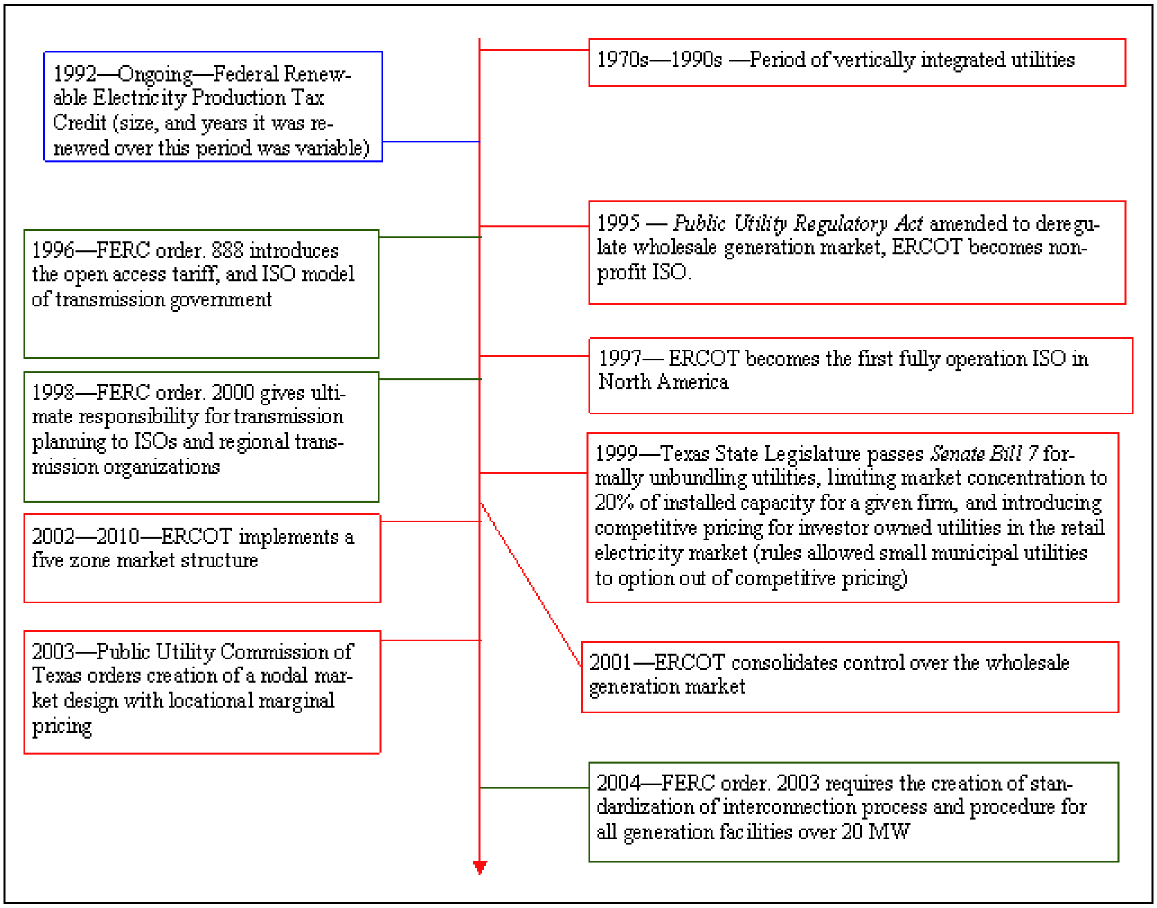
Sources: See Dadson etal. (2011); Doluweera etal. (2011); McCalley etal. (2010); FERC (2004); FERC (1999)

## 4.2.2. Texas

As in Alberta, the period of electricity market reform in Texas began in 1995 and was preceded by a period of reforms tilted toward increased competition in 1970s through to the early 1990s (Zarnikau, 2005). The historical market structure of the Texas electric utilities industry is characterized by several large utility companies, though with approximately 60 smaller municipal or investor owned utilities (Zarnikau, 2005). In 1995, the Texas State Legislature amended the Texas *Public Utility Regulatory Act* to allow for competitive pricing in wholesale electricity (ERCOT, 2010). This amendment included restructuring of the Electric Reliability Council of Texas (ERCOT) to a non-profit independent system operator (ISO) in 1996 in line with FERC order 888 (ERCOT, 2010).

The wholesale electricity market in Texas was designed from its inception to avoid many of the foibles which eventually plagued California during its supposed crisis in 2000 (Zarnikau, 2005). A number of features distinguish the design of the Texas market. These unique features include bilateral contracts between generators and retail distributors to protect consumers from hourly price fluctuations (Zarnikau, 2005). Further, Texas does not operate a centralized electricity spot market as the wholesale market is distributed amongst many utilities, with ‘nodes’ for each generation and distribution facility (Zarnikau, 2005). As well, daily loads are balanced on a day ahead basis and ERCOT has provisions to engage capacity on an hourly basis (Zarnikau, 2005). In 2003 the Public Utility Commission of Texas ordered ERCOT to implement locational marginal cost pricing, and a nodal market design (ERCOT, 2010). The result is a highly complex market with over 4000 localized marginal prices with 550 separate generation sights (ERCOT, 2010). Further, Texas has allowed retail choice for individual consumers, though uptake from consumer choice mechanisms by residential consumers has been low (ERCOT, 2010; Zarnikau, 2005). Overall, the Texas market design is regarded as a success, and with broad based support from system participants, ERCOT has flexibility to tinker with market design (Zarnikau, 2005). Figure 4.4 presents the timeline of policy changes in Texas.

*Figure 4.4 - Texas Market Timeline*



1970s—1990s —Period of vertically integrated utilities

1992—Ongoing—Federal Renewable Electricity Production Tax Credit (size, and years it was renewed over this period was variable)

1995 — *Public Utility Regulatory Act* amended to deregulate wholesale generation market, ERCOT becomes non-profit ISO.

1996—FERC order. 888 introduces the open access tariff, and ISO model of transmission government

1997— ERCOT becomes the first fully operation ISO in North America

1998—FERC order. 2000 gives ultimate responsibility for transmission planning to ISOs and regional transmission organizations

1999—Texas State Legislature passes *Senate Bill 7* formally unbundling utilities, limiting market concentration to 20% of installed capacity for a given firm, and introducing competitive pricing for investor owned utilities in the retail electricity market (rules allowed small municipal utilities to option out of competitive pricing)

2001—ERCOT consolidates control over the wholesale generation market

2002—2010—ERCOT implements a five zone market structure

2003—Public Utility Commission of Texas orders creation of a nodal market design with locational marginal pricing

2004—FERC order. 2003 requires the creation of standardization of interconnection process and procedure for all generation facilities over 20 MW

Sources: See Zarnikau (2005); ERCOT (2010); Zarnikau (2011); Woo, Zarnikau etal. (2011); U.S. National Renewable Energy Laboratory DSIRE database.

## 4.3. Renewable Electricity Penetration and Support Policies

Alberta has had no active support policy for renewable electricity, but it has developed one of the most robust wind driven electricity generation industries in North America. In 2010, electricity generation from wind represented 5.7 percent of Alberta’s installed capacity compared to the Canadian rate of 3.3 percent (Baker et al., 2011). Though Ontario has more installed capacity, 1363 MW compared to Alberta’s 780 MW, the former also has high subsidies and regulatory mandates (Baker et al., 2011). Texas’ success at establishing renewable generators is even more remarkable, as of 2010 the state had 10,089 MW of installed wind generation capacity (Gelman, 2011). The success of wind development in Texas can be attributed to a combination of factors: “enormous resource potential, the establishment of policy targets and a system of tradable Renewable Energy Credits (RECs), federal tax credits designed to encourage investment in renewable energy, and favorable market rules in the competitive ERCOT market” (Zarnikau, 2011). Further, a brief review of literature on scale economies and learning curves in wind development suggest that improvements in the technology relative to changes in cost cannot explain the spurt of investments or supposed increases in competitiveness (Blanco, 2009; Ibenholt, 2002; Kobos et al., 2006; McDonald and Schrattenholzer, 2001). In general, the findings from the literature on induced technological change and learning curves suggest that support policies and institutional context tend to influence renewable electricity projects and penetration more than learning curves (Kobos et al., 2006). While the success of renewable electricity development in Texas is relatively well understood, the high penetration rate for Alberta has remained somewhat of a mystery.

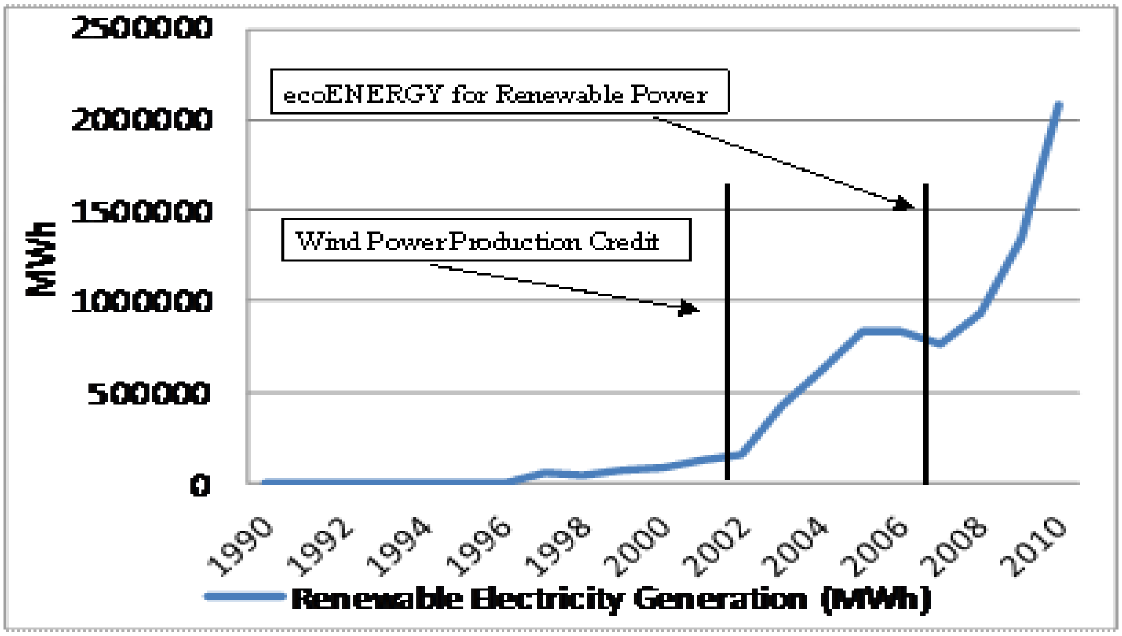
Alberta and Texas seem to differ in that the latter jurisdiction has more actively promoted wind development than the former jurisdiction. However, a comparison of the circumstances in the two regions indicates that the types of policy supports present in Alberta do not differ that much from those in Texas because they are mostly federal policies.[6] There is a modest renewable energy credit trade in Canada, for instance in 2007 1,427,000 MWh of bundled and unbundled green power were produced in Canada (Sustainable Prosperity, 2011). As well, Alberta has significant wind and solar resource potential (Gil et al., 2006). This potential has been exploitable because of generous federal incentives such as *Wind Power Production Incentive* and the *ecoENERGY for Renewable Power,* and other power purchases by the federal government. Indeed, the data presented below in Figure 4.5, clearly demonstrates that federal production

---

[6] Bradley (2005) reports that Alberta had a miniscule, voluntary portfolio goal set at 5.5 percent of total generation from renewable sources by 2008.

subsidies have influenced renewable power development in Alberta. A combination of federal incentives, a burgeoning demand for green power in Canada and the U.S., and Alberta's vast resource potential likely explain the province's renewable penetration rates. This is pertinent in light of the noted comparison with the context of resource exploitation in Texas.

***Figure 4.5 - Renewable Power Production, Alberta (1990-2010)***



Source: National Inventory Reports, Canada

## 4.4. Congestion Management and Transmission Planning

High renewable penetration creates challenges for grid management and coordinating transmission investments and planning. Though issues such as intermittency are often described as technical problems, effects on system wide costs or reliability may be overstated, and result from a lack of participants' experience with the new technologies (Sovacool 2009). In fact, evidence from Texas indicates that transmission rules, investment decisions, and government subsidies have a larger impact on the management of congestion than intermittent renewables. Texas has faced a number of challenges in managing transmission investments. First, much of the development of wind energy in Texas has occurred in the northwestern quadrant of that state, where transmission capacity is limited and removed from load centres (Zarnikau, 2011). The result is a disjunction between generation and transmission capacities, for example in one West Texas district 785 MW of generation capacity were installed compared to the 400 MW of available transmission capacity (Zarnikau, 2005). Failures to coordinate transmission and generation resources have direct effects on congestion and electricity pricing. Woo, Zarnikau et al.(3936, 2011) note: "high wind generation and low load in the wind-rich West ERCOT zone tend to lead to congestion and zonal price differences during any given time period". In order to bring generation and transmission into equilibrium with demand, investments on the order of $5 billion U.S. dollars will be necessary (Zarnikau, 2011). Further, favourable tax treatment for wind generators and ERCOT system rules have been shown to increase spot price volatility even as they reduce prices overall, due in part to their ability to submit negative price bids to ERCOT (Woo, Horowitz, et al., 2011; Woo, Zarnikau, et al., 2011).[7] Therefore, disconnects between renewable penetration rates, available transmission capacity, and the necessity of considering system wide reliability compound the complications of large investment decisions in transmission capacity. Where such conditions hold sway, there are bound to be extensive problems with grid congestion.

Given the apparent similarities between the two jurisdictions it should come as little surprise that Alberta faces similar challenges. The bulk of Alberta's wind generation is concentrated in the southwestern quadrant of the province, where development of the transmission system has not kept pace with the installation of generation capacity (AESO). Alberta's transmission planners face dual challenges of improving capacity in wind rich areas and of improving grid access for bitumen projects (Doluweera et al.,

---

[7] The ability to submit negative bids is a product of production subsidies which allow wind power producers to enter negative bids upto the rate of the subsidy (nominally $0.02 Kwh), or a -$0.02 Kwh, to the system operator. The wind producer then pays the purchaser to take the power. The head of transmission and distribution at British Columbia Hydro confirmed that this happens regularly in the western electricity system, so it is not an isolated phenomenon of Texas.

2011). Demand for electricity from Alberta's petroleum industry is expected to make that sector a net importer of electricity and to strain transmission capacity (Genalta Power, 2011). Further, much of the investment in natural gas capacity within the province is in the form of cogeneration for a given bitumen project, whose first objective is to provide power to the project not the grid (Doluweera et al., 2011; Nyboer et al., 2011). The dearth of transmission capacity within Alberta, and deficiencies in investment planning has created a complex dual challenge of meeting demand from bitumen projects and wind capacity.

AESO studies have determined that wind generation poses a number of challenges for the reliability of Alberta's grid system (AESO, April 20, 2006; AESO, 2006). The AESO has highlighted a number of concerns posed by wind integration, including indentifying a 900 MW installed wind capacity threshold past which violations of system reliability rules occur (AESO, April 20, 2006).In particular, the AESO study found extreme intermittency, on the order of 1200 to 1400 MW of production in three to four hours (Kehler et al., 2005). More broadly, wind penetration in Alberta poses a plethora of technical challenges, some of which interfere with system operation and makes clear the need for additional transmission investment (AESO, 2006).[8] Many of the challenges associated with wind penetration can be solved with technical fixes and changes to market rules, such as constraints on wind power production and construction, or increases in operating reserves (AESO, 2006).[9] Another proposal would increase transmission reliability margins by expanding transmission interconnections

---

[8] The study notes that the technical challenges, include: "voltage control at wind power facilities, system stability during fault conditions, need for transmission reinforcements, impacts on operational performance and related market rules"

[9] These include limits on allowed interconnections between projects and the grid; constraints on bulk transmission capacity allocated to wind projects; and, maximum ramp rate requirements. Changes to operating reserves would increase the amount of stand by generation capacity available to respond to variable wind production.

between Alberta and British Columbia and modifications to Alberta's project development application process (AESO, 2006; AESO, 2007).[10]

## 4.5. Electric Power Emissions

The commonality of high GHG emissions from the electricity industries of Alberta and Texas are explained by the proportion of coal and natural gas combustion technologies in the respective generation mixes (AESO, 2012; Zarnikau, 2011). Second, both jurisdictions have high proportions of demand for electricity from their respective industrial bases (Doluweera et al., 2011; Hadley, 2010).[11] Third, higher penetration rates of intermittent wind generation requires support from a peaking generator, likely a natural gas plant on the margin, in order to maintain system reliability (Freris and Infield 2008). Finally, for Alberta in particular, the baseload capacity of the province is a natural gas and coal mix, both in large scale generators and as cogeneration in industrial settings (AESO, 2012; Doluweera et al., 2011). As wind is an intermittent base load technology, high penetration rates will not effectively displace thermal capacity, once wind penetration has breached a given capacity threshold (Freris and Infield, 2008). The result is that renewable penetration rates can only have a limited displacement effect on high emissions technologies that act as baseloading capacity. This makes it unlikely that purely technological fixes will reduce emissions, without economic abatement policies, such as carbon taxes, supporting them.

Renewable penetration in either jurisdiction cannot be said to have effectively displaced emissions. Moreover, only three base load technologies can be considered emissions neutral – hydroelectricity, nuclear or geothermal – none of which has high penetration rates in Alberta or Texas. The prospects for shifting away from coal and

---

[10] This means increasing slightly the carrying capacity of British Columbia-Alberta grid interconnection.

[11] Industrial electricity demand tends to be constant meaning that jurisdictions with coal and natural gas base load generators are likely to have higher emissions. This combined with the fact that coal generators must run constantly means that high emissions are inevitable.

natural gas are weak, because for Alberta coal is a preponderant and readily available source of fuel, and natural gas is readily available in Texas (Doluweera et al., 2011; Zarnikau, 2011). Further, studies indicate that for Alberta, investments in coal plants can only be made uneconomic in the face of much higher carbon prices than the present $15 per tonne (Doluweera et al., 2011).

## 4.6. Conclusions

In using Alberta and Texas as case studies, a comparison of electricity industries with a range of similarities - high emissions, high renewable penetration rates, and large wind resource endowments – but policy differences can be useful for articulating the challenges facing policymakers in reducing GHG emissions. Further, by applying existing knowledge about power system economics, technical challenges, and regulatory and policy trajectories key lessons can be learned about the workings and effects of different mechanisms. Several key lessons are apparent in the Alberta-Texas comparison:

- First, it can be shown that mismatches between rates of installation of generation and transmission capacity can play a leading role in driving grid congestion which raises system costs and can create the opportunity for distortions such as congestion rents, and increased emissions. These problems are compounded by competing demands for bulk transmission investments from different generation technologies and regional markets.
- Second, direct subsidies from national governments can be shown to have incented rapid development of generation capacity and production from wind power projects. Sudden and near exponential growth in wind power production is not readily explained by technological learning curves, because of the stickiness of capital costs for wind turbines (Blanco 2009). The conclusion appears to be, as conjectured in Figure 4.5, that federal subsidies have played a central role in spurring power production from wind in Alberta.
- Third, due to technical constraints, comparative advantage in fuel sourcing and energy demand profiles in a given economy, electricity generation mixes can take on different forms. The result can be lock-in of given technologies and a stickiness in emissions profiles which can make it difficult to reduce GHGs. Further, technological constraints on the penetration rates of intermittent renewable sources, implies a penetration threshold beyond which thermal displacement ceases and system reliability requirements become important. This latter point explains the reason why high renewable

> penetration rates have failed to displace emissions and may even increase them.

When the results of the regression analyses are assessed in the light the case studies shed on how state and provincial level policies interact with electricity systems, the results are stark. Not only are subsidy policies that favour renewable technologies distortionary in an economic sense, they have perverse impacts on electricity systems. The conclusions of the research are clear, renewable electricity policies could be made less distortionary if they are more technology neutral. The research identifies a clear need to address the technology neutrality of existing policies, transmission planning issues, and the shaving of peak loads. Policies addressing these issues could help to reduce emissions, eliminate distortions and make centrally planned transmission networks in Canada more responsive to the challenges of integrating non-dispatchable, variable technologies.

# 5. Policy Analysis

The econometric analysis demonstrates that provincial and federal government policies designed to incent the development of small scale renewable electricity projects have not been effective at supplanting thermal generation or reducing GHG emissions. Further, the results of the comparative case analysis for Alberta and Texas demonstrate that deregulated markets, with open access to transmission systems can have a direct impact on increasing the renewable electricity penetration rate. Because of the intermittency of most renewable generation and transmission constraints, GHGs may rise coincidently with renewable penetration. This section presents alternative policy options for reducing GHG emissions from the electricity industry that focus on these aspects of the issue. The policies will be evaluated based on a framework of criteria derived from research and used to recommend a policy mechanism or basket of policies that most closely meet the criteria.

## 5.1. Policy Approaches and Mechanisms

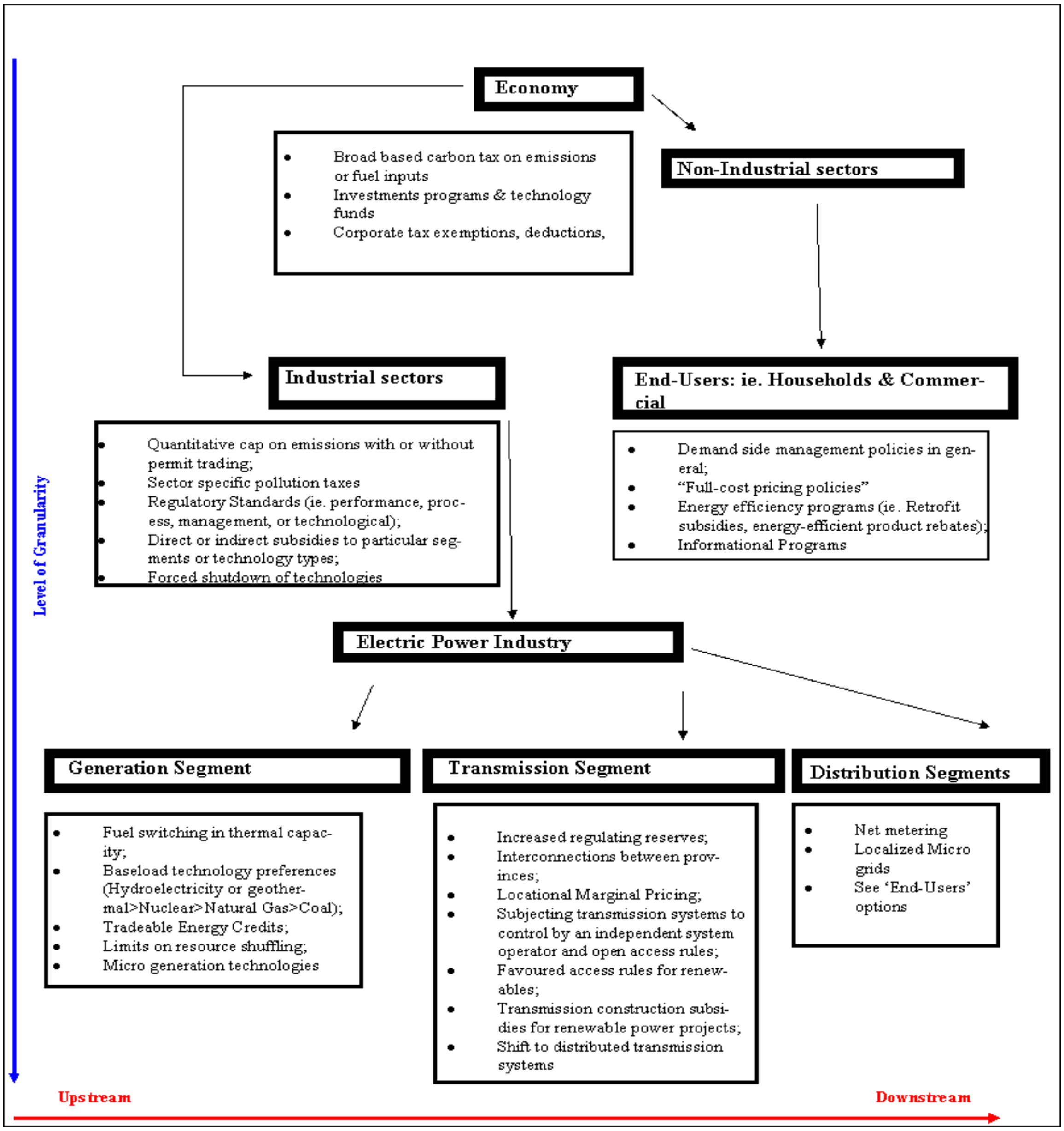
There are a range of mechanisms and policy approaches which could be employed to effectively reduce GHG emissions from electricity generation. Policy makers' have a range of levers at their disposal to reduce GHGs. These levers include broad economic and regulatory policies, load management and energy efficiency measures, and market reforms to change to investment patterns. Each of these mechanisms can be efficiently concentrated across different industries or segments of the given economy or sector. For the electric power industry, the specific segments include the generation, transmission, distribution, and more broadly, end use and consumption patterns. Across these segments there are a range of tradeoffs between different policies or bundles of policy mechanisms. Choice of policy approach and the basket of mechanisms can be subjected to a range of political, economic and administrative constraints, which can lead to vast differences in regulatory strategy, stringency and effectiveness.[12] Figure 5.1 presents a schematic of GHG abatement and technology shifting strategies generally thought to be the main policy mechanisms for the electric power industry.

Any successful policy approach for reducing emissions from electric power can be defined generally to include mechanisms which reduce emissions from baseload generation, and shift investments into renewable or low emissions technologies, while reducing loads during peak times. It is expected that the basket of mechanisms ultimately applied in the policy will induce long run reductions in GHG emissions by shifting baseload technologies. Further, the design of such policies must be sufficiently malleable to incorporate new inventions into the system and meet reliability rules, with a preference towards technologic neutrality.

---

[12] As pointed by a range of scholars conducting research from different jurisdictions, even with the broad regulatory mechanism of *renewable portfolio mechanisms,* broad factors contribute to choice and small differences might yield large differences in efficacy and performance (see Chandler 2009; Huang et al. 2007; Lyon and Yin 2010; Jenner et al. 2012).

*Figure 5.1 - GHG Abatement Policy Schematic for the Electric Power Industry*



## 5.2. Aligning Abatement Policy with Electricity Market Design in the Face of Political Convenience

Designing policy mechanisms to effectively reduce GHG emissions is a difficult task, and such policies can be complicated to implement. The policy by its nature must include mechanisms to achieve the three noted objectives: reduce emissions from baseload technologies; not violate system reliability rules; and, reduce loads at peak times. Additionally, in order for the policy to be successfully implemented in Canada either nationally or in a given province, all mechanisms within the policy must be acceptable to the political calculus of a given level of government, or both levels. This is no easy balance for a policy to achieve, and is certainly one reason for ineffective or lackadaisical policies in Canada.

There are a broad range of provincial policies implemented in Canada including carbon taxes, regulations, and cap and trade approaches. Regulatory approaches have been implemented in Canada, such as Alberta's broad based emissions intensity cap with offset trading, or Ontario's industry specific forced closure of coal fired plants. These regulatory policies are known to be both politically contentious, economically inefficient (Nordhaus, 2006) and in Ontario's case, financially costly (Hrab and Fraser, 2011).[13] Economy wide carbon taxes are generally favoured by economists on efficiency grounds to reduce emissions and shift investment away from GHG intensive sources (Metcalf, 2009; Nordhaus, 2006). However, evaluating any quantitative emissions cap, regulatory standard or broad based carbon tax is well beyond the scope of this industry specific study.

Subsidy and mandate mechanisms have been shown to have limited effects, and in the case of renewable power, are not technology neutral, driving inefficiencies in investment. Though such policies are likely to be necessary in circumstances where carbon pricing is absent and emissions do not reflect the full cost of their damage. Small scale renewable policies, both portfolio mandates and direct subsidies, have been shown in both Canada (by this study) and the U.S. to be ineffective at reducing

---

[13] Hrab and Fraser (2011) note four key lessons from Ontario's forced shutdown policy: (i) "set realistic deadlines that recognize the technical challenges associated with coal replacement"; (ii) "recognize that there are bound to be significant direct costs associated with replacement"; (iii) "recognize that stakeholders should be consulted early in the policy development process"; (iv) "work with neighbouring jurisdictions to ensure that the full environmental benefits of coal replacement are obtained..."

emissions (Prasad and Munch, 2012).[14] There are several reasons for this lack of efficacy. Mandate and subsidy mechanisms have been around in either jurisdiction for a less than a decade, so they may not have had sufficient time to affect the intended change. Second, as subsidy and mandate mechanisms favour certain technologies and impose either cost advantages or enact grid access requirements they create challenges for system operations (Hogan, 2010).[15] Utility programs for demand side management have been developed for Canada and the U.S., and econometric studies have shown the effectiveness of such subsidy programs to be subject to a range of problems (Loughran and Kulick, 2004; Rivers and Jaccard, 2011). The identified issues include free-riding by subsidy recipients and take-up bias, rebound effects, and over-estimation of energy savings (Loughran and Kulick, 2004; Rivers and Jaccard, 2011).[16] This brief scan of subsidies and mandates suggests that in terms of market design and GHG reductions, such mechanisms are problematic choices for load management.

In the analysis of environmental policy for GHGs and air pollution, regulatory policies and broad based taxes are the focal point of attention; and, for load management policy smart grids, energy efficiency subsidies, and peak pricing have been the subject of much discussion. Further, based upon the presumption that renewable electricity policies can supplant base load emissions, governments have pursued costly subsidies and mandates. Many of these policies have been pursued without regard for fundamental principles of power economics or engineering. The functional aspects of electric power systems are often ignored in the design and implementation of such policies, but as William Hogan has noted: “Placing a price on carbon is a critical step. Getting the resulting incentives right will be easier the closer the electricity market design reflects the reality of electricity system operations” (Hogan, 2010). Thus, successfully

---

[14] There a range of reasons for this that I will discuss below.

[15] The actual published copy from the book was not available at the time of writing, I have therefore elected to use an earlier draft obtained from the author. Both citations for the draft and the book are provided in the bibliography section.

[16] Jackson (2010) citing an U.S. Environmental Protection Agency study notes that U.S. program evaluations of utility based demand side management found those programs subject to“10% free riders and 14% spillover effects for a net gain of 4% in the impact of the program...”

reducing emissions in the long run requires a carbon pricing mechanism; this is a requisite for success. Equally important is the design of electric power markets that pricing mechanisms will be imposed upon. The latter area of electricity policy deals directly with transmissions investment strategy, effectively incenting low emission technologies and load management.

In Canada, both federal and provincial mechanism choice and policy have, in general, ignored these critically important issues by valuing political expediency or over market design or abatement policy issues. The policies have been inconsistent with the goal of reducing emissions, and the policy malaise in this area is reflected in the piecemeal efforts of those governments (Holmes, 2012). The electric power industry in Canada faces large investments in infrastructure in all segments in the coming years, but the current market designs do not seem ready to keep pace with the environmental and system management challenges. Between 2010 and 2030, Canadian utilities and transmission grid operators are facing a large volume of equipment retirements which will require large investments on the order of “$195.7 billion in generation, $35.8 billion in transmission, and $62.3 billion in distribution” (Baker.et al., 2011). These are investments that will have a direct impact on the industry’s GHG emissions and it is therefore important that policies shift investment patterns towards socially efficient sources. As well, there is a recognized need for a more adaptable system to meet future policy requirements, such as effective smart grids for load management.

## 5.3. Electricity Market Design Issues: Why not more competition?

Most of the electricity utilities in Canada are owned by provincial governments, and there is a general history of political intervention in the operations of the electric power markets. Political intervention in market and utility operations subvert the ability of utilities to make independent financial decisions and effectively price electricity or align investments with appropriate incentives. In part, this conundrum is the result of political calculus and a clear conflict of interest for management as rate payers are voters, who themselves elect the governments ultimately responsible for the utilities. The political intervention in market operations leads to effective vertical integration and virtually no competition in electricity markets. Competition in electricity markets may have a bad reputation because of events in the 2000-2002 in California crisis,[17] but with appropriate market designs such concerns can be allayed. As well, a review of the economic and engineering literature indicates that competitive markets have major advantages over the vertically integrated, monopolistic variety.

Policymakers should recognize the need for incentives that do not dictate investment in specific technologies, meaning that incentives should be technology neutral. Such incentives can create sufficient flexibility in the system to make the integration of new inventions, such as smart grids, efficient. Indeed, it has been argued that these core principles should always guide electricity market design and that competitive markets are the only system capable of creating the right price signals (Hogan, 2010). It has been demonstrated that competitive markets with independent system operators are more effective compared to vertically integrated utilities at integrating renewables (Electric Power Supply Association, 2008; Hogan, 2010).[18] As well, it is generally recognized that ISOs should have a direct role in governing transmission systems, determining optimal economic dispatch, and operating the spot market (Hogan, 1995). While there is a debate in the literature about what type of ISO design is best, it is generally recognized that such a solution is favourable for all market participants compared to a regulated or vertically integrated solution (Boyce and Hollis, 2005).

---

[17] Indeed the California crisis is really an anomaly. The principle of competition in electricity markets cannot be rejected upon the basis of past experiences. For instance, the case of California was the product of a confluence of: FERC imposed rules constraining market operations; a poorly designed spot market; price caps on wholesale electricity; a forced zonal pricing scheme which did not reflect the realities of system operation; dependence on natural gas in the generation mix; natural gas price spikes; an unusually hot summer; gaming behaviour by market participants and, limited access to exports from British Columbia due to the drought (Scorah et al. 2012; Hogan 2010; Dahl 2004; Ford 2001).

[18]. In part, this effectiveness is due to simplified rules for interconnection, but in the U.S. ISO markets have a disproportionate volume of wind production (Electric Power Supply Association 2008; Hogan 2010)

One of the core reasons for this flexibility is that ISOs decentralize decision making and assigns prices based on the marginal cost to the system of delivering electricity from the generator, through the grid to the customer.[19] A US study examined the effect of deregulation on emissions between 1993 and 2002, it found no direct effect, but noted that the flexibility market economics brought to abatement and investment policies were major advantages (Swisher and McAlpin, 2006). These advantages are derived mainly from the ability of competitive markets to increase economic efficiency. That is, though they do not directly decrease emissions, they make it possible for other policies to work more efficiently and technologies to be easily integrated into the system. If the competitive market is designed correctly it has the potential to be far more efficient than a centrally planned, vertically integrated version. These efficiencies coupled with other policies can help to create incentives for investments in generation, and enhance the efficacy of demand side management or a carbon pricing scheme.

## 5.4. Alternative Policy Options

### *5.4.1. Status Quo*

The proposal is to maintain the current package of policies and do nothing to augment them. Though the econometric estimates performed in this study indicate that the current basket of renewable electricity policies have not been effective at reducing GHG emissions, one of the reasons for this may be that they have not had sufficient time to work. This option proposes continuing with the business as usual case.

---

[19] This form of marginal costing, called locational marginal pricing, assigns a price to each transaction based on the cost of production of electricity from a given facility and combines it with the transmission and system costs to deliver the electricity to the purchaser. William Hogan (2010) characterizes locational marginal pricing as: "a schedule of generation and load at each electrical location. Hand-in-hand with quantity dispatch is a set of market-clearing prices for settlement purposes that capture the system marginal cost of meeting increased load or decreased generation at each location...These locational marginal prices provide an immediate definition of the appropriate spot-price of transmission between any two locations..."

### 5.4.2. *Encouraging Grid Interconnections between Provinces*

The proposal is to build more extensive transmission grid interconnections between provinces which have large hydroelectric capacity, and those with large intermittent renewable resource potential and thermal generating capacity.

Pursuing grid interconnections between provinces is a policy option which should be taken seriously. High voltage transmission capacity between provinces is limited due to individual provincial preferences for exporting, as such much of the transmission capacity is directionally north-south not east-west (Bowman et al., 2009). A review of the modelling presented in the following paragraph indicates that when other electric power variables are accounted for, provincial interconnections seem to raise emissions in individual jurisdictions. However, it should be noted that pooling provincial resources could help to reduce aggregate Canadian electricity emissions intensity (Bowman et al., 2009).

The current status of Canadian provinces as net exporters of electricity to the U.S. depends largely on their ability to exploit hydroelectric capacity stored in reservoirs. However, the long run effects of climate change on hydrologic flows and increased demand for electricity has the potential to shift the status of hydroelectric dominant provinces to net importers (Kiani et al., 2013). Climate related pressure on hydrologic systems, combined with competing demands for water will compromise the energy security of those provinces that depend on hydroelectricity for electric power supply. This is apparent both in historical examples and in a number of modelling exercises that demonstrate the magnitude and nature of these challenges. For instance in British Columbia in 2001, droughts reduced available water resources by 37.5 percent which forced the province to import electricity from the northwestern U.S. power system (Scorah et al., 2012). A recent study of the proposed Alberta and British Columbia intertie suggests that "BC will import wind-generated electricity from Alberta to meet domestic load, thereby storing water in hydro reservoirs...Higher water levels in British Columbia lead to greater energy output from the province's hydroelectric generator and thereby also reduce coal imports from Alberta" (Scorah et al., 2012). As well, GHG emissions are sensitive to wind power output, water reservoir levels and the presence of the intertie (Scorah et al., 2012). Further, wind integration is found to increase the cost of reducing GHGs as emissions become stickier with higher wind generation and the need for more supporting base load. An analysis of Quebec's power system, assuming an isolated grid, found that a 10 percent wind penetration rate required additional hydroelectric capacity (Belanger and Gagnon, 2002; Scorah et al., 2012). There could be significant advantages for enhanced grid interconnections between Ontario and Quebec; Manitoba, Saskatchewan and Northern Ontario; or a given combination of maritime provinces. The challenges of the declining availability of hydroelectric power and increasing wind penetration rates pose major challenges for Canadian utilities.

In order to help address these challenges, the interconnections between provinces could help to reduce system wide costs by increasing access to comparatively advantageous electricity generation mixes. The proposal for increased grid inter-ties in the west, between British Columbia and Alberta, has recently been made based on energy system planning models (Kiani et al., 2013). Under the scenarios modelled by the Pacific Institute for Climate Solutions team, British Columbia becomes a net importer of electricity between 2025 and 2030 (Kiani et al., 2013). One of the cornerstone solutions proposed, and is found to be critical for British Columbia to meet its load requirements, is an increase in transmission capacity with Alberta (Kiani et al., 2013). Thus, it can be said that the literature indicates that in the long term Canada's position as a net exporter of electricity may be compromised and its energy security threatened by not taking advantage of resource pooling through enhanced interprovincial transmission capacity.

### *5.4.3. Enhanced load management policies*

The policy proposal is for provincial utilities in Canada to invest in smart meter technologies and implement a peak load pricing scheme based on time of use.

Electric power utilities face two key challenges in attempting reduce GHG emissions, the first is making effective and efficient investments in generation and transmission, and the second is meeting ever increasing demand for electricity. Transitively, reducing GHG emissions requires a policy to reduce demand. As noted, energy efficiency subsidies in Canada have been found not to have affectively reduced demand due to free riding and rebound effects (Loughran and Kulick, 2004; Jackson, 2010; Rivers and Jaccard, 2011). For any utility, policies to manage this increasing demand are an important contributor both to projected emissions increases and system cost. Indeed, a number of studies have demonstrated the long term need for policies which reflect system costs in electricity prices (Kiani et al., 2013). In order to accomplish this objective, Alberta prices retail electricity based on system costs from the previous month, this is intended to protect consumers from price fluctuations (Dadson et al., 2010).[20] Whatever the schedule applied, pricing relating time of use to individual electricity consumption requires that utilities invest in the installation of ‘smart’ meters. Once consumption can be tracked as it occurs, then appropriate pricing schedules can be applied, and this can be used to suppress demand during peak times.[21] This solution has been recognized in a number of studies as a key policy to reduce system costs and GHG emissions (Stbrac, 2008; Albadi and El-Saadany, 2008).

### *5.4.4. Participant Driven Transmission Investment Planning*

The policy proposal is for implementation of a flexible and decentralized transmission planning investment scheme.

Managing expansion of grid systems to incorporate the development of renewable electricity capacity is a fundamental challenge faced by many jurisdictions. As noted above, Alberta and Texas face the prospect of making large investments in new transmission capacity to meet demand from generators and consumers. Indeed, one of the main challenges facing Germany’s rapid development of its renewable resources is

---

[20] Presumably, the rates from previous month are applied as a price schedule for the current time period. As well, it appears that

[21] Electricity demand during peak times requires higher operating reserves from baseload and peaking generators, in systems with coal and natural gas dominate mixes, this results in dramatically increased emissions. The result is that lower demand during peak times will help to reduce operating reserves and then GHG emissions.

investing in transmission capacity (The Economist, 2013b).[22] The key issue in transmission planning, once a clear need for investment has been determined, is to assess which entities are the primary beneficiaries of expansion. That is, it is important to determine which participants pay for the expansion and the best method for cost recovery. Generally, investment models that do not socialize costs and disperse construction costs amongst the main beneficiaries of the expansion are preferred (Budhraja et al., 2008). Clearly, a number of different regulatory policies exist, including: centralized transmission planning; ‘merchant driven transmission investment’; and, the ‘public contest method’. Centralized transmission planning is the status quo in most Canadian jurisdictions and is based on investment decisions made by the crown utilities. This planning can be inefficient as it subject to uncertainty about future electricity needs. The merchant investment method is essentially driven by private investment, but it too is challenging as firms in jurisdictions which have used it tend to overestimate profitability (Littlechild, 2008). The policy proposed here is the public contest method of transmission planning. This model requires that major transmission expansions be “proposed, approved, and financed by...generators, distribution companies, and large industrial consumers” (Littlechild, 2008).

Different versions of the policy have been implemented in several jurisdictions including Argentina, Chile, and New York State. In the State of New York, the New York Independent System Operator (NYISO) has adopted the public contest scheme (Hogan, 2010), using a unique variation to solve collective action problems[23] wherein the proportion of benefits accrued to participants is difficult to establish. Under these

---

[22] Indeed, Germany faces situation complicated by its aggressive renewable energy policies. In Germany, renewable electricity generators have priority access to the grid during peak times, as well they receive generous production subsidies. Simultaneously, Germany has forced a shutdown its baseloading nuclear facilities. The combined result of these policies is a glut of investment in renewables, increased operating reserve requirements for baseload generators and a shift in financial burden to natural gas plant owners. The upshot is that German utilities are investing in coal plants in order to reduce their financial liabilities. For more on this subject see Economist (2013a).

[23] In this context, collective action problems would be defined as ones where the beneficiaries of the transmission investment may not agree on the terms of construction, and then no new investment in generation may occur.

circumstances, the state regulator and the NYISO seek a “super majority endorsement where the beneficiaries vote and pay for the investment in proportion to the estimated benefits” (Hogan, 2010). This helps to overcome divisions between system participants, while allowing for comparatively decentralized decision making. Further, in Argentina the public contest method is recognized to have reduced deadweight losses from overexpansion as the policies have been designed to link cost to potential beneficiaries (Littlechild, 2008).

### *5.4.5. Reform of existing tax expenditures and subsidies to target decarbonization and not just renewable penetration rates.*

The proposed policy includes a number of reforms to the existing federal and provincial system of tax expenditures and subsidies. The first proposal is to eliminate existing provincial subsidies and reinstitute the lower cost federal *ecoENERGY for Renewable Power* subsidy on a fixed term to a given project. As well, the subsidy would be extended to cover carbon capture and sequestration (CCS), and advanced nuclear generation technologies. The same extension for other low emissions technologies would be made to the relevant tax expenditure, the *Accelerated Capital Cost Allowance*. Finally, to encourage investment is a ‘line constructed per unit of distance’ subsidy to reduce capital costs for renewable power producers wishing to sell electricity onto the grid. This would be designed to replace provincial production incentives, and would cost less as the rate would be lower.

The reason for this proposed change is to make the policy more technology neutral, and to help shift investor preferences about baseload technologies. The fixed term of the reinstated federal subsidy could be designed to provide initial support for some portion of capital costs and then be phased out after a period determined to be financially appropriate. While any subsidy policy is not preferable this basket of reforms could help to reduce costs, and help to align investments with incentives. These types of subsidies are particularly important to help create incentives in a policy environment where there is dedicated abatement policy with a pricing mechanism.

In Canada, the main policy to support the construction of transmission interconnections for renewable electricity producers is the *Accelerated Capital Cost Allowance* (Natural Resources Canada, 2010). The schedule allows for rapid depreciation of assets at rates of 30 and 50 percent on a declining basis, compared to the conventional annual depreciation rate of between 4 and 20 percent (Natural Resources Canada, 2010). This tax treatment combined with provincial support policies should provide an incentive to invest in renewable electricity. Yet based on the econometric estimates it appears that this combination has not been effective mitigation policy. There are two separate interconnection issues in transmission planning. The first is interconnection capital costs and the other is interconnection pricing.[24] The proposed policy is a 'line constructed per unit of distance' subsidy to reduce capital costs for renewable power producers wishing to sell electricity onto the grid. Subsidies that focus on capital costs will tend to be less distortionary than those which are designed as production based, so this design would be preferred over extisting provincial policies (Hogan, 2010). The policy is specifically intended to provide relief of transmission line construction costs up to some specified distance or total subsidy cost for a given project. The policy could be designed to favour specific geographic regions with known to have high resource potential, but limited prospects for development.

### 5.5. *Criteria and Measures*

The following presents the basic criteria which will be used in my policy analysis to assess the options. Tables 5.1 and 5.2 summarize the criteria, measures, and sources for the measures.

**Effectiveness at reducing GHG emissions from electric power –** Based on the regression estimates and the literature, it is possible to anticipate which policy will be effective at reducing emissions.

**Stakeholder Acceptance –** Represents an assessment of the acceptance of policies by different stakeholders. The stakeholders assessed include: provincial governments; the federal government; and, utility industry participants (crown utilities, private utilities,

---

[24] Interconnection pricing relates to the way in which the costs of connecting to the grid, and the associated risks with additional generation are socialized across the system or dispersed amongst system participants. See Hiroux (2005) or Budhraja et al. (2008).

independent power producers).

**Cost –** Represents the cost to the government and rate payers of a given policy. It is measured in terms of budgetary cost[25] and electric system cost[26].

**Conflict with FERC policies –** Assesses whether a policy conflicts with FERC orders and rulings.

**Technologic neutrality –** Tests if a given mechanism can treat all technologies, or low emissions technologies, equally.

---

[25] Budgetary costs assess the cost of a given policy to the public purse of a provincial government or the federal government.

[26] Based on the economics of electricity market design and the literature it is possible to anticipate if a policy will increase the system wide marginal cost of electricity or increase congestion. Initially, I had intended to separate the measure of public acceptability from system cost based on changes in the price of consumer electricity bills, but a review of the literature indicates that this is not an appropriate division. The reason is that changes in consumer electricity prices are highly dependent on the way crown utilities and system operators disperse financial, transmission and power generation costs. Hiroux (2005) notes there are a range of methods for dispersing costs ranging from socialization of all or most costs, to direct payment for each cost by system participants. In other words, the extent of who pays what and how is well beyond the scope of this analysis and reducing stakeholder acceptability to costs on changeable electricity bills that varies by jurisdiction is not appropriate. This makes even benchmarking or rules of thumb difficult to quantify accurately and meaningfully.

*Table 5.1 - Criteria and Measures*

| Criterion | Measure | Definition |
|---|---|---|
| **Effectiveness at reducing GHG emissions** | *Effectiveness at reducing GHG emissions* | Is the policy shown to be effective at reducing the GHG emissions from electricity generation? |
| **Stakeholder Acceptability** | *Provincial Governments* | What extent does the policy reduce or conflict with provincial autonomy over electricity policy? |
| **Stakeholder Acceptability** | *Federal Government* | What extent does a policy affect energy security and the federal role in governing trade policy? |
| **Stakeholder Acceptability** | *Independent and Crown Utilities* | What extent does a policy strand existing capital investments and affect profitability? |
| **Cost** | *Budgetary Cost* | What extent does the policy increase costs to federal and provincial governments? |
| **Cost** | *System Wide Cost and Grid Congestion* | To what extent can the policy be expected to raise system wide costs? |
| **Conflict with FERC policies** | *Conflict with FERC policies* | Is the policy likely to conflict with FERC policies, rulings or precedents? |
| **Technology Neutrality** | *Technology Neutrality* | Does a policy treat all low emissions technologies equally? |

***Table 5.2 – Measures and Analysis***

| Measures | Analysis | Data Source |
|---|---|---|
| *Effectiveness at reducing GHG emissions* | Level of Effectiveness at reducing GHG emissions | Based on a review of the literature |
| *Provincial Governments* | Qualitative description of the level of curbs on provincial autonomy | Based a review of logical imperatives related to legal constraints |
| *Federal Government* | Qualitative description based on a review of the literature | Based on logical deductions drawn from the literature and theory |
| *Independent and Crown Utilities* | Qualitative description based on a review of the literature | Based on a review of the literature and logical deductions based on economic theory |
| *Budgetary Cost* | Quantitative evaluation of program cost where there is data and a qualitative description where there is no data | Quantitative evaluation of program cost where there is data and a qualitative description where there is no data |
| *System Wide Cost and Grid Congestion* | Qualitative description of the extent to which a policy can be expected to increase system wide costs or congestion | Inferences drawn from the literature |
| *Conflict with FERC policies* | Qualitative description of potential conflict with FERC policies | Logical imperatives based on descriptions of FERC rules |
| *Technology Neutrality* | Qualitative assessment of whether a policy treats all technologies equally | Does the policy violate the neutrality principle? |

## 5.6. Analysis of Alternative Policy Options

### *5.6.1. Status Quo*

**Effectiveness at reducing GHG emissions** – The regression estimates performed in support of this study indicate that the current basket of provincial policies is not effective at reducing GHGs. While, federal renewable energy subsidies have helped to decelerate the rate of GHG emissions from the electricity industry in Canada. Indeed, given the renewable penetration threshold noted in the literature and the need to support intermittent renewable generation sources with emissions intensive base load capacity in many provinces, it is possible the policies have actually increased emissions (Freris and Infield, 2008).

### Stakeholder Acceptability

*Provincial Governments* – Renewable electricity policies in Canada cannot be said to have curbed the independence or autonomy of individual provinces in the structure or design of their systems. It should be noted the federal subsidies, *Wind Power Production Incentive* and the *ecoENERGY for Renewable Power,* can be shown to have increased renewable penetration and raised system costs for provincial utilities. The extent to which this qualifies as a reduction in provincial autonomy is a matter of perspective.

*Federal Government* – The status quo does not compromise Canadian energy security or interfere with the federal role in trade.

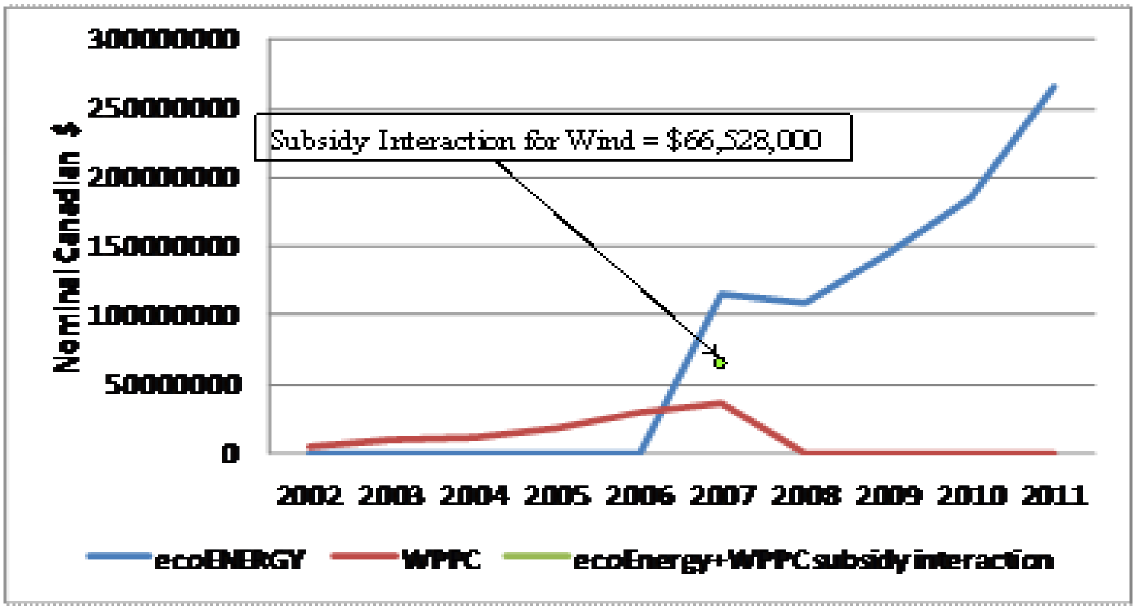
*Independent and Crown Utilities* – The status quo has affected the profitability of some crown utilities, whose provincial governments enacted legislation that required them to sign long term contracts with subsidies to independent power producers. An example is British Columbia. In general, these types of policies have raised system costs as they created a spurt of over investment in intermittent renewable energy.

### Cost

*Budgetary Cost* - It is difficult to say the exact cost of the various subsidy and regulatory programs that have been implemented during the study period, but it is possible to provide a rough estimation using simple calculations. Using renewable energy production data drawn from the U.S. EIA international energy statistics data base, and federal subsidy rates it is possible to roughly calculate the expenditures made by governments under these programs. Total federal expenditures on the *ecoEnergy* subsidy were approximately $819 million, and the expenditure on the *Wind Power*

*Production Credit* was $110 million.[27] Similar calculations have been performed here for British Columbia's *Standard Offer Program* and the two subsidies in Ontario, The approximate total value of the expenditures made in British Columbia were $183 million and in Ontario the value was $1.6 billion .[28] Figures 11 and 12 illustrate the expenditures on subsidies over time for the federal program and those in BC and Ontario.

***Figure 5.2 - Approximate Federal Expenditures on Renewable Energy Subsidies***

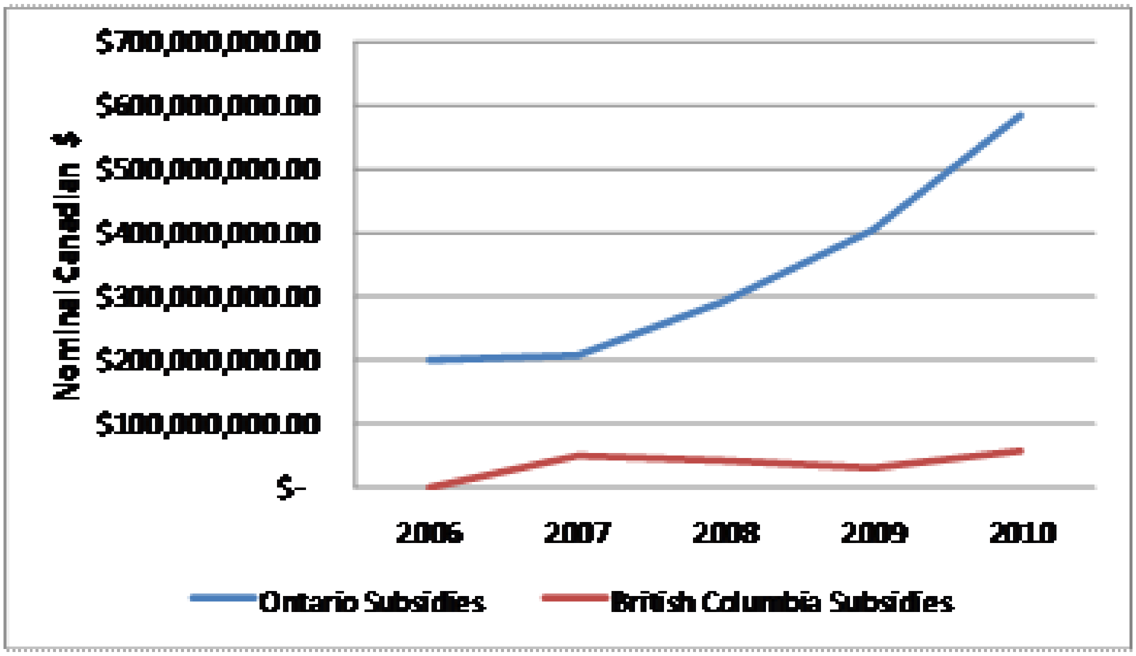


---

[27] The figures presented here are in nominal Canadian dollars, they assume that all wind, geothermal, tidal, solar, and biomass energy produced in Canada were eligible for and received the total subsidy of $0.01 kWh for the *ecoEnergy* (2007-2011) and $0.012 kWh of wind produced in Canada for the *Wind Power Production Credit* (2002-2007).

[28] The figures presented here are in nominal Canadian dollars. The renewable power data were drawn from the 2010 Canadian National Inventory Report. The years included in the calculations for the *Standing Offer Program* are 2007 through 2010, and the years covered by the two Ontario subsidies are 2006 through 2010. Ontario's feed-in-tariff program is still in full operation.

*Figure 5.3 - Approximate Provincial Expenditures on Renewable Energy Subsidies*



*System Wide Cost and Grid Congestion* –General transmission capacity has not kept pace with demand from installed capacity for cases when policy promotes the use of renewables for generation. Congestion results from this mismatch between generation capacity and transmission systems. For example, in Alberta, renewable penetration is associated with an increase in congestion charges thereby raising the costs of the terms of trade. It is reasonable to conclude that the current basket of policies has raised system wide costs.

**Conflict with FERC policies –** Given the presence of policies similar to those in the Canadian basket throughout the U.S. and directly regulated by FERC, it is unlikely that such policies conflict with FERC policies on open access.

**Technology neutrality –** The current basket of policies is not technology neutral, as it contains subsidies and regulatory mandates which favour small-scale renewable energy technologies to the exclusion of other low emissions technologies, such nuclear or large-scale hydroelectric capacity.

### *5.6.2. Encouraging Grid Interconnections Between Provinces*

**Effectiveness at reducing GHG emissions –** The effectiveness of this policy at reducing GHG emissions is expected to be low as modelling studies of western Canada have shown interconnections would likely increase emissions from coal in Alberta (Scorah et al., 2012). However, this finding is highly dependent on assumptions made about hydroelectric conditions and wind penetration. Further, it is possible that interconnections might raise emissions, but still reduce emissions intensities for the electric power industry nationally (Bowman et al., 2009). The main reason for increased GHG emissions under this policy is because pressure on hydrologic resources reduces generation from British Columbia's dams, which results in more demand for Alberta's carbon intensive electricity. This effect is a long term one and can be anticipated to occur in any hydroelectricity dominated province increasing transmission capacity with provinces that have fossil fuel intensive generation capacity.

**Stakeholder Acceptability**

*Provincial Governments* – As the National Energy Board of Canada has responsibility for regulating interprovincial electricity flows and construction of electricity lines. This policy would certainly constrain provincial autonomy. As the number of interconnections increase, the role of the federal government would increase. There would almost certainly be a constitutional debate about regulatory powers in electricity, and whether the federal trade power trumps the provincial powers to regulate infrastructure.

*Federal Government* – The federal government would almost certainly support increased interprovincial transmission capacity. The policy enhances the energy security of all Canadians.

*Independent and Crown Utilities* – Most utilities would support increasing transmission capacity between provinces as it would given them enhanced ability to trade electricity, and the benefits of lower and more stable system costs that would come with pooling resources.

**Cost**

*Budgetary Cost* - In the short term, the policy could increase administrative costs associated with regulating and building the interconnection for both the federal and provincial governments, and the utilities involved. It is difficult to estimate the budgetary costs associated with the administrative burden such expansions would impose on regulators. Certainly, these types of applications are routine and the cost from administrative burden is not anticipated to be high.

*System Wide Cost and Grid congestion* – Increasing the transmission capacity between provinces would be expected to reduce system wide costs and grid congestion in systems that have high renewable penetration rates. An example is Alberta, where increasing the transmission reliability margins on the interconnection with British Columbia has been seen as a solution to grid constraints (AESO, 2006). It should be noted that in a rate impact analysis, the AESO (2011) found that all transmission expansions would increase residential electricity bills by $11 in 2020 and industrial transmission costs by $19.71. However, when the systems costs of congestion are weighed against the slight increase in cost associated with a single project it is likely that this policy will reduce system costs by providing slack transmission capacity.

**Conflict with FERC policies –** In principle, the policy of transmission connections between provinces should not be considered a problem, but in order to export power to the U.S. compliance with the FERC order. 888 OATT *'pro forma'* is important (Carr, 2010). For those provinces that are large net exporters of electricity to the U.S., such a policy could deprive them of access to those power markets (Carr, 2010). Provinces that have competitive markets could have larger transmission connections with provinces that have monopoly utilities, but enhanced transmission capacity would be more difficult to enact without potential NAFTA challenges (Carr, 2010). This constraint is due to reciprocity rules in the FERC order. 888, which state that: "a party is allowed to use the open access provisions of a transmission system only if the jurisdictions they are supplying from or delivering to has comparable open-access transmission provisions" (Carr, 2010). The result is an effective block on Canadian electricity integration (Carr, 2010).

**Technology neutrality –** This policy should treat all generation technologies equally.

### 5.6.3. Enhanced load management policies.

**Effectiveness at reducing GHG emissions –**This policy would help to reduce GHG emissions in the short and long term. As noted above, higher demand during peak times requires larger operating reserve requirements, which means more stand by generation, such as natural gas. This dramatically increases GHG emissions from electric power and is an area where time of use pricing policies could be used to clear price signals and shift behaviour. A number of studies have shown that load management policies which directly link consumption to pricing can effectively reduce GHG emissions (Stbrac, 2008; Albadi and El-Saadany, 2008). In particular, Faruqui et al. (2007) find that eliminating five percent of peak demand in the U.S. through time of use pricing could reduce the number of peaking generators dispatching power significantly resulting in emission reductions. As well, other studies have found that there is high demand responsiveness on the part of consumers to peak and off-peak price differentials, signalling a high likelihood of emission reductions (Faruqui and Palmer, 2012). As well, International Business Machines' (2007) pilot study of smart meters for the Ontario Energy Board found that consumption patterns changed and energy conservation increased in the presence of more dynamic pricing.

**Stakeholder Acceptability**

*Provincial Governments* – This policy does not constrain or reduce provincial autonomy. There are lessons about implementation for provinces considering the installation of smart meters. Though Ontario's installation of smart meters met comparatively little opposition, their introduction in British Columbia aroused great controversy. The differences between the cases may be instructive for jurisdictions looking at demand side management policy using smart meters.

*Federal Government* – This policy does not affect the role of the federal government in electricity in any way.

*Independent and Crown Utilities* – By and large, independent and crown utilities would be expected to support both time of use pricing and the installation of smart meters. The policy is expected to reduce long run system costs and give utilities an enhanced ability to collect data and pinpoint reliability issues in the grid.

**Cost**

*Budgetary Cost* - This policy has a high capital cost related to the installation of the smart meters. For instance, in British Columbia installed approximately 1.8 million smart meters at a cost $930 million (BCUC, 2012; BC Hydro, 2013). This suggests that capital costs work out to approximately $517 per smart meter. Statistics Canada notes that in the 2011 census it counted 13.3 million households, this means that the national cost, that is if every jurisdiction implemented the program, the cost would be approximately $6.9 billion (Statistics Canada, 2013)

*System Wide Cost and Grid Congestion* – This policy is anticipated to reduce system costs by suppressing demands at peak times, shifting individual behaviour and appliance investment decisions, and reducing operating reserve requirements. The potential to reduce system costs is significant. For instance, one study has found there is potential savings in the U.S. from reductions of peak demand through load management on the order of $3 billion, though savings would be smaller in Canada the potential is high (Faruqui et al., 2007). In Ontario, this demand responsiveness was found to have saved customers money on their bills, and to have increased energy conservation (IBM, 2007).

**Conflict with FERC policies –** The policy does not conflict with FERC rulings or orders, so it passes the FERC test.

**Technology neutrality –** This policy is not designed to favour a particular generation technology, so it is nominally technology neutral.

### *5.6.4. Participant driven Transmission Investment Planning*

**Effectiveness at reducing GHG emissions –** By its nature, this policy is not designed to reduce GHG emissions, so no reductions are expected. It should be noted that the policy could allow for expansion of renewable resources if there are enough interested participants, which might indirectly induce reductions of GHG emissions.[29] It should be noted that there are no publicly available environmental assessments which I have been able to locate stating if the public contest has an impact on emissions. In general, transmission issues are not linked directly to emissions.

**Stakeholder Acceptability**

*Provincial Governments* – As the policy would be implemented as a provincial prerogative and the process controlled by provincial regulators, it would not curb autonomy.

*Federal Government* – This policy does not affect the role of the federal government in electricity in any way.

*Independent and Crown Utilities* – This policy would be likely to receive support from independent and crown utilities. The reason for their anticipated support is that the policy is thought to reduce the costs through competition through more competitive bidding for projects. As well, it appears that utilities generally supported the public contest method in the Argentine example (Littlechild and Skerk, 2008).

**Cost**

*Budgetary Cost* – This policy would not incur direct costs to governments as it would be managed by utilities or independent system operators.

*System Wide Cost and Grid Congestion* – The policy is expected to reduce system costs and if implemented efficiently could allow for a reduction of grid congestion. A review of the effectiveness of this policy in Argentina found that it reduced the costs of constructing transmission lines and upgrading existing facilities (Littlechild and Skerk, 2008). This fact has been attributed to the competitive nature of the private tender scheme applied in this policy (Littlechild and Skerk, 2008). The public contest method

---

[29] It should be noted that this claim is only valid if the technologies added through the interconnection are renewable base load technologies, such as geothermal electricity generators.

reduces the incidence of transmission cost socialized across the entire power system because the cost of expansion is dispersed according to the benefits (Budhraja et al., 2008; Hogan, 2010). As well, there is significant potential to reduce faulty transmission investments and subsequent deadweight loss associated with construction which was not necessary and uneconomic.

**Conflict with FERC policies –** The policy has been vetted by FERC and is based on established methods of estimating benefits (NYISO, 2007; Hogan, 2010; Budhraja et al., 2008). It should not conflict with FERC policies.

**Technology neutrality –** The policy does not have an inherent technology preference.

### *5.6.5. Reform of existing tax expenditures and subsidies to target decarbonization and not just renewable penetration rates.*

**Effectiveness at reducing GHG emissions –** It is difficult to conjecture if this policy would reduce emissions and to what extent. If the federal subsidy includes carbon capture and storage or advanced nuclear technologies, it might reduce emissions. In the long run if a carbon pricing mechanism is present, this type of a policy could help to increase the renewable penetration rate. It is unlikely this could reduce emissions or displace thermal capacity.

**Stakeholder Acceptability**

*Provincial Governments* – This policy would involve some implicit federal government involvement in provincial electricity markets, but since the proposal is essentially an extension and adaptation of existing policies or those which existed until recently provincial governments are not likely to protest. Further, the policy could be negotiated on a province by province basis, so it need not be a single national subsidy extended in all provinces, though that would likely be more efficient.

*Federal Government* – While changes to the *Accelerated Capital Cost Allowance,* would likely be supported by the federal government. The budgetary cost associated with reinstituting a subsidy scheme will have fiscal implications for the federal government, and this aspect of the program may thus create a trade off with other government programs.

*Independent and Crown Utilities* – There is no reason to expect that any of the reforms proposed in this policy would negatively affect the profitability of utilities. Indeed, it might enhance their profitability and financial prospects.

### Cost

*Budgetary Cost* - This program would reduce costs for provincial and federal governments. For the federal government, the increased tax expenditure and reinstituted subsidy would increase costs relative to having no program. The new program costs less than the original subsidy scheme as it does not provide subsidies over the full life cycle of the project. Provincial governments could face significantly reduced costs by transitioning to use of a capital cost subsidy rather than a production subsidy. The figures in Table 5.3 present the cost of the federal and provincial subsidies over the course of the years 2006 to 2010. The capital cost subsidy for grid interconnections is far less expensive and is a onetime expense. The figures represent the full cost of covering all interconnections for renewable energy projects built in Canada.[30] The cost of the provincial subsidies is drawn from the calculations used in Figures 5.2 and 5.3.

---

[30] The calculations used for the provincial subsidy are based on the assumption that interconnection represents 12% of all capital costs for small scale renewable projects, this is based on Blanco (2009). Kiani et al. (2013) assume that the installed cost of wind generation is $2000 per KW, this cost is assumed to be constant for all technologies. These parameters are then multiplied against data drawn from U.S. EIA *International Energy Statistics Database* for the installed capacity of all renewable energy technologies in Canada. More precise assumptions could be made but that is beyond the scope for this project.

*Table 5.3 - Reformed Subsidy Costs (Nominal Canadian $ million)*

| | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|
| **Federal Subsidies** | 112.7 | 115.4 | 109.1 | 145.1 | 184.5 |
| **Provincial Subsidies** | $199.39 | $258.86 | $334.47 | $433.67 | $642.88 |
| **Provincial Capital Cost Subsidy** | $3.18 | $3.41 | $3.96 | $5.12 | $5.82 |
| **Provincial Cost Savings** | $196.21 | $255.45 | $330.52 | $428.55 | $637.07 |

*System Wide Cost and Grid congestion* – Any policy designed to increase the renewable penetration rate will raise system costs and increase grid congestion. As this policy is designed to reduce the amount of production incentives available and increase capital investment incentives it should reduce the incidence of grid congestion by a small degree. Again any claim of this nature is subject to the structure of the market design and the degree of disequilibrium between transmission and generation capacity. This policy would certainly be less distortionary than the status quo.

**Conflict with FERC policies –** As long as the policy does not conflict with the open access transmission tariff requirement, which it would not, it should pass the FERC test.

**Technology neutrality –** The policy is not technology neutral, it favours renewable electricity generators and other low carbon technologies.

## 5.7. Summary of Policy Assessment

Based on the analysis of the policy alternatives, each characteristic of individual options will be assessed against each criterion, and then rank ordered accordingly. It would be preferable to quantify each individual criterion for each option with a relevant monetary or physical unit of measure, but the research needed to attain these measures is beyond the scope of the study. In place of physical or monetary units, a qualitative ranking of impacts on the given criterion are presented for each option, and these rankings are weighted relative to importance of the overall study. In essence this is a descriptive analysis, so the assessment of the criteria and measures are supported with evidence from the study.

The colour scheme in the policy evaluation matrix presented in Table 5.4 is derived as follows: red indicates that a policy does not satisfy the requirements of the given criterion; yellow indicates that a policy has partially satisfied the requirements of the given criterion; and, the green indicates that a policy has fully satisfied the requirements of the given criterion. The colour coding is intended to present the complex tradeoffs between different policies.

Table 5.4 indicates that two policy options dominate the others – options three and four. Options one, two, and five do not perform as well compared to other policies. Under the scheme applied in this matrix, stakeholder acceptance, system cost, and effectiveness at reducing GHGs are highly important factors in enhancing the performance of different policy alternatives. There are several points which stand out in this evaluation: only option two violated the FERC test, and option five did not possess high acceptability by the federal government. Several of the criteria were difficult to assess without data or even studies to effectively support conclusions. This was particularly the case when evaluating support from the federal government for a particular policy, as the current federal role in electricity policy is oblique in certain areas.

Overall, the status quo could not be shown to have achieved the main objective of reducing GHG emissions, and the design of many of the individual policies in option one are likely to have raised system costs. Option two, provincial grid interconnections, does not have support from provincial governments and it does not necessarily lower emissions.[31] Options three and four, performed well in most metrics, but option four was

---

[31] Carr (2010) notes that such a policy would require use of NAFTA to challenge the application of FERC rules, such as the 888 *pro forma,* an unlikely scenario.

not found to lower emissions. Option five did not have federal government support, but appears to be moderately effective at reducing GHG emissions.

***Table 5.4 - Policy Evaluation Matrix***

| **Criteria and *Measures*** | **Option 1: Status Quo** | **Option 2: Provincial Grid Interconnections** | **Option 3: Load Management** | **Option 4: Decentralized Transmission Planning** | **Option 5: Technology Neutral Subsidies** |
|---|---|---|---|---|---|
| **Effectiveness at reducing GHG emissions** | 🟨 | 🟥 | 🟩 | 🟨 | 🟨 |
| **Stakeholder Acceptance** | | | | | |
| *Provincial Governments* | 🟩 | 🟨 | 🟨 | 🟩 | 🟩 |
| *Federal Government* | 🟩 | 🟩 | 🟩 | 🟨 | 🟨 |
| *Utilities* | 🟥 | 🟩 | 🟩 | 🟩 | 🟩 |
| **Cost** | | | | | |
| *Budgetary Cost* | 🟥 | 🟩 | 🟨 | 🟩 | 🟨 |
| *System Wide Cost and Grid Congestion* | 🟥 | 🟩 | 🟩 | 🟩 | 🟨 |
| **Conflict with FERC policies** | 🟩 | 🟥 | 🟩 | 🟩 | 🟩 |
| **Technology Neutrality** | 🟥 | 🟩 | 🟩 | 🟩 | 🟥 |

# 6. Recommendations

The combined weight of the research including the econometric analysis, case studies, thorough review of the literature, and review of several policy options indicate a number of important points about GHG emissions and the electric power industry in Canada. First, no policy alone can effectively reduce emissions, even a carbon pricing mechanism, but such a policy is essential to any successful strategy. Secondly, it is clear that current provincial renewable energy policies have not reduced emissions, neither has U.S. demand for ‘green’ power. This challenges the basis of many of those policies. Finally, electricity market design and transmission investment play a critical role in determining the success of mitigation policy. Without an awareness of the fundamentals of electric power systems and the technical and economic challenges they pose, no policy recommendation will be useful.

The first recommendation is that provinces install smart meters and implement time of use pricing. This is a policy which could help to significantly reduce emissions, system costs, and in the long run, suppress increasing electricity demand during peak times. By linking electricity consumption to system cost, a policy of enhanced load management could be extremely effective at reducing demand during peak hours and operating reserve requirements. Load management has an advantage of helping to change fundamental behaviour both about energy consumption and energy efficiency investments. This is recognized as an important long term policy option in Canada, but one which could yield immediate results (Kiani et al., 2013).

The second recommendation is for the implementation in all jurisdictions in Canada of the public contest method of decentralized transmission investment planning. The policy has been found to efficiently align investments with system needs, as well, it has been shown to reduce transmission investment costs (Littlechild and Skerk, 2008; Littlechild, 2008). As well, because investments are paid for by beneficiaries the cost of transmission expansion is not socialized across power systems (Hogan, 2010).

Third, despite the potential inefficiencies of option five, I recommend its implementation, in the absence of a carbon price. Without an effective carbon price and a clear abatement path led by the federal government, there is an important need for policies which incent investment in technologies that are either low emitting or designed to curb emissions. Such technologies are especially needed in Canada's baseload generation fleet. This policy, though somewhat costly in fiscal terms, would help to achieve several of these important goals, especially by shifting the focus of provincial and federal government policy towards abatement.

# 7. Conclusion

Designing policies to reduce GHG emissions from electric power is a complex challenge due to multi-faceted interactions between electricity systems, markets, and consumer behaviour. In Canada, these industry specific challenges are complicated by overlapping and conflicting regulatory policies, and the political calculus of provincial governments who own the utilities, but are elected by the rate payers. This second point is perhaps most pertinent as it implicitly declares intractable many of the policies which could align behaviour and investments with incentives by using price signals. The current basket of renewable policies is not effective at reducing emissions because they fail to relate emissions to the social cost of abatement. In effect, Canada has no abatement policy, and any of the measures proposed here will never successfully decarbonize the electricity industry without a carbon price.

However, this study has identified a number of important reforms, which may be essential for the long term viability of Canada’s electricity markets and energy security. Competitive wholesale and retail electricity markets are an important long term reform all provinces with crown utilities should consider; the case studies and a review of market designs are instructive. Effects from climate change on hydrologic systems may be felt more immediately than crown utilities with many large hydroelectric facilities should like to admit. However, enhanced grid interconnections between provinces may soon be essential for them to meet growing loads, especially in the face of increasing demand for electricity. In order to address the problem of ever rising demand, management of loads with time-of-use pricing, particularly during peak times, will be essential.

# References

Adelaja, A., Y. Hailu, C. McKeown, and A. Tekle. (2010). "Effects of renewable energy policies on wind industry development in the US". *Journal of Natural Resources Policy Research, 2*(3), 245-263.

AESO. Queue management stakeholder consultation session: Friday, October 19, 2007, 1:00 – 4:00 p.m. Retrieved 02/07, 2013, from http://www.aeso.ca/downloads/October_19_2007_Wind_Session_Stakeholder_comments.pdf

AESO. (2006). Wind generation impact studies, phase 2, assessing the impacts of increased wind power on AEIS operations and mitigating measures.. Alberta: Alberta Electric System Operator.

AESO. (2007). Discussion paper: Interconnection queue business practices. Alberta: Alberta Electric System Operator.

AESO. (2011). *Rate impact analysis*. Retrieved 04/23, 2013, from http://www.aeso.ca/transmission/23722.html

AESO. (2012). *AESO long term transmission plan.* Alberta: Alberta Electric System Operator.

AESO. (April 20, 2006). *Cover letter: Wind integration study and reliability threshold.* Alberta: Alberta Electric System Operator.

Albadi, M. and E. El-Saadany. (2008). "A summary of demand response in electricity markets". *Electrical Power Systems Research, 78*(11), 1989-1996.

Baker, B., I. Sklokin, L. Coad, and T. Crawford. (2011). *Canada's electricity infrastructure: Building a case for investment.* Canada: Conference Board of Canada.

Bates, J., O. Edberg and C. Nuttall. (2009). *Minimising greenhouse gas emissions from biomass energy generation.* Bristol, UK: Report of the UK Environment Agency.

BC Hydro. (2013). *Benefits for you*. Retrieved 04/23, 2013, from http://www.bchydro.com/energy-in-bc/projects/smart_metering_infrastructure_program/benefits.html

BCUC. (2012). *Quick facts about smart meters.* Vancouver, British Columbia: British Columbia Utilities Commission.

Belanger, C. and L. Gagnon. (2002). “Adding wind energy to hydropower.” *Energy Policy, 30*(14), 1279-1284.

Blanco, M. I. (2009). “The economics of wind energy.” *Renewable and Sustainable Energy Reviews, 13*, 1372-1382.

Borenstein, S. (2011). *The private and public economics of renewable electricity generation.* University of California, Berkeley: Energy Institute at the Haas School of Business.

Bowman, C., R. Marceau, and R. Griesbach. (2009). Electricity: Interconnecting Canada A strategic advantage, Report of the Canada power grid task force volume II - background and assessment. Ottawa, Ontario: Canadian Academy of Engineering.

Boyce, J. and A. Hollis. (2005). “Governance of electricity transmission systems.” *Energy Economics, 27*, 237-255.

Bradley, D. (2005). Renewable portfolio standards, and other incentives, harmonization opportunities. Ottawa, Ontario: Climate Change Solutions.

Budhraja, V., J. Ballance, J. Dyer, F. Mobasheri, A. Silverstein, and J. Eto. (2008). *Transmission benefit quantification, cost allocation, and cost recovery.* Sacremento, California: Energy Research and Development Division, California Energy Commission.

Canada. Environment Canada. (2012). *Canada’s emissions trends.* Ottawa, Ontario: Queen's Printer for Canada.

Canada. NRTEE. (2012). *Reality check: The state of climate progress in Canada.* Ottawa, Ontario: National Round Table on the Environment and the Economy.

CANMET Energy Technology Centre. *Renewable energy technologies: Small hydro power.* Ottawa, Ontario: Natural Resources Canada.

Carley, S. (2009). "State renewable energy electricity policies: An empirical evaluation of effectiveness". *Energy Policy, 37*, 3071-3081.

Carley, S. (2011). “The era of state energy policy innovation: A review of policy instruments.” *Review of Policy Research, 28*(3), 265-294.

Carr, J. (2010). Power sharing: Developing inter-provincial electricity trade. Toronto, Ontario: C.D. Howe Institute.

Chandler, J. (2009). “Trendy solutions, why do states adopt sustainable energy portfolio standards?” *Energy Policy, 37*(8), 3274-3281.

Coad, L., T. Crawford, and A. Macdonald. (2012). Shedding light on the economic impact of investing in electricity infrastructure. Conference Board of Canada.

Conference Board of Canada. (2013). *Greenhouse gas emissions*. Retrieved 04/22, 2013, from http://www.conferenceboard.ca/hcp/details/environment/greenhouse-gas-emissions.aspx

Cornett, A. (2006). Inventory of Canada's marine renewable energy resources, technical report CHC-TR-041. National Research Council, Canadian Hydraulics Centre,.

Dadson, A., D. Allegretti, and I. Mondrow. (2011). Competition in U.S. and Canadian electricity markets. In Kaiser, G. and B. Heggie (Ed.), *Energy law & policy* (pp. 307-326). Toronto, Ontario: Carswell.

Dahl, C. (2004). International energy markets: Understanding pricing, policies, and profits. Tulsa, Oklahoma: PennWell Corporation.

Delmas, M. a. M. (2011). "U.S. state policies for renewable energy: Context and effectiveness". *Energy Policy, 39*, 2273-2288.

Doluweera, G.H., S.M. Jordaan, M.C. Moore, D.W. Keith, and J.A. Bergerson. (2011). "Evaluating the role of cogeneration for carbon management in Alberta.*" Energy Policy, 39*, 7963-7974.

Drukker, D. M. (2003). "Testing for serial correlation in linear panel-data models ." *The Stata Journal, 3*(2), 168-177.

Electric Power Supply Association. (January 10, 2008). *"EPSA statement on renewable energy in organized electricity market"..* Washington, District of Columbia: Electric Power Supply Association.

ENMAX Energy. (2006). "Federal government chooses ENMAX energy as alberta electricity partner". Retrieved 03/25, 2013, from http://www.enmax.com/Corporation/Media+Room/Current+News+Releases/2006+News+Releases/Federal+Government+Chooses+ENMAX+Energy+as+Alberta+Electricity+Partner.htm

ERCOT. (2010). *Texas nodal market guide.* (No. 3). Texas: Electric Reliability Council of Texas.

Faruqui, A. and J. Palmer. (2012). The discovery of price responsiveness - A survey of experiments involving dynamic pricing of electricity. Harvard Electricity Policy Group.

Faruqui, A., R. Hledlik, S. Newell, and H. Pfeifenberger. (2007). "The power of 5 percent". *Electricity Journal, 20*(8), 68-77.

Federal Energy Regulatory Commission. "Regional transmission organizations", docket no. RM99-2-000; order no. 2000, (December 20, 1999).

Federal Energy Regulatory Commission. "Standardization of generator interconnection agreements and procedures" docket no. RM02-1-001; order no. 2003 - A, (March 5, 2004).

Finance Canada. (November, 1994). *Economic instruments and disincentives to sound environmental practices.* Ottawa, Ontario: Government of Canada.

Ford, A. (2001). "Waiting for the boom: A simulation study of power plant construction in California". *Energy Policy, 29*, 847-869.

Freris, L. and D. Infield. (2008). *Renewable energy in power systems*. Chichester, West Sussex: John Wiley and Sons. Ltd.

Gelman, R. (2011). *2010 renewable energy data book.* U.S. Department of Energy.

Genalta Power. (2011). *2011 Oil sands co-generation report: Oil sands co-generation potential survey.* Alberta: Co-Generation & Power Infrastructure Committee, The Oil Sands Developers Group.

Gil, H., Deslauriers, J.C., Dignard-Bailey, L., and Joos, G. (2006). *Integration of wind generation with power systems in Canada – overview of technical and economic impacts, CETC 2006-01(TR).* Varennes, Quebec: CANMET Energy Technology Centre, Natural Resources Canada.

Government of Alberta. *Offset credit system protocols*. Retrieved 12/10, 2012, from http://environment.alberta.ca/02275.html

Gross, M. (2010). “Energy U-turn in Germany.” *Current Biology, 21*(10), R379-R381.

Gross, R. and P. Heptonstall. (2008). "The costs and impacts of intermittency: An ongoing debate "east is east, and west is west, and never the twain shall meet."". *Energy Policy, 36*, 4005-4007.

Gross, R., W. Blyth, and P. Heptonstall. (2010). "Risks, revenues and investments in electricity generation: Why policy needs to look beyond costs". *Energy Economics, 32*, 796-804.

Grubb, M.J., and N.I. Meyer. (1993). Renewable energy: Sources for fuels and electricity. In Johansson, T.B., H. Kelly, A. Reddy, R. Williams, and L. Burnham (Ed.), (1st ed., pp. 157-212). Washington, D.C.: Island Press.

Hadley, S. W. (2010). *Load projection studies for ERCOT.* Oak Ridge National Laboratory.

Hamilton, G. (2011, October 21, 2011). "BC hydro plays NAFTA card in bid to win green status in california". *Vancouver Sun*

Heptonstall, P. (2007). *A review of electricity unit cost estimates.* United Kingdom Energy Research Centre.

Hiroux, C. (2005). The integration of wind power into competitive electricity markets: The case of transmission grid connection charges. Paris, France: Atomic Energy Commission.

Hogan, W. (1995). "A wholesale pool spot market must be administered by the independent system operator: Avoiding the separation fallacy". *Electricity Journal, 8*(10), 26-37.

Hogan, W. (2010). "Electricity wholesale market design in a low carbon future". In B. Moselle, J. Padilla, and R. Schmalensee (Ed.), *Harnessing renewable energy in electric power system: Theory, practice, policy* (1st ed.). Washington, District of Columbia: Earthscan.

Hogan, W. (2010). "Electricity wholesale market design in a low carbon future" (draft 01/23/10). *Draft for harnessing renewable energy in electric power systems: Theory, practice, policy* (pp. 1-33)

Holmes, M. (2012). All over the map 2012: A comparison of provincial climate change plans. David Suzuki Fourndation.

Holroyd, Peggy and Jennifer Dagg. (2011). Building a regulatory framework for geothermal energy development in the NWT: A report for the government of northwest territories, environment and natural resources department. Drayton Valley, Alberta: Pembina Institute.

Hrab, R. and P. Fraser. (2011). “Climate change and the coal challenge: The case of Ontario.” In Kaiser, G. and B. Heggie (Ed.), *Energy law & policy* (pp. 445-462). Toronto, Ontario: Carswell.

Huang, M. –Y., J.R. Alavalapati, D.R. Carter and M.H. Langholtz. (2007). “Is the choice of renewable portfolio standards random?” *Energy Policy, 35*(11), 5571-5575.

Ibenholt, K. (2002). “Explaining learning curves for wind power.” *Energy Policy, 30*, 1181-1189.

IBM Global Business Services and eMeter Strategic Consulting. (July, 2007). *Ontario energy board smart price pilot final report.* Ontario Energy Board.

International Energy Agency. *IEA/IRENA global renewable energy policies and measures database.* Retrieved 12/10, 2012, from http://www.iea.org/policiesandmeasures/renewableenergy/

IPCC. (2011). In Edenhofer O., Pichs-Madruga R., Sokona Y., Seyboth K., Matschoss P., Kadner S., von Stechow C. (Eds.), *Special report on renewable energy sources and climate change mitigation*. United Kingdom and New York, NY, USA: Cambridge University Press.

Islam, M., A. Fartaj, and D.S.K. Ting. (2004). “Current utilization and future prospects of emerging renewable energy applications in Canada.” *Renewable and Sustainable Energy Reviews, 8*, 493-519.

Jackson, J. (2010). "Improving energy efficiency and smart grid program analysis with agent-based end-use forecasting models". *Energy Policy, 38*(7), 3771-3780.

Jenner, S., G. Chan, R. Frankenberger, and M. Gabel. (2012). “What drives states to support renewable energy?” *The Energy Journal, 33*(2), 1-12.

Juisoto, S. (2006). "The differences that methods make: Cross-border power flows and accounting for carbon emissions from electricity use". *Energy Policy, 34*, 2915-2928.

Kaffine, D., B. McBee, J. Lieskovsky. (2012). *"*Emissions savings from wind power generation: Evidence from Texas, California and the upper Midwest*".* Golden, Colorado: Colorado School of Mines.

Kahn, D. (2012, August 21, 2012). "California will relax its regulation of 'resource shuffling' in cap and trade program". *Environment and Energy News*

Kehler, J., M. Hu, and D. McCrank. (2005). *Incremental impact on system operations with increased wind power penetration.* Alberta: Alberta Electric System Operator.

Kiani, B, A. Rowe, P. Wild, L. Pitt, A. Sophinka, T. Pedersen. (2013). "Optimal electricity system planning in a large hydro jurisdiction: Will British Columbia soon become a major importer of electricity?". *Energy Policy, 54*, 311-319.

Klessmann, C, C. Nabe, and K. Burges. (2008). “Pros and cons of exposing renewables to electricity market risks - A comparison of the market integration approaches in Germany, Spain, and the UK.” *Energy Policy, 36*, 3646-3661.

Kobos, P.H., Erickson, J.D., Drennen, T.E. (2006). “Technological learning and renewable energy costs: Implications for U.S. renewable energy policy.” *Energy Policy, 34*, 1645-1658.

Krupnick, A. and D. Burtaw. (August, 1996). *"*The social costs of electricity: Do the numbers add up?*" discussion paper 96-30.* Washington, District of Columbia: Resources for the Future.

Langniss, O and R. Wiser. (2003). “The renewables portfolio standard in Texas: An early assessment.” *Energy Policy, 31*(6), 527-535.

LeBlanc, N. and D. McColl. (June 2006). Cogeneration opportunities and energy requirements for canadian oilsands projects (summary report, study no. 112). Calgary, Alberta: Canadian Energy Research Institute.

Littlechild, S. (2008). "Some applied economics of utility regulation." *The Energy Journal, 29*, 43-62.

Littlechild, S. and C. Skerk. (2008). "Transmission expansion in Argentina 4: A review of performance." *Energy Economics, 30*(4), 1462-1490.

Loughran, D.S. and J, Kulick. (2004). “Demand-side management and energy efficiency in the United States.” *The Energy Journal, 25*(1), 19-43.

Lyon, T. P., And H. Yin. (2010). “Why do states adopt renewable portofolio standards? an empirical investigation.” *The Energy Journal, 31*(3), 133-157.

Majorowicz, J., and S.E. Grasby. (2010a). “High potential regions for enhanced geothermal systems in Canada.” *Natural Resources Research, 19*(3)

Majorowicz, J., and S.E. Grasby. (2010b). “Heat flow, depth–temperature variations and stored thermal energy for enhanced geothermal systems in Canada.” *Journal of Geophysics and Engineering, 7*, 1-10.

Manomet Center for Conservation Sciences. (2010). *Biomass sustainability and carbon policy study.* Manomet, Massachusetts: Manomet Center for Conservation Sciences.

McCalley, J., R. Kumar, V. Ajjarapu, O. Volij, H. Lui, L. Jin, and W. Shang. (2010). "Models for transmission expansion planning based on reconfigurable capacitor switching". In J. Momoh and L. Mili (Ed.), *Economic market design and planning for electric power systems* (1st ed., pp. 181-236). Hoboken, New Jersey: John Wiley & Sons, Inc.

McDonald, A. and L. Schrattenholzer. (2001). “Learning rates for energy technologies.” *Energy Policy, 29*, 255-261.

Menz, F.C., and S, Vachon. (2006). “The effectiveness of different policy regimes for promoting wind power: Experiences from the states.” *Energy Policy, 34*, 1786-1796.

Metcalf, G. E. (2009). “Designing a carbon tax to reduce U.S. greenhouse gas emissions.” *Review of Environmental Economics and Policy, 3*(1), 63-83.

Ministry of Energy, “Mines and Natural Gas and Responsible for Housing.” *Geothermal resources*. Retrieved 10/15, 2012, from http://www.empr.gov.bc.ca/TITLES/OGTITLES/GEOTHERMAL/Pages/default.aspx

National Energy Board of Canada. (2008). *“Energy brief: Coal fired power generation – an overview,”.* Calgary, Alberta: National Energy Board of Canada.

Natural Resources Canada. (2010). “Tax savings for industry.” Retrieved 01/31, 2013, from http://oee.nrcan.gc.ca/industrial/financial-assistance/1965

Nordhaus, W. D. (2006). “After Kyoto: Alternative mechanisms to control global warming.” *The American Economic Review, 96*(2), 31-34.

Norton Rose OR LLP. (2011). “Canada: Federal government proposes new regulations on coal-fired electricity generation,”. Retrieved 09/27, 2011, from http://www.mondaq.com/canada/x/146758/Oil+Gas+Electricity/Federal+Government+Proposes+New+Regulations+On+CoalFired+Electricity+Generation

Nyboer, J. and G. Kamiya. (2012b). *Development of greenhouse gas intensity indicators for canadian industry, 1990-2010.* Burnaby, British Columbia: Canadian Industrial Energy End-Use Data and Analysis Centre, Simon Fraser University.

Nyboer, J. and G. Kamiya. (2012a). *Energy use and related data: Canadian electricity generation industry, 1990 to 2010.* Vancouver, British Columbia: Canadian Industrial Energy End-Use Data and Analysis Centre, Simon Fraser University.

Nyboer, J., S. Groves, S. Rudd, and K. Lutes. (March, 2011). *A review of existing cogeneration facilities in Canada.* Burnaby, British Columbia: Canadian Industrial Energy End-Use Data and Analysis Center, Simon Fraser University.

Nyboer, John and Kristin Lutes. (2012). *A review of renewable energy in Canada, 2009.* Burnaby, British Columbia: Canadian Industrial Energy End-Use Data and Analysis Center, Simon Fraser University.

New York Independent System Operator. "Order no. 890 transmission planning compliance filing", Inc Docket Number OA08-13-000 14-15 (Federal Energy Regulatory Commission December 7, 2007).

Pelland, S., D.W. McKenney, Y. Poissant, R. Morris, K. Lawrence, K. Campbell, and P. Papadopol. (2006). *The development of photovoltaic resource maps for Canada*. Montreal, Quebec.

Pineau, P., A. Hira, and K. Froschauer. (2004). "Measuring international electricity integration: A comparative study of the power systems under the Nordic council, MERCOSUR, NAFTA". *Energy Policy, 32*, 1457-1475.

Prasad, Monica and Steve Munch. (2012). "State-level renewable electricity policies and reductions in carbon emissions". *Energy Policy, 45*, 237-243.

Quantitative Micro Software. (2009). *Eviews 7 user's guide I and eviews 7 user's guide II*. Irvine, California:

Rivers, N. and M. Jaccard. (2011). "Electric utility demand side management in Canada." *The Energy Journal, 32*(4), 95-118.

Rowlands, I. H. (2007). "The development of renewable electricity policy in the province of Ontario: The influence of ideas and timing." *Review of Policy Research, 24*(3), 185-207.

Science Applications International Corporation. (2009). *Survey of active solar thermal collectors, industry and markets in Canada.* Ottawa, Ontario: Natural Resources Canada.

Scorah, H., A. Sopinka, G. C. van Kooten. (2012). "The economics of storage, transmissions, and drought: Integrating variable wind power into spatially separated electricity grids".
. *Energy Economics, 34*, 536-541.

Sovacool, B., K. (2009). “The intermittency of wind, solar, and renewable electricity generators: Technical barriers or rhetorical excuse?” *Utilities Policy, 17*, 288-296.

Statistics Canada. (2013). “Canadian households in 2011: Type and growth.” Retrieved 04/23, 2013, from http://www12.statcan.gc.ca/census-recensement/2011/as-sa/98-312-x/98-312-x2011003_2-eng.cfm

Stbrac, G. (2008). "Demand side management: Benefits and challenges ". *Energy Policy, 36*(12), 4419-4426.

Stennes, B., K. Niquidet and G.C. van Kooten. (2010). “Implications of expanding bioenergy production from wood in British Columbia: An application of a regional wood fibre allocation model.” *Forest Sciences, 56*(4), 366-378.

Streimikiene, D. (2011). "Assessment of electricity generation technologies based on social costs". 1-4.

Sustainable Prosperity. (2011). The potential of tradeable renewable energy certificates (TRECs) in Canada. Ottawa, Ontario: Sustainable Prosperity.

Swisher, J. and M. McAlpin. (2006). "Environmental impact of electricity deregulation". *Energy, 31*, 1067-1083.

Tannenwald, R. (1997). “State regulatory policy and economic development”. *New England Economic Review,* (March/April), 83-99.

The Economist. (2013). "Germany's energy reform: Troubled turn". *The Economist*, pp. 52.

The Economist. (2013). “Europe's dirty secret: The unwelcome renaissance.” *The Economist*, pp. 54-56.

Weis, T., A. Bailie, A. Doukas, G. Powell, R. Peters, J. Moorhouse, and R. Wong. (November, 2009). *Green power programs in Canada - 2007.* Pembina Institute.

Wiginton, L.K., H.T. Nguyen, and J.M. Pearce. (2010). “Quantifying rooftop solar photovoltaic potential for regional renewable energy policy.” *Computers, Environment and Urban Systems, 34*, 345-357.

Woo, C.K., I. Horowitz, J. Moore, A. Pacheco. (2011). “The impact of wind generation on the electricity spot-market price level and variance: The Texas experience.*”* *Energy Policy, 39*, 3939-3944.

Woo, C.K., J. Zarnikau, J. Moore, I. Horowitz,. (2011). "Wind generation and zonal-market price divergence: Evidence from Texas". *Energy Policy, 39*, 3928-3938.

Woolridge, J. M. (2010). *Econometric analysis of cross section and panel data*. Cambridge, Massachusetts: The MIT Press.

World Wind Energy Association. (2009). *World wind energy report 2009.* Bonn, Germany: World Wind Energy Association.

Zarnikau, J. (2005). “A review of efforts to restructure Texas' electricity market.” *Energy Policy, 33*(1), 15-25.

Zarnikau, J. (2011). “Successful renewable energy development in a competitive electricity market: A Texas case study.” *Energy Policy, 39*, 3906-3913.

# Appendices

# Appendix A. - Statistical Tables

**Table A1 - Response Variable Data, GHG Emissions from Electric Power Generation in Kilotonnes, Canada, 1990-2010**

| Year | Alberta | British Columbia | Manitoba | New Brunswick | Newfoundland | Nova Scotia | Ontario | Prince Edward Island | Quebec | Saskatchewan |
|---|---|---|---|---|---|---|---|---|---|---|
| 1990 | 40000 | 1170 | 525 | 5840 | 1610 | 6830 | 26400 | 101 | 1430 | 10400 |
| 1991 | 41800 | 1040 | 418 | 5270 | 1280 | 7000 | 27700 | 91 | 448 | 10600 |
| 1992 | 45000 | 1270 | 417 | 5980 | 1480 | 7380 | 27400 | 50 | 869 | 12100 |
| 1993 | 45800 | 2340 | 284 | 5010 | 1340 | 7310 | 18300 | 73 | 219 | 12400 |
| 1994 | 49300 | 2180 | 323 | 5960 | 720 | 7120 | 15800 | 57 | 392 | 13300 |
| 1995 | 49000 | 2700 | 219 | 6600 | 1250 | 6900 | 18500 | 38 | 268 | 13900 |
| 1996 | 48100 | 770 | 340 | 5820 | 1160 | 7100 | 20500 | 24 | 265 | 14000 |
| 1997 | 50800 | 1190 | 244 | 8120 | 1210 | 7530 | 25600 | 31 | 296 | 14900 |
| 1998 | 51400 | 1840 | 962 | 9210 | 1020 | 7800 | 33100 | 10 | 1400 | 15100 |
| 1999 | 49800 | 1270 | 546 | 7950 | 940 | 8060 | 35200 | 19 | 980 | 14900 |
| 2000 | 51700 | 2450 | 993 | 8360 | 920 | 8820 | 42300 | 55 | 380 | 14700 |
| 2001 | 52600 | 3030 | 500 | 9800 | 1700 | 7800 | 40200 | 50 | 410 | 15000 |
| 2002 | 52300 | 1180 | 500 | 8500 | 1800 | 7100 | 40100 | 30 | 310 | 15100 |
| 2003 | 54100 | 1330 | 800 | 8200 | 1500 | 8200 | 45300 | 40 | 1580 | 16100 |
| 2004 | 52100 | 1460 | 400 | 9400 | 1300 | 10000 | 34600 | 20 | 1350 | 16600 |
| 2005 | 48500 | 1540 | 530 | 9700 | 1100 | 11400 | 34700 | 10 | 710 | 14500 |
| 2006 | 51100 | 1470 | 400 | 7800 | 700 | 9700 | 29700 | 10 | 840 | 14200 |
| 2007 | 55200 | 1290 | 470 | 7300 | 1100 | 10700 | 32700 | 7 | 1510 | 14600 |
| 2008 | 51500 | 1650 | 430 | 6900 | 900 | 9300 | 27300 | 4 | 370 | 14600 |
| 2009 | 47900 | 1540 | 190 | 7200 | 800 | 8900 | 14600 | 6 | 520 | 15700 |
| 2010 | 48100 | 1430 | 80 | 5400 | 700 | 9500 | 19700 | 1.6 | 340 | 15500 |

## Table A2 - Correlation Analysis for Collinear Relationships

| | GDPCAP | POP | TGEN | EXPORTS | ELEC$ | TEMP | FED | SUB | MAND | NETMET | EAST | SOUTH | WEST | EASTR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GDPCAP | 1.00 | | | | | | | | | | | | | |
| POP | 0.17 | 1.00 | | | | | | | | | | | | |
| TGEN | 0.46 | 0.42 | 1.00 | | | | | | | | | | | |
| EXPORTS | 0.02 | 0.24 | -0.29 | 1.00 | | | | | | | | | | |
| ELEC$ | 0.53 | 0.12 | 0.27 | -0.09 | 1.00 | | | | | | | | | |
| TEMP | -0.08 | 0.48 | -0.13 | 0.16 | 0.14 | 1.00 | | | | | | | | |
| FED | 0.68 | 0.04 | 0.07 | 0.05 | 0.51 | 0.04 | 1.00 | | | | | | | |
| SUB | 0.20 | 0.40 | 0.14 | 0.14 | 0.31 | 0.27 | 0.21 | 1.00 | | | | | | |
| MAND | 0.15 | 0.22 | 0.12 | 0.00 | 0.41 | 0.17 | 0.23 | 0.41 | 1.00 | | | | | |
| NETMET | -0.05 | -0.16 | -0.22 | 0.06 | -0.31 | -0.38 | -0.02 | -0.04 | -0.02 | 1.00 | -0.13 | | | |
| EAST | 0.12 | 0.56 | -0.02 | 0.36 | 0.07 | 0.25 | 0.17 | 0.22 | 0.13 | -0.13 | 1.00 | | | |
| SOUTH | 0.11 | 0.25 | 0.09 | 0.13 | 0.19 | 0.07 | 0.07 | 0.51 | 0.35 | 0.07 | 0.27 | 1.00 | | |
| WEST | 0.10 | -0.02 | -0.11 | 0.01 | -0.11 | 0.12 | 0.06 | 0.05 | -0.07 | 0.18 | -0.12 | -0.02 | 1.00 | |
| EASTR | -0.28 | -0.56 | -0.38 | 0.00 | 0.30 | 0.04 | 0.00 | -0.17 | 0.06 | -0.25 | -0.23 | -0.10 | -0.25 | 1.00 |
| WESTR | 0.26 | -0.18 | 0.23 | -0.27 | -0.35 | -0.35 | 0.00 | -0.03 | -0.18 | 0.38 | -0.34 | -0.04 | 0.37 | -0.67 |

## Table A3 - Individual panel descriptive statistics of $GHG_{it}$

| Statistics | Alberta | British Columbia | Manitoba | New Brunswick | Newfoundland |
|---|---|---|---|---|---|
| Mean | 49338.095 | 1625.714 | 455.762 | 7348.571 | 1168.095 |
| Median | 49800.000 | 1460.000 | 418.000 | 7300.000 | 1160.000 |
| Maximum | 55200.000 | 3030.000 | 993.000 | 9800.000 | 1800.000 |
| Minimum | 40000.000 | 770.000 | 80.000 | 5010.000 | 700.000 |
| Standard Deviation | 3777.231 | 587.321 | 231.196 | 1520.396 | 327.424 |
| Kurtosis | 0.931 | 0.389 | 1.092 | -1.215 | -0.761 |
| Skewness | -0.968 | 1.050 | 0.998 | 0.076 | 0.268 |
| **Statistics** | **Nova Scotia** | **Ontario** | **Prince Edward Island** | **Quebec** | **Saskatchewan** |
| Mean | 8307.143 | 29033.333 | 34.648 | 708.905 | 14200.000 |
| Median | 7800.000 | 27700.000 | 30.000 | 448.000 | 14600.000 |
| Maximum | 11400.000 | 45300.000 | 101.000 | 1580.000 | 16600.000 |
| Minimum | 6830.000 | 14600.000 | 1.600 | 219.000 | 10400.000 |
| Standard Deviation | 1348.325 | 8986.175 | 28.741 | 476.403 | 1630.951 |
| Kurtosis | -0.249 | -0.938 | 0.126 | -0.995 | 0.916 |
| Skewness | 0.854 | 0.065 | 0.912 | 0.786 | -1.123 |

### Table A4 - Summary Unit Root Tests

| **Dependent Variable** | **LnGHG** | | **LnGHG** | | **LnGHG** | | **∆LnGHG** | | **∆LnGHG** | | **∆LnGHG** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Specification** | lagged term | | lagged term, intercept | | lagged term, intercept, trend | | lagged term | | lagged term, intercept | | lagged term, intercept, trend | |
| **Test** | Statistic | P-Value | Statistic | P-Value | Statistic | P-Value | Statistic | P-Value | Statistic | P-Value | Statistic | P-Value |
| **H0: Common unit root process** | | | | | | | | | | | | |
| **Levin, Lin & Chu** | 1.601 | 0.945 | -2.385 | 0.009 | 0.31561 | 0.624 | -12.782 | 0 | -9.643 | 0 | -9.853 | 0 |
| **H0: Individual unit root process** | | | | | | | | | | | | |
| **Im, Pesaran & Shin W-stat.** | - | - | -2.75 | 0.003 | 0.25 | 0.599 | - | - | -8.559 | 0 | -9.346 | 0 |
| **ADF-Fisher Chi-Square** | 14.129 | 0.824 | 41.588 | 0.003 | 25.044 | 0.199 | 162.223 | 0 | 109.172 | 0 | 105.841 | 0 |

# Table A5 –Regression Results for the Initial Specifications

| Case | Base | | Subsidy | | Regional Generation | | Dynamic | |
|---|---|---|---|---|---|---|---|---|
| Specification | 1A~ | | 1B~ | | 1C~ | | 1~ | |
| Variable | $\Delta logGHG_{it}$ | | $\Delta logGHG_{it}$ | | $\Delta logGHG_{it}$ | | $\Delta logGHG_{it}$ | |
| | Coefficient | Standard Errors | Coefficient | Standard Errors | Coefficient | Standard Errors | Coefficient | Standard Errors |
| C | 0.021 | 0.038 | 0.036 | 0.034 | 0.020 | 0.020 | 0.013 | 0.020 |
| $\Delta logGDPCAP_{it}$ | 0.116 | 0.104 | 0.132 | 0.109 | -0.027 | 0.091 | 0.038 | 0.097 |
| $\Delta logPOP_{it}$ | -7.140 | 5.293 | -7.651 | 5.271 | -6.586 | 3.980*** | -6.570 | 4.174 |
| $\Delta logTGEN_{it}$ | 0.648 | 0.126* | 0.644 | 0.127* | 0.913 | 0.221* | 0.903 | 0.265* |
| $\Delta EXPORTS_{it}$ | -2.62E-08 | 1.38E-08** | -2.67E-08 | 1.39E-08** | -1.83E-08 | 1.27E-08 | -1.97E-08 | 1.22E-08**** |
| $\Delta logELEC\$_{it}$ | -0.152 | 0.204 | -0.243 | 0.224 | -0.095 | 0.184 | -0.124 | 0.185 |
| $\Delta TEMP_{it}$ | -0.011 | 0.024 | -0.015 | 0.024 | -0.024 | 0.018 | -0.022 | 0.018 |
| $\Delta FED_{it}$ | | | -11.933 | 3.204* | -10.535 | 2.945* | -10.367 | 2.739* |
| $\Delta SUB_{it}$ | | | -1.491 | 0.728 | -0.917 | 0.580 | -0.950 | 0.585**** |
| $\Delta\ (WESTR_{it} {}^{*} logTGEN_{it})$ | | | | | 0.321 | 0.249 | 0.264 | 0.267 |
| $\Delta(EASTR_{it} {}^{*} logTGEN_{it})$ | | | | | -0.485 | 0.255** | -0.491 | 0.291*** |
| $\Delta logGHG_{it}(-1)$ | | | | | | | -0.145 | 0.076** |
| **Obs.** | 200 | | 200 | | 200 | | 200 | |
| **Adj R^2** | 0.510 | | 0.512 | | 0.616 | | 0.620 | |
| **F-Statistic** | 14.86 | | 13.305 | | 17.851 | | 16.403 | |
| **Schwarz** | 0.704 | | 0.742 | | 0.543 | | 0.585 | |
| **Woolridge T-Test - Null Hypothesis: No serial correlation** | | | | | | | | |
| p-value | 0.000 | | 0.000 | | 0.000 | | 0.007 | |
| **Notes:** | | | | | | | | |
| ~White's Robust Standard Errors; **** 10% < X >1 5% ; *** 10% significance level; | | | | | | | | |
| ** 5% significance level; * 1% significance level | | | | | | | | |

# Appendix B - Hypotheses

**Table E1 – Hypotheses**

| Variable | Level | Explanation |
|---|---|---|
| **GDPCAP** | H0: $\beta \leq 0$, HA: $\beta > 0$ | Increases in gross domestic product per capita should result in greater demand for thermal electricity. The sign should be positive. |
| **TGEN** | H0: $\beta \leq 0$, HA: $\beta > 0$ | Changes in thermal generation should increase emissions. |
| **POP** | H0: $\beta \leq 0$, HA: $\beta > 0$ | Population tends to increase overtime. Therefore, a positive sign is expected. |
| **EXPORTS** | H0: $\beta = 0$, HA: $\beta \neq 0$ | Increases in demand for electricity from the United States is likely to result in increases in all electricity generation, especially fossil fuel generation sources which can ramp up and down more rapidly to meet demand. Due to differences amongst the provinces in generation profiles, the effects on emissions are unclear. |
| **ELEC$** | H0: $\beta = 0$, HA: $\beta \neq 0$ | Electricity prices tend to increase overtime. Nonetheless, the long run effects are difficult to anticipate, so a two-tailed test is appropriate. |
| **FED** | H0: $\beta = 0$, HA: $\beta \neq 0$ | The presence of a direct subsidy to renewable generation should increase renewable electricity generation and contribute to a reduction in GHG emissions. The effect should be a decrease in emissions though this is difficult to anticipate, so a two-tailed test is appropriate. |
| **NETMET** | H0: $\beta = 0$, HA: $\beta \neq 0$ | Increased access to the grid should increase renewable electricity generation and contribute to a reduction in GHG emissions. The long run effects are difficult to anticipate, so a two-tailed test is appropriate. |
| **MAND** | H0: $\beta \leq 0$, HA: $\beta > 0$ | Renewable generation requirements should increase renewable electricity generation and contribute to a reduction in GHG emissions. The effect should be a decrease in emissions. The long run effects are difficult to anticipate, so a two-tailed test is appropriate. |
| **SUB** | H0: $\beta = 0$, HA: $\beta \neq 0$ | The presence of a direct subsidy to renewable generation should increase renewable electricity generation and contribute to a reduction in GHG emissions. The long run effects are difficult to anticipate, so a two-tailed test is appropriate. |
| **FERC888** | H0: $\beta = 0$, HA: $\beta \neq 0$ | The effects of FERC order 888 are difficult to anticipate, so a two sided test is appropriate. |
| **EAST, SOUTH, WEST** | H0: $\beta = 0$, HA: $\beta \neq 0$ | The literature suggests that the sign should be negative, but this is difficult to anticipate. A two-sided test is in order. |

# Appendix C - Data sources and manipulations

**Table H1 - Data Collection Details**

| Data Type | Years | Delineation | Units | Calculation | Source | Table |
|---|---|---|---|---|---|---|
| **GHG Emissions from Electricity Generation** | 1990-2010 | By Province | Kilotonnes of CO2e | Converted to Can $ 2002 | National Inventory Report | |
| **Gross Domestic Product** | 1990-2010 | By Province | Can $ 2002 | Converted to Can $ 2002 | Statistics Canada | Table 379-0025, |
| **Generation** | 1990-2010 | By Province | MWH | | Statistics Canada | Table 127-0001 and Table 127-0002 |
| **Population** | 1990-2010 | By Province | Number of Living People | | Statistics Canada | Table 051-0001 |
| **Electricity Export Revenue** | 1990-2010 | By Province to each State | Can $ 2002 | Converted to Can $ 2002 | National Energy Board of Canada | Table 3A, Export Data Reports |
| **Electricity Price** | 1990-2010 | By Province | $/KWH for Industrial Purchases Under 5000 KW | Converted to Can $ 2002 | Hydro Quebec's Comparison of Electricity Prices in Major North American Cities | |
| **Temperature** | 1990-2010 | By Province | Degrees Celsius | Annual Average | National Climate Data and Information Archive | |
| **Electricity Exports** | 1990-2010 | By Province | MWH | | Statistics Canada | Table 127-0001 and Table 127-0002 |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Provincial Policies** | 1990-2010 | By Province | | | IEA/IRENA Global Renewable Energy Policies and Measures Database and Weis etal. | |
| **Provincial Incentives** | 1990-2010 | By Province | $/KWH | Converted to Can $ 2002 | | |
| **Provincial Net Metering** | 1990-2010 | By Province | Maximum KWs allowed | | | |
| **Provincial Renewables Mandates** | 1990-2010 | By Province | % target | | | |
| **Federal Policies** | 1990-2010 | By Province | | | IEA/IRENA Global Renewable Energy Policies and Measures Database and Weis etal. | |
| **ecoEnergy** | 1990-2010 | By Province | $/KWH | Converted to Can $ 2002 | | |
| **Wind Power Production Incentive** | 1990-2010 | By Province | $/KWH | Converted to Can $ 2002 | | |

# Appendix D - Renewable Resource Potential in Canada

This is appendix provides a more detailed discussion of renewable resource potential, technologies, and barriers to development in Canada.

*Biomass, waste-to-energy and landfill gas* – Biomass energy can either be drawn from forest products or other forms of industrial and agricultural waste, such as landfill gas or poultry waste. All forms of biomass energy can be used to generate electricity or thermal energy for use as process heat, mostly likely as part of a cogeneration operation. Canada has a large stock of forestry based biomass, but the combustion of this stock is not necessarily carbon neutral. Recent studies indicate that the GHG emissions from biomass combustion may not equal the rate of replanting, and emissions can fluctuate based on the engineering parameters of the electricity generation (Manomet Center for Conservation Sciences, 2010; Bates etal., 2009). As well, the economics of biomass combustion in British Columbia have proven to be problematic because of rising marginal transport costs and competition for biomass with the pulp and paper, and milling industries (Stennes etal., 2010).

*Geothermal.* Western Canada has significant geothermal resource potential, which could be harnessed to contribute baseload power to the electricity grid; particularly, in Alberta, British Columbia, the Northwest Territories, and the Yukon Territory (Majorowicz and Grasby, 2010a; Majorowicz and Grasby, 2010b). However, in Canada only British Columbia and the Northwest Territories have a well defined regulatory policy (Holroyd and Dagg, 2011), and British Columbia is the only jurisdiction in Canada that issues permits and has held auctions (Ministry of Energy, Mines and Natural Gas and Responsible for Housing).

*Solar.* There are two primary types of solar energy collection systems – photovoltaic collection and thermal collection of solar radiation[1]. The potential solar photovoltaic energy which could be harnessed to generate electricity in Canada is quite large. A given photovoltaic installation south of James Bay and east of the Rocky Mountains could potentially generate more than 1100 kilowatt hours (kHw) of electricity annually (Pelland etal., 2006)[2]. Further, a recent study on photovoltaic installations estimates that 30 percent of the Ontario's electricity generation needs could be met by rooftop installations (Wiginton et al, 2010)[3]. In the development and deployment of thermal collection capacity Ontario has been the leading jurisdiction in Canada (Science Applications International Corporation, 2009).

[1] Thermal collection of solar radiation relies on direct transfer of solar radiation that is used to heat water.

[2] Pelland etal.'s model makes the following assumptions: "In the scope of this paper only grid-connected systems with no batteries are considered...The losses and overall system performance are specific to each PV [photovoltaic] system, and depend on the type of PV module used (crystalline, polycrystalline, thin film), on its performance under different operating conditions (solar radiation intensity, angle of incidence, temperature, spectral distribution, etc.) and on overall system design..."

[3] The study only modelled potential rooftop capacity in southern Ontario.

*Small- scale hydroelectricity.* Generation technologies in this class differ from large scale hydro-electricity projects in that they apply smaller turbines to more highly concentrated, but smaller volumes of water flows. Analysis performed by CANMET at Natural Resources Canada, identified more than 5500 sites in British Columbia, Newfoundland, the Northwest Territories, Ontario, and the Yukon Territory representing approximately 11000 megawatts (MW) of potential capacity (CANMET Energy Technology Centre). The same study identifies an additional 20000 MW of unexploited low head small-scale hydroelectricity capacity[4], resenting an additional 3000 sites (CANMET Energy Technology Centre).

*Tidal and wave energy.* Electricity generated from tidal flows is collected by devices know as kinetic hydro power, and wave generation technologies are referred to as wave energy converters. Canada's coastal waters have large tidal and wave energy flows, equivalent to about 43000 MW[5] and 183500MW[6] respectively, a fraction of which could be used to generate electricity (Cornett, 2006)[7]. Much of this potential tidal energy is concentrated in the Nunavut Territory, in several sites in British Columbia, and in the Bay of Fundy in Nova Scotia, while potential wave energy is concentrated diffusively along the Atlantic and Pacific coasts (Cornett, A. 2006). Tidal electricity generation technologies are well established in Canada, for example a 20MW kinetic hydro power facility has been operating in Annapolis Royal, Nova Scotia since 1984 (Cornett, 2006).

*Wind* – Wind is by the far the most well developed of all renewable energy technologies and the one for which there has been the most uptake across Canada, leaders in this resources include Alberta, British Columbia, Nova Scotia, Ontario, and Quebec. This demonstrates that Canada has a large wind capacity potential and several large projects are currently being planned or constructed (Gil etal., 2006). Electricity generated from wind is highly intermittent which can pose problems for system planning and integration; however, consequent concerns about high unit costs have been overstated as installed capacity has increased (Gil etal., 2006).

---

[4] Refers to changes in elevation of less than 15 metres.

[5] This capacity is based on 190 sites with a potential capacity greater than or equal to 1MW.

[6] The study assumes that there are isobaths or seafloor contours with a depth of 1000 metres.

[7] The reason for the limited ability to harness these resources for electricity generation depends on the resources type. First for waves, the study notes: "It is important to recognize that due to various factors including environmental considerations, losses associated with power conversion, and socio-economic factors, only a fraction of the available wave energy resource can be extracted and converted into useful power." Second for tidal energy, the study notes: "only a fraction of the available tidal current resource can be converted into useable energy without noticeable impact on tides and tidal flows. The effects of extracting energy from tidal currents and from ocean waves should be assessed carefully on a case-by-case basis."

# Appendix E - Federal Renewable Energy Policies

**Table E1 - Federal Renewable Energy Policies**

| Policy | Jurisdiction | First Year in Effect | Final Year | Type of Mechanism | Value | Target |
|---|---|---|---|---|---|---|
| Class 43.1 and 43.2 Accelerated Capital Cost Allowance | Canada | - | Ongoing | Tax Incentive | Deduction of the full capital cost of the project over the useful life of the equipment | Small scale hydro (<50 MW), wind systems, photovoltaic systems, geothermal electrical systems, biogas systems and wave and tidal energy systems |
| Canadian Renewable and Conservation Expenses | Canada | - | Ongoing | Tax Incentive | Covers exploratory, feasibility and start-up costs for renewable energy projects | Small scale hydro (<50 MW), wind systems, photovoltaic systems, geothermal electrical systems, biogas systems and wave and tidal energy systems |
| ecoENERGY for Renewable Power | Canada | 01/04/07 | 31/03/2011 | Financial/Fiscal | 0.01 $/kWh | Energy Types: Solar, Solar photovoltaic, Geothermal, Power, Hydropower, Multiple RE Sources, Power, Ocean, Tidal, Ocean, Wave |
| Market Incentive Program | Canada | 28/10/02 | 31/03/06 | Financial | | All renewable energy sources |
| Wind Power Production Incentive | Canada | 01/04/02 - 31/03/03 | 31/03/07 | Financial | 0.012 $/kWh | Onshore Wind |

| | | | | | | |
|---|---|---|---|---|---|---|
| Government Purchases of Electricity from Renewable Resources | Canada | 1997 | 2005 | Financial | Multiple purchases | Wind, Onshore, Bioenergy, Biomass for power, Hydropower |

Source: IEA; Weis et al. 2009[1]

---

[1] Where it was possible these sources were validated by comparisons against government reports and policy statements

# Appendix F - Provincial Renewable Energy Policies[1]

**Table F1 - Provincial Renewable Energy Policies**

| Policy | Jurisdiction | First Year in Effect | Final Year | Type of Mechanism | Value | Target |
|---|---|---|---|---|---|---|
| Climate Change and Emissions Management Act | Alberta | 2007 | Ongoing | Government | | Qualifying renewable electricity generators can apply to provide offsets in Alberta's Carbon Offset Compliance Market |
| Standing Offer Program | British Columbia | 2007 | Ongoing | Financial | See slides | 0.05MW to 15MW |
| Coal Fired Electricity Phase Out | Ontario | 2003 | Intended 2007, current deadline 2014 | Regulation | | Phase of all coal fired thermal generation capacity by the end of 2014 |
| Feed-in-Tariff | Ontario | 01/10/09 | Ongoing | Financial/Fiscal | 0.103 – 0.195 $/kWh | Projects over 10kW<br>Energy types: biogas, biomass, landfill gas, solar photovoltaic (PV), wind, and small-scale hydropower |
| Ontario Renewable Energy Standard Offer Programme (RESOP) | Ontario | 2006 | 2009 | Financial/Fiscal | 0.1108 $/kWh for Wind, Hydro, Biomass; 0.42 $/kWh for Solar PV rooftop; 0.0325 $/kWh for on peak hydro and biomass | Projects between 1kW and 10 MW<br>Energy types: Wind, Onshore, Bioenergy, Biomass for power, Hydropower, Solar, Solar photovoltaic |
| Renewable Portfolio Standard | Ontario | 2003 | 2010 | Mandatory | 5% by 2007, 10% by 2010 | Multiple Sources |

---

[1] A more complete list of policies can be found in: Weis et al. (2009). *Green Power Programs in Canada*. The Pembina Institute.

| | | | | | | |
|---|---|---|---|---|---|---|
| Renewable Portfolio Standard | Prince Edward Island | 01/01/2011 | Ongoing | Mandatory | 15% renewables requirement at a minimum price of 0.0775 $/kWh | Multiple sources |
| Renewable Portfolio Standard | Nova Scotia | 01/02/07 | Revised 12/10/10 | Mandatory | 5% by 2011, 10% by 2013, 15% by 2015 | Multiple sources |

Source: IEA; Weis et al. 2009[2]

### Table F2 - Provincial Interconnection and Net Metering Policies

| **Policy** | **Jurisdiction** | **Utilities** | **First Year in Effect** | **Type of Energy Source** | **Target** |
|---|---|---|---|---|---|
| Microgeneration regulation | Alberta | Alberta Energy | 2009 | solar photovoltaics, wind turbines, hydro electric systems, cogeneration systems (fuelled by biomass, biogas, natural gas, etc.), waste energy recovery units, fuel cells, and others | Mini Micro-Generation (x<10 KW)<br>Small Micro-Generation (x<150 KW)<br>Large Micro-Generation (150KW< x > 1 MW) |
| Net Metering Program | British Columbia | BC Hydro | 2005 | Solar photovoltaics, Wind, Micro-hydro, Fuel cell | Any generation unit below 50 KW @ a rate of 0.0999 $/KWH, Live smart BC also provides a maximum $1300 subsidy for the purchase and installation of "distributed generation" equipment |
| Connecting Customer Owned Generation | Manitoba | Manitoba Hydro | 1989 | Wind or Solar Photovoltaics | Under 10MW |
| Net Metering | New Brunswick | New Brunswick Power | 2006 | Renewables | Under 10 KW |
| Under development | Newfoundland | Newfoundland and Labradour Hydro | TBA | | |

---

[2] Where it was possible these sources were validated by comparisons against government reports and policy statements

| | | | | | |
|---|---|---|---|---|---|
| Enhanced Net Metering | Nova Scotia | Nova Scotia Power | 2005 | Solar, wind, tidal, wave, run-of-river hydro, electric, biomass | Under 1000KW |
| Net Metering Program | Ontario | Hydro One | 2005 | | Under 500 KW |
| Net Metering Program | Ontario | Toronto Hydro | 2006 | Wind turbine, micro-hydroelectric, solar radiation, agricultural biomass combustion | Under 500 KW |
| Net Metering | Prince Edward Island | Maritime Electric | 2005 | Renewables | Under 100 KW |
| Self-Generation | Quebec | Hydro Quebec | 2005 | Hydro, wind, solar, geothermal, forest biomass or gas | Under 50 KW |

Source: IEA; Weis et al. 2009[3]

---

[3] Where it was possible these sources were validated by comparisons against government reports and policy statements.