The Development of a Framework for Modelling Greenhouse Gas Mitigation Scenarios in the Electricity Generation Sector

by

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A thesis submitted in partial fulfillment of the requirements for the degree of

Master of Science

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Abstract

Low- or zero-emitting alternative sources of energy have become widely sought for reducing greenhouse gas (GHG) emissions globally. Specifically, in the electricity generation sector, governments, utilities, regulators, and institutions have announced and implemented integrated policy measures such as renewable electricity generation targets, incentives, and efficiency standards for climate change mitigation. However, the associated constraints of recoverable resource viability, public acceptability, and high investment costs, along with limited generation output of alternative energy technologies compared to fossil fuel technologies, could make a low-emission electricity generation mix uneconomical to pursue. Therefore, it is necessary to quantitatively evaluate the greenhouse gas mitigation possible and the associated abatement costs from different integrated alternative energy penetration scenarios in an electricity generation mix in order to make informed policy decisions. The Long-range Energy Alternative Planning (LEAP) software was used to model the power generation sector over a study period of 41 years (2010-2050). Alberta, a Western Canadian province, was selected to evaluate the environmental and policy implications of the foregoing. This study assessed the comparative GHG mitigation in terms of dollar per tonne avoided and cumulative GHG emissions that could result from the adoption of different alternative energy penetration scenarios in which fossil fuels are replaced in an electricity generation mix in the medium term (to the year 2030) and long term (to 2050) using LEAP. Pathways for increasing the renewable share of electricity generation and associated GHG mitigation possible were investigated. The business-as-usual (BAU) scenario and 18 alternative scenarios were developed, simulating situations in which high-emission baseload coal-fired power plants would be retired and replaced by gas-fired power plants for baseload generation, and zero- or low-emission alternatives such as biomass hydro, solar, wind, geothermal, and nuclear are introduced into the generation mix to replace at least two-thirds of retired coal capacity by 2030. Over the study period, the results show that a GHG mitigation potential of 44% to 60% below 2014 reported emissions of 48.9 Mt CO_2 eq. from the electricity generation sector may be achieved by the year 2030. A 30% renewable capacity target would increase the renewable electricity production share from the current 10% to 22% by 2030. The GHG abatement costs of the alternative scenarios range from −\$5/t CO_2 eq. to \$820/t CO_2 eq. compared to the BAU by 2030. By 2050, about 42% to 65% GHG mitigation potential may be achieved with scenario abatement costs of −\$13/t CO_2 eq. to 214/t CO_2 eq. compared to the BAU. The outcomes of this study offer insights into the selection of alternative energy penetration pathways for a lower GHG emission electricity generation mix in Alberta.

Acknowledgements

My steps were divinely ordered by God towards this path and I am forever grateful to Him for this opportunity of a lifetime.

I am grateful to Dr. Amit Kumar for this research opportunity, his guidance and sharing from his depth of knowledge to make this research a success. His wide perspectives and progressive elaboration of the scope of this research work strengthened my ability to work harder and achieve results. His thorough supervision has truly made this work a unique contribution to knowledge.

I wish to acknowledge Dr. Md Ahiduzzaman for his reviews of my scenario assumptions, LEAP model, research papers, and thesis. He also contributed at different stages of the research, reviewing the assumptions, inputs, and analysis of results. Dr. Olufemi Oni was helpful with follow-up reviews and insights for structuring the papers for meaningful impact.

The ease of reading this thesis with proper grammatical expressions and structure was made possible by Ms. Astrid Blodgett. She proofread and edited my many presentations and research papers during the course of this research and I appreciate her for it. I am also thankful to my colleagues in the LEAP/WEAP group for their critical and productive inputs at our several group meetings during this research.

I appreciate the financial support for this research by the NSERC/Cenovus/Alberta Innovates Associate Industrial Research Chair in Energy and Environmental Systems Engineering at the University of Alberta.

Last but not the least, I am grateful for the unwavering love, encouragement, and support from my wife, Funmike, and my sons, Enoch and David, during the course of study.

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List of Abbreviations

AESO	Alberta Electric System Operator
Alt-BAU	Alternate business-as-usual
AIES	Alberta Interconnected Electricity System
AUC	Alberta Utilities Commission
BAU	Business-as-usual
$	Canadian dollar
CLP	Climate Leadership Plan
CO_2 eq.	Carbon dioxide equivalent
COP	Conference of Parties
EIA	Energy Information and Administration
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatt
GWh	Gigawatt-hour
GWh/Yr	Gigawatt-hour per year
Gt	Giga tonnes
IRENA	International Renewable Energy Agency
kV	Kilovolt
LEAP	Long-range Energy Alternatives Planning
NPS	New Policy Scenario
NPV	Net Present Value
MW	Megawatt
MWh	Megawatt-hour
Mt	Million tonnes

ODt	Oven dry tonnes
OECD	Organization for Economic Co-operation and Development
PJ	Petajoule
t	tonne
TWh	Terawatt-hour

Chapter 1 : Introduction

1.1 Background

One of the most discussed issues that motivated debates, negotiations, and consensus at different constitutional levels is climate change [1]. The most recent consensus landmark was in Paris at the 2015 United Nations Climate Change Conference (UNFCCC) of Parties (COP 21), where 195 UNFCCC member states agreed to deep reductions on global emissions [2]. The outcomes of these discussions need to be implemented in the economic and energy sectors of many countries, regions, and cities through revised compliance requirements, regulations, or policies in order to reduce GHG emissions [3].

Over the past three decades, greenhouse gas (GHG) emissions reduction strategies in key economic sectors (i.e., the electricity generation, agriculture, transportation, residential, commercial, and industrial sectors) have been discussed broadly and implemented in different jurisdictions [3-5]. However, the enforcement of GHG mitigation strategies is more aggressive in the electricity generation sector than in the others. This is because it is easier to implement GHG mitigation measures in a small number of publicly or privately owned centralized power plants within a carefully regulated industry than in individual and widely dispersed GHG emission sources [6, 7]. An example of a major GHG emissions reduction initiative in both North America and Europe is the phase-out of coal-fired electricity generation [8, 9]. In the United States, over 50 GW of coal-fired electricity generation capacity was retired between 2010 and 2017, and an additional 33 GW is projected to be phased out by 2025 [10]. According to the American Coalition of Coal Electricity (ACCE), approximately 99 GW of coal-fired electricity generation capacity have been announced for retirement or conversion to other fuels in the United States by 2030 [11]. In Canada, Ontario provided leadership in 2014 by completely phasing out coal-fired electricity generation, which accounted for 25% of its electricity generation in 2007. As a result of this phase-out, Ontario reduced its GHG emissions by approximately 30-34 Mt CO_2 eq. [12, 13]. Of late, Alberta, the highest GHG-emitting province in Canada, likewise committed to coal-fired electricity generation phase-out by 2030 as one of the key measures for GHG emissions reduction [14]. While the phase-out of coal-fired electricity generation is gaining acceptance and is beneficial in areas other than climate change mitigation, electricity demand is increasing, and cleaner and cost-effective generation substitutes are required to fill this demand and reliably sustain the electricity generation sector into the future. The United States Energy Information and Administration [15] estimates a 1.9% average annual growth in global net electricity generation from 2012 to 2040, with wind and hydropower electricity generation projected to account for two-thirds of the increase.

1.1.1 Global electricity generation sector and related GHG emissions

Global electricity generation has increased nearly fourfold over the past four decades, from 6,131 TWh in 1973 to 23,816 TWh in 2014. The Organization for Economic Co-operation and Development (OECD) countries and China account for the largest shares of global electricity generation at 45.2% and 24%, respectively [16]. Despite the increasing share of renewable electricity generation, the world's electricity generation is still predominantly achieved by fossil fuel (coal, natural gas, and oil) combustion. According to the International Renewable Energy Agency (IRENA), the share of global renewable electricity generation was 18% in 2010 and it is projected to increase to 21% by 2030 under a business-as-usual scenario [17]. In terms of fossil fuel combustion, the electricity and heat generation sector account for the largest share (42%) of CO_2 emissions from fuel combustion sources [18].

1.1.2 Overview of Canada's GHG emissions and electricity generation sector

Canada is among world's leading GHG emitters in terms of both absolute GHG emissions and per capita GHG emissions [18, 19]. In 2015, Canada's total GHG emissions were 722 Mt CO_2 eq. [20]. Over a period of two consecutive decades, Canada's annual GHG emissions consistently averaged 723 Mt CO_2 eq. between 1996 and 2005 and 720 Mt CO_2 eq. between 2006 and 2015 [20]. These figures show that a more determined effort is required to meet the federal government's commitment of 622 Mt CO_2 eq. and 525 Mt CO_2 eq. GHG emissions by 2020 and 2030, respectively [13]. The two major economic sectors that contribute to Canada's GHG emissions are the oil & gas and transportation sectors. There has, however, been a decline in GHG emissions in the electricity sector. Canada's GHG emission trend by economic sector is shown in Figure 1-1.

Electricity in Canada is generated from fossil fuels and nuclear and renewable sources. The fossil fuel sources include coal, natural gas, and oil and the nuclear source is mainly uranium. The renewable sources are hydro, wind, biomass, and solar.

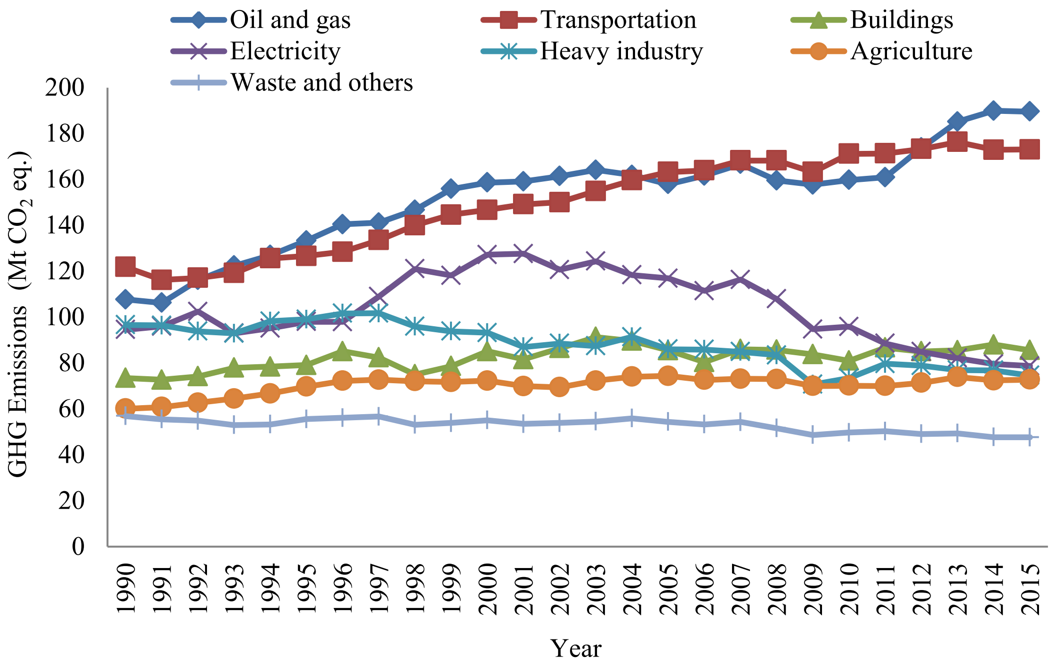


Figure 1-1. Canada's GHG emission trend by economic sector [21]

Canada's electricity generation and related GHG emissions trend contrasts the global trend, in which both electricity generation and related GHG emissions nearly doubled between 1990 and 2013 [22]. Between 2005 and 2014, Canada's average electricity generation grew by approximately 2.44 TWh per year and the sector's average GHG emissions declined by 4.14 Mt CO_2 eq. per year [21]. Estimates of Canada's aggregate carbon intensity (ACI) fell from 0.22 Mt CO_2 eq./TWh to 0.15 Mt CO_2 eq./TWh in 2005 and 2014, respectively. Ang and Su [22] defined the ACI as the ratio of total CO_2 emissions from fossil fuels in electricity production to the total electricity produced in the country expressed in Mt CO_2 eq./TWh.

The declining GHG emissions in Canada's electricity generation sector can be attributed to the impact of several policy implementations for GHG mitigation such as massive investments in end-use efficiency, grid reinforcements, and alternative electricity generation.

1.1.3 Overview of Alberta’s GHG emissions

Alberta is globally acknowledged for its vast reserves of fossil-fuel based natural resources and is thus very important in GHG emissions discussions. The province is also a crucial part of Canada’s overall environment, energy, and sustainable economic growth with about 80% and 64% of Canada’s crude and natural gas, respectively, produced in Alberta [23]. Therefore, the most substantial share of the province’s total emissions is from the oil sands mining and oil & gas sectors. The electricity generation sector is next in terms of GHG emissions because of fossil-fuel dependent electricity generation.

In 2015, Alberta’s share of Canada’s total GHG emissions was the largest at approximately 38%, and since 1990 the province’s total GHG emissions have increased by approximately 57% [21]. While Alberta produces only 11% of Canada’s total electricity generation, it accounts for about 58% of GHG emissions from Canada’s electricity generation sector [24]. Quebec. on the other hand, Canada’s largest electricity producer at about 189 TWh electricity (31% of Canada’s total electricity generation), has only 0.25 Mt CO_2 eq. electricity generation GHG emissions [24] as a result of its dependence mainly on hydroelectricity.

Annual electricity sector GHG emissions and total electricity generation in Canadian provinces between 2005 and 2014 are shown in Figure 1-2. The bars represent the GHG emissions in Mt CO_2 eq. and the lines represent the electricity generation in TWh. The announcement of the Climate Leadership Plan (CLP) [14] in November 2015 in Alberta signified the determination to change course and responsibly reduce GHG emissions in every economic sector in the province. The CLP anticipates that the electricity generation sector's share of GHG emissions will fall from 17% in 2013 to 9% in 2030 [14].

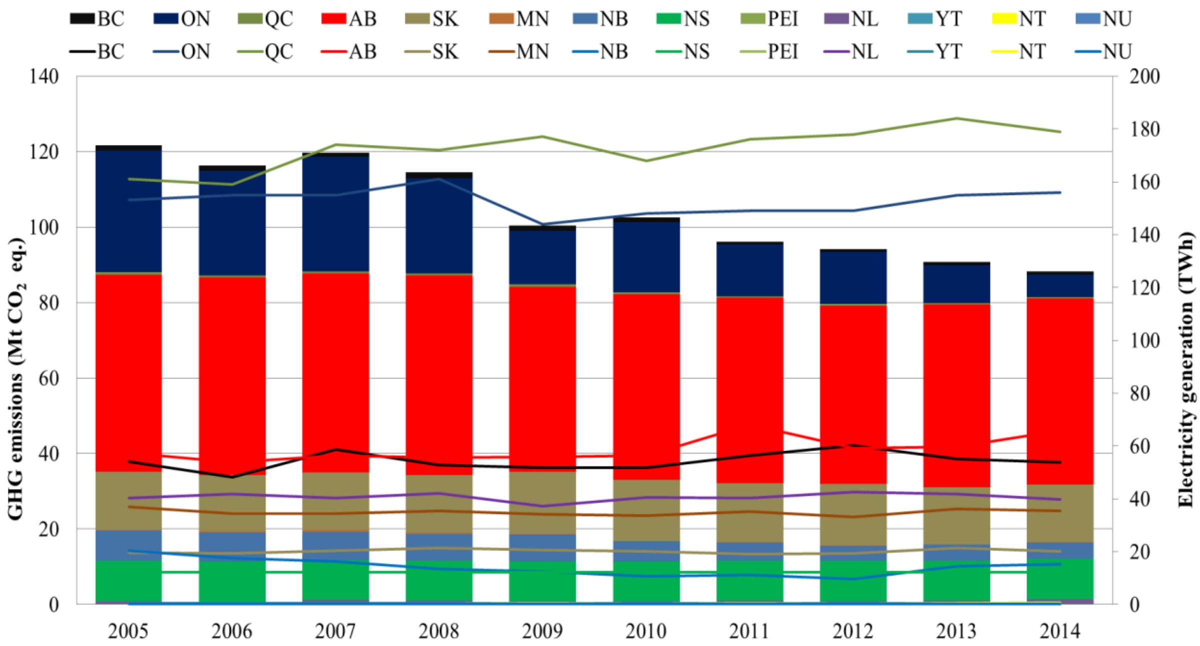


Figure 1-2. Electricity sector GHG emissions and generation in Canadian provinces (data adapted from [24])

1.2 Research motivation

The trend of replacing fossil-fuel based electricity generation with low or zero emission alternatives has led to studies on quantitative assessments, prediction of future GHG emissions reductions, and the social and environmental impacts as determined by cost-benefit frameworks. According to Fellows et al. [25], beyond adding alternative electricity generation capacity to attain specific GHG emission reduction targets, prioritizing and establishing a cost-effective strategy would better achieve a long-term policy target.

Many studies have used different energy models and simulation softwares for the assessment of the electricity generation sector for policy decision making in different jurisdictions around the world. Gomez et al. [26] used LEAP to investigate the Spanish electricity sector. The study focused on analysis of past generation pathways to draw up lessons for future energy planning. The MARKAL model was used by Sulukan et al. [27] to analyze cogeneration implementation in the Turkish energy system. The study concentrated on the impacts of encouraging increased use of cogeneration as an option for demand side management. Neves et al. [28] used HOMER, EnergyPLAN energy and self-built modelling tools to investigate the demand response strategies using Corvo Island as a case study. They focused on demand response for optimizing the electricity supply. EnergyPLAN model was developed by Ma et al [29] to examine and analyze the existing energy structure and future alternative sustainable energy strategies for Hong Kong. The study focused on only two pathways, electricity import and substituting nuclear electricity generation with renewables, for mitigating GHG emissions in the electricity generation sector. Zhou et al [30] used LEAP to recommend policy measures for non-fossil fuel energy for achieving China's 2020 climate change target. The results from the study examined the generation sector and the results indicate that the penetration of non-fossil fuel energy could contribute almost one-fifth of the total emissions reduction target by 2020. The EnergyPLAN simulation tool was used by Ali et al [31] to analyze the future strategy for CO_2 emissions from Singapore's electricity generation sector. The study focused on three scenarios to present the 2020 GHG emissions reduction target in Singapore's electricity generation sector.

The study done by Oniszk-Popławska et al. [32] used the Strategic Assessment Framework for the Implementation of Rational Energy (SAFIRE) model to assess future renewable energy developments in Poland. The study focused on individual renewable technologies for policy decision making. The multi-region unit commitment (MRUC) model was developed by Howard et al [33] to estimate existing and near term electricity generation GHG emissions for New York state and city. The study concentrated on performance parameters of 191 generators to estimate GHG emissions factors for formulating policies for demand-side efficiency measures. The Open Source Energy Modelling System (OseMOSYS) was used by Lyseng et al. [34] to develop 13 scenarios to investigate the impact of carbon pricing for the Alberta electricity generation sector. The study results indicate that coal with CCS is economical to justify the importance of low-carbon baseload generation. Subramanyam and Kumar [35] used LEAP to model GHG mitigation scenarios for Alberta's electricity demand and supply sectors. The model developed for the study did not comprehensively incorporate Alberta's electricity generation sector structure and relevant forecasts of carbon prices, capital cost and gas prices.

Based on the literature review carried out, a summary presented above, limited studies examine the GHG abatement cost to compare the different pathways investigated for reducing GHG emissions. Past work on future assessments of GHG emissions for Alberta's electricity generation sector shows that the results were mostly inapplicable in light of present policy shifts [34-36]. This research was undertaken to answer, through a quantitative evaluation and analysis of the medium-term and long-term consequences of present policy implementations in the electricity generation sector, how GHG mitigation options and reduction targets could be cost-effectively achieved.

This research presents a detailed integrated resource planning model for the assessment of Alberta's electricity generation sector with the aim of achieving lower GHG emissions within the time constraints of targeted renewable capacity penetration and the phase-out of coal-fired electricity generation. The research work is useful for informed policy planning and decision making for low or zero emission alternative energy deployment to reduce GHG emissions in a high-emission fossil-fuel dominated electricity generation mix.

1.3 Research objectives

The overall objective of this research is to develop an integrated resource planning energy model using the Long-Range Energy Alternatives Planning (LEAP) system model to assess future GHG mitigation potential and abatement costs in an electricity generation mix. The research objective is achieved by identifying and developing pathways for the penetration of low or zero GHG emission electricity generation alternatives such as biomass, hydro, wind, solar, geothermal, and nuclear to replace a share of fossil fuel generation capacity by a specified year while maintaining baseload generation. Alberta (a Western Canadian province) was selected as a case study, and the specifics of the research objectives are to:

- Develop the baseline (BAU) scenario and assess the GHG emissions reduction achievable in the generation mix
- Identify alternative energy scenarios and evaluate their feasibility for increasing low or zero emission electricity generation capacity to replace fossil-fuel based electricity generation capacity
- Assess the GHG mitigation achievable for the identified scenarios using the LEAP model
- Develop a GHG abatement cost curve to evaluate the social cost benefit of the identified scenarios in terms of cumulative GHG mitigation compared to the BAU scenario

1.4 Research methodology

An energy model was developed with the LEAP-Alberta model. The overall method is based on the understanding of the fundamental concept of an interconnected electricity generation, transmission and distribution system such that total electricity generation output is demand-driven in order to achieve a balance between supply and demand. The total electricity generation output is based on a synchronized dispatch of different fossil fuel-fired and renewable power plants according to merit order. The total electricity demand according to the demand sectors is structured under the demand module. Similarly, different types of existing or possible generation technologies as processes are structured under their respective transformation modules. The baseline data on both the demand and supply sides are input to the model to represent the reference or BAU scenario. Other scenarios of likely future developments are also created based on the existing BAU framework and variable data input. The results of the BAU were compared with historical data for validation, and abatement cost curves were developed. Chapters 2 and 3 of the thesis describe the details of methodologies and model formulation. The method used in the study to develop the framework for Alberta is shown in Figure 1-3.

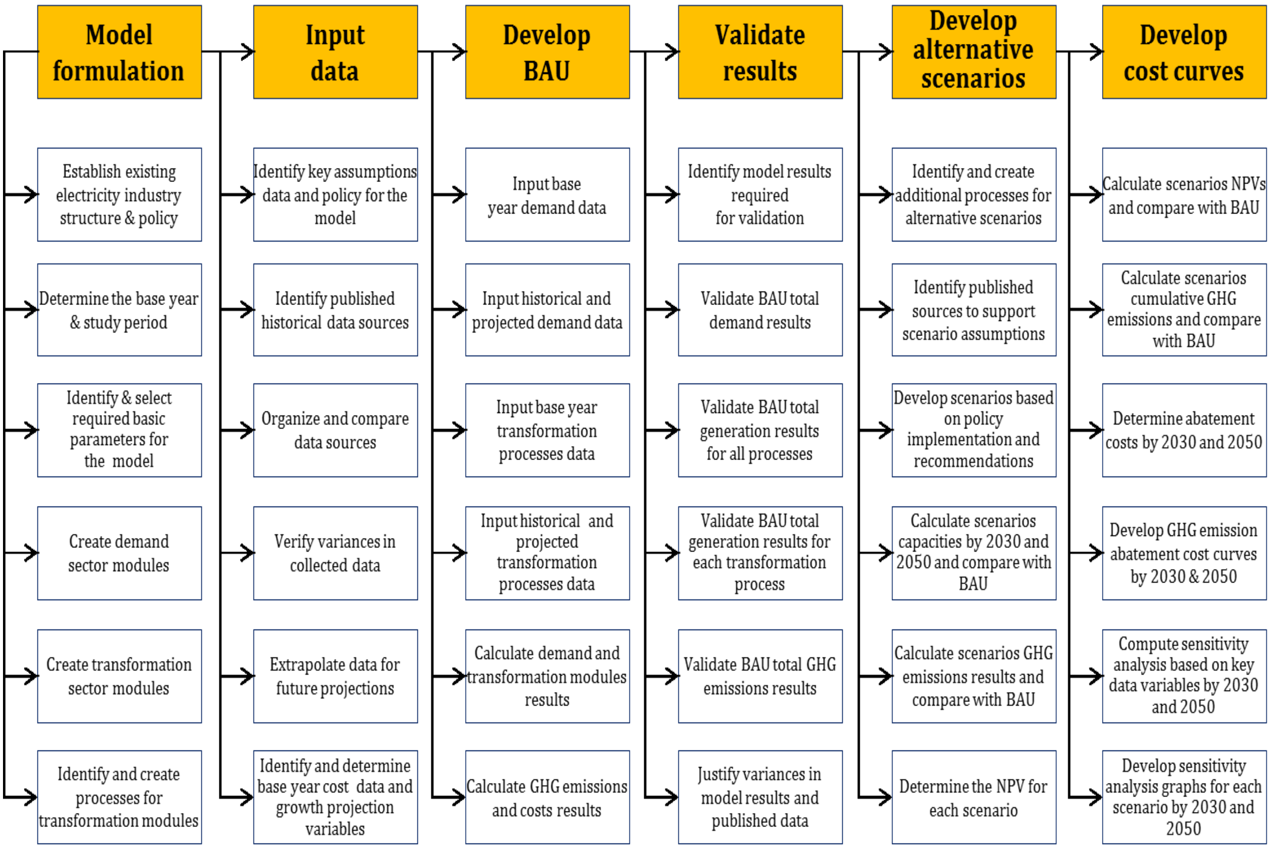


Figure 1-3. Activity flowchart of the LEAP model development framework

1.5 Limitations of the study

The LEAP-Alberta model developed for the study is limited to the following:

- The forecast period is 2010 to 2050 (41 years) and the model base year is 2010.
- The study is limited to Alberta's electricity generation sector and incorporates relevant policy shift recommendations of the Climate Leadership Plan (CLP).
- Total electricity demand data are imported from the results of the detailed bottom-up demand sector LEAP-Alberta model developed for Alberta.
- All historical and projected generation capacity data are taken from literature including Alberta Electric System Operator's AESO's most recent long-term outlook reports.

- Generation capacity data beyond 2037 are extrapolated based on literature and AESO's data.
- The performance and operating parameters of specific power plants are not within the scope of this study. Suitable assumptions are based on average annual performance and operating data of power plants technologies (transformation processes) categorized by feedstock fuel.
- The effect of battery storage is not modelled in any of the scenarios as the integration of storage modeling capabilities into the LEAP-Alberta model software is still under development.
- The developed model does not have the capability to validate historical electricity prices or to forecast future electricity prices in a deregulated "energy only" wholesale electricity market. In Alberta's deregulated "energy only" wholesale electricity market, electricity prices are uncertain and fluctuate in real time according to forces of demand and supply
- Electricity transmission interconnection infrastructure costs relative to the location of power plants are not included in the total transformation costs and GHG abatement costs.
- Alberta-specific hourly generation profiles of wind, solar, and hydro generation were not incorporated into the model and so the impact of weather patterns on total annual generation and load curve was not determined.

1.6 Organization of the thesis

The thesis is organized into four chapters and additional sections for the table of contents, list of tables, list of figures, list of abbreviations and appendices. The chapters are summarized as follows:

Chapter 1 summarizes the global and Canadian electricity industry in the context of GHG emissions and describes the motivation and methodology of the research. The chapter also summarizes the limitations of the study.

Chapter 2 reviews the theoretical and developable potential of available renewable energy resources in Alberta. It describes the model development including the assumptions, key operating, and cost input parameters and reviews in detail the BAU scenario and validates the model BAU results. This chapter also discusses the model results of future demand, generation, and GHG emissions of additional baseline scenarios based on the planning forecasts of the Alberta Electric System Operator (AESO).

Chapter 3 discusses the rationale for the development of 18 alternative scenarios. The chapter also discusses the model results in terms of GHG emissions profile and the abatement cost curves. It also explores the estimates of additional GHG emissions reduction possible for the 18 different generation mixes based on changes in future operating parameters during the study period. Sensitivity analyses were performed to understand the effect of upward or downward changes in gas prices, carbon tax, capital cost, and interest rates on the abatement costs of each scenario under similar model demand and generation assumptions.

Chapter 4 presents the research conclusions and recommends opportunities for further work based on results of this study.

Appendix A comprises the summary of the BAU and alternative scenarios in the LEAP-Alberta model. Appendix B contains additional table of comments on cost data input to the LEAP-Alberta model. Appendices C and D contains the different graphs and tables of output results of sensitivity analysis of each alternative scenario considered in the study

Chapter 2 : The Development of a Framework for the Assessment of Greenhouse Gas Mitigation Scenarios in an Electricity Generation Mix

2.1 Introduction

The electricity sector is of interest in any jurisdiction because of its significance to economic development. Many studies have shown that demand for electricity is one of the most important growth indicators of any country. Independent studies on both electricity demand and generation have also confirmed the relationship with economic growth. The World Bank affirms that energy, especially electricity, is crucial to economic growth due to rising income and population growth [37]. Ferguson et al. [38] compared the correlation coefficient between the Organization for Economic Cooperation Development (OECD) countries, including Canada, and non-OECD countries and concluded that economic growth over time is directly related to electricity demand.

While studies on the significance of the connection between electricity and economic growth are common, a similar relationship of direct GHG emissions from using fossil-fuel fired electricity generation is also well known [39]. As of 2014, 42% of the global energy-related CO_2 emissions, i.e., 32.4 Gt are from the power generation sector [40]. Two-thirds of global electricity generation mix is from fossil fuels, with coal accounting for 77% of GHG emissions (10 Gt CO_2 eq.) from electricity generation [41, 42].

In Canada, 11% share of the total GHG emissions of 722 Mt CO_2 eq. in 2015 are from the electricity generation sector [21]. Canada's electricity generation consists of fossil, renewable and nuclear fuel sources. The fossil fuel sources include coal, oil and natural gas. The renewable fuel sources include hydro, wind, biomass and solar and the nuclear fuel source is uranium. Canada can be acknowledged a major player in the world electricity generation. In 2014, it was the 6th largest electricity producer accounting for 3% share of the world's total electricity generation of 23,903 TWh, and 3rd largest exporter of electricity accounting for 8% share of global electricity generation export of 690 TWh [43]. Compared to other developed countries electricity generation from non-emitting sources is high in Canada, with about 80% electricity generation from non-emitting fuel sources [43, 44]. Therefore, it can be inferred that only about 20% share of Canada's electricity generation result in its total electricity generation GHG emissions of 79 Mt CO_2 eq. As of 2016, coal-fired electricity generation still exist in four out of the thirteen Canadian provinces [43]. The four provinces are Alberta, New Brunswick, Nova Scotia and Saskatchewan.

Excluding the demand (behind-the-fence load) met by on-site generation by gas-fired cogeneration plants, Alberta's electricity generation is predominantly from carbon-intense emission fossil fuels of coal (64%) and natural gas (26%) [45]. Alberta's generation differs from Canada's relatively low carbon emission electricity generation through hydro (63%) and nuclear (13%) [46], with only about a 10% share of renewable electricity generation from wind, hydro and biomass. Alberta's fossil-fuel dominated electricity generation accounts for over half of Canada's total electricity generation sector GHG emissions. As a jurisdiction depends on its natural resources for economic and infrastructural development, so the province of Alberta became the leading greenhouse gas (GHG) emitter in Canada. For Alberta to reduce its GHG emissions and respond to climate change, the province must implement new policies in the electricity generation sector as well as in other key economic sectors. One of the recommendations is to phase out coal-fired electricity generation by 2030 [14]. Since electricity generation from coal-fired power plants dominates the generation mix of the province, it is pertinent to plan for a future that reduces GHG emissions without coal-fired electricity generation. Alberta's

Climate Leadership Plan (CLP) [14] has made proposals for mitigating climate change and its associated socio-economic impacts. The CLP recommends increasing the share of renewable electricity generation while gradually phasing out all existing coal-fired generation by 2030. The CLP also proposes a 30% target for generation from renewable energy sources and the replacement of 50-75% of retired coal generation with renewables. But the comprehensive quantitative assessment of the GHG emissions is not well understood. This thesis aims at addressing this gap.

Finding solutions to decreasing GHG emissions has resulted in focus on opportunities of energy efficiency improvements and alternative electricity generation. The outright elimination of all polluting forms of electricity generation would be the best solution if low emission resources were comparatively more accessible, cheaper, and more efficient. While some localities primarily generate electricity from low emission resources, it is impossible to depend solely on low emission alternatives in many places in short to medium term. Therefore, a shift to cleaner electricity generation is usually required to support increasing demand and economic growth.

A LEAP-based framework for modeling electricity generation sector from 2010 to 2050 was developed. LEAP is an energy planning and forecasting tool for energy policy analysis and climate change mitigation assessment [47]. LEAP and other energy modeling software [48-50] have been recognized for their influence on energy and environmental policy development around the world. Many research papers have investigated and analyzed the outputs from LEAP and other energy planning and forecasting models for GHG emissions mitigation in the energy demand and transformation sectors. Ghandan and Koomey [51] analyzed scenarios for energy forecasting and identify alternative fuels in California's power generation mix.

Ikonomopoulos et al. [52] investigated and analyzed the GHG emissions forecast for electricity production in Greece up to 2030. McPherson and Karney [53] developed a model to analyze the BAU and potential scenarios of a diversified generation mix in Panama with the aim of reducing GHG emissions. In Mexico, LEAP was used to determine the feasibility of using biofuels in the transportation and electricity generation sectors [54]. Specifically for Alberta, Lyseng et al. [34] developed a techno-economic optimization model to analyze the impact of carbon pricing to 2060 for the Alberta electricity generation sector using the Open Source Energy Modelling System (OSeMOSYS).

Subramanyam et al. analyzed combined scenarios of energy demand and supply in Alberta [55]. They developed Sankey diagram energy flows from source to end use (demand sectors). This diagram identified efficiency alternatives for GHG emissions reduction in Alberta. Further work by Subramanyam and Kumar [35] used the LEAP model to assess GHG mitigation scenarios.

The overall objective of this thesis is to assess sector-specific policy shifts such as the coal-fired electricity generation phase-out and renewable electricity targets relevant to future generation capacity mix planning. There is very limited work on assessment of the impact of GHG mitigation scenarios in the electricity generation sector and a comprehensive framework to assess these. This thesis addresses this gap.

The specific objectives of this research are to:

- Develop a framework to assess potential GHG mitigation in an electricity generation sector
- Identify and assess the potential for GHG mitigation through renewable resource use in electricity generation sector

- Conduct a case study for Alberta's electricity generation sector, a western Canadian province.

2.2 Background to Alberta's electricity sector

The Electric Utilities Act (2003) is the primary legislation that governs the Alberta electricity sector. Alberta's electricity sector was formerly vertically integrated and regulated similar to the traditional electricity sector structure common in many Canadian provinces. In a vertically integrated electricity sector, the generation, transmission, and distribution of electricity services are mainly provided by three major investor- and municipally owned utility companies in distinct geographical areas. These companies control the three primary activities of the electricity market: generation, transmission, and distribution. In a vertically integrated sector, there is no competition around geographical areas, and electricity prices are regulated [56].

Presently, the electricity sector in Alberta consists of both regulated and deregulated market structures [57]. The electricity generation and retail sectors function as a deregulated market with competition among several industry players that have open access to the grid. The generation market operates on a wholesale power market structure, known as power pool, in which electricity prices are determined hourly all year round. In the market structure, known as "energy only," electricity producers are paid for the energy supplied to the market but receive no compensation for ensuring capacity is available [58, 59]. Fundamentally, the principle of demand and supply drives both the hourly price of electricity and decisions on the type and operation of new generation capacity.

The transmission (72 kV to 500 kV) and distribution (less than 25 kV) sectors function as a regulated market under a cost-of-service model. The cost of service is a pricing model in which consumers remunerate investment and operating expenses incurred for providing a service. The existing electricity supply to the transmission grid in Alberta is made up of a mix of fossil fuels, renewable energy, and imports. Fossil fuel generation technologies use coal and natural gas. Existing renewable electricity generation is from wind, hydro, biomass, and solar. In 2015, the total installed electricity generation capacity was 16,288 MW [60] from 124 generation facilities [61].

As shown in Figure 2-1 [45, 60], approximately 78% (13,503 MW) of Alberta's installed generation capacity is fossil-fuel based. The installed generation capacity is made up of 16 subcritical coal generation facilities with a total installed generation capacity of 5,360 MW, two supercritical coal plants with a total installed capacity of 929 MW, and 31 cogeneration plants with total installed capacity of 4,502 MW. There are also six combined cycle plants with a total installed capacity of 1,702 MW and 28 simple cycle technologies with a total installed capacity of 996 MW. The remaining 17% (2,785 MW) of the total installed capacity is made up of 20 wind power plants with a total installed generation capacity of 1,463 MW and 12 biomass and waste heat power plants with a total installed capacity of 428 MW. In addition, Alberta has an intertie import capacity of 1,103 MW. The interties are connected with the neighboring provinces of British Columbia and Saskatchewan and with the United States through the state of Montana [45].

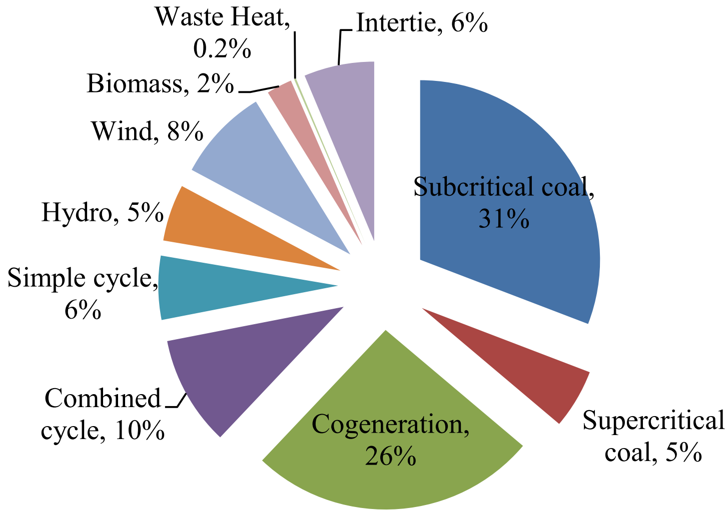


Figure 2-1. Alberta's installed generation and intertie capacities as of 2015 (data adapted from [45, 60])

2.3 Review of Alberta's renewable electricity generation

The existing renewable electricity generation in Alberta includes biomass, hydro, wind, and solar. The renewables share of electricity generation from 2005 to 2015 in Alberta and in the world is shown in Figure 2-2. Alberta's renewable electricity generation share fluctuated between a minimum and maximum range of 7-10% of the province's total electricity generated whereas the world's renewable electricity generation share is consistent and rapidly increased from less than 4% in 2005 to over 5% by 2015.

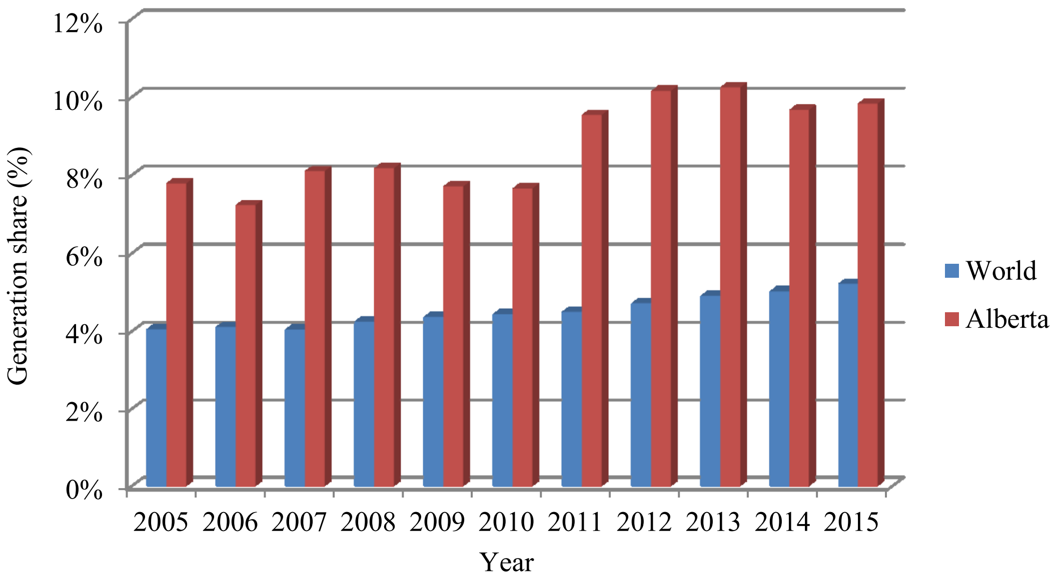


Figure 2-2. Alberta's and the world's renewable electricity generation shares in the mix (data adapted from [45, 62])

One of the primary considerations for the use of renewable energy in an electricity generation mix is the adequacy of available resources. Table 2-1 summarizes the estimated potential for renewable energy resources in Alberta from different studies. A review of these studies suggests that there is enormous potential for renewable electricity generation in Alberta. Nevertheless, the actual recoverable resources still depend on technical, environmental, and economic justifications.

Table 2-1. Summary of Alberta's renewable energy resource potentials

Renewable resource	MW	PJ	GWh/Yr	Assumptions	Ref.
Wind	64,000	-	-	5% of Alberta's total area of 642,000 km^2 is suitable for a 2 MW wind turbine capacity requiring a land area of 1 km^2.	[63]
	150,000	-	-	-	[64]
Hydro	11,600	-	-	-	[63]
	11,800	-	-	-	[65]
	-		42,030	Investigated remaining developable	[66]

Renewable resource	MW	PJ	GWh/Yr	Assumptions	Ref.
				hydroelectric energy potential at identified sites.	
	-	-	53,050	Investigated ultimate developable hydroelectric energy potential.	[66]
	-	-	103,360	Investigated theoretical maximum hydroelectric energy potential.	[66]
Biomass	15,500	-	-	-	[63]
	-	522.9	-	1995-2004 annual harvesting quantity levels for wood biomass, agricultural biomass, and municipal solid waste.	[67]
	-	585	-	Investigated potential estimates for forest biomass, forest and mill residues, municipal solid waste, and food processing waste	[68]
	1,204	-	-	Based on higher heating value 18.5/ODt and 25% plant efficiency on annual estimates of total forest residue biomass classified as logging residues, low-quality trees, dead or dying trees and mill processing residues.	[69]
	-	458	-	-	[70]
	-	700	-	Estimated total energy available from biomass resources in Alberta.	[71]
	-	-	21,166	Forest residues (3,889 GWh), mill residues (889 GWh), agriculture surplus straw (16,388 GWh)	[72]
Geothermal	10,000	-	-	Estimate based on 0.5% recoverable from potential 21 billion GWh at 5.0 km depth	[63]
	120,000	-	-	Recoverable estimate of potential geothermal resources.	
Solar	-	25	-	Estimate of solar PV distributed power generation.	[71]

2.3.1 Wind generation potential and installed capacity

As of 2015, Canada has the seventh largest installed wind capacity in the world, with an installed capacity of 11,026 MW [73]. Alberta has experienced tremendous growth in wind generation capacity since the early 1990s when installed capacity was barely 1.0 MW. Estimates of wind generation potential in Alberta range from 64 GW to 150 GW [63, 74]. As of 2015, Alberta has the third largest installed wind electricity generation capacity in Canada at 1,463 MW, which represents approximately 13% of the country's total installed capacity. Southern Alberta has the greatest potential for wind energy with annual average wind speeds of 4.5-10 m/s at 80 m above ground level [74]. The installed wind capacity in Canada as of 2015 is shown in Figure 2-3. Between 2010 and 2015, Alberta's wind generation share of its total generation mix almost doubled, increasing from 2.7% (1,582 GWh) to 5.1% (4,089 GWh) [45, 75].

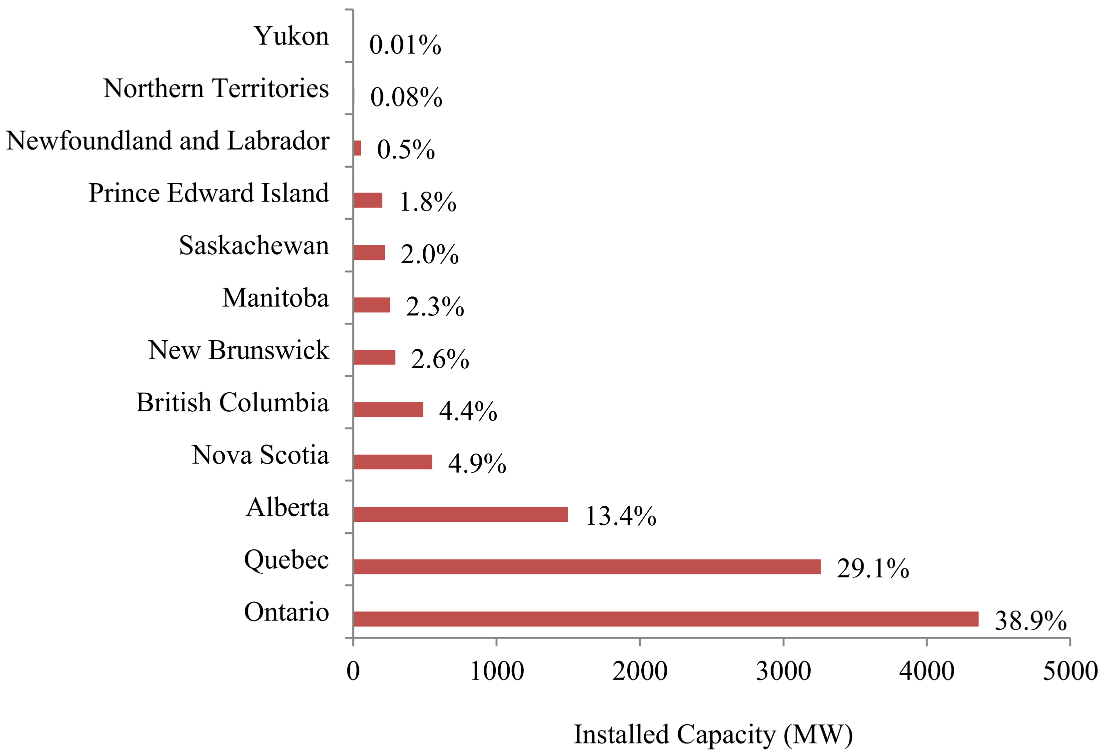


Figure 2-3. Installed wind capacity in Canada as of 2015 (data adapted from [73])

2.3.2 Hydroelectricity generation potential and installed capacity

Hydroelectricity generation in Alberta is relatively low compared to Canada as a whole. As of 2015, the total installed capacity for hydroelectricity generation in Alberta was 894 MW accounting for about 2.2% of the total [45]. Canada has the third largest hydroelectric generation in the world, with a total installed capacity of approximately 79.5 GW including pumped hydro storage [76]. Alberta's hydroelectricity is constrained from full output operation at peak loads, usually during the winter; average capacity between 2010 and 2015 was 27%. The estimated potential for hydroelectricity ranges from 11.6 -11.8 GW [63, 65]. A study by Hatch Ltd. [66] on Alberta's hydroelectric energy resources analyzed nine river basins and concluded that the largest hydroelectric potential is in five rivers located in northern Alberta.

2.3.3 Biomass generation potential and installed capacity

Electricity generation from biomass is seen to produce low carbon emissions in the range of 30g CO_2 eq./kWh – 132g CO_2 eq./kWh [77, 78] and in most cases is carbon dioxide neutral [79]. Therefore, large-scale electricity generation from biomass is a renewable energy alternative that may be possible in Alberta due to its vast resource availability. Weldemichael and Aseefa [70] estimated the potential for biomass resources in the province to be 458 PJ. Thakur [69] showed that 1.2 GW of electricity generation capacity might be possible in Alberta from forest biomass sources such as logging residues, low-quality trees, deads or dieing trees, and mill processing residues. As illustrated by Turkenburg [80], existing or ongoing conversion pathway development for biomass includes electricity generation, heating, and transportation fuels.

2.3.4 Geothermal generation potential and installed capacity

Geothermal energy is the heat contained in the earth's interior. Geothermal energy is a unique renewable resource because it can support baseload electricity generation unlike wind and solar. A geothermal power plant's capacity factor can be as high as 95% [81]. Currently, there is no geothermal plant for electricity generation either in Alberta or elsewhere in Canada, but geothermal energy is commonly used for direct use and in heat exchange systems [82]. Hoffman et al. [83] stated that a limitation of geothermal electricity generation in Alberta is its average geothermal gradient, which was considered inadequate for commercial development. However, further studies indicate that electricity generation may be feasible in the Western Canadian Sedimentary Basin (WCSB) using enhanced geothermal systems [83]. Minimum and maximum potential estimates for geothermal generation in Alberta range from 4.2 GW to 555 GW with recovery at 5% and 20%, respectively [84].

2.3.5 Solar generation potential and installed capacity

Alberta's solar electricity generation share is negligible compared to existing renewable electricity generation such as hydro, wind, and biomass. As of May 2016, solar electricity generation was mainly solar PV, with a total installed capacity of approximately 10 MW widely dispersed at different residential and commercial buildings [85]. In Alberta, such small-scale renewable and alternative electricity generation is permitted by the micro-generation regulation is under the Electric Utilities Act (2003) [86]. The estimated potential for solar PVs in Alberta is 25 PJ [71] and 9,177 TWh/year for concentrated solar power (CSP) [87]. With the announced incentive support for solar electricity generation [88], it is anticipated that micro-generation solar capacity will grow rapidly over the next 15 years in Alberta.

2.4 Electricity generation model development

The Long-range Energy Alternatives Planning (LEAP) system is a data-intensive framework for energy-environment investigation in all sectors of an economy. LEAP is used by over 30,000 registered users in over 190 countries [47]. It is a scenario-based analytical tool for climate change mitigation assessment for energy consumption, production, and resource extraction [89]. The LEAP framework shown in Figure 2-4 [89, 90] analyzes demand, transformation, resource, and environmental aspects of different energy systems. It consists of three major hierarchical interconnected modules (branches), namely demand, transformation, and resource for developing location- and sector-specific energy models. LEAP is unique with its technology and environment database of technical features, costs, and environmental impacts of energy technologies [90]. In the present study, a data-intensive LEAP energy model was developed to review and assess future electricity generation and associated GHG emissions under specified policy and economic conditions.

This study evaluates Alberta Electric System Operator's (AESO) electricity generation planning based on anticipated future demand growth and generation development. The reference (or BAU) scenario was developed with AESO's previous and recent generation planning data [45, 60, 75, 91, 92]. Other AESO scenarios were developed based on different capacity generation mixes of renewables and gas-fired generation to achieve a renewable target and maintain baseload electricity generation.

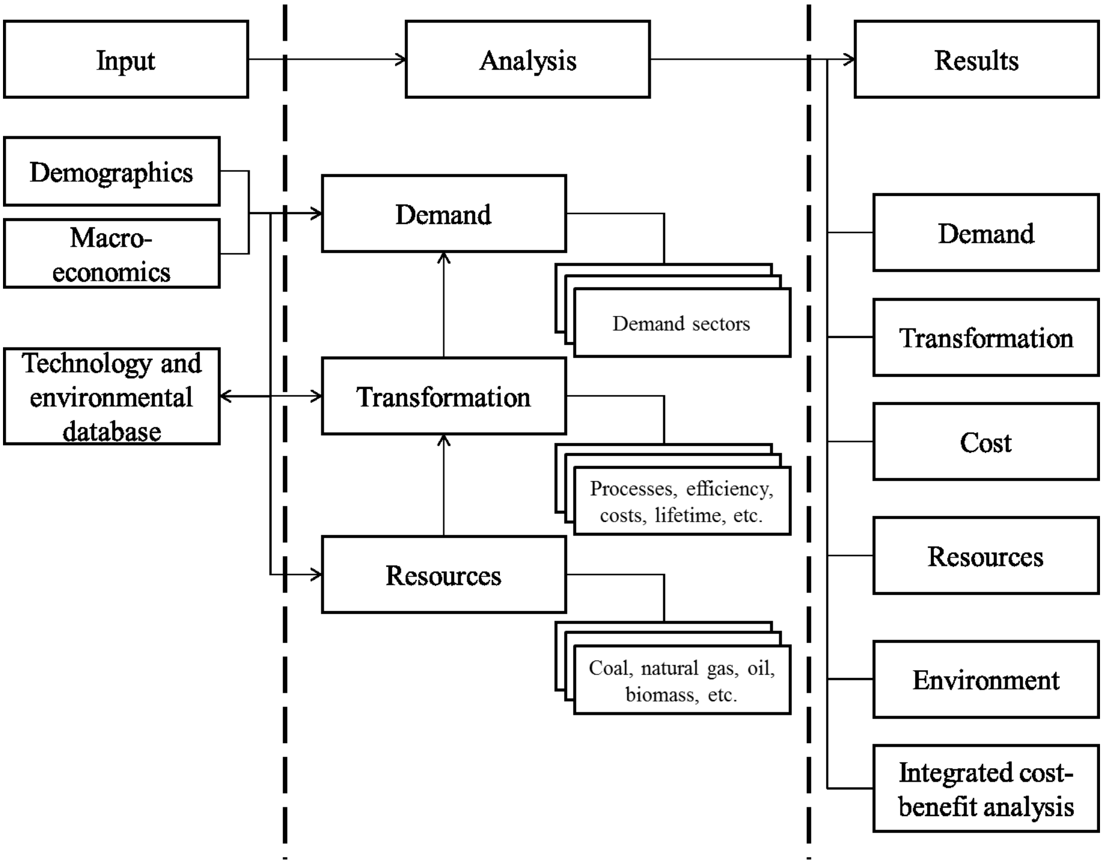


Figure 2-4. Basic LEAP model framework (figure adapted from [89, 90])

The first step in setting up this study's LEAP model was to identify the modules to be examined. The modules relevant to this study are the demand, transformation, and resource extraction modules. The output results of the electricity generation model developed in LEAP's transformation module are driven by the overall demand sector input data. The transformation module is characterized by the electricity generation and transmission and distribution sector processes.

The second step involved is arranging the modules in order of energy flow sequence from the lowest level to the highest level. At the lowest level is the primary resource extraction module followed by the transformation module in the middle and the demand module at the highest level. The next step was to specify the primary resources produced indigenously and imported. Energy resource conversions were simulated in the transformation module from extraction point to final consumption each process.

The final step is the creation of generation module processes and demand sectors that represent the level of detail required for our analysis. In this research, the Alberta electricity sector was used as a case study in developing the LEAP model framework. The structure of the electricity sector as modeled in the LEAP transformation module is shown in Figure 2-5. In Alberta, electricity generation dispatch is fully matched with demand by merit order, a sequence of energy dispatch from power producers based on lowest cost offer. The LEAP energy model was developed to estimate total generation and resulting emissions based on to future load growth considerations and environmental policy interpretations. The model was developed for a 2010-2050 study period with data input from Alberta Electric System Operator (AESO)'s historical, recent, and forecast generation and demand planning data [45, 60, 75, 91, 92]. The year 2010 was selected as the base year for the model with historical data input from 2010 to 2015 and forecast data from 2016 to 2050.

This research incorporated comprehensive industry-specific data (i.e., load curves, varying annual capacity factors, transmission and losses, reserve margin, gas, and carbon price forecasts) to assess the electricity generation dispatch of each process in a generation mix and the extent of GHG mitigation possible in the electricity generation sector. Four scenarios representative of industry development trends and environmental policy assumptions are discussed and analyzed in this chapter. These are the business-as-usual (also called the reference scenario), high growth, low growth, and the alternate case scenarios. Each scenario has assumed forecasts for anticipated total electricity demand growth and complementary generation capacity development.

The energy demand data are adopted from the total energy (expressed in thousand GWh) output results of the updated bottom-up estimates developed in the LEAP model for the residential, commercial, industrial, transportation, and agricultural demand sectors, and the behind-the-fence (BTF) load from 2010-2050. The total system demand, excluding transmission and distribution losses, is the sum of the electricity demand from the residential, commercial, industrial, transportation and agricultural demand sectors. The BTF load is the demand that is served fully or partially by on-site electricity generation, primarily from gas-fired cogeneration plants [93].

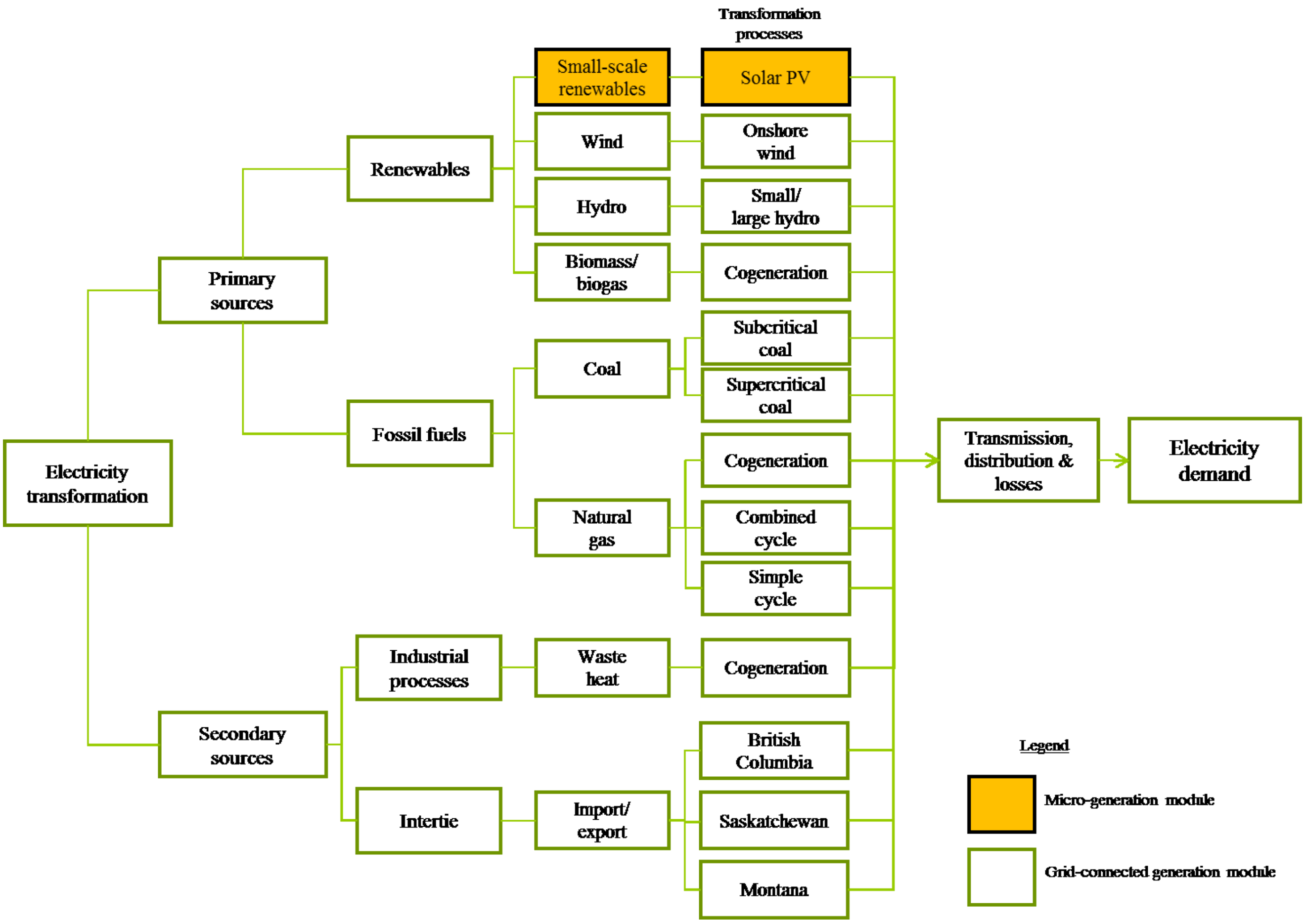


Figure 2-5. LEAP transformation module structure for Alberta's electricity sector

The sum of the system load and the BTF load is the total Alberta Internal Load. Figure 2-6 shows the structure of the Alberta Internal Load. The total Alberta Internal Load represents the BAU (reference) demand for the model. Distinct from the demand sector, in which the data input are adopted from the Alberta energy demand model output, transformation tree data are organized to into two broad sub-categories, micro-generation and grid-connected generation. The micro-generation sub-category, shown in Figure 2-5, mainly includes small-scale solar photovoltaic and wind generation technologies of 5 MW capacity or less for direct electricity supplied to end users (homes, businesses, and farms) and the supply of excess electricity generated to the distribution grid system. The grid-connected sub-category includes those electricity generation plants that are connected to the transmission system, also known as the Alberta Interconnected Electric System (AIES).

The processes (generation technologies) connected to the AIES include subcritical and supercritical coal-fired plants, cogeneration, and combined cycle and simple cycle gas-fired generation plants as well as renewable energy generation technology such as hydroelectricity, wind, and biomass power plants. Other processes created in the grid-connected sub-division include waste heat power plants, solar, geothermal, and nuclear power plants. At present, solar, geothermal, and nuclear power plants are not producing electricity in the AIES generation mix. However, studies and reports have shown that they have potential for future consideration in the generation mix and fuel sources in Alberta [83, 92, 94].

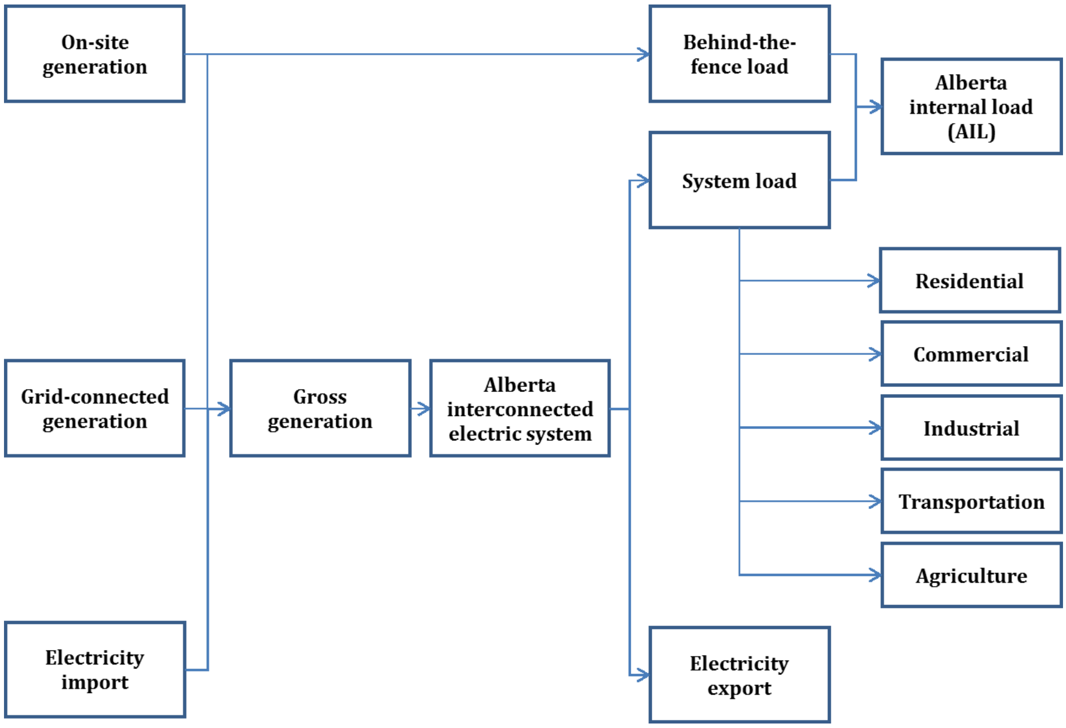


Figure 2-6. Structure of Alberta's interconnected electricity system and internal load

The data used for the build-up and verification of the model were obtained from AESO's previous and current generation outlook [60, 91, 92], annual market statistics reports [45, 75], and other sources [95]. The reports provide information such as capacity, annual load curves, capacity factors (maximum availability in LEAP), and efficiencies for each technology based on the actuals reported for the base year, 2010. Input capacity data from the first scenario year (2011) to the final year (2050) are based on the historical data up to 2015 and projections from 2016 to 2037. Capacity data projection from 2038 to 2050 (the end year for the study period) was extrapolated from the respective estimated annual growth rates of available future data projections. Other base year data input [91, 96-101] to the LEAP model is shown in The overnight cost is an estimate of the entire process, from planning through completion, at which a plant could be constructed assuming no interest was incurred during its construction period [102]. The overnight cost assumptions for each generation technology include the owner's cost, engineering procurement and construction costs and contingency [103].

Table 2-2. The capital cost data are based on overnight costs.

The overnight cost is an estimate of the entire process, from planning through completion, at which a plant could be constructed assuming no interest was incurred during its construction period [102]. The overnight cost assumptions for each generation technology include the owner's cost, engineering procurement and construction costs and contingency [103].

Table 2-2. Base year data input to the LEAP model

Processes (Generation technology)	**Capital cost[a] ($/kW)**	**Fixed O&M[a] ($/kW)**	**Variable O&M[a] ($/MWh)**	**Maximum availability[b] (%)**	**Process efficiency (%)**	**Capa-city credit (%)**	**Life-time**	**Ref.**
Subcritical coal	1,244	35.1	13	86	33.56	100	15[c]	[63, 96, 97, 104]
Supercritical coal	1,723	35.1	12	86	39.5	100	19[d]	[63, 96, 97, 104]
Cogeneration	1,119	6.94	2.5	73	84	100	30	[63, 96, 97, 104]
Combined cycle	1,190	6.5	1.9	32	51	100	30	[63, 96, 97, 104]
Simple cycle	939	14.1	13.8	15	38	100	30	[63, 96, 104, 105]
Hydro	3,014	29	0	25	95	50	50	[63, 96, 104, 105]
Wind	2,203	79	0	27	35	20	30	[63, 96, 104, 105]
Solar	3,498	45	0	16	15	0	30	[63, 96, 104, 105]
Biomass (forest residue)	2,130	60	52	29	25	100	30	[35, 63, 69, 96, 104, 106]
Biomass (straw)	2,300	66	47	29	25	100	30	[35, 63, 69, 96, 104, 106]
Waste heat	1,854	6	8.24	29	28	100	30	[63, 104, 107]
Nuclear	5,449	184	5	90	33	100	30	[63, 96, 99, 104]
Geothermal	5,746	18	9.93	90	17	100	30	[63, 101, 104, 108]
Intertie (import)	-	-	51	27	95	100	-	[45, 63]

a. Where applicable, capital, fixed and variable O&M costs are converted to 2010 dollars (LEAP base year) from reference location based on Bank of Canada exchanges rates [109, 110], regional indices of 1.08 and 2.16 for transfer projects from US Gulf coast to Canada [111].Variable O&M costs of gas-fired cogeneration, combined cycle, and simple cycle processes exclude fuel costs.

b. Except for solar, biomass straw, nuclear, geothermal, maximum availability was assumed. Maximum availability for other processes was calculated for the base year and each year from 2011 to 2015 based on equation (1). The maximum availability of cogeneration and combined cycle is assumed to increase up to 75% by 2020 due to the phase-out coal-fired electricity generation between 2020 and 2029.
c. Subcritical coal plant lifetime is assumed to coincide with the proposed retirement schedule of coal-fired electricity generation.
d. Supercritical coal plant lifetime is assumed to coincide with the proposed retirement schedule of coal-fired electricity generation.

The maximum availability input in the LEAP model was calculated for the base year and other historical years for each generation technology. It is expressed as the ratio of actual energy generated (GWh) in the year to the theoretical maximum that could be produced at installed capacity in the same year. From equation (1), maximum availability was determined for each year from 2010 to 2015:

Maximum availability (%), $$M_a = \frac{E_{actual}}{C_{installed} \times N} \quad (1)$$

where,

$E_{actual} = Actual\ energy\ generated\ in\ the\ year\ (GWh)$

$C_{installed} = Installed\ capacity\ (GW)$

$N = Total\ number\ of\ hours\ in\ a\ year\ (hours)$

The lifetime of subcritical and supercritical coal power plants is lowered to match their retirement schedule assumptions as shown in Table 2-3 [60]

Table 2-3. Retirement schedule assumptions of coal-fired power plants [60]

Coal-fired generation assets		Capacity (MW)	Year of commissioning	BAU retirement date assumptions
	Battle River 3	149	1969	2019
	Sundance 1	280	1970	2019
	HR Milner 1	144.3	1972	2019
	Sundance 2	280	1973	2019
	Battle River 4	155	1975	2025
	Sundance 3	353	1976	2026
	Sundance 4	406	1977	2026
Subcritical coal power plants	Sundance 5	406	1978	2027
	Sundance 6	401	1980	2028
	Battle River 5	385	1981	2028
	Keephills 1	395	1983	2028
	Keephills 2	395	1984	2028
	Sheerness 1	390	1986	2027
	Genesee 2	400	1989	2027
	Sheerness 2	390	1990	2027
	Genesee 1	400	1994	2029
Supercritical coal power plants	Genesee 3	466	2005	2029
	Keephills 3	463	2011	2029

2.5 LEAP model energy dispatch

One of the key considerations for energy dispatch in the LEAP transformation module for grid-connected electricity generation is the dispatch rule. The dispatch rule defines the manner in which each process dispatches its available generation capacity to meet demand. The “merit order dispatch” is the selected dispatch rule in Alberta and in the LEAP model. The merit order assumption assigned for each process is shown in Table 2-4.

Table 2-4. LEAP model merit order assumptions

Process	**Merit order**	**Comments [45]**
Subcritical and supercritical coal-fired plants	1	• Coal-fired generation is usually dispatched before any higher-priced generation technology because it delivers stable baseload energy and it is more economical to continue operating than incur the high costs of stopping and restarting.
Gas-fired cogeneration plants	1	• Most gas-fired cogeneration plants dispatch electricity regardless of price because electricity is a secondary need.
Wind, solar	1	• Assumed to be fully dispatched when available due to seasonality constraints.
Hydro, biomass, waste heat geothermal and nuclear	1	• Assumed to be dispatched as baseload generation when available. Solar, geothermal and nuclear generation technologies are not included in the Alberta energy market but are included in the LEAP model for scenario analysis.
Combined cycle	2	• Assigned a merit order of 2 because of historically low capacity factor.
Simple cycle	3	• Simple-cycle gas-fired generation is usually dispatched after all lower-priced generation has been dispatched.

After merit order assumptions have been assigned, the merit order sequence is used to determine the capacity available for each generation technology. Groups with the same merit order are dispatched together through a discrete approximation of the load curve and split it into vertical strips based on a defined yearly shape [112]. An Alberta-specific load duration curve [113] for the base year, 2010, was adopted for our model, as shown in Figure 2-7 [113]. The minimum demand (6,641 MW) was approximately 65% of the peak load. The minimum demand is in early July at 4,442 cumulative hours, and the maximum demand (10,196 MW) is in December at 8,394 cumulative hours. The average load as 8,187 MW, and the total energy demand was 71,722 GWh.

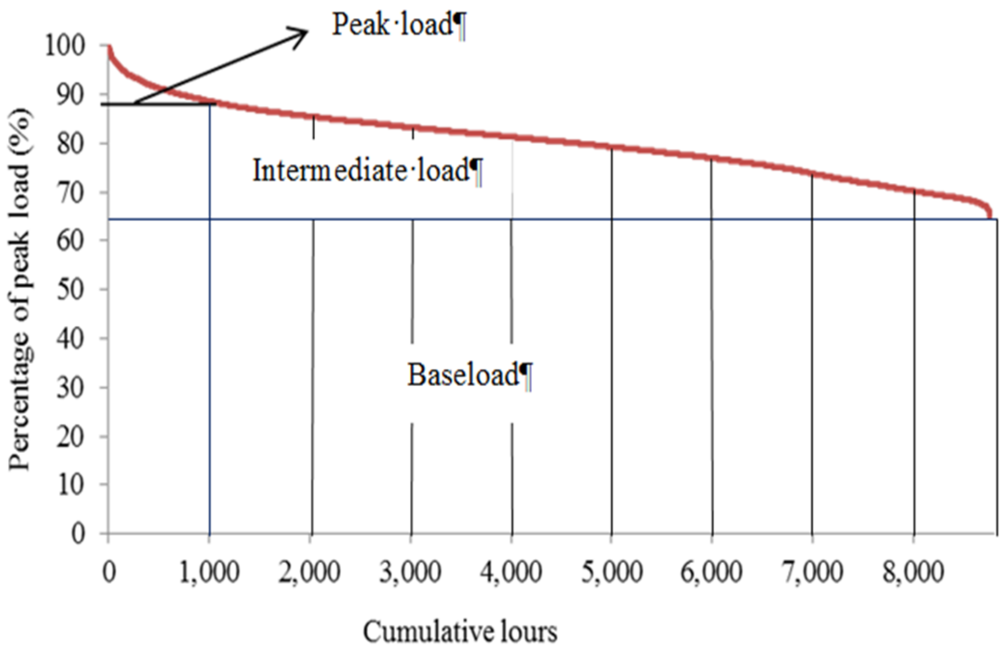


Figure 2-7. 2010 Alberta load duration curve (% of peak load) (data adapted from [113])

2.5.1 Fuel costs

Fuel cost is an important component required to calculate the module total cost balance and the production costs output results. With the planned phase-out of traditional baseload support from coal-fired power plants by 2030, gas-fired cogeneration and combined cycle generation processes are expected to primarily sustain baseload in a future generation mix. Therefore, expected increase in gas use will result in a corresponding increase in total production cost. The LEAP model developed incorporates the natural gas price forecasts from the National Energy Board [114], shown in Figure 2-8.

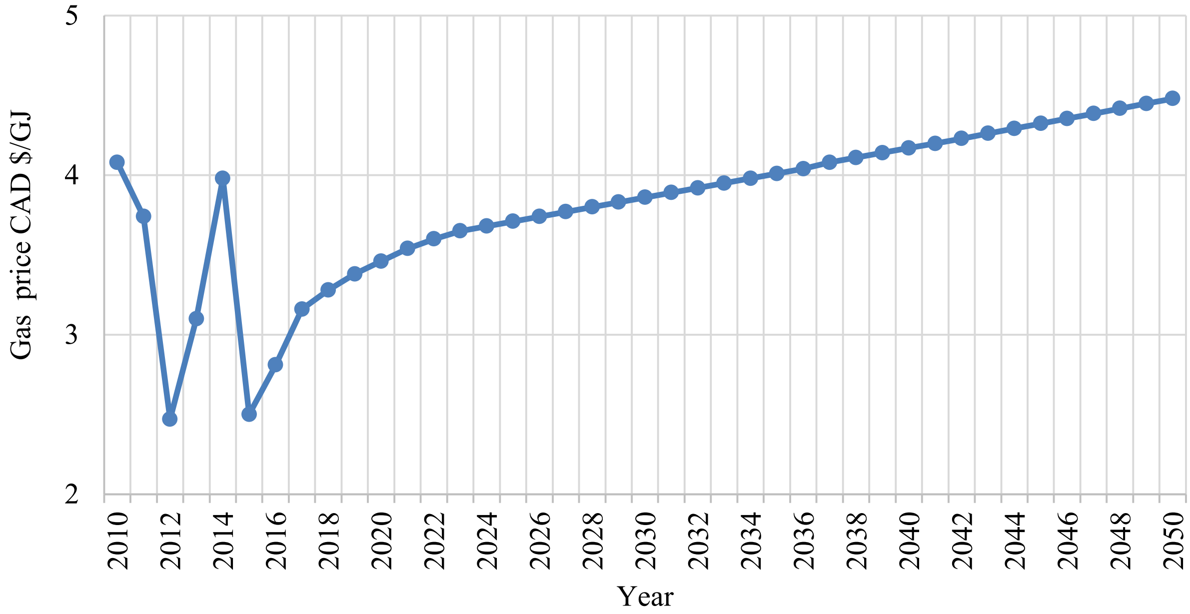


Figure 2-8. Gas price projections [114]

2.5.2 Environmental externality cost

Externality costs were specified for CO_2 emissions in our LEAP model as they apply to Alberta's electricity generation sector. The Stockholm Environment Institute defines externality cost as "social damage costs per unit of pollutant" [115]. This cost is incorporated into the model and ranges from CAD $20/unit CO_2 in 2017 to CAD $30/unit CO_2 in 2018 with an increase in subsequent years of 2% above the inflation rate [14]. According to the Alberta Specified Gas Emitters Regulation [116], facilities (including power plants) that generate more than 100,000 tons of CO_2 emissions a year are required to reduce their emissions intensities. The required annual emission intensity reduction was 12% until 2015 and was later increased, through an amendment [116], to 15% and 20% in 2016 and 2017, respectively. By incorporating annual changes in carbon prices and emission intensities, the externality costs in the LEAP model were determined, and they are included in the overall social cost-benefit calculations.

2.6 Results & discussion

2.6.1 Validation of model results

The LEAP model output results are compared to historical data on total demand, production (energy-generated) by technology, and total GHG emissions for Alberta. All verified data match well and within 10%. In all validation cases examined, there are some noticeable differences between the LEAP results and reported historical data. The justification for the differences is that LEAP data input and assumptions were based on average estimates of the characteristics of sub-groups of similar generation technologies rather than on individual generating plants connected to a transmission network. Reported historical data are an aggregate of actual technical data and operating metered volumes captured in real time and recorded for power plants that generate electricity into the AIES.

2.6.2 Validation of total generation

Figure 2-9 shows the validation of the total electricity generation results from the LEAP model. The total generation results in the LEAP model was verified against historical actual generation data from AESO and the Alberta Utilities Commission (AUC). The LEAP results were confirmed through published data for the years 2005 to 2015.

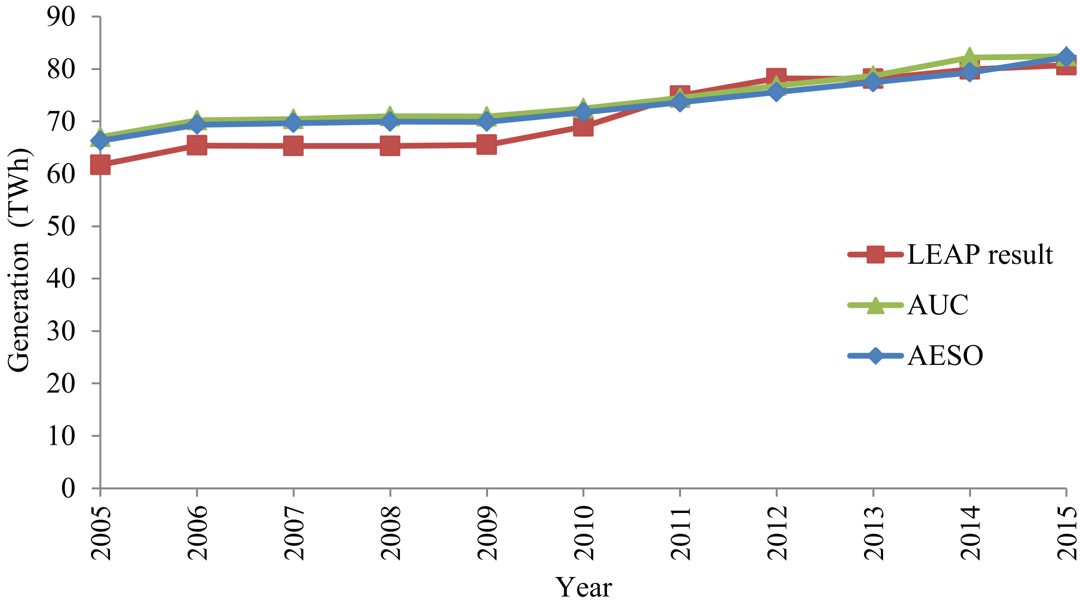


Figure 2-9. Total electricity generation output validation

2.6.3 Total electricity demand validation

As the primary detailed input for the developed LEAP model was based on the electricity generation sector, it was necessary to incorporate the corresponding total electricity demand for generation dispatch to occur. Therefore, the energy demand sector LEAP model discussed by Davis et al. [117] was imported into the present electricity generation LEAP model. Figure 2-10 shows the output of the validation obtained for the total energy demand. The output of total demand in the LEAP model was compared with AESO's actual energy demand data for 2005-2015 [75, 91, 92].

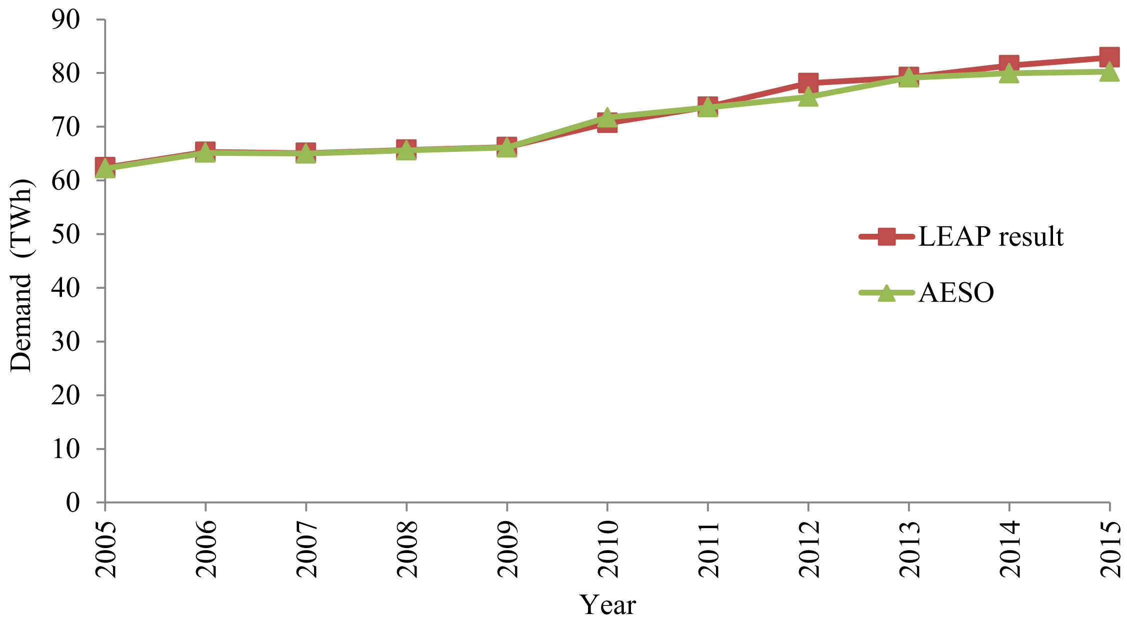


Figure 2-10. Total electricity demand validation

2.6.4 GHG emissions validation for the electricity generation sector

The total GHG emissions output of the LEAP model was compared with Environment and Climate Change Canada's National Inventory Report data [118] for Alberta's electricity generation sector for 2009-2014. The data validation is shown in Figure 2-11.

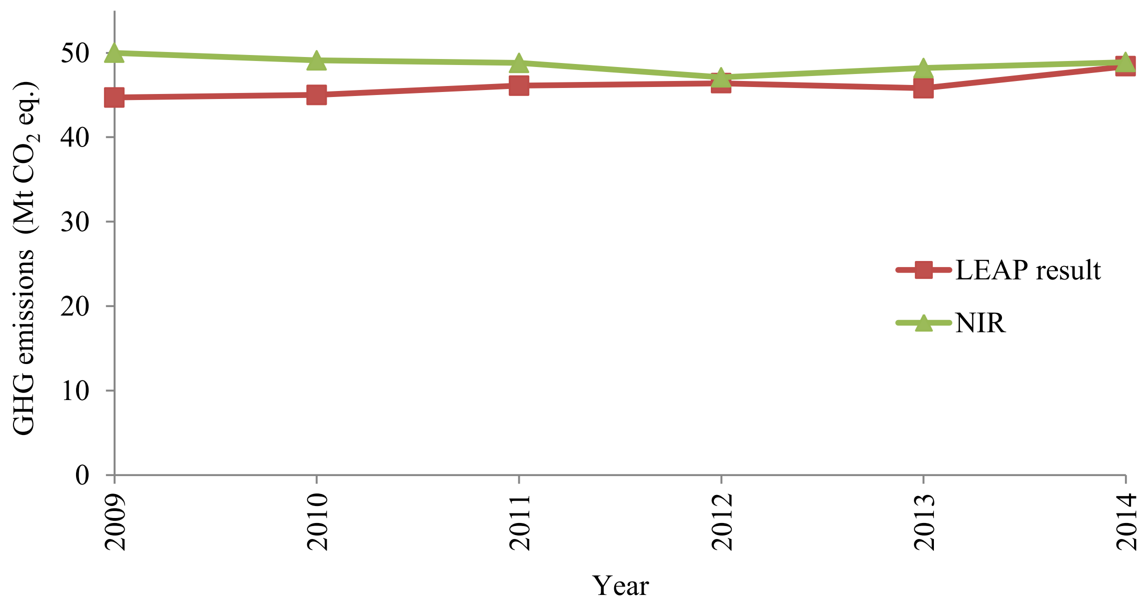


Figure 2-11. GHG emissions validation for the electricity generation sector

2.6.5. Coal-fired generation output validation

The LEAP model generation output validation for coal-fired generation (combined output of subcritical and supercritical coal technologies) is shown in Figure 2-12. The model result was compared with the AUC's historical actual data from 2005 to 2015.

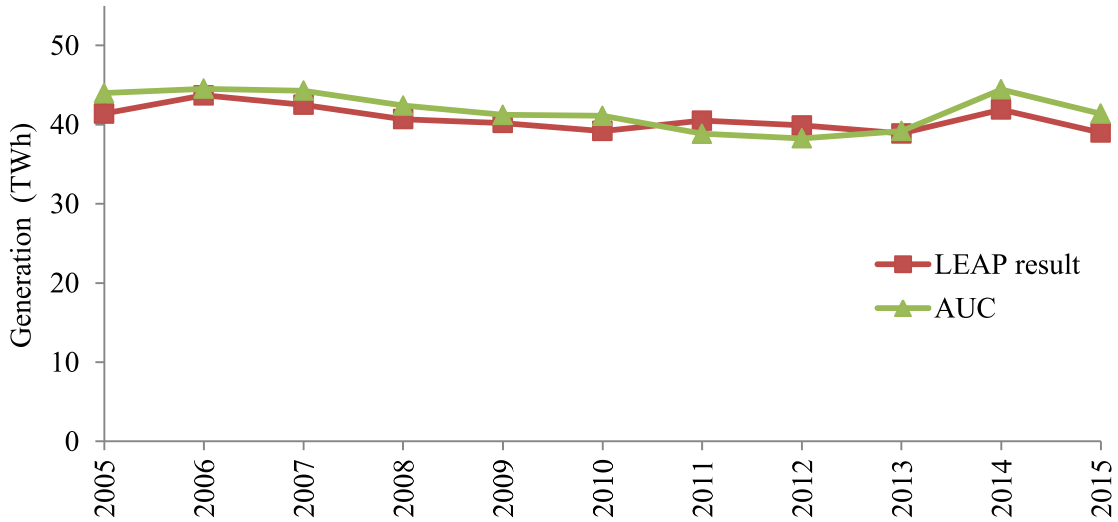


Figure 2-12. Coal-fired generation output validation

2.6.6 Gas-fired generation output validation

The AUC's historical aggregate energy dispatch data from gas-fired technologies (cogeneration, combined cycle, and simple cycle) were used to validate the LEAP output results and are shown in Figure 2-13. Validation by gas-fired generation technology type is shown in Figure 2-14 to 2-16.

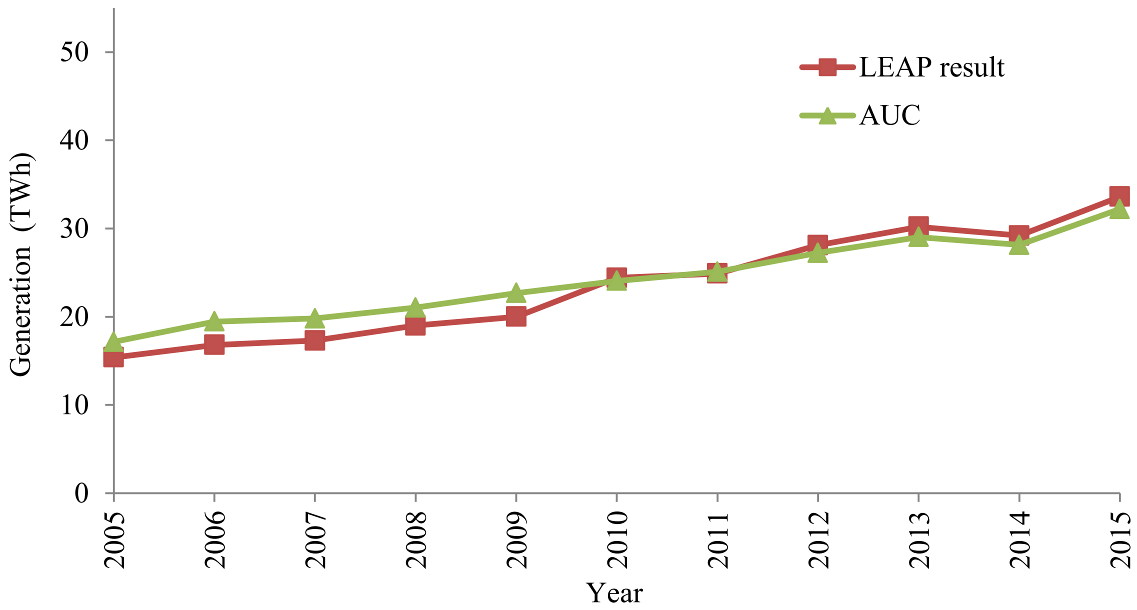


Figure 2-13. Gas-fired generation output validation

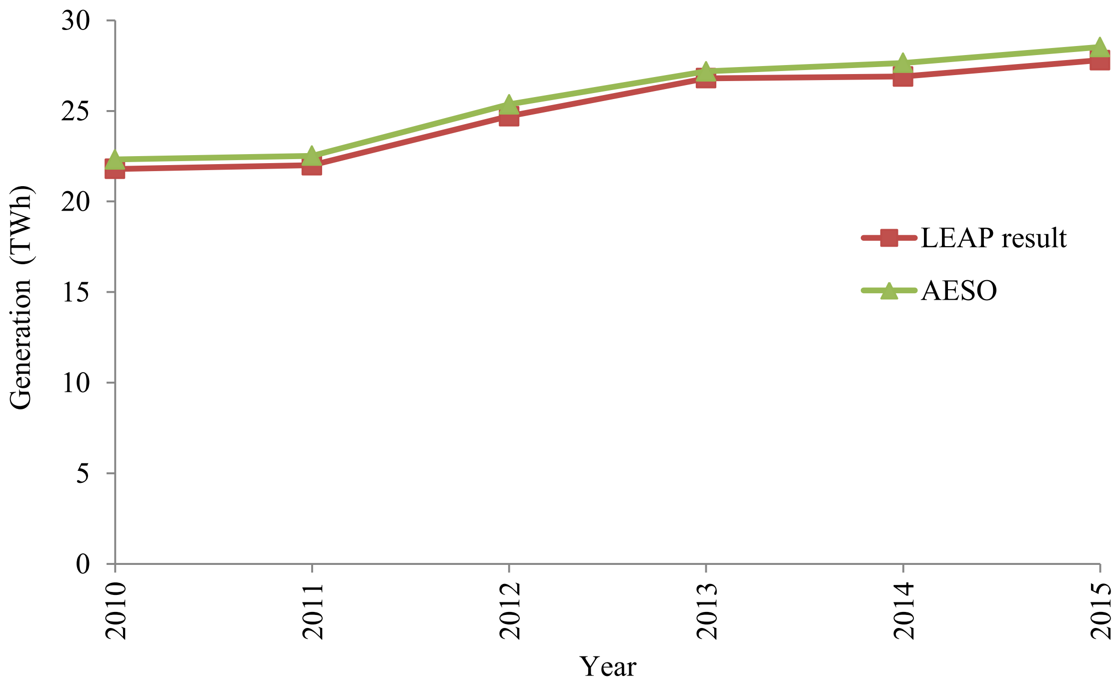


Figure 2-14. Gas-fired cogeneration generation output validation

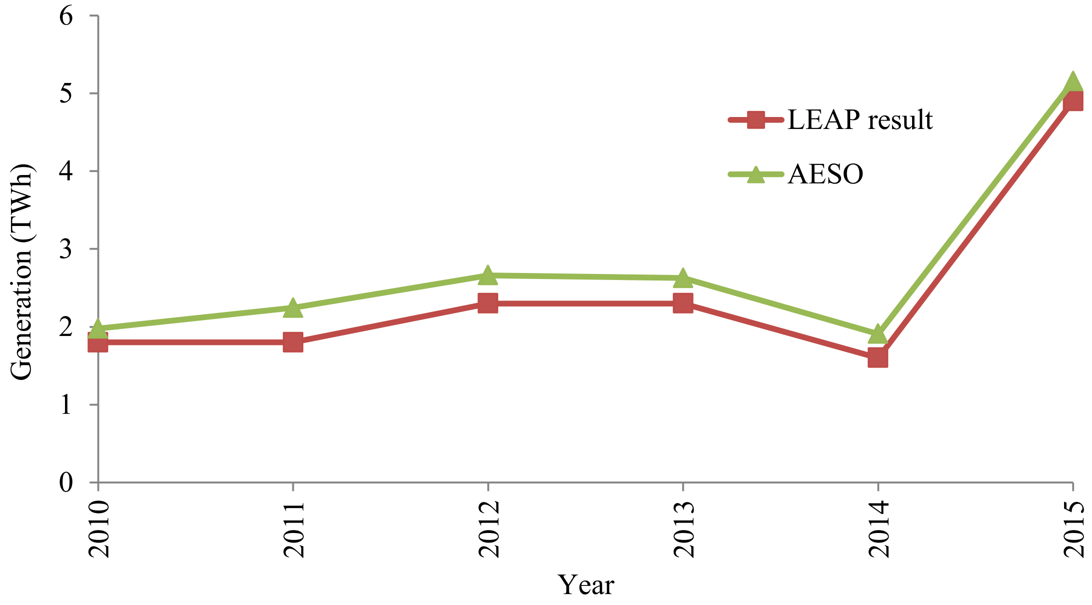


Figure 2-15. Gas-fired combined cycle generation output validation

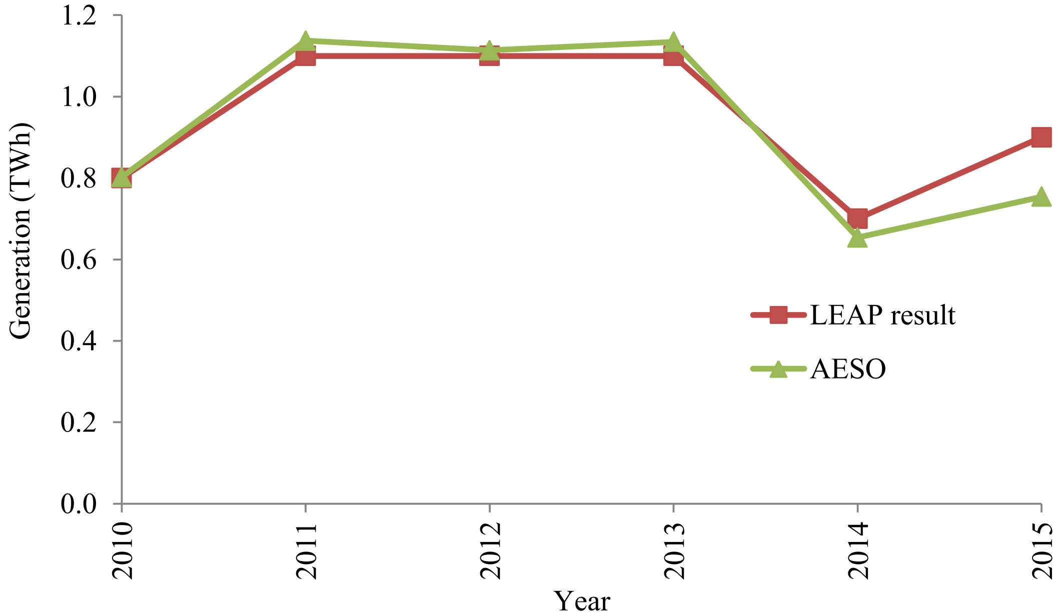


Figure 2-16. Gas-fired simple cycle generation output validation

2.6.7 Hydroelectricity generation output validation

The validated LEAP output for hydroelectricity generation is shown in Figure 2-17. The LEAP output result was validated with the AUC's historical hydroelectricity data for the years 2005 to 2015.

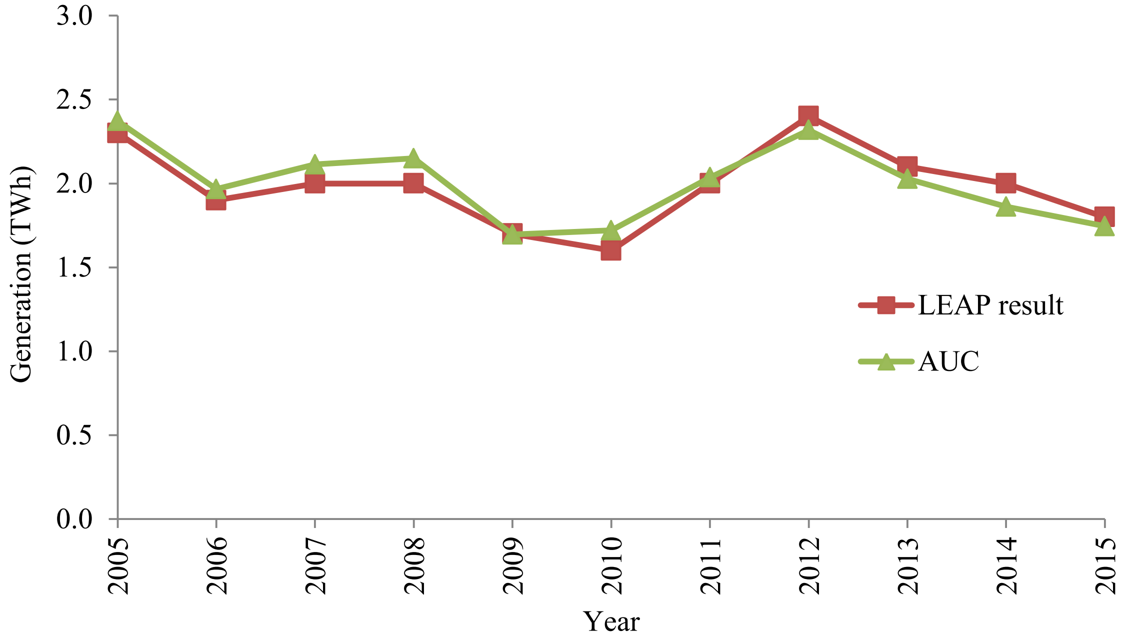


Figure 2-17. Hydroelectricity generation output validation

2.6.8 Wind generation output validation

The validated LEAP output for wind electricity generation was validated through the AUC's historical generation data from 2005 to 2010 and is shown in Figure 2-18.

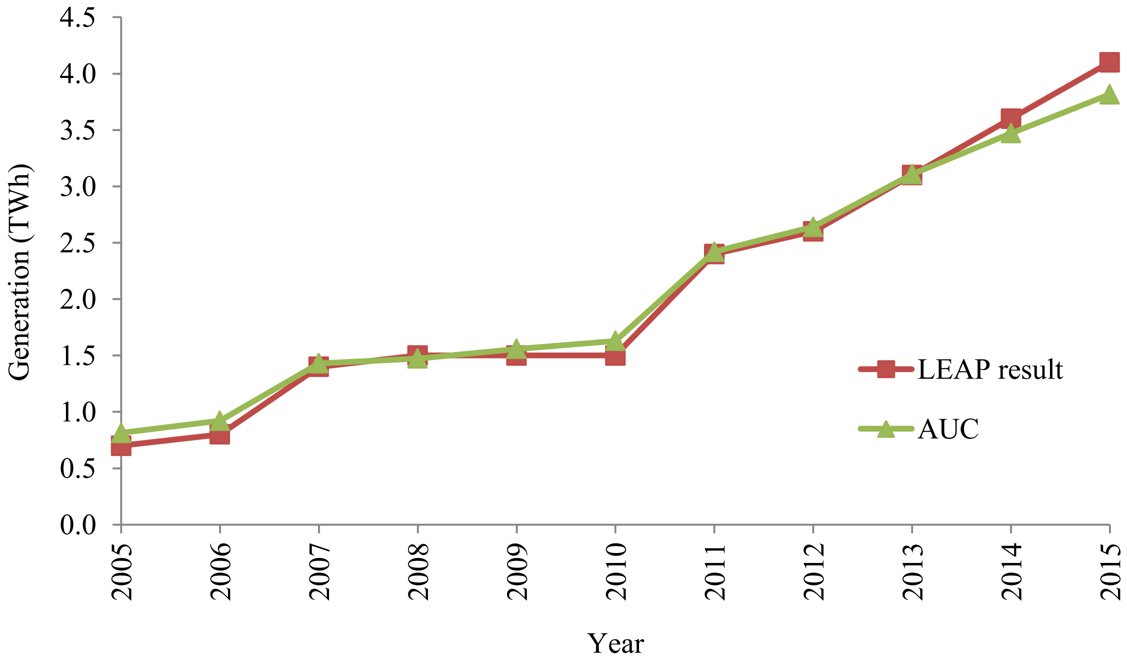


Figure 2-18. Wind generation output validation

2.6.9 Other (biomass and waste heat) generation output validation

The validated results for both biomass and waste heat generation were combined as shown in Figure 2-19. The wide differences between the LEAP results and AESO's actual data are because the capacity factors in the LEAP model for both biomass and waste heat are assumed to be the same and therefore determined based on average values for "other" as reported by AESO for 2011 to 2105 [45]. These two generation technologies were classified as "other" by AESO, and there was no further publicly accessible information on the specific breakdown of their historical generation capacities and energy generated. However, to clearly differentiate generation technologies in our model and for ease of developing scenarios, the separate capacities for biomass and waste heat were determined based on a further search on the type of generation technology for each power plant classified as "other" on AESO's generation asset list [61]. However, compared with the validated results described in sections 2.6.1 to 2.6.8 of this chapter, there is no significant impact on the model results as the "other" generation output is a minor share (0.09-1.3%) of the total annual generation between 2010 and 2015.

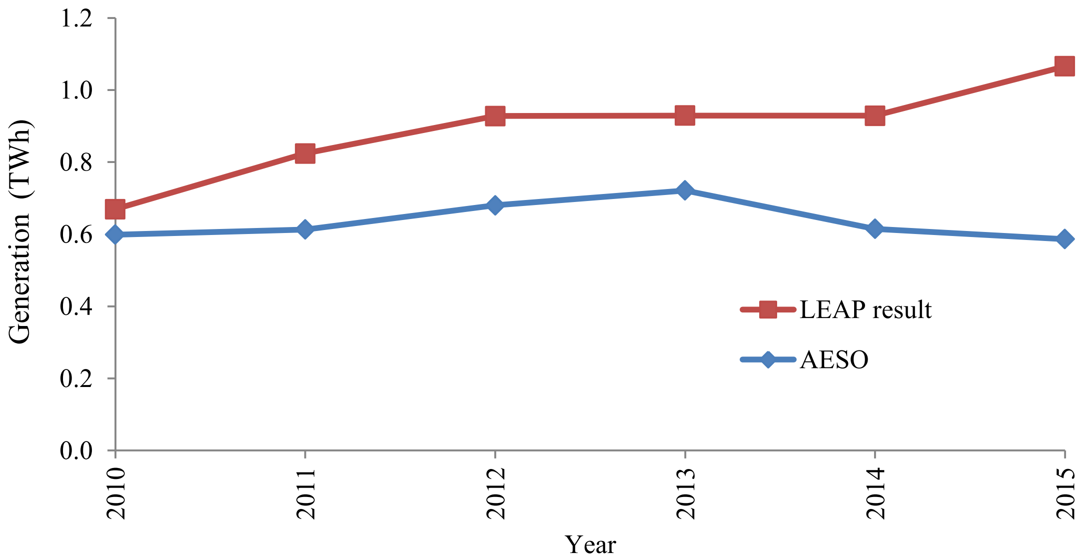


Figure 2-19. Other generation output validation

2.7 Business-as-usual scenario results

The business-as-usual (BAU) scenario or the reference scenario is simulated in the developed LEAP model using AESO's most recent outlook report [60] that forecasts long-term electricity demand growth and generation development in Alberta. The demand forecast moderate load growth based on several factors including future oil sands development. As such, the generation plan was assessed based on present and forecast industrial development and environmental policy.

The environmental policy for the generation pathway follows the recommendations of the Alberta Climate Leadership Panel [14]. The panel recommended phasing out coal-fired generation and replacing at least two-thirds of retired coal generation with renewables by the year 2030. Consequently, nearly 6.3 GW of the retired coal generation capacity would be replaced by new renewable generation capacity by 2030. The forecast generation capacity in the BAU scenario is consistent with AESO's most recent long-term outlook report [60] with data up to 2037. However, to provide data for our entire study period, the forecast data from 2038 to 2050 were extrapolated based on estimated growth rates determined from AESO's data projections.

The results calculated from our model on installed capacity (GW) and generation output (GWh) for each generation technology and intertie for the BAU scenario under the study period are shown in Figure 2-20 and Figure 2-21. By 2030 and 2050, the forecasts of total installed generation capacity are approximately 25 GW and 32 GW, respectively. The total installed generation capacity for renewables increased from 2.8 GW in 2015 to 8.5 GW by 2050 with a wind generation capacity share of approximately 84%. This is due to increased wind generation capacity from approximately 1.5 GW in 2015 to 7.1 GW by 2050.

Following the retirement of coal-fired generation capacity, the total installed fossil-fuel generation capacity share in the generation mix is projected to fall from 77% to 70% by 2050. The installed capacity of gas-fired generation will increase from 1.7 GW to 9.5 GW by 2050 as it will replace baseload generation. The corresponding forecast of total generation by 2030 and 2050 is approximately 107 TWh and 120 TWh, respectively. The renewable generation share of the total generation will increase by up to three times the existing generation of 8.4 TWh to 24 TWh by 2030 and up to four times the existing generation to 32.4 TWh by 2050.

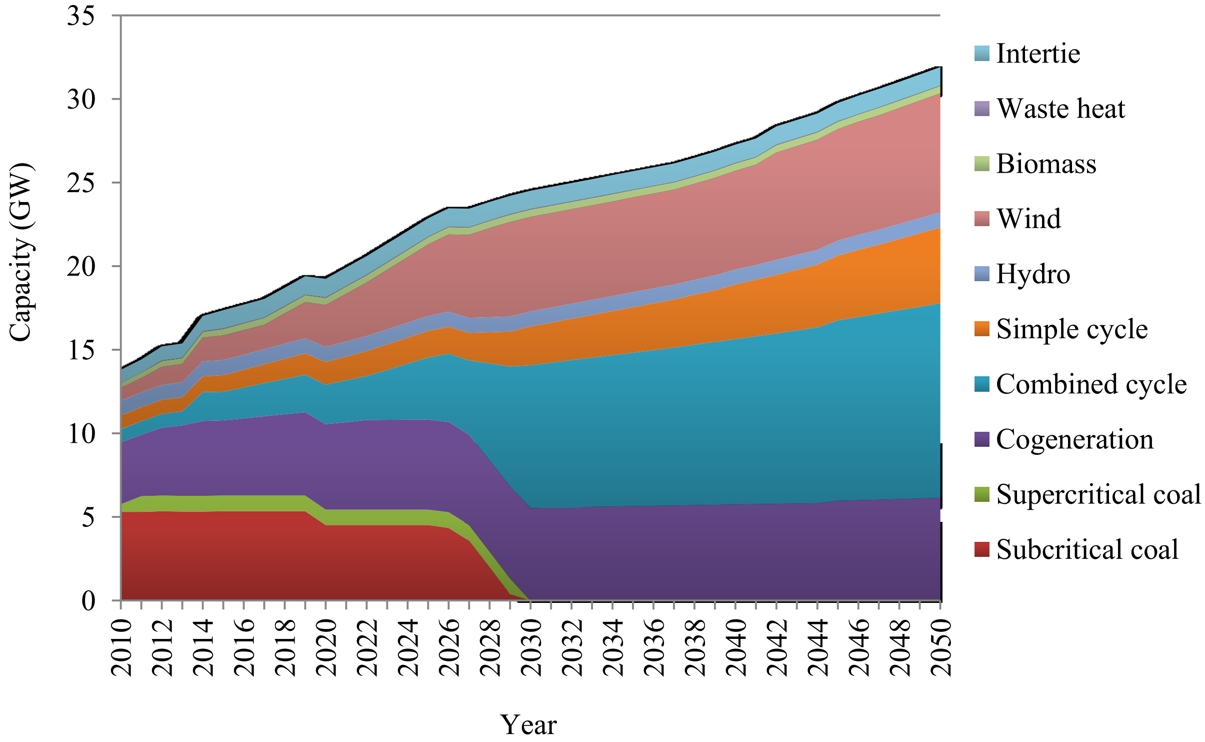


Figure 2-20. BAU installed generation and intertie capacity forecast

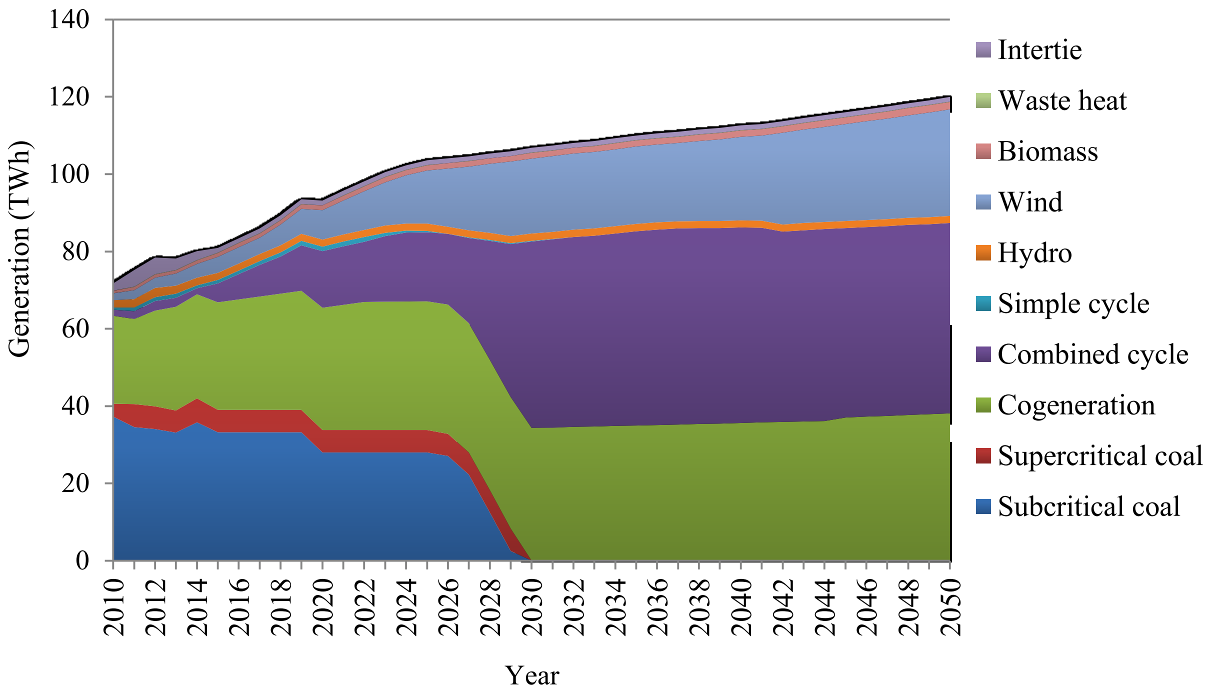


Figure 2-21. BAU total generation forecast

2.7.1 BAU GHG emissions

The LEAP output results of the BAU GHG emissions are shown in Figure 2-22. The estimated electricity generation sector GHG emissions by 2030 and 2050 are 27.4 Mt CO_2 eq. and 28.6 Mt CO_2 eq., respectively. The model results indicate an estimated GHG mitigation potential by 2030 for the BAU scenario of approximately 21.5 Mt CO_2 eq. below the 2014 GHG emissions of 48.9 Mt CO_2 eq. [119]. By 2030, GHG emissions are expected to decline by 44% from actual 2014 emissions [119]. Similarly by 2050, GHG emissions are expected to decline by 42% from actual 2014 emissions. Our LEAP results of 27.4 Mt CO_2 eq. GHG emissions in 2030 are relatively close to the forecast GHG emissions of 28.8 Mt CO_2 eq. [14] by 2030. The average annual GHG emissions from coal-fired subcritical and supercritical generation technologies fell from 38 Mt CO_2 eq. before the 2015-2019 phase-out period to 28 Mt CO_2 eq. during the 2020-2029 phase-out periods.

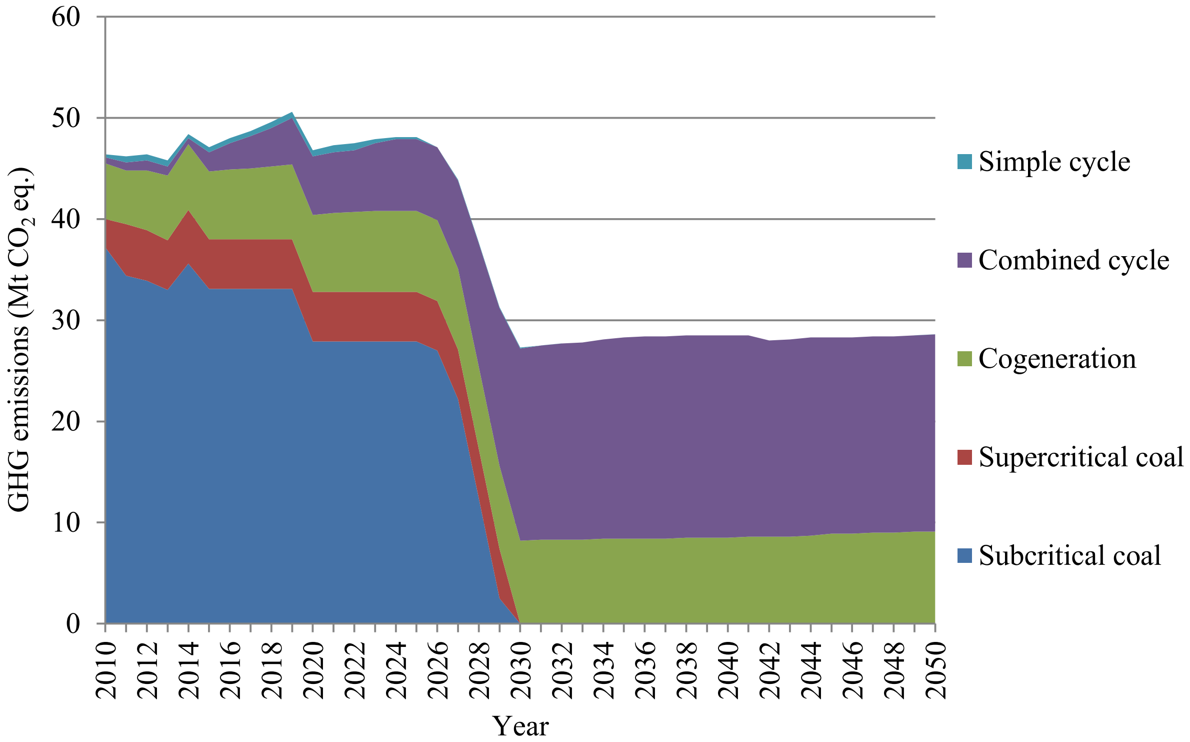


Figure 2-22. BAU GHG emissions forecast

2.8 Other AESO scenarios

The LEAP model further analyzed AESO's low growth, high growth, and alternate-BAU (Alt-BAU) scenarios for realistic planning [60]. In these scenarios, the impact of various assumptions about future demand growth and policy implementation on generation planning different from those considered in the BAU case was investigated. The summary of key assumptions for each scenario is shown in Table 2-5 [60].

Table 2-5. Summary of other AESO scenarios and assumptions

AESO scenarios	Demand and generation capacity growth assumptions	Economic and environmental policy assumptions
Low growth	• Limited demand growth with a projected peak demand of 13.8GW. • Lower generation development as a result of limited demand.	• Limited economic growth attributed to the operation of existing and new oil sands projects scheduled for completion and no new oil sands projects advanced. • Environmental policy is similar to the BAU, the assumed replacement of nearly 6.3 GW retired coal-fired generation capacity with 4.2 GW new renewables capacity (wind only) by 2030.
Alternate-BAU (Alt-BAU)	• Same demand growth projections as the BAU scenario with a projected peak demand of 15.2 GW by 2030.	• Retirement of coal-fired generation capacities earlier than 2030. • 9.3 GW renewables capacity (wind, solar, and large-scale hydroelectricity generation).
High growth	• Relatively high demand growth with a projected peak demand of 17 GW by 2030. • Increased cogeneration capacity as a result of increased oil sands development and demand.	• Strong economic recovery is attributed to the rebound of crude oil prices, leading to the development of deferred oil sands projects. • The environmental policy is similar to the BAU, the assumed replacement of nearly 6.3 GW retired coal-fired generation capacity with 4.2 GW new renewables capacity (wind only) by 2030.

2.8.1 Analysis of the BAU and other AESO scenario results

The BAU and other AESO scenarios were assessed based on different demand and generation capacity assumptions as explained above. Figure 2-23 illustrates the total electricity generation and corresponding GHG emissions projections of the BAU and other AESO scenarios. The total electricity generation (TWh) and GHG emissions output results are based on different demand growths for each scenario. The generation capacity mix of the BAU and other AESO scenarios are shown in Table 2-5. The Alt-BAU case is an alternate interpretation of the climate change policy for a renewable generation share (instead of a generation capacity share) of retired coal generation. Consequently, to compensate for the lower energy output of intermittent renewables, the Alt-BAU scenario has a higher total renewable capacity share (36% and 42% by 2030 and 2050, respectively) than the other scenarios. The Alt-BAU scenario proposes an ambitious plan for the new renewable capacity of 7,200 MW within a timeframe of less than 15 years, by 2030. By 2030, the Alt-BAU scenario projects a total new generation capacity of 15,427 MW (50% renewable capacity penetration) compared to 13,390 MW for the BAU scenario. Consequently, a GHG emissions reduction of 54% and 63% below 2014 levels may be achieved for the Alt-BAU scenario by 2030 and 2050, respectively, because of the higher renewable generation capacity.

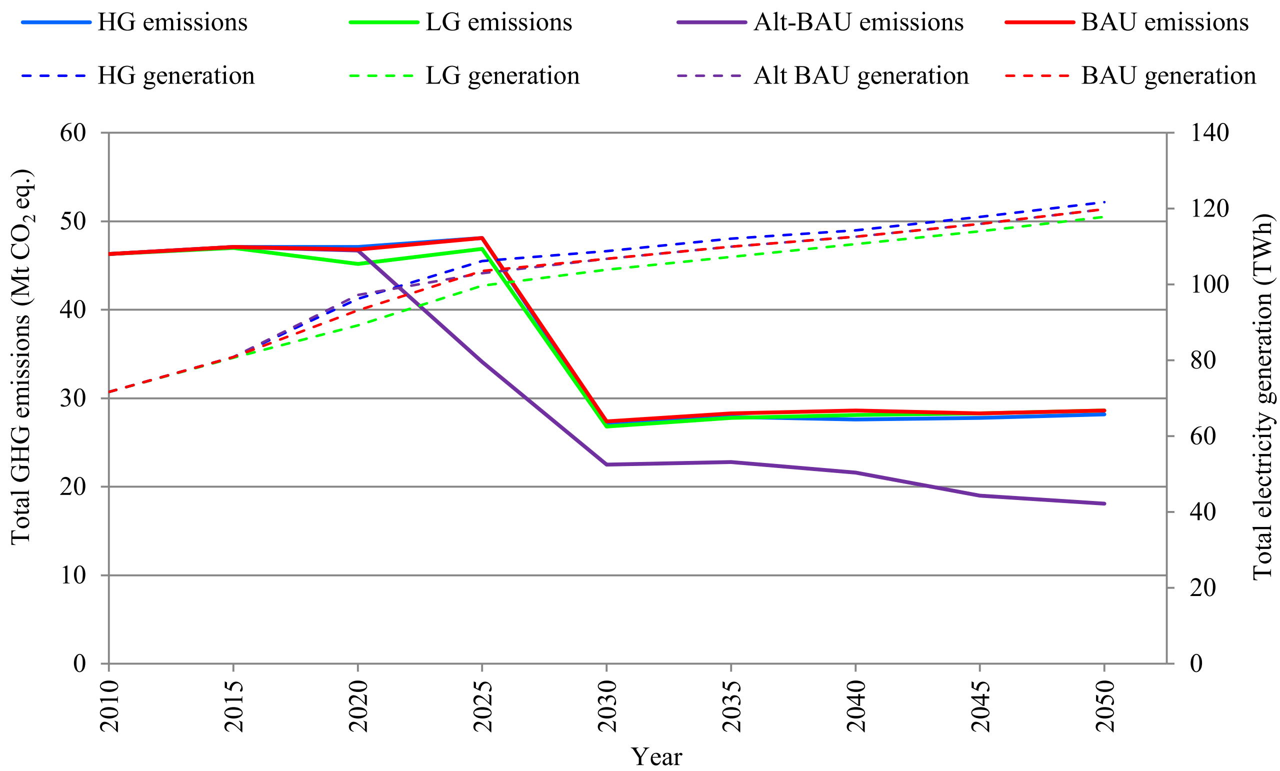


Figure 2-23. BAU and other AESO scenarios' GHG emissions and generation forecast

The reverse of the Alt-BAU scenario with respect to total renewable capacity is the high growth scenario, with lower total renewable capacity shares of 26% and 23% by 2030 and 2050. The high growth scenario is projected to show significant increases mainly from gas-fired generation capacity due to the assumed strong economic recovery and development of major oil sands projects and their operation. The total installed generation capacities of the high growth scenario are 26.7 GW and 36.8 GW in 2030 and 2050, respectively. The corresponding GHG emissions are 27 Mt CO_2 eq. and 28.2 Mt CO_2 eq. by 2030 and 2050, respectively. Because of lower GHG emission-intensive and higher efficiency cogeneration generation output that exceeds the combined cycle generation in the generation mix, the yearly average GHG emissions output of the high growth scenario between 2030 and 2050 is 0.5 Mt CO_2 eq./year below the BAU scenario, despite significantly higher generation projections of 7,100-6,100 GWh over the period.

Table 2-6. BAU and supplementary scenarios generation capacity (MW)

	2015	2030				2050			
Branches	BAU	BAU	Alt-BAU	Low growth	High growth	BAU	Alt - BAU	Low growth	High growth
Subcritical coal	5,360	-	-	-	-	-	-	-	-
Supercritical coal	929	-	-	-	-	-	-	-	-
Cogeneration	4,502	5,552	5,552	5,148	6,812	6,152	6,092	5,265	6,785
Combined cycle	1,716	8,541	7,180	7,632	9,420	11,628	8,859	10,638	16,471
Simple cycle	996	2,311	3,679	2,352	2,357	4,546	4,185	3,936	3,375
Hydro	894	894	1,224	894	894	894	3,314	894	894
Wind	1,463	5,663	8,663	5,662	5,662	7,129	12,116	7,144	7,144
Biomass	400	441	441	441	441	441	441	441	441
Waste Heat	28	28	28	28	28	28	28	28	28
Solar	-	-	1,000	-	-	-	1,650	-	-
Intertie (Import)	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103	1,103
Total (MW)	17,391	24,533	28,870	23,260	26,717	31,921	37,788	29,449	36,241

Because of the limited economic growth and reduced demand growth projections, the low growth scenario has the lowest generation capacities (23,260 MW and 29,249 MW by 2030 and 2050, respectively) of all the scenarios. The equivalent GHG emissions are 26.8 Mt CO_2 eq. and 28.6 Mt CO_2 eq. with total generation outputs of approximately 103,597 GWh and 116,115 GWh by 2030 and 2050, respectively.

2.9 Chapter summary

The developed LEAP model assessed GHG mitigation in the electricity sector. The study analyzed specific generation planning scenarios driven by expected climate change policy decisions using Alberta as a case study. The GHG emissions and generation for each scenario indicate that the phase-out of coal-fired electricity generation by 2030 would significantly reduce GHG emissions as electricity demand increases in the medium and long term. Although the model assessed Alberta's electricity generation sector, it is comprehensive and flexible in generation planning and incorporating economic and environmental policy elements in different jurisdictions. The BAU and high and low growth scenarios confirmed that replacing two-thirds of retired coal-fired capacity with renewable generation capacity could reduce GHG emissions in the electricity generation sector to approximately 21 Mt CO_2 eq. below 2014 levels by 2050. Between 2030 and 2050, the BAU results shows an 8.7% (or an annual average growth of approximately 0.4%) increase in cumulative GHG emissions. However, due to increased shares of renewable electricity generation (from 22% to 27%) between 2030 and 2050, emission intensity will fall from 0.25 t CO_2 eq./MWh to 0.24 t CO_2eq./MWh. By 2030, the total renewable electricity generation of the BAU increased from approximately 7 TWh to 23 TWh with a wind electricity generation share of about 85%. The Alt-BAU scenario with higher renewable capacity penetration results in about 48% (11.4 TWh) increase in total renewable electricity generation compared to the BAU. The high growth scenario which is expected to see a rapid electricity demand growth that is higher than the BAU results in 0.4 Mt CO_2 eq. lower than BAU by 2030. The lower GHG emissions output of the high growth scenario compared to the BAU is consistent for the forecast period between 2030 and 2050. The advantage of lower emission intensity of gas-fired cogeneration electricity generation can be beneficial to sustaining reduced GHG emissions with increasing demand in the long term. Therefore, it is recommended that gas-fired cogeneration capacity should be given priority, whenever possible, to drive capacity additions and to provide baseload instead of gas-fired combined cycle capacity. It is envisaged that further interesting conclusions could be drawn from the model if grid-connected battery storage technology is considered to support intermittent renewable electricity generation. Hence, it would be important for further work to analyze the impact of large-scale battery storage on the grid once the functionality is available.

Chapter 3 : An Assessment of Generation Mix Scenarios for Greenhouse Gas Mitigation in an Electricity Generation Sector

3.1 Introduction

The electricity generation sector is a major economic sector that contributes to global greenhouse gas (GHG) emissions through intensive fossil fuel use. In 2015, GHG emissions due to global fuel use and industry were 36.3 Gt CO_2 eq. [120]. Despite the increasing trend in renewable electricity generation capacity, especially from solar PV and wind [121], the fossil fuel electricity generation share remains high; 66.7% of global electricity production is from fossil fuels [122]. As there is no substitute for electricity and its generation is mainly from fossil, renewable, and nuclear fuel sources, it seems practical to focus on either the fuel or the technology choices for electricity generation to reduce GHG emissions significantly. Sims et al. [6] predicted over a decade ago that the electricity generation sector is a key target for GHG mitigation and emission control because it is easier to mitigate and control emissions in a relatively limited number of large power plants than in, for example, millions of vehicles with small and dispersed emissions. Also, studies have shown that the highest emissions reduction from electricity generation is through technological measures of cleaner or renewable electricity generation and efficiency improvement. For example, a CO_2 reduction of 2.5% is a standard estimate for an efficiency increase from 40 to 41% in a gas-fired electricity generation plant [123]. The GHG emission mitigation options in the electricity generation sector are wide-ranging and can be deployed either as independent or integrated solutions. Options include fuel switching, increasing fuel conversion efficiencies of thermal power plants, carbon capture, sequestration, and storage, a shift to low- or zero-emission technologies, and energy response planning.

It is not unusual, then, that many national, regional, state or provincial jurisdictions emphasize their GHG emission reduction and mitigation policy targets in the electricity generation sector. The share of electricity generation from renewable sources and targets by different countries and regions are listed in an earlier study [121]. California legislated its goal of reducing GHG emissions by 50% by 2030 through renewable electricity generation, and Williams et al. suggested that up to 74% renewable energy penetration may be possible, subject to a combination of seamless technological and operational innovations, and achieve a 27% GHG emission reduction [124]. In Europe, Denmark led with 53% renewable electricity generation in 2014 [125] and has set a target of 100% renewable electricity generation by 2050 [126]. Sweden has already surpassed its target of 50% renewable electricity generation by 2020 [127]. Germany, with 33% renewable electricity generation, also plans for 100% renewable electricity supply by 2050 [128]. The overall impacts of setting and sometimes surpassing different targets have, since 1990, resulted in a 3.6% annual average growth in global renewable electricity generation, higher than the 2.9% growth rate of electricity generation [129]. According to the U.S. Energy Information Administration (US EIA) [15], renewable electricity generation could exceed coal-fired electricity generation by 2040. Figure 3-1 shows the projected trends in global renewable electricity generation as well as other fuel sources.

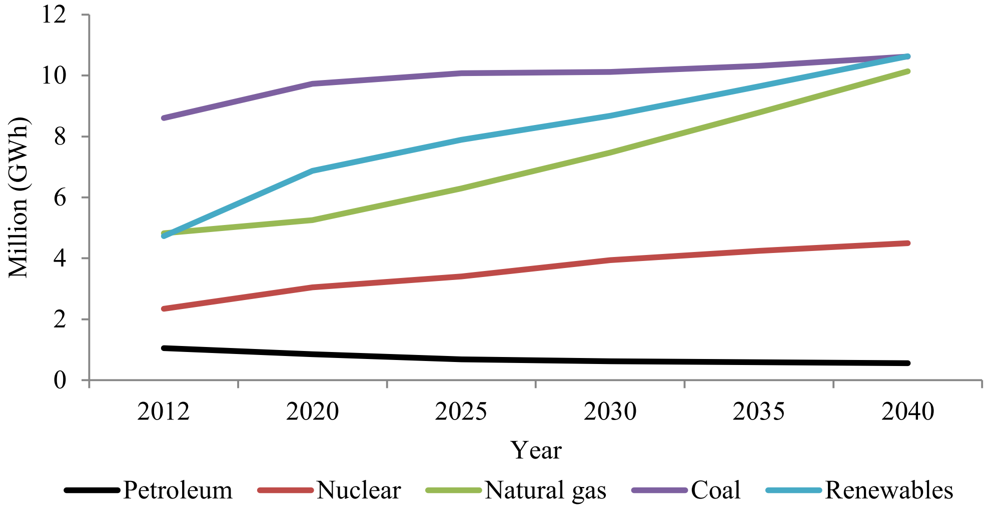


Figure 3-1. Global electricity generation forecast by fuel (data adapted from [15]**)**

The province of Alberta has been a leading climate change supporter among the major global energy sector economies through its implementation of the recommendations of its Climate Leadership Plan (CLP). The CLP recommended specific actions for reducing GHG emissions and subsequently the provincial government passed the Climate Leadership Act (2016) [130]. Some of the CLP recommendations include the expedited retirement of approximately 6.3 GW of coal-fired generation capacity, 30% renewable electricity generation, an economy-wide carbon levy, and output-based allocation of GHG emissions for large emitters. The CLP projects that the electricity generation sector emissions will represent about 9% (28.8 Mt CO_2 eq.) of Alberta's GHG emissions by 2030 [14]. However it not clear what pathways would lead to major reduction and the associated cost of doing this. Investigating pathways to reduction targets is appropriate for sound policy decisions. This is aimed at investigating renewable electricity generation pathways (here called scenarios) and analyzed their GHG emissions reduction potential and mitigation costs using the Long-range Alternatives Energy Planning (LEAP-Alberta) system.

The detailed functions and description of LEAP can be found elsewhere [89]. Several studies have used LEAP and other simulation software to analyze future trends of energy demand [131-133] and supply [36, 53, 134, 135] of different cities, regions, and countries across the world. As a scenario-based modeling and management tool, LEAP assesses GHG mitigation potential under various scenarios. McPherson and Karney [53] developed and analyzed the effects of four pathways of future renewable electricity penetration in Panama's electricity sector. Subramanyam et al. [131] estimated the GHG emissions mitigation potential of 46 pathways for Alberta's commercial and institutional sector up to the years 2030 and 2050. To estimate the impact of reductions in GHG emissions on water demand, Dar [136] integrated LEAP and WEAP (Water Evaluation And Planning system) to investigate a power generation scenario in which subcritical coal-fired power plants are replaced with natural gas-fired power plants. Other energy modeling software has been used to analyze future GHG emissions reductions for Alberta. Hasan used the Canadian Energy System Simulation (CanESS) model to investigate three scenarios of coal, natural gas, and high hydro import-dependent generation penetration for reducing GHG emissions in the electricity grid [36]. All three scenarios assumed coal-fired power plants would be replaced at their normal end of life, though the policy direction for Alberta's electricity generation sector will see these plants retired sooner.

A study by Subramanyam and Kumar [35] identified scenarios for GHG mitigation in Alberta's demand and supply sectors. On the supply side, the scenarios include coal-fired electricity generation capacity in the generation mix. Neither the independent nor the integrated mitigation scenarios include solar or geothermal renewable energy, and the model framework is solely based on grid-connected electricity generation. A recently completed study integrated LEAP with WEAP by investigating the water savings potential for different GHG mitigation scenarios using renewables in an electricity generation mix [137]. The scenarios assumed equivalent generation from combined cycle generation was replaced with hydroelectricity, biomass, and nuclear capacities in order to assess water savings potential. None of these studies considered the impact of gas and carbon price.

While several studies have shown the mitigation potential of GHG emissions in Alberta's electricity generation sector, this work assumes the feasible potential of available renewable resources replacing fossil fuel generation capacity in the generation mix and thus is contributes in addressing gap in knowledge in the following ways: it is consistent with and assumes the most recent policy implementations such as the phase-out of coal-fired electricity generation by 2030, renewable electricity generation capacity targets, and carbon pricing revenue to account for externality cost. Furthermore, this study incorporates the impact of gas pricing forecasts in the total transformation cost, including capital, fixed, and variable operating and maintenance costs, to determine overall GHG abatement costs of each scenario's generation mix in the medium (2030) and long term (2050).

The specific objectives of this study are to:

- Develop the baseline (BAU) scenario and assess the GHG emissions reduction achievable in the generation mix using the LEAP-Alberta model
- Identify integrated generation mix scenarios and evaluate their potential to increase low- or zero-emission electricity generation capacity to replace fossil-fuel based electricity generation capacity
- Assess the GHG mitigation achievable for the identified generation mix scenarios using the LEAP-Alberta model

- Develop a GHG mitigation cost curve to evaluate the associated cost and cumulative GHG mitigation of the identified scenarios

3.2 Model structure and scenario formulation

The developed LEAP model covers the years 2010 to 2050 with 2010 as the base year. Alberta (a western Canadian province) was selected for this study. The model incorporates the total electricity demand in all the energy demand sectors and the electricity transformation sector processes including transmission losses. The LEAP transformation module was split into micro-generation and grid-connected generation segments based on the existing regulatory framework of electricity generation fed into the distribution and transmission systems. The micro-generation module consists of both small- and large-scale solar PV technology generating self-use electricity and distribution system supply by residential and commercial buildings with nameplate generation capacities less than 5 MW [138]. The grid-connected generation module consists of large-scale fossil fuel and renewable generation technologies above 5 MW delivering electricity generated directly from the Alberta Interconnected Electric System (AIES) through the high-voltage transmission system. The Alberta electricity sector LEAP model flow diagram is shown in Figure 3-2.

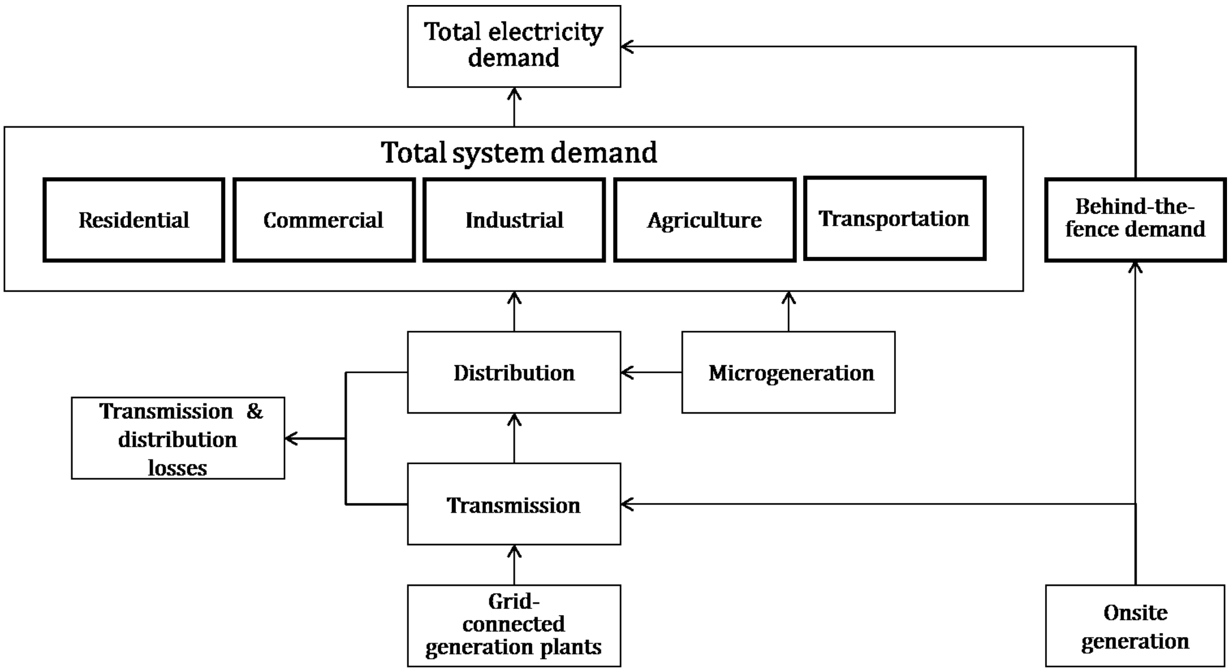


Figure 3-2. Alberta electricity sector LEAP model flow diagram

Whereas predicting future energy demand and generation mixes is useful for climate and energy policy decision makers, the objective of scenario formulation is to assess several options and possibilities [139]. The data input for the model scenarios built upon Alberta Electric System Operator's (AESO) reference (BAU) scenario and AESO's plan to reduce electricity generation GHG emissions by achieving 5 GW of new renewable generation capacity by 2030. This clarifies the CLP recommendation of "an increase in overall share of renewables to 30%" [14]. Therefore, the principle for scenario formulation is the equivalent replacement of capacity share of fossil fuel-based electricity generation with renewable generation capacities. 18 different generation mix scenarios were developed to achieve a target of 5 GW new renewable capacity by 2030 and the data to 2050 were extrapolated based on the penetration rates of the technologies planned for AESO's BAU scenario. The generation mix scenarios and their key assumptions are summarized in Appendix A of this thesis.

Beyond 2030, it is assumed that increasing shares of alternative generation capacity replace an equivalent capacity of gas-fired generation capacity of either cogeneration or combined cycle capacity projections anticipated in the BAU scenario. The base year cost input data to LEAP-Alberta model is shown in Table 3-1. A previous study [140] discussed the validation of the model BAU results for total electricity demand and generation.

Table 3-1. Base year cost input data to LEAP-Alberta model

Processes	Capital cost[a] ($/kW)	Fixed O&M[a] ($/kW)	Variable O&M[a] ($/MWh)	Ref.
Subcritical coal	1,244	35.1	13	[97]
Supercritical coal	1,723	35.1	12	[97]
Cogeneration	1,119	6.94	2.5[b]	[97]
Combined cycle	1,190	6.5	1.9[b]	[97]
Simple cycle	939	14.1	13.8[b]	[105]
CTG retrofit	150	23.5[c]	9.8[b]	[141]
Hydro	3,014	29	0	[105]
Wind	2,203	79	0	[105]
Solar (grid-connected)	3,498	45	0	[105]
Solar (microgeneration)	3,763	45		[105, 142]
Biomass (forest residue)	2,130	60	52	[69, 106]
Biomass (straw)	2,300	66	47	[69, 106]
Waste heat	1,854	6	8.24	[107]
Nuclear	5,449	184	5	[99]
Geothermal	5,746	18	9.93	[99, 143]
Intertie (electricity import)	-	-	51[d]	[45]

a. Where applicable, capital, fixed and variable O&M costs are converted to 2010 dollars (LEAP base year) from reference location based on Bank of Canada exchanges rates [109, 110], regional indices of 1.08 and 2.16 for transfer projects from US Gulf coast to Canada [111].

b. Fuel cost excluded.

c. Fixed and variable O&M cost of CTG retrofit power plants is assumed to be 33% lower compared to subcritical coal power plants.

d. Alberta's 2010 average pool price of electricity is assumed.

3.3 The business-as-usual (BAU) scenario

The business-as-usual (BAU) scenario represents the demand forecast of moderate load growth considering several factors such as a projection of future oil sands development and the phase-out of coal-fired generation by 2030 [14]. The AESO assumed that wind would replace up to 4.2 GW of 6.3 GW coal-fired electricity generation capacity to be retired by 2030. The overall new gas-fired generation development and installed capacity of approximately 9.2 GW (more than twice the installed new wind capacity) will comprise 1.1 GW cogeneration, 6.8 GW combined cycle, and 1.3 GW simple cycle generation capacity by 2030. The maximum projected installed capacities are 25 GW and 32 GW by 2030 and 2050, respectively. Generation development is primarily assessed based on the present and forecast industrial development and environmental policy impact. The detailed estimate of installed generation capacity in the BAU scenario is shown in Table 3-2.

Table 3-2. BAU scenario generation mix

	Installed capacity (MW)			Added capacity (MW)	
Processes	**2015**	**2030**	**2050**	**2015-2030**	**2030-2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	8,541	11,628	6,825	3,087
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	5,663	7,129	4,200	1,466
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4 Alternate generation mix scenarios

3.4.1 Scenario 1: Wind-CTG I scenario

The wind-CTG scenario is an integrated generation mix based on new wind generation capacity of 5 GW by 2030 and the conversion of approximately 2.4 GW of existing subcritical coal plants by 2021 and 2023 to natural gas-based power plants. Alberta's map showing its existing coal power plants' locations are shown in Figure 3-3.

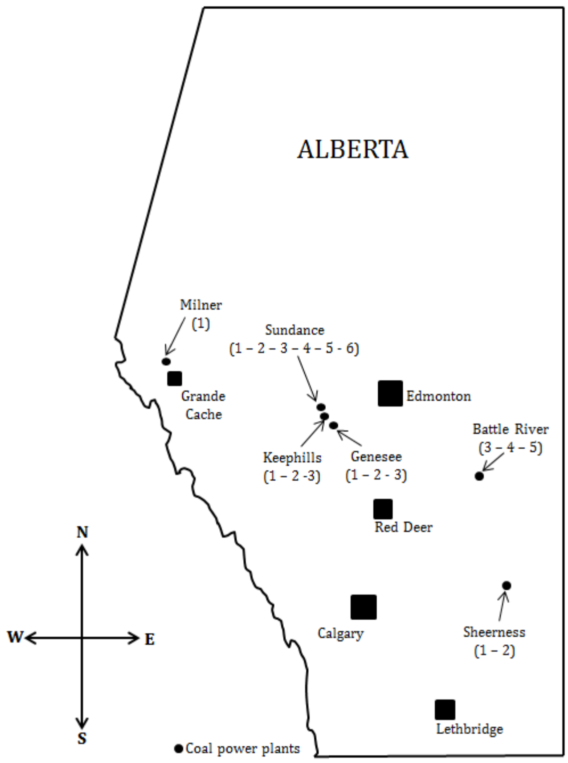


Figure 3-3. Alberta's map showing existing coal power plants

The Government of Alberta and TransAlta (one of Alberta's electricity producers) recently agreed to an earlier phase-out of some of TransAlta's coal-fired generation capacity [144]. Based on an earlier study the conversion of coal burners to gas could reduce CO_2 by 40% and extend the life of its subcritical coal plants by 15 years with a minimal investment of $125-150/kW [141]. The upper cost limit of $150/kW was assumed for the Alberta LEAP model base year. Once converted, the CTG power plants are expected to serve as backup capacity to support electricity generation from intermittent renewables. It is anticipated that the Sundance 3 to 6 and Keephills 1 and 2 coal power plants would be converted to gas-fired generation between 2021 and 2030 [145]. The installed capacity of the generation mix by 2030 and 2050 is shown in Table 3-3.

Table 3-3. Wind-CTG I scenario generation mix

	Capacity (MW)			Added (MW)	
Processes	**2015**	**2030**	**2050**	**2015-2030**	**2030-2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	6,680	10,819	4,964	4,139
Simple cycle	996	996	4,546	-	3,550
CTG retrofit**	-	2,376	-	2,376	-
Hydro	894	894	894	-	-
Wind	1,463	6,463	7,938	5,000	1,475
Biomass	400	441	441	41	-
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	9,764

*Coal-fired electricity generation is phased-out by 2030

**CTG retrofit power plants retired (after 15 years lifetime) between 2034 and 2037

3.4.2 Scenario 2: Wind-CTG II scenario

The wind-CTG II scenario is an integrated scenario of new wind and coal-to-gas conversion plants. In this case, higher penetration of coal-to-gas conversion plants is assumed. It is also planned that approximately 1.5 GW of Battle river and Sheerness subcritical coal-fired power plants will be converted before the end of 2020 [146]. Adding the 1.5 GW to the assumed CTG capacity in wind-CTG I scenario generation mix, the combined capacity of the CTG plants in this scenario is 3.9 GW and altogether accounts for about 62% of Alberta's total coal-fired generation capacity of 6.3 GW. The installed capacity of the generation capacity mix by 2030 and 2050 is shown in Table 3-4.

Table 3-4. Wind-CTG II scenario installed generation mix

	Capacity (MW)			**Added capacity (MW)**	
Processes	**2015**	**2030**	**2050**	**2015-2030**	**2030-2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	5,211	10,819	3,495	3,087
Simple cycle	996	996	4,546	-	2,235
CTG retrofit**	-	3845	-	3,845	-
Hydro	894	894	894	-	-
Wind	1,463	6,463	7,938	5,000	1,475
Biomass	400	441	441	41	-
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,397

*Coal-fired electricity generation is phased-out by 2030

**CTG retrofit power plants retired (after 15 years lifetime) between 2034 and 2037

3.4.3 Scenario 3: Wind-cogen I scenario

A previous study on retrofitting of coal plants to natural gas based plants in the United States, ascertained that most proposals for CTG conversions are nearly always complete replacement of coal-fired electricity generation with new gas-fired units at the same location [147]. The wind-cogen I scenario is an integrated scenario of wind and natural gas cogeneration plants. This scenario assumed an alternate generation mix pathway for wind-CTG I scenario to retire 44% subcritical coal plants between 2021 and 2023 and replace with natural gas cogeneration plants instead of conversion to natural gas based plants. 2.4 GW of assumed that new natural gas cogeneration capacity is added between 2021 and 2023 and 5 GW new wind generation capacity is added to the existing generation capacity. Beyond 2030, it is assumed that new gas-fired electricity generation would be cogeneration instead of combined cycle. Estimates of installed generation capacities in 2030 and 2050 are shown in Table 3-5.

Table 3-5. Wind-cogen I scenario generation mix

	Capacity (MW)			**Added capacity (MW)**	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal	5,360	-	-	-	-
Supercritical coal	929	-	-	-	-
Cogeneration	4,502	8,738	9,876	4,236	600
Combined cycle	1,716	5,870	7,914	4,154	3,087
Simple cycle	996	996	3,735	-	2,235
Hydro	894	894	894	-	-
Wind	1,463	6,463	7,938	5,000	1,475
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,929	13,431	7,397

*Early retirement of 2.4 GW subcritical coal power plants to replace with cogeneration between 2021 and 2023. Coal-fired electricity generation is phased-out by 2030.

3.4.4 Scenario 4: Wind-cogen II scenario

In Alberta, the use of cogeneration power plants is mostly common for steam assisted gravity drainage (SAGD) in oil sands production activities. In 2015, about 74% (3.3 GW) of total cogeneration plants are used in Alberta's oil sands [148]. Electricity generation is typically a secondary product in many cogeneration plants in Alberta, hence, baseload electricity supply to the grid is offered at low prices independent of pool price of electricity [45, 75]. A study by Layzel et al [149] proposed high-capacity penetration of cogeneration in Alberta oil sands as one of the solutions to reducing GHG emissions in the industry. Therefore, wind-cogen II scenario is an integrated scenario of wind and natural gas cogeneration plants. In this case, a higher penetration of new cogeneration capacity is assumed to replace 62% (3.9 GW) of existing subcritical coal plants between 2020 and 2023. The installed capacity of the generation mix by 2030 and 2050 is shown in Table 3-6.

Table 3-6. Wind-cogen II scenario generation mix

	Capacity (MW)			Added capacity (MW)	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	10,503	11,638	6,001	600
Combined cycle	1,716	4,105	6,152	2,389	3,087
Simple cycle	996	996	3,735	-	2235
Hydro	894	894	894	-	-
Wind	1,463	6,463	7,938	5,000	1,475
Biomass	400	441	441	41	-
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17391	24533	31929	13,431	7397

*Early retirement of 3.9 GW subcritical coal power plants to replace with cogeneration by 2021 and 2023. Coal-fired electricity generation is phased-out by 2030.

3.4.5 Scenario 5: Wind-only scenario

In the wind-only scenario it is assumed that only onshore wind-based renewable generation capacity is added during the study period. This assumption presumes that there is adequate accessible and developable capacity for the wind from its estimated potential of 64 GW [63]. By 2030, 5 GW of new wind generation capacity would be installed to add to the existing generation capacity of approximately 1.5 GW. Beyond 2030, it is assumed that new wind generation capacity added to the generation mix replaces a share of combined cycle capacity anticipated in the BAU scenario. Based on earlier estimates, it is projected that the total installed wind capacity is 7.9 GW by

2050 [60]. A study by Lyseng et al., it is projected that there would be 8.0 GW of installed wind generation by 2060 [34]. The share of wind generation capacity is expected to increase from 8.4% in 2015 to approximately 25% by 2050. The renewables shares of total installed capacity (including intertie capacity) are 32% and 29% by 2030 and 2050, respectively. Table 3-7 shows the estimates of installed generation capacities in 2030 and 2050.

Table 3-7. Wind-only scenario installed generation mix

	Installed capacity (MW)			**-Added capacity (MW)**	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,741	10,819	6,025	3,087
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	6,463	7,938	5,000	1,475
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,397

*Coal-fired electricity generation is phased-out by 2030

3.4.6 Scenario 6: Wind-biomass I scenario

The wind-biomass I scenario is the integrated deployment of both wind and biomass capacity into the generation mix. A previous study estimated that 11-15% of GHG emissions can be mitigated using agricultural and forest-based biomass in Alberta [70]. For this scenario, the use of agricultural residue (straw) as feedstock to the biomass power plant for GHG mitigation was investigated. The forest-based biomass share in this scenario is similar to that of the BAU. The potential for biomass-based generation capacity from uncollected straws in Alberta is about 2 GW, and an optimum plant size of 0.2 GW per power plant is anticipated for development to reach 1 GW by 2030 [106]. It was assumed that maximizing this potential could provide an additional 2 GW to the existing biomass generation capacity to substitute the share of the BAU scenario's anticipated combined cycle generation capacity by 2050. The detailed generation capacity mix is shown in Table 3-8.

Table 3-8. Wind-biomass I scenario generation mix

	Installed capacity (MW)			**(Retired)/added capacity (MW)**	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,741	9,628	5,866	1,887
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	5,463	7,129	4,200	1,666
Biomass (forest residue)	400	441	441	41	-
Biomass (straw)	-	1,000	2,000	1,000	1,000
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.7 Scenario 7: Wind-biomass II scenario

Unlike the wind-biomass I scenario, the wind-biomass II generation capacity substitutes the share of the BAU scenario's anticipated cogeneration and combined cycle capacity between 2030 and 2050. 1 GW straw-based biomass capacity substitutes the BAU cogeneration capacity share by 2030 and the remaining 1 GW straw-based biomass substitutes the BAU combined cycle generation capacity share by 2050. The assumption for the generation capacity penetration of both biomass and wind by 2030 and 2050 is the same as the wind-biomass I scenario. The installed generation capacity mix is shown in Table 3-9.

Table 3-9. Wind-biomass II scenario generation mix

	Installed capacity (MW)			Added capacity (MW)	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	4,852	5,160	350	308
Combined cycle	1,716	8,241	10,620	6,525	2,379
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	5,463	7,129	4,200	1,666
Biomass (forest residue)	400	441	441	41	-
Biomass (straw)	-	1,000	2,000	1,000	1,000
Waste Heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.8 Scenario 8: Wind-biomass-hydro scenario

The wind-biomass-hydro scenario is the integrated penetration of new wind, biomass, and hydroelectricity capacities into the generation mix. New wind generation capacity is assumed to be 3.5 GW and 4.0 GW by 2030 and 2050, respectively. According to an earlier study [69], the estimated power generation potential for forest residue in Alberta is 1.2 GW. The highest penetration potential of biomass generation capacity of 1.2 GW was assumed by 2050.

The penetration of hydroelectricity generation capacity is modeled similarly to AESO's alternate policy scenario [60]. Given long lead-time constraints for regulatory approval typical of new hydroelectricity development and construction, 0.33 GW and

0.77 GW of new hydroelectricity generation capacity penetration by 2030 and 2037 was assumed, respectively. It was also assumed that 5 GW each of wind and forest residue-based biomass renewables will be added to the generation mix by 2030 as new renewable generation capacity. The estimated new wind and biomass generation capacities are 4.3 GW and 0.4 GW, respectively by 2030. Beyond 2030, an additional 0.4 GW biomass generation capacity is introduced to attain the maximum potential of 1.2 GW of forest residue biomass and to replace gas-fired combined cycle energy by 2050 [69]. The total installed renewable capacity is shown in Table 3-10.

Table 3-10. Wind-biomass-hydro scenario generation mix

	Installed capacity (MW)			Added capacity (MW)	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal*	5360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1050	600
Combined cycle	1,716	7,752	10,458	6,036	3,067
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	1,224	1,994	330	770
Wind	1,463	5,763	6,440	4,300	316
Biomass (forest residue)	400	800	1,200	400	400
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.9 Scenario 9: Wind-biomass-solar scenario

The wind-biomass-solar scenario is an integrated new renewable generation capacity development made up of 4.2 GW wind, 1.2 GW biomass, and 1.5 GW solar photovoltaic to replace a share of retired coal-fired and anticipated combined cycle generation capacity by 2050. It is anticipated that a high share of growth in installed solar capacity would be in the residential and commercial sectors. Therefore, it was assumed that 90% of installed solar capacity is directly connected to the distribution system through micro-generation from residential and commercial installations. As an example, in Ontario, the leading Canadian province in solar power, about 13% of the contracted solar capacity of 2,227 MW was transmission-connected in 2016 [150]. Likewise, in the United States, most of the growth in solar installations is in the residential sector, where installed capacity increased from 27 MW in 2005 to 1, 231 MW in 2014 [151].

This scenario is structured with a micro-generation module linked with the transmission-connected generation module such that residential and commercial solar PV processes are first fully dispatched before other processes in the transmission grid-connected module. A 77 MW transmission-connected ground-mounted solar photovoltaic capacity is proposed to be constructed at the south end of Vulcan County, Alberta by 2018 [152]. The share of total installed renewable capacity in the overall capacity mix is 28% by both 2030 and 2050. Similarly, the renewable generation estimate is 25-28% between 2030 and 2050. Installed generation capacity estimates are shown in Table 3-11.

Table 3-11. Wind-biomass-solar scenario generation mix

Processes	**Installed capacity (MW)**			**Added capacity (MW)**	
	2015	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1050	600
Combined cycle	1,716	7,782	10,029	6,066	2,297
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	5,063	6,169	3,600	1,106
Biomass (forest residue)	400	800	1,200	400	400
Waste heat	28	28	28	-	-

Processes	Installed capacity (MW)			Added capacity (MW)	
	2015	2030	2050	2015 - 2030	2030 - 2050
Solar	-	100	300	100	200
Intertie	1,103	1,103	1,103	-	-
Sub-Total	17,391	23,633	30,421	6,242	6,788
Solar PV (micro-generation)	8	900	1,500	892	600
Total	17,399	24,491	31,921	13,423	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.10 Scenario 10: Wind-geothermal scenario

The wind-geothermal scenario assumes the penetration of wind and geothermal into the generation mix. 0.5 GW of geothermal electricity generation is added by 2050 with 25 MW new geothermal electricity generation capacity assumed to be added every year between 2022 and 2041. The nameplate capacity ratings of some of geothermal power plants in North America range from 18-102 MW [153]. In Alberta, initial estimates of 0.3-0.5 GW geothermal electricity generation may be possible in future [5]. The 0.5 GW estimate assumed in this scenario was based on communication with industry [154]. The detailed generation capacity mix of the wind-geothermal scenario is shown in Table 3-12.

Table 3-12. Wind-geothermal scenario generation mix

	Installed capacity (MW)			Added capacity (MW)	
Processes	2015	2030	2050	2015 - 2030	2030 - 2050
Subcritical coal*	5,360	-	-	-	-
Supercritical coal	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,741	11,128	6,075	3,387
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	6,238	7,129	4,775	891
Biomass (forest residue)	400	441	441	41	-

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015 - 2030	2030 - 2050
Waste heat	28	28	28	-	-
Geothermal	-	225	500	75	425
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.11 Scenario 11: Wind-hydro I scenario

Given the typical long lead-time constraints of constructing hydro power plants, along with the estimated 11.8 GW hydroelectricity potential in Alberta [65], two integrated wind-hydro scenarios, wind-hydro I and wind-hydro II were investigated in this study. The objective was to evaluate the impact of 1.1-2.2 GW of new capacity penetrations of hydro in the medium and long term. The wind-hydro I scenario is an integrated scenario of wind and 1.1 GW hydroelectricity generation capacity penetration into the generation mix by 2050. Equivalent capacities of wind and hydro are assumed to replace a share of the coal-fired generation capacity that will phased out by 2030 and the combined cycle capacity anticipated in the BAU by 2030 and 2050. The new renewable generation capacity of 5 GW by 2030 is expected to be made up of wind (4.7 GW) and hydro (0.33 GW). In an earlier study [60], it was assumed that up to 1.1 GW of new hydro generation capacity may be possible by 2037 government's support. The hydro and wind electricity generation capacities will likely increase to approximately 2 GW and 6.1 GW, respectively by 2037. The total projected generation capacity by 2050 is approximately 32 GW. The detailed generation capacity mix is shown in Table 3-13.

Table 3-13. Wind-hydro I scenario generation mix

	Installed capacity (MW)			Added capacity (MW)	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,741	10,819	5,255	2,457
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	1,224	1,994	330	770
Wind	1,463	6,133	6,838	4,670	996
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,929	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.12 Scenario 12: Wind-hydro II scenario

It is assumed in the wind-hydro scenario II that wind and hydroelectricity renewable generation capacities are incorporated into the capacity mix by 2030 and 2050. The hydroelectricity generation capacity penetration is modeled based on an earlier study's forecast with potential projects of 0.33 GW and 0.77 GW [60]. According to the Canadian utility company ATCO, capacities on the Slave (1.8 GW), Athabasca (1.5 GW), and Peace rivers (1.5 GW) totalling 4.8 GW represent immediate potential hydroelectricity projects opportunities in Alberta [155]. Therefore, in addition to the existing hydroelectricity generation capacity, a 2.2 GW hydroelectricity generation capacity was incorporated into the generation mix with penetrations of 1.1 GW each in 2030 and 2040, respectively. These estimates assume that nearly half the aforementioned potential projects are developed by 2050. This additional capacity is not quite one-fifth of the 11.8 GW potential for hydroelectricity generation in Alberta. The breakdown of the generation capacity mix is shown in Table 3-14.

Table 3-14. Wind-hydro II scenario generation mix

	Installed capacity (MW)			Added capacity (MW)	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030-2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,711	9,428	6,025	1,687
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	1,994	3,094	1,100	1,100
Wind	1,463	5,363	7,129	3,900	1,766
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,929	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.13 Scenario 13: Wind-nuclear I scenario

Previous studies, have investigated the feasibility and economics of nuclear electricity generation for future oil sands extraction and upgrading in Alberta and their conclusions support its use in effectively avoiding CO_2 emissions typical of the industry [156-158]. While the electricity requirement for oil sands operations and extraction is low compared to steam use for the direct heating of heavy oil, nuclear energy can be a cheaper source for oil sands steam production use and baseload electricity supply to the transmission grid. At higher gas prices (i.e.,$6.16-12.32/GJ), steam and electricity produced by natural gas may be more expensive than nuclear energy using the 0.75 GWe Advanced CANDU Reactor, ACR-700 [158]. While there are no immediate plans for nuclear electricity generation in Alberta, this study evaluated some scenarios in which nuclear generation is integrated should there be support in the future. The wind-nuclear I scenario is a combined wind and nuclear generation capacity development to substitute similar-capacity coal-fired plants and new cogeneration capacities in the BAU scenario. It assumed that 0.75 GW nuclear generation capacity replaces the similar capacity of the BAU-anticipated cogeneration capacity by 2028 and 2038. The detailed generation capacity mix of the wind-nuclear scenario is shown in Table 3-15.

Table 3-15. Wind-nuclear I scenario generation mix

	Installed capacity (MW)			Added capacity (MW)	
Processes	**2015**	**2030**	**2050**	**2015 - 2030**	**2030 - 2050**
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	4,752	4,960	250	208
Combined cycle	1,716	8,541	11,314	6,825	2,773
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	5,710	7,129	4,247	1,419
Biomass (forest residue)	400	441	441	38	-
Waste heat	28	28	28	-	-
Nuclear	-	753	1,506	753	753
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.14 Scenario 14: Wind-nuclear II scenario

The wind-nuclear II scenario represents integrated wind and nuclear electricity generation capacity added to the generation mix to replace equal shares of new generation capacity from combined cycle capacity by 2030 and 2050. 3.75 GW of nuclear capacity was assumed to be installed by 2050 to substitute the BAU-anticipated combined cycle generation capacity by that year (1.5 GW in 2028, 1.5 GW in 2038, and 0.75 GW in 2045). The details of the wind-nuclear II scenario generation capacity mix are shown in Table 3-16.

Table 3-16. Wind-nuclear II scenario generation mix

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015 - 2030	2030 - 2050
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,741	7,863	6,025	122
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	4,957	7,129	3,494	2,172
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Nuclear	-	1,506	3,765	1,506	2,259
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,583	31,921	13,431	7,388

*Coal-fired electricity generation is phased-out by 2030

3.4.15 Scenario 15: Wind-nuclear III scenario

The wind-nuclear III scenario is similar to the wind-nuclear I scenario. However, in the former it is assumed that new nuclear generation capacity substitutes a share of the BAU-anticipated cogeneration capacity. Nuclear capacity is assumed to be added to the generation mix to replace the equivalent new generation capacity of combined cycle between 2030 and 2050. It assumed that 0.75 GW per power plant of nuclear electricity generation capacity is added to the generation mix by 2028 and 2038. The capacity generation mix of the wind-nuclear III scenario is shown in Table 3-17.

Table 3-17. Wind-nuclear III scenario generation mix

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015-2030	2030 - 2050
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015-2030	2030 - 2050
Combined cycle	1,716	7,741	10,130	6,025	2,381
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	5,707	7,129	4,247	1,419
Biomass (forest residue)	400	441	441	38	-
Waste heat	28	28	28	-	-
Nuclear	-	753	1,506	753	753
Intertie	1,103	1,103	1,103	-	-
Total	17,391	24,533	31,921	13,431	7,346

*Coal-fired electricity generation is phased-out by 2030

3.4.16 Scenario 16: Wind-solar I scenario

The wind-solar I scenario is the integrated renewable capacity of the wind and solar introduced into the generation mix to replace the share of retired coal-fired generation and new combined cycle capacity by 2030 and 2050. Based on an earlier study [60], the penetration of 1 GW of solar electricity generation by 2030 was assumed. Similar to other scenarios with integrated solar capacities, it was assumed that 10% (0.1 GW) of the installed solar capacity of 1 GW would be transmission-connected and the remaining 90% (0.9 GW) connected to the distribution system through micro-generation. The shares of renewable capacity and generation in the total generation mix are 28-31% and 25-31%, respectively, by 2030 and 2050. The details of the generation capacity mix for the wind-solar I scenario are shown in Table 3-18.

Table 3-18. Wind-solar I scenario generation mix

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015 - 2030	2030 - 2050
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015 - 2030	2030 - 2050
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,741	8,988	6,025	1,247
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	894	894	-	-
Wind	1,463	5,463	7,969	4,000	2,506
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Solar	-	100	300	100	200
Intertie	1,103	1,103	1,103	-	-
Sub-total	17,391	23,633	30,421	6,242	6,788
Solar PV (micro-generation)	8	900	1,500	892	600
Total	17,399	24,533	31,921	13,423	7,388

* Coal-fired electricity generation is phased-out by 2030

3.4.17 Scenario 17: Wind-solar II scenario

The wind-solar II scenario is different from the wind-solar I scenario in that it assumes a 1.8 GW of distribution system-connected (microgeneration) solar capacity 2050. In this scenario, the impact of integrating increased solar capacity into the generation mix at the micro-generation level was investigated. By mid 2015, grid-connected solar generation in Ontario was about 8% (140 MW) of the installed solar generation capacity of 1.8 GW [150]. The capacity generation mix is shown in Table 3-19.

Table 3-19. Wind-solar II scenario generation mix

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015 - 2030	2030 - 2050
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,741	8,788	6,025	1,047
Simple cycle	996	2311	4,546	1,315	2,235

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015 - 2030	2030 - 2050
Hydro	894	894	894	-	-
Wind	1,463	5,463	7,969	4,000	2,506
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Solar	-	100	200	100	100
Intertie	1,103	1,103	1,103	-	-
Sub-total	17,391	23,633	30,421	6,242	6,488
Solar PV (micro-generation)	8	900	1,800	892	900
Total	17,399	24,533	31,921	13,423	7,388

* Coal-fired electricity generation is phased-out by 2030

3.4.18 Scenario 18: Wind-solar-hydro scenario

The wind-solar-hydro scenario assumes the renewable capacity penetration of wind (5.4 GW), solar (1.5 GW), and hydro (1.1 GW) substitutes an equivalent capacity share of retired coal-fired generation and anticipated combined cycle generation by 2050. Like the wind-biomass-hydro scenario, the penetration of the hydroelectricity generation capacity is modeled based on an earlier study's projections [60]. The total capacity of solar generation assumes that Alberta develops its solar generation potential rapidly. Alberta recorded a 44% growth in solar capacity over one year, and approximately 0.6 GW of solar capacity is in different stages of development for micro-generation and transmission-connected generation [159]. The share of renewable generation capacity in the total generation mix is 27-28%, and the corresponding proportion of renewable generation is 24-29% by 2030 and 2050, respectively. The generation capacity mix of the wind-solar-hydro scenario is shown in Table 3-20.

Table 3-20. Wind-solar-hydro scenario generation mix

Processes	Installed capacity (MW) 2015	2030	2050	Added capacity (MW) 2015 - 2030	2030 - 2050
Subcritical coal*	5,360	-	-	-	-
Supercritical coal*	929	-	-	-	-
Cogeneration	4,502	5,552	6,152	1,050	600
Combined cycle	1,716	7,741	9,019	6,025	1,278
Simple cycle	996	2,311	4,546	1,315	2,235
Hydro	894	1,224	1,994	400	700
Wind	1,463	5,133	6,838	3,670	1,705
Biomass (forest residue)	400	441	441	41	-
Waste heat	28	28	28	-	-
Solar	-	100	300	100	200
Intertie	1,103	1,103	1,103	-	-
Sub-total	17,391	23,633	30,421	6,242	6,867
Solar PV (micro-generation)	8	900	1,500	892	600
Total	17,399	24,533	31,921	13,423	7,396

* Coal-fired electricity generation is phased-out by 2030

3.5 Efficiency and capacity factor improvements

The key technological improvements in electricity generation technologies and the electrical grid focus on continuous developments. These efforts usually translate into increasing efficiency or capacity factor and result in GHG emission reduction. While no new major technological discovery or innovation is expected to occur during this study period (2010-2050), it is anticipated that existing technologies would actively continue to improve. Therefore, the impact of improvements in hydro, wind, combined cycle, and solar generation technologies on GHG emissions for each of the generation capacity mix scenarios by 2030 and 2050 was investigated; the results are given in section 4.2.

3.6 Cumulative mitigation cost and benefit analysis

The purpose of the cost-benefit analysis in LEAP is to identify socially acceptable policy scenarios but not their financial viability. A more detailed analysis is necessary to ascertain economically and financially viable scenarios. The model evaluated the cumulative costs and benefits of each scenario and compared them to the BAU scenario. The net present value (NPV) was determined by applying the discount rate of 5% to the projected real costs over the study period back to the base year (2010). The elements in the cumulative cost-benefit analysis in Eq. (1) include the transformation capital costs *CC*, fixed operating and maintenance cost *FOM,* variable operating and maintenance costs *VOM*, gas fuel cost *FC*, and externality costs *EC*.

$$\text{NPV} = \left[\sum_{n=1}^{N} \left(CC_{n,k} + FOM_{n,k} + VOM_{n,k} + FC_{n,k} + EC_{n,k}\right)/(1+i)^{n-1}\right] \qquad (1)$$

Appendix B summarizes the assumptions of each cost.

The GHG mitigation cost curve was developed for each scenario to compare them to the BAU scenario in the medium (2010-2030) and long term (2010-2050). The mitigation cost is the ratio of the difference between the cumulative NPV of an alternative scenario and the BAU scenario and similar differences in cumulative GHG emissions for that scenario and the BAU scenario. It is expressed in $ per tonne CO_2 equivalent, and it is mathematically expressed as:

$$\text{GHG abatement cost } = \frac{\sum(\text{NPV})_{BAU} - \sum(\text{NPV})_{S}}{\sum(\text{GHG})_{BAU} - \sum(\text{GHG})_{S}} \qquad (2)$$

where,

$\sum(\text{NPV})_{BAU}$ = Net present value of the BAU

$\sum(\text{NPV})_{S}$ = Net present value of an alternative scenario

$\sum(\text{GHG})_{BAU}$ = Cumulative GHG emissioss of the BAU

$\sum(\text{GHG})_{S}$ = Cumulative GHG emissions of an alternative scenario

3.7 Sensitivity analysis

The sensitivity of different input parameters on the GHG abatement costs for each scenario in relation to the BAU was investigated. The gas price, carbon tax, capital cost, and interest rate by ±30% was varied to determine the impact on GHG abatement cost for each scenario generation mix with respect to the BAU by 2030 and 2050, respectively. The results are discussed in section 3.8.4.

3.8 Results and discussion

3.8.1 Installed capacity and generation

Figure 3-4 and Figure 3-5 show the generation capacity shares for the developed scenarios and the BAU by 2030 and 2050, respectively. The corresponding generations for each process to 2030 and 2050 are shown in Table 3-21 and Table 3-22, respectively. Renewable (excluding nuclear) electricity generation capacity shares range from approximately 26-32% and 27-36% by 2030 and 2050, respectively. The corresponding renewable (excluding nuclear) electricity generation shares range from approximately 19-25% and or 26-31% by 2030 and 2050, respectively. It can be concluded that the 5 GW new renewable capacity target is approximately 5-9% below the CLP recommended 30% renewable electricity generation share by 2030 [14] (nuclear-based scenarios excluded). However, up to 31% renewable electricity generation could be achieved by 2050.

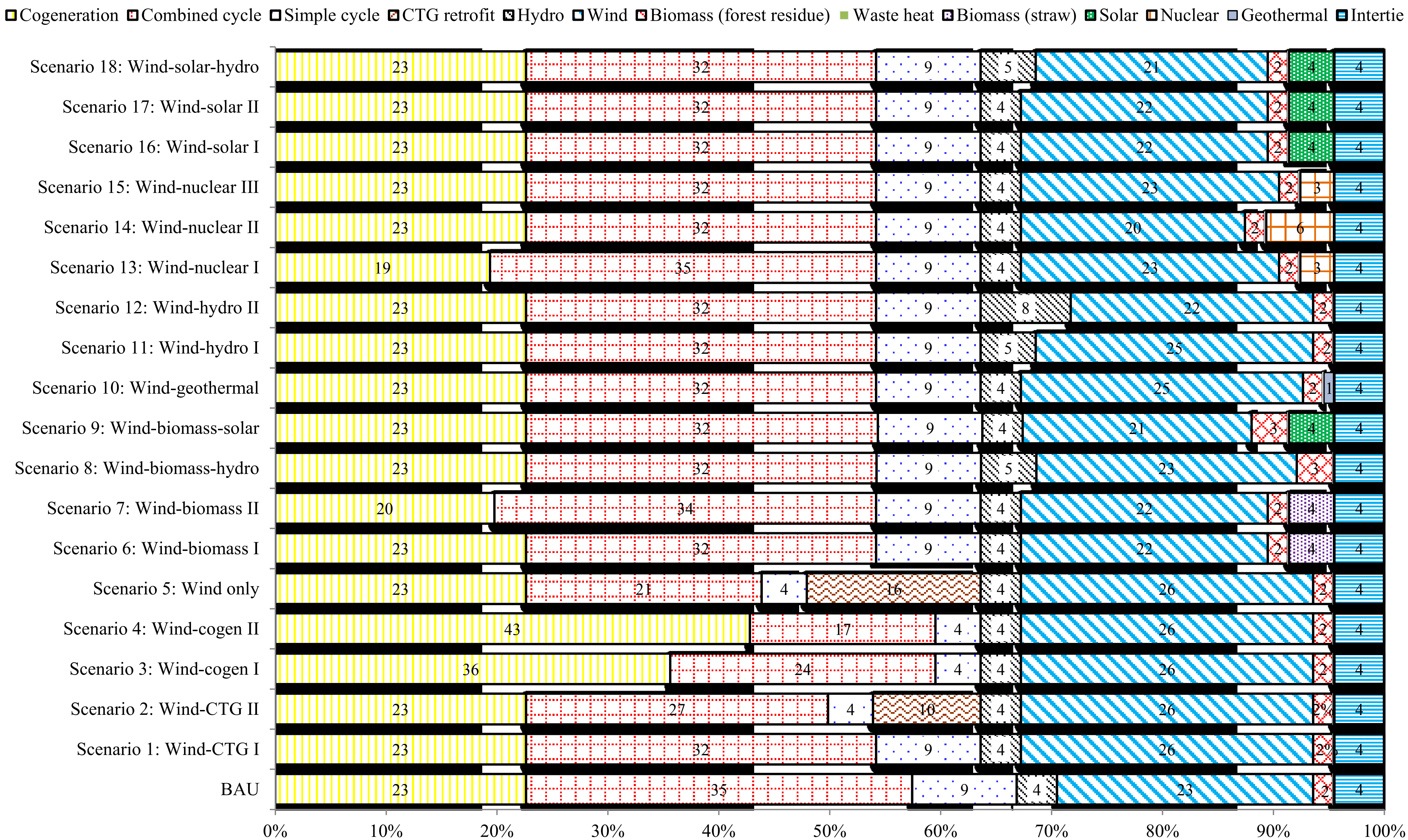


Figure 3-4. Installed generation capacity shares (%) by 2030 based on LEAP-Alberta model

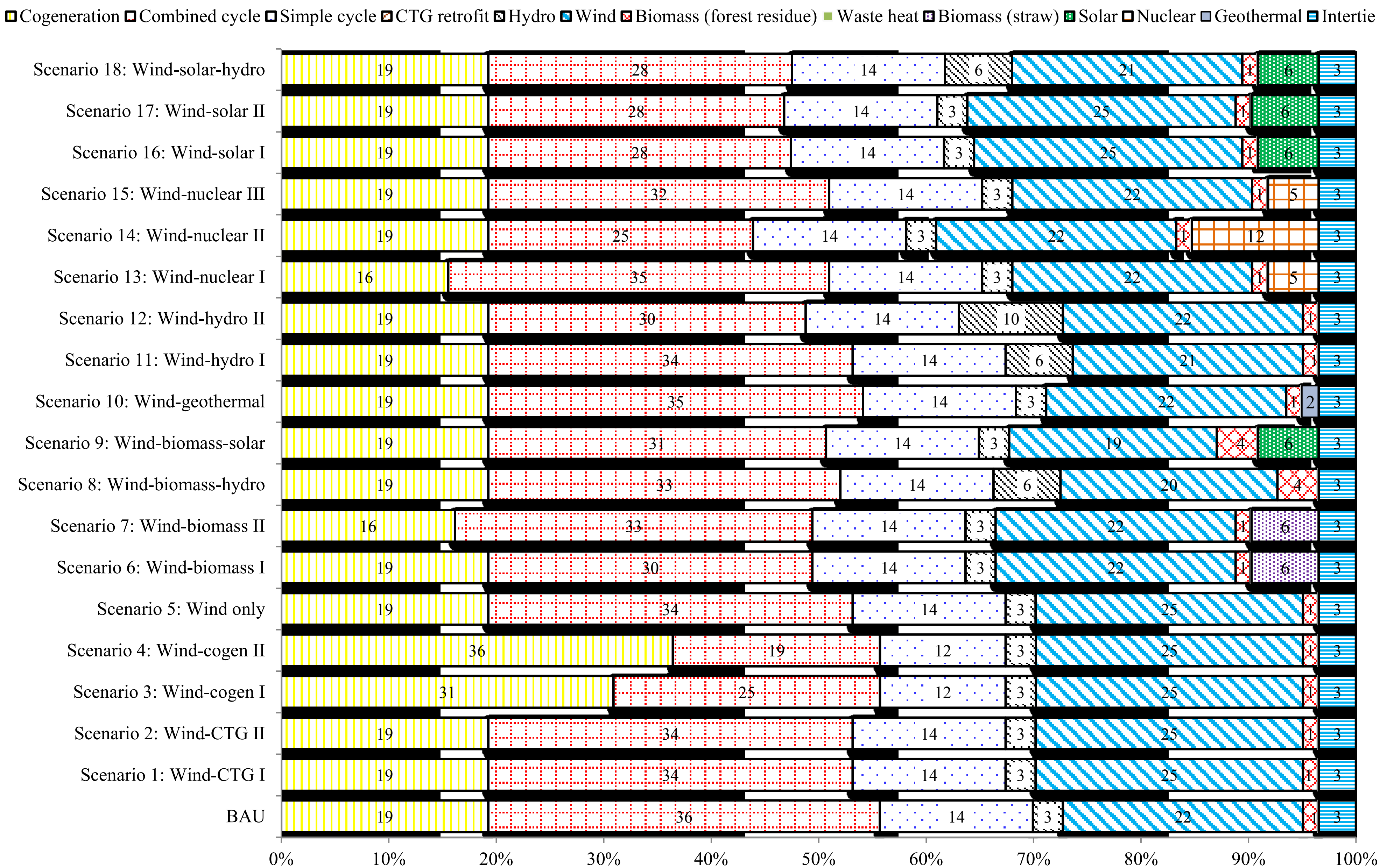


Figure 3-5. Installed generation capacity shares (%) by 2050 based on LEAP-Alberta model

Table 3-21. Total generation (TWh) by 2030 based on LEAP-Alberta model

Scenario		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
Processes	**BAU**	**Wind-CTG I**	**Wind-CTG II**	**Wind-Cogen I**	**Wind-Cogen II**	**Wind only**	**Wind-biomass I**	**Wind-biomass II**	**Wind-biomass-hydro**	**Wind-biomass-solar**	**Wind-geoth-ermal**	**Wind-hydro I**	**Wind-hydro II**	**Wind-nuclear I**	**Wind-nuclear II**	**Wind-nuclear III**	**Wind-solar I**	**Wind-solar II**	**Wind-solar-hydro**
Cogeneration	34.3	41.0	41.0	64.5	76.0	34.3	34.3	30	34.3	34.3	34.3	34.3	34.3	29.4	34.3	34.3	34.3	34.3	34.3
Combined cycle	48.2	39	36.4	15.4	4.0	44.8	45.5	49.9	45.3	46.6	44.1	45.2	46	47.3	39.2	42.4	46.4	46.4	46.7
Simple cycle	0.2	-	0.2	-	-	0.7	0.7	0.7	0.7	0.7	0.6	0.7	0.7	-	-	-	0.7	0.7	0.8
CTG retrofit	-	-	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	1.8	1.8	1.8	1.8	-	1.8	1.8	1.8	2.5	1.8	1.8	2.5	4.1	1.8	1.8	1.8	1.8	1.8	2.5
Wind	19.5	22.2	22.2	22.2	22.2	22.2	18.8	18.8	19.8	17.4	21.4	21.1	18.4	19.6	17	19.6	18.8	18.8	17.6
Biomass (forest residue)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.6	2.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Waste heat	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Biomass (straw)	-	-	-	-	-	-	2.5	2.5	-	-	-	-	-	-	-	-	-	-	-
Solar	-	-	-	-	-	-	-	-	-	1.4	-	-	-	-	-	-	1.4	1.4	1.4
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	11.6	5.8	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	1.7	-	-	-	-	-	-	-	-
Intertie	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Total	106.7	106.8	106.8	106.8	106.8	106.5	106.3	106.4	106.5	106.1	106.6	106.5	106.2	106.6	106.6	106.6	106.1	106.1	106

Table 3-22. Total generation (TWh) by 2050 based on LEAP-Alberta model

Scenario		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
Processes	**BAU**	**Wind-CTG I**	**Wind-CTG II**	**Wind-cogen I**	**Wind-Cogen II**	**Wind only**	**Wind-biomass I**	**Wind-biomass II**	**Wind-biomass-hydro**	**Wind-biomass-solar**	**Wind-geoth-ermal**	**Wind-hydro I**	**Wind-hydro II**	**Wind-nuclear I**	**Wind-nuclear II**	**Wind-nuclear III**	**Wind-solar I**	**Wind-solar II**	**Wind-solar-hydro**
Cogeneration	38	45.4	45.4	72.9	82.5	38	38	31.9	38	38	38	38	38	30.7	38	38	38	38	38
Combined cycle	49.3	38.8	38.8	11.3	1.8	46.2	44.2	50.3	46.4	47.2	45.4	48.1	44.8	45	20.2	37.6	43.5	43.2	45.6
Simple cycle	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CTG retrofit	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydro	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	4.1	1.8	1.8	4.1	6.4	1.8	1.8	1.8	1.8	1.8	4.1
Wind	27.6	30.7	30.7	30.7	30.7	30.7	27.6	27.6	24.9	23.8	27.6	26.4	27.6	27.6	27.6	27.6	30.8	30.8	26.4
Biomass (forest residue)	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	5.2	5.2	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Waste heat	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Biomass (straw)	-	-	-	-	-	-	5.1	5.1	-	-	-	-	-	-	-	-	-	-	-
Solar	-	-	-	-	-	-	-	-	-	2.5	-	-	-	-	-	-	2.5	2.8	2.5
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	11.6	29.1	11.6	-	-	-
Geothermal	-	-	-	-	-	-	-	-	-	-	3.9	-	-	-	-	-	-	-	-
Intertie	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Total	119.9	119.9	119.9	119.9	119.9	119.9	119.9	119.9	119.9	119.8	119.9	119.8	120.0	119.9	119.9	119.8	119.8	119.8	119.8

3.8.2 GHG emissions forecast and reduction potential

The GHG emissions forecast of the BAU and the alternative scenarios during the study period are shown in Figure 3-6. By 2030 and 2050, the BAU GHG emissions are 27.4 and 28.6 Mt CO_2 eq., respectively. The BAU GHG emissions are higher than any in the alternative scenario generation mixes for the study years ending 2030 and 2050. The lowest GHG emissions of 19.8 Mt CO_2 eq. and 17.2 Mt CO_2 eq.by 2030 and 2050, respectively, were found in the wind-cogen II and wind-nuclear II scenario generation mixes. The GHG emissions trends in all scenarios show a consistent decline of 43-51% between 2025 and 2030 with the retirement of nearly 87% (5.5 GW) of installed coal-fired generation capacity during this period. The GHG emissions forecast of the wind-hydro II and wind-nuclear II scenarios indicates a slightly higher annual emissions output between 2017 and 2027 due to the delayed penetration of about 22-30% of the shares of the alternative generation capacity target of 5 GW between 2027 and 2030. The wind-hydro II and wind-nuclear II scenarios generated more electricity from combined cycle (with corresponding higher GHG emissions output) than the other scenarios in order to support increasing electricity demand. Beyond 2030 and up to 2050, GHG emissions for all scenarios are below 29 Mt CO_2 eq. and this is indicative of the longer-term impact of the increasing alternative (renewable and nuclear) generation capacity share of 27-36%.

The GHG emissions profile is consistent across all scenarios with the maximum reduction potential achieved during the coal phase-out period between 2020 and 2030. Between 2030 and 2050, the GHG emissions for the BAU scenario increased by 4.4% due to emissions from gas-fired combined cycle generation, which are 42% of the total generation mix and account for 68% of the total GHG emissions. This shows that the development of gas-fired cogeneration technologies with lower GHG emission intensity, instead of gas-fired combined cycle generation capacity, would maintain baseload requirements effectively and simultaneously reduce GHG emissions in the long term. Efficiently distributed cogeneration plants could be developed for a distribution system-connected electricity supply as well as for the heating and cooling needs of some commercial and industrial facilities around the province.

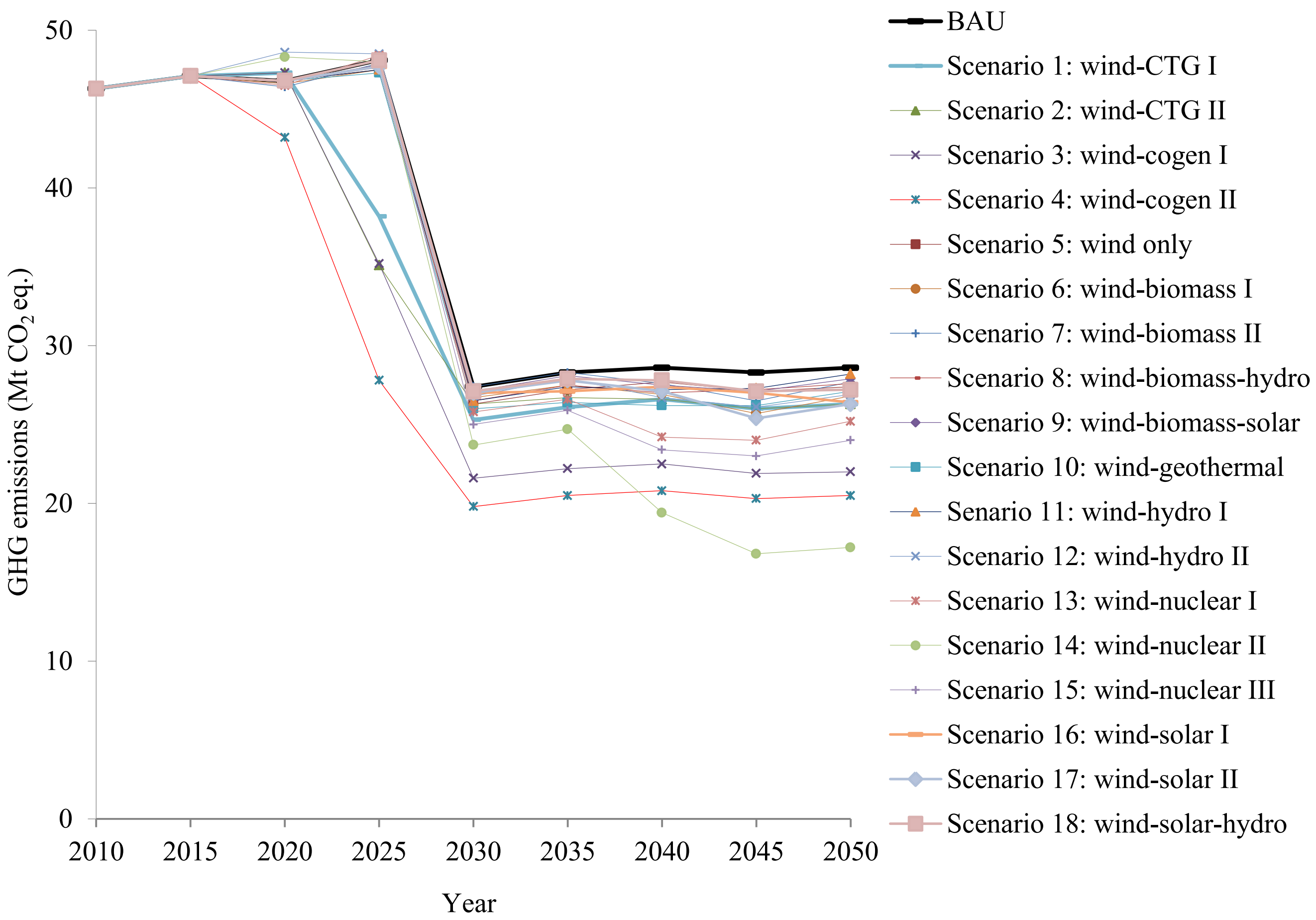


Figure 3-6. BAU and alternative scenarios' GHG emissions forecast based on LEAP-Alberta model

The emissions reduction potential of each scenario compared to Alberta's actual 2014 emission levels reported by Environment and Climate Change Canada [21] for the electricity generation sector is summarized in Table 3-23.

Table 3-23. GHG emission reduction potential compared to actual 2014 emission levels based on LEAP-Alberta model results

Scenario	2030 Emissions reduced (Mt CO_2 eq.)	2030 Percentage reduction	2050 Emissions reduced (Mt CO_2 eq.)	2050 Percentage reduction
BAU	21.5	44%	20.3	42%
Scenario 1: wind-CTG I	23.6	48%	22.6	46%
Scenario 2: wind-CTG II	22.6	46%	22.6	46%
Scenario 3: Wind-cogen I	27.3	56%	26.9	55%
Scenario 4: Wind-cogen II	29.1	60%	28.4	58%
Scenario 5: wind only	22.6	46%	21.5	44%
Scenario 6: wind-biomass I	22.2	45%	22.1	45%
Scenario 7: wind-biomass II	21.5	44%	21.2	43%
Scenario 8: wind-biomass-hydro	22.4	46%	21.3	44%
Scenario 9: wind-biomass-solar	21.8	45%	21.0	43%
Scenario 10: wind-geothermal	22.9	47%	21.8	45%
Scenario 11: wind-hydro I	22.4	46%	20.7	42%
Scenario 12: wind-hydro II	22.1	45%	22.0	45%
Scenario 13: wind-nuclear I	23.1	47%	23.7	48%
Scenario 14: wind-nuclear II	25.2	52%	31.7	65%
Scenario 15: wind-nuclear III	23.9	49%	24.9	51%
Scenario 16: wind-solar I	21.9	45%	22.5	46%
Scenario 17: wind-solar II	21.9	45%	22.6	46%
Scenario 18: wind-solar-hydro	21.8	45%	21.7	44%

By 2030, the BAU scenario generation mix has the lowest emission reduction potential of 44% and the wind-CTG I, wind-cogen I & II, and wind-nuclear I, II & III scenario generation mixes show higher GHG emission reduction potential, above 46%. Similarly, by 2050, the BAU and wind-hydro I scenario generation mixes show the lowest emission reduction potential and the wind-cogen I & II and wind-nuclear I, II & III scenario generation mixes show higher emission reduction, above 46%.

In addition to the GHG emission reduction potentials explained above, it was observed that capacity factors and efficiency improvements are key input parameters that could further reduce overall GHG emissions of the BAU and alternative scenarios without a change in demand. According to Johnstone et al. [160], stringent policies and environmental regulations are a significant factor in determining production efficiency. The assumptions, which are subject to future technological innovations and improvements in the main parameters, include but are not limited to a 50% capacity factor for wind [161] and hydro electricity generation by 2030, a 60% process efficiency of natural gas combined cycle generation [162], and a 20% solar PV capacity by 2030 [163]. The efficiency improvement in natural gas combined cycle generation results in the greatest potential to further reduce GHG emissions (between 2.1 Mt CO_2 eq. and 3 Mt CO_2 eq. by 2030, and between 0.1 Mt CO_2 eq. and 2.9 Mt CO_2 eq. by 2050). The GHG mitigation potential of the BAU and alternative scenarios could be further improved by 6-8% and 4-8% by 2030 and 2050, respectively provided that wind can achieve a 50% average capacity factor by 2030. Similarly, further increases of 2-6% and 2-10% in mitigation potential could be reached by 2030 and 2050, respectively, should hydroelectricity achieve a 50% average capacity by 2030. An increase in solar PV capacity factor from 16-20% results in the least potential to further reduce GHG emissions (between 0 Mt CO_2 eq. and 0.1 Mt CO_2 eq. by 2030, and between 0 Mt CO_2 eq. and 0.3 Mt CO_2 eq. by 2050 The reduction potentials of these key parameters compared to the baseline parameters by 2030 and 2050 are shown in Figure 3-7 and Figure 3-8, respectively.

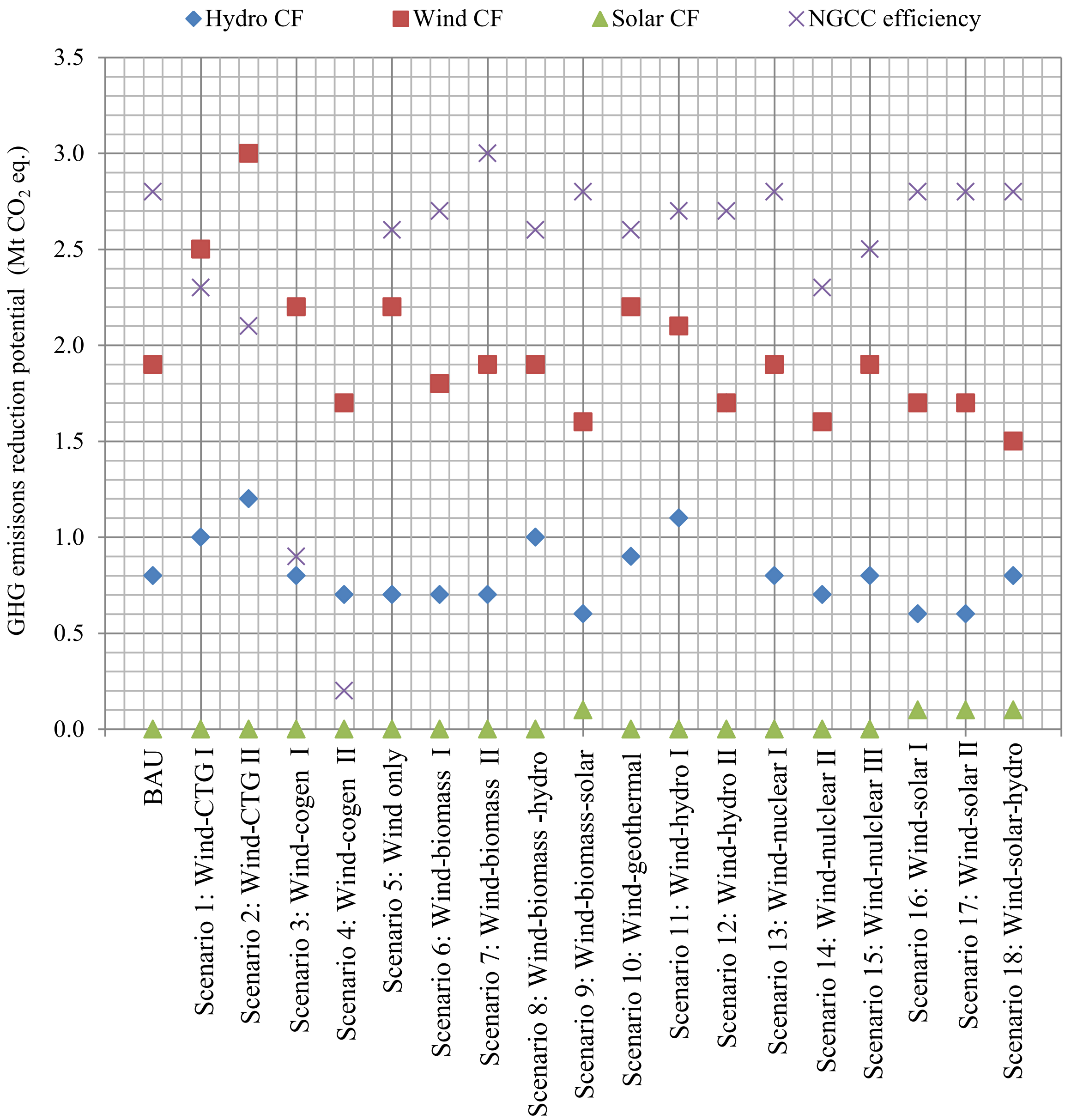


Figure 3-7. GHG emission reduction potentials due to improvements in selected parameters by 2030 based on LEAP-Alberta model

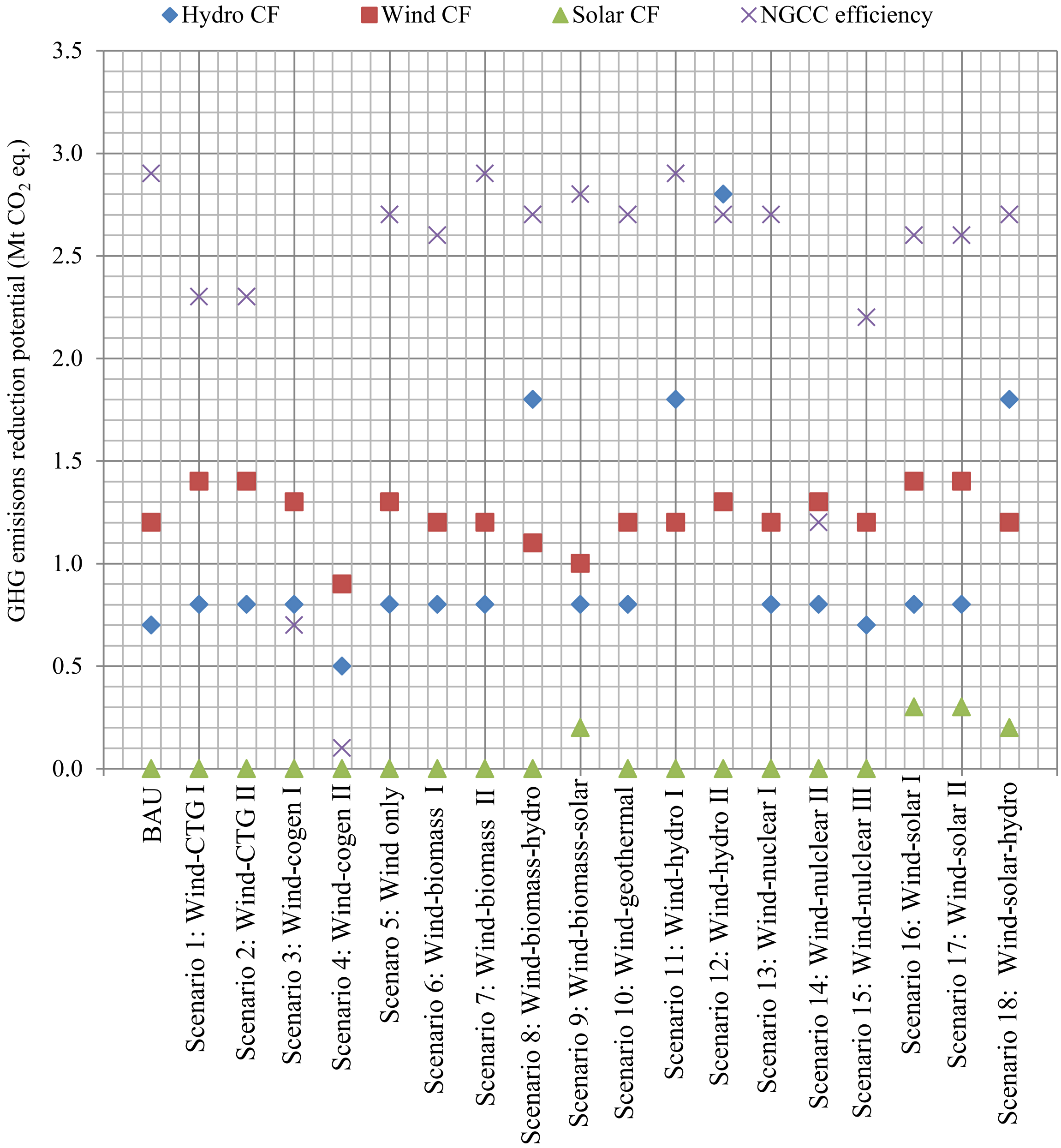


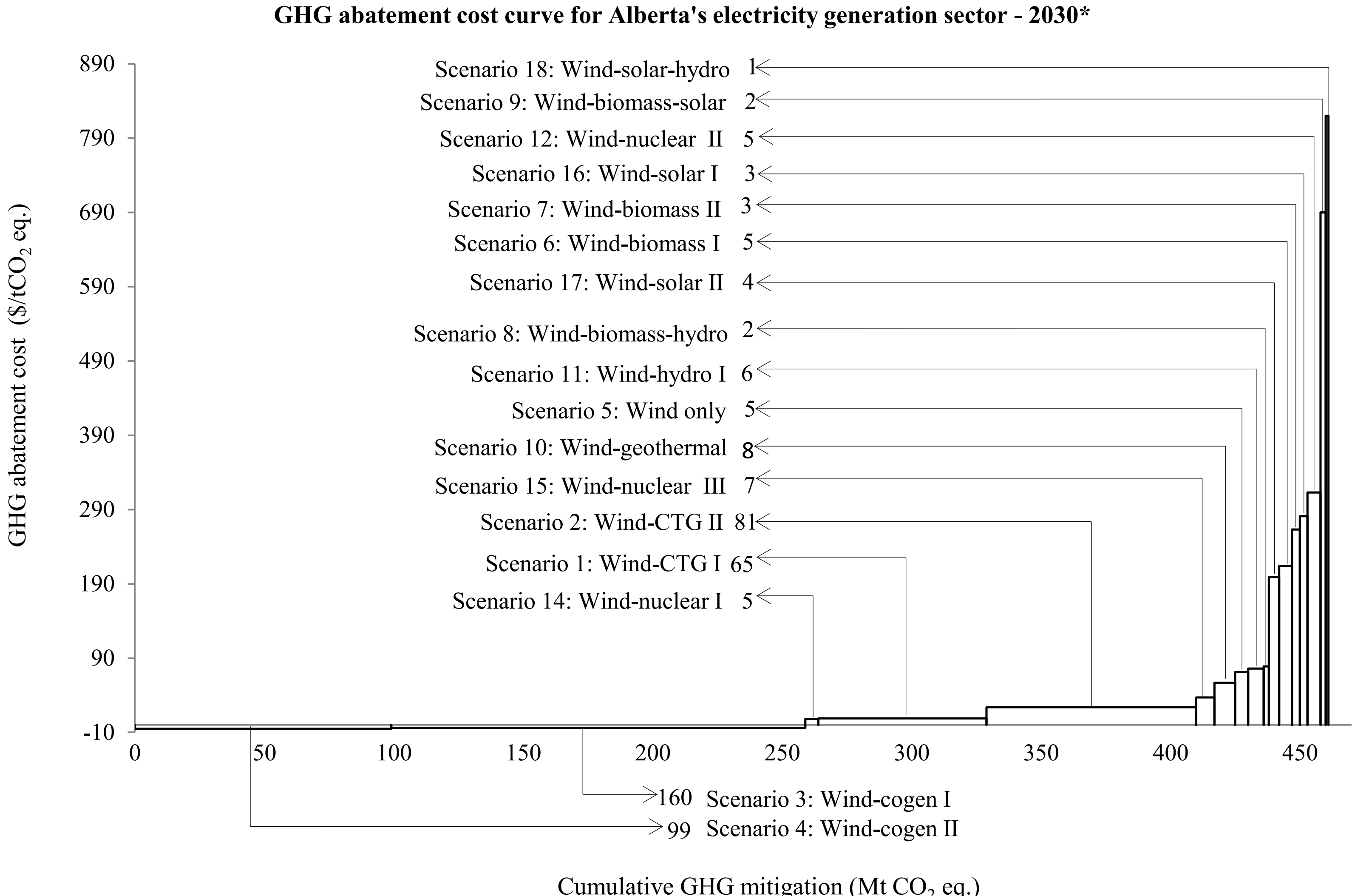
Figure 3-8. GHG emission reduction potentials due to improvements in selected parameters by 2050 based on LEAP-Alberta model

3.8.3 Cumulative GHG abatement cost

There are several possible mitigation measures in the electricity generation sector but the key mitigation measures implemented in this study are the phasing out of coal-fired generation and increasing renewable and nuclear electricity generation capacities to replace coal and gas-fired electricity generation capacity in the medium and long term. The summary of the cumulative NPV (converted to 2015 dollars), GHG mitigation costs, and GHG savings of each scenario compared with the BAU scenario by 2030 and 2050 is shown in Table 3-24. The cumulative GHG abatement cost curves for each scenario by 2030 and 2050 are shown in Figure 3-9 and 3-10, respectively. The cost curves represent the relative incremental costs and cumulative GHG emissions mitigation achievable for each scenario compared to the BAU in the medium and long term. The block height indicates the cost in \$/Mt of CO_2 eq. mitigated by each scenario and the block width indicates the potential GHG savings contribution achievable by the associated generation mix scenario by 2030 and 2050, respectively. In Figure 3-9 and 3-10 each bar represents a different generation mix. Between 2010 and 2030, the cumulative GHG mitigation of the wind-hydro II scenario is 11 Mt CO_2 eq. higher than the BAU because of the late penetration of about 15% (0.77 GW new hydro capacity) of the 5 GW renewable capacity target by 2030. However, by 2050 the wind-hydro II scenario results in a reduced cumulative GHG emissions mitigation of 17 Mt CO_2 eq. higher than the BAU.

Table 3-24. Summary of NPV, GHG abatement costs, and cumulative GHG mitigation compared with the BAU scenario

Scenarios	2010-2030 NPV (Million $)	2010-2030 GHG abatement costs ($/t CO_2 eq.)	2010-2030 Cumulative GHG mitigation (Mt CO_2 eq.)	2010-2050 NPV (Million $)	2010-2050 GHG abatement costs ($/t CO_2 eq.)	2010-2050 Cumulative GHG mitigation (Mt CO_2 eq.)
Scenario 1: wind-CTG I	606	9	65	228	2	108
Scenario 2: wind-CTG II	1,978	24	81	1,487	12	121
Scenario 3: Wind-cogen I	−542	−5	99	−2,577	−12	223
Scenario 4: Wind-cogen II	−614	−4	160	−4,019	−13	318
Scenario 5: wind only	374	71	5	580	21	27
Scenario 6: wind-biomass I	1,143	214	5	3,922	108	36
Scenario 7: wind-biomass II	911	263	3	4,010	214	19
Scenario 8: wind-biomass-hydro	196	79	2	1,559	62	25
Scenario 9: wind-biomass-solar	1,263	690	2	3,308	195	17
Scenario 10: wind-geothermal	448	57	8	1,445	31	47
Scenario 11: wind-hydro I	418	76	6	994	39	26
Scenario 12: wind-hydro II	1,180	n/a	−11	2,058	124	17
Scenario 13: wind-nuclear I	42	8	5	2,658	37	71
Scenario 14: wind-nuclear II	1,666	313	5	5,682	34	166
Scenario 15: wind-nuclear III	261	37	7	2,431	27	89
Scenario 16: wind-solar I	898	281	3	2,068	74	28
Scenario 17: wind-solar II	734	199	4	1,834	54	34
Scenario 18: wind-solar-hydro	761	820	1	1,937	110	18



***NPV of costs discounted to 2015**

Figure 3-9. GHG abatement cost curve for Alberta's electricity generation sector (2010-2030) based on LEAP-Alberta model

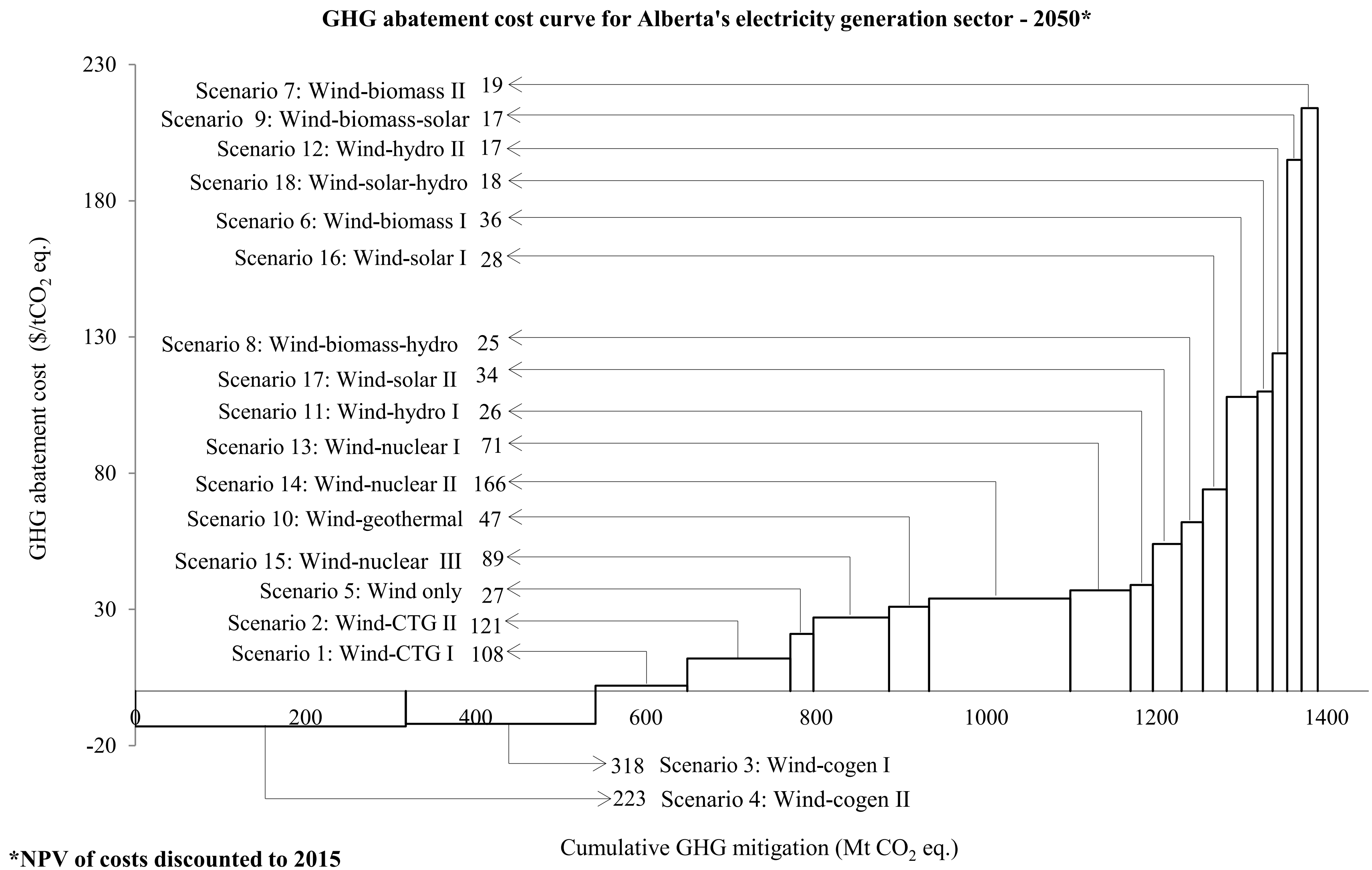


Figure 3-10. GHG abatement cost curve for Alberta's electricity generation sector (2010-2050) based on LEAP-Alberta model

The wind-cogen I and II scenario generation mixes have negative GHG abatement costs of \$5/t CO_2 eq. and \$4/t CO_2 eq. compared the BAU, with the highest cumulative GHG emissions mitigation of 99 Mt CO_2 eq. and 160 Mt CO_2 eq., respectively, compared to the BAU by 2030. Similarly, by 2050, the wind-cogen I and II scenario generation mixes have negative GHG abatement costs of \$12/t CO2 eq. and \$13/t CO2 eq. compared to the BAU, with the highest cumulative GHG emissions mitigation of 223 Mt CO_2 eq. and 318 Mt CO_2 eq. respectively compared to the BAU. The significant cumulative GHG emissions mitigation result by 2030 and 2050 of the wind-cogen I and II scenario generation mixes can be attributed to both the early phase-out of coal-fired electricity generation from subcritical coal power plants between 2020 and 2030, and their replacement with lower emission-intensity, more efficient baseload gas-fired cogeneration. This translates to the cost-effectiveness of the wind-cogen I and II scenario generation mixes due to the fall in cumulative externalities and fuel costs and from higher capacity penetration of more efficient gas-fired cogeneration compared to the BAU. A similar trend is also observed with the wind-CTG I and II scenario generation mixes but with GHG abatement costs higher than the BAU. The reduction of coal-fired generation through to the conversion of shares of existing subcritical coal-fired capacity to gas between 2021 and 2023 is expected to result in significant cumulative GHG emissions mitigation by 2030 and 2050. The wind-CTG I and II scenario generation mixes have higher cumulative GHG emissions mitigation of 65 Mt CO_2 eq. and 8 Mt CO_2 eq. with corresponding abatement costs of \$9/t CO_2 eq. and \$24/t CO_2 eq., respectively, higher than the BAU by 2030. With the retirement of the CTG plants after their extended lifetime of 15 years between 2036 and 2038, the cumulative GHG emissions mitigation of the wind-CTG I and II generation mixes is further increased to 108 Mt CO_2 eq. and 121 Mt CO_2 eq., respectively, by 2050. Compared to the other scenarios, the trend of low abatement costs and corresponding high cumulative

GHG emissions mitigation is consistent for wind-cogen I & II and wind-CTG I &II scenario generation mixes by 2030 and 2050, respectively. The wind-CTG I and II scenario generation mixes have abatement costs of \$2/t CO_2 eq. and \$12/t CO_2 eq., respectively, by 2050. The wind-nuclear II scenario generation mix has the highest cumulative mitigation of 166 Mt CO_2 eq. with an abatement cost of \$27/t CO_2 eq. due to the high capacity penetration of zero-emission nuclear electricity generation. Due to the long lead time (9-12 years) required for the construction and operation of hydroelectricity generation capacities of 0.33 GW and 0.77 GW by 2028 and 2030, respectively, the integrated wind-hydro II scenario shows a negative GHG emissions mitigation impact compared to the BAU scenario by 2030. It is interesting that the abatement costs and cumulative GHG mitigation of the wind-geothermal scenario are \$31/t CO_2 eq. and 47 Mt CO_2 eq. with only 0.5 GW geothermal capacity penetration in the generation mix compared to the BAU scenario by 2050. This is because of the ability of geothermal plants to operate as a baseload plant and at a capacity factor of up to 90%, comparable to gas or nuclear power plants.

By 2050, the wind-CTG I and II, wind-only, and wind-nuclear III scenarios show abatement costs below \$30/t CO_2 eq. The wind-geothermal, wind-hydro I, wind-nuclear I and II scenario generation mixes have GHG abatement costs in the range of \$30-50/t CO_2 eq. The wind-biomass-hydro, and wind-solar I and II scenarios have mitigation costs in the range of \$50-100/t CO_2 eq. The wind-biomass I and II, wind-biomass-solar, wind-hydro II and wind-solar-hydro scenario generation mixes have abatement costs above \$100/t CO_2 eq. Of all the scenarios, the wind-biomass-solar and wind-biomass II scenarios have the highest abatement costs (\$195/t CO_2 eq. and \$214/t CO_2 eq., respectively) by 2050. The wind-solar-hydro scenario has the lowest cumulative GHG mitigation (1 Mt CO_2 eq.) with abatement costs of \$820/t CO_2 eq. by 2030. Similarly, by 2050, the wind-hydro II and wind-biomass-solar scenario have the lowest cumulative GHG mitigation of 17 Mt CO_2 eq. with mitigation costs of \$124/t CO_2 eq. and \$195/t CO_2 eq., respectively. The wind-biomass-solar and wind-solar-hydro integrated scenarios also have relatively high GHG abatement costs of \$690-820/t CO_2 eq. by 2030. The relatively high wind-biomass-solar-based integrated scenario abatement cost fell nearly 3.5 times from \$690/t CO_2 eq. in 2030 to \$195/t CO_2 eq., by 2050. The wind-solar-hydro scenario generation mix, which seemed to be the most anticipated renewable penetration development path for Alberta's generation mix, has a relatively high GHG abatement cost of \$820/t CO_2 eq. with a corresponding low cumulative GHG emissions mitigation of 1 Mt CO_2 eq. compared to the BAU by 2030. However, over a longer term, the GHG mitigation costs fell nearly 7.5 times below the BAU to \$110/t CO_2 eq. with a corresponding cumulative GHG emissions mitigation of 18 Mt CO_2 eq., by 2050.

3.8.4 Sensitivity analysis results

Detailed graphical representations of the sensitivity analysis for all the scenarios compared to the BAU are shown in Appendix C of this thesis. The key observation is that gas price and capital cost have the highest effect on abatement costs for all scenarios by 2030 and 2050. Increasing capital cost and carbon price changes have more impact on increasing GHG abatement costs of the wind-cogen I and II scenario generation mix by 2030. Whereas in the long-term (2050), increasing gas price and capital costs have more impact on GHG abatement costs of the wind-cogen I and II scenarios. Other than the wind-CTG I & II scenario generation mixes with earlier coal phase-out due to coal-to-gas conversions, increasing gas prices reduce GHG abatement costs and decreasing gas prices raise abatement costs. Decreasing capital costs reduces GHG abatement costs, and increasing capital costs raises GHG abatement costs, whereas carbon price and interest rates show limited sensitivity to GHG mitigation cost. The carbon price does not have any significant impact on GHG abatement cost because of both the increasing penetration of low- or zero-emission technologies in the scenario generation mix in the long term and low-emission gas-fired electricity generation. The sensitivity analysis suggests that renewable electricity generation, as a GHG emissions reduction measure, could become increasingly uncompetitive compared to gas-fired electricity generation with reduced gas prices.

3.9 Chapter summary

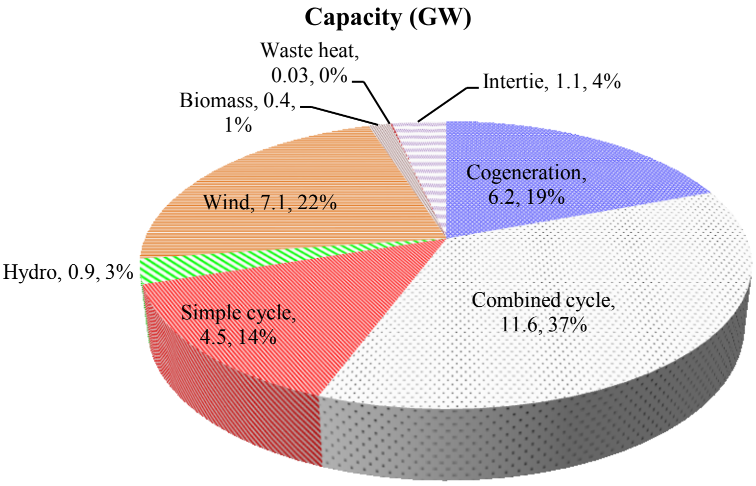
The environmental and economic assessments of the BAU and 18 scenarios of low or zero GHG mitigation potentials of electricity generation mix were assessed in this study using the LEAP model for Alberta, a western Canadian Province and one of the largest energy producing jurisdictions in North America. The GHG emission profile of each scenario was analyzed and compared with the BAU scenario. By 2050, the wind-cogen II scenario generation mix shows the lowest transformation cost (based on 2015 NPV) of −$4,019 million compared to the BAU. Although the wind-nuclear II scenario generation mix has a higher cumulative GHG emission mitigation of 166 Mt CO_2 eq., its transformation cost is nearly 4 times the wind-CTG II scenario with a relatively higher cumulative GHG emissions mitigation of 121 Mt CO_2 eq. by 2050. Since CTG plants are expected to serve as backup capacity for various electricity generation from solar and wind, the actual generation dispatch from the CTG power plants is lower than in the cogeneration and combined cycle power plants. This suggests that the significant cumulative GHG emissions mitigation achieved for the wind-CTG I and II scenario generation mixes is not solely as a result of the electricity generation from the CTG plants but also the impact of the withdrawal of higher emissions-intensity subcritical coal-fired electricity generation ahead of their scheduled retirements. This result suggests that a decision to phase out some share of existing subcritical coal-fired generation capacity ahead of scheduled retirements and convert plants to gas effectively reduces GHG emissions in the electricity generation sector. However, it is much more cost effective to phase-out some share of existing coal-fired electricity generation ahead of scheduled coal retirements and replace the retired capacity with new cogeneration capacity. The results of this study would help focus the direction of policy and investment decisions for attaining sustained GHG emission reduction in the electricity generation sector. While this study has investigated various potential scenarios of renewable penetration for GHG mitigation in Alberta's electricity generation sector, the responsibility for specific development pathway will be based on balancing AESO's grid operation capability and technological preferences of key stakeholders.

Chapter 4 : Conclusions and Recommendations for Future Research

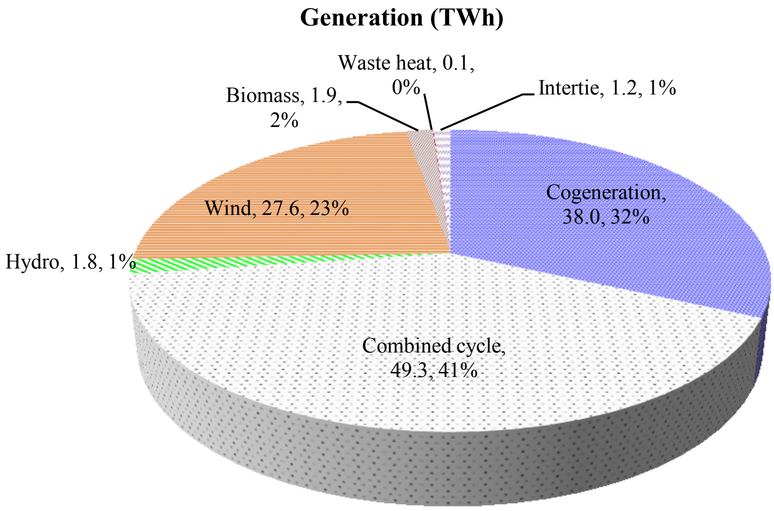
4.1 Conclusions

The electricity generation sector is crucial to the economic and infrastructural growth of any jurisdiction but it has also become important to reduce its associated environmental impacts towards achieving a sustainable development. This research is focused on assessment of GHG mitigation options in the electricity generation sector. Alberta is Canada’s third-largest electricity producer and highest in GHG emissions from the electricity generation sector. Alberta’s electricity generation sector is anticipated to transform considerably through its strategy to reduce the province’s GHG emissions. The overall objective of this research is to identify different generation mix pathways to and abatement costs in reducing GHG emissions in Alberta’s electricity generation sector within the constraints of economic growth, environmental policies, renewable energy potentials, electricity demand growth, and generation development. However, it is reasonable to conclude that the magnitude of GHG emissions reduction achievable could potentially increase in the electricity generation sector when integrated with GHG emission reduction strategies on both the demand and supply sides. This study comprehensively incorporated the results of detailed bottom-up estimates to determine the total electricity demand forecast to match with total generation. On the supply side, the integrated generation mix scenarios assumed time-bound commitments on coal-fired electricity generation phase-out and increased capacity penetration of zero- or lower-emission alternative electricity generation.

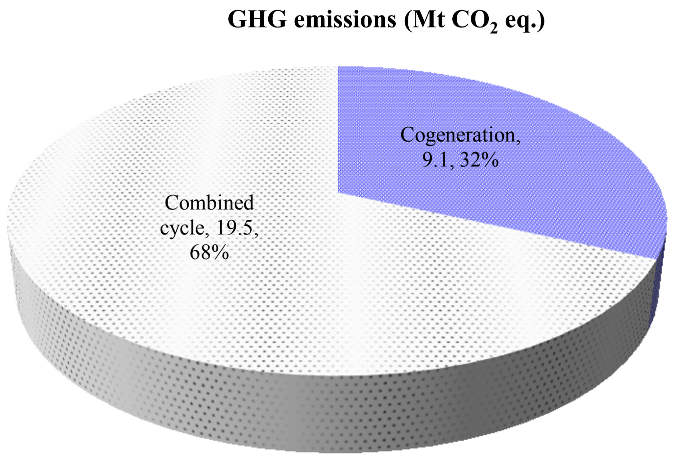
The LEAP-Alberta model was developed and used to analyze Alberta’s electricity generation sector forecasts for capacity, generation, GHG emissions, cumulative GHG mitigation potential, and GHG abatement costs of the different alternative scenario generation mixes compared to a business-as-usual (BAU) scenario in the medium (2030) and long term (2050). The methodology is used to develop first the model framework based on the structure of Alberta's electricity generation sector and then the BAU scenario generation mix. The model validation indicated that the BAU results obtained for total electricity demand, total generation, generation according to each process, and total GHG emissions match closely with published historical data for Alberta for earlier years. The shares of installed generation capacity, generation, and GHG emissions by 2050 for the BAU generation are shown in Figures 4-1 and 4-2.



(a)



(b)



(c)

Figure 4-1. Shares of installed capacity (a), generation (b), and GHG emissions (c) BAU generation mix by 2050

The scenarios developed show that Alberta's electricity generation sector has the potential to cut its GHG emissions to 21.5 – 26.4 Mt CO_2 eq. below 2014 levels by 2030. The emissions reduction potential of the BAU and other alternative scenarios are shown in Figure 4-2. Factors that limit the magnitude of reduction are the timing of the phase-out of coal-fired electricity generation by 2030 and the share of alternative zero- or low-carbon electricity generation capacity introduced to replace the baseload capacity of coal-fired electricity generation. The deepest cuts in GHG emissions are observed in scenarios associated with earlier phase-outs of coal-fired generation capacity, for retirement or for conversion to gas-fired capability, and also in integrated scenarios with geothermal and nuclear capacities in the generation mix. The Alt-BAU scenario, which assumed an earlier-than-anticipated phase-out of coal-fired electricity generation and a higher renewable capacity of approximately 11,328 MW to generate about one-third of total electricity generation by 2030, showed in the highest emissions reduction potential of 26.4 Mt CO_2 eq. (54% emissions reduction) compared to 2014 levels.

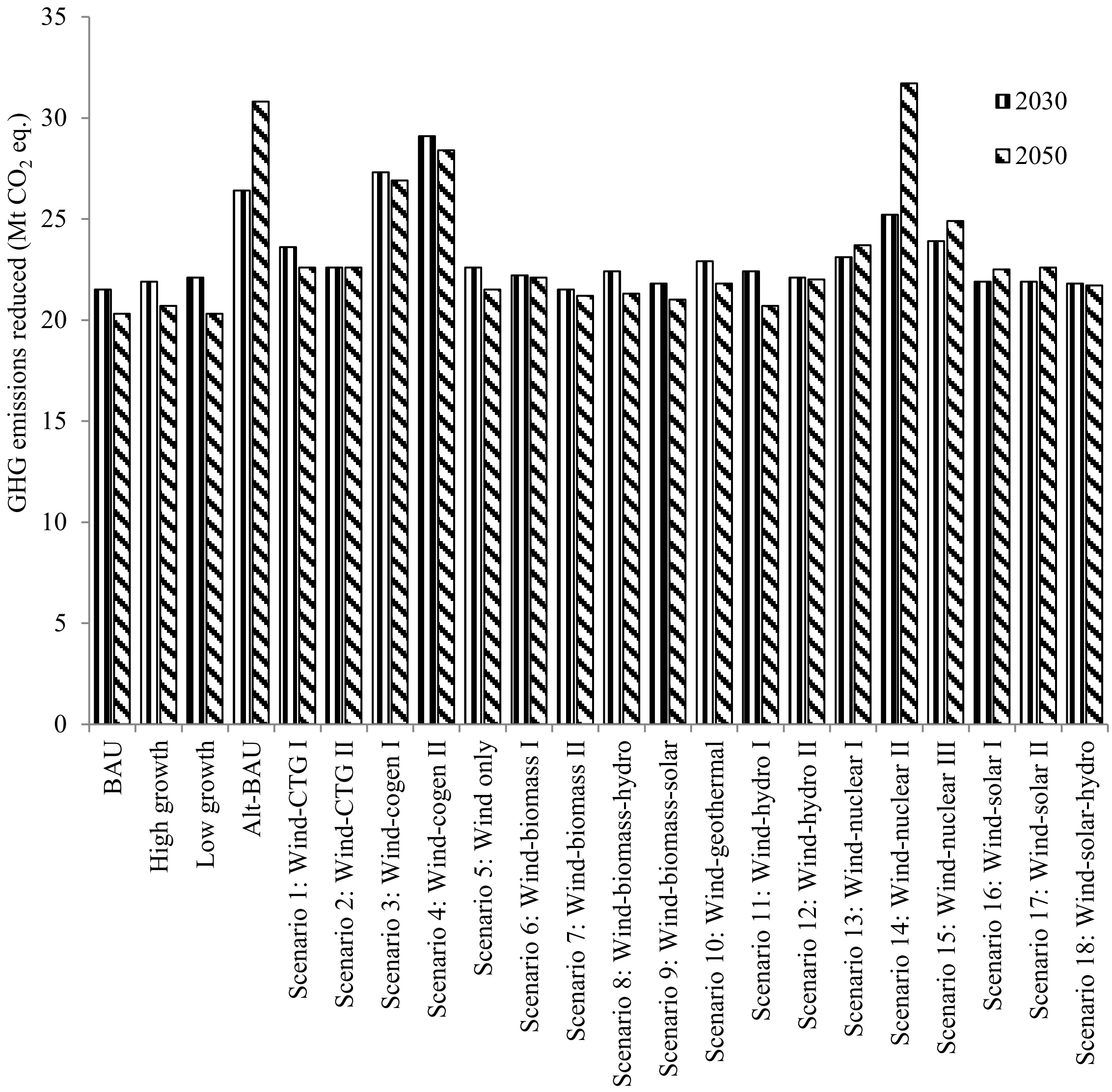


Figure 4-2. Reduction in GHG emissions by 2030 and 2050, compared to actual 2014 levels

The LEAP-Alberta model results for Alberta's electricity generation sector show that with increasing demand, the penetration of combined gas-fired electricity generation capacity to support the baseload beyond 2030 marginally increases GHG emissions in the long term, even with increasing shares of renewable electricity generation capacity. Annual GHG emissions for the generation mix scenarios investigated are sustained below 29 Mt CO_2 eq. between 2030 and 2050. However, there is a more consistent GHG emissions reduction impact in the longer term with the penetration of nuclear electricity generation to replace gas-fired combined cycle electricity generation. This is because nuclear electricity generation can adequately support baseload generation with no GHG emissions. Although a previous effort at nuclear electricity generation in Alberta was not successful, future consideration could be given to nuclear generation as a replacement for gas-fired electricity generation in the long term (and to sustain GHG emissions reduction).

This study also developed GHG abatement cost curves to assess the cumulative GHG mitigated and abatement costs of different generation mix scenarios compared to the BAU. The wind-cogen I scenario generation mix is the most attractive of the scenarios both in terms of cumulative GHG mitigated and abatement and transformation costs compared to the BAU. The cost curve for Alberta's electricity generation sector is shown in Figure 4-3.

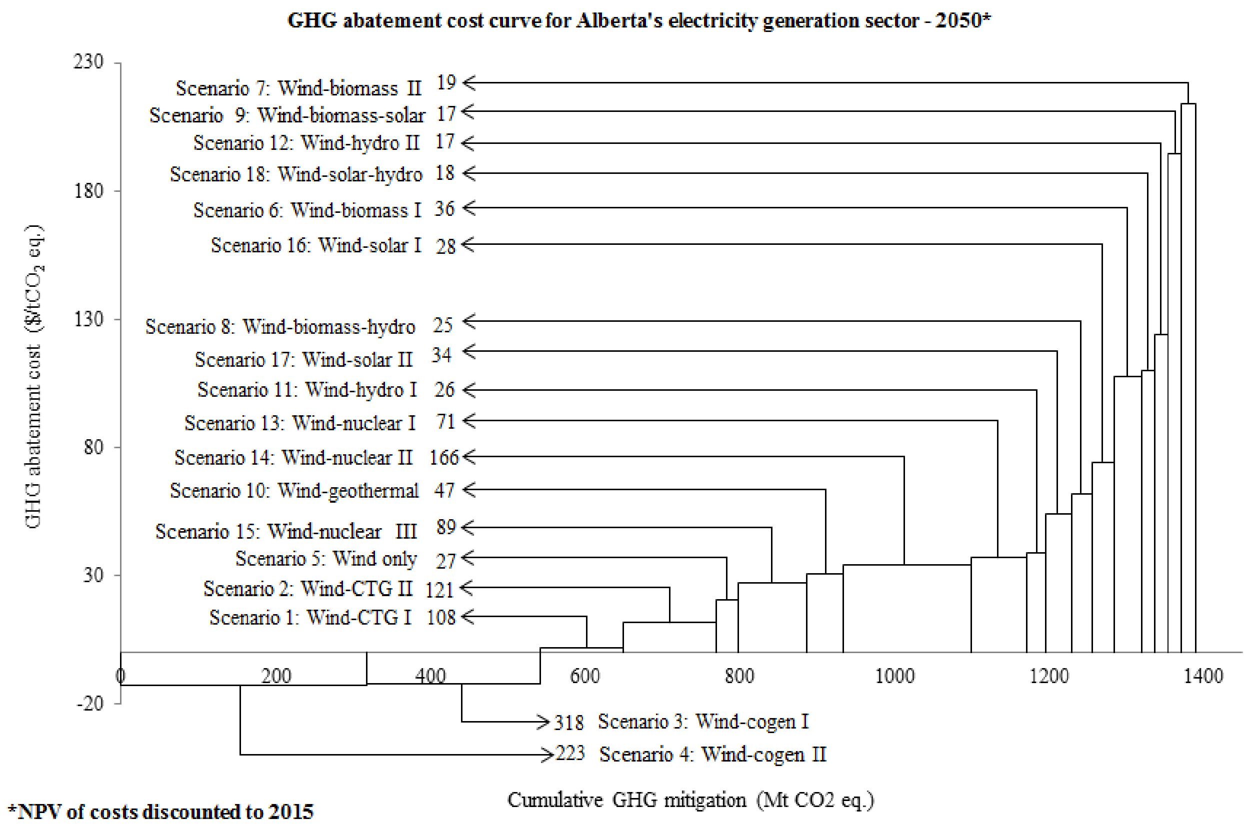


Figure 4-3. GHG abatement cost curve for Alberta's electricity generation sector (2010-2050)

While our study found that Alberta has large potential to use its renewable energy resources to reduce electricity sector GHG emissions, it is necessary to be cautious of generation over-capacity challenges and excessive investment burden in the electricity transmission infrastructure required to deliver these resources to remote locations. It is also important to note that Alberta's electricity market is also transitioning from an energy-only market to a capacity market in order to mitigate wholesale electricity pricing uncertainties and protect consumers.

In general, the methodology presented in this study is useful as a basis for analyzing future GHG emissions reduction potential of the fossil-fuel dominated electricity generation mix in other jurisdictions, taking into account the impact of fuel and carbon price changes.

4.2 Recommendations for future work

Considering the typical challenges of reducing GHG emissions and sustaining reliability in a sector that depends on an emissions-intensive fossil fuel electricity generation mix, further studies should focus on:

- Investigating GHG mitigation scenarios for Saskatchewan's electricity generation sector, which, like Alberta's, is fossil-fuel dominated and is responsible for the second-largest share of GHG emissions in Canada's electricity generation sector.
- Simulating large-scale grid-connected battery storage and other energy storage capabilities of different power plants in a generation mix to further reduce GHG emissions. In the past, theoretical explanations have justified concerns about the stability and reliability of the grid transmission system to handle high electricity generation from intermittent renewables. However, this has not been found to be a significant risk for European utility operators that have successfully managed their total electricity generation with up to 50% wind electricity generation. A further action to mitigate risks of grid stability from intermittent renewable electricity generation is the application of a grid-connected battery infrastructure for storing excess energy.

Such infrastructure is rapidly gaining significance in some utilities in North America, and in Alberta the rules governing the operating and technical requirements of battery storage facilities have been in effect since 2016. AESO is presently reviewing existing rules and developing rates for grid-connected battery storage. The capability of the LEAP model software to incorporate battery storage is under development in anticipation of future grid transformation and implications for GHG emissions for the electricity generation sector. The development of a LEAP-Alberta model to assess the mitigation potential and cost benefits of scenarios related to battery storage may provide insights for policy formulation and electricity generation planning.

- Lastly, the implementation of output-based allocation (OBA) policies to determine an emissions performance baseline for thermal power plants would stimulate technological innovation among electricity producers that would help reduce GHG emissions. Increasing the efficiency of combined cycle electricity generation has a very high potential to reduce GHG emissions. A detailed assessment of scenarios relating to future efficiency improvement opportunities and technological changes in thermal electricity generation could complement GHG mitigation options that re-evaluate the need for additional new generation capacity and subsequent higher capital investments.

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Appendix A

Table A1. Summary of generation mix scenarios and key assumptions

Scenario	Acronym	GHG mitigation	Key assumptions
Business-as-Usual	BAU	New wind and gas generation capacities added to the generation mix.	4.2 GW new wind capacity to replace two-thirds of 6.3 GW retired coal capacity by 2030. 350 MW new wind generation capacity added each year from 2018 to 2029. Total installed wind generation capacity is 4.2 GW and 6.8 GW by 2030 and 2050, respectively. Approximately 9.2 GW of new capacity addition from natural gas-fired cogeneration (1.1 GW), combined cycle (6.8 GW) and simple cycle (1.3 GW) by 2030. Total projected generation capacity by 2050 is 32 GW. Capacity additions from 2037 to 2050 are extrapolated from AESO's growth projections [60] between 2027 and 2037.
Scenario 1	Wind-CTG I	5 GW new wind and conversion of approx. 44% capacity share of existing subcritical coal plants converted to gas (CTG) between 2021 and 2023.	2.4 GW out of the existing subcritical coal capacity of 5.4 GW is assumed for conversion to gas. It is anticipated that TransAlta's Sundance 3 to 6 and Keephills 1 and 2 coal power plants would be converted to gas-fired generation between 2021 and 2030 [145].
Scenario 2	Wind-CTG II	5GW new wind and 60% capacity share of existing subcritical coal plants	Higher capacity penetration of CTG plants into the generation mix 3.9 GW out of the existing subcritical coal capacity of 5.4 GW is assumed for conversion to gas based on the anticipated CTG capacity and additional

Scenario	Acronym	GHG mitigation	Key assumptions
		converted to gas between 2021 and 2023.	1.5GW of ATCO's Battle River and Sheerness subcritical coal-fired power plants before the end of 2020 [146].
Scenario 3	Wind-cogen I	5 GW new wind and 2.4 GW gas-fired cogeneration capacity to replace subcritical coal capacity between 2021 and 2023.	This scenario is an alternative to wind-CTG I scenario generation mix. Early retirement of 2.4 GW subcritical coal capacity, but instead of conversion to gas, replaced with gas-fired cogeneration plants.
Scenario 4	Wind-Cogen II	5 GW new wind and 3.8 GW gas-fired cogeneration capacity to replace subcritical coal capacity between 2020 and 2023.	Higher capacity penetration of gas-fired cogeneration capacity into the generation mix. This scenario is an alternative to wind-CTG II scenario generation mix. Early retirement of 3.9 GW subcritical power plant capacity, but instead of conversion to gas, it is replaced with gas-fired cogeneration plants.
Scenario 5	Wind only	5GW new renewable generation capacity from wind only by 2030.	Based on AESO's renewable electricity program, the target is to achieve 5 GW of additional renewable capacity by 2030 [164]. Wind electricity generation capacity increased to approximately 6.5 GW and 6.6 GW of new natural gas-fired combined cycle generation capacity by 2030. It is assumed that 5 GW out of 6.3 GW retired coal capacity will be replaced by wind only by 2030. Total projected generation capacity at 2050 is approximately 32 GW.
Scenario 6	Wind-biomass I	5GW wind and biomass capacity added to the generation mix by 2030.	The biomass feedstock assumed in this scenario is agricultural straw. 1 GW of biomass electricity generation capacity to replace equivalent share of new natural gas combined cycle capacity between 2030 and 2050.

Scenario	Acronym	GHG mitigation	Key assumptions
Scenario 7	Wind-biomass II	5GW combined wind and biomass capacity added to the generation mix by 2030.	Similar to wind-biomass I, the biomass feedstock assumed in this scenario is agricultural straw. However, higher capacity penetration of biomass is assumed. 2 GW biomass electricity generation capacity with 1 GW each penetration of biomass electricity generation capacity by 2030 and 2050, respectively.
Scenario 8	Wind-biomass-hydro	5 GW combined wind, biomass and hydro capacities added to the generation mix by 2030.	New renewable generation capacity of 5 GW made up of wind (3.5 GW), biomass (0.4 GW) and hydro (0.33 GW) by 2030. It is assumed that 1.2 GW of forest residues biomass electricity generation capacity may be possible by 2050 [69]. Total projected generation capacity by 2050 is approximately 32 GW.
Scenario 9	Wind-biomass-solar	5GW combined wind, solar and biomass capacities added to the generation mix by 2030.	New renewable generation capacity of 5 GW by 2030 made up of wind (2.8 GW), biomass (0.4 GW) and solar (1 GW).Installed capacity of wind, solar and solar electricity generation increased to approximately 6.9 GW by 2030. It is assumed that 10% (0.1 GW) share of total installed solar capacity of 1GW will be transmission-connected and remaining 90% (0.9 GW) connected to the distribution grid (micro-generation).
Scenario 10	Wind-geothermal	5GW combined wind and geothermal capacity added to the generation mix by 2030.	0.5 GW of geothermal electricity generation by 2050 with 25 MW of new geothermal electricity generation capacity to be added each from 2028 to 2047. Initial estimates in the range of 0.3-0.5 GW geothermal electricity generation may be possible in the future [92]. This assumption was considered valid based on initial results confirmed by communication with an industry expert [154].

Scenario	Acronym	GHG mitigation	Key assumptions
Scenario 11	Wind-hydro I	5 GW combined wind and hydro capacities added to the generation mix by 2030.	New renewable generation capacity of 5 GW by 2030 made up of wind (4.7 GW) and hydro (0.33 GW). Similar to AESO's alternate scenario, it is assumed that up to 1.1 GW of new hydro generation capacity may be possible by 2037 with support from AESO's proposed renewable electricity program. Capacity of hydro and wind electricity generation increased to approximately 2 GW and 6.1 GW, respectively by 2037. Total projected generation capacity by 2050 is approximately 32 GW.
Scenario 12	Wind-hydro II	5 GW wind and hydro capacity added to the generation mix by 2030.	Higher hydro capacity penetration into the generation compared to wind-hydro I scenario generation mix. 2.2 GW of new hydroelectricity generation capacity to be incorporated into the generation mix by 2050. The penetration of hydroelectricity generation capacity is modelled similar to AESO's alternate scenario (mid-growth policy) [60]. The potential for hydroelectricity generation in Alberta is 11.8 GW.
Scenario 13	Wind-nuclear I	5 GW wind and nuclear electricity generation capacity added to the generation mix by 2030.	0.75 GW nuclear capacity to replace equivalent capacity of new cogeneration capacity in 2030 and 2044 compared to the BAU.
Scenario 14	Wind-nuclear II	Wind and nuclear electricity generation capacity added to the generation mix by 2030.	Higher nuclear capacity penetration into the generation mix. Nuclear to replace equivalent new generation capacity from combined cycle capacity by 2030 and 2050 compared to the BAU. 3.75 GW nuclear electricity generation capacity by 2050. 1.5 GW in 2030, 3 GW in 2037 and 2045. A previously proposed 4 GW nuclear power plant in Northern Alberta was shelved [165].

Scenario	Acronym	GHG mitigation	Key assumptions
Scenario 15	Wind-nuclear III	Wind and nuclear capacities added to the generation mix by 2030.	Installed capacity of nuclear and wind electricity generation capacity is 1.2 GW and 4.5 GW (5.7 GW in the BAU), respectively by 2030. It is assumed that the nuclear electricity generation is introduced by 2030.
Scenario 16	Wind-solar I	5 GW combined wind and solar renewable generation capacity added to the existing generation mix by 2030.	1GW penetration of solar electricity generation modelled similar to AESO's alternate scenario (mid-growth policy) [60]. Similar to the generation mix in Ontario province, it further assumed that 10% (0.1 GW) of total installed solar capacity of 1 GW will be connected to the transmission grid and remaining 90% (0.9 GW) connected directly to the distribution system through micro-generation.
Scenario 17	Wind-solar II	5 GW combined wind and solar generation capacities added to the generation mix by 2030.	New renewable generation capacity of 5GW made up of wind (4 GW) and solar (1 GW) by 2030. It is assumed that 10% (0.1 GW) share of total installed solar capacity of 1 GW will be connected to the transmission grid and remaining 90% (0.9 GW) connected to the distribution grid (micro-generation). As of Q2 2015, grid-connected solar generation in Ontario province is about 8% (140 MW) of total installed solar generation capacity of 1.8 GW [150].
Scenario 18	Wind-solar-hydro	5 GW combined wind, solar and hydro capacity added to the generation mix by 2030.	New renewable generation capacity of 5 GW made up of wind (3.7 GW), solar (1 GW) and hydro (0.33 GW) by 2030. Same as scenario 4 above, it is assumed that 10% (0.1 GW) share of total installed solar capacity of 1 GW is transmission-connected and remaining 90% (0.9 GW) is distribution system-connected as micro-generation.

Appendix B

Table B1. Transformation cost assumptions

Transformation costs	Comments
Capital cost	As shown in Table 2-2 and 3-1. Forecast based on projected growth rates of investment costs between 2015 and 2040 for gas and renewable electricity generation technology and assumed technology learning rates [166].
Fixed & variable operating and maintenance (O&M) costs	As shown in Table 2-2 and 3-1. Forecast assumed 2% based on average annual inflation rates [166].
Interest rate	Assumed 5%.
Fuel Cost	NEB gas pricing forecasted up to 2040 and extrapolated to 2050 [114].
Carbon price	Emissions reduction limits of 15% and 20% and a carbon price of \$20/ton and \$30/ton, respectively, in 2016 and 2017. Carbon price to increase based on inflation plus 2% from 2018. [14, 116].

Appendix C

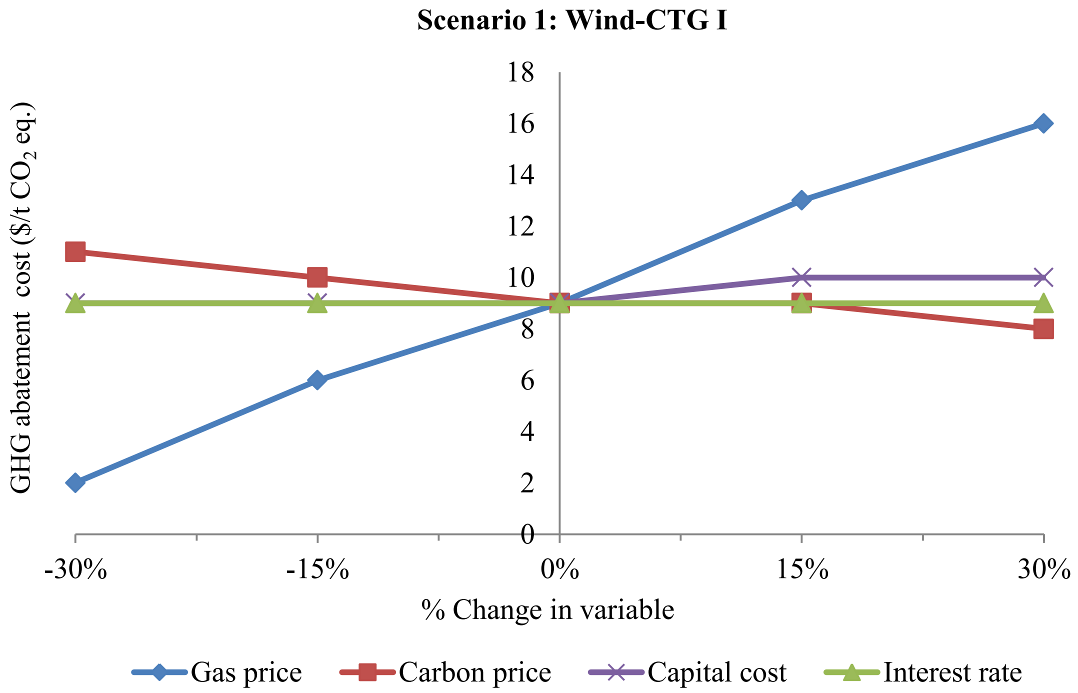

Fig. C. 1. Sensitivity analysis graph for wind-CTG I scenario generation mix by 2030

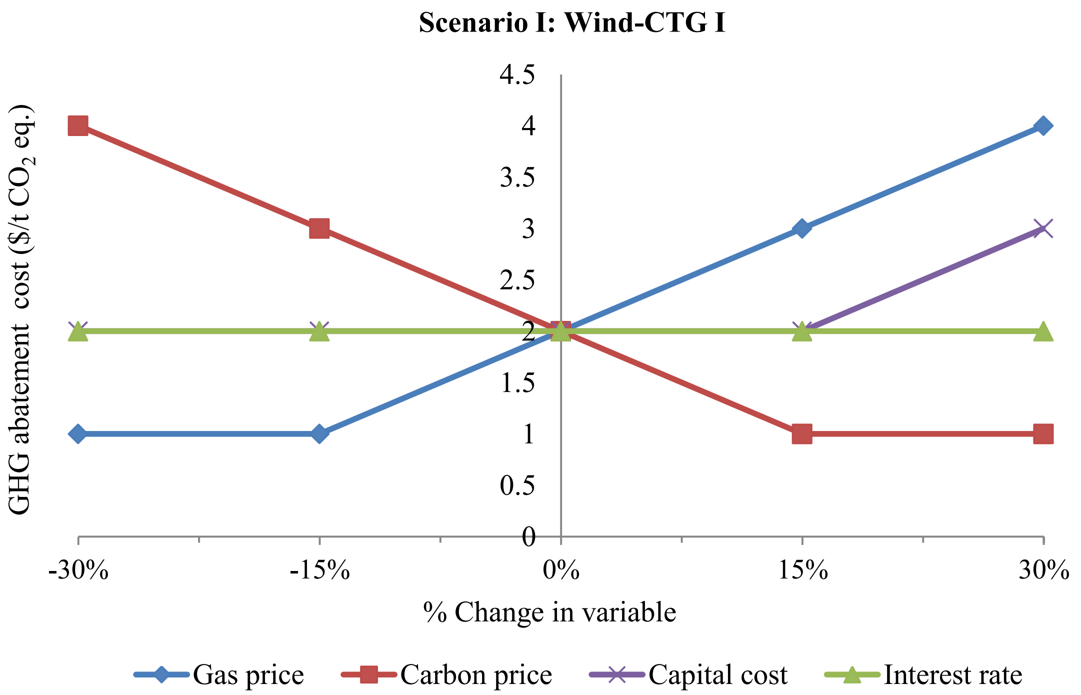

Fig. C.2. Sensitivity analysis graph for wind-CTG I scenario generation mix by 2050

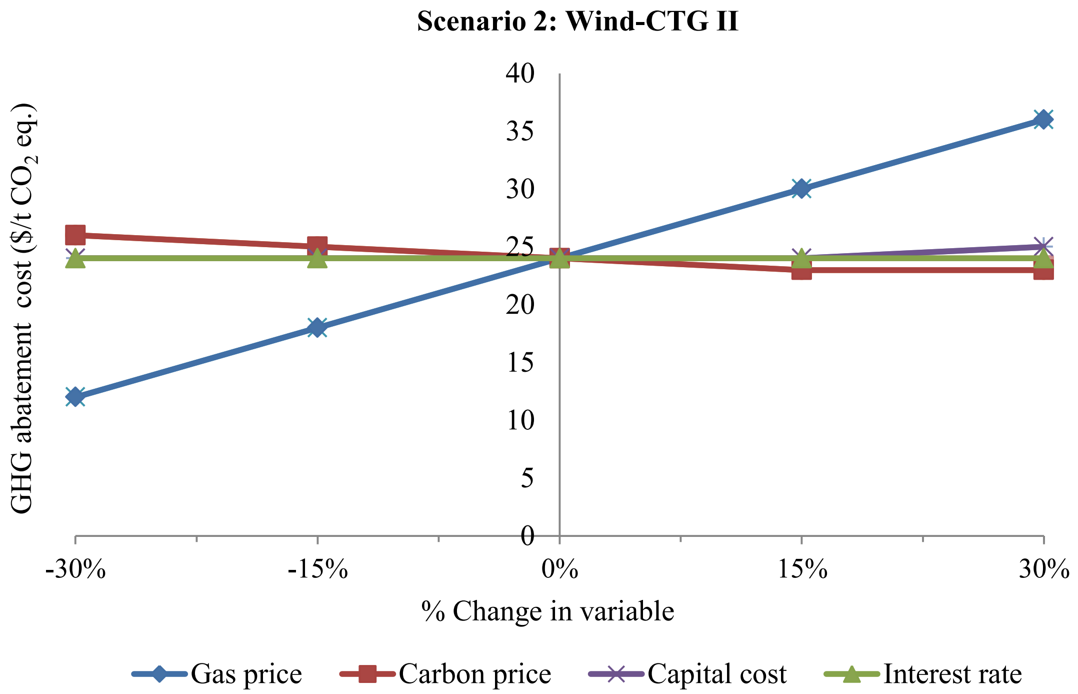

Fig. C.3 Sensitivity analysis graph for wind-CTG II scenario generation mix by 2030

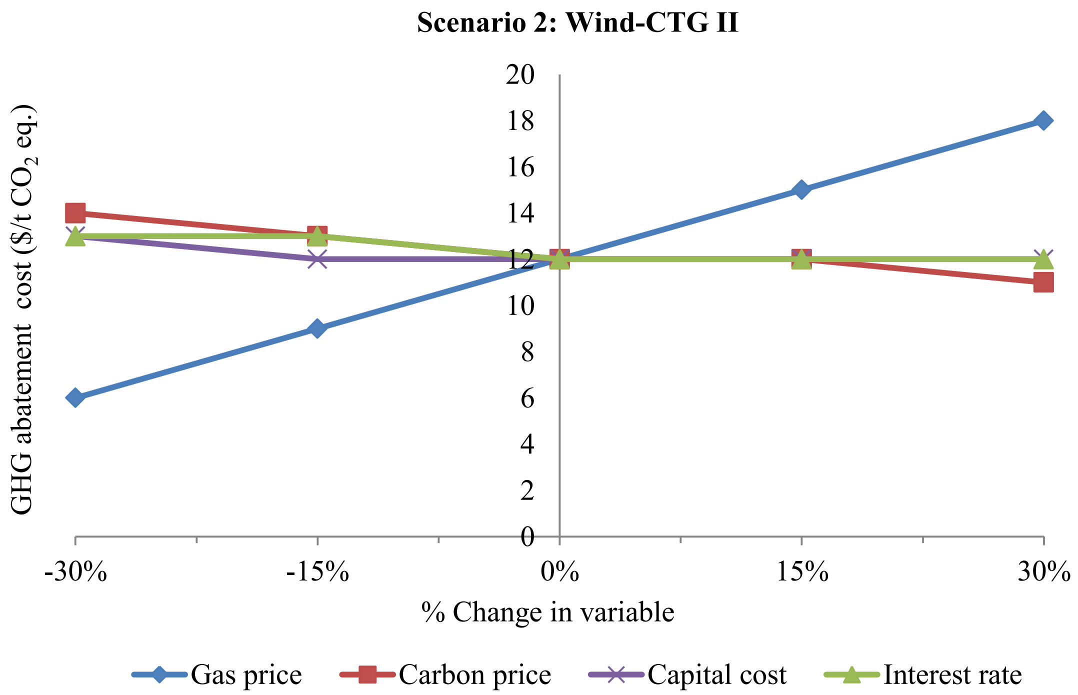

Fig. C 4 Sensitivity analysis graph for wind-CTG II scenario generation mix by 2050

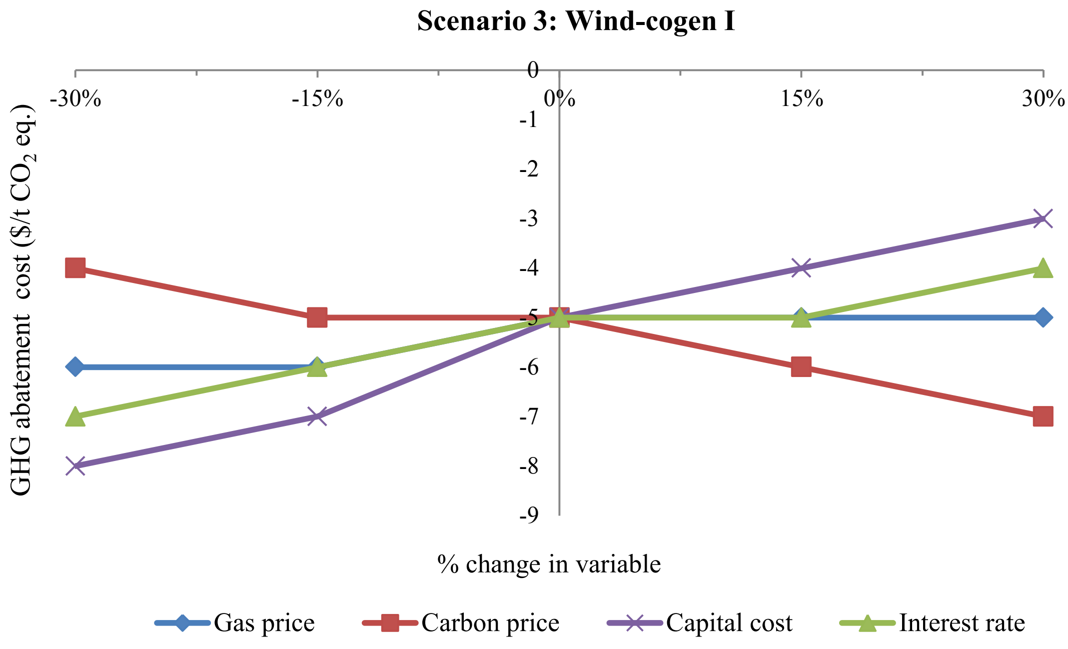

Fig. C.5. Sensitivity analysis graph for wind-cogen I scenario generation mix by 2030

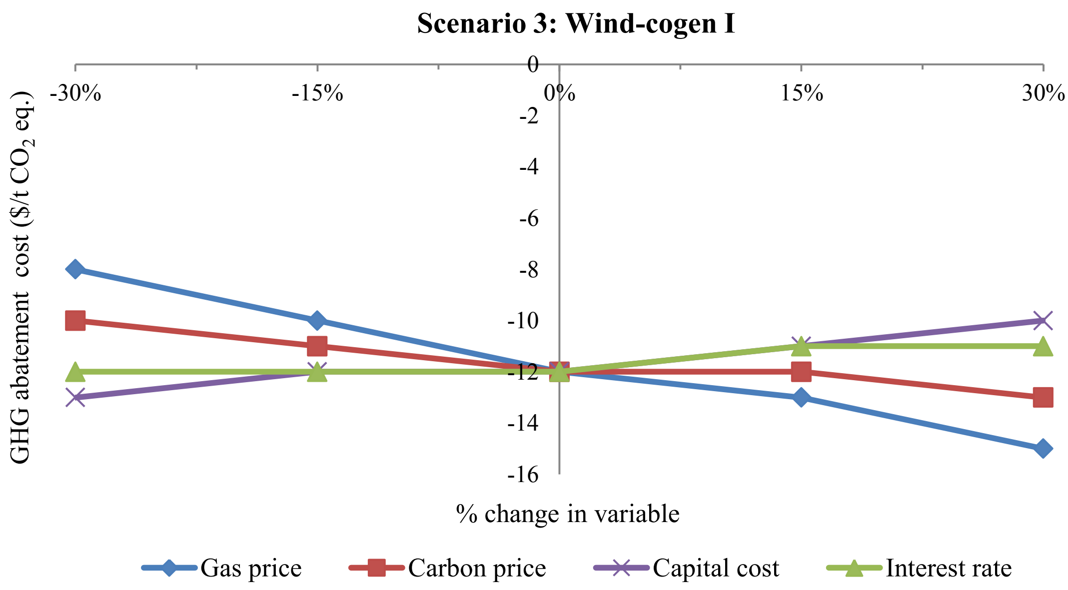

Fig. C.6. Sensitivity analysis graph for wind-cogen I scenario generation mix by 2050

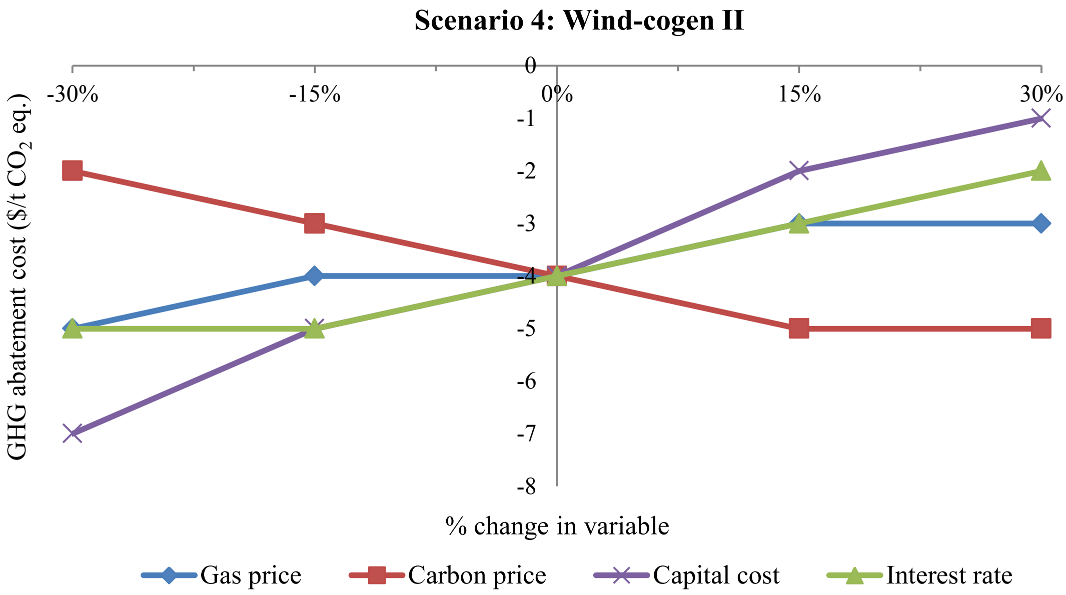

Fig. C.7. Sensitivity analysis graph for wind-cogen II scenario generation mix by 2030

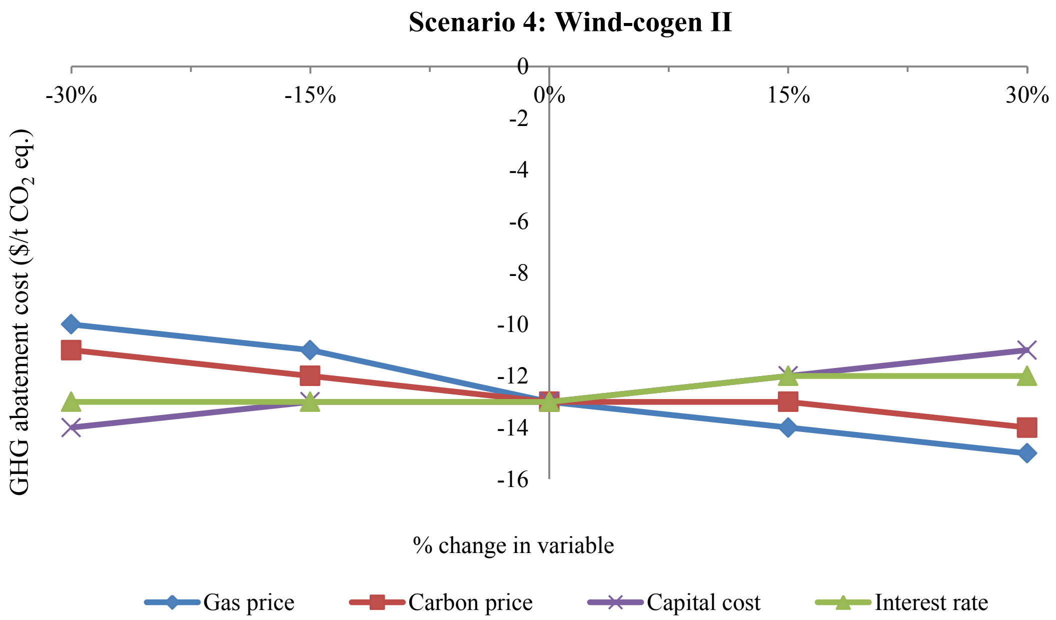

Fig. C.8. Sensitivity analysis graph for wind-cogen II scenario generation mix by 2050

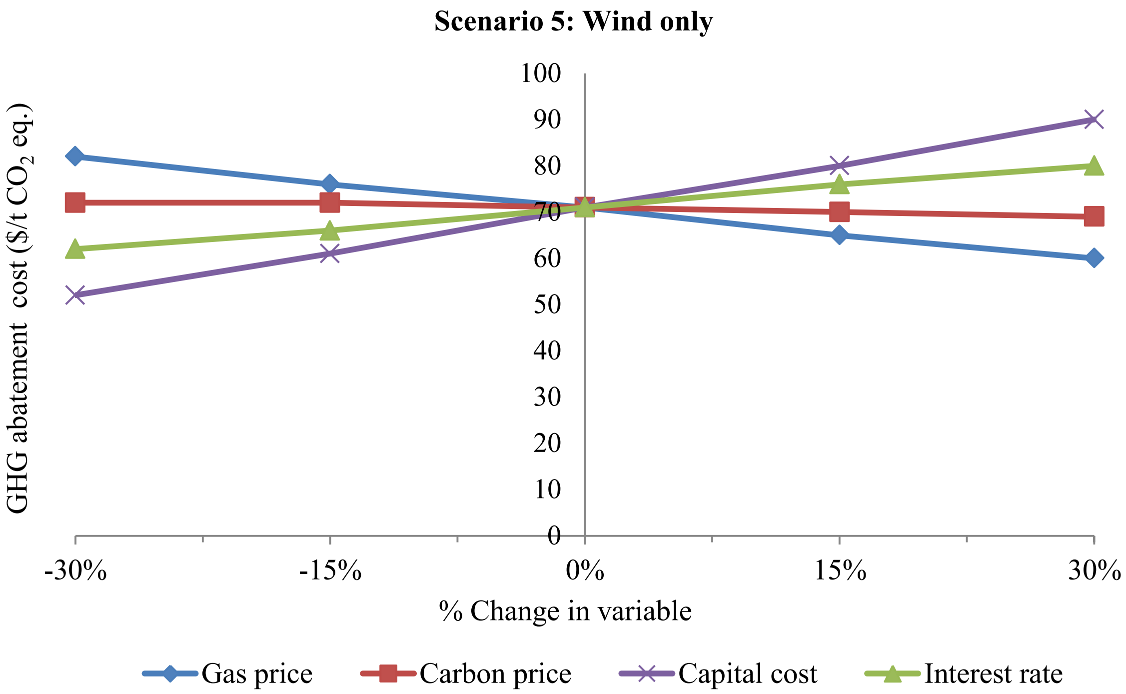

Fig. C.9. Sensitivity analysis graph for wind-only scenario generation mix by 2030

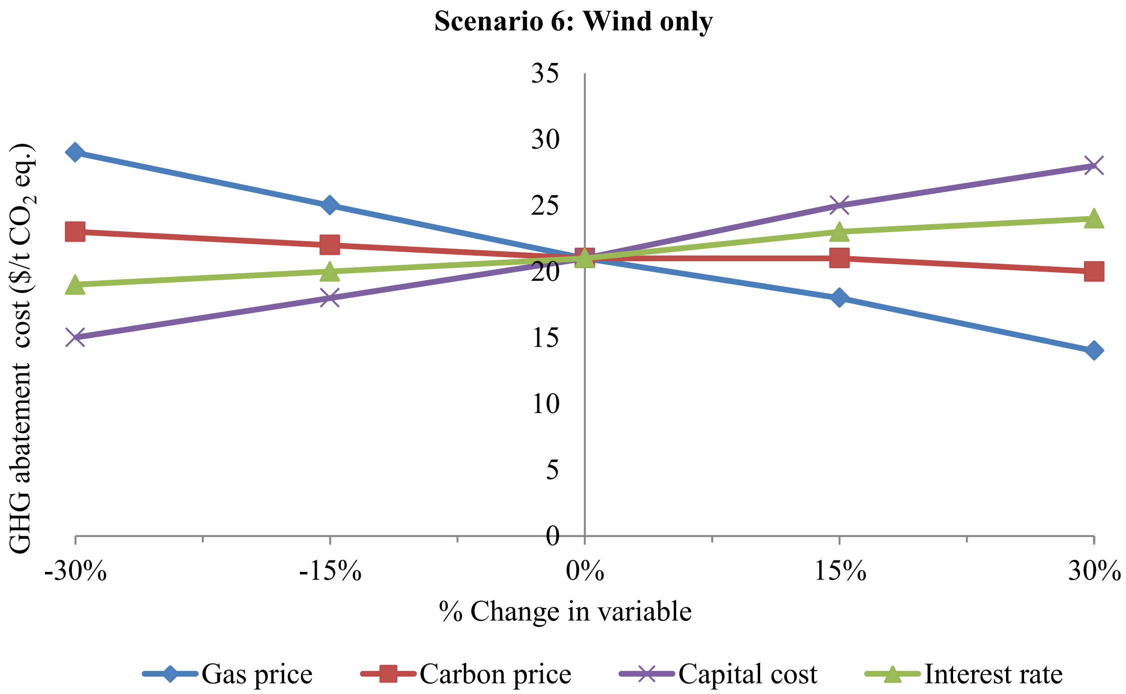

Fig. C.10. Sensitivity analysis graph for wind only scenario generation mix by 2050

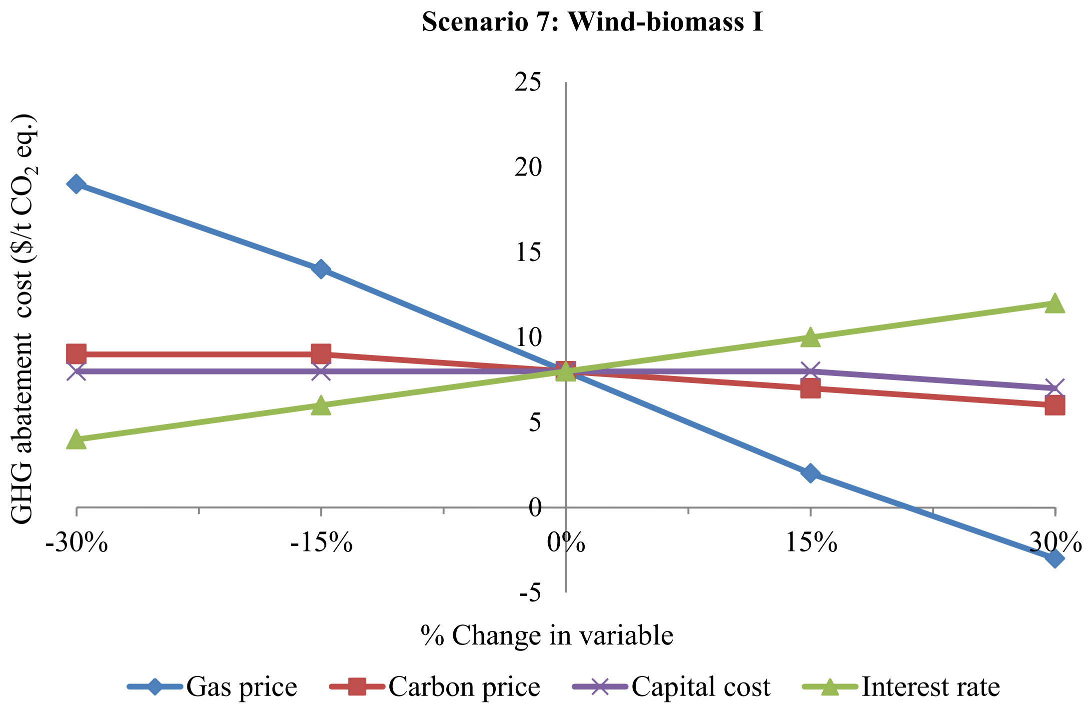

Fig. C.11. Sensitivity analysis graph for wind-biomass I scenario generation mix by 2030

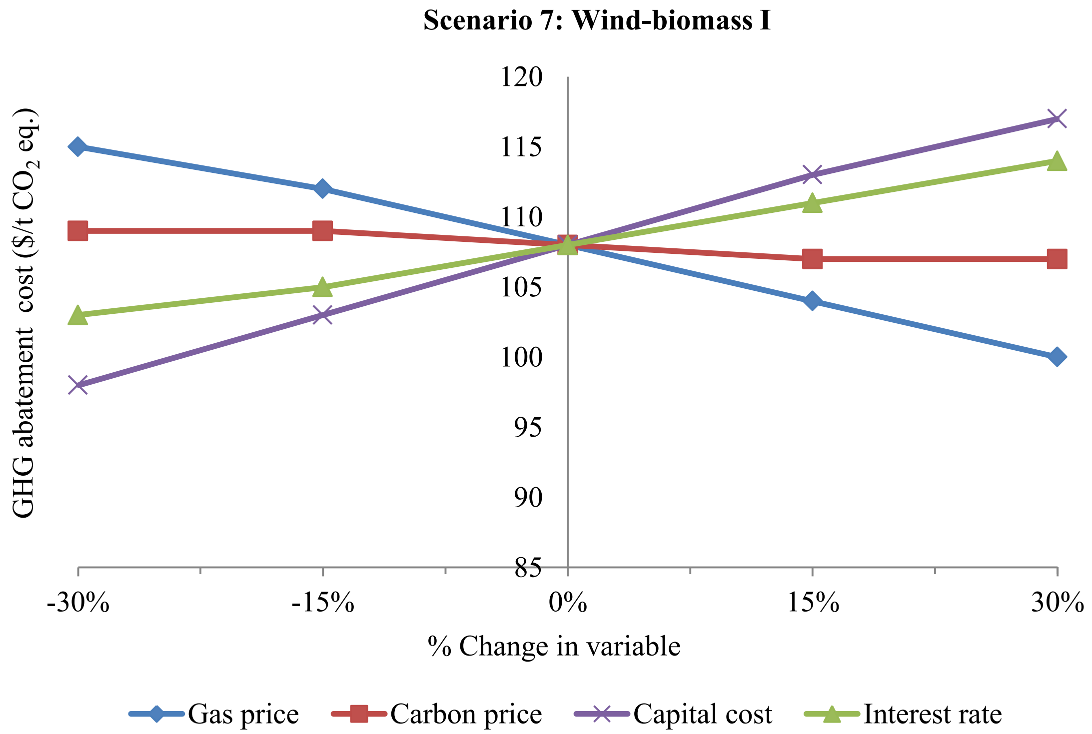

Fig. C. 12. Sensitivity analysis graph for wind-biomass I scenario generation mix by 2050

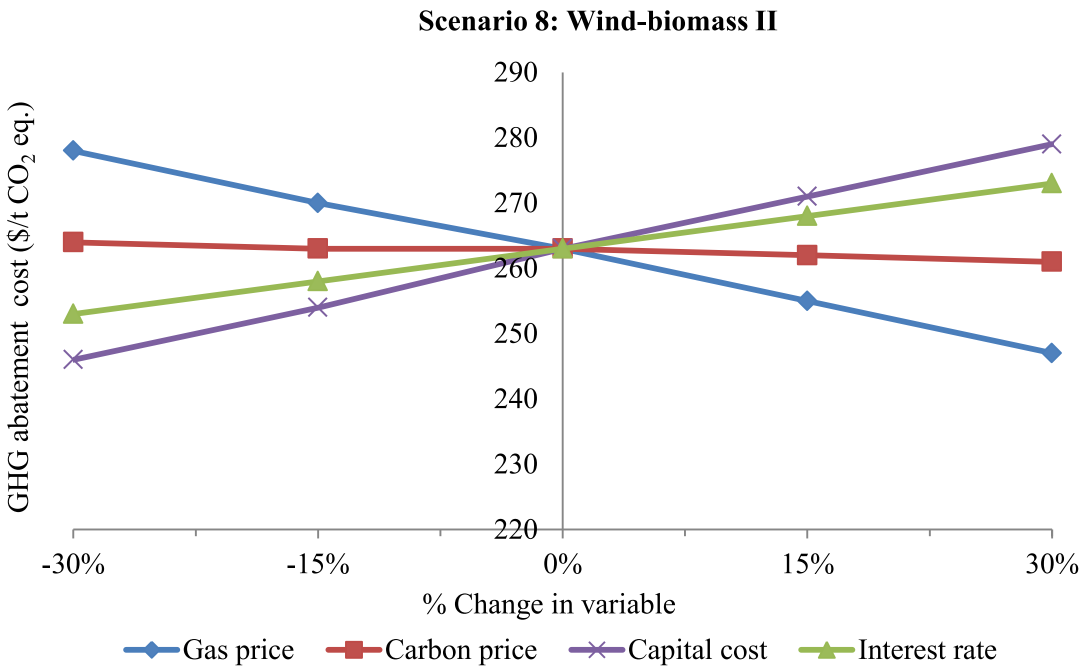

Fig. C.13. Sensitivity analysis for wind-biomass II scenario generation mix by 2030

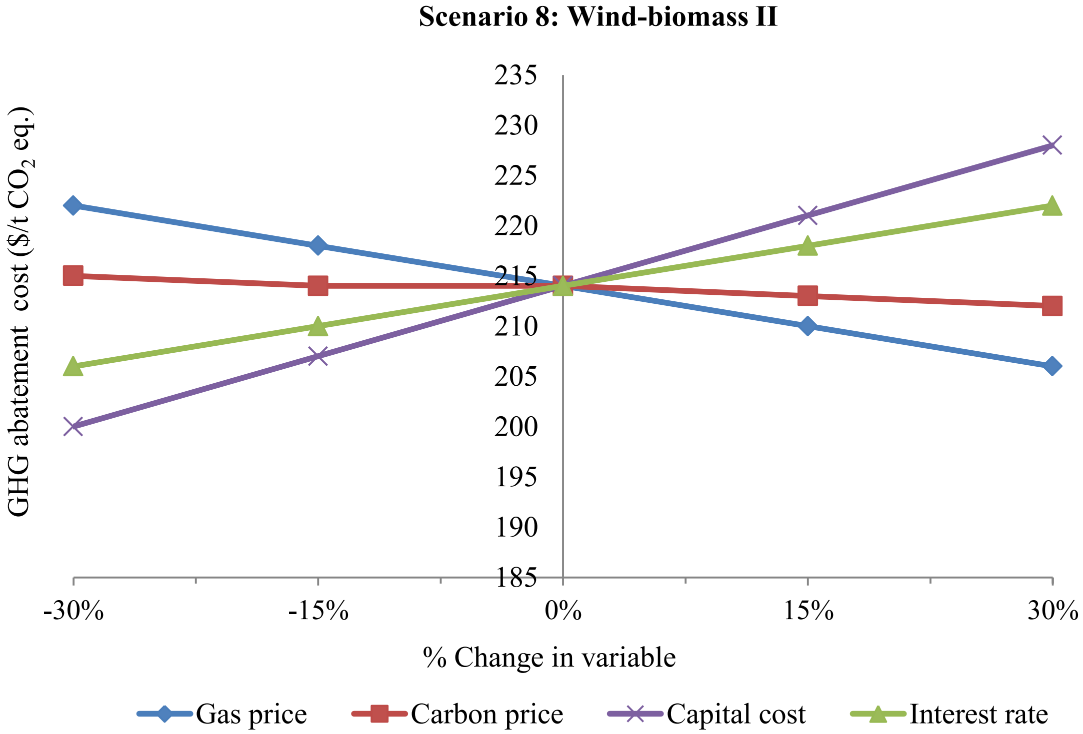

Fig. C.14. Sensitivity analysis graph for wind-biomass II scenario generation capacity mix by 2050

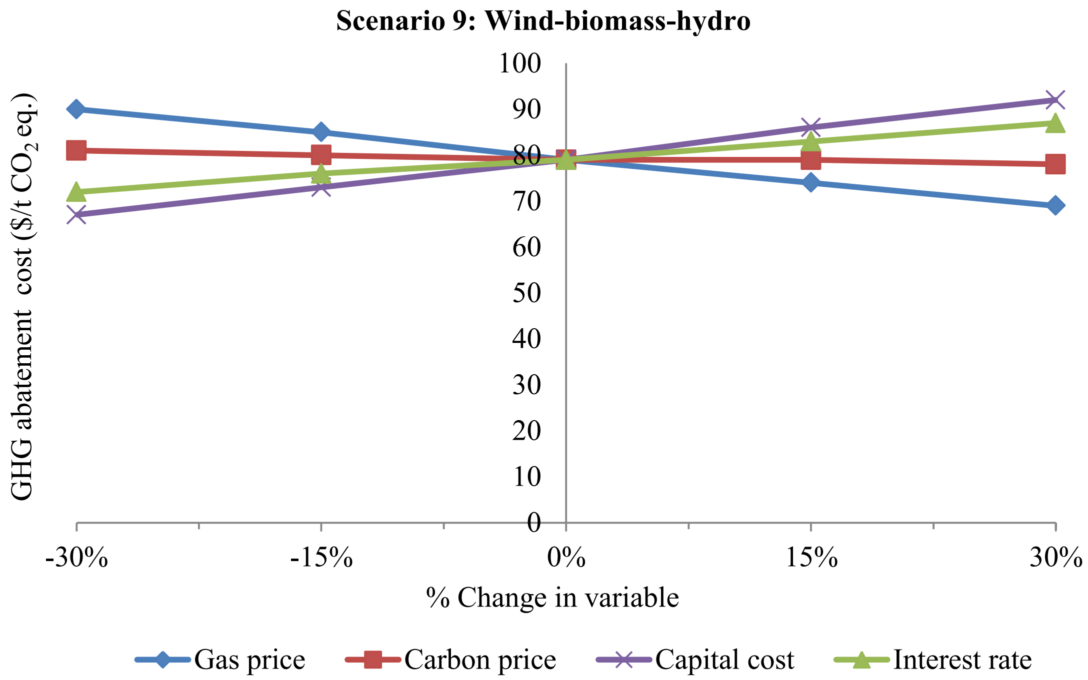

Fig. C. 15. Sensitivity analysis for graph wind-biomass-hydro scenario generation mix by 2030

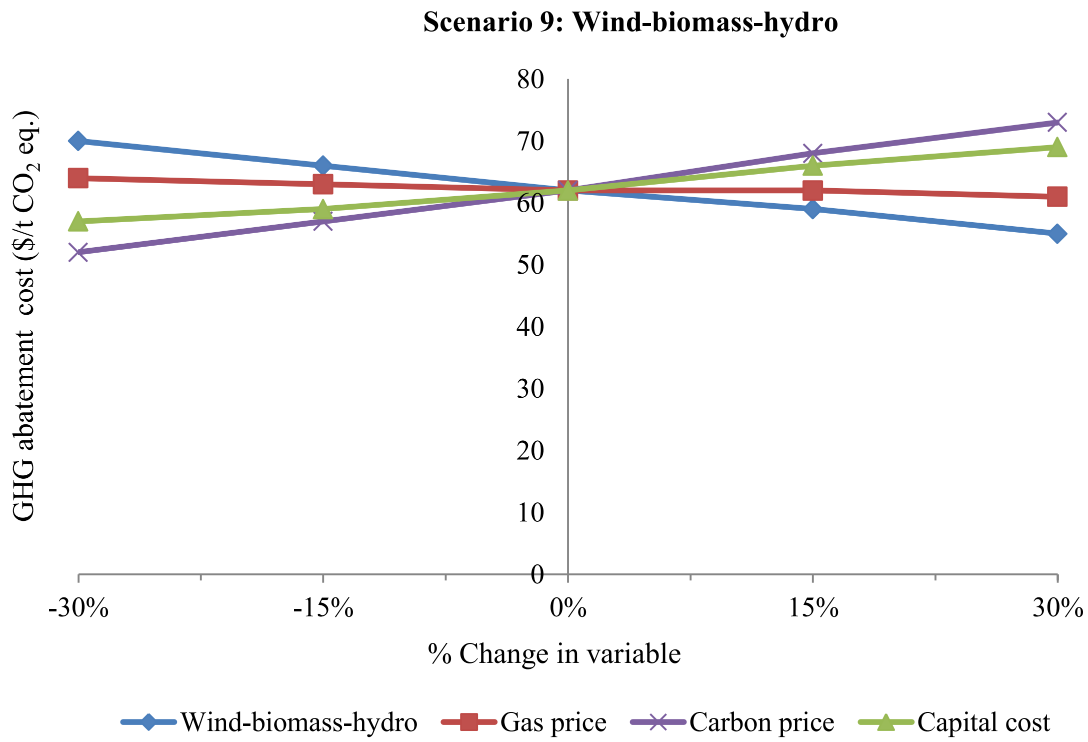

Fig. C.16. Sensitivity analysis graph for wind-biomass-hydro scenario generation mix by 2050

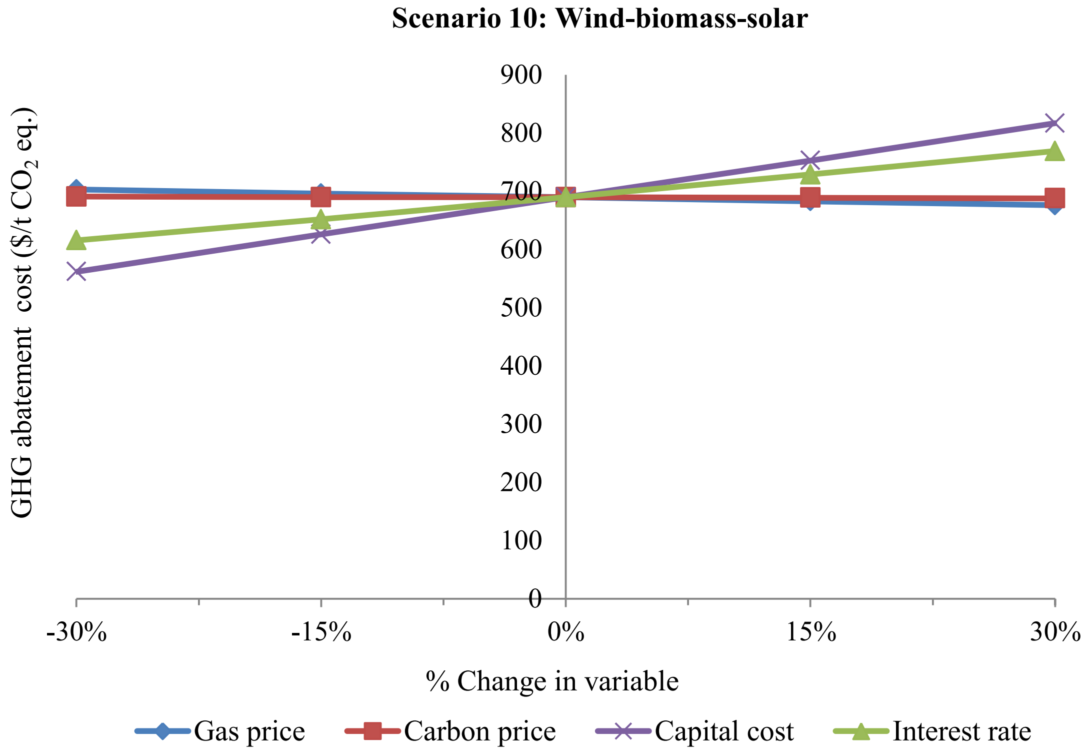

Fig. C.17. Sensitivity analysis graph for wind-biomass-solar scenario generation mix by 2030

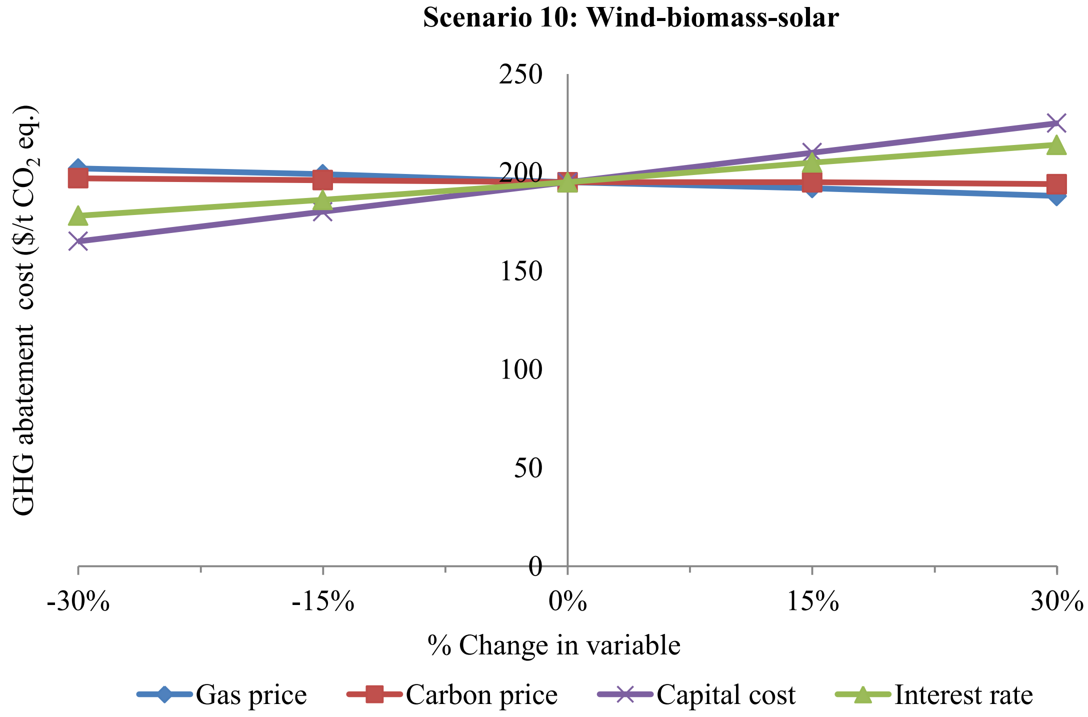

Fig. C. 18. Sensitivity analysis graph for wind-biomass-solar scenario generation mix by 2050

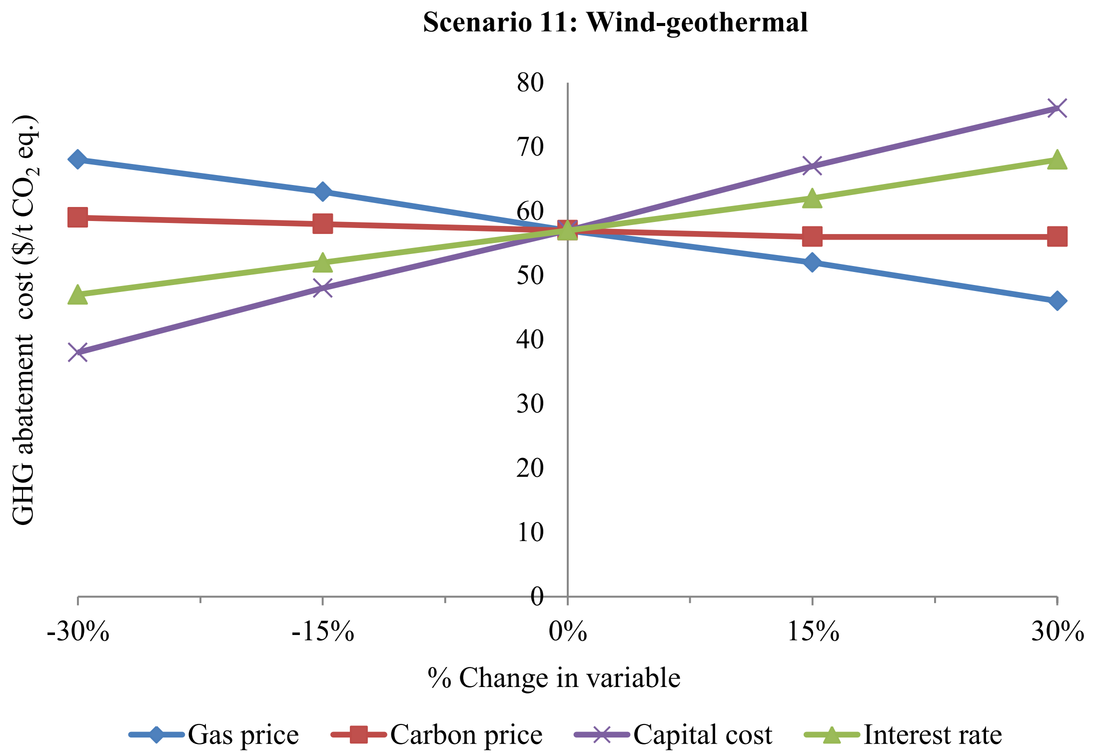

Fig. C.19. Sensitivity analysis graph for wind-geothermal scenario generation mix by 2030

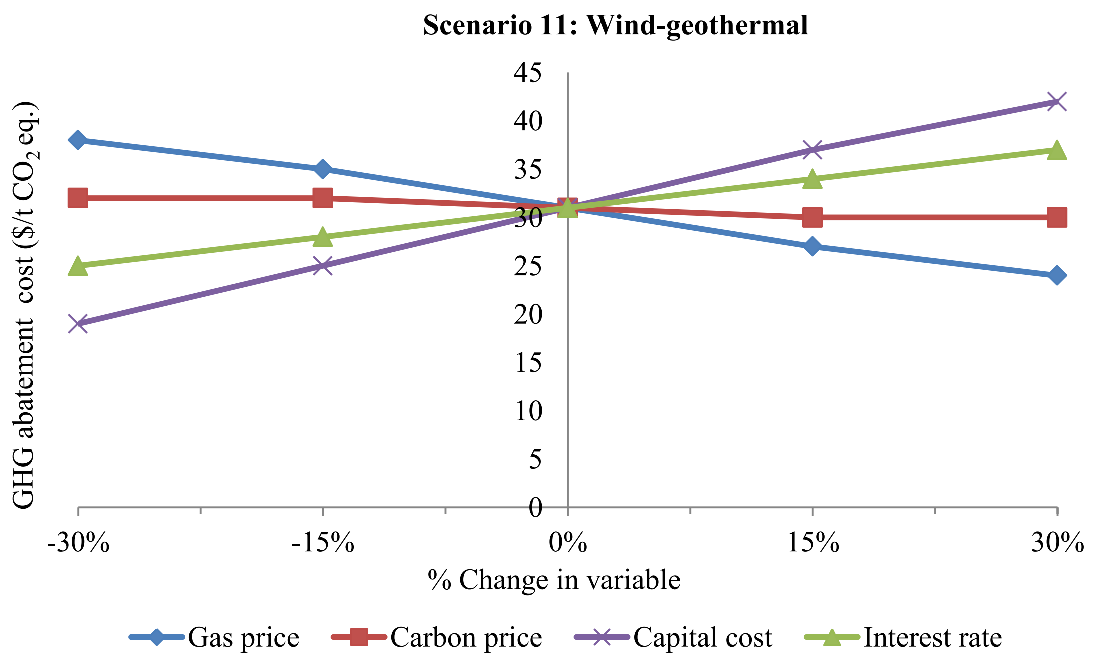

Fig. C. 20. Sensitivity analysis graph for wind-geothermal-Solar scenario generation mix by 2050

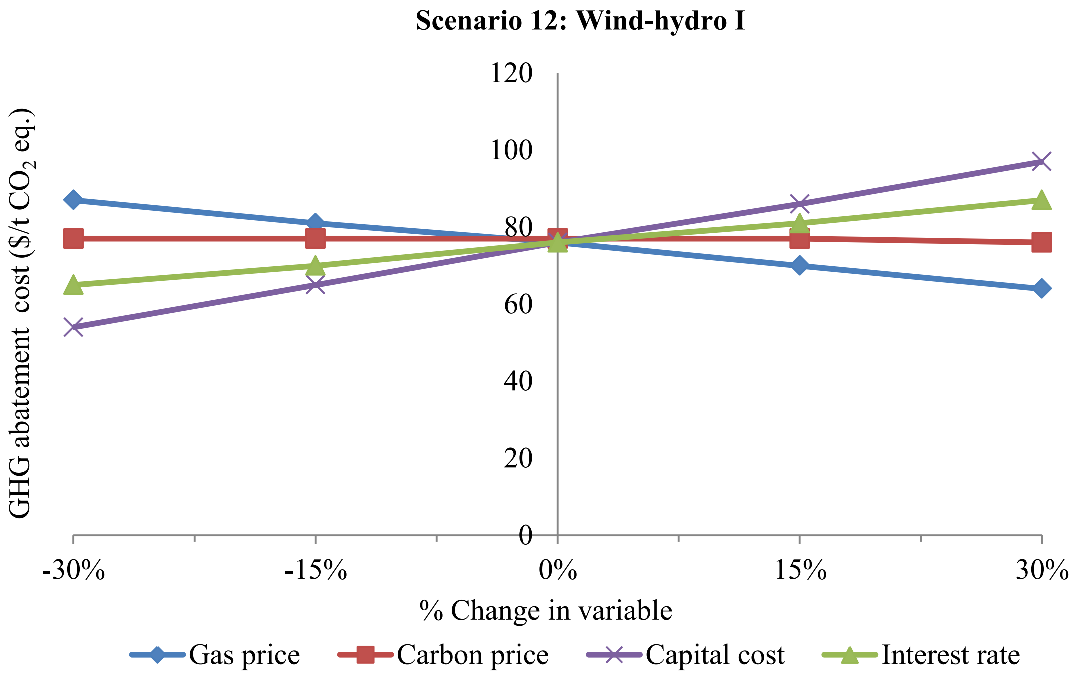

Fig. C. 21. Sensitivity analysis graph for wind-hydro I scenario generation mix by 2030

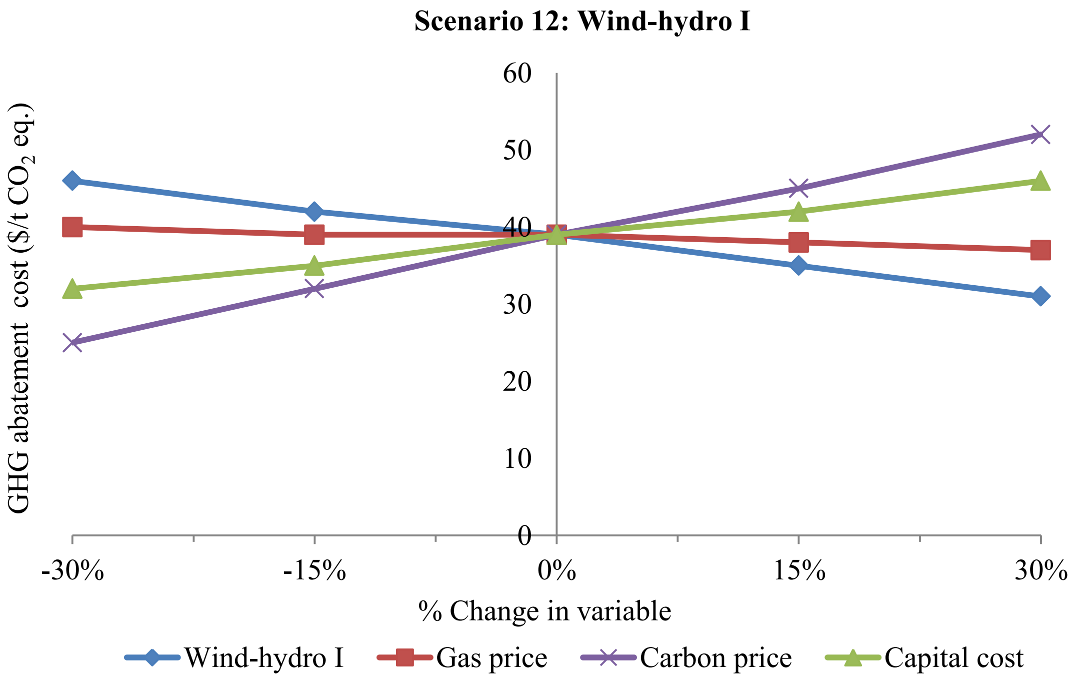

Fig. C. 22. Sensitivity analysis graph for wind-hydro I scenario generation mix by 2050

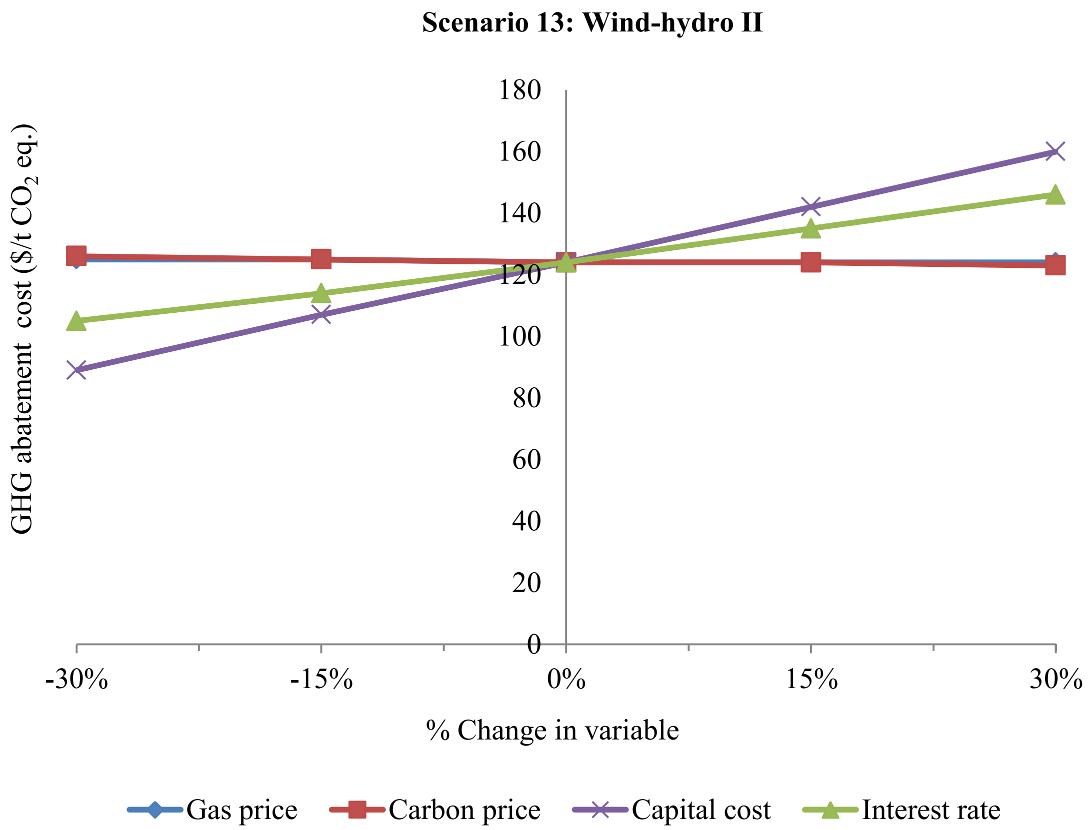

Fig. C. 23. Sensitivity analysis graph for wind-hydro II scenario generation mix by 2050

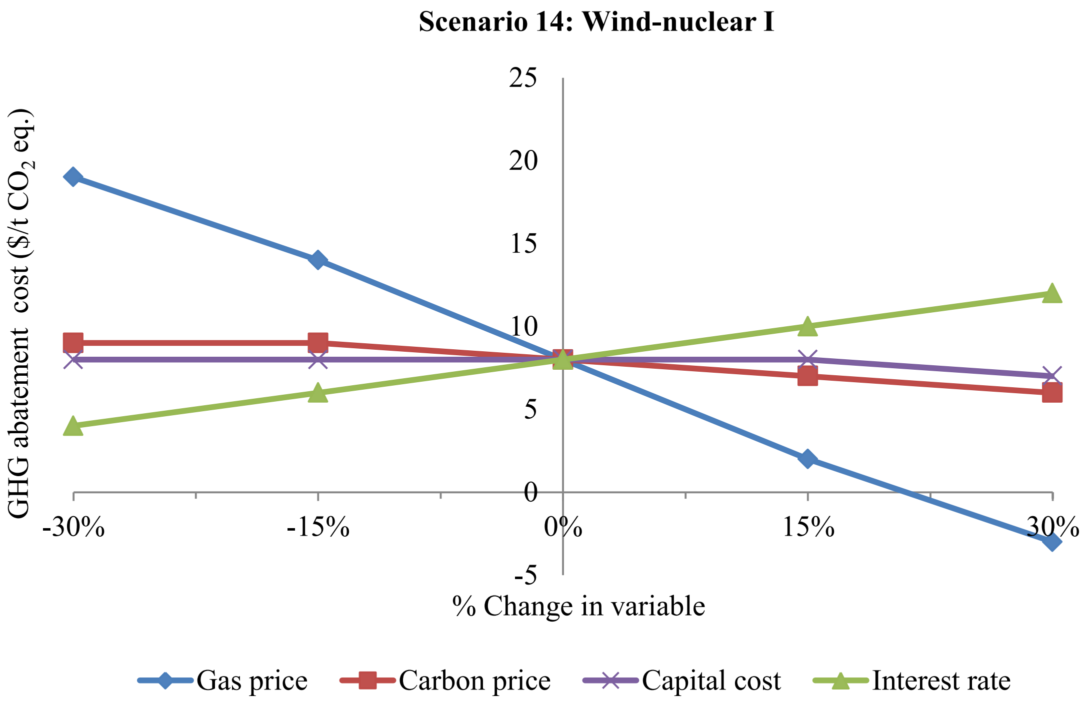

Fig. C. 24. Sensitivity analysis graph for wind-nuclear I scenario generation mix by 2030

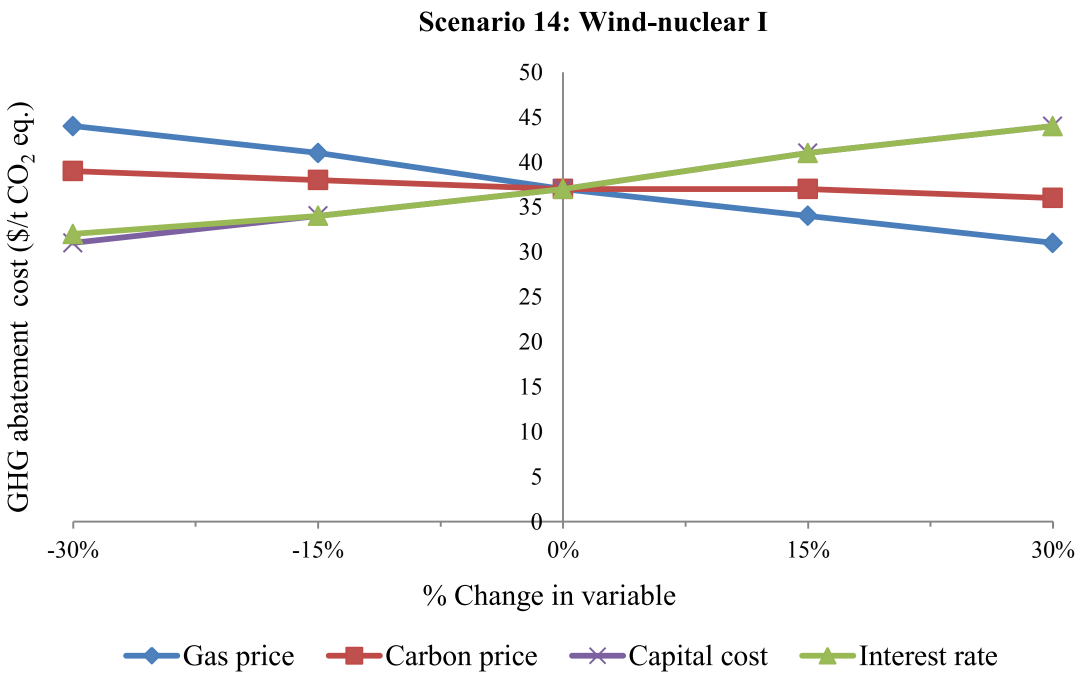

Fig. C. 25. Sensitivity Analysis for graph wind-nuclear I scenario generation mix by 2050

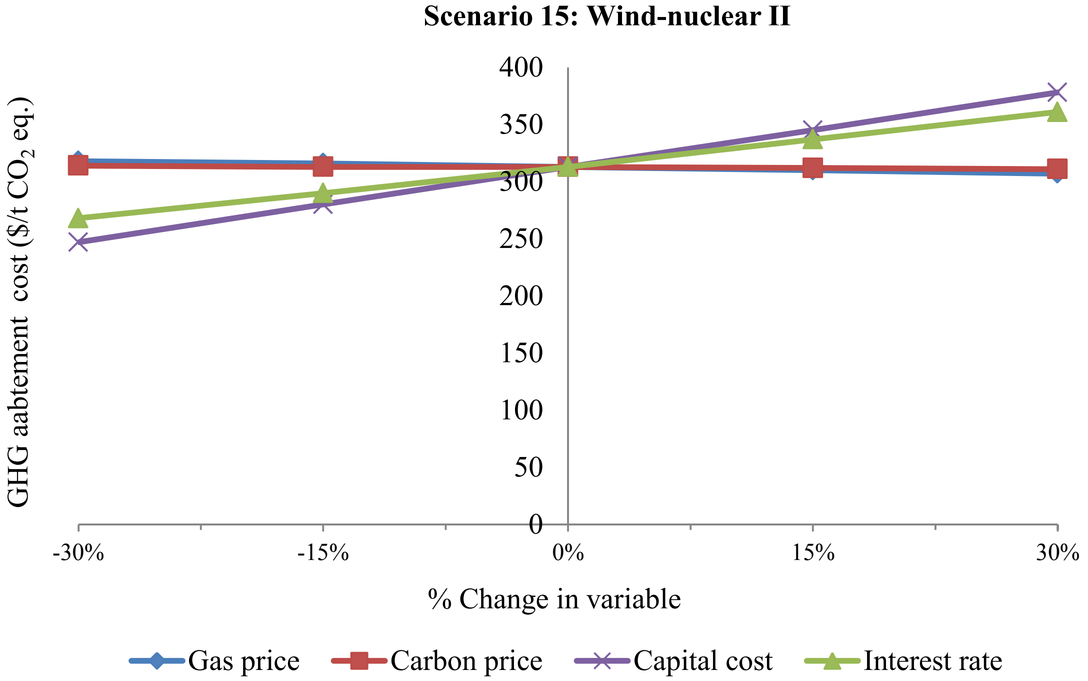

Fig. C. 26. Sensitivity analysis graph for wind-nuclear II scenario generation mix by 2030

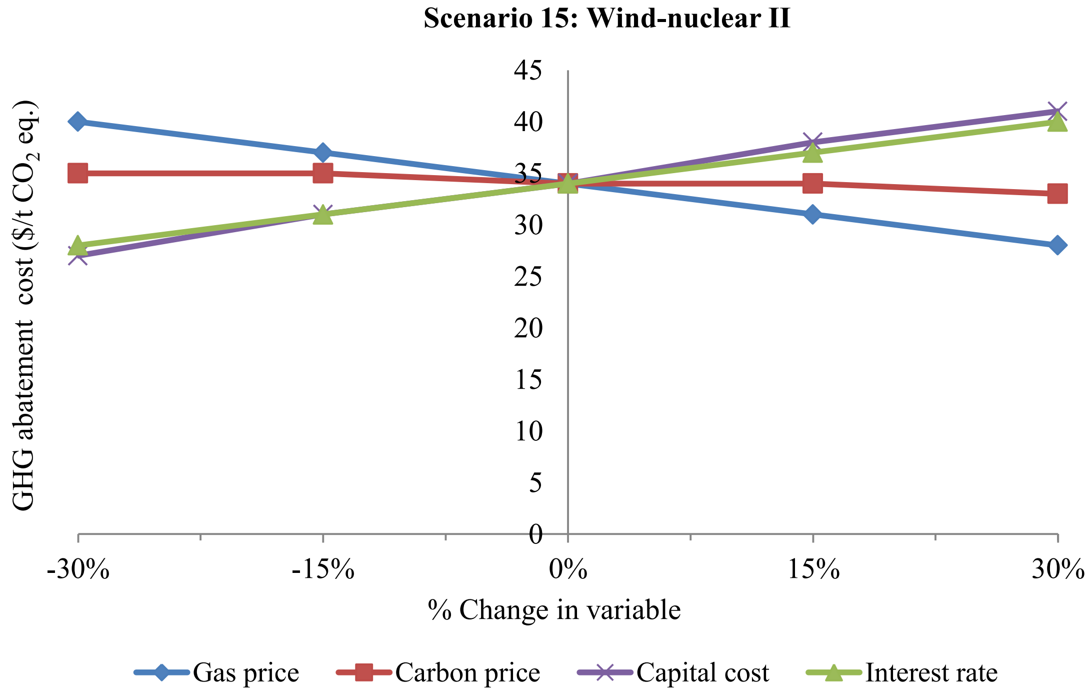

Fig. C. 27. Sensitivity Analysis for graph wind-nuclear II scenario generation mix by 2050

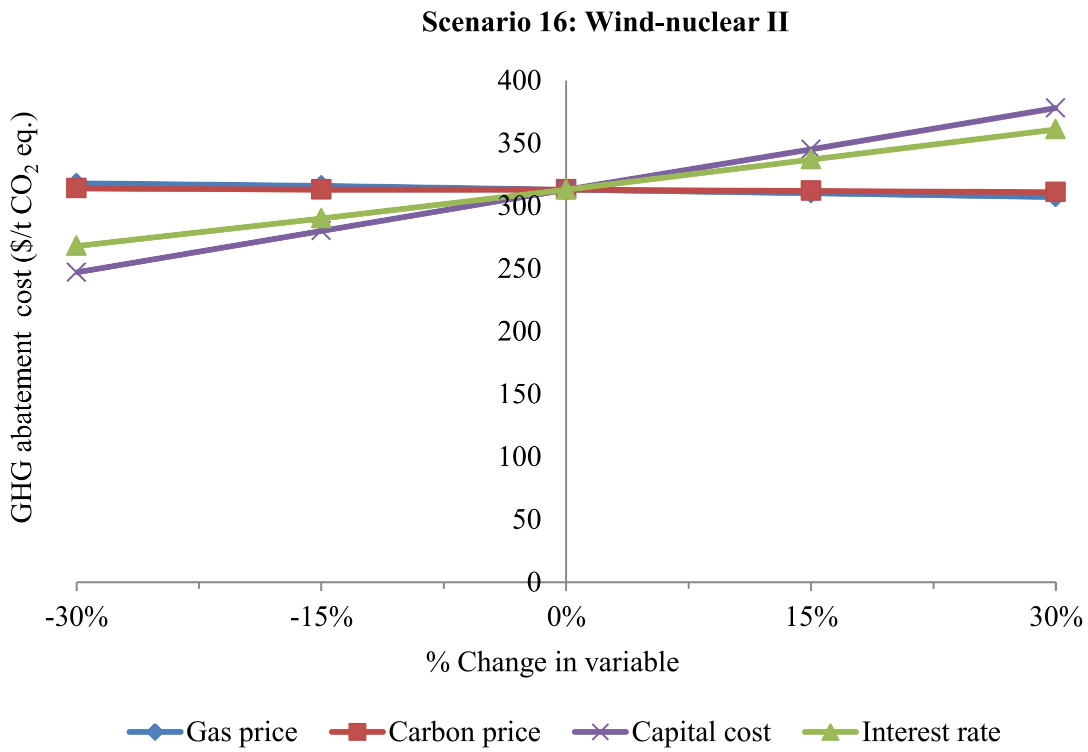

Fig. C.28. Sensitivity analysis graph for wind-nuclear III scenario generation mix by 2030

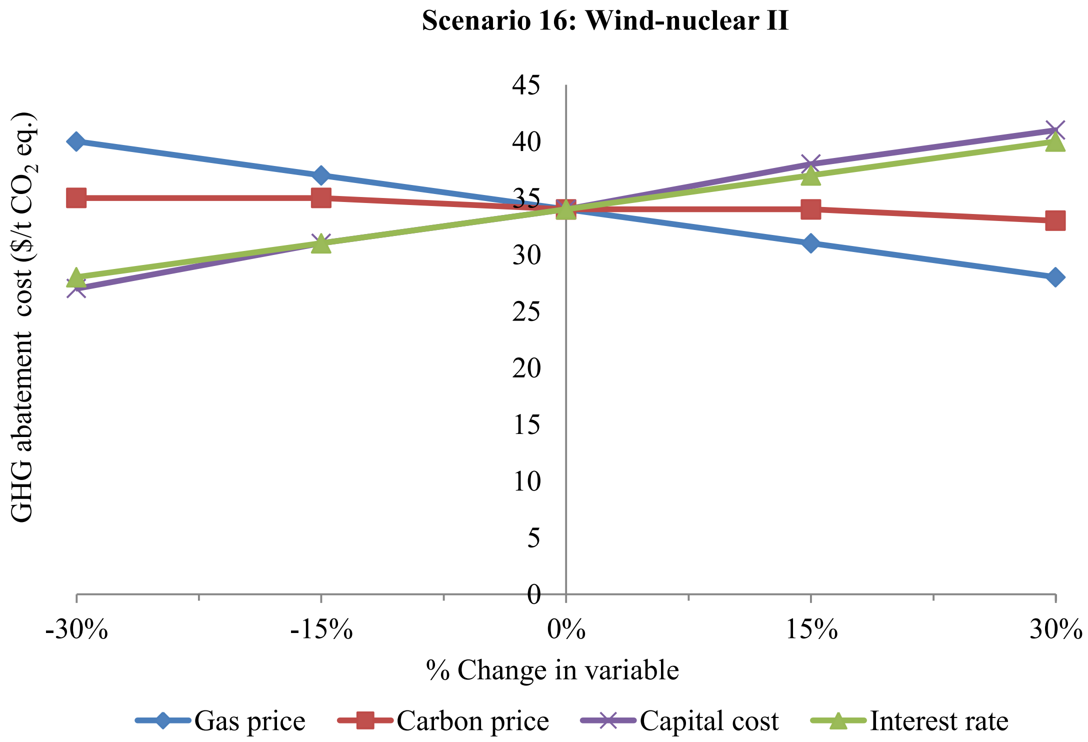

Fig. C. 29. Sensitivity analysis graph for wind-nuclear III scenario generation mix by 2050

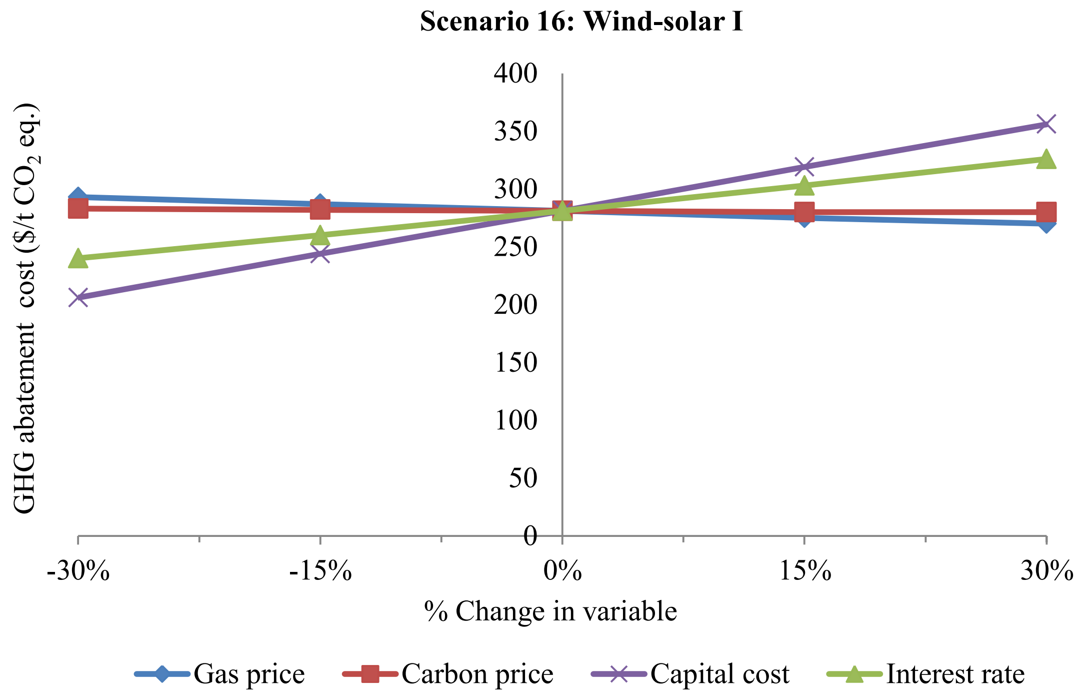

Fig. C. 30. Sensitivity analysis graph for wind-solar I scenario generation mix by 2030

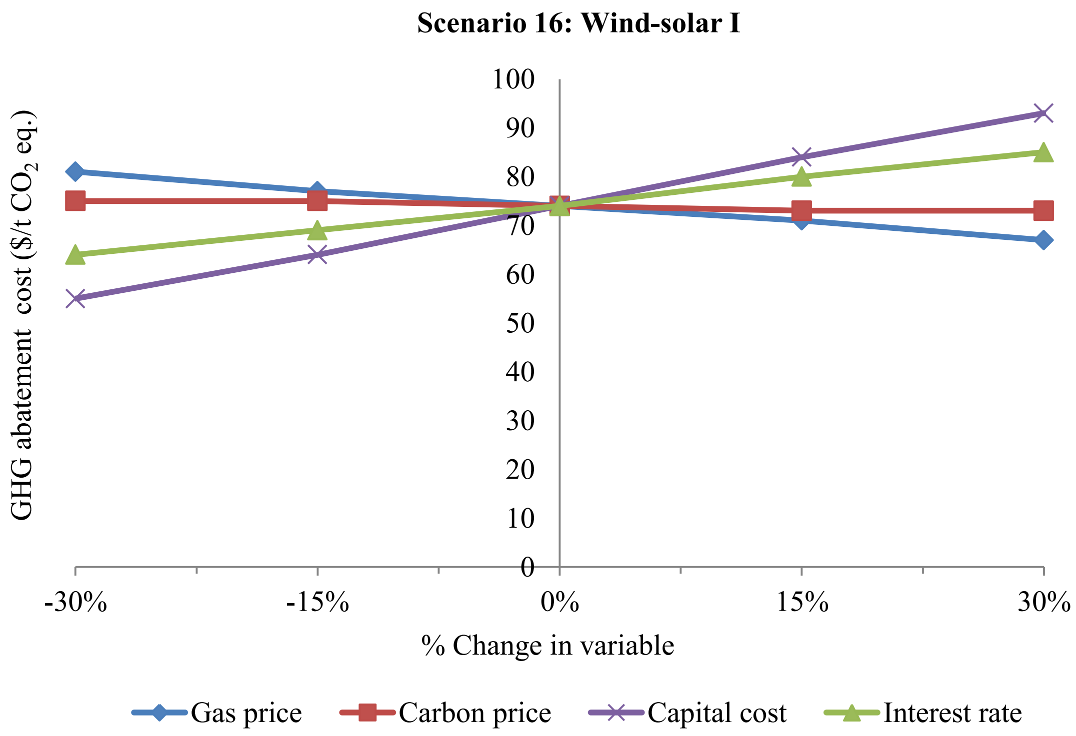

Fig. C. 31. Sensitivity analysis graph for wind-solar I scenario generation mix by 2050

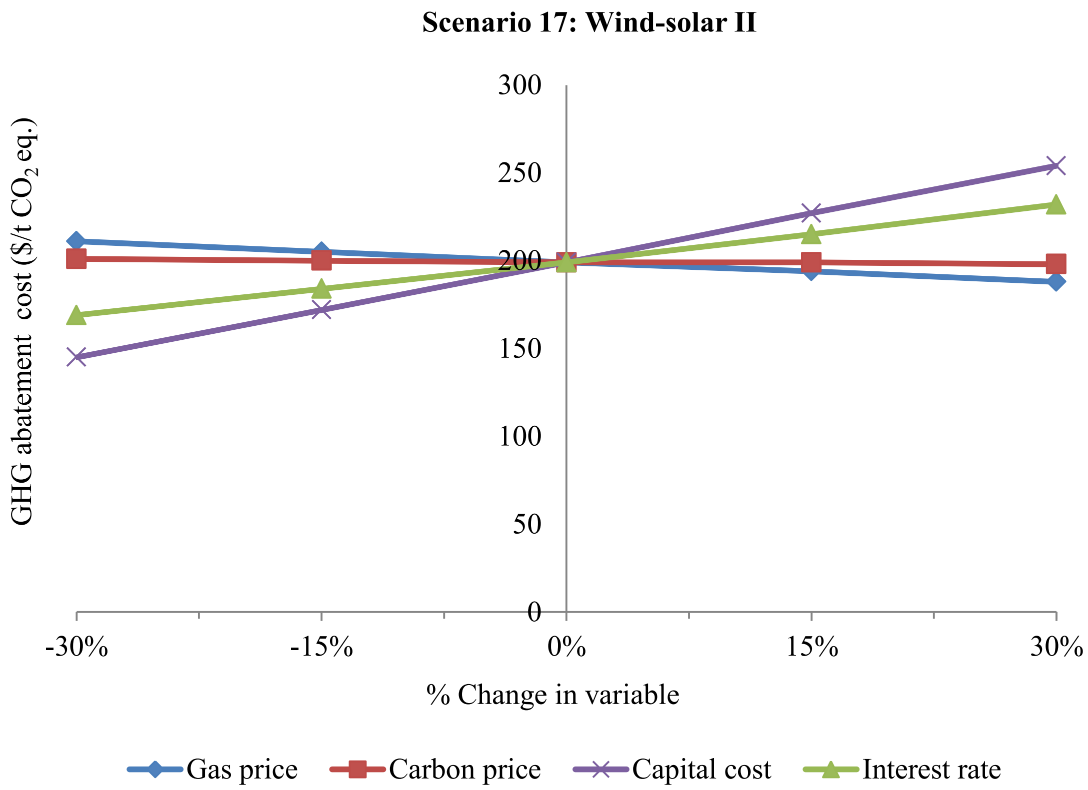

Fig. C. 32. Sensitivity analysis graph for wind-solar II scenario generation mix by 2030

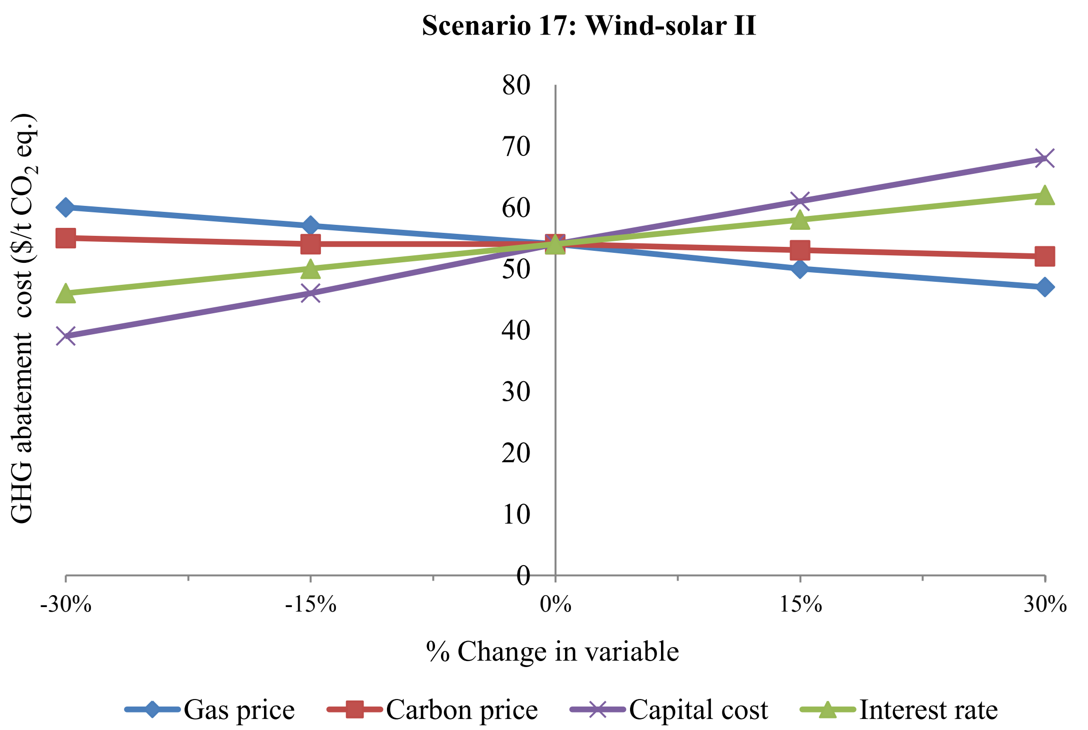

Fig. C. 33. Sensitivity analysis graph for wind-solar II scenario generation mix by 2050

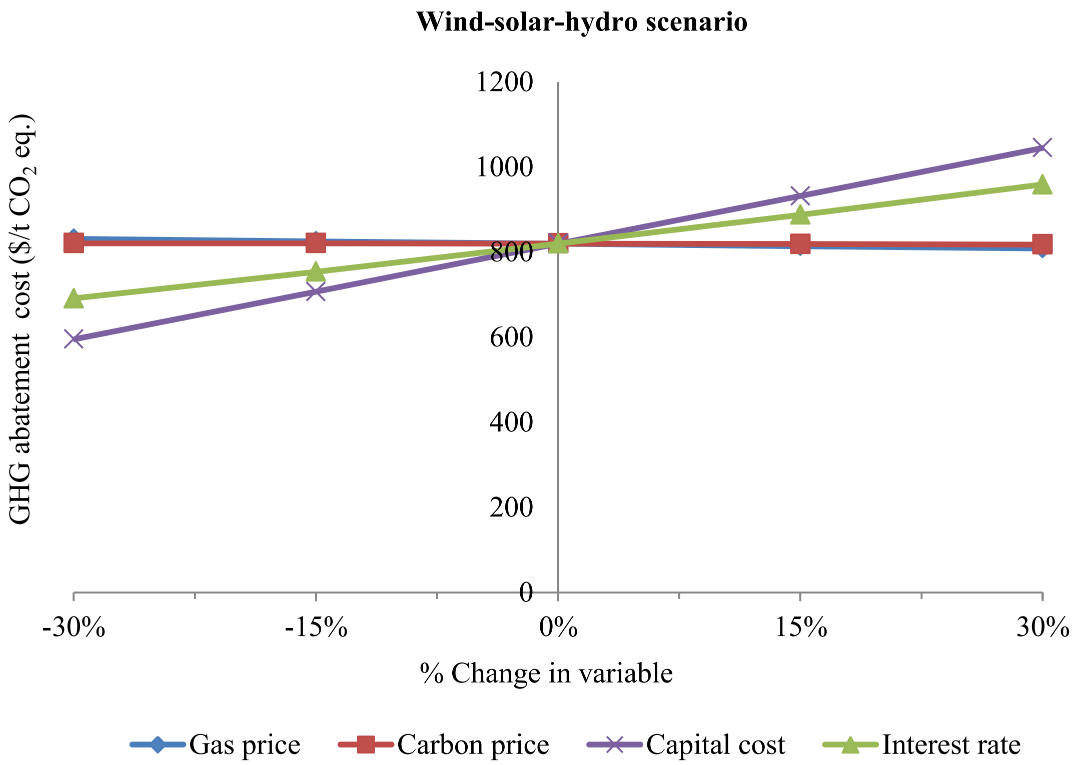

Fig. C. 34. Sensitivity analysis graph for wind-solar-hydro scenario generation mix by 2030

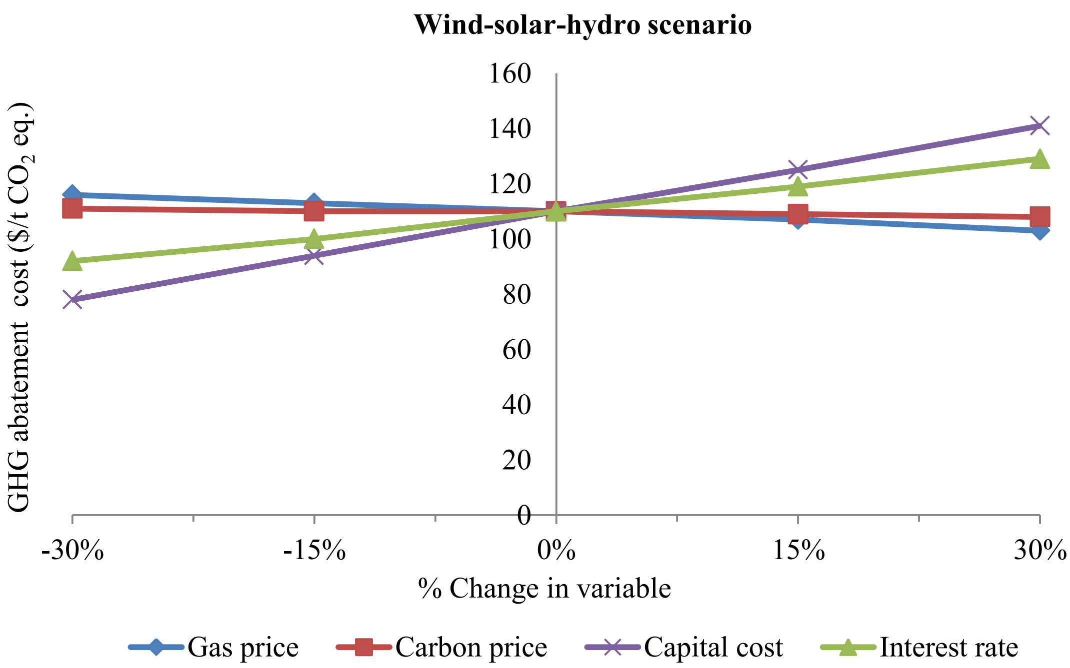

Fig. C. 35. Sensitivity analysis graph for wind-solar-hydro scenario generation mix by 2050

Appendix D

Table D1. Sensitivity analysis results of GHG abatement cost based on variations in gas price

	2030					2050				
Scenarios	**-30%**	**-15%**	**0%**	**15%**	**30%**	**-30%**	**-15%**	**0%**	**15%**	**30%**
Scenario 1: wind-CTG I	2	6	9	13	16	1	1	2	3	4
Scenario 2: wind-CTG II	12	18	24	30	36	6	9	12	15	18
Scenario 3: Wind-cogen I	-6	-6	-5	-5	-5	-8	-10	-12	-13	-15
Scenario 4: Wind-cogen II	-5	-4	-4	-3	-3	-10	-11	-13	-14	-15
Scenario 5: wind only	82	76	71	65	60	29	25	21	18	14
Scenario 6: wind-biomass I	227	220	214	207	201	115	112	108	104	100
Scenario 7: wind-biomass II	278	270	263	255	247	222	218	214	210	206
Scenario 8: wind-biomass-hydro	90	85	79	74	69	70	66	62	59	55
Scenario 9: wind-biomass-solar	703	696	690	683	676	202	199	195	192	188
Scenario 10: wind-geothermal	68	63	57	52	46	38	35	31	27	24
Scenario 11: wind-hydro I	87	81	76	70	64	46	42	39	35	31
Scenario 12: wind-hydro II	n/a	n/a	n/a	n/a	n/a	125	125	124	124	124
Scenario 13: wind-nuclear I	19	14	8	2	-3	44	41	37	34	31
Scenario 14: wind-nuclear II	318	316	313	310	307	40	37	34	31	28
Scenario 15: wind-nuclear III	47	42	37	32	27	34	30	27	24	21
Scenario 16: wind-solar I	293	287	281	275	270	81	77	74	71	67
Scenario 17: wind-solar II	211	205	199	194	188	60	57	54	50	47
Scenario 18: wind-solar-hydro	831	825	820	814	809	116	113	110	107	103

Table D2. Sensitivity analysis results of GHG abatement cost based on variations in carbon price

	2030					2050				
Scenarios	**-30%**	**-15%**	**0%**	**15%**	**30%**	**-30%**	**-15%**	**0%**	**15%**	**30%**
Scenario 1: wind-CTG I	11	10	9	9	8	4	3	2	1	1
Scenario 2: wind-CTG II	26	25	24	23	23	14	13	12	12	11
Scenario 3: Wind-cogen I	-5	-4	-4	-3	-3	-10	-11	-13	-14	-15
Scenario 4: Wind-cogen II	-2	-3	-4	-5	-5	-11	-12	-13	-13	-14
Scenario 5: wind only	72	72	71	70	69	23	22	21	21	20
Scenario 6: wind-biomass I	215	215	214	213	212	109	109	108	107	107
Scenario 7: wind-biomass II	264	263	263	262	261	215	214	214	213	212
Scenario 8: wind-biomass-hydro	81	80	79	79	78	64	63	62	62	61
Scenario 9: wind-biomass-solar	691	690	690	689	688	197	196	195	195	194
Scenario 10: wind-geothermal	59	58	57	56	56	32	32	31	30	30
Scenario 11: wind-hydro I	77	76	76	75	74	40	39	39	38	37
Scenario 12: wind-hydro II	n/a	n/a	n/a	n/a	n/a	126	125	124	124	123
Scenario 13: wind-nuclear I	9	9	8	7	6	39	38	37	37	36
Scenario 14: wind-nuclear II	314	313	313	312	311	35	35	34	34	33
Scenario 15: wind-nuclear III	38	38	37	36	36	28	28	27	27	26
Scenario 16: wind-solar I	283	282	281	280	280	75	75	74	73	73
Scenario 17: wind-solar II	201	200	199	199	198	55	54	54	53	52
Scenario 18: wind-solar-hydro	821	821	820	819	818	111	110	110	109	108

Table D3. Sensitivity analysis results of GHG abatement cost based on variations in capital cost

	2030					2050				
Scenarios	**-30%**	**-15%**	**0%**	**15%**	**30%**	**-30%**	**-15%**	**0%**	**15%**	**30%**
Scenario 1: wind-CTG I	9	9	9	10	10	2	2	2	2	3
Scenario 2: wind-CTG II	24	24	24	24	25	13	12	12	12	12
Scenario 3: Wind-cogen I	-7	-5	-4	-2	-1	-14	-13	-13	-12	-11
Scenario 4: Wind-cogen II	-5	-5	-4	-3	-2	-13	-13	-13	-12	-12
Scenario 5: wind only	52	61	71	80	90	15	18	21	25	28
Scenario 6: wind-biomass I	190	202	214	226	238	98	103	108	113	117
Scenario 7: wind-biomass II	246	254	263	271	279	200	207	214	221	228
Scenario 8: wind-biomass-hydro	67	73	79	86	92	52	57	62	68	73
Scenario 9: wind-biomass-solar	562	626	690	753	817	165	180	195	210	225
Scenario 10: wind-geothermal	38	48	57	67	76	19	25	31	37	42
Scenario 11: wind-hydro I	54	65	76	86	97	25	32	39	45	52
Scenario 12: wind-hydro II	n/a	n/a	n/a	n/a	n/a	89	107	124	142	160
Scenario 13: wind-nuclear I	8	8	8	8	7	31	34	37	41	44
Scenario 14: wind-nuclear II	247	280	313	345	378	27	31	34	38	41
Scenario 15: wind-nuclear III	28	32	37	41	46	21	24	27	30	33
Scenario 16: wind-solar I	206	244	281	319	356	55	64	74	84	93
Scenario 17: wind-solar II	145	172	199	227	254	39	46	54	61	68
Scenario 18: wind-solar-hydro	595	707	820	932	1045	78	94	110	125	141

Table D4. Sensitivity analysis results of GHG abatement cost based on variations in interest rate

	2030					2050				
Scenarios	-30%	-15%	0%	15%	30%	-30%	-15%	0%	15%	30%
Scenario 1: wind-CTG I	9	9	9	9	9	2	2	2	2	2
Scenario 2: wind-CTG II	24	24	24	24	24	13	13	12	12	12
Scenario 3: Wind-cogen I	-7	-6	-5	-5	-4	-12	-12	-12	-11	-11
Scenario 4: Wind-cogen II	-5	-5	-4	-3	-2	-13	-13	-13	-12	-12
Scenario 5: wind only	62	66	71	76	80	19	20	21	23	24
Scenario 6: wind-biomass I	201	207	214	221	228	103	105	108	111	114
Scenario 7: wind-biomass II	253	258	263	268	273	206	210	214	218	222
Scenario 8: wind-biomass-hydro	72	76	79	83	87	57	59	62	66	69
Scenario 9: wind-biomass-solar	616	652	690	729	769	178	186	195	205	214
Scenario 10: wind-geothermal	47	52	57	62	68	25	28	31	34	37
Scenario 11: wind-hydro I	65	70	76	81	87	32	35	39	42	46
Scenario 12: wind-hydro II	n/a	n/a	n/a	n/a	n/a	105	114	124	135	146
Scenario 13: wind-nuclear I	4	6	8	10	12	32	34	37	41	44
Scenario 14: wind-nuclear II	268	290	313	337	361	28	31	34	37	40
Scenario 15: wind-nuclear III	29	33	37	41	46	22	25	27	30	33
Scenario 16: wind-solar I	240	260	281	303	326	64	69	74	80	85
Scenario 17: wind-solar II	169	184	199	215	232	46	50	54	58	62
Scenario 18: wind-solar-hydro	691	754	820	888	959	92	100	110	119	129