The Development of a Technology-Explicit Bottom-Up Integrated Multi-Regional Energy Model of Canada

by:

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Abstract

Greenhouse gas (GHG) emissions are currently at the crux of political, environmental, technological, and cultural discussions due to climate change. A drastic reduction of GHG emissions is needed in order to mitigate potentially catastrophic climate change impacts. This thesis presents the development of a bottom-up, data intensive, multi-regional energy model for Canada using the Long-range Energy Alternatives Planning (LEAP) system. A novel energy model, the LEAP-Canada model employs an accounting-based framework to provide the ability to examine extensive ranges of energy use and GHG mitigation strategies. Business-as-usual energy and GHG emission outlooks are provided for Canada on the national level and for its provinces including British Columbia, Alberta, Saskatchewan, Manitoba, Quebec, Ontario, and Atlantic Canada on individual levels. The LEAP-Canada model offers a unique and updated outlook on Canada's integrated energy system as of 2017 and provides bottom-up capabilities for energy efficiency analysis, energy planning, and GHG mitigation scenario assessments to the year 2050.

This research also interprets the energy flow from available primary fuel to end use in all of the provinces and territories in Canada for the year 2012 using Sankey diagrams. These flow charts illustrate energy production, imports, exports, and local consumption by economic sector, and quantify the amount of useful and rejected energy. The inflow and outflow values could help determine existing energy efficiencies and energy intensity improvement potential. This pictorial view of energy flow could help policy makers set targets for improving energy efficiency, select strategies for the reduction of greenhouse gases emissions, and help satisfy the vast global climate change challenges. An overview and analysis of the GHG landscape in Canada for the

years 2014, 2030, and 2050 with Sankey diagrams is also conducted. Each major economic sector in Canada was analyzed, i.e., the electricity generation, residential, commercial and institutional, mining and upstream oil and gas industry, other industry sectors, transportation, and agriculture sectors. The emissions released in these sectors (combustion, fugitive, and non-energy) were traced back to the resources and fuels responsible. GHGs in exported resources and fuels are included in the analysis. Diagrams are provided for Canada as well as for all the major provinces in Canada including British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, and the Atlantic Provinces. Comparisons between these regions were made in terms of absolute emissions and emission intensities.

The LEAP-Canada model was then used to appraise, to 2050, the Western Canadian crude available for export as well as the energy demands and GHG emissions brought into each province from the Line 3, Energy East, Trans Mountain, Northern Gateway, and Keystone XL pipelines. Scenarios in which pipelines are proposed but not constructed were also analyzed. The impacts of crude-by-rail alternatives using bitumen with 30%, 15%, and 0% diluent were assessed and compared. Finally, this work quantifies oil sands emissions between 2010 and 2050 with the LEAP-Canada model. The greenhouse gas strategy of using British Columbia's hydropower for oil sands operations was evaluated.

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Abbreviations

AB – Alberta

AESO – Alberta Electric System Operator

BAU – Business-as-usual

BC – British Columbia

bbl - Barrel

CAD – Canadian dollar

CANSIM – Canadian socio-economic information management

CAPP – Canadian Association of Petroleum Producers

CERI – Canadian Energy Research Institute

CESAR – Canadian Energy System Analysis Research

CEUD - Comprehensive Energy Use Database

CHP – Combined heat and power

CLP – Climate Change Plan

CNG – Compressed natural gas

CO_2 - Carbon dioxide

CO_2e – Carbon dioxide equivalent

CSS – Cyclic steam stimulation

DC – Direct current

DRU – Diluent recovery unit

E3MC – Energy, Emission and Economy Model for Canada

ECCC – Environment and Climate Change Canada

EFR – Energy Futures report

GCAM – Global Change Assessment Model

GDP – Gross domestic product

GHG – Greenhouse gas

HVAC – Heating, ventilation and air conditioning

IEA – International Energy Agency

IEO – International Energy Outlook

IPCC - Intergovernmental Panel on Climate Change

kJ – Kilojoule

kT – Kilo-tonne

LEAP – Long-range Energy Alternatives Planning

LNG – Liquid natural gas

LUCF – Land use change and forestry

MB – Manitoba

Mb – Thousand barrels

MMb – Million barrels

MJ – Megajoule

MSW – Mixed Sweet Light Crude Oil

MT – Megatonne

NB – New Brunswick

NEB – National Energy Board

NG – Natural gas

NGL – Natural gas liquids

NIR – National Inventory Report

NFL – Newfoundland and Labrador

NRCan – Natural Resources Canada

NS – Nova Scotia

O&M – Operations and maintenance

OEE – Office of Energy Efficiency

ON – Ontario

PEI – Prince Edward Island

PJ – Petajoule

QB – Quebec

SAGD – Steam-assisted gravity drainage

SCO – Synthetic crude oil

SK – Saskatchewan

StatCan – Statistics Canada

TED – Technology and Environmental Database

TJ – Terajoule

TIM – The Informetrica Model

U.K. – United Kingdom

U.S. – United States

US DOS – United States Department of State

WCS – Western Canada Select

WEAP – Water Evaluation and Planning System

WEO – World Energy Outlook

WRI – World Resources Institute

WTI – West Texas Intermediate

1 Chapter I: Introduction

1.1 Energy use in Canada

Energy systems have enabled a high quality of life for many people in developed nations and its growth is imperative to the evolution of developing nations [1]. However, the energy system is complex and has adverse environmental impacts. Human beings have contributed to the alteration of the natural climate system into a global warming trend due to greenhouse gas (GHG) emissions from energy use. The GHG emissions associated with energy use need to be reduced while simultaneously accommodating the world's growing energy needs; this poses a momentous challenge. If measures to mitigate emissions are not taken, there may be adverse impacts on the planet [2].

To address climate change, many countries have adopted the Paris Agreement to limit the global mean temperature rise to below 2 degrees Celsius [3]. To avoid exceeding a 2-degree global temperature increase and stabilize the climate, GHG emissions must be rapidly reduced [4]. On April 22, 2016, Canada signed on to the Paris Agreement with plans to be a climate leader [5, 6]. Although Canada is responsible for only approximately 2% of worldwide GHG emissions, the country is one of the largest per capital energy users and emitters in the world [7]. In addition, approximately 77% of Canada's energy comes from non-renewable fossil fuels [8]. These issues make it imperative for Canada to transition from a high-energy, high-carbon society to a high-energy, low-carbon society.

Canada has the largest hydrocarbon base in North America and is at the upper ranking of energy production and exports irrespective to all types of energy. For example, crude oils and natural gas are 5th and 4th, respectively, in production and export in the world market; uranium is 2nd both in production and export in the world market; and hydroelectricity and biofuel are 3rd and 5th, respectively, in production in the world [9]. Canada has allocated $195 million under the ecoENERGY Efficiency program over five years [10]. In Canada, energy consumption increased by about 23% over the last two decades [11]. Canada's energy expenditure is largely in the residential, commercial, and industrial sectors. About $152 billion was spent on energy to operate heating and cooling devices, appliances, cars, and industrial processes in 2009. This is equivalent to about 11% of the country's GDP [12].

Canada has a complex energy flow. Energy production, local consumption, and inter-provincial and international exports and imports are common in Canada. The residential, commercial and institutional, industrial, transportation and agriculture sectors are all energy demand sectors. Canada's energy consumption in 2012 was 8,735 PJ. The industrial sector consumed the largest share of end use energy (38.38%), followed by transport (29.65%), residential (16.70%), commercial and institutional (12.24%), and agriculture (3.03%). The energy used by these five sectors emitted 473.4 million tonnes (CO_2 equivalent) of GHGs in 2012 [11], of a total 699 million tonnes (CO_2 equivalent) that year [9]. The total fossil fuel production was 16,459 PJ in 2012; the major forms of fossil fuels are crude oil (47.6%) and natural gas (38.7%). Coal and natural gas liquids contributed 9.6% and 4.0%, respectively, of the fossil fuel supply in 2012. As energy consumption increases, GHG emissions from fossil fuel production have also increased and went up by 10% between 2005 and 2012 [9]. Net GHG emissions increased by 36%, 29%, and 8% in the transportation, commercial/institutional, and industrial sectors, respectively, between 2005 and 2009 [12].

1.2 GHG emissions in Canada

Greenhouse gas (GHG) emissions are currently at the crux of political, environmental, technological, and cultural discussions due to climate change. It is accepted by at least 97% of climate scientists that human activity influences climate change [13]. Human-induced GHG emissions must be drastically reduced in order to mitigate negative climate change impacts such as changes in sea level, weather severity, and social instability [14]. A breakdown of global sources of GHG emissions is shown in Figure 1-1. China, the United States (U.S.), and the European Union generate close to 50% of GHG emissions.

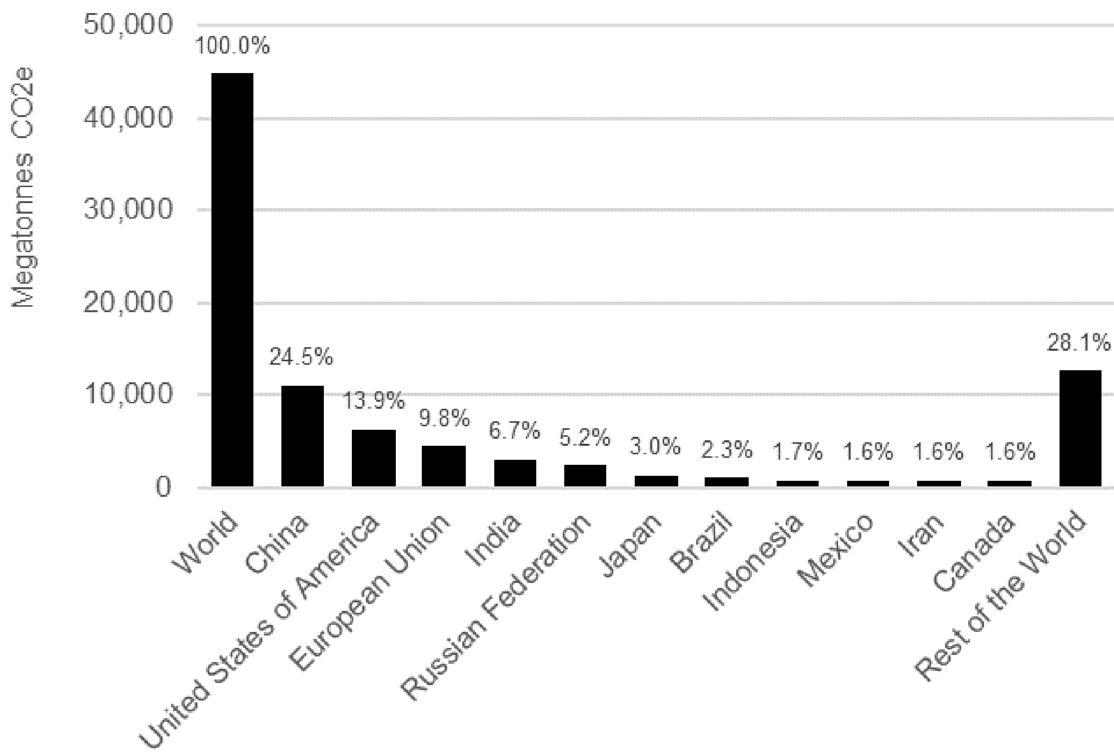

Figure 1-1: Global sources of GHG emission by country in 2012 [15]

Canada emitted 1.6% of global GHG emissions in 2012. However, in terms of emission intensity per person, there is a different picture. Figure 1-2 shows the per capita emissions of the top ten emitters in 2011 by country (values include the effects of land use change and forestry [LUCF]). Here, Canada is the most GHG-intensive entity. This is relevant as its population could grow by up to 80% of 2013 levels by 2063 [16]. In addition, if Canada can reduce its emission levels and emissions intensity, a world precedent would be set. Other nations may follow suit by replicating Canada's policies or technologies, thereby greatly contributing to emissions reductions globally.

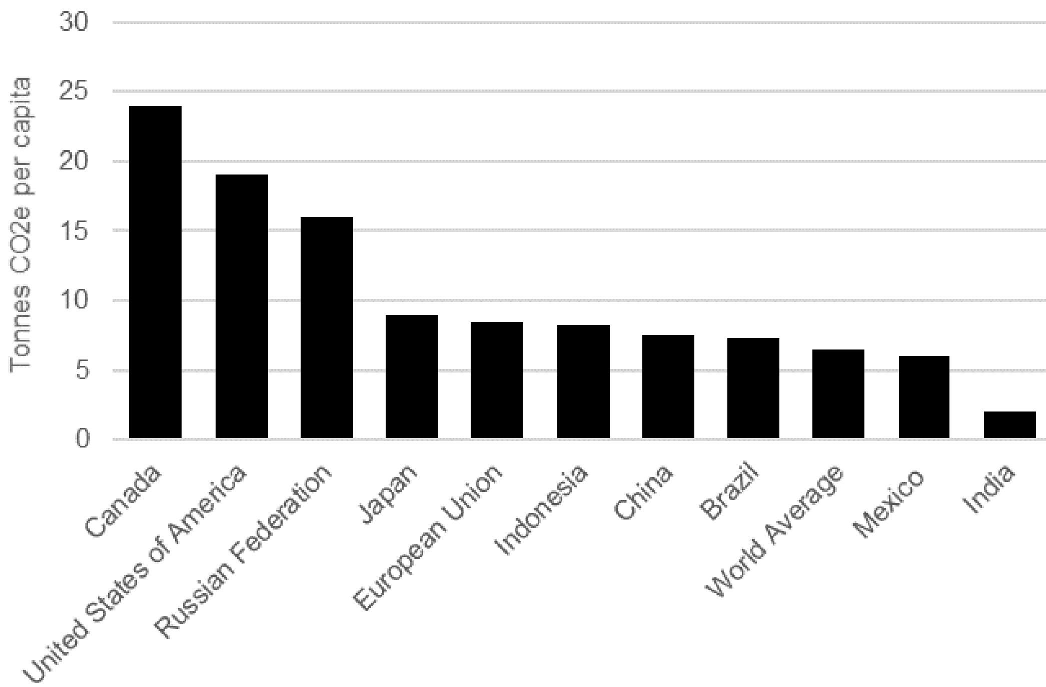

Figure 1-2: Comparison of GHG intensity of the top ten global emitters in 2011 [17]

There is much debate over how to curb GHG emission levels. Many strategies are currently in practice such as carbon tax, carbon cap and trade, and replacing GHG-intensive power production with renewables. A summary is provided in Table 1-1 outlining the strategies in place in Canada to reduce GHG emissions and combat climate change.

Table 1-1: Selected Canadian climate change targets and actions

Canada	$2 billion Low Carbon Economy Trust [18]
	Phase-out subsidies for the fossil fuel industry [18]
	Reduce total GHG emissions by 17% relative to 2005 emission levels by 2020 [19]
	Reduce total GHG emissions to 30% below 2005 levels by 2030 [20]
	$2.65 billion climate finance commitment over five years [20]
	Federal carbon tax proposed to reach 50 $/tonne by 2022
British Columbia	2050 emissions reduction target of 80% below 2007 levels [21]
	The province is part of the International Zero Emission Vehicle Alliance and has announced it will strive to make all new passenger vehicles zero-emission by no later than 2050 [20]
	Carbon tax of $30/tonne [22]
Alberta	Carbon tax of $20/tonne in 2017, $30/tonne in 2018, and thereafter increasing 2% above inflation annually [23]
	Phase-out of coal-fired electricity generation by 2030 [23]
	Emission limit of 100 MT in the oil sands [23]
	45% reduction of methane emissions from oil and gas extraction by 2025 [23]
Saskatchewan	Reduction of emissions to 20% below 2006 levels by 2020 [24]

	50% electricity generation from renewables by 2030 [20]
Manitoba	2030 target to reduce GHG emissions by one-third over 2005 levels, by one-half by 2050, and carbon neutral by 2080 [24]
Ontario	15% reduction below 1990 levels by 2020 and 37% below 1990 levels by 2030 [25] 80% emission reduction below 1990 levels by 2050 [25] Implementing a cap and trade system [25]
Quebec	Part of the International Zero Emission Vehicle Alliance [20] 2030 target of 37.5% reduction below 1990 levels [20] Cap and trade program in place
Atlantic provinces	35-45% reduction in regional GHG emissions below 1990 levels by 2030 [20]

1.3 Energy modelling

To manage the energy system responsibly while maintaining its benefits during the transition to a sustainable low carbon society, science-based decision making is required to assist in government energy policy making and overall energy management. An energy model provides a detailed framework to represent a complex energy system in an understandable and organized way. Decision makers may use the model to gather real data or test hypotheses based on assumptions about the future. The model is a tool to evaluate outcomes of choices in order to determine which option best addresses the issues at hand. Further to this, decisions can be optimized to give the best possible choice given a set of constraints.

A multitude of energy models have been developed with varying approaches. Jebaraj and Iniyan [26] describe in a chronology the energy model landscape up to 2004. Bhattacharyya and Timilsina [27] give an in-depth background and analysis of prominent energy models used in the UK as of 2009. Qudrat-Ullah [28] gives a more focused but less comprehensive look at energy modelling practices as of 2013 and includes numerous case studies of energy model applications. Pfenninger et al. [29] discuss the challenges present in modern-day energy modelling as well as suggested approaches for solutions; their paper includes sources for reviews of the energy model landscape.

The prevalent uses of energy modelling are for government policy making, energy efficiency analysis, and GHG emission mitigation analysis. Policy or technology options can be evaluated with energy models to gather evidence to support decisions. Scenarios may be run to gain further insights into possible futures, given certain policy measures and assumptions. Laes and Johan [30] discuss the relationship between policy makers and energy modelers. The impacts of energy efficiency and technology changes are also actively analyzed with energy models. McNeil et al. [31] describe a bottom-up model used to quantify the impacts of energy efficiency programs in the building sector in China. With climate change becoming more prominent, energy models are used to assess current and future greenhouse gas levels and test different mitigation options. Energy models have been developed to represent many large integrated energy systems as described in the International Energy Agency's (IEA) World Energy Outlook (WEO) [32] or to analyze a system of very limited scope; many of these are reviewed by Suganthi and Samuel [33]. Soto and Jentsch, [34] compare various models in their ability to be applied to the residential sector of a country. Mohareb and Kennedy [35] explore various low-carbon policy strategies for large cities such as Toronto, Canada.

Various classifications of energy models have been used in the literature. Hall and Buckley [36] propose a uniform classification scheme to reduce confusion in categorizing energy models. The most prominent models have a top-down or bottom-up analytical approach and econometric, optimization, simulation, or accounting frameworks. A top-down approach to modelling considers the wider economy as opposed to only the energy sector and relies on historical relationships to predict behavior while a bottom-up approach is technology-driven and focuses in detail on the energy system only [37]. Optimization models such as MARKAL/TIMES use linear programming to choose the least costly pathways for future years [38]. Simulation models such as Energy 2020 simulate the behavior of an energy system using historical economic parameters [39]. Accounting models such as the Long-range Energy Alternatives Planning (LEAP) model rely on the modeler to specify all the parameters of the energy system rather than simulate or optimize future outcomes [40].

Water-based models also exist which can complement energy analysis. The Water Evaluation and Planning (WEAP) system is a tool for integrated water resource planning [41]. WEAP can be integrated with LEAP for integrated water and energy planning and analysis. N. Agrawal has developed an integrated WEAP-LEAP model for GHG emission mitigation analysis in Alberta's power sector [42]. This model was used to analyze various scenarios for GHG mitigation potential, water consumption, and cost of GHG mitigation [42].

Other types of models exist which are capable of integrating policy, energy, water, and GHG emission analysis. The Global Change Assessment Model (GCAM) is a dynamic-recursive model capable of simulating energy and environmental policy scenarios [43]. Kyle et al. [44] developed a GCAM model to analyze water demand impacts of GHG mitigation technologies in the power sector. Integrated models and assessments such as these are becoming increasingly important in the light of climate change urgency [45, 46].

1.4 Knowledge gaps

In the Canadian context there is limited work in the area of energy modelling. As of 2014, there are currently only three known actively used Canadian models capable of performing comprehensive analyses: TIMES-Canada [47], Energy 2020 [39], and CanESS [48]. The TIMES-Canada model is a multi-regional optimization model that has analyzed five scenarios, a baseline scenario, plus four alternate scenarios with low and high oil prices and slow and fast socio-economic growth trends [47]. The TIMES-Canada model was used to generate an outlook of the electrification of Canada's road transportation sector [49]. Energy 2020 is a multi-regional simulation-based model and is used in conjunction with a macroeconomic model called The Informetrica Model (TIM) to form Environment Canada's Energy, Emission and Economy Model for Canada (E3MC) [50]. Both the NEB and Environment and Climate Change Canada (ECCC) use E3MC for their annual reports. In the NEB's most recent report they projected a business-as-usual scenario to 2040 as well as two price cases, a pipeline constraint case, and two liquid natural gas (LNG) export cases [51]. They provide both national and regional outlooks describing projected energy demand breakdowns and energy production levels. ECCC uses E3MC to produce their Emission Trends Report, which provides statistics and projections on

GHG emissions in Canada to the year 2020 [50]. The CanESS model is a simulation model that uses historical data from 1978 to 2010 to project future energy use and emissions to 2100 [48].

These existing models, while highly valuable, have limitations. Optimization-based models are not transparent and are limited to optimization studies. Linear programming is used to produce optimized results based on least cost. This method of calculation can be seen as a "black box" and makes it difficult for decision makers to interpret results in a transparent way. Studies completed with optimization models are limited to cost-based analyses and the availability and accuracy of cost data. Simulation models rely on historical trends to project future outcomes. This can be a limited approach in the context of the complexity of energy systems. Without a technological focus, detailed energy analysis is limited. Industry commonly goes through technology and process shifts that can drastically affect energy use and/or emissions. Without detailed technology-explicit energy demand trees, especially for industrial activity, accurate modelling may not be possible. Given the complex nature of the energy supply-demand-policy landscape, models that rely on optimization or historic trends alone have limited applicability. A hybrid model that is capable of integrating optimization capabilities, historic trends, technology specific demand trees, user-specified variables, and a transparent calculation structure is useful. Such a model would be flexible enough to enable a wider range of studies. Development of such a model is the primary focus of this research.

ECCC publishes reports on GHG emissions that contain detailed analyses of past emissions [7, 50]. Currently there are no analyses of projected GHG emissions for Canada. ECCC forecasts up to 2020; these figures were last released in 2014 [50]. The National Energy Board (NEB) releases periodic Energy Future Reports (EFR) that project energy demand to 2040 but no GHG details. There are currently no detailed long-term outlooks of Canada's GHG emissions. Canadian national and regional energy and emission outlooks to 2050 do not exist in the peer-reviewed literature. Such outlooks are provided from this research.

A method of analyzing GHGs is through Sankey diagrams. Sankey diagrams are widely used to visualize and compare flow patterns of various themes. Industry processes or specific sectors are often analyzed for mass and energy balance. Large-scale energy and GHG accounting is another common application. The International Energy Agency (IEA) uses a Sankey diagram format to visualize energy balances and final energy consumption [52]. The Canada Report on Energy Supply and Demand (RESD) includes an energy flow Sankey diagram depicting resource and fuel production and disposition [53]. A 2015 Quebec GHG Sankey was produced by Canadian Energy System Analysis Research (CESAR) [54]. The World Resources Institute (WRI) created a U.S. GHG emission flowchart [55]. No detailed set of Canadian GHG Sankey diagrams has been published, yet such a set could provide both the public and policy makers with an enriched understanding of and quick reference guide to Canada's GHG paradigm. Through this research, such diagrams have been created and analyzed.

There is debate in Canada around proposed pipelines and transport of oil sands. A multi-regional energy and emission analysis of future pipeline use has not been conducted. There have also been proposals to supply the oil sands with electricity from British Columbia hydro power to mitigate oil sands emissions. There is limited published scientific analysis of the cost and emission mitigation effectiveness of this strategy. These analyses are also conducted in this thesis.

1.5 Objectives of research

The primary objective of this study is to develop a novel energy model, the LEAP-Canada model, to fill the gaps discussed above. The objectives of the LEAP-Canada model are to provide an energy model of Canada with the following features:

- Fully integrated energy system – The supply-demand structure of the energy system should be interdependent. Increases or decreases in energy demand should affect energy supply production, imports, and exports. Energy production should impact resource reserves.
- Fully integrated multi-regional energy system – Each independent region in Canada (provinces and territories) should have its own independent fully integrated energy system as described above. These independent regions are linked by inter-regional energy trade.
- Technology-explicit bottom-up demand trees – The demand sector would be developed from the bottom-up starting at the end use technology in any given sector. This gives a more accurate and true approach to calculating energy demands and allows for technology specific changes.
- Accounting-based calculation framework – A transparent and flexible methodology for calculating results. The accounting framework allows for studying of resource,

technology, environmental, and social costs. Optimization and simulation capabilities exist as well.

Secondary objectives of this work are the following:

- Provide an in-depth multi-regional analysis of Canada’s complete energy system with energy Sankey diagrams
- Use the newly developed LEAP-Canada model to complete the following:
    - Produce baseline energy projections to the year 2050 for Canada and the major regions of Canada
    - Produce baseline GHG emission projections to the year 2050 for Canada and the major regions of Canada
    - Provide an in-depth multi-regional analysis of Canada’s current and future GHG emission’s with GHG Sankey diagrams
    - Perform a multi-regional analysis of the proposed major crude oil pipeline’s impacts on energy demand, GHG emissions, and crude-by-rail transport.
    - Perform an evaluation of importing BC-Hydro power to oil sands as a GHG emission mitigation strategy

While other energy models may exist, having multiple models with different methodological structures is useful in rigorous scientific analysis of an issue and provides decision makers with a wider spectrum of policy analysis capabilities. Overall, the LEAP-Canada model offers a unique and updated outlook on Canada’s energy system, as well as providing technology-explicit capabilities for energy efficiency analysis, energy planning, and GHG mitigation assessment.

1.6 Limitations of research

There is criticism regarding the effectiveness of energy models in supporting policy-making efforts. Most of these criticisms, according to Laes and Johan [30], are due to undisclosed model assumptions and ineffective communication by the modelers about what kinds of studies are best suited for their particular model. Laes and Couder argue that it is critical for policy makers to understand the underlying assumptions, model structure, and data used to generate projections in order to achieve desired outcomes and clarify model results [30]. With that said, assumptions, input data, and calculation structures will be described in detail in this thesis. Known constraints and limitations of this research and the LEAP-Canada model are the following:

- The modelling period spans 40 years (2010-2050)
- Demand tree development was limited to publically available statistical data. Industrial and agricultural end-use energy consumption data was lacking. While data for several industrial sub-sectors were developed through this work, some sub-sectors will be based on aggregate fuel use data, rather than end-use device data.
- Energy transformation capacity projections, resource reserve additions, resource production, device energy efficiency improvements, economic indicators, and demographic projections were based on the latest available projections which are publically available. These are subject to change as time passes.
- Reasonable assumptions have been developed where data are not available. These assumptions are described in the appropriate sections of the thesis.
- Climate change can affect the average energy intensity of technologies in various sectors (for example: space heating in Canadian households). Climate change variables are not in the scope of this research.

1.7 Organization of thesis

This thesis has 7 chapters. The contents of chapters 2, 3, and 4 have been submitted for publication as separate papers at the time of this writing. The submissions all include relevant contents form chapter 1 (introduction) and 7 (conclusion). The contents of chapters 5 and 6 will also be submitted as separate papers. There will be some repetition across chapters due to this format.

Equations are labelled in chronological order across chapters. Figures and tables are labelled with a chapter-index format (example Table 1-2 indicates the second table in the first chapter).

Chapter 1 provides an introduction to energy use and emissions in Canada. It discusses Canada's current energy and GHG emission paradigm in the global context. The current federal and provincial GHG emission policy landscape is discussed. A literature review on energy modelling is presented. The objectives of this thesis are outlined, as are the knowledge gaps they are meant to fill.

Chapter 2 gives a multi-regional analysis of Canada's energy system in 2012. Sankey diagrams are used to illustrate the energy flow in Canada from natural resource to final consumption. The life cycle of energy resources and overall efficiency of national and sub-national energy systems are examined.

Chapter 3 comprises of the LEAP-Canada development methodology and generation of energy and GHG emission outlooks to 2050. The LEAP-Canada model framework, energy demand tree development, energy supply system development, assumptions, and other details are explained here. Energy and GHG emission outlooks to 2050 are presented graphically and discussed.

Chapter 4 contains national and regional GHG Sankey diagrams. Analyses of GHG emissions flow from natural resource to point of emission in 2014, 2030, and 2050 are covered. Emissions contained in exported resources are estimated for Canada and the major regions of Canada.

Chapter 5 examines the proposed major crude oil pipelines – Keystone XL, Trans Mountain, Energy East, Line 3, and Northern Gateway. Implications of approving or denying the pipelines are considered. A multi-regional analysis is conducted to determine energy demands and GHG emissions associate with each proposed pipeline. Alternative crude-by-rail scenarios are also analyzed and compared.

Chapter 6 consists of a background about Alberta's oil sands, detailed oil sands energy and GHG emission outlooks, and a GHG mitigation assessment of using BC-Hydro power in the oil sands. The cost effectiveness and impacts on BC's domestic electricity supply are studied.

Chapter 7 concludes the thesis and recommends further expansions of this research. Improvements to the LEAP-Canada are suggested and well suited study topics for the model are proposed.

The Appendix contains results tables of energy demand, GHG emissions, and energy production for Canada. It also includes tables of energy demand and GHG emissions of the provinces and territories individually. Results are shown for years 2010, 2020, 2030, 2040, and 2050. The model has over 2 million data points across the study period.

2 Chapter II: Mapping Canadian Energy Flow from Primary Fuel to End Use[1]

2.1 Background

Sankey diagrams are a widely used flow-pattern visualization tool that use arrows to illustrate a process; the width of the arrow and lines indicates the energy intensity of a particular process [56]. The diagrams show energy flow from primary sources to end uses through different processes and consumptions in different economic sectors. Several tools are described in the literature for the flow process visualization. Graveland describes the flow of different material, energy, exergy, and chemical processes using a tool called Exan™ Pro [57]. Another report describes the conversion of 2-D Sankey diagrams into 3-D diagrams for energy-efficient product development in mechanical engineering with virtual reality tools [58]. Szargut et al. use a band diagram for energy and exergy flow of thermal, chemical, and metallurgical processes [59]. Visualization tools are used to present global energy flow processes and efficiencies at different stages of energy conversion for planning and implementing measures to lower GHG emissions. Ma et al. did an evaluation and validation study using Sankey diagrams for energy flow from primary source to end use in China [60]. From the publications cited above, one can observe that Sankey diagrams facilitate the selection of energy-efficient scenarios of energy flow. Cullen and Allwood described a global map of energy conversion efficiency through a Sankey diagram for the reduction of GHG emissions [61]. Suzanne et al. described the use of a Sankey diagram to

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[1] A version of this chapter has been submitted for publication, titled:

M. Davis, M. Ahiduzzaman, and A. Kumar, "Mapping Canadian Energy Flow from Primary Fuel to End Use," *Energy Conversion and Management (Submitted),* 2017.

show annual consumption of electricity and natural gas and other end-use energy for a building hub. Through Sankey diagrams, the researchers easily identified large sources of end-use consumption with seasonal variations for different sectors [62]. These studies describe the evolution of mapping global energy with the help of Sankey diagrams. The diagrams can also be used to analyze energy flow in order to predict future scenarios. Lombard et al. used a Sankey diagram to analyze energy flow for heating, ventilation, and air conditioning (HVAC) and found that HVAC systems were responsible for approximately 50% of a building's total energy consumption and identified areas for efficiency improvement [63]. The diagrams also illustrate energy transformations in thermal comfort services (i.e., heating and cooling). Efficiency improvements should be focused on those areas of energy flow that have the highest potential for energy savings and GHG emissions mitigation. These can be calculated in the energy flow chains of a Sankey diagram. System energy loss can also be shown in Sankey diagrams [40, 61].

Further examples of Sankey diagram usage to map energy pathways are the mapping of energy use in the U.S. [64], a GHG emissions flow diagram [65], global energy flows from primary energy through carriers to end-uses and losses done for the year 2004 [66], global exergy and carbon flow diagrams [67], U.S. energy flow process diagrams done in 2014 [68], an energy flow diagram of the U.K. in 2010 [69], and energy flow diagrams for China [70].

As energy production, distribution, and consumption are complex, a Sankey diagram is an appropriate tool for analyzing energy flow. An earlier study investigated energy flows for Alberta's energy sector, one of the provinces in Canada [71]. Little has been reported on end use and rejected energy within Canada's economic sectors. The overall objective of this chapter is to develop a complete map of energy flow patterns using Sankey diagrams in different Canadian provinces as well as a gross energy flow of Canada as a whole. This study addresses energy flow from primary fuel to end use as well as the useful and rejected energy through the various energy transformation and end-use processes in different sectors in Canada. There are different inter-provincial export-imports as well as international export-imports, all of which will be discussed in this paper.

2.2 Methodology

2.2.1 Energy database

Canada's energy flow was mapped using energy-mix data. Energy data for coal, crude oil, natural gas, natural gas liquids, hydro, nuclear, biomass, etc., were used to analyze flow processes. Energy from import sources was also included in the synthesis. The energy data, available up to 2012, were collected from the Government of Alberta, Natural Resources Canada, the Canadian socio-economic information management (CANSIM) database, and the World Nuclear Association [9-12, 72, 73].

2.2.2 Sectoral energy analysis

Energy demand in the residential, commercial and institutional, industrial, transport, and agriculture sectors was analyzed in this study. Energy input, used energy, and waste energy in the economic sectors were analyzed and quantified. Energy from fossil sources (coal, crude oil, natural gas, and natural gas liquids), renewable sources (hydro-electricity, biomass, wind, and solar), nuclear sources, and imports were critically synthesized and plotted on Sankey diagrams to indicate the flow processes.

2.2.3 Developing Sankey diagrams

Sankey diagrams are flow diagrams in which the width of the lines indicates the quantity of flow. In this study, these diagrams are used to illustrate energy flow processes from primary fuel to end use. The diagrams help us understand specific energy flows in each economic demand and supply sector as well as distribution of energy with respect to different processes. In this study, energy distribution is estimated through the various stages of energy flow, identify major energy flows in various economic sectors, and illustrate total useful energy and energy loss. Though some very recent data are available in some sectors (up to 2015), 2012 data is fully available and used in this study to allow for a comprehensive sector-wide annual study. All emerging small-quantity energy sources such as wind, solar, and biomass are included in the diagrams. The main two sources of inflow energy in Canada are indigenous production and imports. Energy outflow is through local consumption, non-fuel use, and exports. The gross flow of the Canadian energy pool is shown in Figure 2-1. Energy resource sectors are clearly identified by category and type of energy. Stock in supply sources is maintained by indigenous production and import from and export to provinces and the U.S. Primary fuel includes coal, crude oil, natural gas, natural gas liquids, and biomass. Electricity comes mainly from hydro, nuclear, coal, and natural gas (Table 2-1). The energy demand sectors are Canada's five economic sectors: residential, commercial and institutional, industrial, transport, and agriculture. The end-use sub-categories of the demand sectors are: space heating and cooling, lighting, running appliances, industrial and mining processes, and passenger and freight transport (Table 2-2).

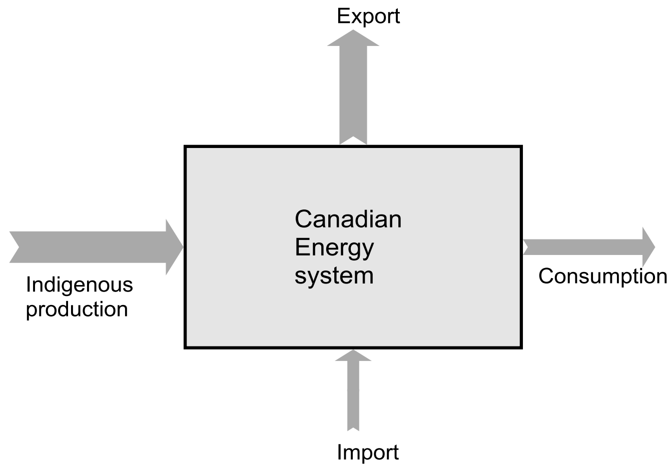

Figure 2-1: Canada's gross energy flow

Table 2-1: Canada's energy supply sector

Source category	**Source sub-category**	**Description**
Supply source	Indigenous production	Primary energy production in Canada
	Import	Primary energy and electricity imported to Canada
	Export	Primary energy and electricity exported from Canada
Primary source	Stock change	Primary energy stock variation (based on pipeline movements and refinery inventory)
	Nuclear	Electricity from nuclear power
	Hydro	Electricity from hydro-power
	Wind	Electricity from wind power
	Solar	Electricity from solar power

Source category	Source sub-category	Description
	Biomass	Combustible forest/agriculture residues, biofuel
	Coal	Bituminous, sub-bituminous, lignite coal, coal coke
	Crude oil	Fuel oil, petroleum products
	Natural gas	Natural gas, coal bed methane
	Natural gas liquids	Condensate and other liquids from natural gas
Energy carrier	Fuel	Oil, gas, coal, biofuel used for engines, boilers, burners
	Electricity	Electricity generation from power plants including Combined heat and power (CHP), nuclear, hydro, and other renewables
	Non-fuel	Industrial material from petroleum sources

Table 2-2: Energy demand side sectors in Canada

Economic sectors	Description
Residential	Energy demand for space heating and cooling, water heating, appliances, and lighting. Energy comes from both primary and secondary sources
Commercial and institutional	Energy demand for space heating and cooling, water heating, space lighting, and street lighting
Industry	Energy demand for mining, pulp and paper, production and processing of chemicals and metals, pipeline transportation, and forest processing
Transport	Energy demand for passenger, freight, and off-road transportation
Agriculture	Motive and non-motive power, non-energy use of petroleum

The map of energy flows from source to end use is given in Figure 2-2. The main energy sources include nuclear, hydro, coal, crude oil, natural gas and gas liquids, and others. These are derived from net indigenous production, net import, and stock variation. Electricity is the main secondary energy carrier. Most electricity comes from hydro, nuclear power, biomass, and coal power plants. Electricity export and import are also included in the map. The data for the energy sources are mainly derived from Natural Resources Canada's (NRCan) energy use database, StatsCan's Canada Yearbook, and CANSIM's database, all for 2012 [73-75]. Rejected and useful energy in each sector was calculated based on ratios reported by Kaiper in 2003 [76] (Table 2-3).

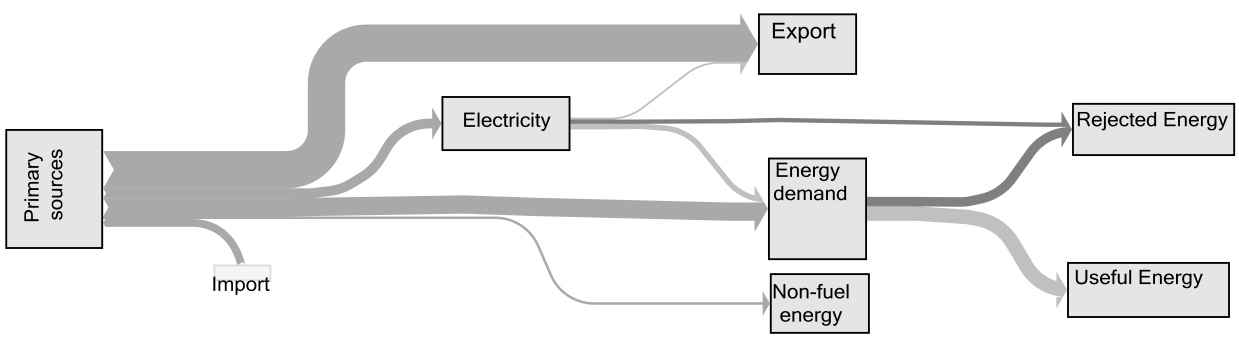

Figure 2-2: Sankey diagram showing energy flow from source to end use

The software tool e!Sankey pro 3.2, was used to generate the Sankey diagrams for this study [77]. The energy flow for the provinces and territories as well as all of Canada is illustrated in Sankey diagrams and discussed in the results and discussion section. The energy available to each energy source module was calculated as shown in Equation (1). The outflow of the energy was balanced as shown in Equation (2).

Table 2-3: Rejected and useful energy ratios

Economic sectors	Useful / rejected energy ratio
Residential	0.75
Commercial and institutional	0.75
Industry	0.80
Transport	0.20
Agriculture	0.80
Electricity generation	0.30

$$\text{Energy available} = \text{Production} + \text{Imports} + \text{Stock changes} - \text{Losses} \qquad (1)$$

$$\text{Outflow energy} = \text{Energy demand} + \text{Non-fuel use} + \text{Export} \qquad (2)$$

2.3 Results and discussion

2.3.1 Integrated energy flow for all provinces and territories in Canada

The total energy available in Canada's energy flow in 2012 was estimated to be 27,981 PJ and is shown in Table 2-4 and Figure 2-3. Of the total energy flow, approximately 3,387 PJ were from imported sources, and the remaining 24,594 PJ were from in-country sources. Supply side energy comprises local production, imports, and stock changes, and demand side energy comprises local energy demand, exports, and non-fuel uses of energy. Canada's energy sources can be divided into two main sources, fossil fuel and non-fossil fuel. Non-fossil fuels can be divided into two main sources, renewable and nuclear. The highest amount of energy flow was observed to be 21,393 PJ (76.46%) from fossil sources followed by nuclear (4,500 PJ, 16.08%) and renewable (2,049 PJ, 7.32%). Most of the energy available in Canada in 2012 was from crude oil (38.91%), followed by natural gas (24.94%), nuclear (16.08%), coal (6.69%), hydro-electricity (4.85%), and others (5.08%).

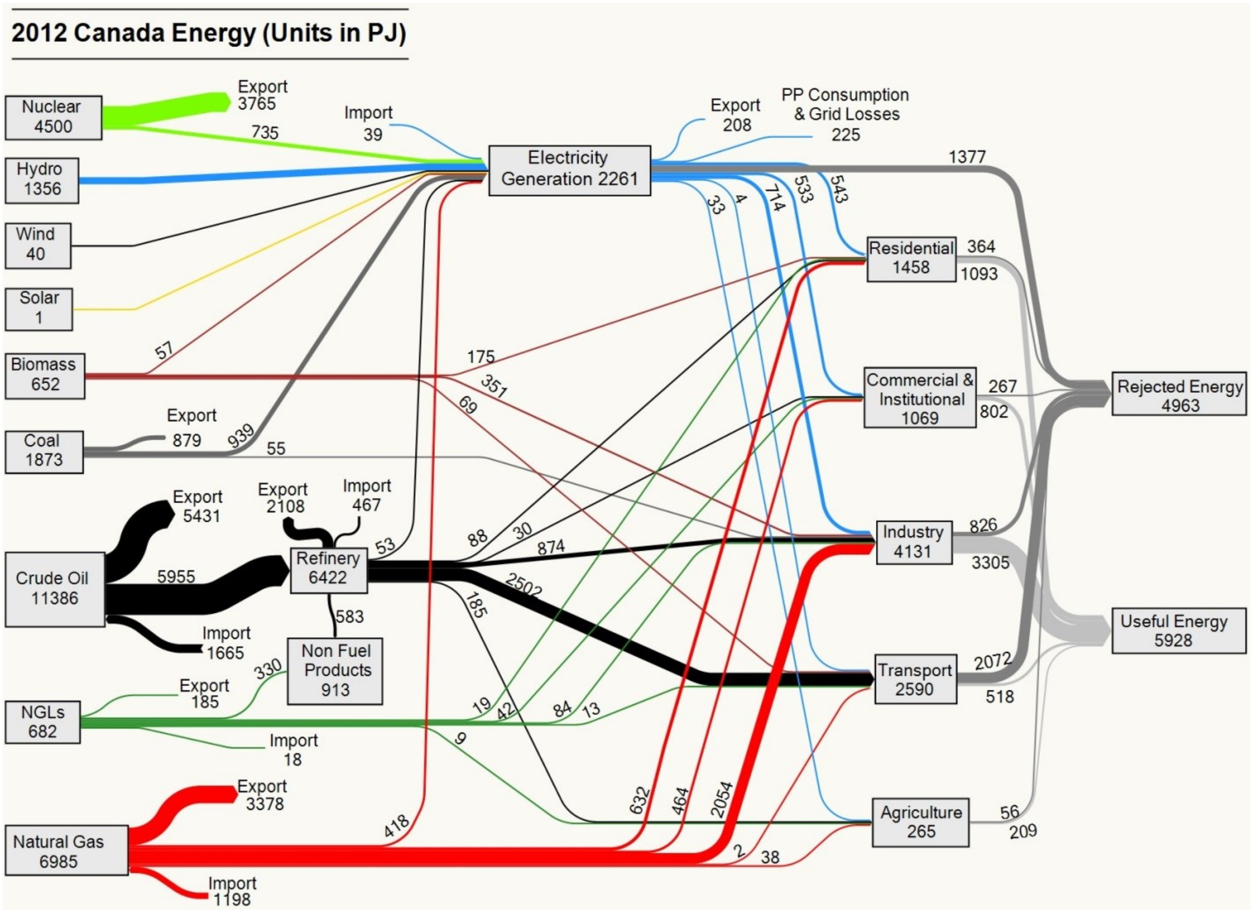

Figure 2-3: Integrated energy flow Sankey diagram for Canada, 2012

Table 2-4: Ranking of energy flow from primary sources to demand sectors in Canada in 2012

Source	PJ	Proportion	End use/consumption	PJ	Proportion
Primary source			**Economic sector**		
Crude oil	11853	42.36%	Industry	4131	14.76%
Natural gas	6985	24.96%	Transport	2590	9.26%
Nuclear	4500	16.08%	Residential	1458	5.21%
Coal	1873	6.69%	Commercial/institutional	1069	3.82%
Renewables	1397	4.99%	Agriculture	265	0.95%
NGLs	682	2.44%	Sub total	9513	34.00%
Biomass	652	2.33%	Generation/transmission losses	1601	5.72%
Electricity import	39	0.14%	Non-fuel use	913	3.26%
Total	27981	100%	Export		
			Crude oil	7539	26.94%
Supply source			Nuclear	3765	13.46%
Indigenous	24594	87.90%	Natural gas	3378	12.07%
Import	3387	12.10%	Coal	879	3.14%
Total	27981	100.00%	Electricity	208	0.74%
			NGLs	185	0.66%
			Sub total	15954	57.02%
			Total	27981	100.00%

Most of Canada's energy is exported. More energy (15,954 PJ) is exported than imported, which clearly indicates that Canada is a net energy exporter country. The energy exported is comprised of fossil fuels, nuclear sources, and electricity. The main sources of exported energy were crude oil (7,539 PJ), followed by nuclear (3,765 PJ), natural gas (3,378 PJ), coal (879 PJ), electricity (208 PJ), and NGLs (185 PJ). 2,261 PJ of electricity were available in Canada in 2012. Of the total electricity supply, 2,222 PJ were generated in the country [78, 79]. Canada generated 3.6% more electricity in 2012 than in 2009 [78]. More than 60% of the national electricity mix came from hydro-power (1,356 PJ), which makes Canada the second largest hydro-electricity producing country in the world [80].

On the demand side, 9,513 PJ were consumed in Canada in 2012. Energy is supplied to the demand side as oil, natural gas, coal, NGL, electricity, and biomass. The industrial sector consumed the highest amount of energy, 4,131 PJ (43.42%), followed by the transport sector at 2,590 PJ (27.23%), the residential sector at 1,458 PJ (15.33%), the commercial and institutional sector at 1,069 (11.24%), and the agriculture sector at 265 PJ (3.03%) [11, 81-86]. Energy consumption by type showed that almost 97% of transportation energy came from crude oil. The industrial sector consumed mainly natural gas (38.0%), electricity (21.31%), crude oil (26.10%), biomass (10.47%), and a small amount (4.12%) from other sources.

Energy losses and useful energy consumption are also plotted on the Sankey diagrams. Most energy loss occurred in the transportation sector (80%), followed by electricity generation from thermal power plants (72.65%) (excluding the renewables, hydro-wind-solar), the commercial and institutional sector (24.98%), the residential sector (24.97%), the agriculture sector

(21.13%), and the industrial sector (20%). The Sankey diagram illustrates that the highest energy efficiency was found in the industrial sector and the lowest in the transport sector. The overall ratio of rejected to useful energy was estimated to be 0.84.

2.3.2 British Columbia

The total energy flow for British Columbia in 2012 is illustrated in Figure 2-4. Total available energy in British Columbia's energy mix is estimated to be 2,937 PJ in 2012. Of the total available energy, 83.25% came from fossil sources and the rest from renewable sources. Among the fossil fuels, natural gas provided the largest share (43.21%) of the total energy mix followed by coal (24.72%), crude oil (14.27%), and NGLs (1.06%). The total amount of electricity available in the province was 300 PJ [78, 79]. Of this total, 265 PJ were generated in the province; this is 13.25% more than the amount generated in 2009 [78]. Electricity came mainly from hydro (78.33% of the total electricity mix) and the rest from imports (11.67%) and other sources (wind and biomass). Approximately 20% of the total electricity was exported. Coal was not used in the provincial energy mix; all of the province's coal is exported. Crude oil production was not enough to meet the demand; therefore, more was imported. Natural gas is abundant in the province; about 78.64% (998 PJ) of the natural gas was exported. In the demand sectors, 1,005 PJ of energy were consumed. Of the total consumption, the industrial sector consumed the highest amount of energy (36.72%) in the province followed by the transport sector (34.13%), the residential sector (15.92%), the commercial sector (11.24%), and the agriculture sector (2%) [11, 81-86]. The ratio of rejected and useful energy is estimated to be 1:1.20. Total imported energy was 1823 PJ, whereas total exported energy was 361 PJ. This demonstrates a deficit in energy production in the province in 2012.

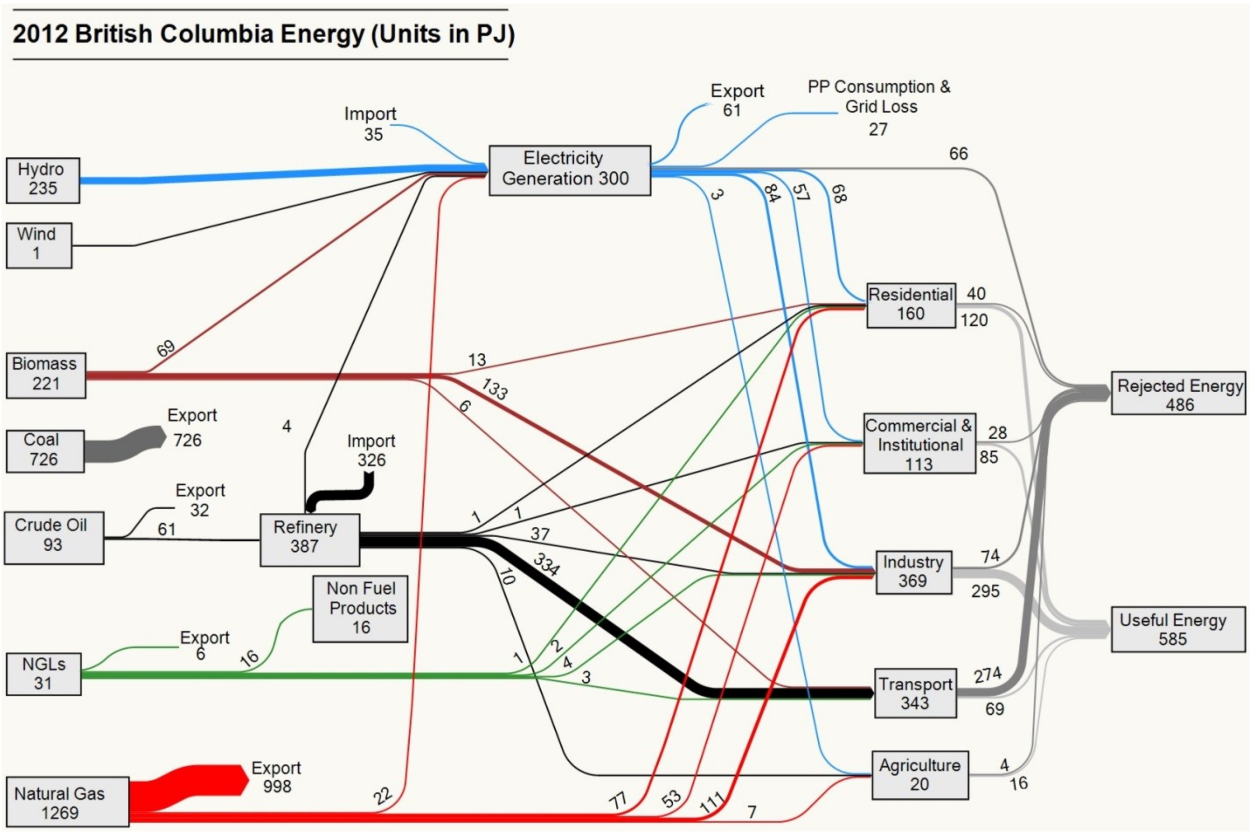

Figure 2-4: Sankey diagram of energy flow for British Columbia in 2012

2.3.3 Alberta

Alberta's total energy flow in 2012 is illustrated in Figure 2-5. Alberta's total energy supply including electricity imports was 11,505 PJ in 2012. Of this total, almost 99% came from fossil sources and the remaining 1% came from hydro, wind, and biomass. Among the fossil fuels, crude oil contributes the most energy (52.73%) followed by natural gas (36.84%), coal (6.46%), and natural gas liquids (NGLs) (2.78%). Electricity generated in Alberta's energy mix was an estimated 252 PJ [78, 79], which is 5.4% more than the electricity generated in 2009 [71]. About 91% of electricity available was from fossil fuel sources. A significant amount of coal (587 PJ) was consumed to generate electricity [87]. In Alberta electricity is generated from coal and natural gas (NG). During the study year, total electricity consumption in Alberta was 215.4 PJ. To meet the demand, 27 PJ of electricity were imported; however 1 PJ was exported. This suggests that electricity generation lags behind demand.

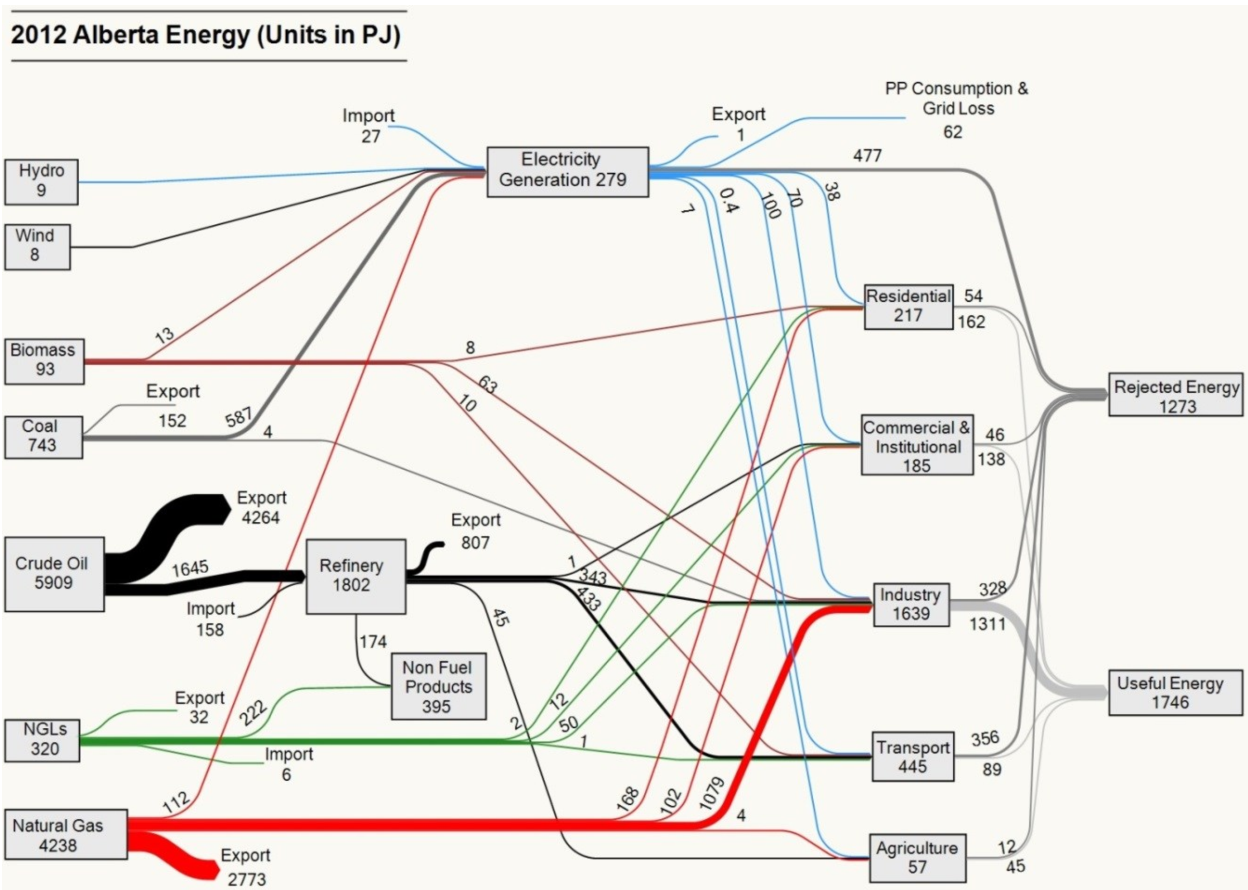

Figure 2-5: Sankey diagram showing energy flow for Alberta in 2012

Alberta produces a large amount of fossil-based fuel, more than is consumed, and a significant amount of this fuel is exported. Crude oil exports were the highest (5,071 PJ) followed by NG (2,773 PJ) and NGLs (32 PJ). Non-fuel use of fossil fuel is seen in crude oil (174 PJ) and NGLs (222 PJ). On the demand side, 2,543 PJ of energy were consumed. Among the economic demand sectors, the industry sub-sector consumed the most energy (64.45%), followed by transport

(17.50%), residential (8.53%), commercial (7.27%), and agriculture (2.24%) [11, 81-86]. The overall ratio of rejected energy to useful energy is estimated to be 1:1.37. The total import of energy was 191 PJ, whereas the total export was 8,029 PJ. This shows that there was a surplus in energy production in Alberta in 2012.

2.3.4 Saskatchewan

The total energy flow for Saskatchewan in 2012 is illustrated in Figure 2-6. The total available energy in Saskatchewan's energy mix was 7,604 PJ in 2012. The total electricity pool in the province was 79 PJ, of which 77 PJ came from in-province generation [78, 79]. This is 2.6% more than the electricity generated in 2009 [78]. Of the total energy supply, about 59% (4,500 PJ) came from nuclear sources; however, no nuclear energy is consumed in the province. The remainder of energy came almost entirely from fossil fuels and a limited amount came from hydro, wind, and biomass in the study year. Other than nuclear, the highest contribution was recorded by natural gas (1,716 PJ), followed by crude oil (1,076 PJ), coal (233 PJ), and NGLs (46 PJ). In the electricity sector, the major share came from coal. Major exports came from natural gas (1,428 PJ), followed by crude oil (868 PJ), NGLs (33 PJ), and some other sources, mainly electricity (3 PJ). In the demand sector, 538 PJ of energy were consumed by different economic sectors in Saskatchewan in the study year. Of the total demand, the industrial sector consumed the most energy (47.77%) in the study year followed by the transport sector (24.16%), the agriculture sector (11.52%), the residential sector (9.11%), and the commercial sector [11, 81-86]. The ratio of rejected and useful energy is 1.19. Total imports of energy were 8 PJ, and total exports were 6832 PJ. This indicates a significant surplus of energy production by the province in 2012.

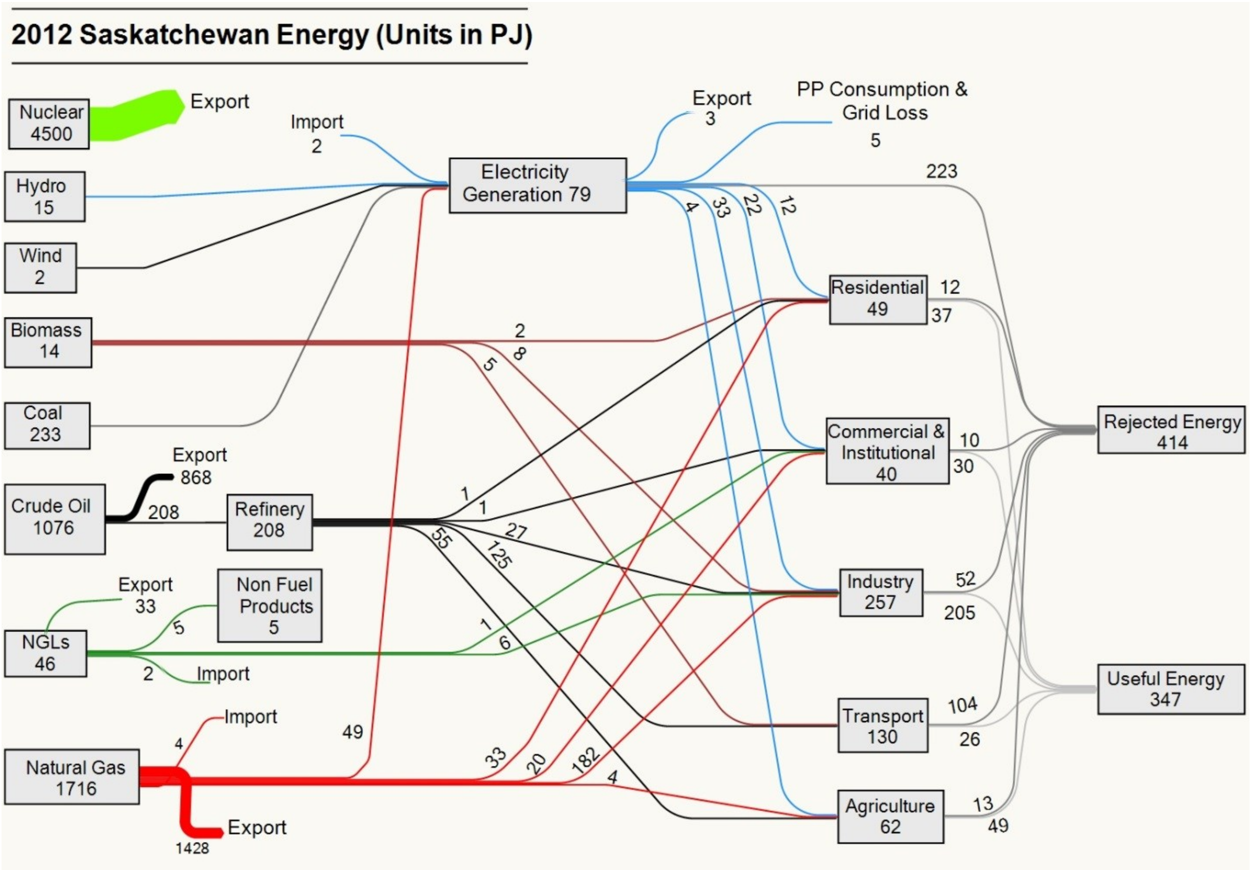

Figure 2-6: Sankey diagram showing energy flow for Saskatchewan in 2012

2.3.5 Manitoba

The total energy flow for Manitoba in 2012 is illustrated in Figure 2-7. Total available energy in Manitoba's energy mix was 435 PJ in 2012. Of the total energy available, 46.90% came from crude oil followed by hydro-electricity (26.67%), NG (17.01%), NGLs (4.86%), biomass (3.21%), and the rest from wind and coal. Almost all the electricity in 2012 came from hydro-power plants; some came from imports and other sources. Of the total electricity, 120 PJ [78, 79] came from in-province generation; this figure is 2.4% lower than the amount generated in 2009 [78]. Hydro generation was 116 PJ; however, 122 PJ of electricity was recorded in the power mix. This is likely due to electricity loss during transmission. About 30% of the total pooled electricity was exported in 2012. In the demand sectors, 287 PJ of energy were consumed in 2012. Of the total energy demand, the highest amount of energy was consumed in the transport sector (34.49%), followed by the industrial sector (24.74%), the residential sector (18.12%), the commercial and institutional sector (14.98%), and the agriculture sector (7.67%) [11, 81-86]. The ratio of rejected and useful energy is estimated to be 1:1.35. The total amount of energy imported was 165 PJ, whereas the total exported was 132 PJ. This demonstrates a deficit in energy production in the province in 2012.

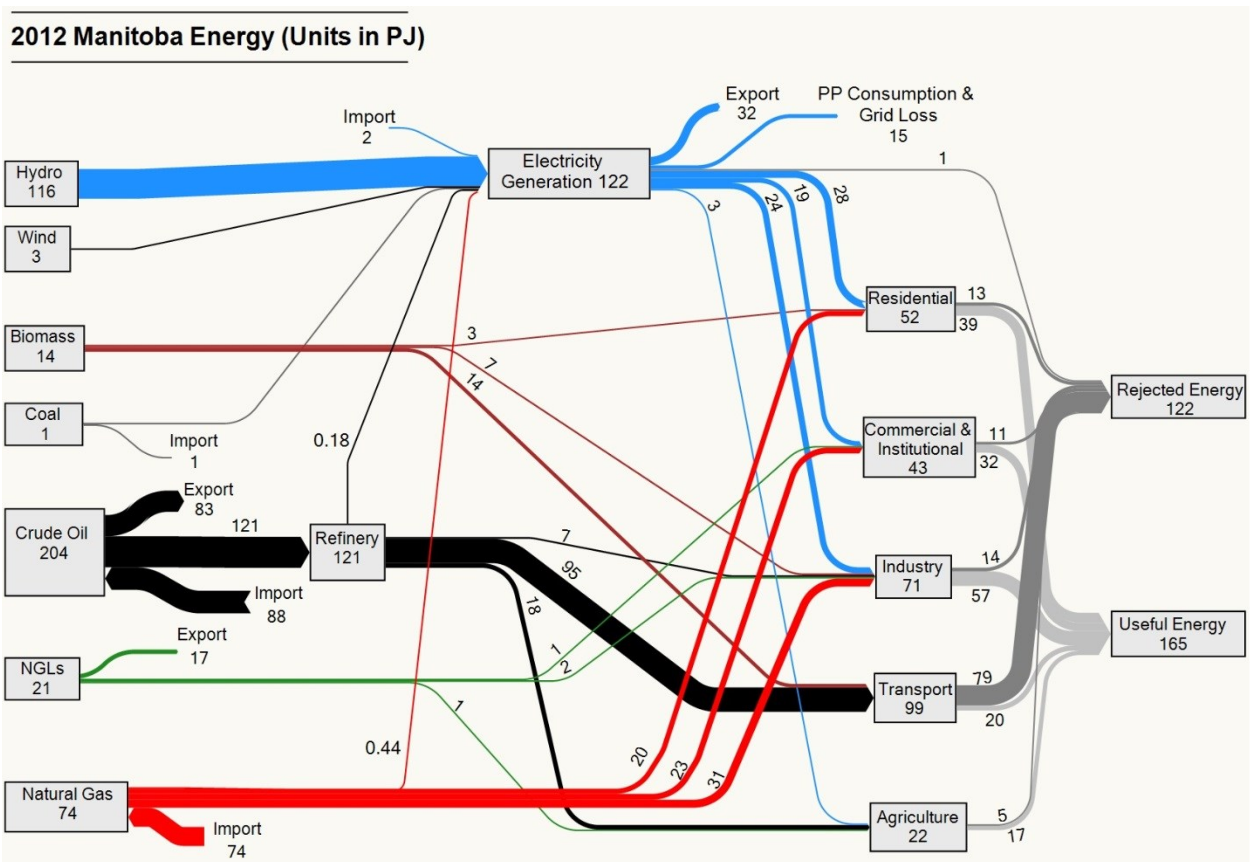

Figure 2-7: Sankey diagram of energy flow for Manitoba in 2012

2.3.6 Ontario

The total energy flow for Ontario in 2012 is illustrated in Figure 2-8. The total available energy in Ontario's energy mix in 2012 was 7,577 PJ. The energy mix in Ontario is exceptional in that all types of energy are present in the mix. Ontario imported all of Saskatchewan's nuclear energy (4,500 PJ) and processed it. 692 PJ of nuclear energy were used to produce electricity, and the remainder was exported. The total electricity in the pool was 573 PJ in 2012 [78, 79]. Of this total, 553 PJ came from in-province generation; this figure is 4.3% higher than the electricity generated in 2009 [78]. The province has a significant amount of hydro- (122 PJ) and wind- (14 PJ) generated electricity and generated 1 PJ of solar electricity in 2012. Ontario is the only province with a significant level of solar power production in the study year. The fossil fuel resource availabilities are crude oil (1,555 PJ), NG (953 PJ), NGLs (210 PJ), and coal (65 PJ). Crude oil and natural gas were mostly from imported sources with little coming from provincial production. Energy from crude oil contributed most of the province's internal energy flow-mix (1,143 PJ) followed by NG (953 PJ), nuclear (692 PJ), NGLs (132 PJ), biomass (138 PJ), hydro (122 PJ), and wind and solar. The share of non-fuel fossil energy use was 285 PJ and came from crude oil and NGLs. Electricity in this province was provided from eight different in-province fuel sources as well as imported electricity. The major share of electricity came from nuclear; other sources are hydro, NG, coal, biomass, wind, and solar. In the demand sector, 2,583 PJ of energy were consumed in 2012. Of the total energy demand, the transport sector scored the highest consumption rate (32.91%) followed by the industrial sector (28.80), the residential sector (19.67%), the commercial and institutional sector (16.22%), and the agriculture sector (2.40%) [11, 81-86]. The ratio of rejected and useful energy is calculated to be 1:0.93. Total imports of energy were 7,091 PJ, whereas total exports were 4,154 PJ. This indicates a deficit in energy production for the province in 2012.

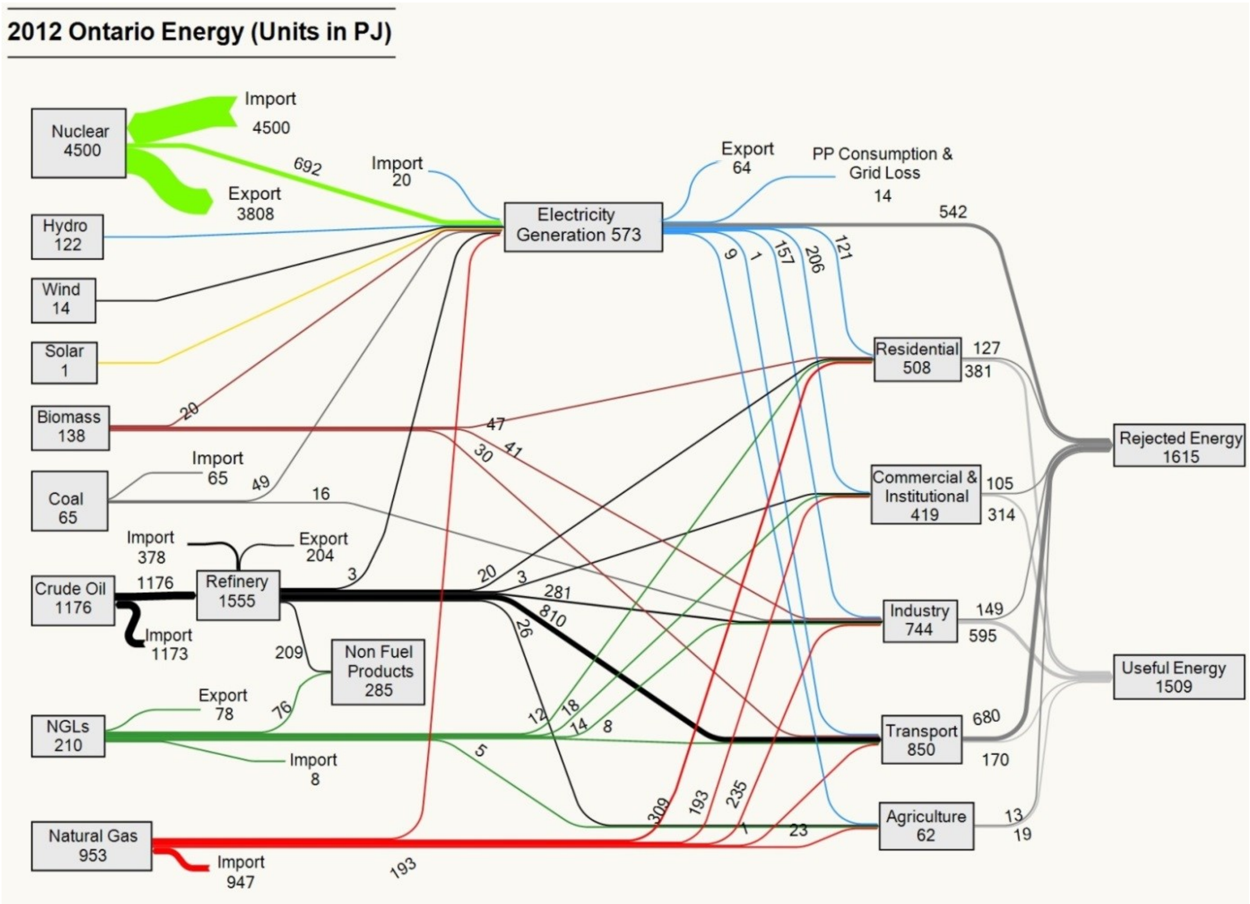

Figure 2-8: Sankey diagram showing energy flow for Ontario in 2012

2.3.7 Quebec

The total energy flow for Quebec in 2012 is illustrated in Figure 2-9. The total available energy in Quebec's energy mix was 2,321 PJ in 2012. The total electricity pool in the province was 840 PJ, out of which 716 PJ came from in-province generation [78, 79]. This is 1.3% more than the electricity generated in 2009 [78]. The province is rich in hydro-electricity and produced 691 PJ in 2012, half the amount produced nationally. Most of the fossil fuel used in Quebec was imported during the study year. Crude oil contributed most of the energy in the mix (43.60%) followed by hydro-electricity (29.77%), NG (9.69%), and biomass (7.37%); the remainder came from other sources (nuclear, NGLs, coal, and wind). In the electricity mix, the primary share came from hydro (82.26%) and the second largest share came from imported sources (14.75%). The major energy exports were oil (377 PJ), electricity (117 PJ), and NGLs (17 PJ). In the demand sector, 1,692 PJ of energy were consumed in 2012. Of this total, the industrial sector consumed the highest amount of energy (34.57%) in 2012 followed by the transport sector (30.38%), the residential sector (20.86%), the commercial and institutional sector (12.29%), and the agriculture sector (1.89%) [11, 81-86]. The ratio of rejected and useful energy is calculated to be 1:1.43. Total imports of energy were 1417 PJ and total exports were 511 PJ. This indicates a deficit in energy production in the province in 2012.

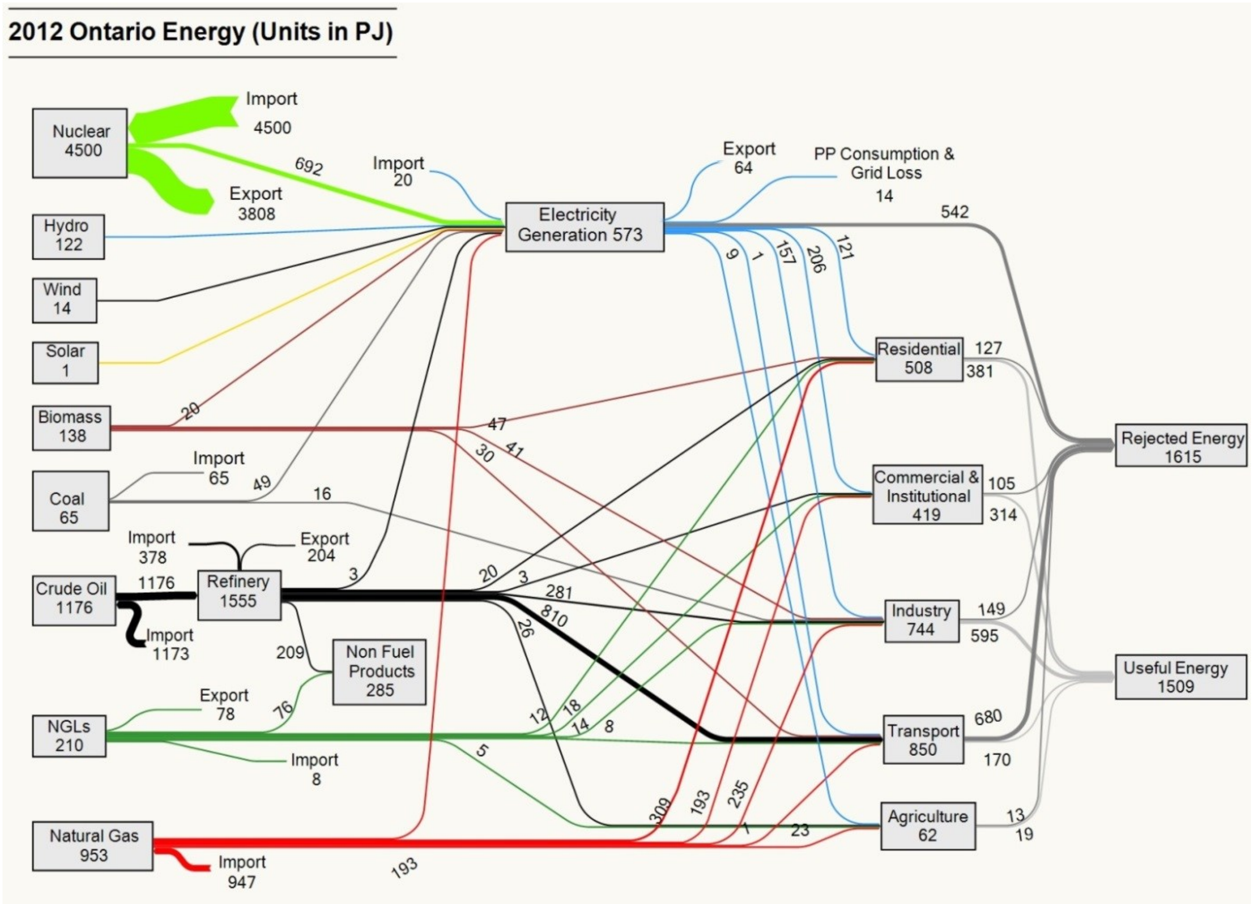

Figure 2-9: Sankey diagram showing energy flow for Quebec in 2012

2.3.8 Atlantic Provinces (Newfoundland and Labrador, Nova Scotia, New Brunswick, Prince Edward Island)

The total energy flow for the Atlantic Provinces in 2012 is illustrated in Figure 2-10. 1,721 PJ of energy were available in the energy flow mix in the Atlantic provinces in that year, of which about 276 PJ were imported. Large shares of available energy came from crude oil (1,283 PJ). About 75% of the Atlantic's crude oil energy was exported. Of the electricity available, the mix comprised nuclear, hydro, wind, coal, and imports for a total of 262 PJ. Of this total, 236 PJ [78, 79] was generated within the Atlantic provinces in 2012; this figure is 3.5% more than the amount generated in 2009 [78]. Hydro-power dominated the electricity mix share with 63% of the total. About 48% of the electricity was exported during the study year. There appears to be an abundance of electricity in these provinces. Total energy supply disposition to different economic sectors was estimated to be 520 PJ. The transport sector consumed the highest demand share (39.81%), followed by the industrial (24.23%), residential (22.50%), commercial and institutional (11.54%), and agriculture sectors (1.92%) [11, 81-86]. The overall ratio of rejected energy to useful energy is estimated to be 1:0.90. The total export of energy (1,099 PJ) was higher than the imports, indicating there was surplus energy production in the Atlantic provinces in 2012.

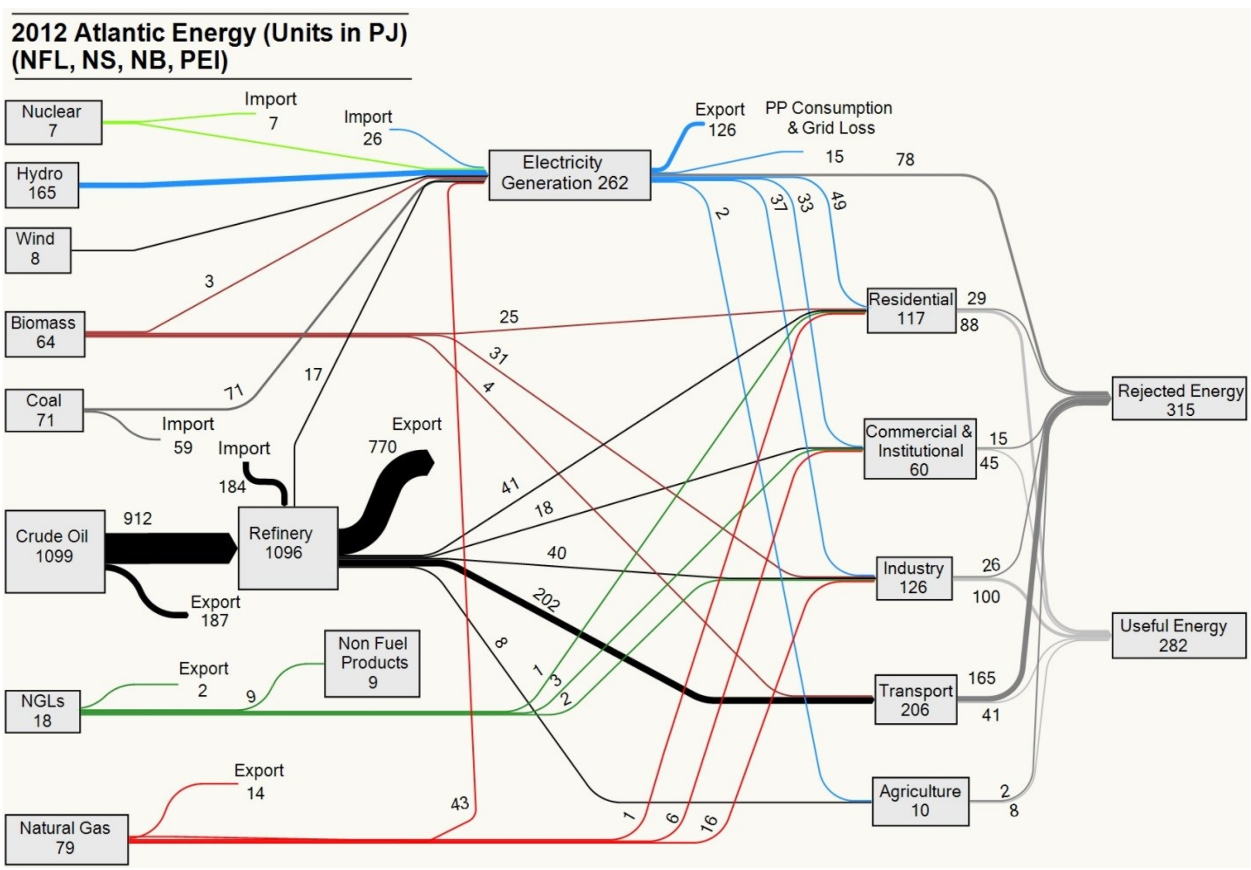

Figure 2-10: Sankey diagram showing energy flow for the Atlantic Provinces in 2012

2.3.9 Territories

The total energy flow for Northern Canada (Yukon, the Northwest Territories, and Nunavut) in 2012 is illustrated in Figure 2-11. The total available energy in the Territories' energy mix was 63.31 PJ in 2012. Of the total energy available in the mix, crude oil contributed the highest amount (83.72%), followed by NG (10.74%), hydro (3.95%), NGLs (1.58%), and wind (0.02%). The total electricity generated was estimated to be 4.7 PJ [78, 79]. This is 6.8% more than the electricity generated in 2009 [78]. Most of the crude oil produced (35 PJ) was exported. On the demand side, the total energy consumed was estimated to be 24.3 PJ. Of the total demand, the industrial sector consumed the highest amount of energy (41.56%) in the study year followed by the transport sector (23.46%), the commercial sector (20.58%), the residential sector (11.52%), and the agriculture sector (2.88%) [11, 81-86]. The ratio of rejected and useful energy is calculated to be 1:1.80. Total imports of energy were 22 PJ, whereas total exports were 35 PJ. This indicates a surplus in energy production for the territories in 2012.

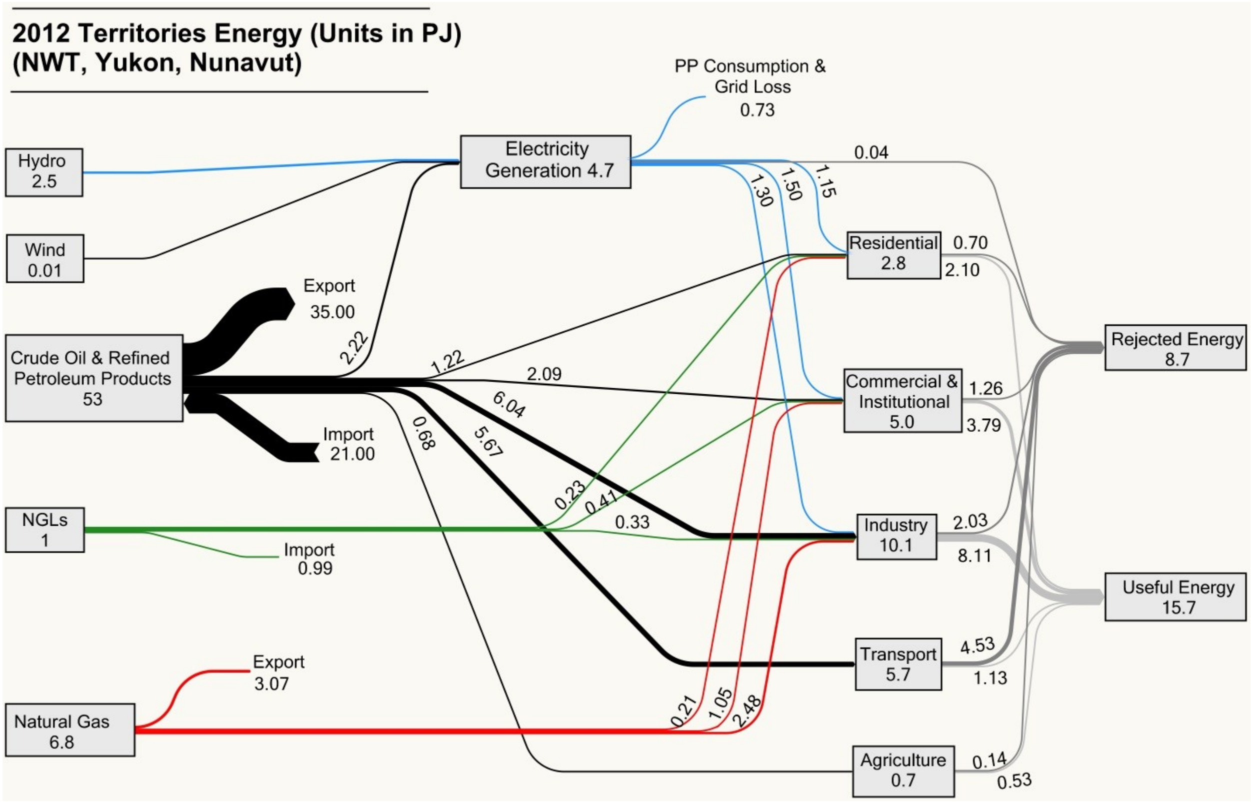

Figure 2-11: Sankey diagram showing energy flow for the territories in 2012

3 Chapter III: The Development of a Bottom-Up, Data-Intensive, Integrated Multi-Regional LEAP-Canada Energy Model and Energy and GHG Outlooks to 2050[2]

3.1 Methodology

3.1.1 LEAP energy model

The LEAP system is a computer-based tool used for energy modelling and planning. It is widely used for energy policy analysis and climate change mitigation assessment [88]. It can be used to forecast energy supply and demand over a long-term planning horizon, and various scenarios can be analyzed assuming different sets of assumptions. The analysis structure of LEAP is shown in Figure 3-1. The energy model developed for this study uses LEAP's demand, transformation, resource, non-energy sector emissions, and environmental database with demographics and macro-economic indicators as a basis for Canada's energy system.

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[2] A version of this chapter has been submitted for publication, titled:

M. Davis, M. Ahiduzzaman, and A. Kumar, "The Development of Energy and GHG Outlooks to 2050 for Canada using an Integrated Multi-Regional LEAP-Canada Energy Model," *Energy (Submitted),* 2017.

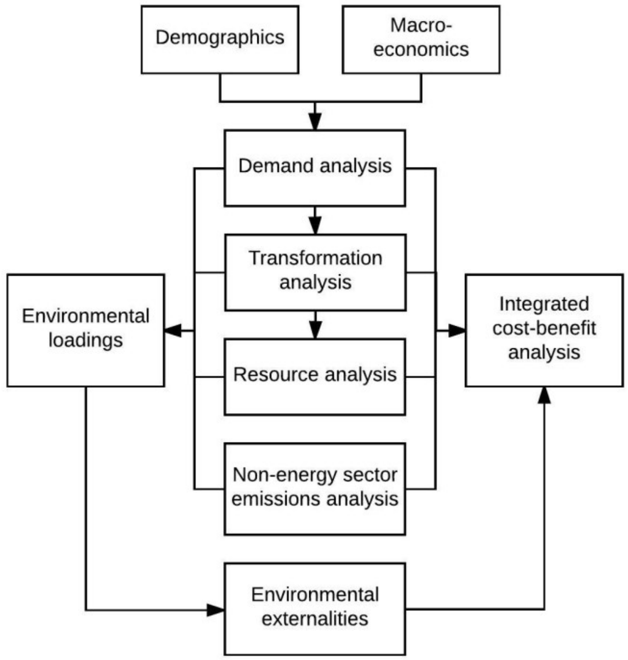

Figure 3-1: LEAP calculation structure [88]

3.1.2 Data sources

The primary sources of data for the development of the model are publically available statistical data and/or published government reports. Primary data sources are listed in Table 3-1. Each data source is referenced in more detail in subsequent sections. Other data sources that were less frequently used and not listed here are referenced in the subsequent sections. Several data were developed wherever not available.

Table 3-1: Principal data sources

Source	Description/Use
Natural Resources Canada (NRCan) Office of Energy Efficiency (OEE) Comprehensive Energy Use Database (CEUD) [89]	End-use energy demand Sectoral activity
Canadian socio-economic information management (CANSIM) Tables [90]	End-use energy demand (pipeline and non-energy use) Energy transformation data
National Energy Board (NEB) Energy Futures Reports (EFR) [51]	GDP, population, assumptions for energy intensity, sectoral activity future changes, energy supply and resource production projections, model validation
Technology and Environment Database (TED)	The TED holds information on technical characteristics, costs, and environmental impacts over a range of technologies [88]
National Inventory Report (NIR) [7]	Non-energy emissions, fugitive emission factors, model validation

3.1.3 LEAP-Canada model development

The model can be split into 4 key areas (or modules) of development: demand, transformation, resources, and non-energy effects. The demand module contains all of the sectors where energy is consumed. For this study, 5 overarching sectors were chosen: residential, commercial &

institutional, industrial, transportation, and agriculture. The transformation module contains all the processes that extract and convert resources. The resource module contains the primary and secondary resources used in the model. The non-energy effects module allows the input of variables to represent GHG emissions that are not related to energy transformation or use. Examples are agriculture emissions from cattle farming (enteric fermentation) or waste emissions from landfills or incineration. LEAP allows the modeler to design the demand trees and define the technologies and/or processes used throughout the model. The development of each module is covered in further detail in subsequent sections. The TED stores information on numerous fuels and technologies, including emission factors, which are applied to any combustion of fuel in the demand and transformation modules. Figure 3-2 shows the basic structure and energy flow of the LEAP-Canada model. The model is demand-driven, meaning the calculations start with the demand sector. When there is demand for a fuel, the transformation processes are dispatched to produce the required energy commodities. If there are in-sufficient reserves or processes to supply a commodity, imports will be brought into the province either from outside the model area (Canada) or from another province. If production exceeds demand, the excess will be exported. Imports and exports targets can be specified exogenously or calculated endogenously based on excess production or shortages.

A high-level visual overview of the process used to develop the model is shown in Figure 3-3. The first stage of development is to gather raw data on energy demand, disposition, conversion, and resources. Based on the quantity of available data, demand trees are designed and transformation processes are determined. The energy intensities of the end-use devices are then calculated from the data, and activity variables are determined. The demand trees are programmed into the model with the activity and energy intensity variables for the base year of 2010. The transformation module processes are also modelled with the 2010 data on energy extraction, conversion, and disposition. Resource data are entered on reserves, imports, and exports. This concludes the formation of the base year.

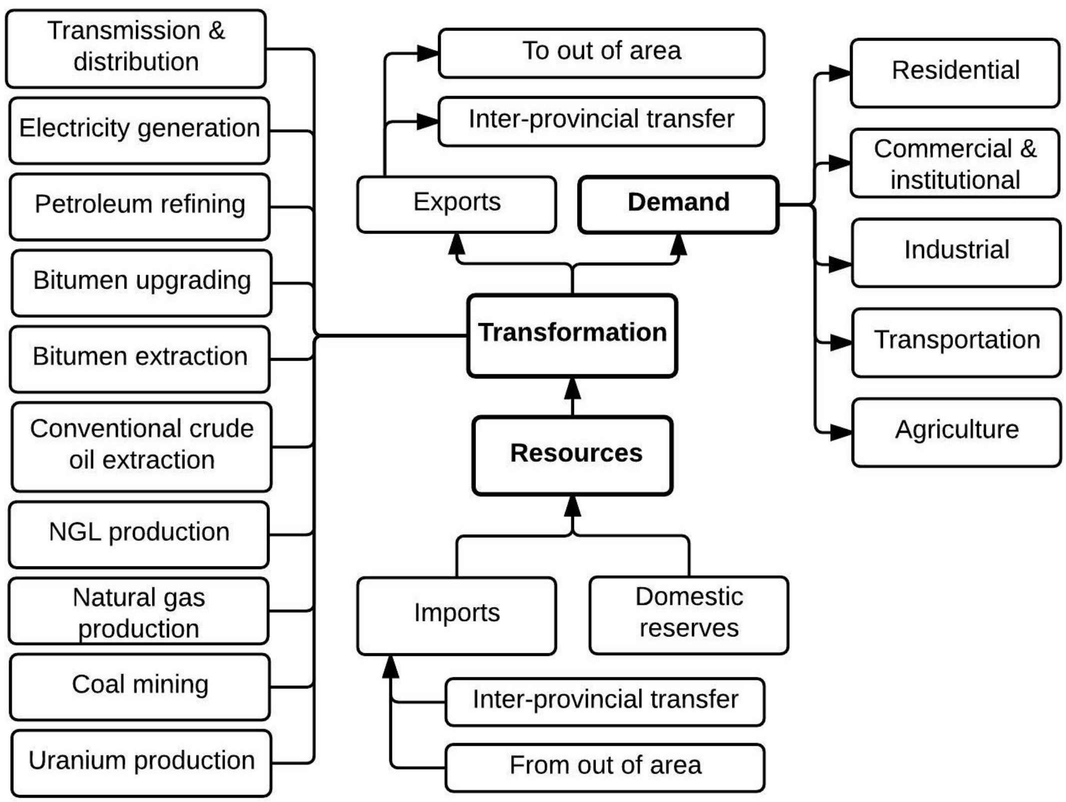

Figure 3-2: LEAP-Canada model structure

The reference scenario refers to all years other than the base year (2011 to 2050). For the years where data exist (2011-2014 in most cases), the actual values are used in the reference case for the demand and transformation variables. Energy intensity changes are also reflected in the reference scenario and will be explained further in the subsequent sections. Finally, validation is performed to compare the model results with other sources.

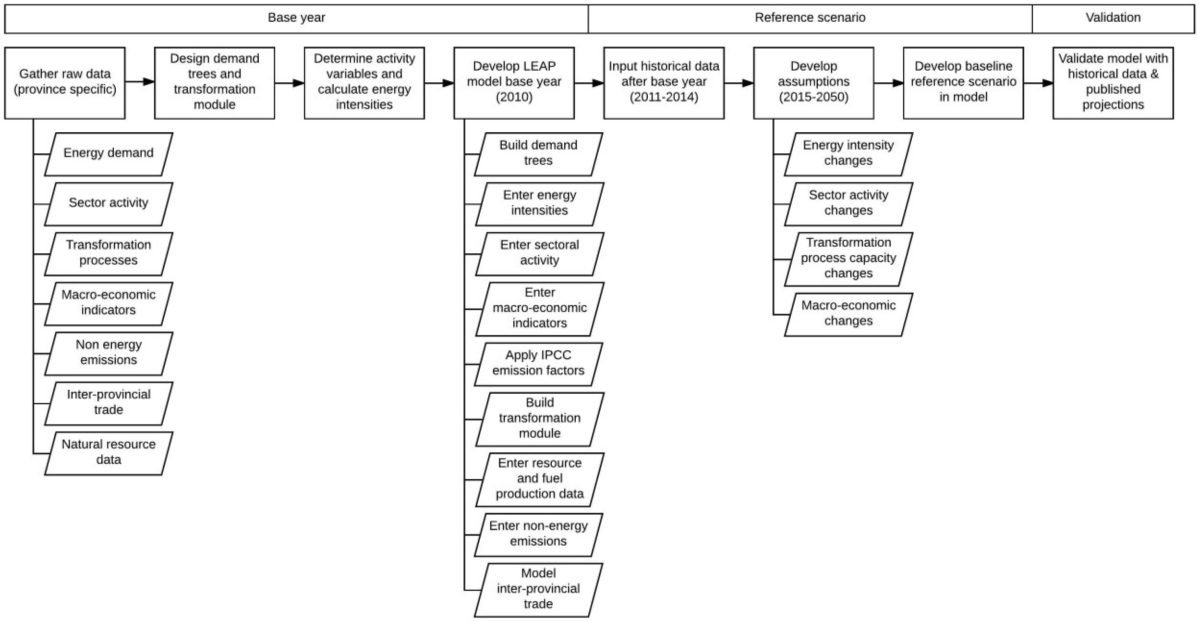

Figure 3-3: LEAP-Canada model development process

3.1.3.1 Demand sector development

The demand module includes all of the end-use demand sectors in Canada. The demand branches include the residential, commercial & institutional, industrial, transportation, and agriculture sectors. These were chosen as they are considered the broadest categories for which energy consumption in Canada is considered [91]. Each branch is developed from the bottom up, meaning the end-use device is defined and traced upwards into sub-categories and to the overarching sector. Each end-use device has a calculated energy intensity that represents the amount of energy it consumes per unit of sectoral activity. Sectorial activity is defined as the variable that characterizes major drivers of energy consumption in a particular sector [91]. The energy intensity units used for each sector are given in Table 3-2. The general formula used to calculate energy intensity from raw data is Equation (3); however, what the energy intensity values represent can be different for every sector. The device energy intensity together with sectorial activity determines the energy demand calculated in the model (Equation (4)).

$$Energy\ Intensity\ of\ Device = \frac{energy\ used\ by\ device\ in\ a\ particlar\ sector}{sectoral\ activity\ unit} \tag{3}$$

$$LEAP\ Energy\ Demand = \sum Energy\ Intensity\ of\ Devices * Activity\ of\ Use \tag{4}$$

Table 3-2: Energy intensity units

Sector	**Energy intensity units**
Residential	GJ / household
Commercial and institutional	MJ / m^2 of floor space
Industrial	kJ / Canadian dollar (CAD) of industrial GDP or specific to sub-sector
Transportation	Passenger transport: MJ / passenger-km Freight transport: MJ / tonne-km
Agriculture	MJ / CAD of agricultural GDP

The data used to calculate the energy intensities and the activity units for the base year are taken from NRCan's OEE CEUD [89]. Each province's and territory's data are extracted for the year 2010 and used to calculate energy intensities and activity levels, which are in turn used in the LEAP model. The demand module has approximately 46,000 data points for the 2010 base year, including energy, activity, and environmental variables. Approximately 2.2 million total data points exist in the model for the years 2010 to 2050.

3.1.3.1.1 *Residential sector*

The demand tree developed for the residential sector is shown in Figure 3-4. This sector has four dwelling types: single attached homes, single detached homes, apartments, and mobile homes. Each dwelling has end-use devices that fall under one of five end-use categories: space heating, water heating, lighting, space cooling, and appliances. Space heating and water heating have electric, natural gas, heating oil, wood, and propane heating devices. Space cooling has central units and window or room AC units that are electricity powered. Appliances include dishwasher, refrigerator, freezer, clothes washer and dryer, range, and other.

The final energy intensity of residential devices represents the average Canadian consumption per household of each specific device (Equation (3)). The raw data detail the end-use category fuel share as an average value for all dwelling types. It is assumed that this value is the same across all dwelling types. The energy intensity calculation was completed for all end-use devices, in all dwelling types, in all provinces and territories of Canada.

Historical population and population projections up to 2040 were taken from the NEB 2016 EFR [92]. After 2040, the trend line from 2035 to 2040 was used to calculate the population for the remaining years up to 2050. The household projections used in this study consider the decreasing demographic trend of average dwelling occupancy in Canada. Household stock data were obtained for the years 2005 to 2013 from NRCan’s OOE CEUD [89]. A linear trend for people per household was extrapolated to 2050. The number of households was then calculated based on the aforementioned population projections and the projected people per household. Device energy intensities for the years 2010-2013 were changed to reflect the regional trends. Household energy intensity is expected to decline at a rate of 0.7% per year from 2013 to 2040 due to improved household device and building efficiencies [51]. This is assumed for all provinces and territories in the model for all end-use devices. This trend was extended in the model to 2050.

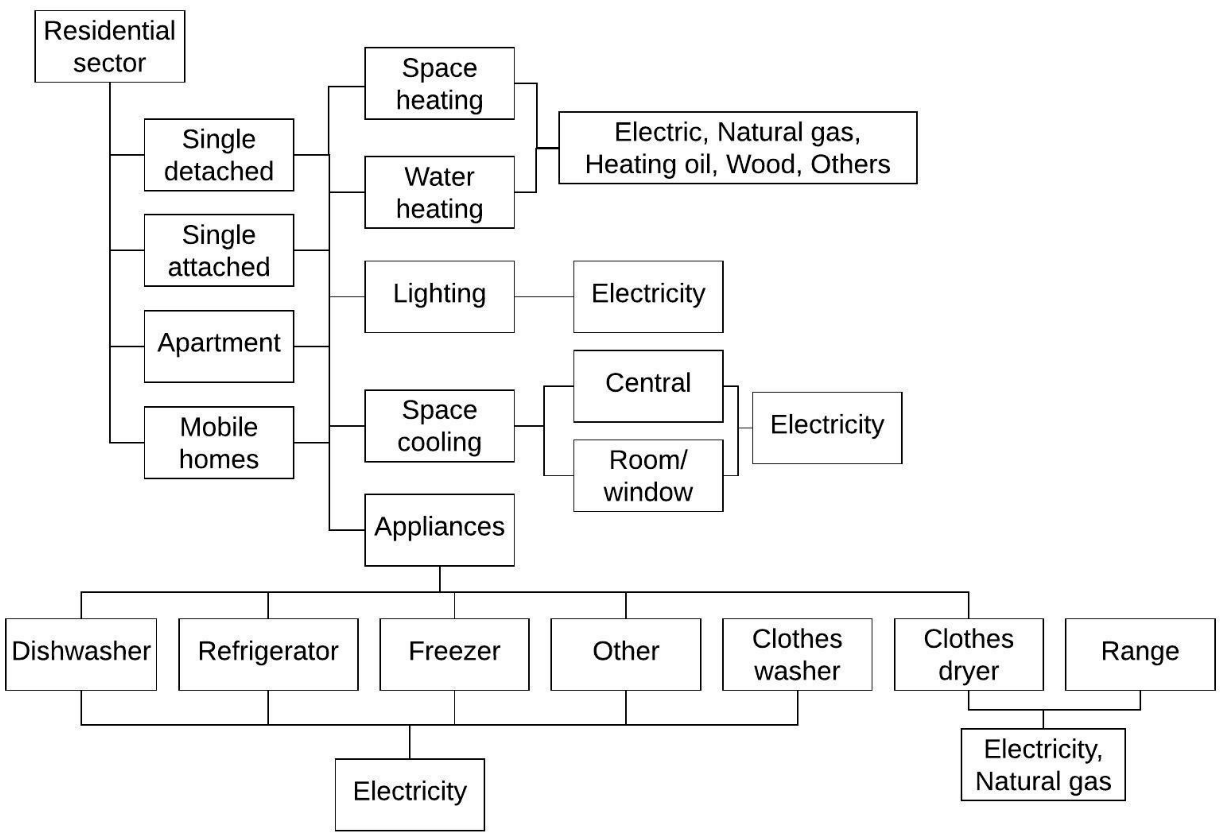

Figure 3-4: Residential demand tree

3.1.3.1.2 *Commercial and institutional sector*

The commercial & institutional sector is divided into 11 sub-sectors, which are shown in Figure 3-5. Each sub-sector has the energy use categories of space heating, water heating, auxiliary motors, lighting, auxiliary equipment, and space cooling. Space heating and water heating have electric, natural gas, heating oil, wood, and propane heating devices. Lighting and auxiliary motors consume only electricity. Space cooling has electricity and natural gas devices. Auxiliary equipment includes any stand-alone devices such as appliances or other equipment.

The final energy intensity represents the average Canadian energy consumption per square meter of commercial & intuitional floor space for each specific device. The raw data give the end-use category fuel consumption for each fuel type and the total floor space for each sub-sector. These were used in (3 to calculate the energy intensity for the devices in each sub-sector. This calculation was completed for all end-use devices, in all commercial & institutional sub-sectors, in all provinces and territories of Canada

Future commercial floor space was calculated from the growth trend from 2005 to 2013 [89]. Energy intensities from 2010-2013 were changed for each region to reflect regional trends. Energy intensity is expected to decrease at 0.9% per year from 2014 to 2040 due to building code improvements [51]. The energy intensity decline at a rate of 0.9% per year is assumed for all provinces and territories in the model for all end-use devices and continues in the model to 2050.

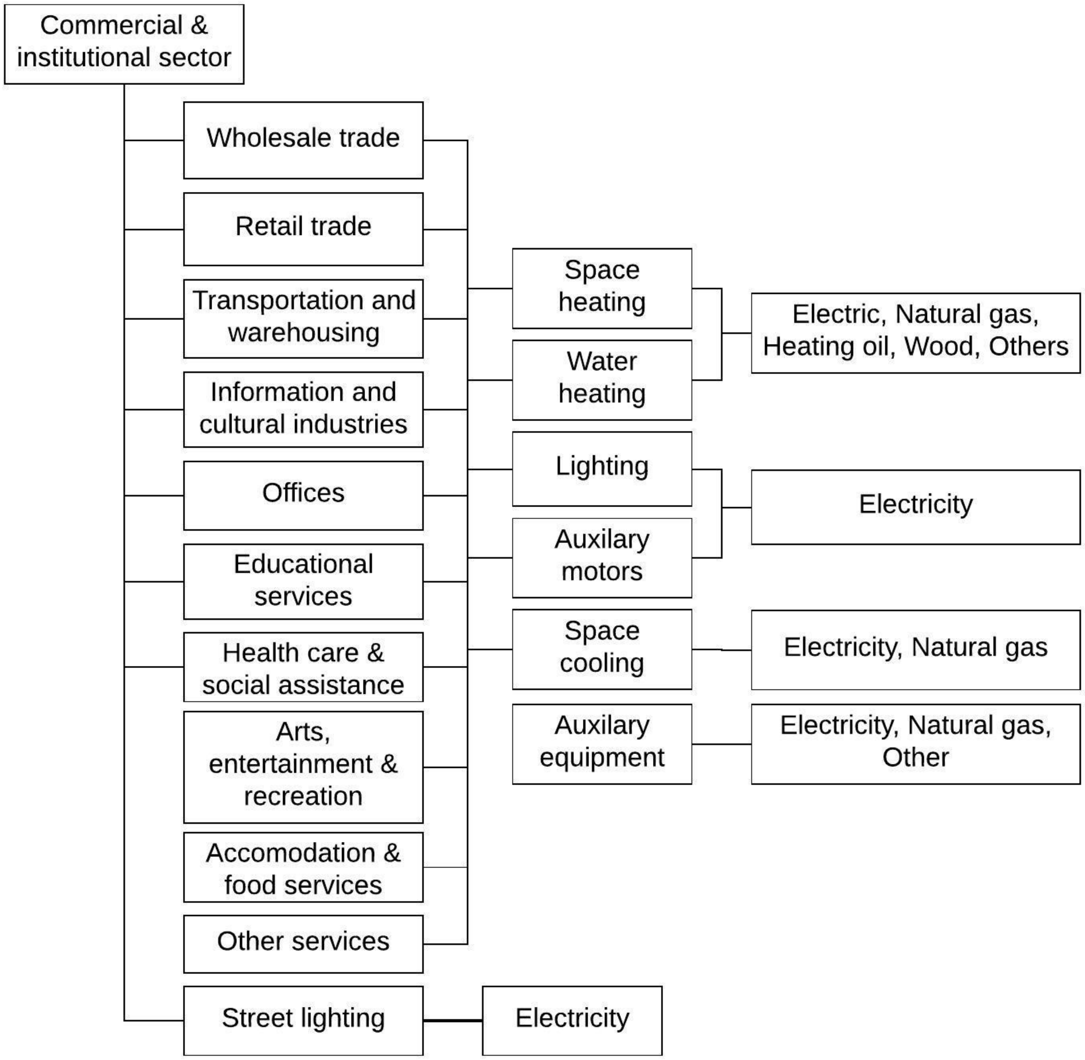

Figure 3-5: Commercial & institutional demand tree

3.1.3.1.3 *Industrial sector*

The industrial sector is divided into 11 sub-sectors, which are shown in Figure 3-6. As data for the industrial sector is generally lacking, each sub-sector has energy use categories by fuel type only, as opposed to by end-use device, with the exception of the mining, petroleum refining, and Alberta's pulp & paper sub-sectors. The oil sands surface mining and petroleum refining demand trees and energy intensities were taken from previous work [93, 94]. These demand trees are continued from Figure 3-6 in subsequent diagrams. The Alberta's pulp & paper demand tree and energy intensities were also expanded based on work by Shafique [95].

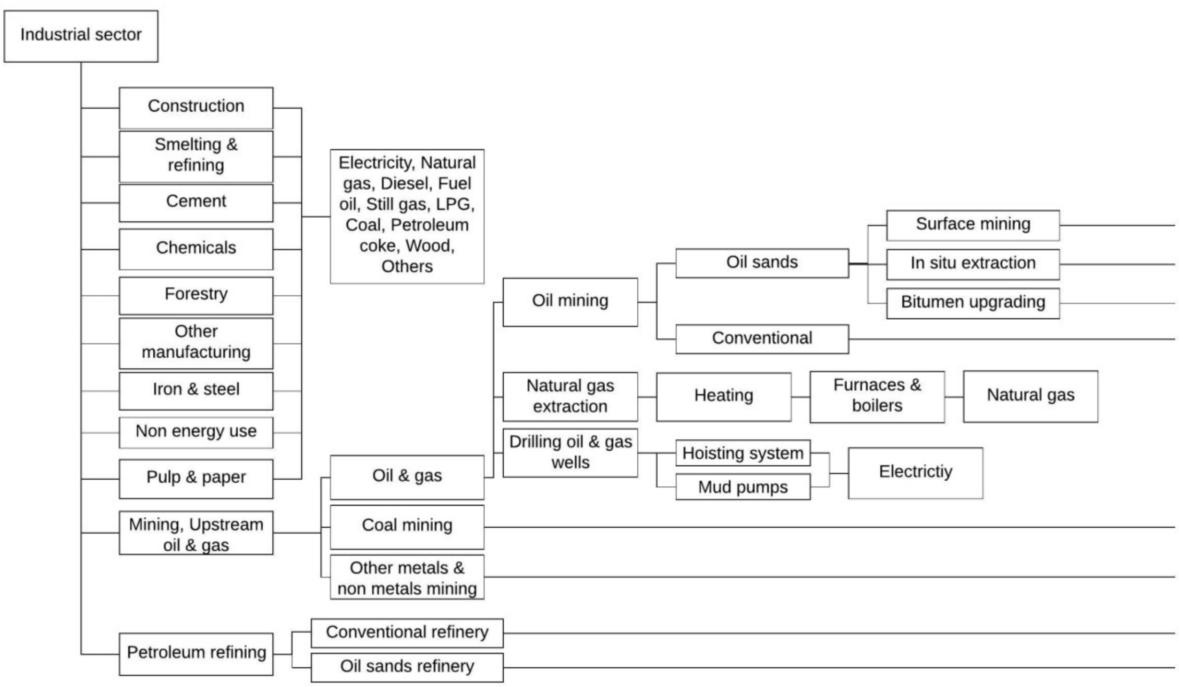

Figure 3-6: Industrial demand tree

Final energy intensity values for the industrial sub-sectors of construction, smelting and refining, cement, chemicals, forestry, other manufacturing, iron and steel, and non-energy use represent the average Canadian energy consumption per CAD of GDP for each specific sub-sector fuel use. The NEB is referenced for historical GDP, and 2007 dollars are used as the activity variable for each region [92]. Non-energy use is not included in the CEUD so CANSIM Tables 128-0013 and 128-0016 were used to calculate the energy intensity for non-energy uses [96, 97]. These calculations were completed for all industrial sub-sectors, in all provinces and territories of Canada.

Energy intensities from 2010 and 2013 were changed based on regional trends. Industry activity changes in future years are assumed to track GDP changes as projected by the NEB with the exception of the petroleum refining, mining & upstream oil & gas, and Alberta's pulp & paper sub-sectors. For the years 2041-2050, a trend is extrapolated from 2035-2040 values. Industrial energy intensity improvements are assumed to occur by 0.4% per year over the projection period. 0.4% is the average Canadian industrial energy intensity improvement from 1990 to 2013 according to CEUD data.

3.1.3.1.3.1 Mining and upstream oil and gas sub-sectors

The oil mining sector demand trees and energy intensities are based on earlier work on in-situ extraction, surface mining, conventional oil mining, bitumen upgrading [93, 98]. The mining sector demand trees for oil mining, bitumen upgrading, and other mining are shown in Figure 3-7, Figure 3-8, and Figure 3-9, respectively. Oil mining and bitumen upgrading have energy intensity units in *energy-unit/barrel of oil produced*. Crude oil production data were obtained from the NEB [92]. Coal production data were obtained from CANSIM Table 135-0002, and energy intensities are in *energy-unit/tonne of coal produced* [99]. "Other mining" varies from region to region and so an aggregate fuel-use demand tree was used with energy intensities of *kJ/CAD*, similar to other industrial sub-sectors.

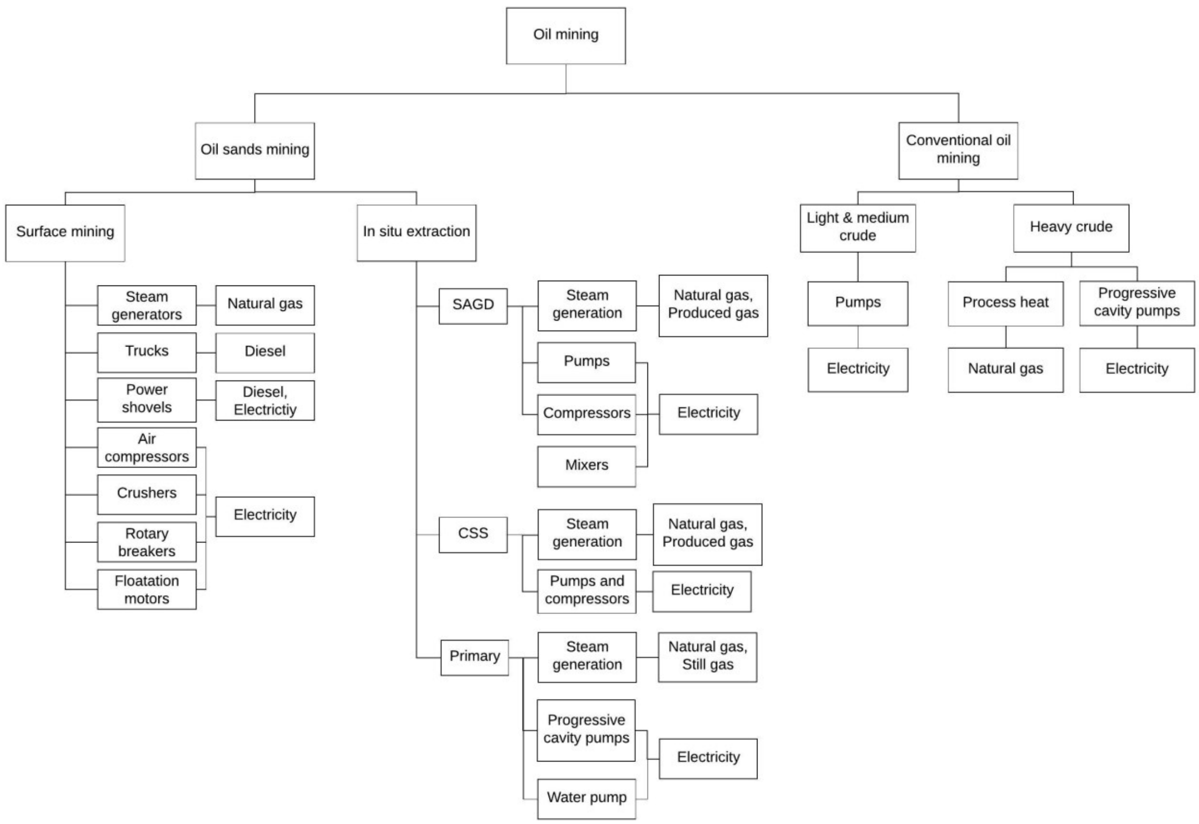

Figure 3-7: Oil mining demand tree [93, 98]

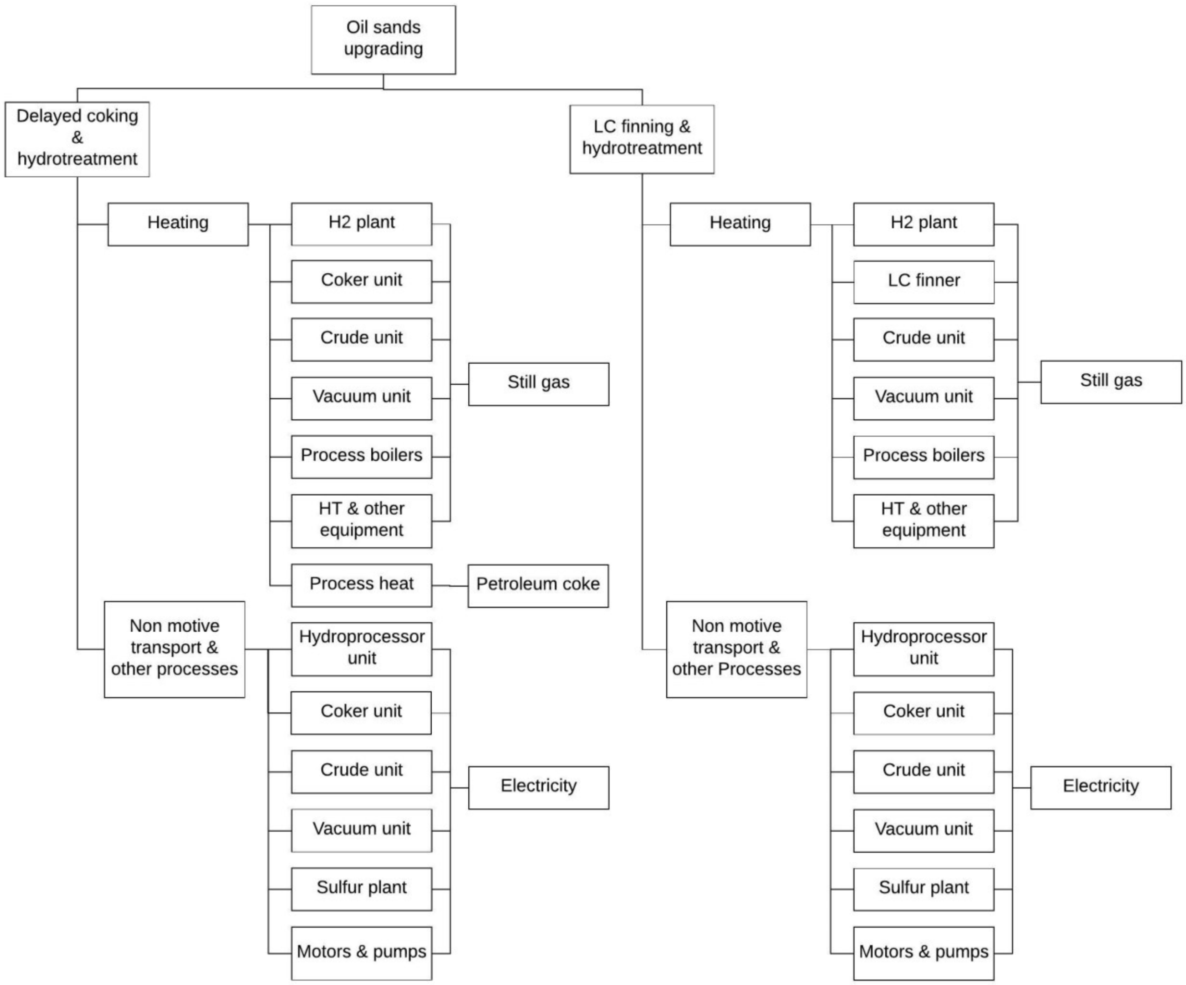

Figure 3-8: Bitumen upgrading demand tree [93, 98]

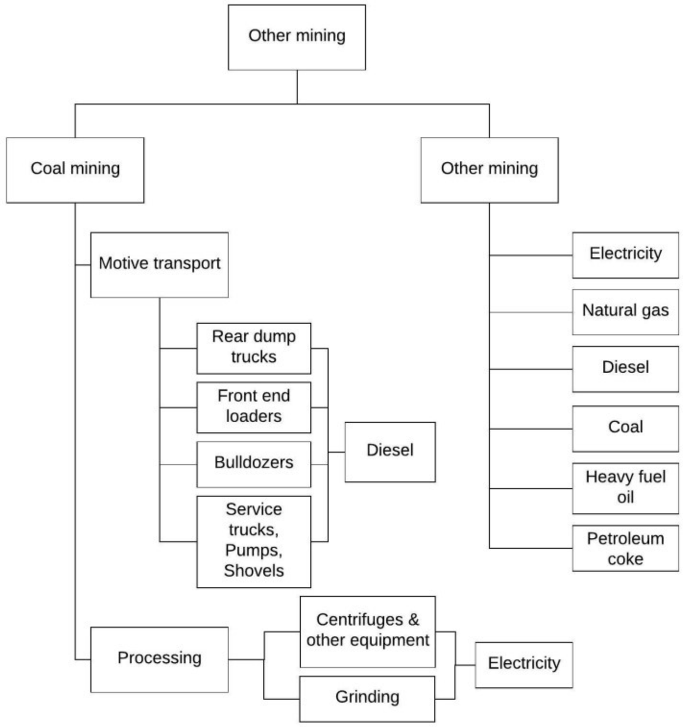

Figure 3-9: Other mining demand tree [93]

Projected production levels for oil mining for all regions were taken from the NEB up to 2040 [92]. For 2041-2050, the growth trend was extrapolated from the years 2035-2040 for each region with the exception of Alberta. An earlier report on the oil sands was used to determine production growth from 2041-2050 for Alberta [98]. Coal production in all regions was assumed to decrease by 1.2% per year until 2050 based on the 2016 NEB EFR projection of Canadian coal production to 2040 [51]. For all other production levels, the average projected growth from 2035-2040 is used for 2041-2050. Electric energy intensities in the oil sands were assumed to decrease by 0.054% per year and conventional oil mining motors were assumed to have a 0.13% per year efficiency improvement through the projection period, based on literature [100]. Other mining energy intensities were assumed to stay constant.

3.1.3.1.3.2 Petroleum refining

The detailed petroleum refining demand trees for conventional oil and oil sands synthetic crude oil (SCO) are shown in Figure 3-10 and Figure 3-11, respectively. The energy intensities developed by Talaei et al. [94] are in *energy-unit/barrel* of charged crude and are assumed to be constant for every region. CANSIM Tables 126-0001 and 134-0001 and the Canadian Association of Petroleum Producers (CAPP) Statistical Handbook were used to obtain the amount of each crude type sent to refineries in each region [84, 101, 102]. Additional refining capacity is expected for Alberta through the construction of the Sturgeon Refinery. All other regions are assumed to produce based on current capacity.

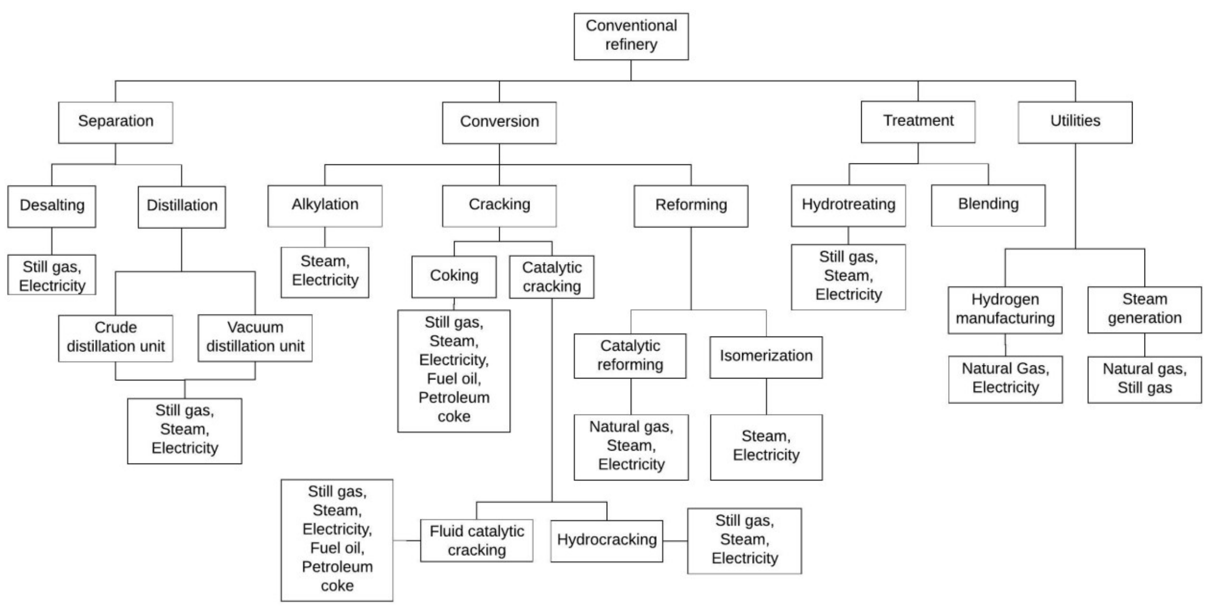

Figure 3-10: Conventional oil-based petroleum refinery demand tree [94]

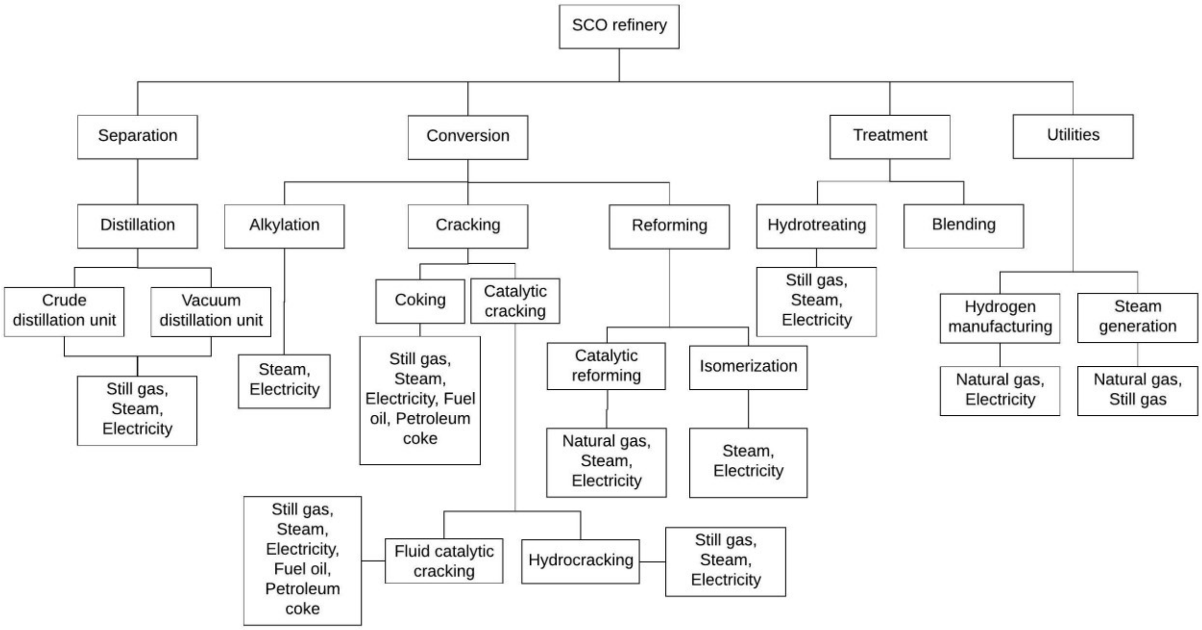

Figure 3-11: Oil sands-based petroleum refinery demand tree [94]

3.1.3.1.3.3 Alberta pulp & paper sub-sector

The development of the demand tree and energy intensities was based on earlier work by Shafique [95]. Alberta's pulp & paper mill demand trees are illustrated in Figure 3-12. Black liquor consumption intensity was added to the demand three based on NRCan's energy consumption data [89].

The reference scenario assumes no new mills are built in the Alberta pulp & paper sector but that existing mills will reach production levels using full capacity by 2050 and energy intensities remain constant over the projection period [95].

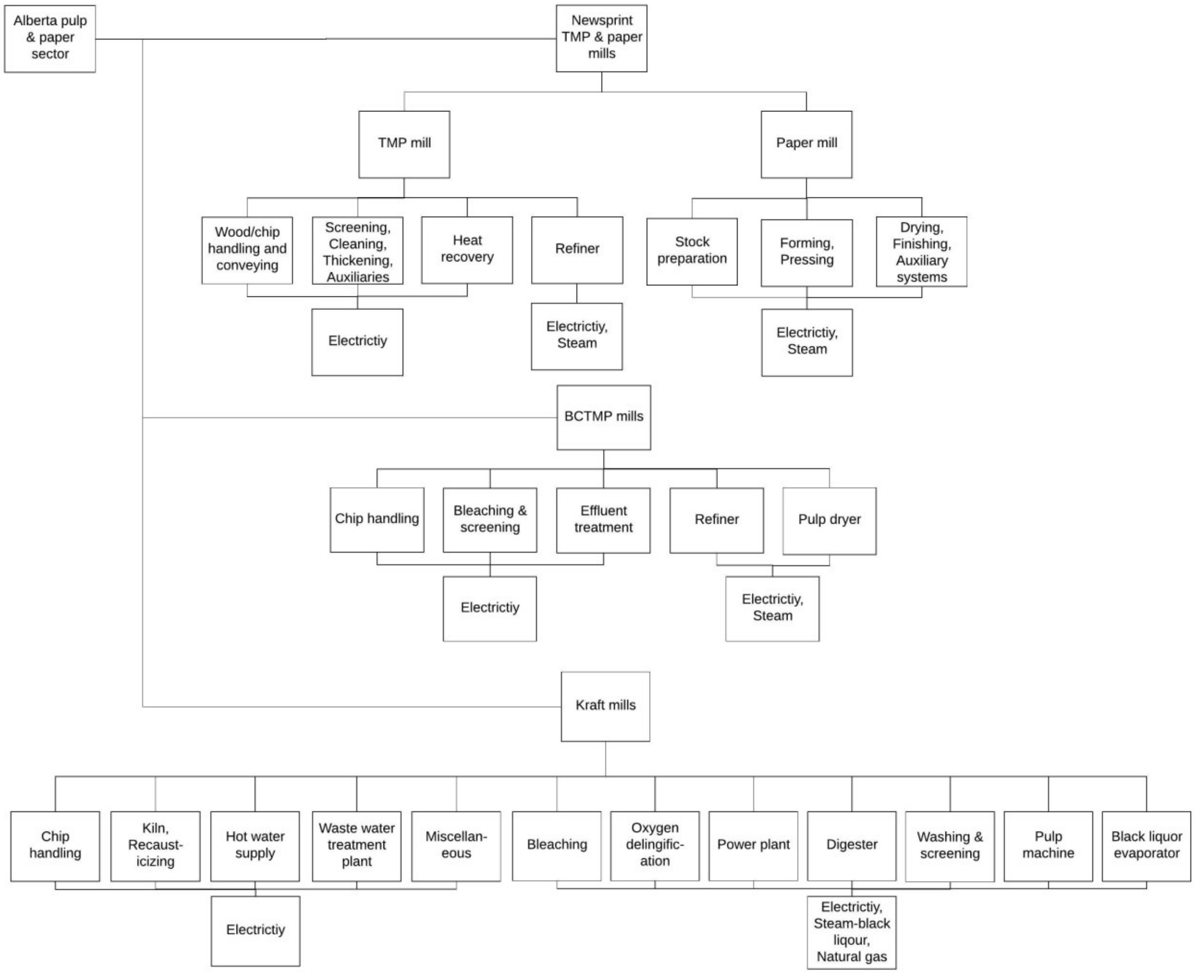

Figure 3-12: Alberta pulp & paper sector demand tree [95]

3.1.3.1.4 *Transportation sector*

The transportation sector is divided into five vehicle transportation categories and one pipeline transport category as illustrated in Figure 3-13. Road, air, rail, and marine transport types are segregated by passenger and freight transport. Road transport is divided by passenger and freight and then by vehicle type and fuel. Air, rail, and marine are divided by passenger and freight, and then by fuel. Off-road in the transportation sector is specific to recreation vehicle gasoline use.

Other off-road vehicles are considered in the industrial or agricultural sector. Pipeline movements are fueled by electricity, natural gas, or diesel.

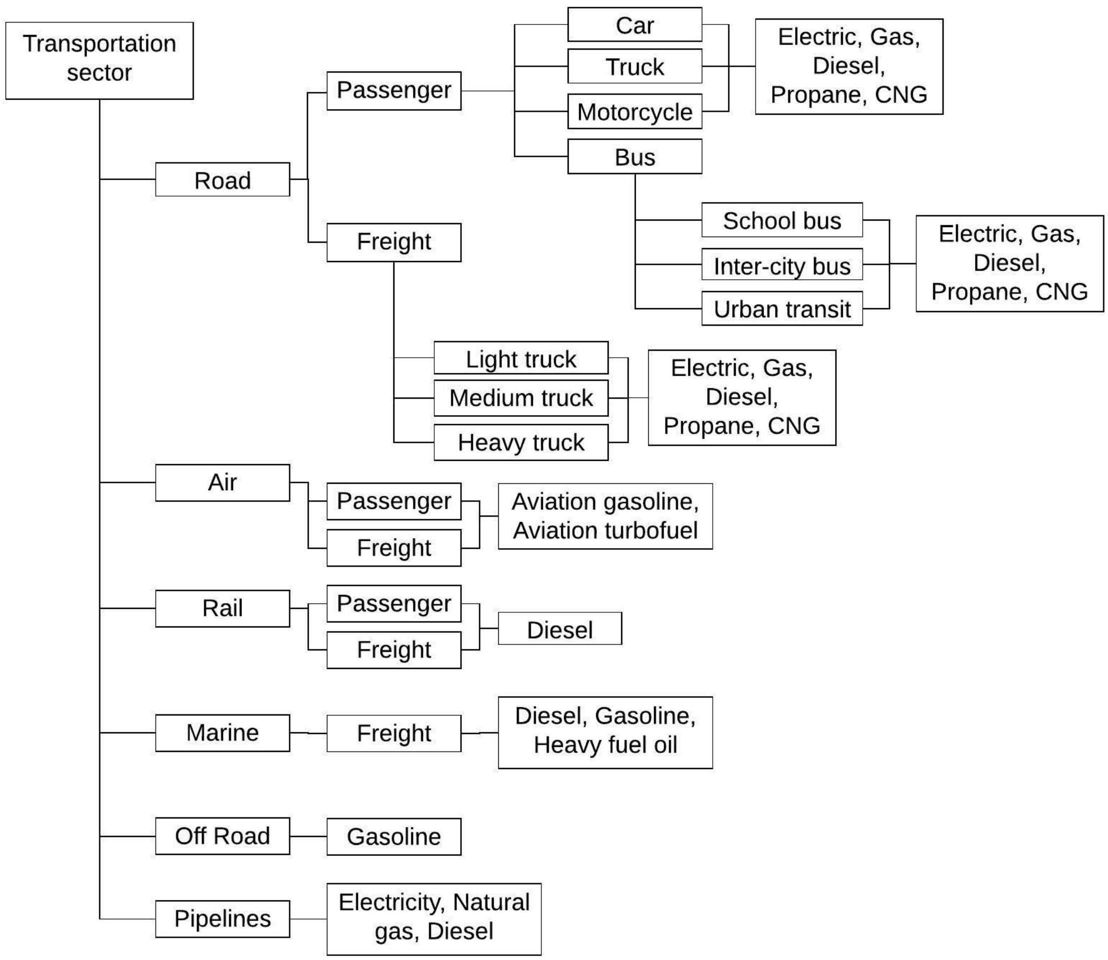

Figure 3-13: Transportation demand tree

The number of passenger-kilometers and freight-kilometers was used to calculate per capital travel values. These per capita values were used as the overarching activity units for the transportation modes. The final energy intensity represents the average energy consumption for each end-use vehicle in each province. Pipeline energy consumption is not included in the CEUD and so CANSIM Table 128-0016 is referenced to gather the pipeline energy consumption data for the calculation of the energy intensity in units of kJ/CAD of industry GDP in every province [97]. These calculations were completed for all vehicles in the six transportation categories, in all provinces and territories of Canada.

The transportation sector has activity units of unit-km/person, so any change in population will cause a corresponding change in transportation activity. The population projections are taken from NEB [92] up to 2040, and the 2041-2050 values were extrapolated for the years 2035 to 2040. The number of road passenger-km per person, tonne-km per person, and road travel energy intensity improvements were assumed to increase over the projection period at the same rate as the historical values from 2005-2013 for each region [89].

3.1.3.1.5 *Agriculture sector*

The level of data presented in the CEUD has energy use categories only by fuel type, and the demand tree was developed to reflect this (see Figure 3-14). This sector was not developed in detail as energy use in recent years totals approximately 3% of Canadian secondary energy consumption [103]. The final energy intensity represents the average Canadian energy consumption per CAD of the GDP of agriculture. The CEUD gives the fuel consumption used in the agricultural sector as well as the GDP. These are used to calculate the energy intensity for the fuels. These calculations are completed in all provinces and territories of Canada.

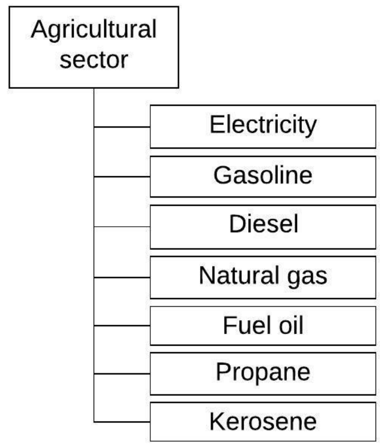

Figure 3-14: Agriculture sector demand tree

Agricultural activity was extrapolated based on the historic agricultural GDP trend from 1990 to 2013. Energy intensity improvements were derived from extrapolation the historical energy intensity values from 1990 to 2013 for each province.

3.1.3.2 Transformation processes development

The transformation module contains the processes that convert resources from one form to another or the mining/extraction of a resource. A transformation module has the basic process as described in the energy flow diagram in Figure 3-15. A transformation process is dispatched if there is a demand for a specific commodity. The module will first use domestic resource reserves for input; if there are insufficient reserves or process capacities available, the required fuel will be imported. Each transformation process is defined by a series of variables. The variables used in this model are shown in Table 3-3. During the transformation process there can be losses due to inefficiencies or auxiliary fuel use at the process location. Fugitive emissions can be released from the process itself or emissions can be emitted from the combustion of auxiliary fuels. Fugitive emissions are exogenously added as intensities (tonne CO_2e per PJ of energy produced) as sourced from the NIR [104]. Auxiliary fuel use is calculated from CANSIM Table 128-0016 [97]. The transformation module contains approximately 6,700 data points.

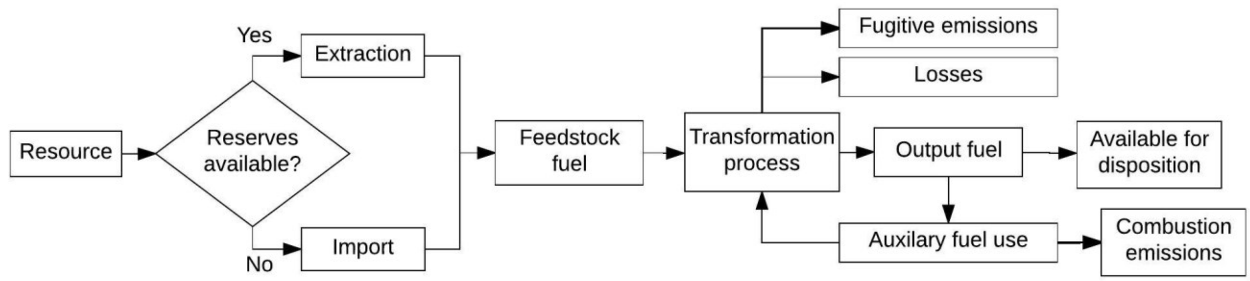

Figure 3-15: LEAP-Canada transformation processes

Table 3-3: Transformation process variable descriptions

Variable	Description
Dispatch rule	Determines how the module is run. Can be set to produce only as demand requires or at full capacity
Exogenous capacity	The capacity available for production
Maximum availability	The percentage of time a module is available to produce
Historical production	Any real data available representing past production
Process efficiency	Energy content of the output fuels divided by that of the input fuels

3.1.3.2.1 *Electricity generation*

Electricity generation capacity is based on the NEB's projections. The technologies modelled are listed in Table 3-4 [92]. The model generates electricity based on the merit order, capacity, and maximum availability.

Table 3-4: Electricity generation technologies

Variable	Efficiency	Dispatch merit order	Maximum availability
Oil combustion plant	41	2	30
Natural gas simple cycle	45	3	20
Natural gas steam	35	2	40
Natural gas combined cycle	70	2	70
Natural gas cogeneration	38	2	75
Coal	39	1	70
Nuclear	31	1	90
Biomass plant	35	1	60
Solar	n/a	1	28
Wind	n/a	1	33
Hydro, Tidal, Wave	n/a	1	50

3.1.3.2.2 *Petroleum refining*

The petroleum refining module has 17 output fuels and 4 input fuels as shown in Table 3-5. All auxiliary fuel use is included in the demand module of the model as it is in the CEUD. The percent shares of each feedstock fuel for each region were determined from CANSIM Table 134-0001 Statistics Canada [101]. Each region's refineries were modelled as shown in Table 3-6. Historical production data were used for 2010-2015, and refineries were assumed to run at full capacity from 2016-2050.

Table 3-5: Petroleum refining fuels

Output fuels			**Feedstock fuels**
Gasoline	Aviation turbo fuel	Jet kerosene	Synthetic crude oil
Heavy fuel oil	Aviation gasoline	NGL	Light or medium crude oil
Diesel	LPG	Refinery feedstock's	Heavy crude oil
Light fuel oil	Propane	Asphalt	Bitumen
Petroleum coke	Kerosene	Other petroleum products	
Lubricants	Still gas		

Table 3-6: Petroleum refineries in Canada [102]

No.	Refinery	Capacity (Thousand bbl/day)	Region
1	Irving refinery, St. John	300,000	NB
2	North Atlantic refinery, Come by Chance	115,000	NFL
3	Imperial Oil refinery, Dartmouth	13,514	NS
4	Suncor refinery, Montreal	137,000	QB
5	Valero refinery, Levis	265,000	QB
6	Suncor refinery, Sarnia	85,000	ON
7	Imperial Oil refinery, Sarnia	121,000	ON
8	Shell refinery, Corunna	75,000	ON
9	Imperial Oil refinery, Nanticoke	112,000	ON
10	Consumers Coop refinery, Regina	130,000	SK
11	Moose Jaw refinery, Moose Jaw	17,000	SK
12	Husky asphalt refinery, Lloydminister	29,000	AB
13	Suncor refinery, Edmonton	147,000	AB
14	Imperial Strathcona refinery, Edmonton	187,000	AB
15	Shell refinery, Fort Saskatchewan	100,000	AB
16	NWR refinery, Redwater	50,000 in 2018; 100,000 in 2022; 150,000 in 2025	AB
17	Parkland refinery, Bowden	147,000;	AB

No.	Refinery	Capacity (Thousand bbl/day)	Region
		0 in 2012	
18	Husky refinery, Prince George	12000	BC
19	Chevron refinery, Burnaby	55000	BC

3.1.3.2.3 *Bitumen extraction and upgrading*

The bitumen extraction transformation module has two processes, one for in situ bitumen extraction and one for bitumen surface mining. Table 3-7 shows the bitumen upgraders modelled. Bitumen upgrading efficiency was assumed to be 84% [84, 105] . Upgraders were dispatched at full capacity throughout the study period with a maximum availability of 84% [102].

Table 3-7: Bitumen upgraders in Canada [102]

No.	Refinery	Capacity (Thousand bbl/day)	Region
1	NWR upgrader, Redwater	50,000 in 2018; 100,000 in 2022; 150,000 in 2025	AB
2	CNRL upgrader, Fort McMurray	156,000; 201,000 in 2016; 281,000 in 2017	AB
3	CNOOC upgrader, Fort McMurray	72,000	AB

No.	Refinery	Capacity (Thousand bbl/day)	Region
4	Syncrude upgrader, Fort McMurray	407,000	AB
5	Suncor Base and Millennium upgrader, Fort McMurray	440,000	AB
6	Shell Scotford upgrader, Fort Saskatchewan	255,000	AB
7	Husky upgrader, Lloydminister	49,000	SK

3.1.3.2.4 *Conventional crude extraction*

Historical production was taken from the NEB's Energy Future Report [92]. Data for the years 2041-2050 were extrapolated from the 2035-2040 growth rates.

3.1.3.2.5 *NGL production*

Natural gas liquid production includes propane, butane, and ethane. Historical production data were taken from the NEB's Energy Future Report [51]. Data for the years 2041-2050 were extrapolated from the 2035-2040 growth rates.

3.1.3.2.6 *Natural gas extraction and processing*

This process represents natural gas extraction and on-site processing, venting, and flaring. CANSIM Table 131-0001 was used to find data for producer consumption. Production data were taken from the NEB's 2016 EFR [92]. Data for the years 2041-2050 were extrapolated from the 2035-2040 growth rates.

3.1.3.2.7 *Coal mining*

Historical production data were obtained from CANSIM Table 135-0002 for the years 2010-2013. Data for the years 2014-2040 were taken from the NEB's Energy Future Report [51]. Data for the years 2041-2050 were extrapolated from the 2035-2040 growth rates. An overall rate of decline of 1.2% per year for Canada was used in each province based on the 2016 NEB EFR projection of Canadian coal production to 2040 [51].

3.1.3.2.8 *Uranium production*

Historical production and export data were obtained from the World Nuclear Association [72]. The reference scenario production increases with world growth in nuclear power, according to the 2016 International Energy Outlook (IEO) [32].

3.1.3.3 Resources

3.1.3.3.1 *Reserves*

Historical reserves and additions were used in the model for 2010-2014. It is assumed in the reference scenario that there is no constraint on the availability of reserves. This assumption implies that sufficient annual additions of reserves will keep the reserve balance available to meet demands. It is also assumed that technology will progress to allow previously inaccessible resources to become economically feasible to extract during the study period.

3.1.3.3.2 *Imports / exports / inter-regional trade*

Data for the imports, exports, and fractions are from CANSIM Table 128-0016 [97]. Historical trade is recorded in the model from 2010-2014. Interregional trade was modelled by specifying relative in-area import and export fractions between the provinces and territories. Future trade was assumed to hold the same import and export fractions as those from 2015.

3.2 Results and discussion

3.2.1 Model capabilities and suitable studies

The primary intent of creating the model is not only to predict the future of the energy system but to have a tool to assess specific impacts of different decisions. Suitable studies may involve evaluating government or industry decisions. Given the multi-regional structure of the model, federal or provincial government policy options can be evaluated by comparing direct and indirect social and/or technology costs as well as GHG mitigation effectiveness. Energy supply policies such as the phasing out of fossil fuel-based power and the phasing in of renewables can also be evaluated. The model can optimize future power mixes based on costs, taking into account carbon taxes, capital costs, and operating costs.

The model structure is technology-explicit for most sub-sectors and thus ideal for comparing the effectiveness of energy efficiency and fuel switching opportunities and their impact on GHG emissions. A cost-benefit analysis can be performed for specific technologies used in residential, commercial & institutional, transportation, and industries. The detailed bottom-up demand trees for the industrial sector allow for techno-economic assessments to evaluate specific equipment or process changes in very specific sub-sectors. This is a unique feature in the LEAP-Canada model and will continue to be developed further.

3.2.2 Canada's energy demand and GHG outlooks

The three territories and ten provinces were modelled as regions. The four Atlantic provinces of New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland are presented here in an aggregated outlook. The territories were omitted from this analysis, as the energy demand of the territories is less than one percent of total Canadian demand, but were included in the Canadian outlooks. The energy demand outlooks presented here are secondary demands; they do not include energy consumed during transformation processes. The GHG outlooks include all emissions from demand, transformation, and non-energy sources.

The results of Canada's regional and sectoral energy demands are shown in Figure 3-16. The total growth in energy demand for Canada between 2010 and 2050 is 27%. The largest growth occurs in Alberta with a 1.2% per year average demand growth. The largest energy consumers at the end of the study period are Alberta (35% of 2050 demand), Ontario (27% of 2050 demand), Quebec (16% of 2050 demand), and British Columbia (10% of 2050 demand). The largest per capita consumers in 2050 are Alberta (672 GJ/person) and Saskatchewan (407 GJ/person). The industrial sector in Canada is responsible for the majority of the energy demand throughout the study period with 55% of demand in 2050, followed by the transportation sector with 20% of demand in 2050. The industrial sector also accounts for the largest growth over the projection period with 1.1% annual average growth. The transportation sector demand declines an average of 0.2% per year.

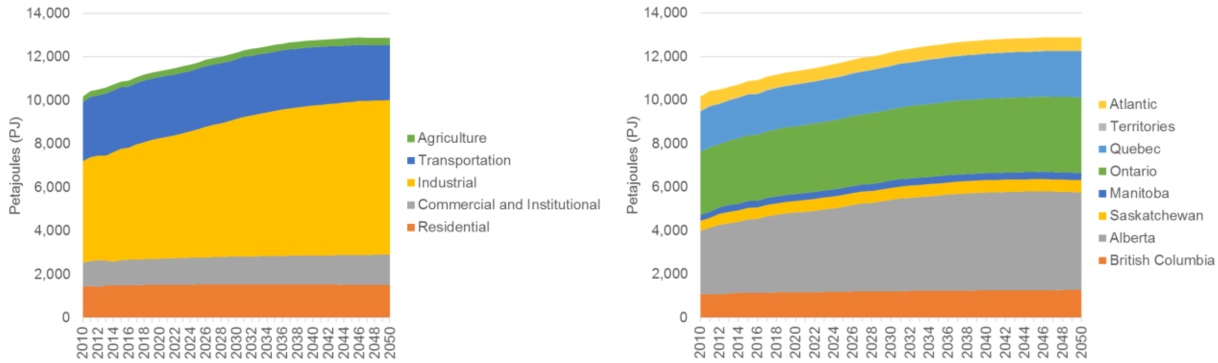

Figure 3-16: 2010 – 2050 Canada energy demand outlook

The results of Canada's regional and sectoral GHG emissions are shown in Figure 3-17. The total growth in emissions for Canada between 2010 and 2050 is 13%, which brings total emissions to 798 MT CO_2e. Alberta contributes the most emissions throughout the study period, with 40% of total Canadian emissions in 2050. Ontario and Quebec are the next highest-emitting provinces in Canada in 2050 with 24% and 10% of the respective emissions. Oil products and natural gas in Canada are responsible for the majority of the emissions throughout the study period with 36% and 31%, respectively, in 2010. By 2050 oil products and natural gas account for 32% and 42% of emissions, respectively. Coal emissions fall 82% between 2010 and 2050, resulting in 2% of 2050 emissions, down from 2010 emissions of 11%.

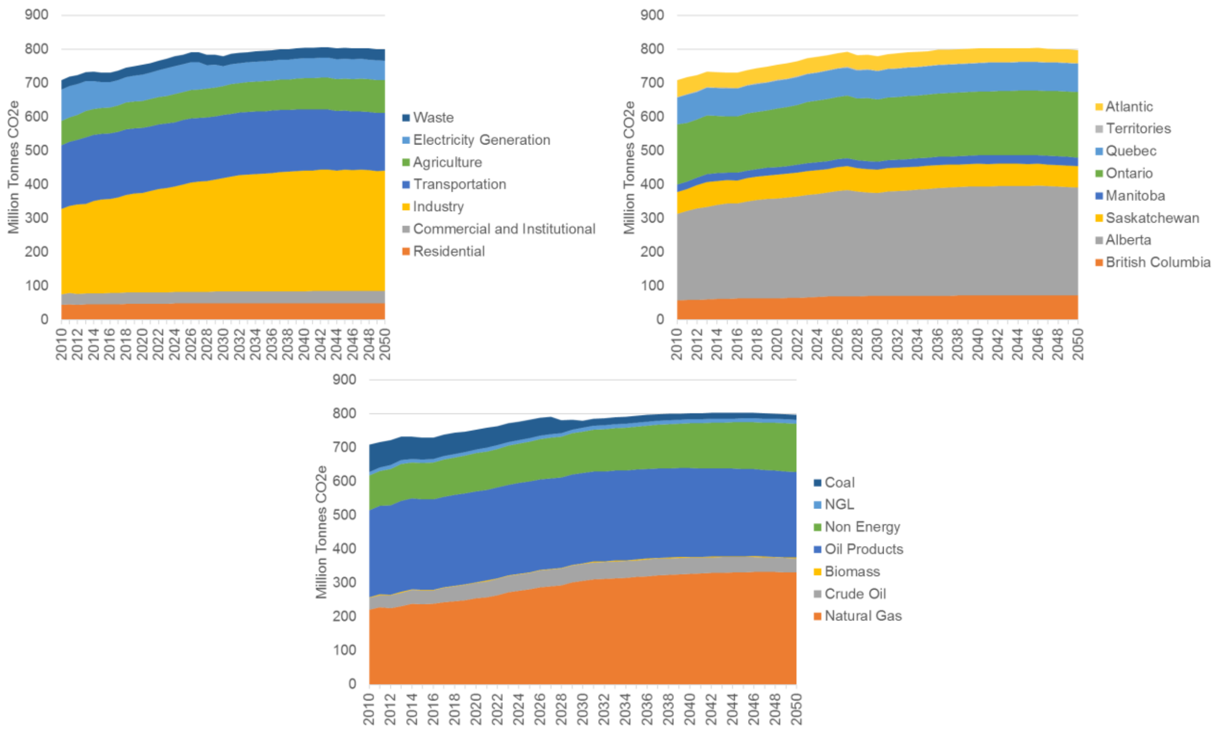

Figure 3-17: 2010 – 2050 Canada GHG outlook by sector (upper left), by region (upper right), and by fuel (bottom)

Energy demand and GHG emissions were validated with Statistics Canada, the NEB, and Environment Canada. Energy demand was validated with the Report on Energy Supply and Demand for 2010-2015 with variances between 1.7% and 5.7% (it should be noted that the NEB variances with the RESD for the same years is between 5.6% and 7.9%). The projection period was validated with the NEB's 2016 Energy Outlook from 2010-2040 where energy demands of the LEAP-Canada model and NEB have a difference of less than 4%. From 2010-2020, the LEAP-Canada model's emissions have a 0-1.2% difference from Environment Canada's projections.

3.2.2.1 British Columbia

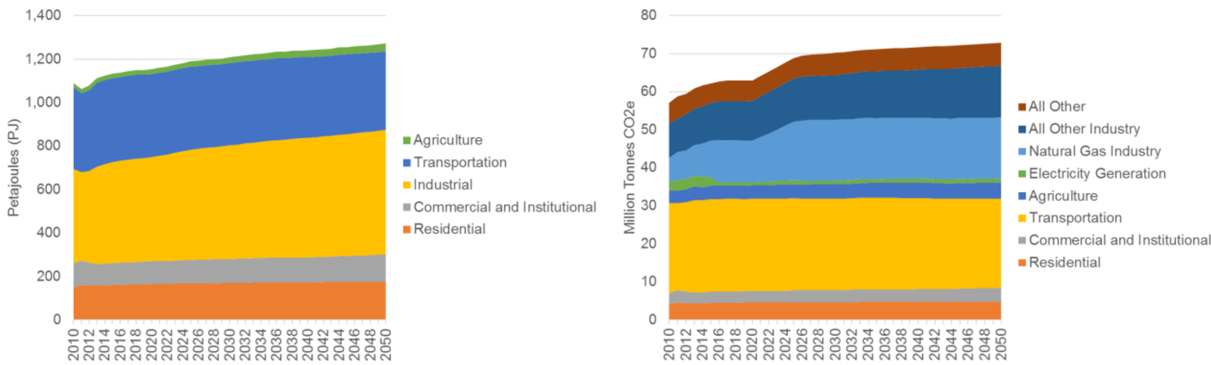

Figure 3-18: British Columbia energy (left) and GHG (right) outlooks

From 2010 British Columbia's secondary energy demand grows to 1,271 PJ by 2050, an average annual growth of 0.3%. British Columbia's GHG emissions were 60 MT CO_2e in 2010 and reach 73 MT by 2050, an average annual growth of 0.6%. This growth is mainly due to a 160% increase in natural gas emissions from extraction and processing.

3.2.2.2 Alberta

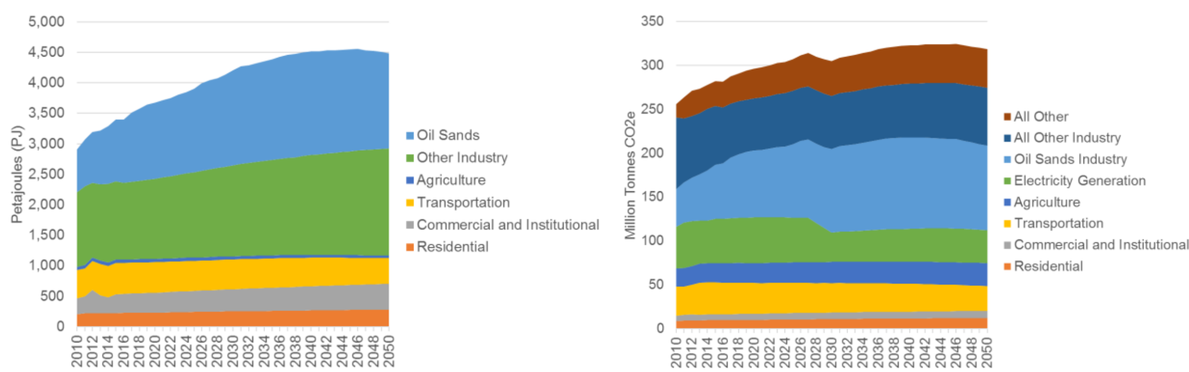

Figure 3-19: 2010 – 2050 Alberta energy (left) and GHG (right) outlooks

Alberta's secondary energy demand will grow to 4288 PJ by 2050, an average growth of 1.2% per year. Alberta's oil sands sector accounts for 24% of the demand in 2010 and 35% in 2050 with a growth of 121% over the projection period. Alberta's emissions will grow on average 0.5% per year over the projection period and reach 318 MT in 2050. Coal emissions in 2010 were 42 MT (16% of Alberta's total emissions), but the phase-out of coal power will eliminate all coal emissions by 2030, as reflected by the drop in electricity generation emissions. Natural gas combustion is responsible for 45% of emissions in 2010 and will grow an average of 1.4% per year over the projection period reaching 70% of 2050's total emissions. This growth is driven by in situ oil sands production.

3.2.2.3 Saskatchewan

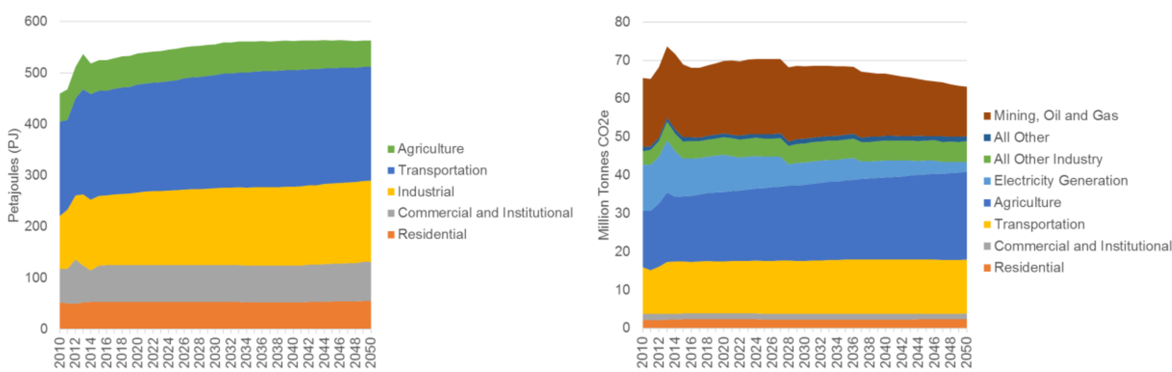

Figure 3-20: 2010 – 2050 Saskatchewan energy (left) and GHG (right) outlooks

Saskatchewan energy demand will grow to 563 PJ by 2050, an average annual growth of 0.4%. Saskatchewan's largest demand sector is industry, which grows 1.1% per year on average. Emissions decrease over the projection period due to the retiring of coal power facilities and decreasing oil extraction and reach 63 MT by 2050, a 0.1% annual decline.

3.2.2.4 Manitoba

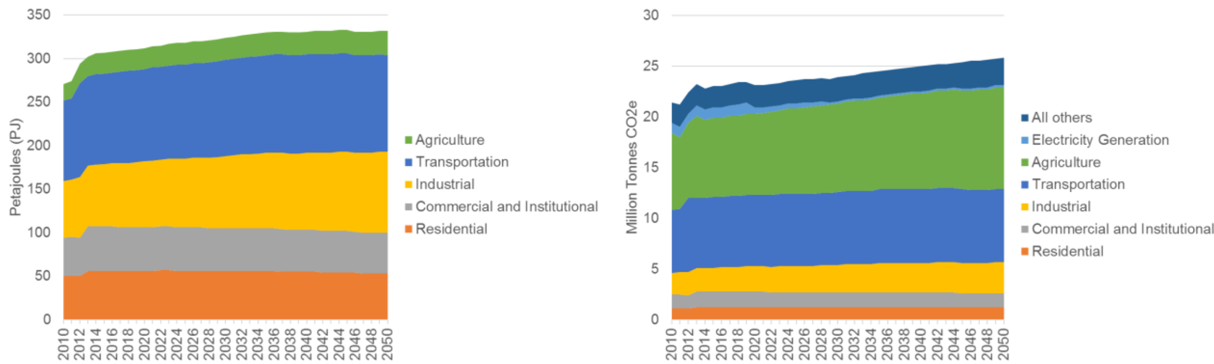

Figure 3-21: 2010 – 2050 Manitoba energy (left) and GHG (right) outlooks

Manitoba's energy demand will grow to 332 PJ by 2050, a growth of 0.5% per year on average. The largest energy consuming sector in 2010 and 2050 is the transportation sector, which makes up 34% and 33% of energy demands, respectively. Manitoba's GHG emissions reach 26 MT by 2050, an average annual growth of 0.4%. The majority of Manitoba's emissions are non-energy agriculture emissions.

3.2.2.5 Ontario

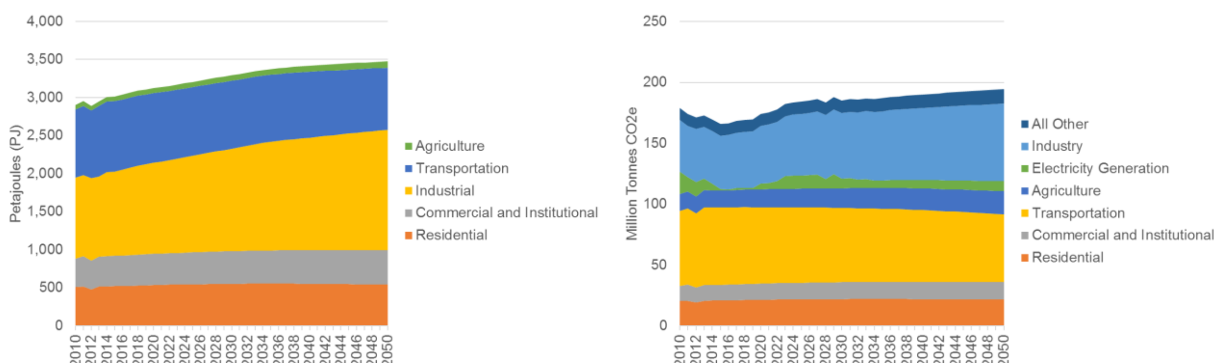

Figure 3-22: 2010 – 2050 Ontario energy (left) and GHG (right) outlooks

In 2010 Ontario's energy demand grows to 3,477 PJ by 2050, an average growth of 0.4% per year. Ontario's highest consuming sectors are road transportation and single detached households. Road transportation, which accounts for 26% of total energy demand in 2010, experiences a decline of 0.4% per year over the projection period to 18% of demand in 2050. Single detached households make up 12% of demand in 2010 and 11% in 2050. Ontario's GHG emissions increase to 194 MT in 2050, at an average rate of 0.2% per year. Transportation and industry emissions make up the largest emission shares. They are predominantly from oil products which account for 48% of 2010 emissions and 44% of 2050 emissions. The next largest source of emissions is natural gas with 28% of total emissions in 2010 growing to 33% of emissions in 2050, a growth of 0.6% per year.

3.2.2.6 Quebec

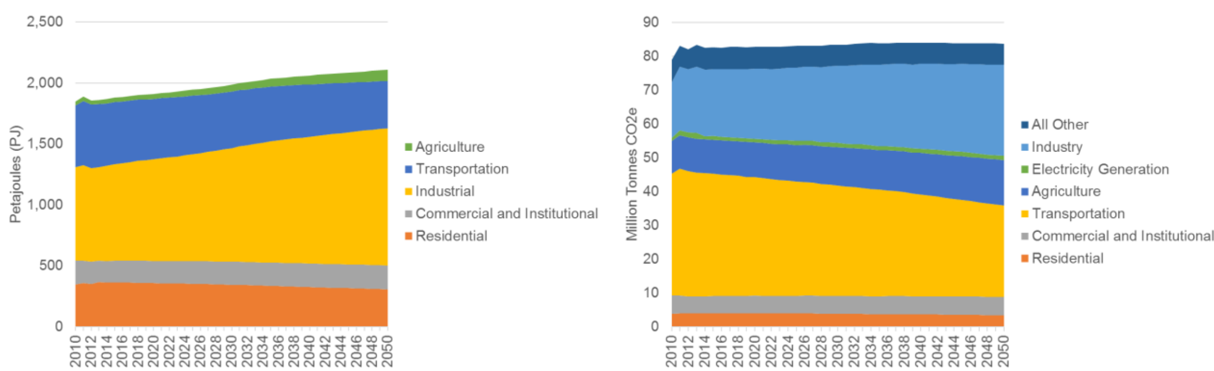

Figure 3-23: 2010 – 2050 Quebec energy (left) and GHG (right) outlooks

Quebec's energy demand grows to 2,109 PJ by 2050, a growth of 0.3% per year. Quebec's highest consuming sectors are road transportation and single detached households. Road transportation accounts for 22% of total energy demand in 2010 experiences a decline of 0.7% per year over the projection period resulting in 12% of demand in 2050. Single detached households make up 12% of demand in 2010 and 9% in 2050 with a decline of 0.2% per year. Quebec's GHG emissions grow to 84 MT in 2050, a growth of 0.1% per year. The majority of

Quebec's emissions are from gasoline and diesel, which together account for 47% of emissions in 2010 and 36% in 2050.

3.2.2.7 Atlantic provinces

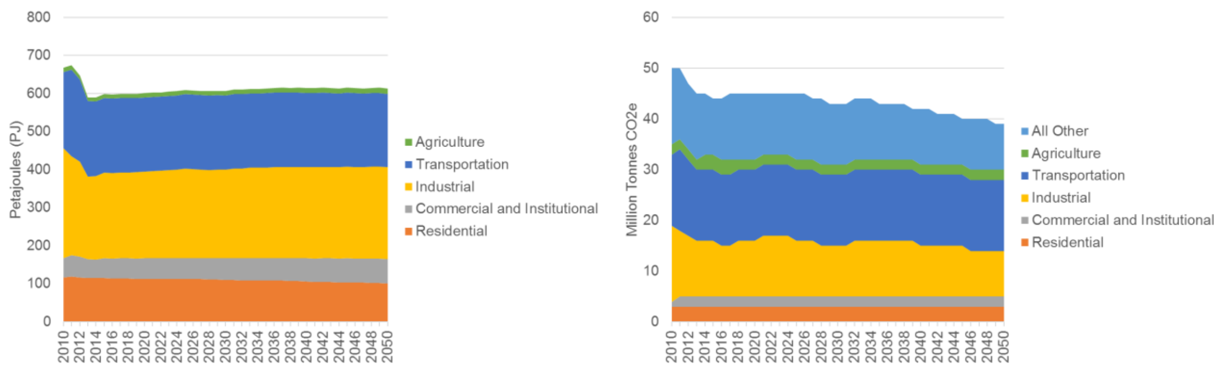

Figure 3-24: 2010 – 2050 Atlantic Provinces energy (left) and GHG (right) outlooks

The Atlantic provinces' energy demand grows to 614 PJ by 2050, a growth of 0.2% per year. The highest consuming sectors are road transportation, single detached households, and petroleum refining. Road transportation accounts for 21% of total energy demand in 2010 and experiences a decline of 5% over the projection period resulting in 22% of demand in 2050. Single detached households make up 14% of demand in 2010 and 13% in 2050 while experiencing a decline of 13%. Petroleum refining accounts for 12% of demand in 2010 and 11% in 2050 with a decline of 22%. Atlantic Canada's GHG emissions decrease to 39 MT by 2050 mainly because less crude oil will be extracted and there will be less coal-fired electricity.

4 Chapter IV: An Analysis of Canada's Greenhouse Gas Emissions using Sankey Diagrams[3]

4.1 Methodology

4.1.1 Sankey diagrams

All diagrams presented in this chapter were produced using eSankey! software [77]. The Sankey diagrams can be used to illustrate the flow of GHGs (in megatonnes [MT] of carbon dioxide equivalent [CO_2e]) from one point to another where the thickness of the flow arrow is proportional to the quantity of emissions. The structure used in this study is shown in Figure 4-1. The flow starts at a resource and ends at an end-use sector. Each box within a diagram is referred to as module. The modules displayed within the diagrams are explained in Table 4-1. Emissions associated with land-use changes are not considered in this study. From the end-use sector there is a release of emissions into the atmosphere; this is represented by the gray arrow pointing upwards. The numbers under the name of the resource or end-use sector represent the amount of GHGs emitted by that resource or end-use sector.

[3] A version of this chapter has been submitted for publication, titled:

M. Davis, M. Ahiduzzaman, and A. Kumar, "An Analysis of Canada's Greenhouse Gas Emissions using Sankey Diagrams," *Energy for Sustainable Development (Submitted),* 2017.

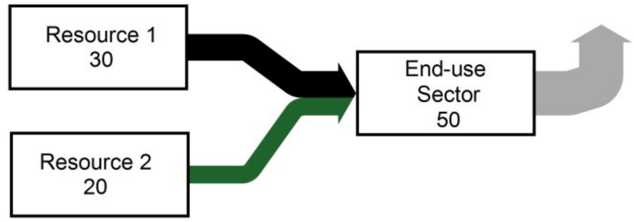

Figure 4-1: Basic GHG sankey structure

Another element of the diagrams is an "export" or "removal" module. This module indicates the GHG content of the resources that are exported or transferred out of Canada or out of province. The methodology for calculating these values is described in the next section. Lastly, fugitive emissions are included in the diagrams to ensure a comprehensive analysis of emissions. Since these emissions are not associated with the combustion of fuels, they are represented by their own module with a flow arrow terminating in the sector in which they are released. The diagrams balance with Equation (5).

$$\begin{aligned} &Resource\ Emissions + Fugitive\ Emissions \\ &\quad = Sectoral\ Emissions + Electricity\ Generation\ Emissions \\ &\quad + Exports\ or\ Removals + Waste\ Disposal\ Emissions \end{aligned} \tag{5}$$

The electricity sector is represented by an "electricity generation" module in the diagrams, as shown in Figure 4-2. This module is a point of emissions and is shown with a gray arrow pointing upwards. There are also arrows connecting the electricity generation module to the end-use sectors that consume electricity. These arrows represent the GHG emissions released during electricity generation and are proportional to the amount of electricity used by each end-use demand sector. The numbers displayed on the diagrams for these arrows are not included in the end-use sector's emission count to avoid double counting. They are only accounted for as a total release from the electricity generation module.

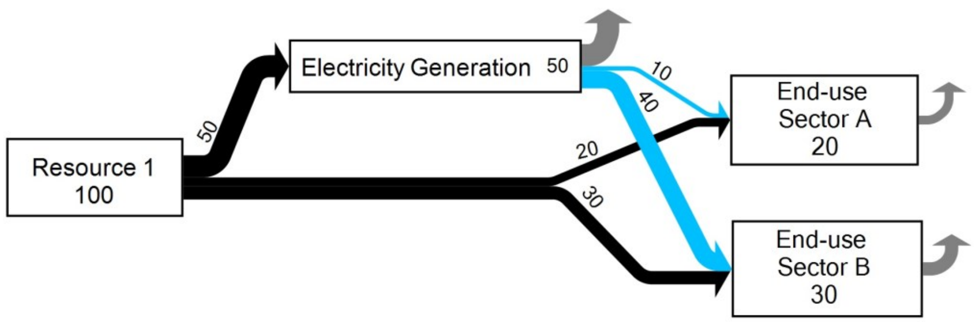

Figure 4-2: Electricity generation Sankey structure

Table 4-1: Sankey diagram module descriptions

Module	**Description**
Electricity generation	Includes conventional thermal, conventional steam turbine, combustion turbine, and internal combustion turbine power plants. Electricity exports are not shown as GHG emissions are not transferred.
Residential	Includes single detached, single attached, apartment, and mobile homes. GHG-emitting end-use devices are space heaters, water heaters, range, and clothes dryers [106].
Commercial and institutional	Includes wholesale trade, retail trade, transportation facilities and warehousing, information and cultural industries, offices, educational services, health care and social assistance, arts and entertainment,

Module	Description
	recreation, accommodation and food services, street lighting, and other services. GHG-emitting end-use devices are space heaters, water heaters, auxiliary equipment, and space cooling [106].
Other industry sectors	Includes construction, pulp and paper, petroleum refining, smelting and refining, cement, chemicals, forestry, other manufacturing, iron and steel and non-energy products [106]. GHG emissions are based on industry-specific end-use devices for pulp & paper and petroleum refining. GHG emissions for other industries are estimated based on aggregated fuel use of each industry.
Mining and upstream oil and gas industry	Includes natural gas extraction, crude oil extraction, coal mining, metal, and other non-metal mining. GHG emissions are based on industry-specific end-use devices for natural gas extraction, crude oil extraction, and coal mining. GHG emissions for metal and other non-metal mining are estimated based on aggregated fuel use of each in each province.
Transport	Includes road, rail, air, marine, and pipeline transportation [106]. GHG emissions are based on specific vehicle type uses.
Agriculture	All farming types (plant and animal). GHG emissions are based on aggregate fuel use.
Fugitive emissions	Fugitive emissions from fossil fuels are released from mining, production, processing, transmission, storage, or delivery. Agricultural fugitive emissions include enteric fermentation, manure, soils, burning of crop residues, and fertilizers [7].
Waste disposal	Includes emissions from solid waste disposal, waste treatment, waste incineration, and wastewater handling [7].
Exports	This module is present in the national diagrams representing the GHG content in exported resources to other countries.

Module	Description
Removals	This module is present in the province-level diagrams and refers to the GHG content in fuel that is removed from the province as either exports or provincial transfers.

Emission flows less than 0.5 MT CO_2e are not shown. Totals summed from the flows may not be equal due to rounding. Emission intensities are calculated for in-region emissions only. Canada's territories were not included in individual provincial analyses as they account for only 0.1% of Canada's emissions.

4.1.2 Estimating 2014, 2030, and 2050 GHG emissions

4.1.2.1 LEAP-Canada energy model

The LEAP-Canada model was used to generate GHG emissions levels for the years 2014, 2030, and 2050. The model input data are from various public reporting sources, mainly Natural Resources Canada (NRCan) [107], the National Energy Board [108], and the Canadian socio-economic information management system (CANSIM) [73]. Some of the end-use energy consumption data in the industrial sector were developed. The model uses Intergovernmental Panel on Climate Change (IPCC) emission factors to estimate the emission levels of combusted fuels. Emissions are calibrated with the National Inventory Report's (NIR) data [7], which are close to this study's 2014 results (< 1% deviation from total Canada emissions).

The data and assumptions governing energy and emission results in 2030 and 2050 are summarized in the following section. A detailed explanation of assumptions can be found in other work by the authors [109]. Assumptions include future demographic changes, sectoral activity changes, and energy intensity changes of end-use devices in each sector. The assumptions relate to energy demands as most human-caused GHG emissions depend on the level and type of energy use.

4.1.2.2 LEAP-Canada model data and assumptions overview

4.1.2.2.1 *Demographic assumptions*

Population estimates for each region for 2014 and 2030 were taken from CANSIM [110]. A historical trend in population growth is used to project population in 2050. GDP in 2014 and 2030 are taken from the 2016 NEB Energy Futures Report [108]. A historical trend in population growth is used to project GDP in 2050.

4.1.2.2.2 *Residential sector*

Residential dwelling stock and energy demands in 2014 were obtained from NRCan's Office of Energy Efficiency (OEE) Comprehensive Energy Use Database (CEUD) [106]. The number of residential dwellings in 2030 and 2050 was estimated based on historical growth trends and took into account a decreasing demographic dwelling occupancy trend in Canada. Household energy intensity is assumed to improve 26% by 2050 compared to 2014 levels, based on NEB estimates of improved device and building efficiencies [108]. IPCC Tier 2 emission factors were used for residential space heating devices. IPCC Tier 1 emission factors were used for all other residential devices.

4.1.2.2.3 *Commercial and institutional sector*

Commercial and institutional floor space and energy demands in 2014 were obtained from NRCan's OOE CEUD [106]. The total floor space in 2030 and 2050 was estimated based on energy demand projections from NEB [108]. The energy intensity of commercial and institutional energy use is assumed to improve 3% by 2030 and 32% by 2050 compared to 2014 levels based on NEB estimates of improved commercial building code improvements [108]. IPCC Tier 1 commercial emission factors were used for all devices.

4.1.2.2.4 *Mining and upstream oil and gas industry sectors*

Coal production and crude oil extraction for the years 2014 and 2030 are based on NEB estimates [108] and the Alberta Energy Regular ST98 Report [111]. Coal and conventional crude production in 2050 is based on historical growth rates. Oil sands production in 2050 is based on a report by the Canadian Energy Research Institute (CERI) [112]. Electric energy intensity improvements in the oil sands are assumed to increase by 2.4% by 2030 and 5.4% by 2050 compared to 2014 [113]. Conventional oil mining motor efficiency is assumed to increase by 1% by 2030 and 2.25% by 2050 compared to 2014 [113]. It is assumed that all other mining energy intensities stay constant. IPCC Tier 1 industrial emission factors were used for all devices.

4.1.2.2.5 *Other industry sectors*

Industrial energy demands in 2014 were obtained from NRCan's OOE CEUD [106]. Industry activity changes in 2030 and 2050 were assumed to grow at the same pace as the GDP, with the exception of the petroleum refining and Alberta pulp & paper sub-sectors, which have different growth rates, based on historical trends and 0% expected growth, respectively. Energy intensity is assumed to improve industry-wide by 6.4% by 2030 and 14.4% by 2050 compared to 2014 based on historical trends. IPCC Tier 1 industrial emission factors were used for all devices.

4.1.2.2.6 *Transportation*

2014 transportation data were obtained from NRCan's OOE CEUD [106]. Transportation activity is assumed to change with population. Changes in road passenger-kms per person, tonne-kms per person, and road travel energy intensity by 2030 and 2050 are based on historical trends. IPCC Tier 1 transportation emission factors were used for all vehicles.

4.1.2.2.7 *Agriculture*

Agriculture energy demands in 2014 were obtained from NRCan's OOE CEUD [106]. Agricultural activity is assumed to change with GDP for 2030 and 2050. Energy intensity improvements by 2030 and 2050 are estimated based on historical trends. IPCC Tier 1 agricultural emission factors were used for all devices.

4.1.2.2.8 *Electricity generation*

Electricity generation capacities for 2014 and 2030 were taken from the NEB Energy Futures Report [108]. 2050 capacities are determined from average historical capacity growth rates. Electricity generation is dispatched as required based on model demand and available capacity. IPCC Tier 1 electricity generation emission factors are used for all power production technologies.

4.1.2.3 Calculating GHG exports

The GHG content of exported resources and fuels was calculated using the LEAP-Canada model and validated with published values on fuel GHG content from Environment Canada [50]. The values and validation are shown in Table 4-2. The LEAP-Canada emission factors for petroleum products, natural gas, and NGLs were calculated with Equation (6). Conventional crude oil, and

SCO were estimated with Equation (7) and bitumen was estimated with Equation (8). All crudes are shown in the diagrams as a single flow, which is the aggregation of values calculated for individual crude types. A calculation was also performed to estimate the share of in-Canada emissions from the production of resources and fuels that are exported (see Equation (9)).

$$LEAP\ Emission\ Factor\ A = \frac{emissions\ due\ to\ secondary\ use\ [g\ CO2e]}{energy\ consumed\ due\ to\ secondary\ use\ [MJ]} \tag{6}$$

$$LEAP\ Emission\ Factor\ B = \frac{refining\ emissions\ [g\ CO2e]}{amountof\ crude\ refined\ [MJ]} + \frac{petroleum\ product\ combustion\ emissions\ [g\ CO2e]}{petroluem\ product\ consumption\ [MJ]} \tag{7}$$

$$LEAP\ Emission\ Factor\ C = \frac{upgrading\ emissions\ [g\ CO2e]}{amount\ of\ bitumen\ upgrdaed\ [MJ]} + LEAP\ Emission\ Factor\ B \tag{8}$$

$$Share\ of\ emissions\ due\ to\ exports \quad (9)$$

$$= \frac{GHG\ emissions\ due\ to\ total\ production\ of\ resource\ [MT\ CO2e]}{total\ in-Canada\ emissions\ \ [MT\ CO2e]}$$

$$* \frac{exported\ resource\ [TJ]}{total\ production\ of\ resource\ [TJ]}$$

Table 4-2: Emission factors

Fuels to be exported	**LEAP (g/MJ)**	**Environment Canada (g/MJ)**	**% Difference**
Natural gas	51.24	49.88	3%
NGL (propane)	68.1	N/A	N/A
Gasoline	69.34	68.5	1%
Jet kerosene (other)	71.43	68.82	4%
Diesel	73.88	74.08	0%
LPG (other)	59.33	60.61	-2%
Coal	89.31	90.87	-2%
Avgas (other)	70.10	73.37	-4%
Light fuel oil (other)	72.77	70.43	3%
Heavy fuel oil (other)	72.81	74.58	-2%
Conventional crude oil (crude oil)	74	N/A	N/A
Bitumen (crude oil)	82	N/A	N/A

Fuels to be exported	LEAP (g/MJ)	Environment Canada (g/MJ)	% Difference
SCO (crude oil)	74	N/A	N/A

4.2 Results and Discussion

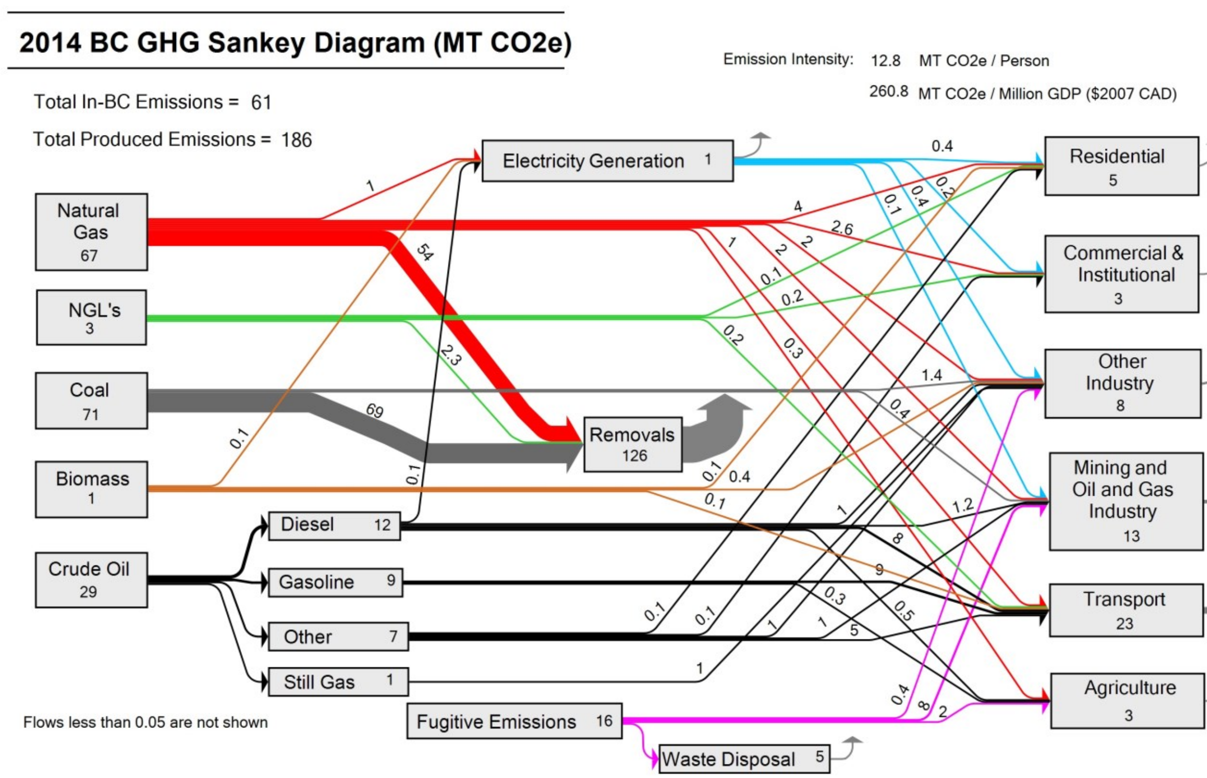

Figure 4-3: 2014 BC GHG Sankey diagram with resources and sectors

The LEAP-Canada model shows that in-BC emissions were 61 MT of GHGs in 2014 (Figure 4-3), a figure comparable to the NIR's 62.9 MT. BC's largest GHG emitter in 2014 was the transportation sector with 23 MT (38% of the total in-BC emissions). These emissions are primarily due to the burning of gasoline (9 MT CO_2e) and diesel (8 MT CO_2e) in road transportation. The second largest emitting sector was the mining and upstream oil and gas industry, which is responsible for 12 MT CO_2e. Fugitive emissions made up 8 MT (13% of total in-province emissions), which are primarily from natural gas production and processing. The electricity sector emitted only 1 MT in 2014 as 97% of BC's electricity was supplied by non-emitting renewable resources (primarily hydro). Most of the emissions (including removed) are from natural gas at 70 MT CO_2e (38% of total), followed by crude oil at 28 MT CO_2e (15% of total emissions). Total BC removals in 2014 were estimated to contain approximately 126 MT of CO_2e. In terms of removed emissions, coal was found to be the top emitting resource, accounting for 56% of removals and 38% of total emissions. The emission intensity of BC was 12.8 tonnes per person and 260.8 tonnes per million dollars of GDP, 38% below the Canadian average for both.

Figure 4-4 and Figure 4-5 show BC's emissions in 2030 and 2050, respectively. Total in-BC emissions will increase from 61 MT in 2014 to 70 MT in 2030 and 73 MT in 2050. This increase is largely driven by an increase in natural gas extraction in the mining and oil and gas sector. The most notable changes compared to 2014 emissions are natural gas removals, which increase from 54 MT to 136 MT by 2030 and remain steady to 2050. Coal removals will decrease from 69 MT in 2014 to 57 MT by 2030 and 45 MT by 2050. The emissions intensity per capita increases by 2.3% by 2030 but ultimately decreases by 6.25% by 2050 relative to 2014 levels. The emissions intensity per dollar of GDP steadily declines to 11.4% by 2030 and 31% by 2050 relative to 2014 levels.

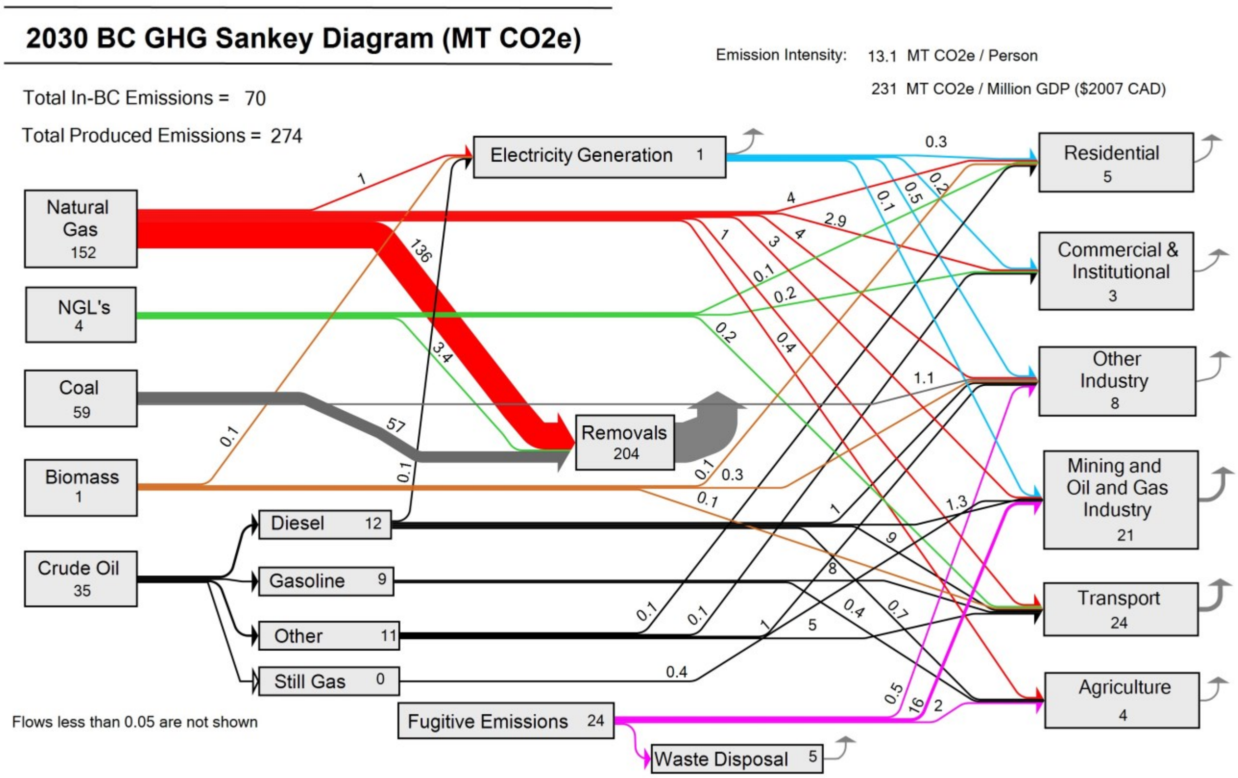

Figure 4-4: 2030 BC GHG Sankey diagram with resources and sectors

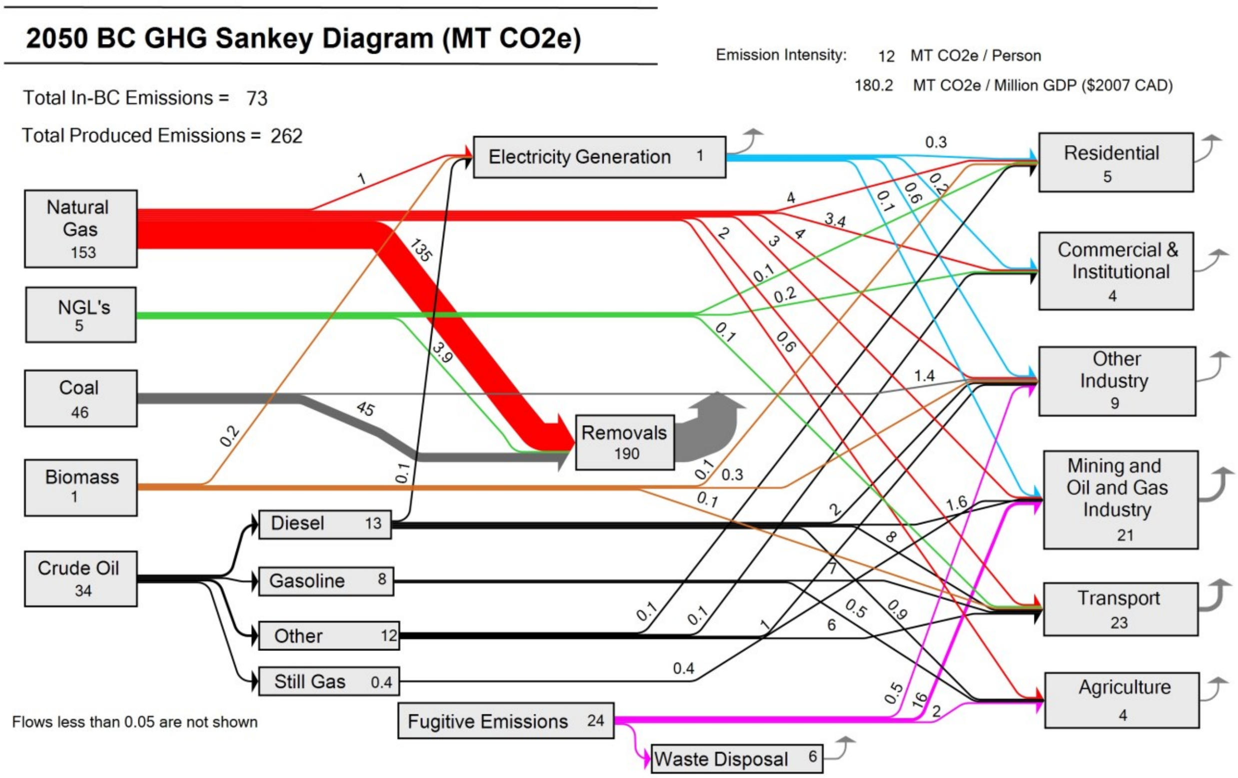

Figure 4-5: 2050 BC GHG Sankey diagram with resources and sectors

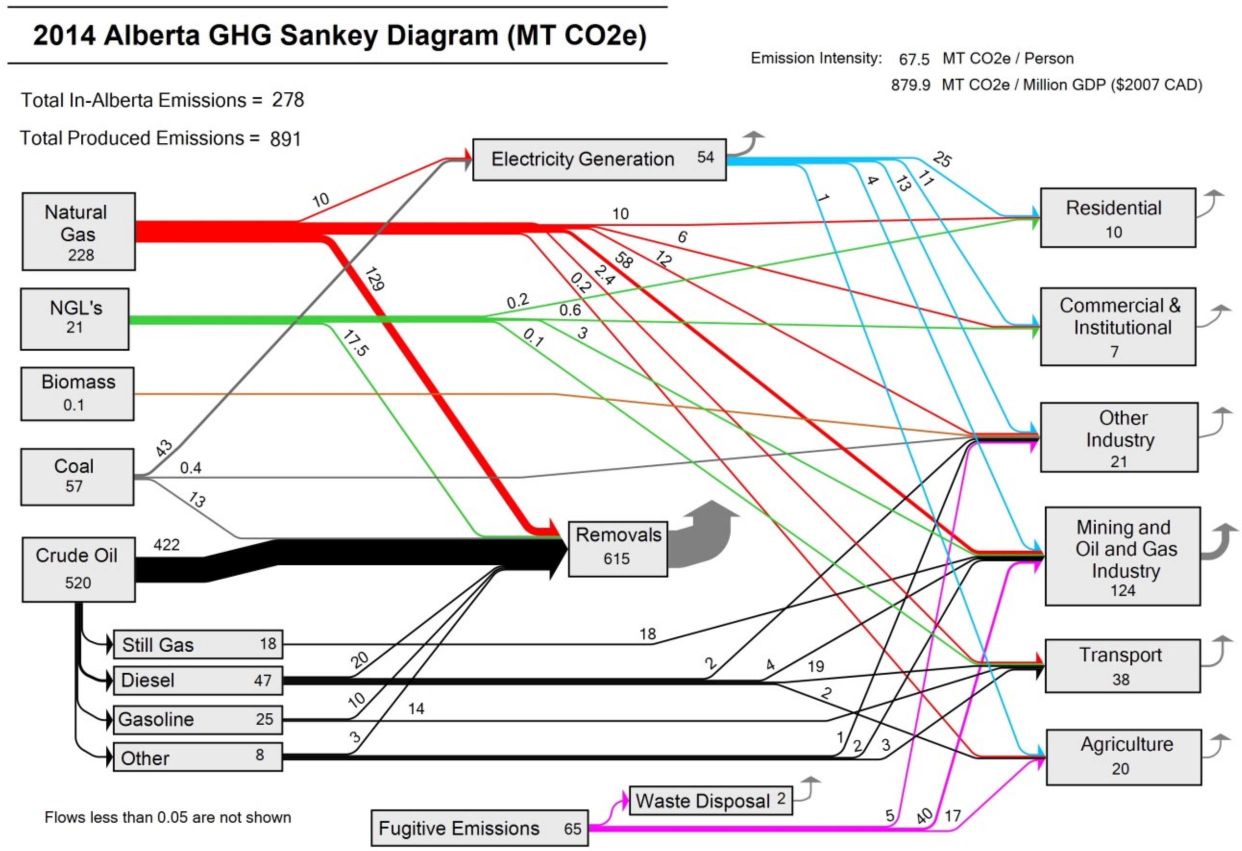

Figure 4-6: 2014 Alberta GHG Sankey diagram with resources and sectors

The LEAP-Canada model shows that in-Alberta emissions were 278 MT of GHGs in 2014 (Figure 4-6), a figure comparable with the NIR's 274 MT. Alberta's largest GHG emitter in 2014 was the mining and upstream oil and gas industry with 124 MT of GHGs, largely a result of the burning of natural gas (58 MT CO_2e) and fugitive emissions (40 MT CO_2e). The second largest emitting sector was the electricity generation sector where coal is responsible for 79% of the emissions and natural gas for the remainder. The majority of the total produced emissions including removals were from crude oil with 520 MT (58% of total emissions), followed by natural gas at 228 MT (27% of total emissions). Alberta removed approximately 615 MT CO_2e, mainly in the form of crude oil. The emission intensity was 67.5 tonnes per person and 879.9 tonnes per million dollars of GDP, 228% and 109% above the national average, respectively.

Figure 4-7 and Figure 4-8 show Alberta's emissions in 2030 and 2050, respectively. Total in-Alberta emissions increase from 278 MT in 2014 to 305 MT by 2030 and 318 MT by 2050. A phase out of coal power will cause a decrease in 43 MT of electricity generation emissions between 2014 and 2030. The mining and oil and gas industry will experience a 20% growth forcing 124 MT in 2014 to grow to 147 MT by 2030 and 149 MT by 2050. This is largely driven by increases in emissions from natural gas use. Removals will increase from 615 MT in 2014 to 897 MT by 2030 (a 46% increase) and 900 MT by 2050. Crude oil exports are the main driver for this increase. Emission intensity per capita decreases by 13% by 2030 and 29% by 2050 relative to 2014 levels. Emission intensity per dollar of GDP steady declines to 12% by 2030 and 32% by 2050 relative to 2014 levels.

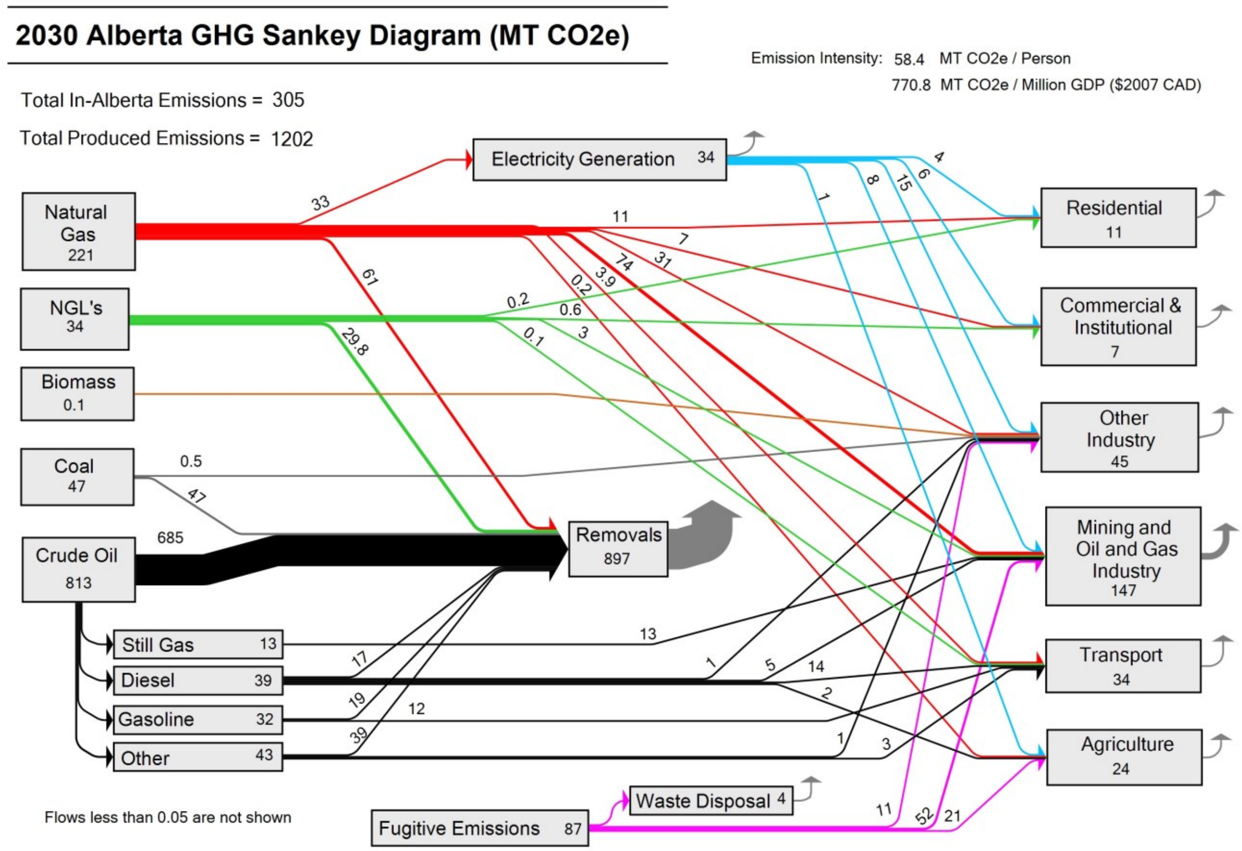

Figure 4-7: 2030 Alberta GHG Sankey diagram with resources and sectors

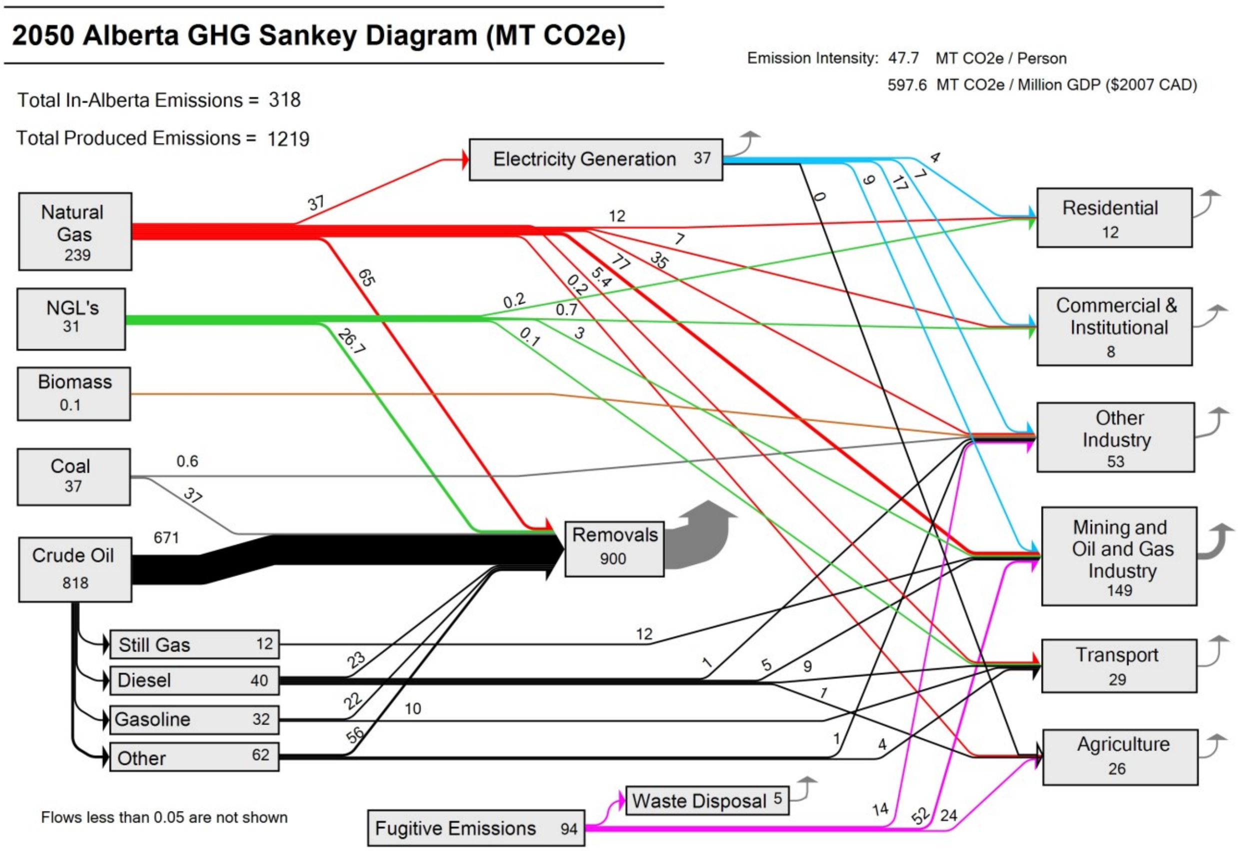

Figure 4-8: 2050 Alberta GHG Sankey diagram with resources and sectors

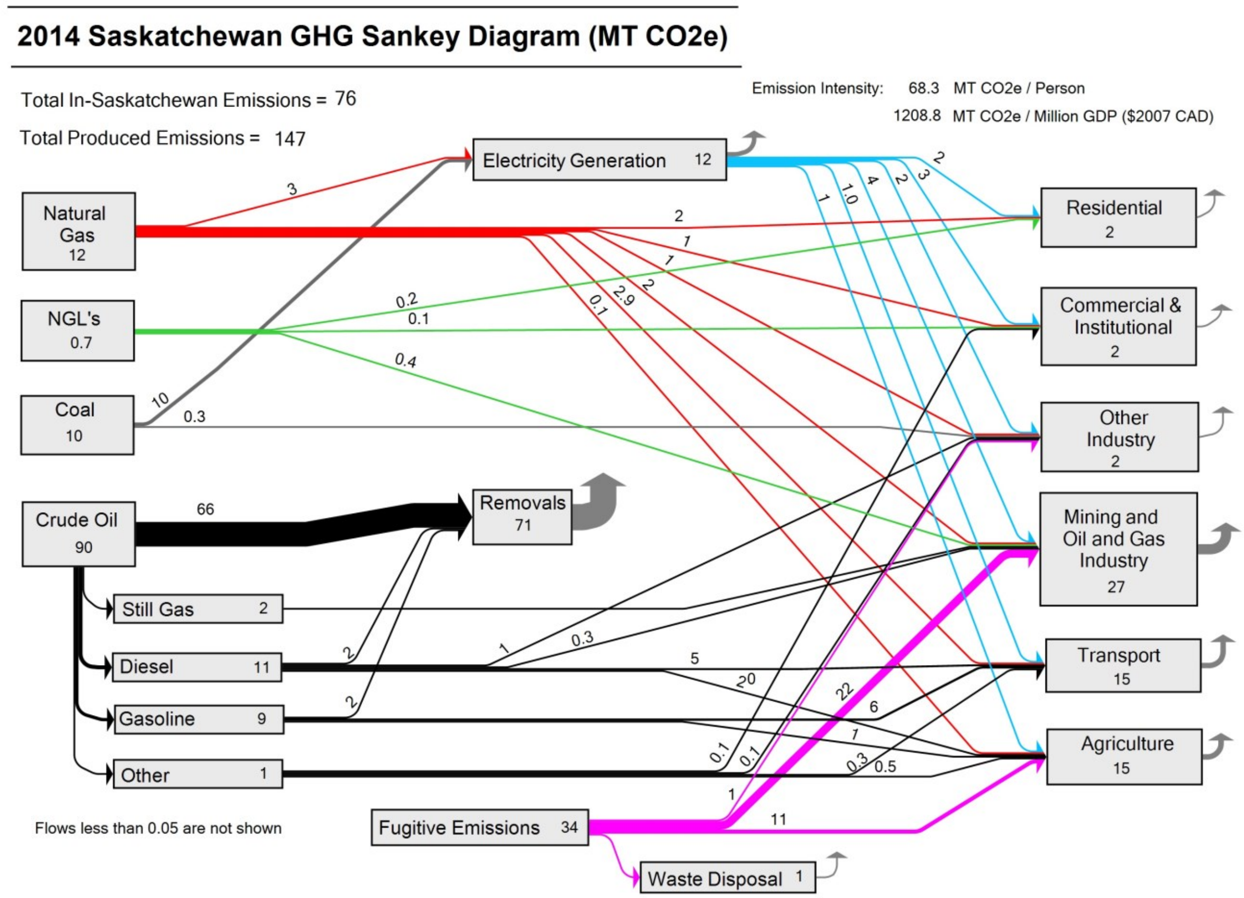

Figure 4-9: 2014 Saskatchewan GHG Sankey diagram with resources and sectors

The LEAP-Canada model shows that in-Saskatchewan emissions were 76 MT CO_2e in 2014 (Figure 4-9), a figure comparable with the NIR's 75.5 MT. The largest GHG emitter in 2014 was the mining and upstream oil and gas sector with 27 MT CO_2e, primarily due to fugitive emissions (22 MT) from the extraction of heavy crude oil. The second largest emitting sector was the agriculture sector where fugitive emissions also made up the lion's share. 71 MT CO_2e contained in resources were transferred from the province. The emission intensity was 68.3 tonnes per person and 1209 tonnes per million dollars of GDP, 232% and 188% above the Canadian average, respectively.

Figure 4-10 and Figure 4-11 show Saskatchewan's emissions in 2030 and 2050, respectively. Total in-Saskatchewan emissions will decrease from 76 MT in 2014 to 68 MT by 2030 and 63 MT by 2050. Coal power is reduced by over half between 2014 and 2030 and virtually eliminated by 2050. Crude removals increase 20% by 2030 but ultimately decrease 29% by 2050, relative to 2014 levels. Emissions from the mining and oil and gas industry decrease 26% by 2030 and 48% by 2050, relative to 2014 levels. Emission intensity per capita decreases by 19% by 2030 and 28% by 2050 relative to 2014 levels. Emission intensity per dollar of GDP steady declines to 24% by 2030 and 39% by 2050 relative to 2014 levels.

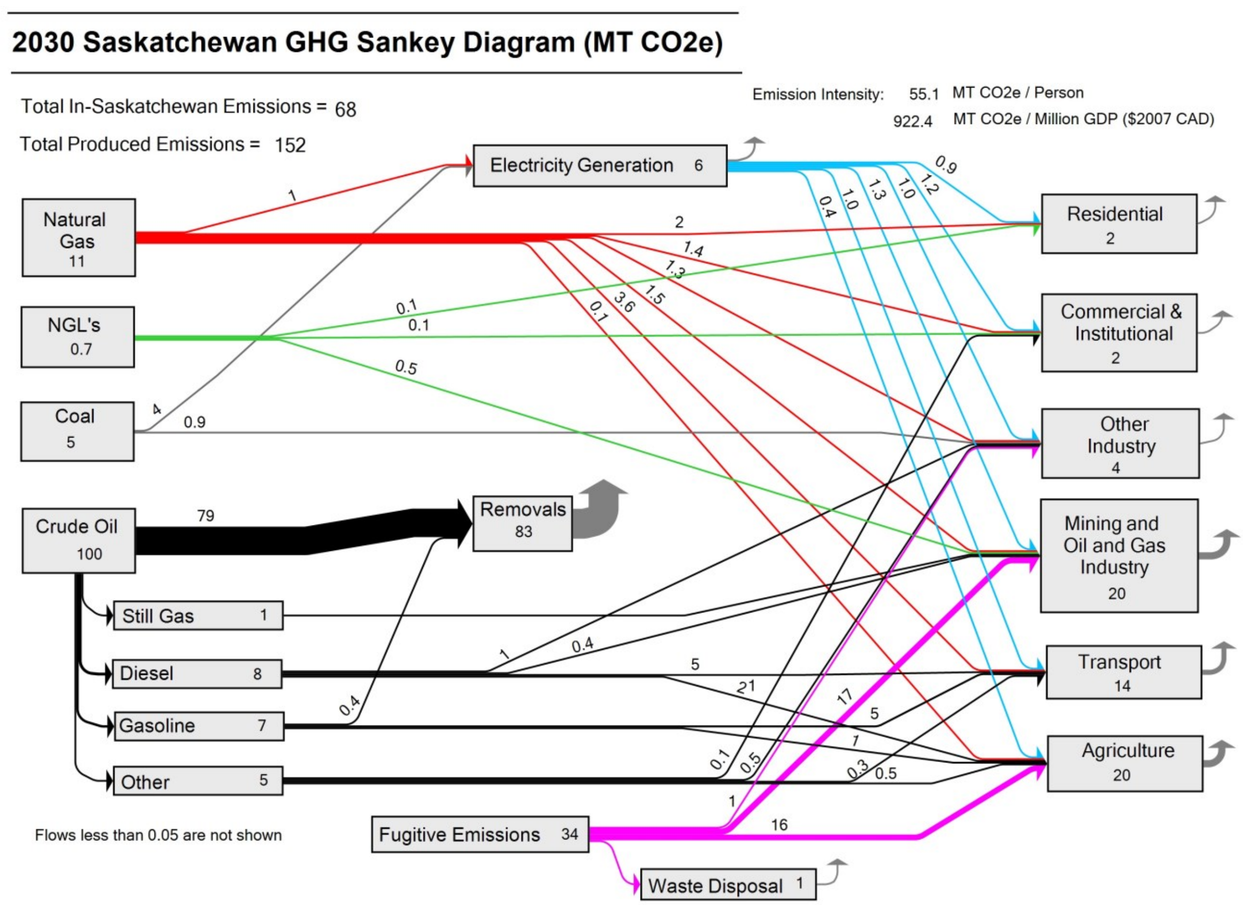

Figure 4-10: 2030 Saskatchewan GHG Sankey diagram with resources and sectors

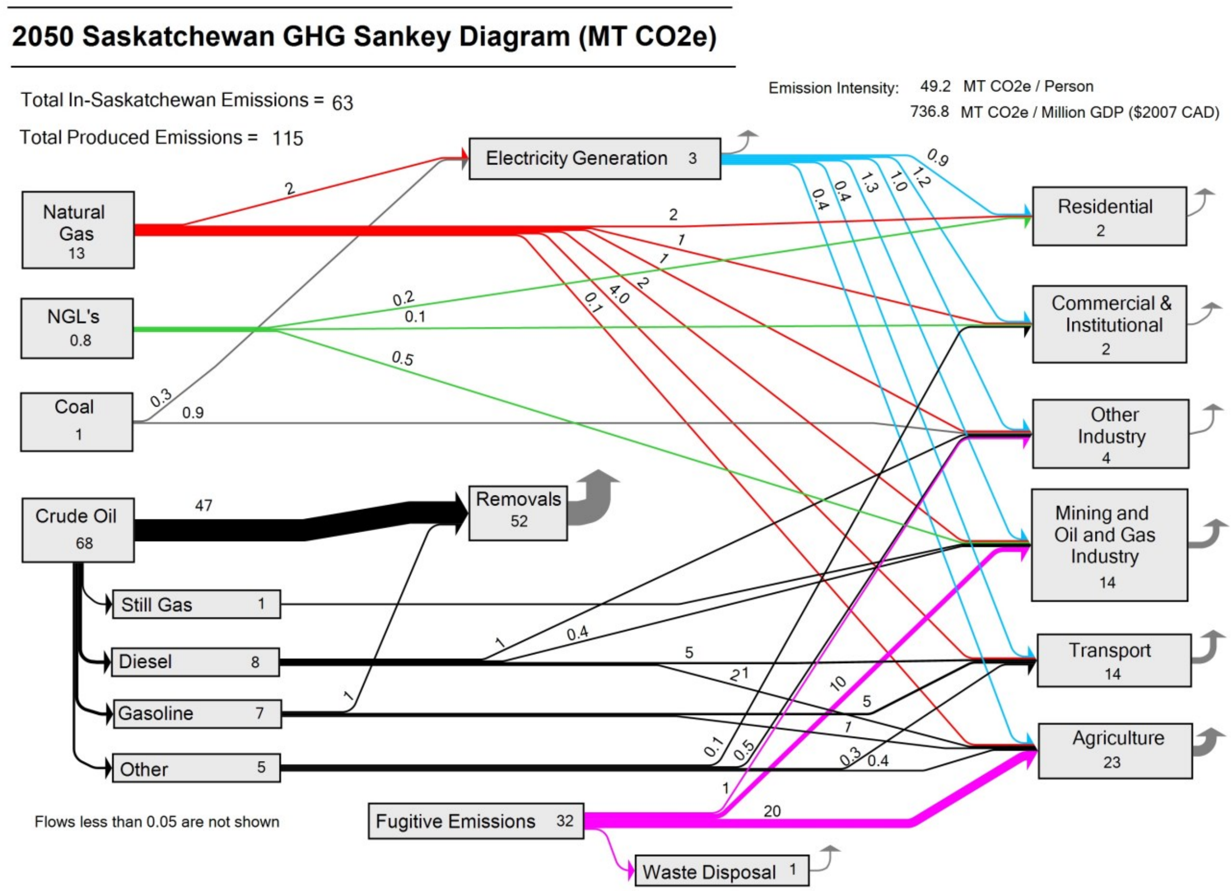

Figure 4-11: 2050 Saskatchewan GHG Sankey diagram with resources and sectors

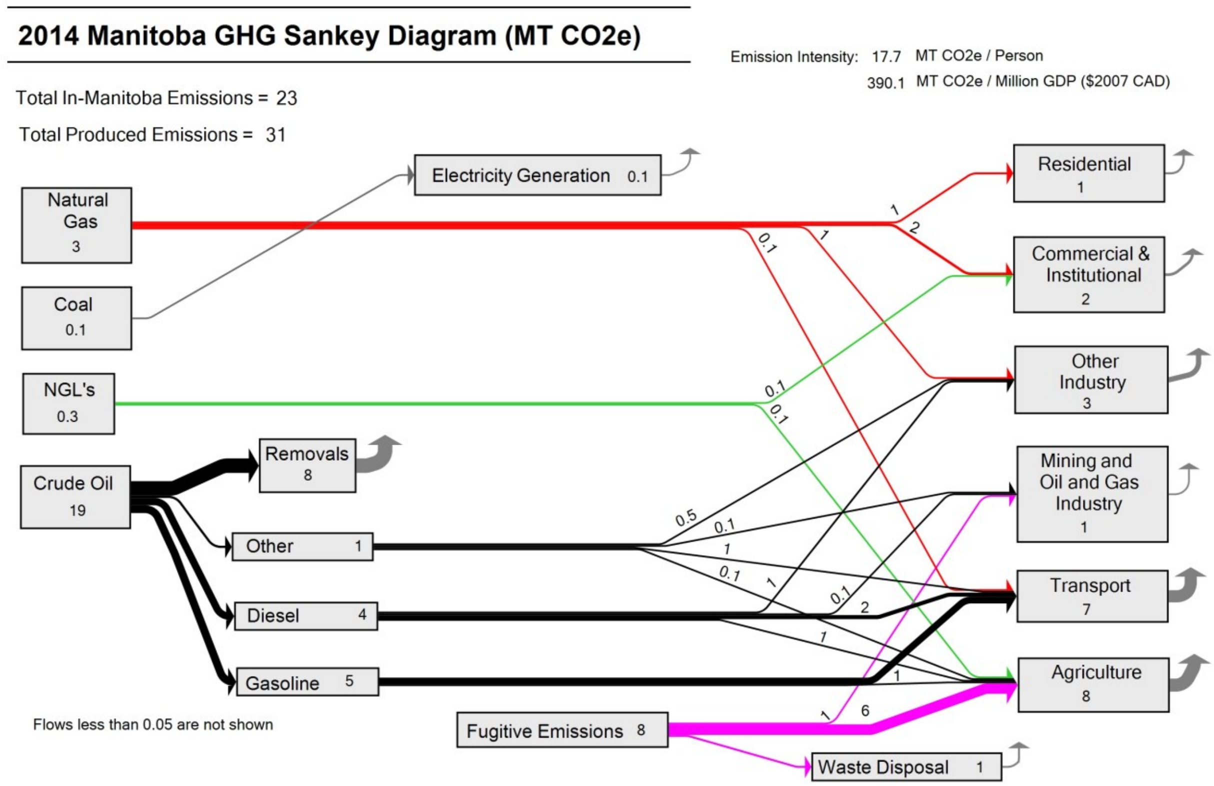

Figure 4-12: 2014 Manitoba GHG Sankey diagram with resources and sectors

Manitoba's total in-province emissions were 23 MT CO_2e (Figure 4-12), comparable with the NIR's 21.5 MT. Manitoba's largest GHG emitter in 2014 was the agriculture sector with 8 MT of GHGs. The second largest emitting sector was the transport sector with 7 MT CO_2e. There were 8 MT of removals in the form of crude oil. The emission intensity was 17.7 tonnes per person and 390.1 tonnes per million dollars of GDP, 14% and 7% below the Canadian average, respectively.

Figure 4-13 and Figure 4-14 show Manitoba's emissions in 2030 and 2050, respectively. Total in-Manitoba emissions decrease from 23 MT in 2014 to 24 MT by 2030 and 26 MT by 2050. The emissions intensity per capita decreases 8% by 2030 and 10% by 2050 relative to 2014 levels. The emissions intensity per dollar of GDP declines 16% by 2030 and 26% by 2050 relative to 2014 levels.

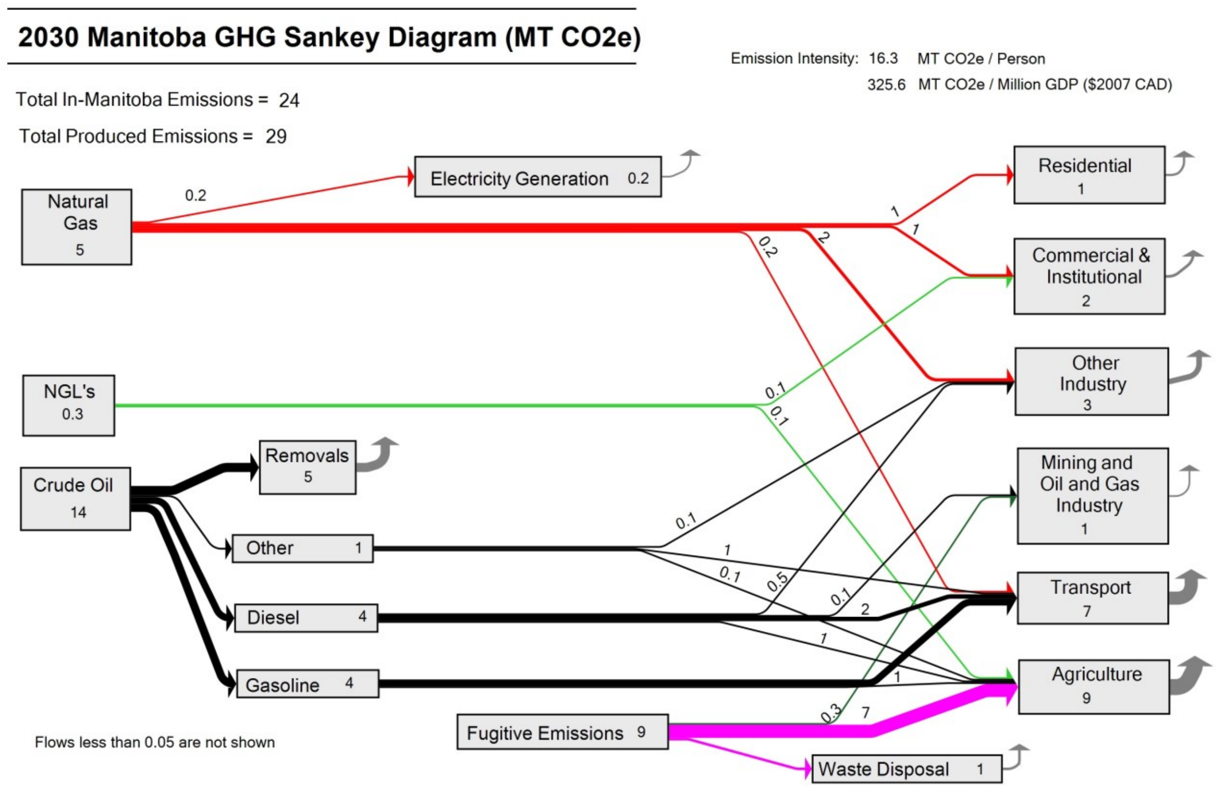

Figure 4-13: 2030 Manitoba GHG Sankey diagram with resources and sectors

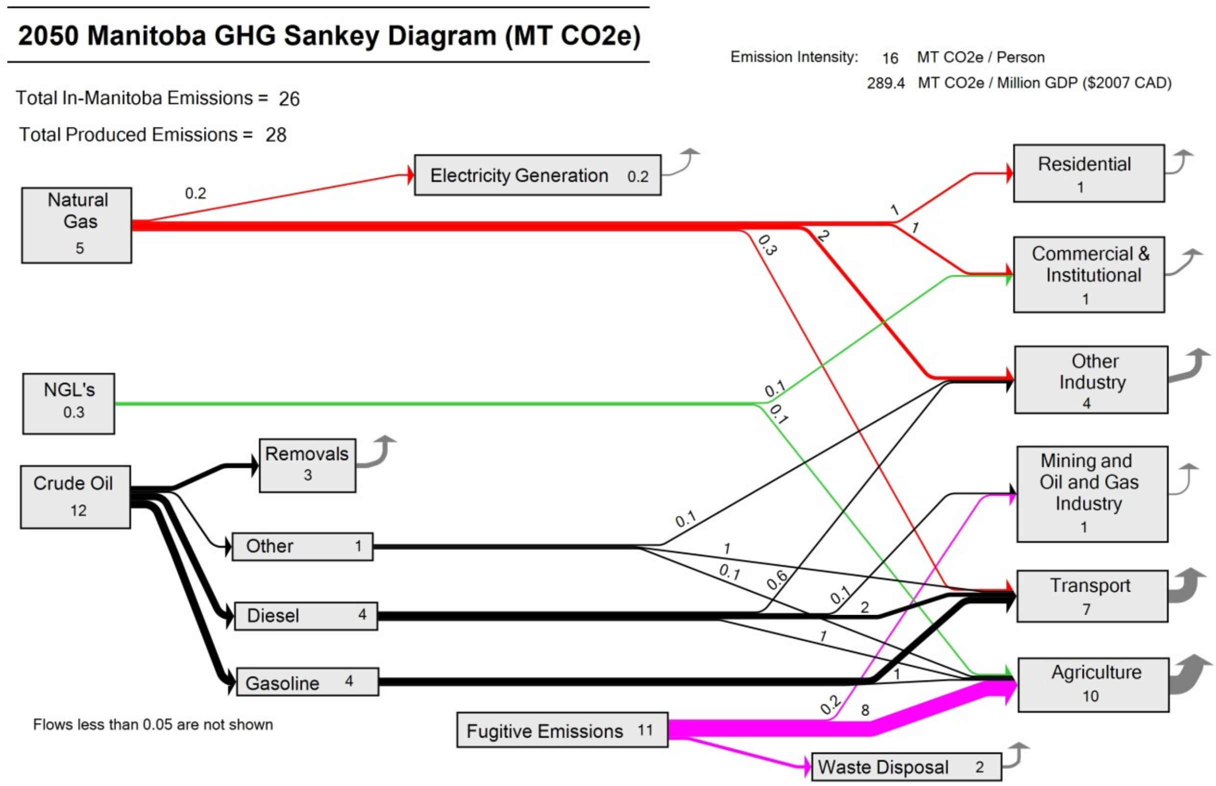

Figure 4-14: 2050 Manitoba GHG Sankey diagram with resources and sectors

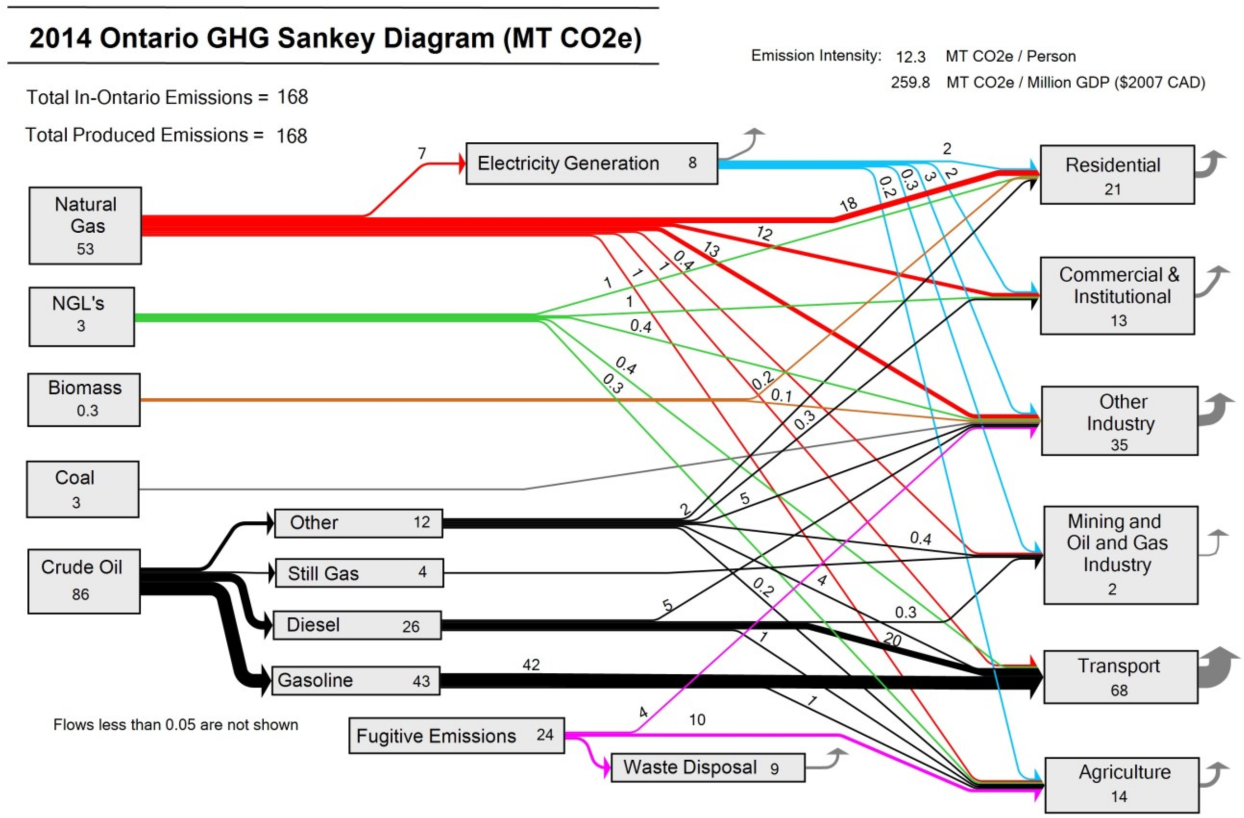

Figure 4-15: 2014 Ontario GHG Sankey diagram with resources and sectors

Ontario's in-province GHG emissions total for 2014 was 168 MT (Figure 4-15), comparable with the NIR's 170 MT. Ontario's largest GHG emitter in 2014 was the transportation sector with 68 MT CO_2e. This was primarily due to the burning of gasoline (42 MT) and diesel (20 MT) fuel in road transportation. The second largest source of emissions was from iron and steel production in the other industry sector (11 MT), petroleum refining (7 MT), and other manufacturing activities (7 MT). Ontario did not export or transfer any fossil fuels and so had zero emission removals. The emission intensity was 12.3 tonnes per person and 259.8 tonnes per million dollars of GDP, 40% and 38% below the Canadian average, respectively. Figure 4-16 and Figure 4-17 show Ontario's emissions in 2030 and 2050, respectively. Total in-Ontario emissions increase from 168 MT in 2014 to 185 MT by 2030 and 194 MT by 2050. The largest growth will occur in other industries which sees a 34% and 64% increase in 2030 and 2050, respectively, relative to 2014 levels. Emission intensity per capita decreases 10% by 2030 and 15% by 2050 relative to 2014 levels. Emission intensity per dollar of GDP declines 19% by 2030 and 33% by 2050, relative to 2014 levels.

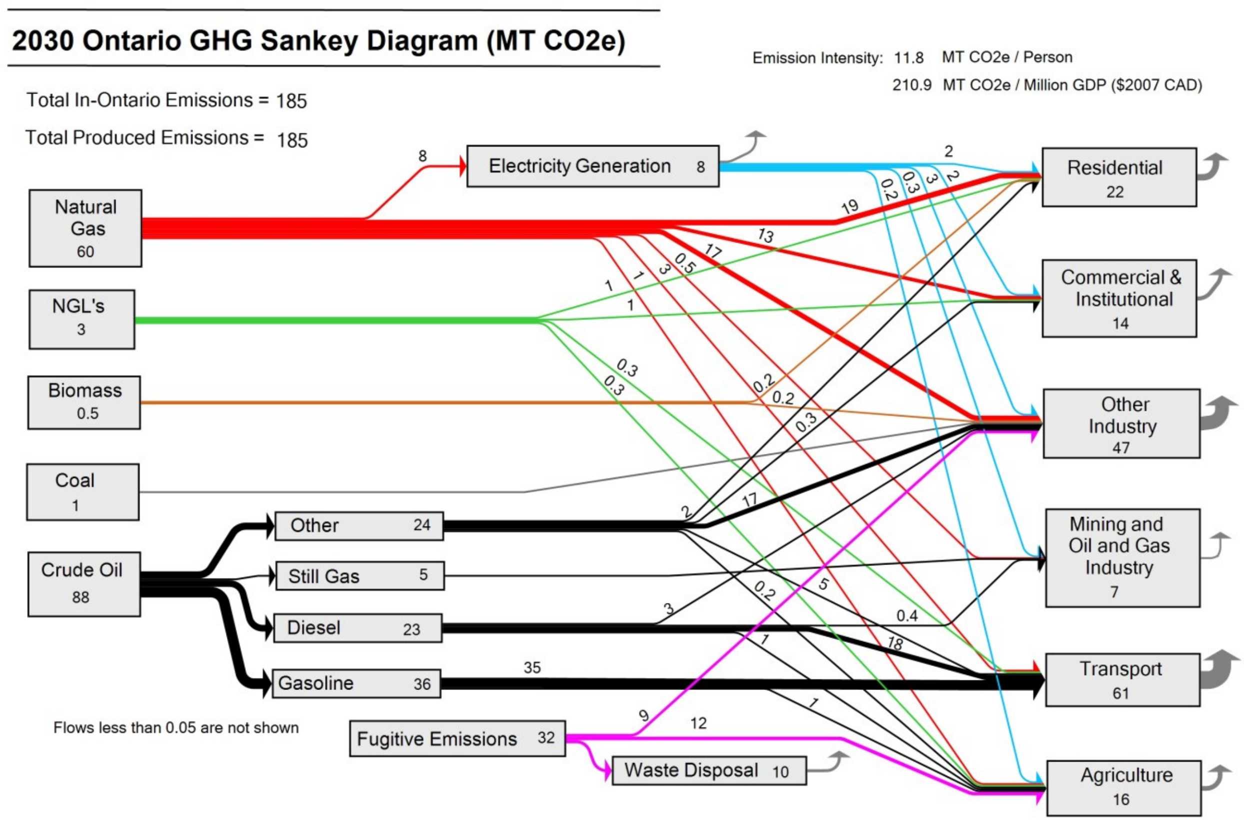

Figure 4-16: 2030 Ontario GHG Sankey diagram with resources and sectors

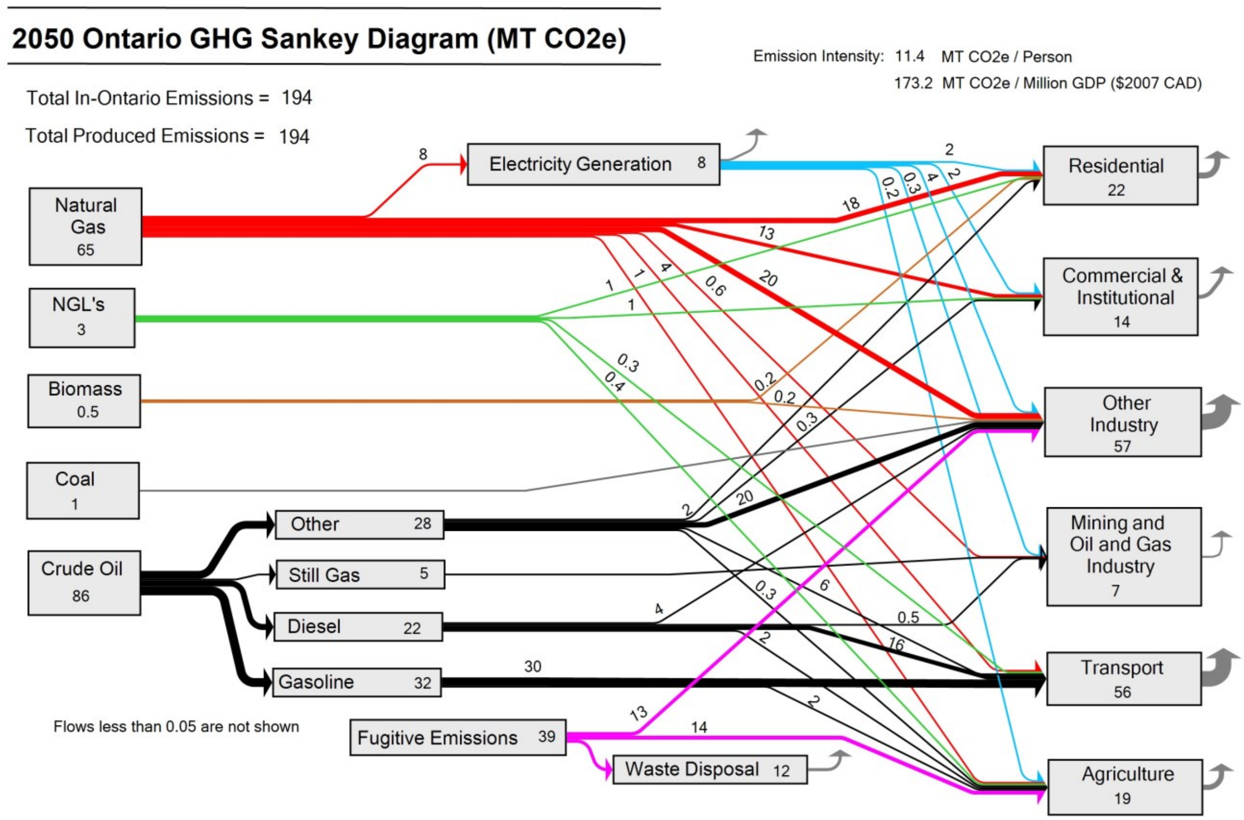

Figure 4-17: 2050 Ontario GHG Sankey diagram with resources and sectors

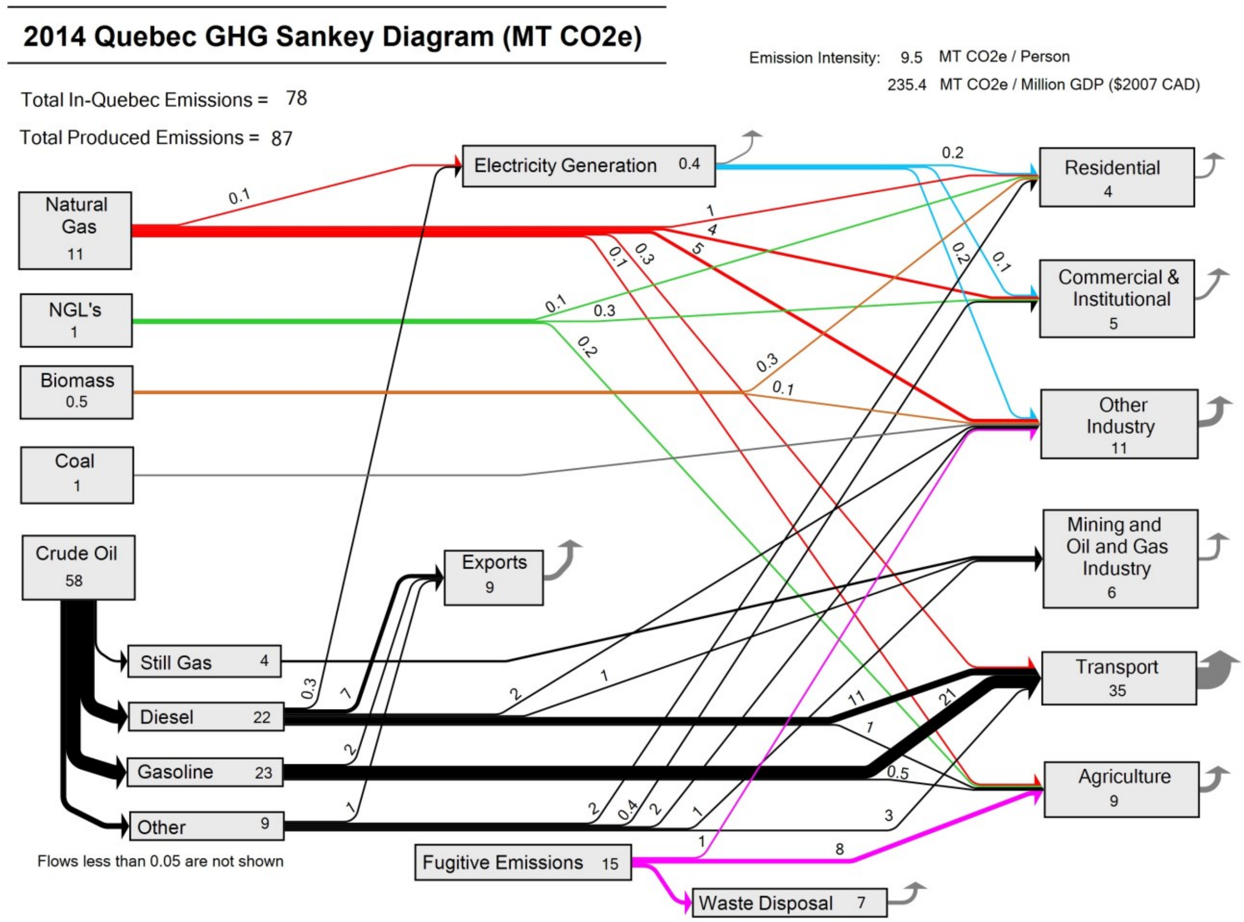

Figure 4-18: 2014 Quebec GHG Sankey diagram with resources and sectors

Quebec's in-province GHG emission total for 2014 was 78 MT (Figure 4-18), comparable with the NIR's 82.7 MT. Quebec's largest GHG emitter in 2014 was the Transportation Sector with 35 MT of GHGs. This was primarily due to the burning of gasoline (21 MT) and diesel (11 MT) in road transportation. 9 MT CO_2e were transferred from the province from refineries. The emission intensity was calculated to be 9.5 tonnes per person and 235.4 tonnes per million dollars of GDP, 54% and 44% below the Canadian average, respectively.

Figure 4-19 and Figure 4-20 show Quebec's emissions in 2030 and 2050, respectively. Total in-Quebec emissions increase from 78 MT in 2014 to 83 MT by 2030 and 84 MT by 2050.

Increases in vehicle efficiency will allow for more petrol fuels available for exporting. Exports will grow 122% by 2030 and 167% by 2050, relative to 2014. The emissions intensity per capita decreases 3% by 2030 and remains steady to 2050, relative to 2014 levels. The emissions intensity per dollar of GDP declines 17% by 2030 and remains steady to 2050, relative to 2014 levels.

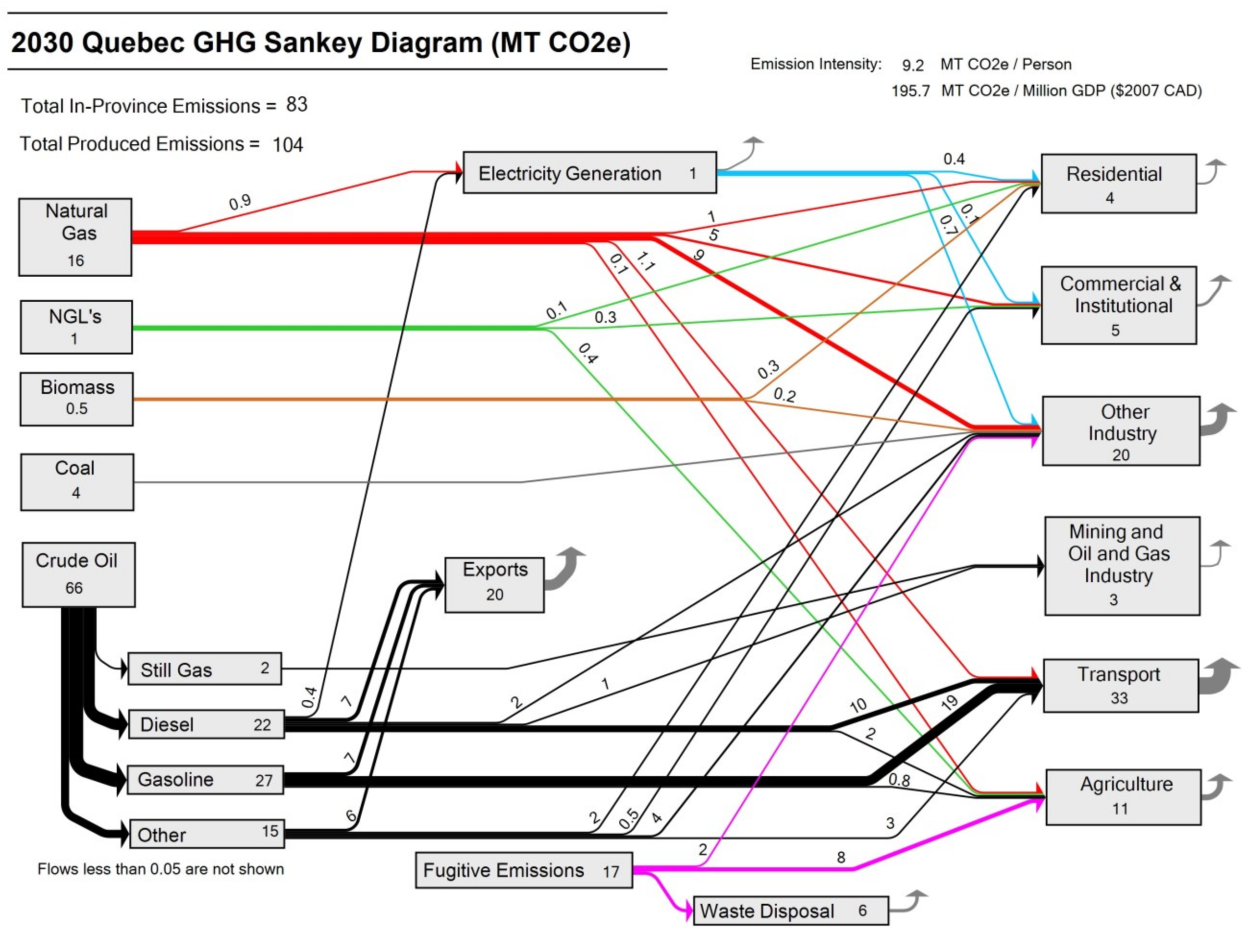

Figure 4-19: 2030 Quebec GHG Sankey diagram with resources and sectors

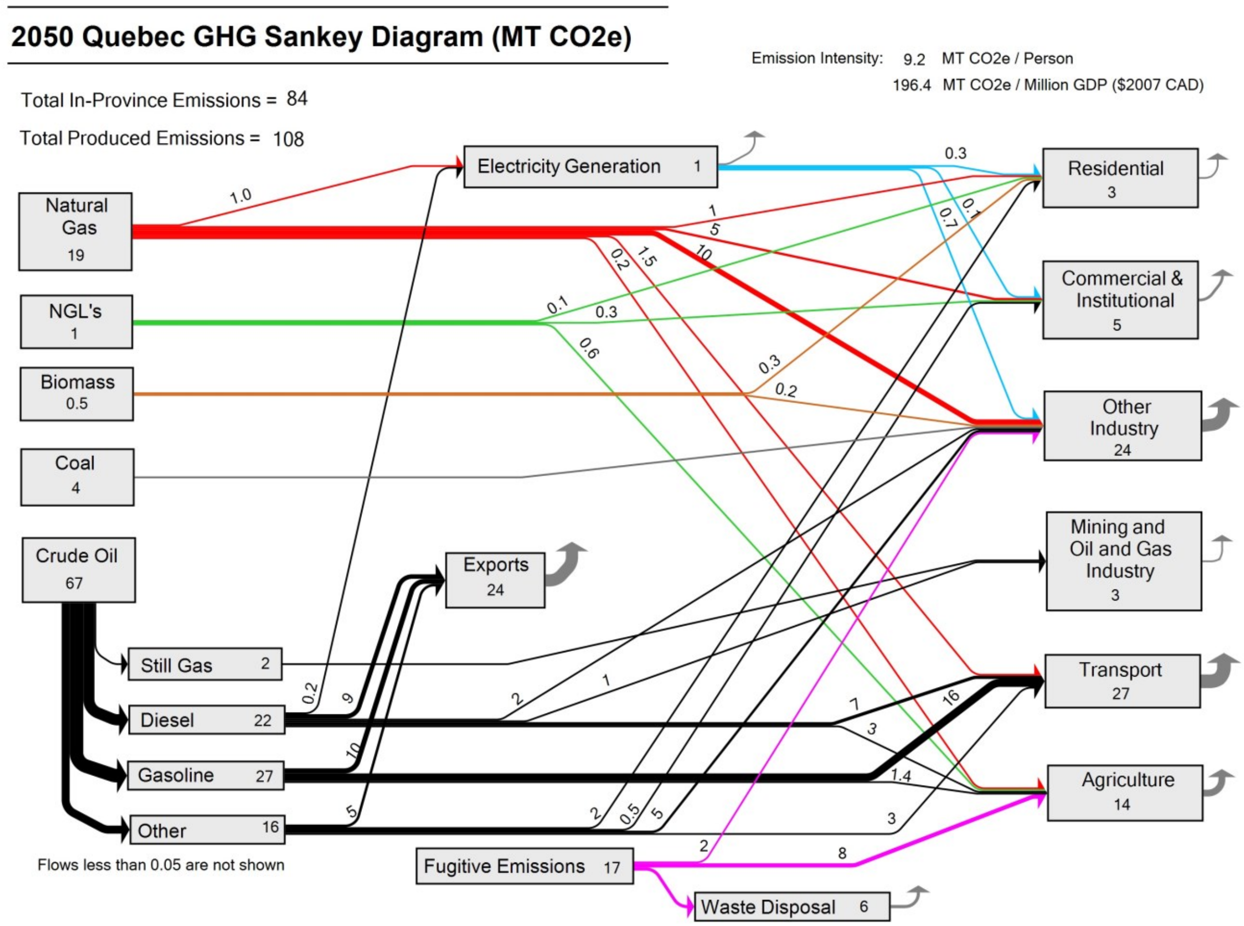

Figure 4-20: 2050 Quebec GHG Sankey diagram with resources and sectors

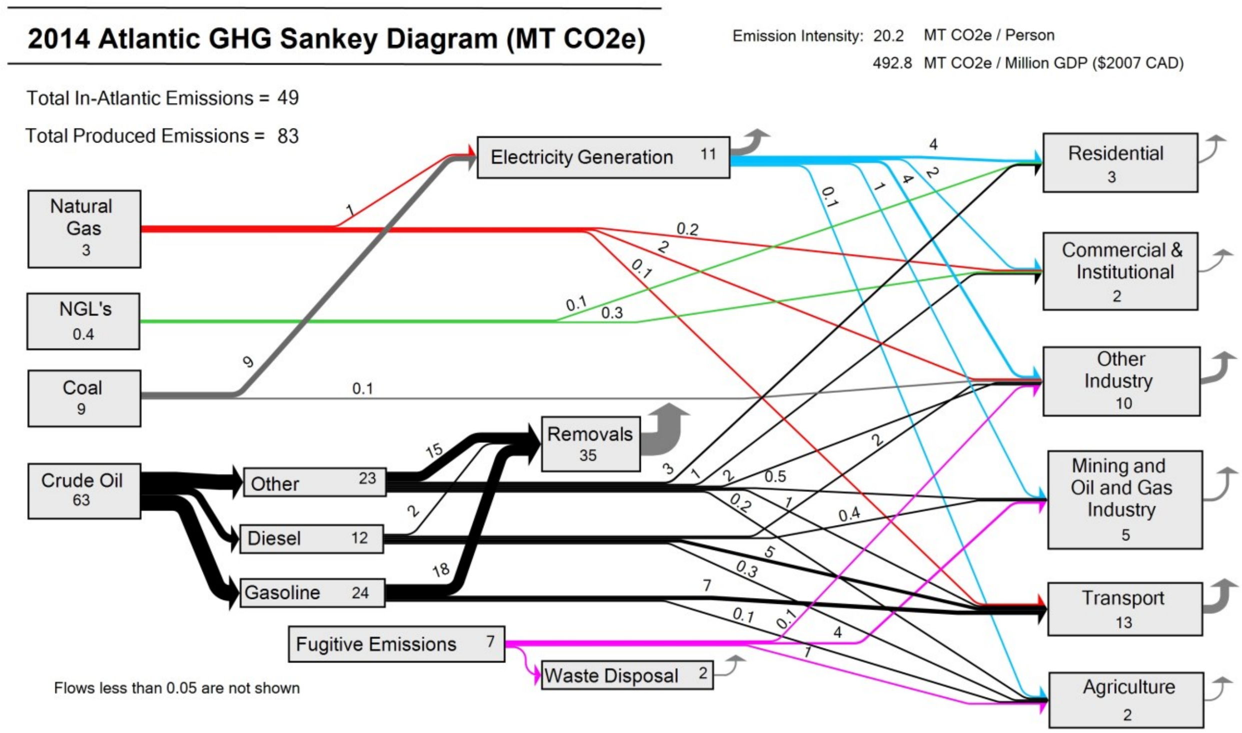

Figure 4-21: 2014 Atlantic GHG Sankey diagram with resources and sectors

New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland make up the Atlantic Provinces of Canada. The cumulative in-province emissions of these provinces in 2014 was 49 MT CO_2e (Figure 4-21), comparable with the NIR's 44 MT. The largest emission source in Atlantic Canada was the transportation sector. The second largest source of emissions was the electricity generation sector due to the prevalence of coal power. The region removed 35 MT in 2014, mainly from refinery production in New Brunswick. The emission intensity was 20.2 tonnes per person and 492.8 tonnes per million dollars of GDP, 0% and 17% above the Canadian average, respectively.

Figure 4-22 and Figure 4-23 show the Atlantic Provinces' emissions in 2030 and 2050, respectively. Total in-Atlantic emissions decrease from 49 MT in 2014 to 42 MT in 2030 and 39

MT in 2050. Changes in the Atlantic Provinces' emissions landscape will be limited. Electricity generation will see a steady decline in emissions to 36% less than 2014 levels. The emissions intensity per capita decreases 14% by 2030 and 18% by 2050, relative to 2014 levels. The emissions intensity per dollar of GDP declines 25% by 2030 and 39% by 2050, relative to 2014 levels.

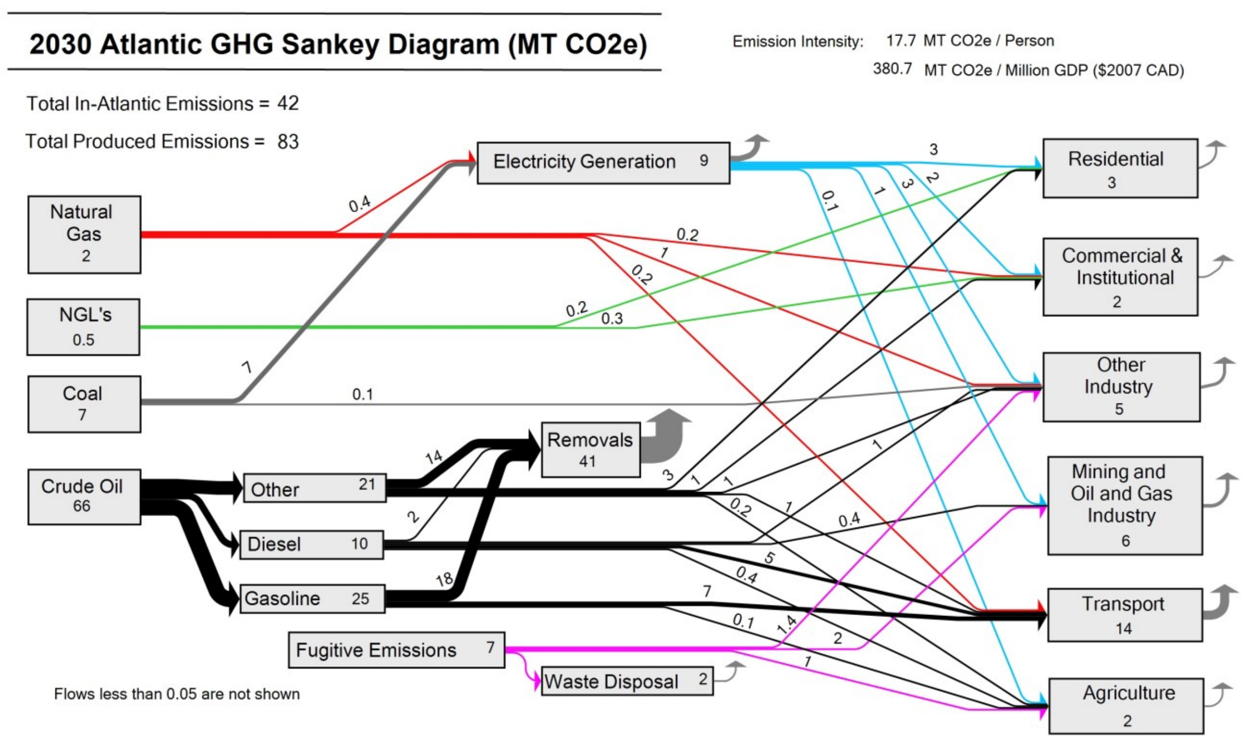

Figure 4-22: 2030 Atlantic GHG Sankey diagram with resources and sectors

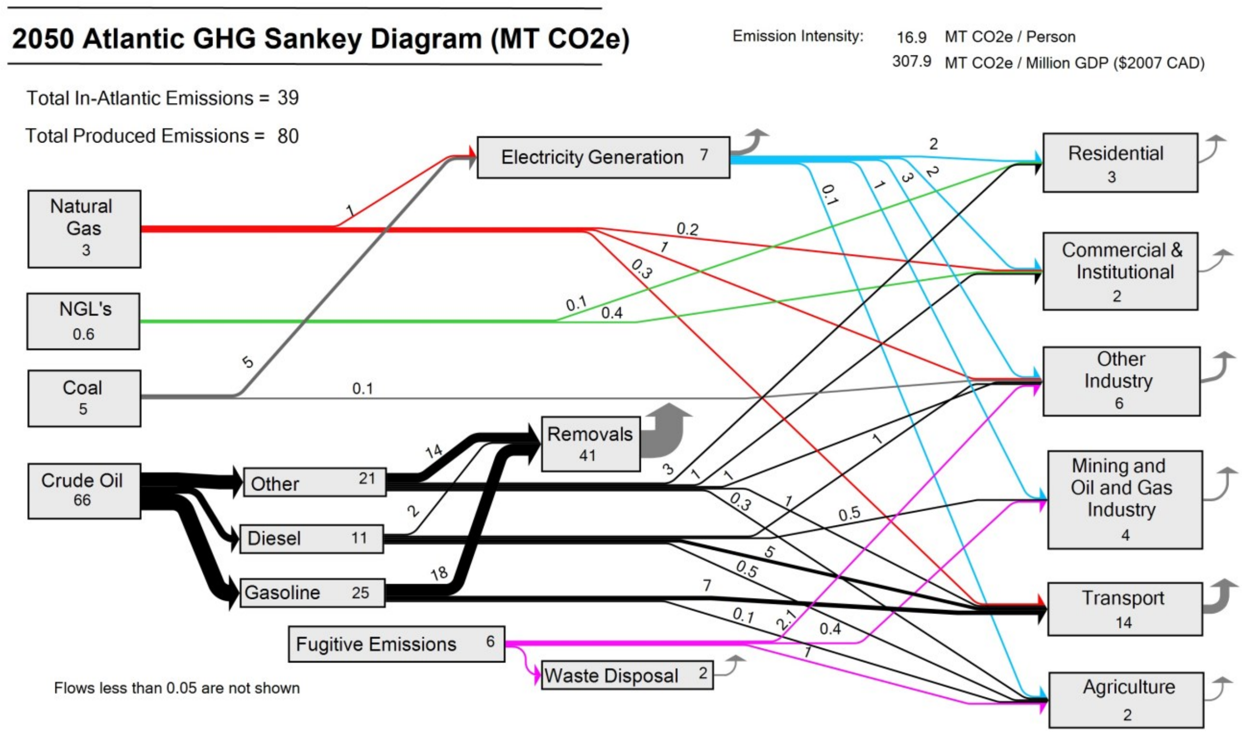

Figure 4-23: 2050 Atlantic GHG Sankey diagram with resources and sectors

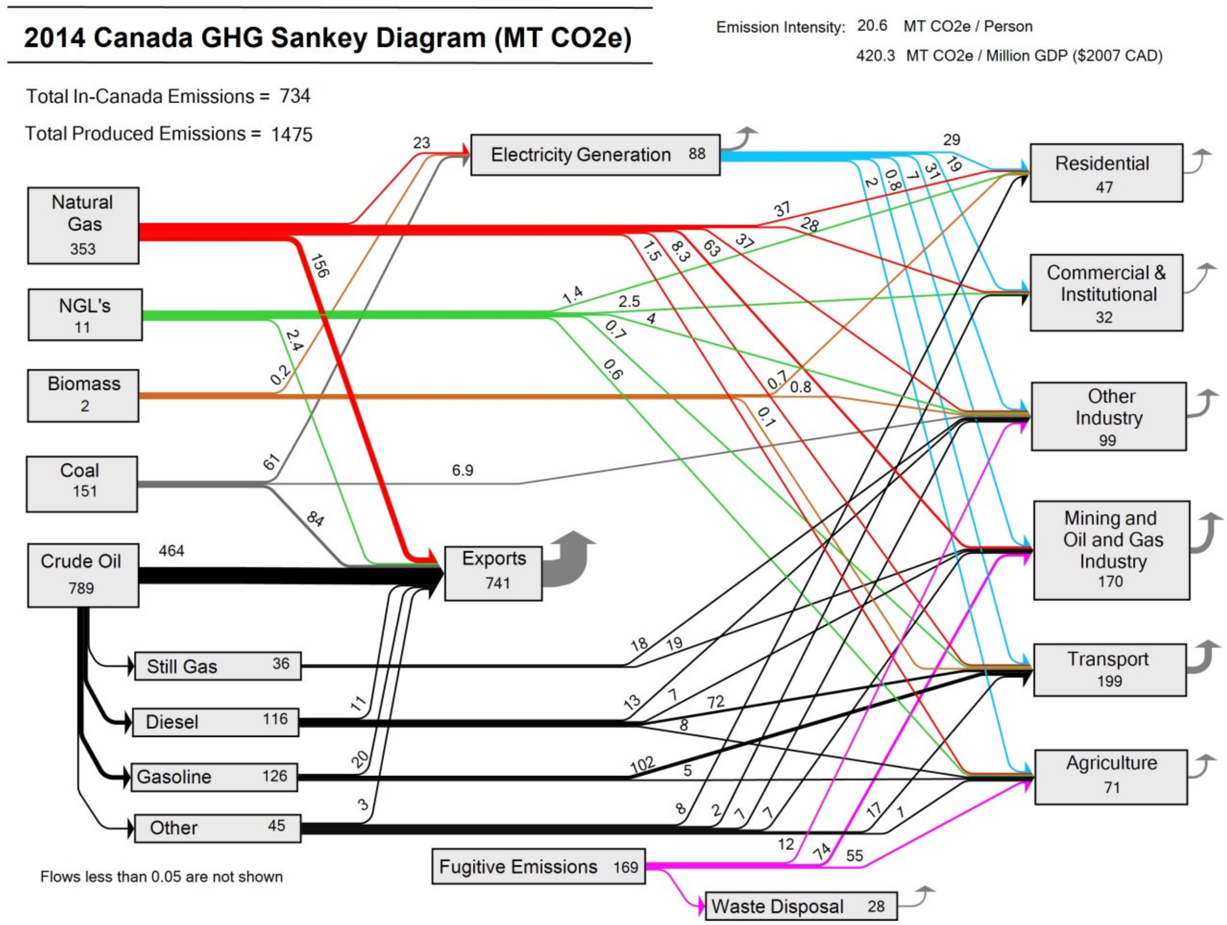

Figure 4-24: 2014 Canada GHG Sankey diagram with resources and sectors

The model shows that in-Canada emissions were 734 MT of GHGs in 2014 (Figure 4-24), matching the NIR's 734 MT. Canada's largest GHG emission sector in 2014 was the Transportation Sector with 199 MT of GHGs (27% of total GHG emissions). This was primarily due to the burning of gasoline (102 MT) and diesel (72 MT) in road transportation. Passenger and freight road transport made up the largest shares of the transport sector and accounted for 10.2% and 9.3% of the total Canadian GHG emissions, respectively. The second largest emitting sector was the mining and upstream oil and gas industry, which was responsible for 170 MT of CO_2e. The largest share of these emissions was the 74 MT CO_2e in fugitive emissions (10% of total Canadian GHG emissions). Alberta and Saskatchewan emitted most of these fugitive emissions during oil and gas extraction (approximately 40 MT and 22 MT of CO_2e, respectively). The largest fuel type combusted in the mining and upstream oil and gas sector was natural gas (63 MT CO_2e); of this, 38 MT were from Alberta oil sands operations. The other industry sector was the third largest emitting sector at 99 MT of CO_2e (13% of total emissions) and was made up primarily of petroleum refining (21 MT), other manufacturing (17.9 MT), iron and steel production (13.1 MT), and the chemical industry (12 MT). The main fuels producing the emissions were natural gas (37 MT), still gas (18 MT), and diesel (13 MT). The residential and commercial sectors together emitted 79 MT CO_2e (11% of Canada's total GHG emissions), of which 82% were from natural gas space and water heating. The agricultural sector emitted 71 MT CO_2e in 2014; 55 MT CO_2e were from non-energy related emissions. The electricity sector emitted 88 MT CO_2e (12% of total emissions) in 2014. The two primary sources of emission were coal (61 MT) and natural gas (23 MT). Coal power emissions were mainly from Alberta (43 MT), Saskatchewan (10 MT), and the Atlantic Provinces (7 MT). Natural gas power emissions were mainly from Alberta (10 MT) and Ontario (7 M). The sectors with the largest electricity demands were from other industry sectors (31 MT), the residential sector (29 MT), and the commercial and institutional sector (19 MT). Canada's emission intensity was calculated to be 20.6 tonnes per person and 420.3 tonnes per million dollars of GDP in 2014.

In terms of the resources responsible for the emissions (including exported emissions), most are from crude oil (789 MT, or 53% of total emissions) followed by natural gas (374 MT, or 25% of total emissions). About 59% of total crude oil emissions were exported and the rest were emitted within Canada.

It is estimated that approximately 741 MT CO_2e were emitted in Canadian exports, most of which are sent to the USA. In 2010 98.1% of Canadian petroleum products, 100% of natural gas, and 100% electricity exports were to the USA [114]. USA GHG emissions in 2014 were 6,870 MT of CO_2e. About 11% of these emissions may have originated from resources extracted in Canada. It is estimated that approximately 14% of in-Canada emissions are due to producing resources that are exported.

Figure 4-25 illustrates Canada's in-country emission landscape by resource, region, and end-use sector. It shows emissions released within the country only. Together the regions make up Canada's total of 734 MT. The resource totals on the left side plus the non-energy emissions add up to 734 MT. The end-use sectors on the right plus the non-energy emissions also total 734 MT. Fugitive emissions in this diagram are included in the resource totals, not separated out as in the other diagram formats. This diagram shows that the transportation and mining and upstream oil and gas sectors were the most GHG intensive. The energy use of natural gas and crude oil and oil products together produced the majority of GHGs (76% of the total). Alberta and Ontario released the most of all provinces and together made up 61% of Canada's emissions. Quebec, Saskatchewan, British Columbia together made up 29% of Canada's emissions. Atlantic Canada, Manitoba, and the territories made up the remaining 10%.

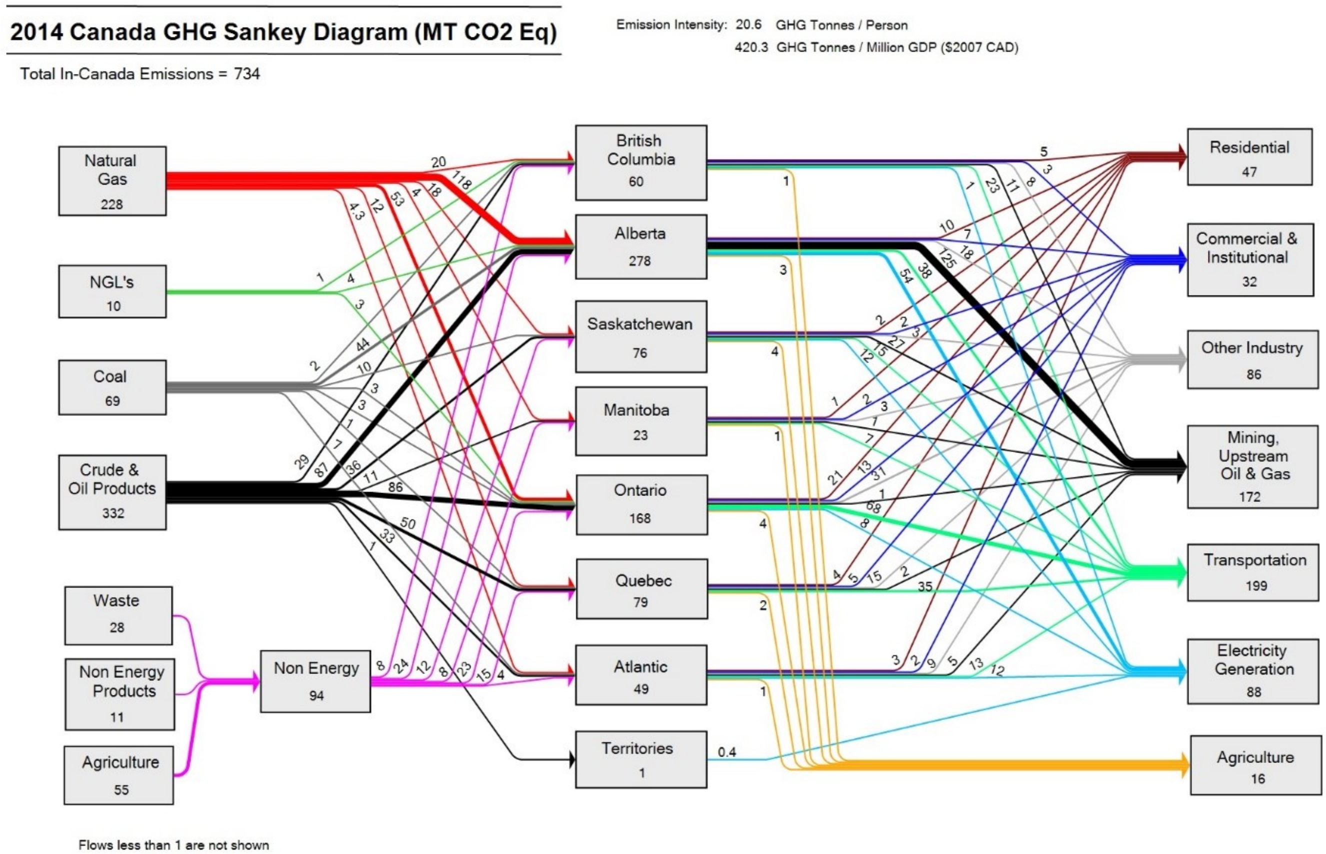

Figure 4-25: 2014 Canada GHG Sankey diagram with resources, regions, and sectors

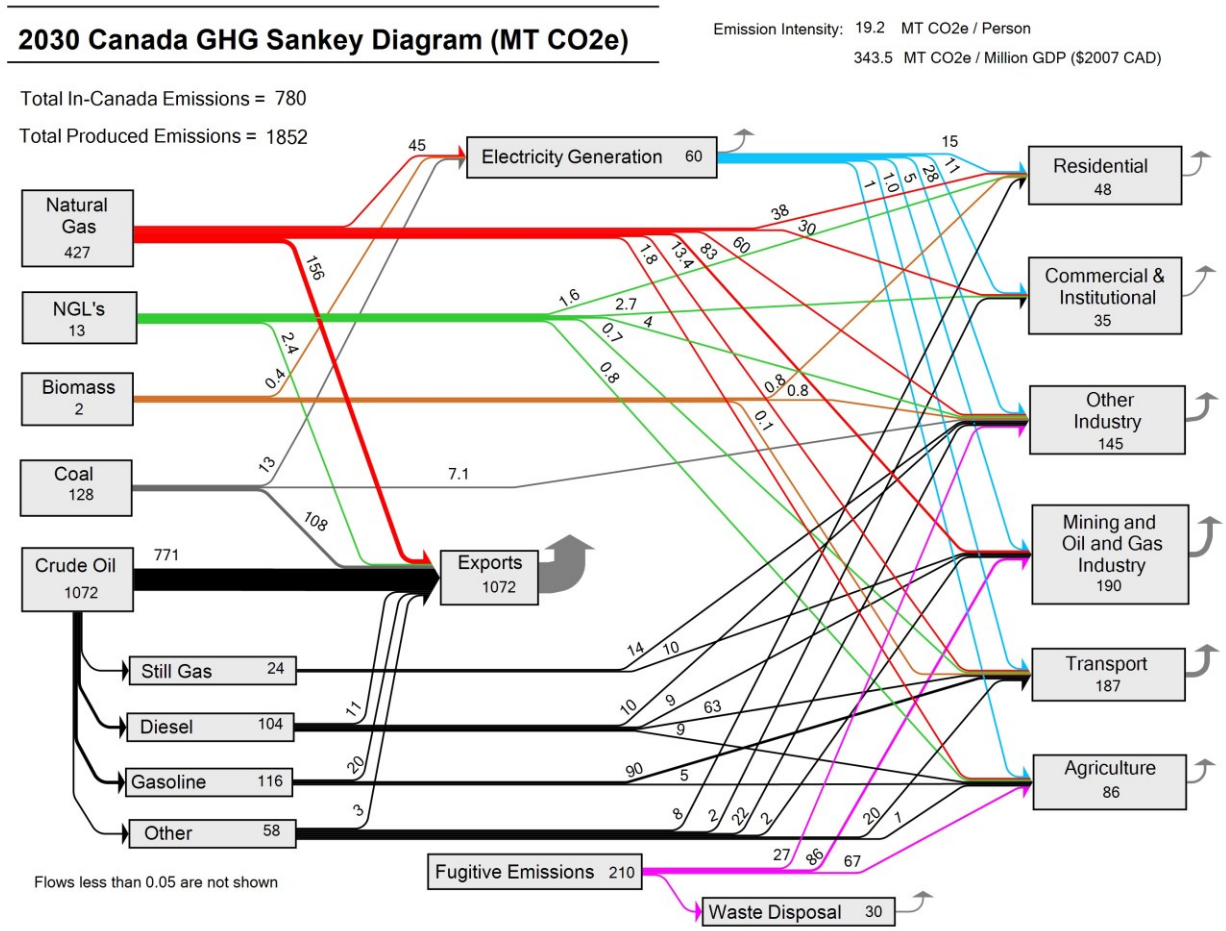

Figure 4-26: 2030 Canada GHG Sankey diagram with resources and sectors

The model predicts that Canada will emit 780 MT of GHGs in-country in 2030 (Figure 4-26). Canada's largest GHG emission sector in 2030 will be the mining and upstream oil and gas industry, which will surpass the transportation sector. This is due to drastic projected growth in oil sands production. The second largest emitting sector will be the transportation sector, responsible for 187 MT CO_2e. Other industrial sectors will be the third largest emitting sector with 145 MT CO_2e. The residential and commercial sectors together will emit 83 MT. The agricultural sector will emit 86 MT CO_2e, of which 67 MT are from non-energy related emissions. In terms of the resources responsible for the emissions, most are predicted to come from crude oil with 302 MT CO_2e (39% of total emissions), followed by natural gas with 271 MT CO_2e (35% of total emissions). . The electricity sector emits 60 MT CO_2e (8% of total emissions) in 2030. The primary source of electricity emissions in 2030 will be natural gas (45 MT). The sectors with the largest electricity demands will be other industry (28 MT), the residential sector (15 MT), and the commercial and institutional sector (11 MT). Figure 4-27 shows Canada's projected emissions in 2030 by resource, region, and end-use sector.

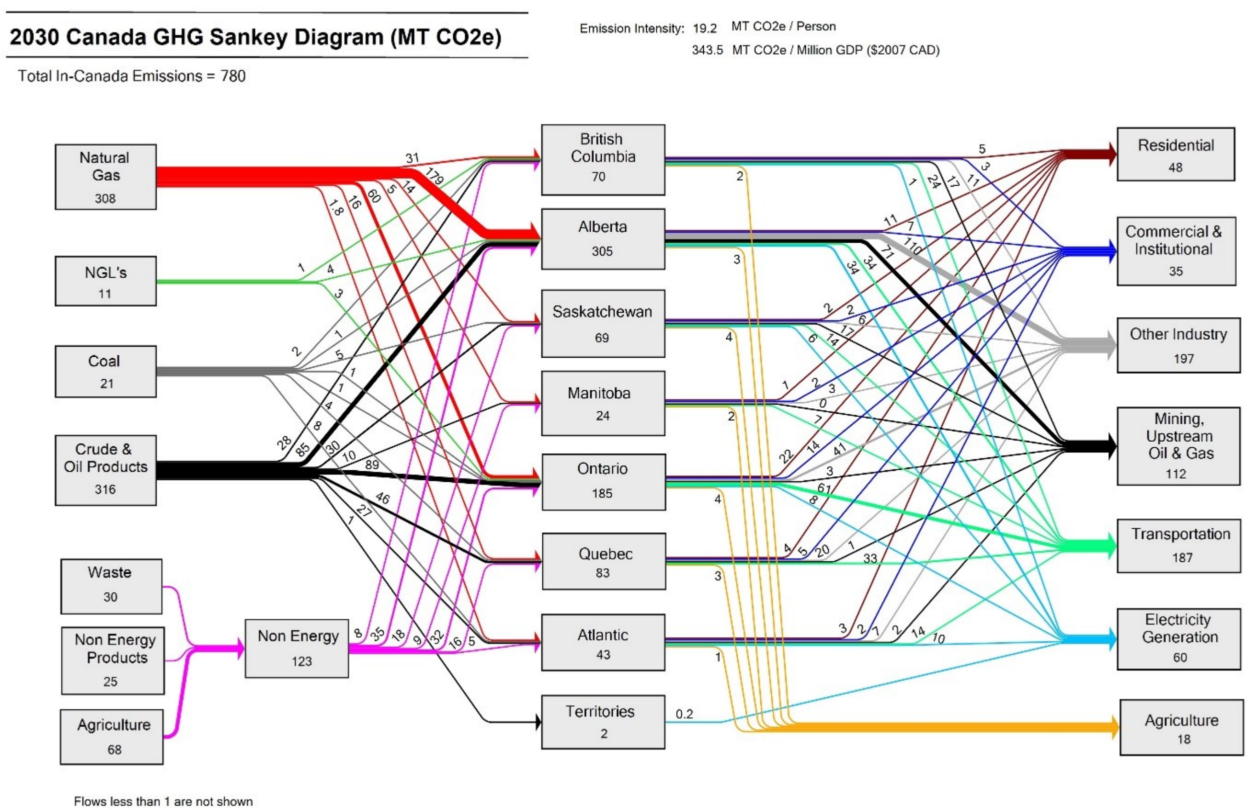

Figure 4-27: 2030 Canada GHG Sankey diagram with resources, regions, and sectors

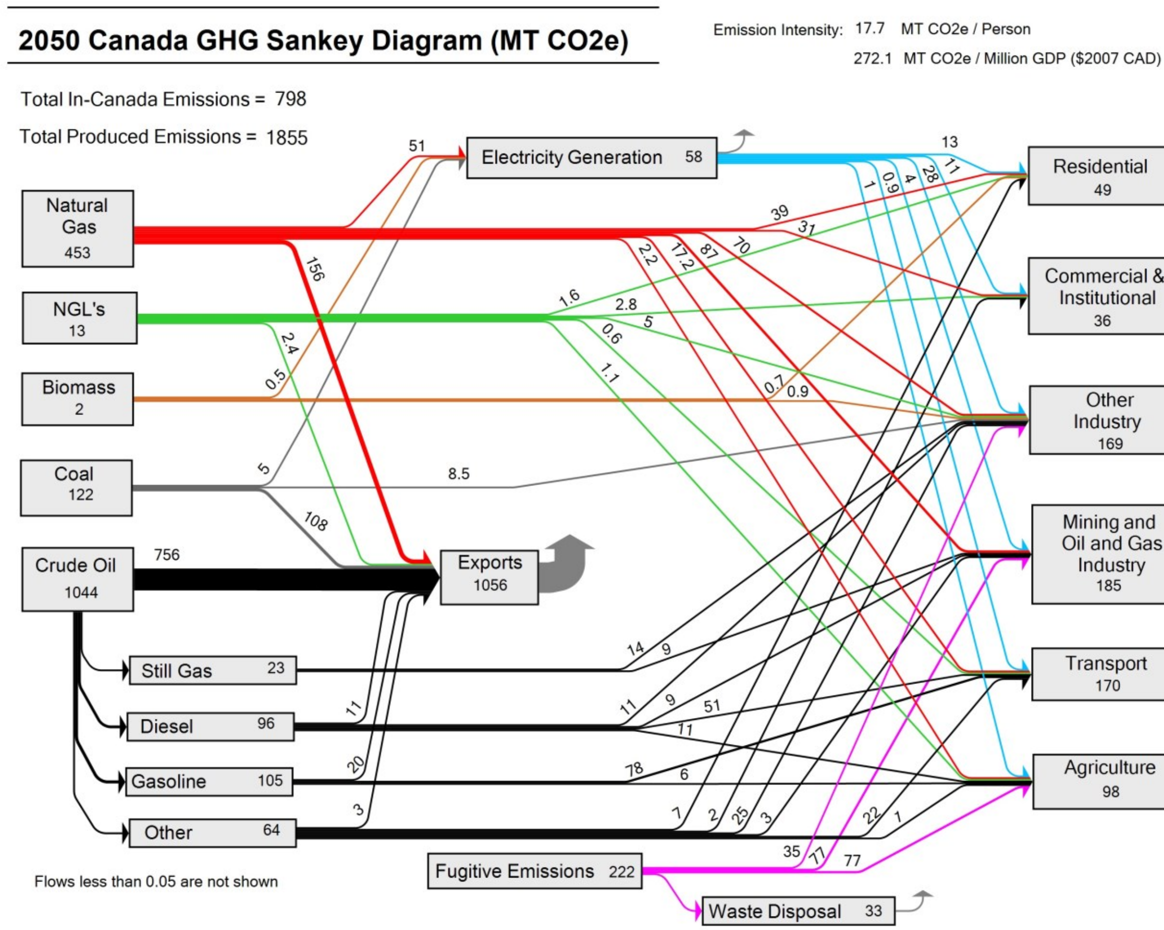

Figure 4-28: 2050 Canada GHG Sankey diagram with resources and sectors

The model shows that Canada will emit 798 MT of GHGs in-country in 2050 (Figure 4-28). Most of the GHGs will be from the mining and oil and gas sector with 185 MT CO_2e. The next highest source will be from the transportation sector, which will be responsible for 170 MT CO_2e. Other industry will be the third largest emitting sector with 169 MT CO_2e. The residential and commercial sectors together will emit 85 MT. The agricultural sector will emit 98 MT, of which 77 MT will be from non-energy related emissions. Most emissions will be from natural gas (297 MT, or 37% of total emissions), which is predicted to surpass crude oil's 288 MT (36% of total emissions). Efficiencies in transportation and growth in natural gas-fueled electricity production will make this possible. The electricity sector will emit 58 MT in 2050, and the primary source of emissions will be natural gas (51 MT). The sectors that will have the largest electricity demands will be other industry (28 MT portion), the residential sector (13 MT portion), and the commercial and institutional sector (11 MT portion). Figure 4-29 shows Canada's projected emissions in 2050 by resource, region, and end-use sector.

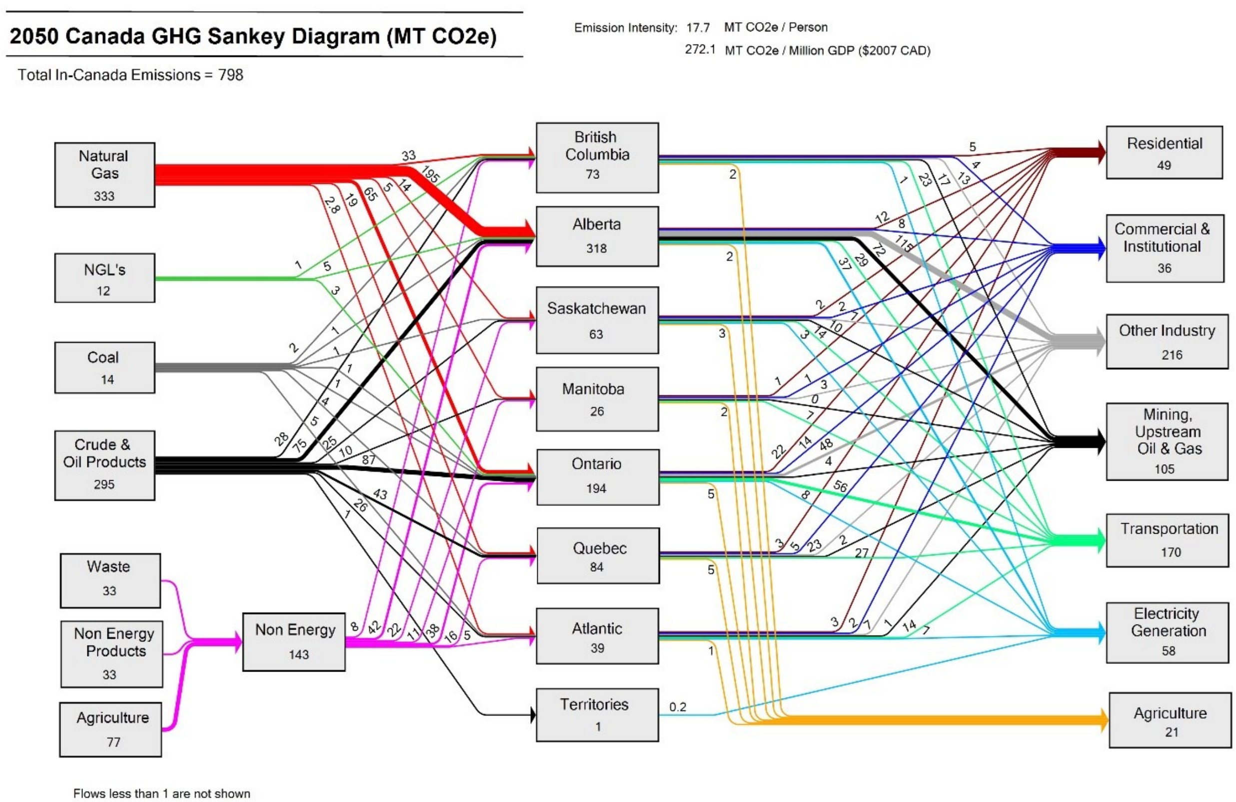

Figure 4-29: 2050 Canada GHG Sankey diagram with resources, regions, and sectors

Diagrams for the years 2014, 2030, and 2050 (Figures 5 to 31) were created to provide a detailed picture of a business-as-usual emission landscape in Canada. Canada's emission intensity is calculated to be 19.2 tonnes per person and 343 tonnes per million dollars of GDP in 2030, a 7% and 19% improvement, respectively, from 2014. Canada's emission intensity is predicted to be

17.7 tonnes per person and 272 tonnes per million dollars of GDP in 2050, an 16% and 35% improvement, respectively, from 2014. Canada is projected to see a 6% increase in emissions between 2014 and 2030 and a 2% increase in emissions from 2030 to 2050.

5 Chapter V: The Implications of Crude Oil Pipeline and Rail Transport on Canada's Energy and Emission Outlook to 2050 Through the LEAP-Canada Model[4]

5.1 Introduction

Canada's emission target is to reach 622 megatonnes (MT) carbon dioxide equivalent (CO_2e) by 2020 and 524 MT CO_2e by 2030, a 29% decrease from 2014 levels [115]. Canada also recently agreed to play a leading role in limiting the global mean temperature rise to well below 2 degrees Celsius at the Paris Agreement [115]. Unfortunately, projections show that emissions are likely to increase by 19% from 734 MT in 2014 to between 765 and 875 MT by 2030 [115]. This quandary has been at the heart of pipeline discussions, as many have argued that Canada cannot both reach its climate change targets and build crude oil pipelines. This study examines the effects of building, or not building, proposed major crude export pipelines.

In 2013, Canada was the world's fifth largest producer and third largest exporter of hydrocarbons [116]. By the end of 2014, Canada's proven crude oil reserves ranked third globally [116]. In 2014, 97% of crude reserves and 58% of production in Canada were from oil sands resources, which demonstrates that Alberta's oil sands are a significant contributor to Canada's crude oil paradigm [116]. These statistics show that Canada, and, in particular, Alberta's, oil sands are a major energy player both nationally and internationally.

[4] To be submitted for publishing.

Pipelines play a crucial role in Canada as they deliver required energy commodities both to Canadians and export markets. In 2015, $99.7 billion of energy products were transported via trans-border pipelines at a cost of $7.3 billion [117]. Currently, 97% of exported crude oil goes to the U.S., and, with oil sands production expected to drastically increase in the near future, possibly by as much as 25% between 2015 and 2030, producers will be looking to export more product to other markets [118]. With current pipelines near full capacity, additional pipelines have been proposed to allow access to further export markets.

The 2015-2016 crude oil pipeline capacity out of Western Canada was approximately 3.7 million barrels per day (MMb/d) [116]. Current expansions approved and under construction will increase the capacity to approximately 4 MMb/d by 2019; no further additions are approved currently. The projected crude oil available for export by 2040 is 5.13 MMb/d [119]. Constraints on moving crude from Western Canada to export markets may have implications on Canada's energy and emission outlook, from the transportation method to upstream production impacts.

Five major pipelines have been proposed to expand pipeline capacity and allow more Canadian oil to reach outside markets, as shown in Table 5-1 and Figure 5-1. At the time of this study, the Northern Gateway pipeline request has been denied [120]. The Trans Mountain and Line 3 Replacement pipelines have been approved [121, 122]. The Energy East pipeline has faced strong controversy and opposition; review of its proposal is ongoing [123]. The Keystone XL is a trans-national pipeline. In late 2015 the U.S. rejected the application; however, due to recent political shifting in the U.S., the pipeline has been approved.

Table 5-1: Major export pipeline proposals

Pipeline Name	Company	Origin	Termination	Capacity (thousand bbl/d)	Distance (km)	Status
Northern Gateway	Enbridge	Bruderheim, AB	Kitimat, BC	525 (oil) 193 (condensate)	1,172	Denied
Trans Mountain Expansion	Kinder Morgan	Edmonton, AB	Burnaby, BC	590	1147/1180 (Twin line)	Approved
Energy East	TransCanada	Hardisty, AB	St. John, NB	1,100	4,516	Pending
Keystone XL	TransCanada	Hardisty, AB	Monchy, SK (continued in the U.S. to Steele City, NE)	830	525 (in-Canada)	Approved
Line 3 Replacement	Enbridge	Edmonton, AB	Gretna, MB	370	1,073 (in-Canada)	Approved

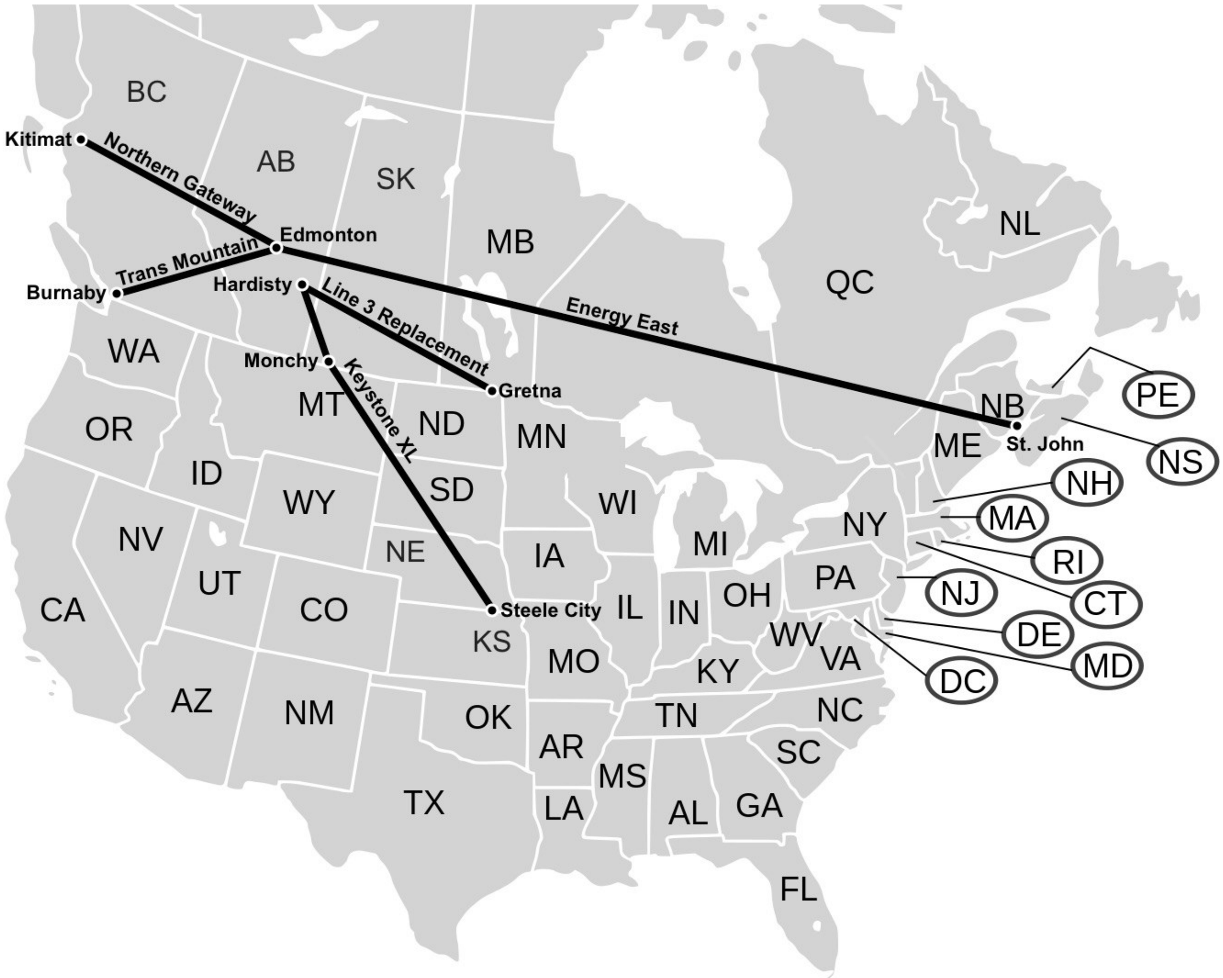

Figure 5-1: Proposed major pipeline route map

Because there has been insufficient capacity to move all available crude oil through pipelines, rail transport has been used since 2012 to meet capacity demand [124]. In 2015, 4% of exported crude was moved by rail [124]. Crude-by-rail transport is expected to increase into the future, especially if expected crude oil production increases are not met with corresponding pipeline expansions. By 2040, Canadian crude production is expected to be 41% above 2015 production, and, if pipelines are not expanded, approximately 1.2 MMb/d of crude could require rail transport [119]. Compared to the historical peak of 0.161 MMb/d in 2014, this is a 645%

increase in crude-by-rail transport. According to CAPP [125], this is plausible as rail capacity was expanded to 1.4 MMb/d in 2016.

Transporting crude by pipeline is generally more energy efficient, costs less, and is safer than rail [125-127]. Since rail transport is costlier than pipeline on a larger scale and longer distances [126], a pipeline constraint forcing more crude-by-rail transport would decrease the profits of producers. It is not known how upstream production would be impacted by the eroded investment interest from the higher costs of larger scale rail use. The Keystone XL Final Supplemental Environmental Impact Statement from the United States Department of State (US DOS) provides a market analysis of oil sands products subjected to constrained pipelines and concludes that production is not easily constrained [128]. The statement's business-as-usual (BAU) analysis showed that a pipeline capacity increase of zero would lower the price received by producers by up to $8 per barrel. The US DOS concluded this would not be enough to alter current and planned supply growth given a West Texas Intermediate (WTI) equivalent price of over $75/bbl, even with conservative assumptions on rail shipment costs. The US DOS suggested that supply costs may outweigh investment benefits in the WTI equivalent range of $65-$75 per barrel, and so an increased transportation cost in this price range due to a pipeline constraint may affect investments. Prices below this range would likely not provide favorable returns on investments, regardless of pipeline constraints.

The National Energy Board (NEB) Energy Futures Report (EFR) has studied a constrained oil export pipeline capacity scenario [129]. The scenario assumes the WTI – Western Canadian Select (WCS) crude price differential increases to US$10/bbl and the WTI – Alberta Mixed

Sweet (MSW) crude price differential increases to US$5/bbl due to pipeline constraints, causing lower netback prices for producers. The EFR modelling suggests the lower prices received by producers deters investment capital for conventional oil and oil sands by 15% and 9%, respectively, and overall crude production decreases by an average of 7% per year from 2015-2040.

Despite the potential negative effects of shifting to crude-by-rail transport, some optimism is expressed in the literature. Rail transport provides the advantages of existing infrastructure, flexible delivery speeds and routes, and less requirement for diluent [125-127]. Rail economics would likely become more favorable in the future, if investment increase due to higher use of rail for crude transport, so much so that the U.S. Keystone XL Environmental Impact Statement [130] suggests that the shipping costs of bitumen by rail could be close to dilbit shipping costs by pipeline. IHS Energy [131] also shows optimism for crude-by-rail transport in a report that explores the cost details of shipping bitumen by rail with different diluent ratios. Moreover, an earlier study by the authors found that rail transport of crude could become economical compared to pipeline at larger scales and longer distances [126].

The purpose of this chapter is twofold. The first objective is to quantify the energy and GHG emissions associated with expanding pipeline capacity as proposed. The second objective is to show the impacts of not building the pipelines and instead relying on rail. This builds upon earlier studies by the authors which assessed the techno-economics, and, analyzed the lifecycles of hypothetical crude pipeline vs rail transport scenarios [126, 127]. This chapter expands on the past research [126, 127] by applying their findings to assess the real world year-by-year impacts of proposed pipelines.

The proposed pipelines and rail alternatives were modelled with the LEAP-Canada model. Incremental energy demand and GHG emissions were analyzed, taking into account the unique energy supply-demand sector and outlook in each province in Canada. It is intended for this research to reach not only the scientific community but also the public, given the widespread debate regarding crude oil transportation and the public's interest in the matter [132].

5.2 Methodology

5.2.1 Study structure

The overarching process flow for this study is shown in Figure 5-2. Any of the available oil exports generated from LEAP that are more than the existing pipeline capacity are fed through the process flow. Depending on the fate of the pipelines, four scenarios are assessed:

Scenario 1 – Pipeline Scenario: All proposed pipelines are approved and constructed. A diluted bitumen blend of 70% bitumen and 30% diluent (dilbit) is used to transport bitumen.

Scenario 2 – Rawbit Rail Scenario: The five proposed pipelines are not approved and not constructed. Any crude oil available for export over the pre-existing pipeline capacity is transported via rail in the rawbit form (100% bitumen). 100% rawbit transport begins in 2017; crude oil transported prior to that is in the dilbit form. Diluent recovery is required for rawbit transport.

Scenario 3 – *Railbit Rail Scenario:* The five proposed pipelines are not approved and not constructed. After bitumen is extracted, no diluent is added or removed, and the content is assumed to be 15% diluent from the production process.

Scenario 4 – Dilbit Rail Scenario: The five proposed pipelines are not approved and not constructed. Any oil available for export over the pre-existing pipeline capacity is transported via rail in the dilbit form (70% bitumen and 30% diluent).

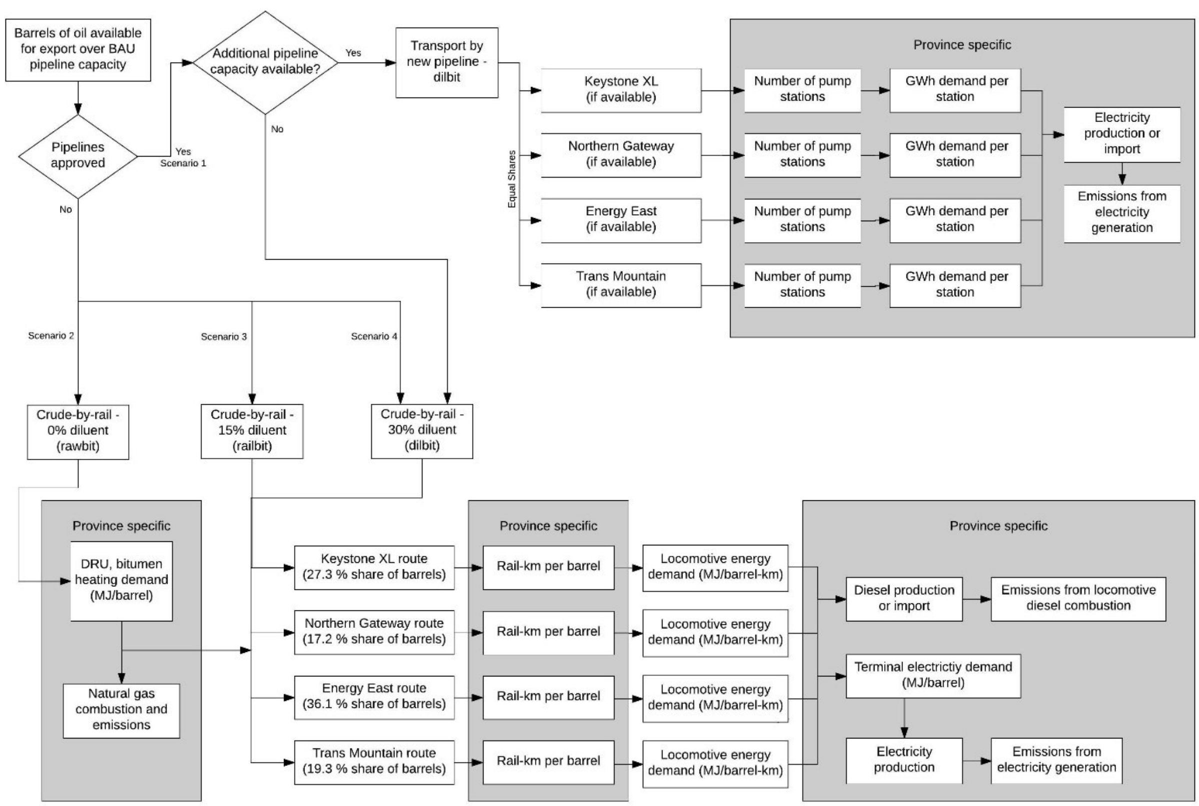

Figure 5-2: LEAP-Canada oil export transportation flow diagram

5.2.2 LEAP-Canada model

Long-range Energy Alternatives Planning (LEAP) software was used to develop an energy model of Canada's energy sector for the years 2010-2050 [40, 109]. The LEAP model is an energy-accounting model developed using bottom-up technology-specific end-use energy consumption data. It comprehensively depicts Canada's energy landscape including the energy demand sectors, resource transformation processes, and natural resources.

The basic structure of the model is shown in Figure 5-3. Computations begin with energy demand, which drives all other model equations. The residential, commercial and institutional, industrial, transportation, and agricultural sectors create energy demands from end-use devices. The transformation modules produce the types of energy required, which are fed from the resource module. If a particular region does not have the domestic resource reserves or transformation processes to fulfil an energy requirement, imports are used or energy is transferred from another region. If excess energy production occurs in a region, export or regional trade occurs.

The model was developed to provide a baseline for energy and GHG emission analyses. Most of the data used to create the model were derived from publically available statistics and reports. The principle data sources are listed in Table 5-2. Tier 1 and 2 IPCC emission factors were applied to fossil fuel combustion for emission accounting, and annual historical emissions (2010-2014) were verified with the National Inventory Report (NIR) [7]. Provincial energy demands were projected through a number of demographic, GDP, policy, and technology assumptions specific to each province. Province-specific oil production growth for future years was taken from the NEB, the Alberta Energy Regulator (AER), and the Canadian Energy Research Institute's (CERI) projections [105, 112, 119].

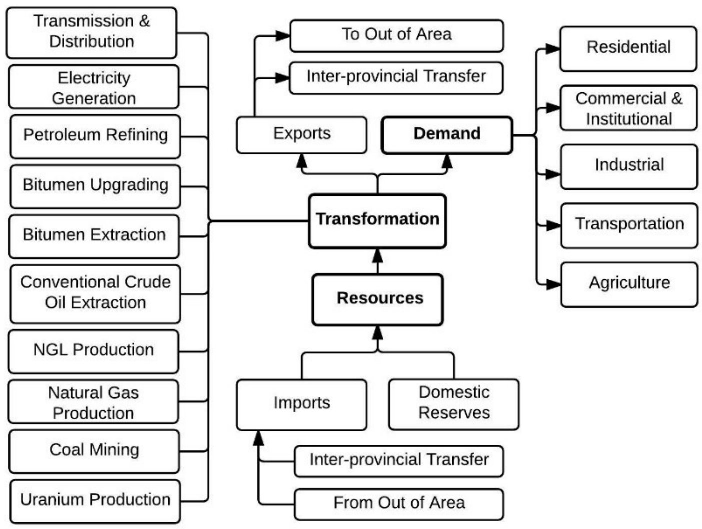

Figure 5-3: LEAP-Canada model structure [109]

Table 5-2: LEAP-Canada model principal data sources [109]

Source	**Description/Use**
Natural Resources Canada (NRCan) Office of Energy Efficiency (OEE) Comprehensive Energy Use Database (CEUD) [106]	End-use energy demand, sectoral activity
Canadian socio-economic information management (CANSIM) Tables [73]	End-use energy demand (pipeline and non-energy use), GDP, population, energy transformation data
National Energy Board (NEB) Energy	Assumptions for energy intensity and activity

Source	Description/Use
Futures Reports (EFR) [129]	projections, macro-economic projections, energy supply projections
Technology and Environment Database (TED)	The TED holds information on technical characteristics, costs, and environmental impacts (IPCC emission factors) for a range of technologies [88]

The transportation demand tree was expanded for this study to include proposed pipeline and crude-by-rail transportation alternatives. The scope of this study includes the development of the proposed pipelines and crude-by-rail branches and the energy intensities over the study period. The proposed pipelines were segregated in the demand tree. Energy demands for each pipeline were calculated using the energy intensities of the pump stations in each province and oil export types and quantities to 2050. Crude–by-rail transport was segregated into the rail routes that would be used to move crude to the same markets as the proposed pipelines. Energy demands were estimated by calculating locomotive and rail terminal energy intensities as well as crude-by-rail export types and quantities to 2050.

5.2.3 Crude exports model

The model calculates for any given year the amount of bitumen, synthetic crude oil (SCO), heavy crude, and light crude available for international export from Alberta and Saskatchewan, based on production in excess of Canadian demand. Model results were validated for accuracy by comparing the outputs to historic years where statistical crude export data were available. The model's crude exports varied by 1.8%, 1.2%, 2.1%, and 4.7% with 2010-2013 statistical values, respectively. Bitumen volume available was increased to account for added diluent required for pipeline transport at a 70% bitumen, 30% diluent ratio [133]. It was assumed that in any year the volumes were first sent through available pipeline capacity. Any crudes available after existing pipelines are fully used were sent through the proposed pipelines in equal proportions to the capacity of each pipeline. Any crudes available after existing and proposed capacities are fully used were sent by rail transport.

5.2.4 Pipeline transport model

The pipelines' branches include the major pipelines that have recently been approved or denied or are pending review. Each of the proposed pipelines has a specific number of pump stations in each province that contain oil pumps, condensate pumps, and natural gas turbines depending on the pipeline. Existing pipeline capacity data are from the NEB [129].

The Trans Mountain and Keystone XL pipelines were modelled to start service in the year 2019, and the Northern Gateway and Energy East in 2021. These dates correspond to construction times cited in the NEB applications, with a 2017 construction start date. The energy demands for the pump stations for each pipeline in each province were calculated from the application fillings with the NEB for each pipeline. It was assumed that 80% of the design power capacity of each pump station is reached as pipeline capacity use of 100% is reached. The power demands were modeled to change in proportion to the capacity use of each pipeline. It was assumed that all the crude moved with the new pipelines is in the dilbit form and other crudes available for export are transferred with existing pipelines. Given that the majority of projected increases in production are for diluted bitumen, this is likely to be the case. The results obtained from this method of calculating pipeline energy demand were verified with the methods presented by Nimana et al. [127].

Electricity production takes place in each province where the pump station electricity demand exists; imported electricity is used where there is insufficient generation capacity. The GHG emissions from electricity generation are unique to the power generation technology mix of each province. This power mix changes over time corresponding to each province's unique power generation projections. IPCC Tier 2 emission factors were used for the power plants.

Construction energy and GHG emissions were not included in the analysis. Operation and maintenance emissions are considered to be negligible. Fugitive emissions were not taken into account either as they have been found to be negligible during pipeline operation, according to the Keystone XL environmental impact assessment [128].

5.2.5 Rail transport model

When oil is moved by rail due to insufficient pipeline capacity, it is assumed that each route is used in proportion to the proposed pipeline capacities, similar to the pipeline transport model. The distance of track for each route is estimated for each province, as shown in Table 5-3. Distances were estimated and verified with CAPP [125] and Tarnoczi [134]. The locomotive energy intensities were calculated from Statistics Canada's data on diesel fuel consumption for freight transport, yard switching and work trains, and the number of tonne-km of freight transported, giving units of MJ of diesel consumption per tonne-km of freight transported by rail [135, 136].

Table 5-3: Crude-by-rail route distances

Pipeline Name	Origin	Termination	Estimated Rail Distance (km)
Northern Gateway	Bruderheim, AB	Kitimat, BC	1,475 (BC-1018 AB-457)
Trans Mountain	Edmonton, AB	Burnaby, BC	1,150 (BC-759, AB-391)
Energy East	Hardisty, AB	St. John, NB	4,110 (AB-256, SK-562, MB-474, ON-1847, QC-591, NB-380)
Keystone XL	Hardisty, AB	Monchy, SK (continued in the U.S.)	900 (AB-105, SK-795)
Line 3	Edmonton, AB	Gretna, MB	1491 (AB-345, SK-788, MB-358)

The specifications from the Dot-111 tanker were used to calculate the amount of each type of crude that can be transported, given the weight and volume limits and taking into account the tare weight [137]. The energy intensity for moving each type of crude oil, diluent, and empty tankers was calculated on a MJ per barrel-km basis. Rail terminal energy intensity was calculated using estimated terminal electricity demand and oil capacity from the US DOS report [128].

The transportation of pure bitumen with no diluent (rawbit) requires the removal of diluent in a diluent recovery unit (DRU). Typically, diluent addition is required during surface treatment of bitumen post extraction. The diluent content at this stage is less than that required for pipeline transportation, typically 12-18% by volume [131]. For this analysis, 15% is assumed. Because of this process diluent content, a DRU is employed to remove the diluent. Heating is required during the loading and unloading of the bitumen. The energy intensities for these processes were derived from Nimana et al. [127].

Empty car return was assumed for all routes except the Northern Gateway, where diluent is returned as it is with the proposed pipeline. Energy intensity improvements in rail transport were assumed to reach 15% by 2030 and 35% by 2050 compared to 2010 levels [138].

Energy use and emissions from the construction of rail infrastructure and fugitive emissions from rail car loading and unloading were not included because, combined, they make up less than 1% over the life cycle of crude-by-rail transport [134].

5.3 Results and Discussion

The first result calculated by the model is the quantity of oil exports from Western Canada, namely Alberta and Saskatchewan. Figure 5-4 shows the projected oil available for export from Western Canada. The existing and planned export pipeline capacity includes the Line 3, Keystone XL and Trans Mountain. The proposed pipeline capacity includes the Northern Gateway and Energy East. The shaded region represents the range of exports depending on high and low oil price assumptions from the NEB; the low and high price ranges will reach 48 and 127.5 US$/bbl WTI, respectively, by 2040 [119]. The maximum expected use limit is shown to be 87.5% of the available capacity. This is a reasonable estimate as historical use rates have fallen between 85 and 90%; spare capacity is desired for better flexibility and control over costs [117, 129].

The model projects oil exports will grow continuously until reaching a peak in 2039 at just under 864,000 m^3/d (5.4 MMb/d). This is comparable to the NEB's projection of 5.13 MMb/d (6% variance). Due to the recent drops in oil prices and the slowdown of Western Canada's economy, oil export projections are less than they were at the time of pipeline applications. As seen in Figure 5-4, a large amount of spare capacity will come online after 2019. By the peak in 2039, crude oil available for export will be 104% of planned pipeline capacity, a shortage of 34,700 m^3/d. With high price assumptions, the proposed-approved pipeline capacities would experience above 90% utilization between 2031 and 2048. With low price assumptions, none of the proposed-unapproved capacity would be required.

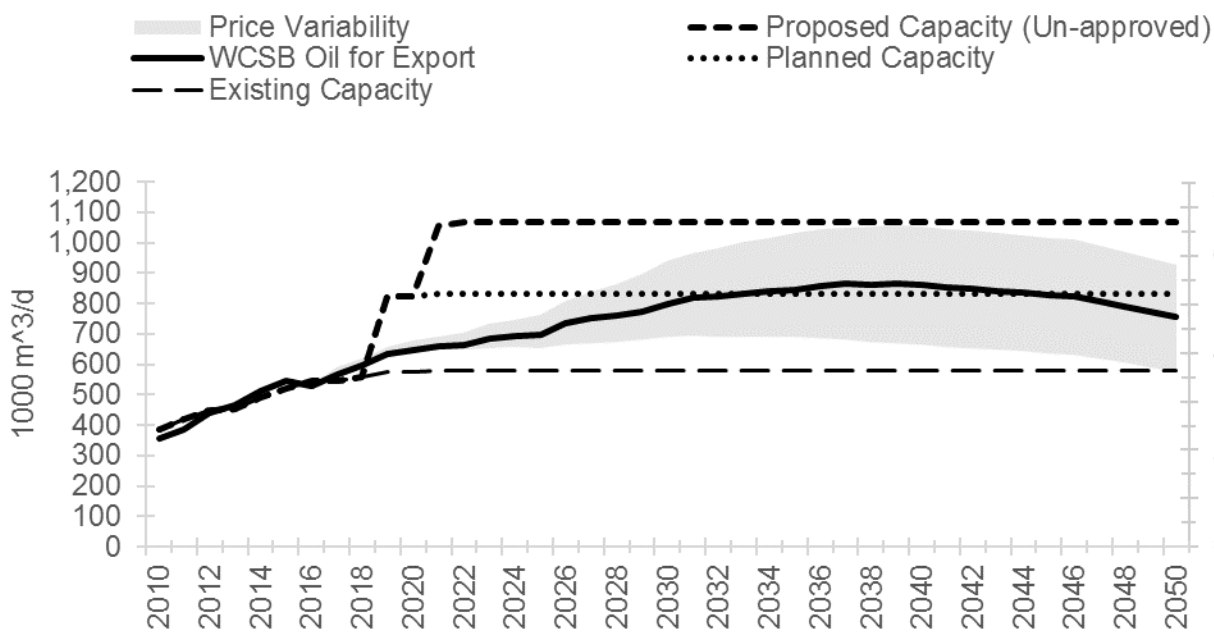

Figure 5-4: Current and proposed pipeline capacity based on the LEAP-Canada model

5.3.1 Pipeline impacts

This section quantifies the energy and GHG emissions associated with operating the proposed pipelines to the year 2050. Figure 5-5 shows the projected energy demands for each pipeline assuming all the oil available for export is sent by pipeline when available. The Energy East pipeline is the most impactful due to its significant length of 4,516 km. The cumulative incremental energy demand from pipeline operations over the study period is 966 PJ, which is 0.2% of the total cumulative energy demand for Canada over the study period.

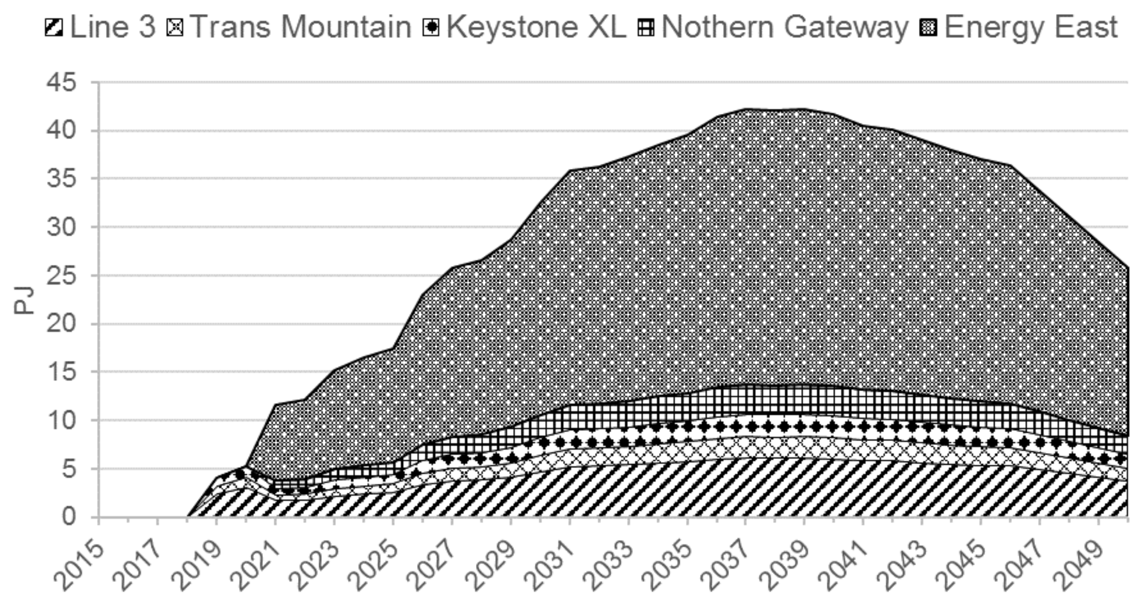

Figure 5-5: Pipeline energy demand projections based on the LEAP-Canada model

Figure 5-6 breaks down the cumulative energy demand over the study period by province and by pipeline. British Columbia sees an increase of 21 PJ from the Northern Gateway Pipeline and 27 PJ from the Trans Mountain Pipeline. Alberta and Saskatchewan gain 179 and 195 PJ of energy demand, respectively, with all 5 of the proposed pipelines originating there. Manitoba, Ontario, Quebec, and New Brunswick see an increase of 81, 324, 92, and 47 PJ, respectively. Ontario faces the largest energy demands because 45% of the Energy East pipeline length would be in Ontario (2030 km).

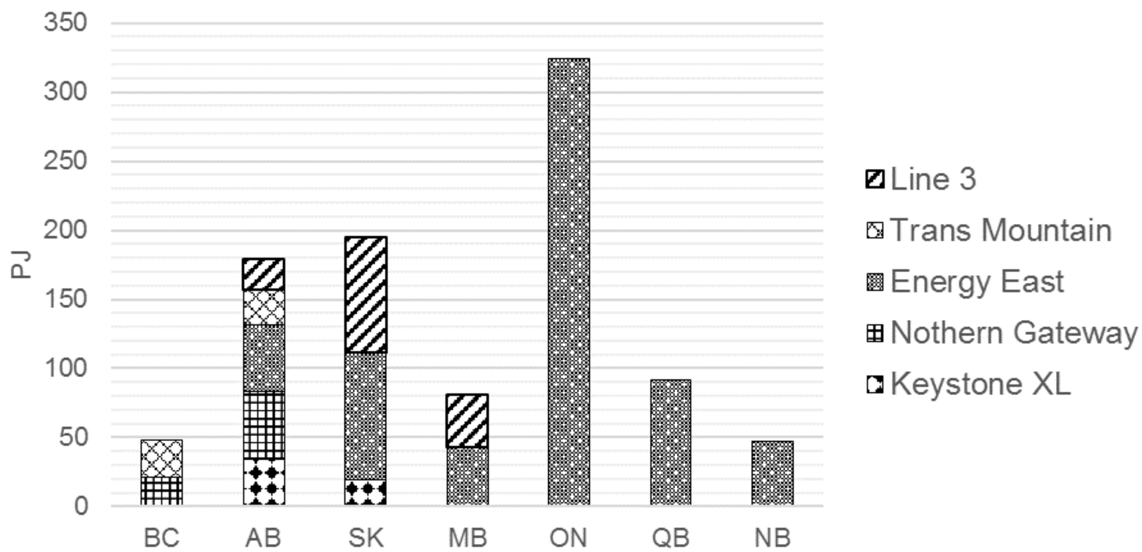

Figure 5-6: Cumulative energy demand to 2050 by province for proposed pipelines based on the LEAP-Canada model

Figure 5-7 shows the results of the emissions analysis of proposed pipeline operations. Ontario, Saskatchewan, and Alberta are responsible for most of the emissions over the projection period. This takes into account the recent climate policy announcements for reducing coal power emissions and increasing renewable contributions to the grid mix. The grid intensities over the projection period for each province are shown in Figure 5-8. In terms of cumulative emissions to 2050, Ontario has the most with 29 MT, followed by Saskatchewan with 16.5 MT and Alberta with 15 MT CO_2e. The total cumulative emissions released by pipeline operations by 2050 are 65 MT CO_2e. BC, Manitoba, and Quebec also have emissions but they are not shown the figure as they make up less than 0.1 MT.

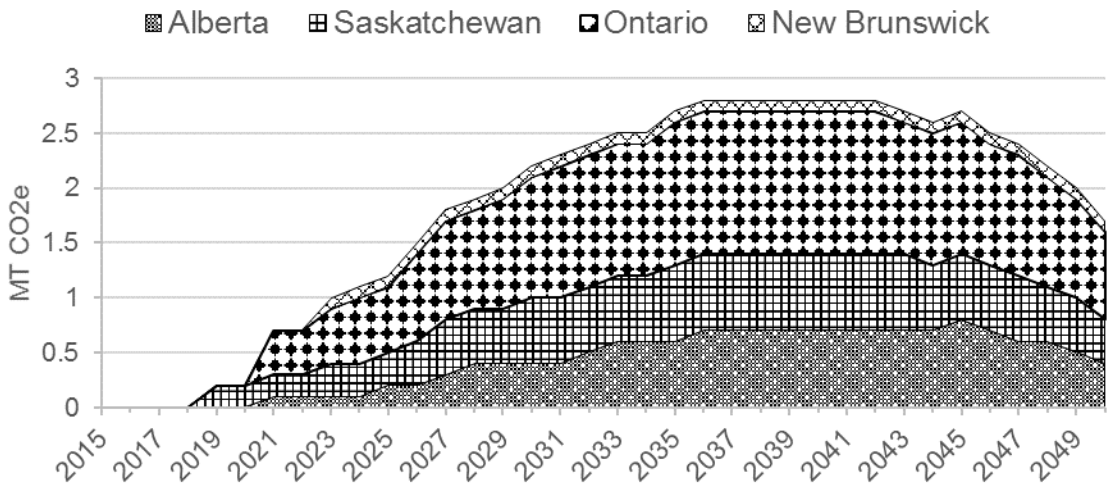

Figure 5-7: Pipeline GHG emission projections based on the LEAP-Canada model

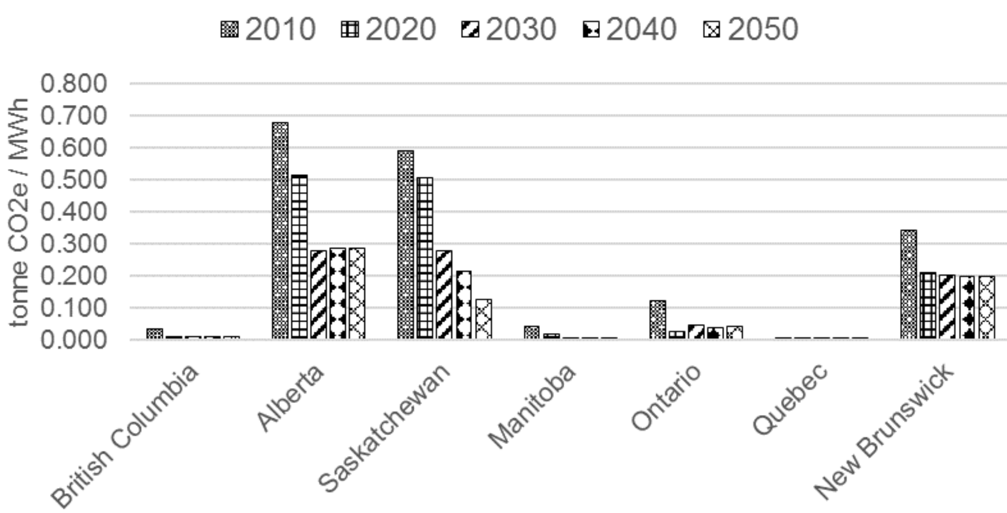

Figure 5-8: Regional grid intensity factors based on the LEAP-Canada model

5.3.2 Alternative rail scenarios

The range in which constrained pipeline capacity might decrease upstream investment and production is $65-$75 WTI per barrel [128]. As shown in Figure 5-9, the reference scenario price is within this range between 2020 and 2024. The high price falls within this range for one year (2018). The low price scenario never crosses this range. It is assumed that a constrained production scenario due to pipeline capacity constraints is unlikely as this would require prices to remain in the range indefinitely. Therefore, if the proposed pipelines are not approved, it is assumed that oil production would not decrease and that rail transport would be used to transport the oil available for export over existing and planned pipeline capacities.

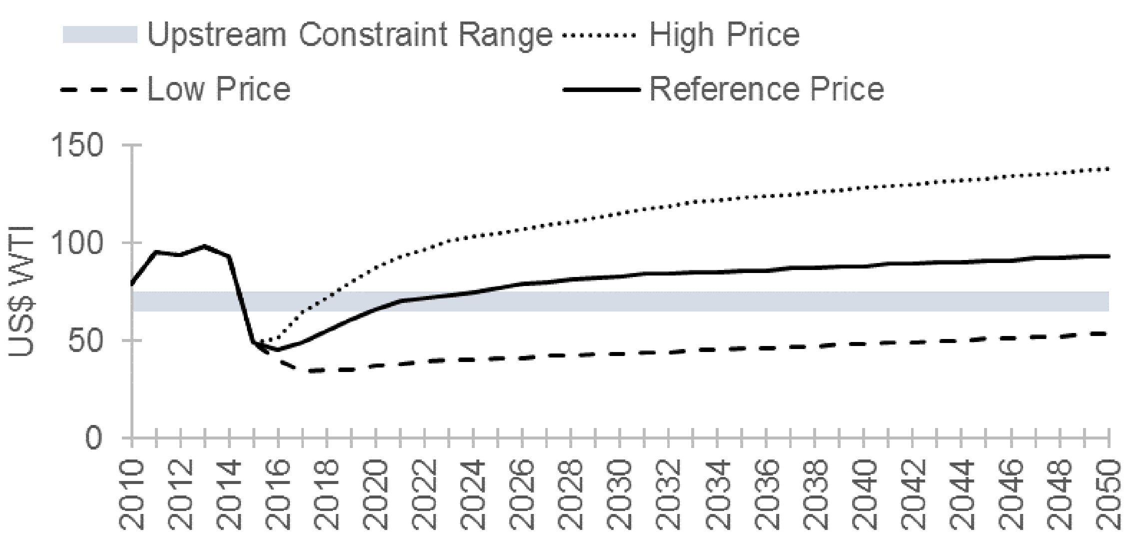

Figure 5-9: NEB price projections and supply constraint range [119, 128]

The impacts of crude-by-rail transport alternatives are important considerations when determining pipeline implications. The calculated crude-by-rail energy intensities used in the model are provided in Table 5-4. Figure 5-10 shows the energy demand for pipelines and the alternative modes of transport of dilbit, railbit, and rawbit by rail for the five transportation routes. The lines in the figure represent scenarios where all oil available for export is transported by the named transport method. A BAU scenario is included to show the expected impacts of approving the Trans Mountain, Keystone XL, and Line 3 pipelines. Any remaining crude available for export over the approved pipeline capacity is sent by dilbit-rail to the destinations of the unapproved pipelines (Energy East and Northern Gateway) in equal proportions to their pipeline capacities. Since scenario differences would not be seen until the pipeline completion years, energy demand and emissions remain the same until 2019. Rail transport of rawbit is the most energy intensive throughout the entire projection period. Pipeline transport is the least energy intensive. While pipeline energy demands are primarily from the power requirements for the pumps used for crude and diluent return, rail energy requirements are from crude transport, empty car return, diluent return, and loading/unloading terminals. The BAU scenario shows lower energy requirements than the all-pipeline scenario. This is primarily because the Energy East route is only moderately used for the short period when the approved pipelines are fully utilized. Figure 5-11 shows the projected GHG emissions corresponding to the energy projections.

Table 5-4: Calculated energy intensities for crude-by-rail transport

Energy Intensity	**2017**	**2020**	**2030**	**2040**	**2050**
MJ/barrel-km of rawbit	0.050	0.050	0.047	0.041	0.036
MJ/barrel-km dilbit	0.047	0.046	0.043	0.038	0.033
MJ/barrel-km diluent	0.043	0.042	0.040	0.035	0.031
MJ/barrel-km of light crude	0.048	0.047	0.044	0.039	0.034
MJ/barrel-km of heavy crude	0.046	0.045	0.043	0.038	0.033
MJ/barrel-km SCO	0.045	0.044	0.042	0.037	0.032
MJ/barrel-km of railbit	0.050	0.049	0.046	0.041	0.035
Bitumen Heating Intensity (GJ/bbl)	0.0053	0.0053	0.0051	0.005	0.0049
DRU Energy Intensity (GJ/bbl)	0.0525	0.0521	0.0508	0.0494	0.0481
Terminal Electricity Demand (MJ/bbl)	1.184	1.184	1.184	1.184	1.184

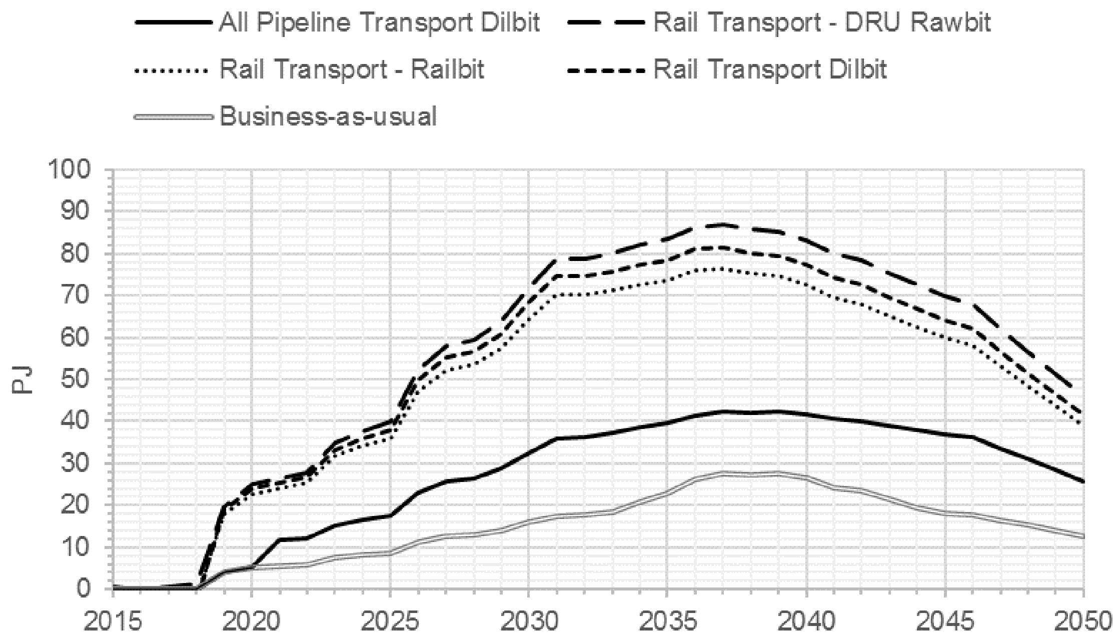

Figure 5-10: Energy demand projections by scenario based on the LEAP-Canada model

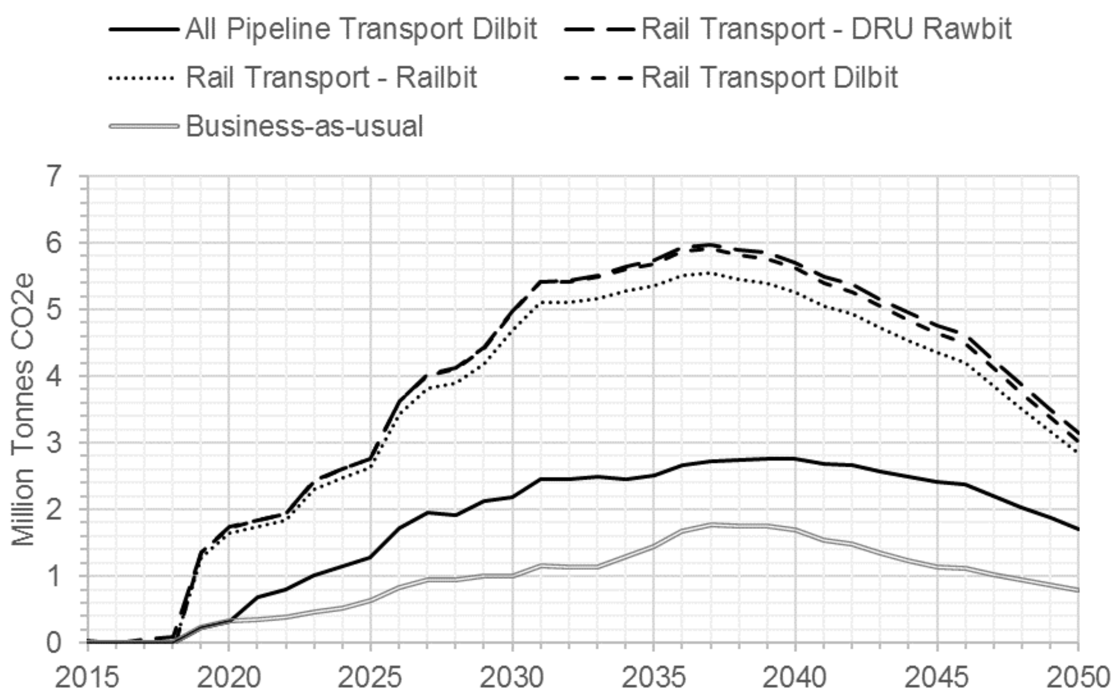

Figure 5-11: GHG emission projections by scenario based on the LEAP-Canada model

Figure 5-12 shows provincial energy and GHG emission impacts for each scenario. In all scenarios, pipeline transport shows the lowest impact. A rawbit crude-by-rail scenario has the next lowest energy and emission impacts in all provinces except Alberta. Since diluent must be removed post extraction for rawbit transport, Alberta sees the highest energy and emission increases from the rawbit scenario. The dilbit and railbit scenarios are similar. It was found that transportation by rail in all cases produced approximately 82-108% higher energy demands and 99-115% more emissions than pipeline. According to the model, the recent approvals of the Line 3, Trans Mountain Expansion, and Keystone XL pipelines will mitigate between 48-89 MT CO_2e in Canada over the study period, an average of 2.2 MT per year, through avoided crude-by-rail shipping and the long distance Energy East pipeline.

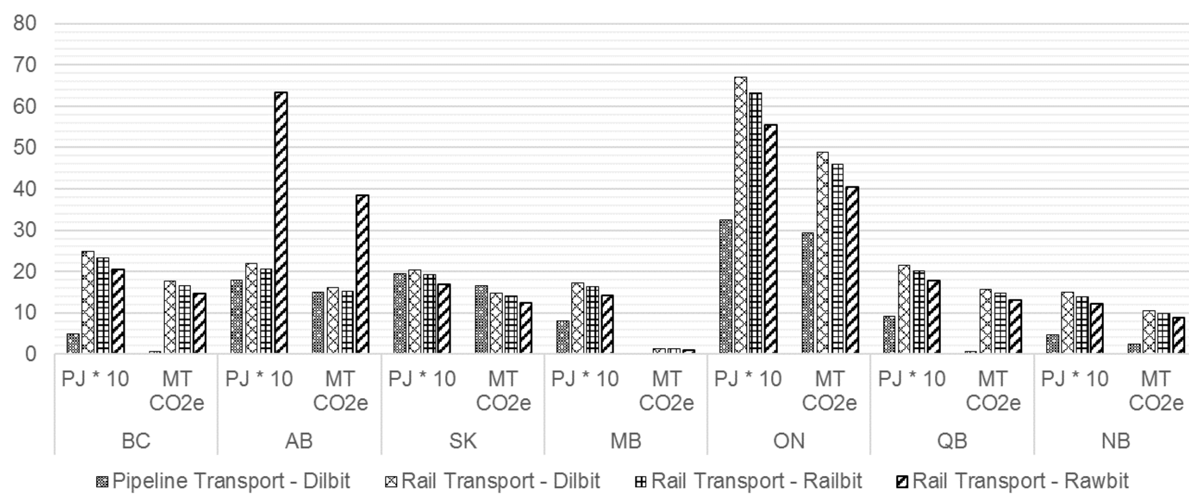

Figure 5-12: Cumulative energy and GHG emissions to 2050 by scenario based on the LEAP-Canada model

6 Chapter VI: Projections of Oil Sands Emissions and Evaluation of BC Hydroelectricity Imports for Oil Sands GHG Mitigation with the LEAP-Canada Model[5]

6.1 Introduction

As of year-end 2014, Canada's oil reserves ranked third globally, of which Alberta's oil sands made up approximately 97% [139]. Cumulative oil sands production as of 2014 was 1.66 billion cubic meters, and the ultimate potential was estimated to be 50 billion cubic meters [105]. The National Energy Board (NEB) projects that cumulative production will reach approximately 9.63 billion cubic meters by 2050 [92]. This growth poses challenges associated with meeting greenhouse gas (GHG) reduction targets because oil sands production is a highly emission-intensive process.

Oil sands are a heavy oil resource composed of a viscous mixture of oil, sand, and water, called bitumen. There are two methods of extracting bitumen – surface mining and in situ recovery. Surface mining is similar to traditional mining operations. The bitumen is dug from an open pit mine and transported by truck. Surface mining is economical when a bitumen reservoir is located close to the surface. When a reservoir is deep, in situ recovery is used to extract the bitumen through wellbore pumping. Current in situ practices employ three methods: primary extraction (such as for conventional heavy oil), steam-assisted gravity drainage (SAGD), and cyclic steam stimulation (CSS). SAGD and CSS both involve heating the reservoir with steam to reduce the

[5] To be submitted for publishing.

viscosity of the bitumen so it can be pumped. SAGD is the preferred method of production as it typically has high rates of production relative to primary and CSS extraction methods. Approximately 20% of remaining oil sands reserves can be recovered with surface mining with the balance requiring in situ methods [105].

The largest difference in energy requirements between surface mining and in situ techniques is the thermal energy requirement. The Canadian Energy Research Institute (CERI) reported the average thermal energy intensity for surface mining and in situ extraction of bitumen to be 0.33 GJ/bbl and 1.18 GJ/bbl, respectively [112]. The large difference in thermal energy requirement is due to the high amount of steam required for in situ extraction. Electricity requirements for SAGD were reported to be slightly higher with an average value of 16.68 kWh/bbl for SAGD and 11.20 kWh/bbl for surface mining [112].

In 2014, oil sands operations contributed the largest share (35%, 68 Mt) to Canada's oil and gas emissions. In situ extraction accounted for 44% of total oil sands emissions [7]. Oil sands steam is primarily produced through the combustion of natural gas in a boiler or cogeneration plant. Oil sands emission intensity decreased between 1990 and 2005 from 121 kg CO_2e to 89 kg carbon dioxide equivalent (CO_2e) and has only slightly decreased since 2005 to 83 kg CO_2e as of 2014 [7].

Efforts have been spent studying emission mitigation pathways for oil sands and the impacts of climate policy on oil sands development. Nimana et al. [140] analyzed GHG emission impacts of varying cogeneration in the oil sands. The authors concluded that GHG emissions can be cut in surface mining and in situ by up to 25% and 48%, respectively. Ouellette et al. [141] concluded that oil sands cogeneration growth could reduce Alberta's emissions up to 26% by 2030. Ordorica-Garcia et al. [142] provided economic and GHG emission impacts of different scenarios with integrated oil sands carbon capture and storage technology. The authors showed that a reduction up to 39% above the baseline is possible by 2030. McKellar et al. [143] used expert elicitation to investigate future changes in oil sands GHG emission intensities for in situ, mining, and upgrading. They concluded that new technology would produce the largest reductions in GHG emissions, but process improvements could also be effective. Chan et al. [144] evaluated scenarios of oil sands production under different climate policy conditions in different parts of the world. The authors concluded that climate policy both in and outside Canada will have a significant negative impact on oil sands growth. An earlier study compared hydroelectric power options for oil sands [145]. This included Alberta, Manitoba, and British Columbia (BC) hydropower resources. This study's findings suggested a BC hydropower integration to be most feasible.

Research and development into in situ recovery has led to promising process improvements and novel solvent-enhanced recovery methods that could improve overall production efficiency from 15% to up to 35% [146]. Solvent-based extraction technologies have the potential to drastically reduce GHG emissions but have not yet been commercialized. Groundwater contamination is of particular concern for solvent-based techniques [146]. Electricity-based recovery also has the potential to reduce GHG emissions; however, the technology is currently unproven and its economic competitiveness is uncertain [146].

The Alberta Government has announced ambitious climate policy targets to combat climate change. The Alberta Climate Leadership Plan (CLP) was developed to implement carbon emission reduction strategies in the province. The CLP imposes a 100 megatonne (MT) per year limit for oil sands emissions. Emissions in 2015 were under 70 MT; however, oil sands extraction is expected to increase 57% by 2030 and 72% by 2040 [92]. If emissions increase at the same pace, the imposed limit will surely be exceeded. Oil sands are a significant contributor to Alberta's GDP, revenue, and investment. Finding effective strategies to mitigate oil sands emissions is important for Alberta's economy [147].

One strategy to reduce oil sands emissions is to import low-emission BC Hydro-produced electricity to the oil sands. This strategy has not been evaluated by a long term bottom-up multi-regional energy model. Detailed projections of the energy demands and GHG emissions to 2050 are also not found in the peer-reviewed literature. The objectives of this chapter are to:

- Use the Long-range Energy Alternatives Planning (LEAP) model [40] of Canada (LEAP-Canada) [109] to give updated projections of oil sands electricity demand and emissions to 2050.
- Evaluate the mitigation potential and cost effectiveness of the oil sands importing electricity from BC Hydro.
- Investigate BC's long term electricity supply adequacy to meet domestic provincial demands and potential to export electricity to the oil sands.

6.2 Methodology

6.2.1 LEAP-Canada model

The LEAP-Canada model is a bottom-up energy accounting model that was developed to serve as a tool for evaluating energy and emission scenarios. The model includes detailed regional breakdowns of energy demands across residential, commercial and institutional, industrial, transportation, and agricultural sectors. It also features resource transformation processes for all provinces and territories. A baseline scenario was developed for the years 2010-2050 based on data from Statistics Canada (StatCan), Natural Resources Canada (NRCan), and the National Energy Board (NEB). The basic structure of the model is shown in Figure 6-1. When demand sectors require energy, the transformation modules dispatch to meet the demands. If transformation modules cannot meet demand, imports are transferred from another province or from outside Canada. Details on the LEAP-Canada model can be found in the authors' previous work [109].

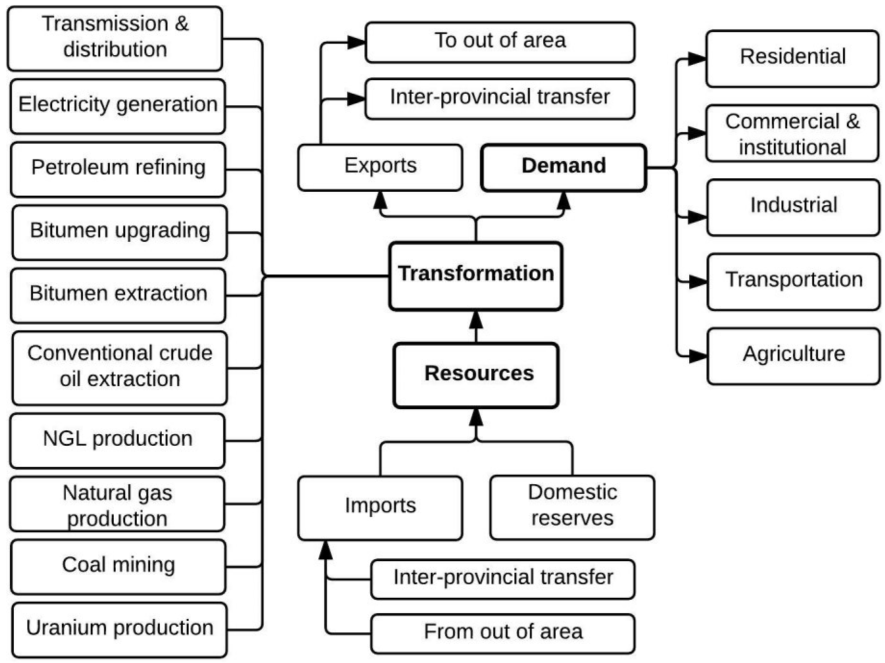

Figure 6-1: LEAP-Canada model framework [109]

The LEAP-Canada model is uniquely suited to project oil sands emissions and inter-provincial trade due to its bottom-up technology-explicit energy demand trees and integrated regions. The LEAP-Canada model's oil sands production projections up to 2040 are based on the 2016 NEB Energy Futures Update Report (EFR). The 2016 EFR included market developments and many recent federal and provincial climate policy announcements that were made in 2016 [92]. The NEB's supply modelling considers domestic and global economic indicators. Projections from 2040 to 2050 were based on the expected production changes from literature [112]. Electricity load curves specific to Alberta and BC were used in the model [148, 149]. Oil sands energy demands were calculated in LEAP based on oil production levels and energy intensities in the demand trees. Extraction and upgrading demand trees are shown in Figure 6-2 and Figure 6-3. Energy intensities were taken from earlier studies [93, 112].

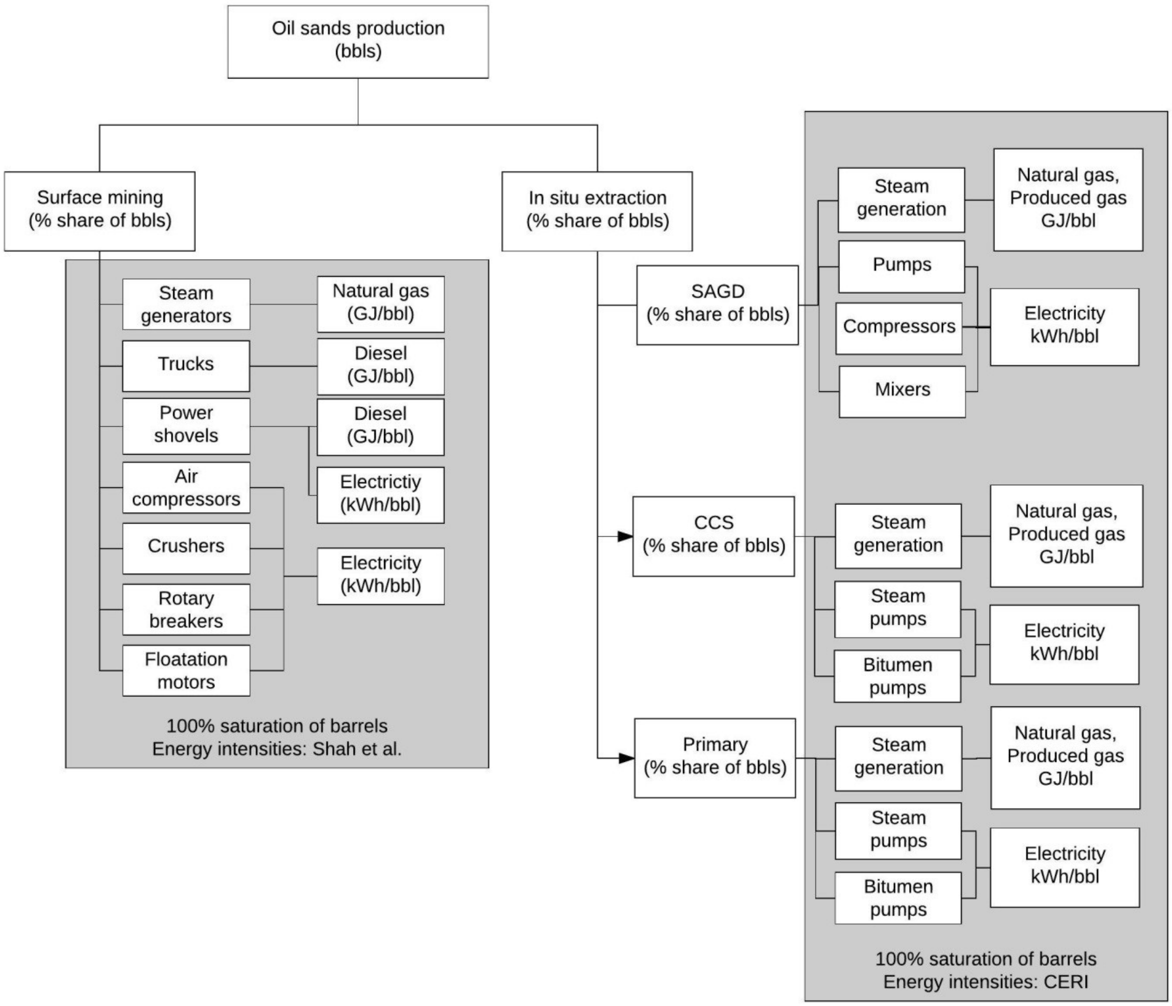

Figure 6-2: Oil sands production energy demand tree as developed in the LEAP-Canada model

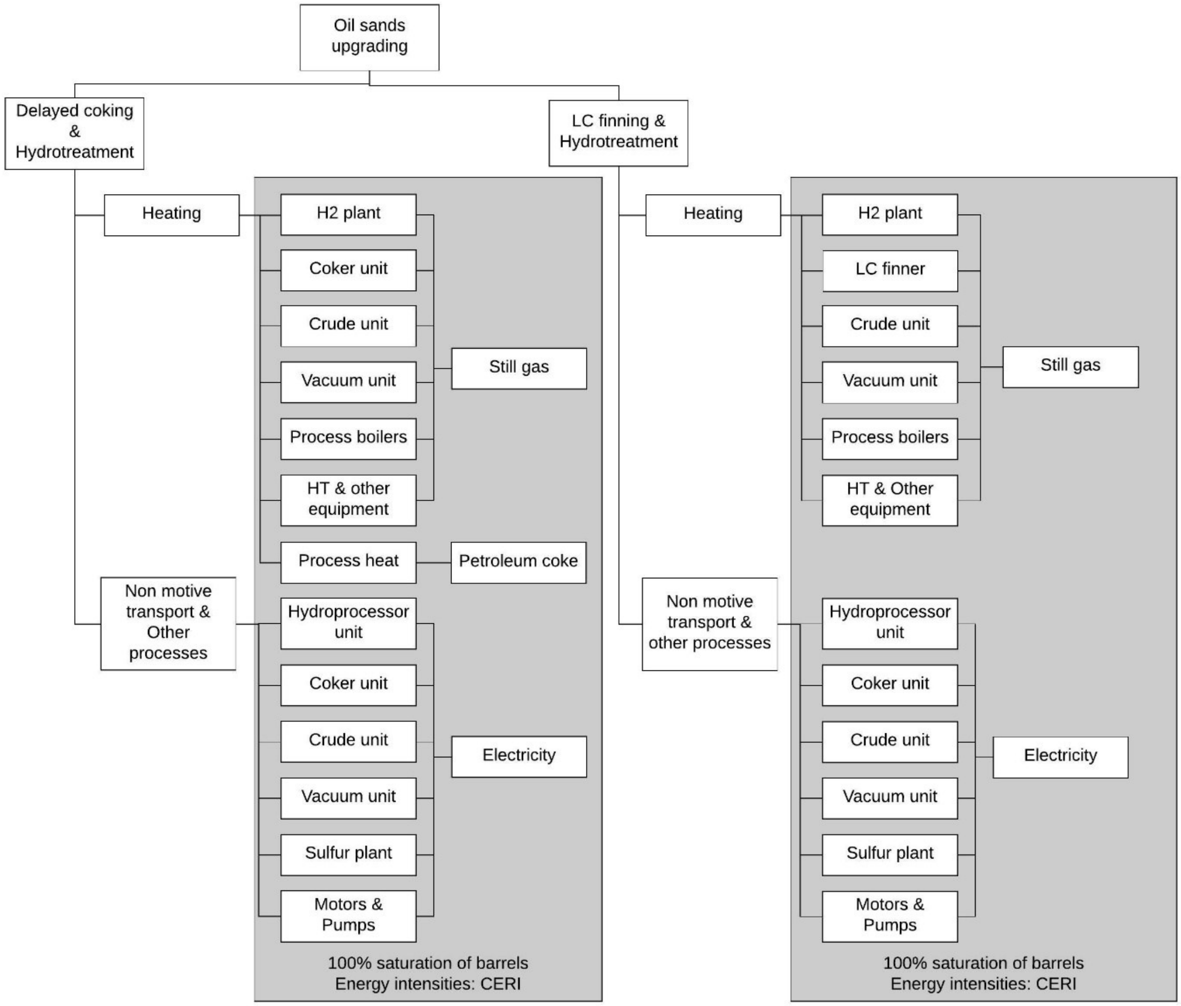

Figure 6-3: Oil sands upgrading energy demand tree as developed in the LEAP-Canada model

6.2.2 Scenario analysis

Two BC hydropower options were considered for supplying electricity to the oil sands. The first was to increase the exiting intertie capacity between Alberta and BC. The second was to use the Site C dam (currently under construction) exclusively for oil sands. These have been identified in literature [145] as the most feasible options after analyzing potential hydropower sites in BC, Alberta, and Manitoba. The intertie option would involve building upon existing intertie infrastructure to increase the existing capacity by approximately 500 MW [145]. The Site C dam has a design capacity of 1100 MW [145]. It was assumed a direct current (DC) transmission line from Site C to Alberta would be used.

Capacity and costs for the Site C generating station were sourced from the official Site C Clean Energy Project website [150]. Transmission costs for Site C and the intertie were sourced from an earlier study [145]. BC Intertie option capacity costs were sourced from an earlier study [145]. Alberta cogeneration electricity costs were sourced from the Alberta Electric System Operator (AESO) [151]. All of these variables are presented in Table 6-1.

This study compares cost competitiveness and electricity supply adequacy for the business-as-usual (BAU) scenario and the two BC hydropower scenarios. Two pathways were assessed for each option as depicted in Figure 6-4. Capacity additions from either the intertie or Site C could either effectively replace or be integrated in addition to cogeneration electricity capacity. The cogeneration electricity capacity replaced by a BC source would effectively be retired, but the plants would remain and be dedicated to thermal and back-up electricity as BC may not be able to keep up with 100% of demand. Capacity addition from either the intertie or Site C would not replace cogeneration capacity but would supplement existing capacity. This would mean cogenerated electricity is available for export from the oil sands to the rest of Alberta and would have an impact on the grid emissions intensity.

Table 6-1: LEAP-Canada model variables ($2010)

Variable	Cogeneration	Site C	Intertie
Capacity (MW)	n/a	1100 [150]	500 [145]
Discount rate	5%	5%	5%
Life (years)	30 [145]	70 [150]	70
Max capacity factor	85% [151]	53% [150]	75% [145]
Operational date	n/a	2025 [150]	2019 [145]
Capital cost ($/MW)	1,976,170 [151]	8,805,745 [150]	526,400 [145]
Fixed operation & maintenance cost ($/MW)	13,720 [151]	15,591 [150]	174,840 [145]
Variable operation & maintenance cost ($/MW)	3,626 [151]	9,087 [150]	n/a
Fuel / Water rental / Import costs ($/MWh)	Projected NG prices by NEB [92]	6.3 [150]	40 [145]
Other	n/a	2,496,000 [150]	n/a
Annual transmission losses	n/a	122,000 [145]	196,000 [145]

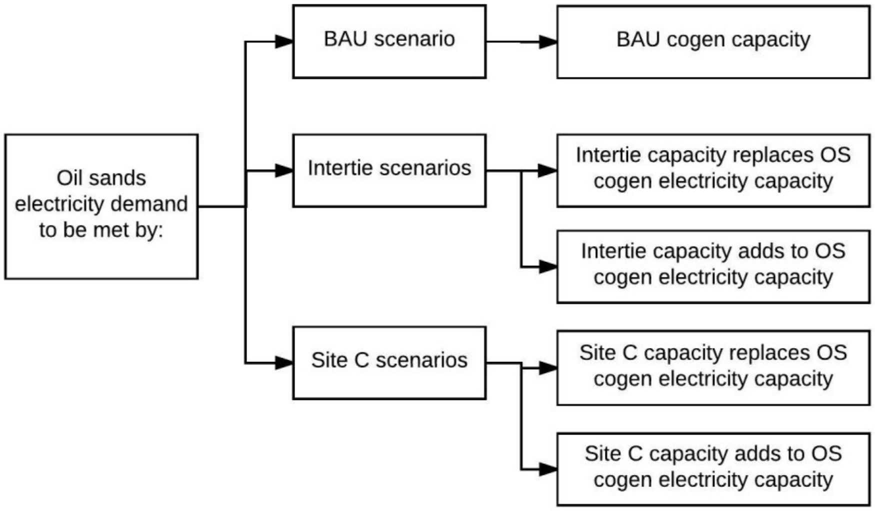

Figure 6-4: Scenarios assessed to meet OS electricity demand

6.2.3 GHG abatement cost curve

A GHG abatement cost curve illustrates quantitative comparisons between scenarios. The curves show the cumulative cost ($/tonne) of GHG mitigation and the total GHG mitigation of each scenario. The mitigation costs are based on the incremental GHGs and production costs of each scenario compared to the BAU scenario. The CLP carbon levy was applied to all fossil fuel emissions. The $/tonne values were arrived at by using Equation (10). The $/tonne costs are cumulative costs from the base year to a specified year. The variable "x" indicates the particular scenario. The variable "n" represents the year during the evaluating period. The variable "i" represents the base year of the evaluation period.

$$Scenario_x\ GHG\ Mitigation\ [\$/tonne] = \sum_{n=i}^{n} \frac{ScenarioCost_{xn} - ScenarioCost_{BAUn}}{ScenarioEmissions_{xn} - ScenarioEmissions_{BAUn}} \quad (10)$$

The *ScenarioCost* variables contain all costs associated with demand, supply, and carbon emission, as shown in Equation (11). Demand costs for this study were not considered because energy demand was consistent across all scenarios. Transformation costs include fuel costs of electricity generation, capital costs of electricity plants, and operation and maintenance (O&M) costs of running the electricity plants, as shown in Equation (12). Externality costs are costs accrued from imposed prices on carbon emissions.

$$ScenarioCost_n = demand\ costs_n + transformation\ costs_n + externality\ costs_n \quad (11)$$

$$\begin{aligned} &Transformation\ Costs_n \\ &\qquad = feedstock\ fuel\ costs_n + annualized\ capital\ cost_n + O\&M\ costs_n \end{aligned} \quad (12)$$

The *ScenarioEmission* variables were determined from the model output of GHG emissions calculated by Equation (13). Demand emissions and non-energy emissions were not considered during scenario analysis as they were equal across all scenarios. Transformation emissions were made up of combustion emissions from fuel and electricity production and fugitive emissions from resource extraction and processing, as shown in Equation (14). For this study, only combustion emissions from electricity production were considered. This is reasonable as any increase or decrease in natural gas demand due to varied electricity imports would not likely warrant any change in resource extraction in Alberta but simply a slight increase or decrease in natural gas available for export.

$$ScenarioEmissions_n = demand\ emissions_n + transformation\ emissions_n + non\ energy\ emissions_n \tag{13}$$

$$Transformation\ emissions_n = combustion\ during\ transformation\ process_n + fugitive\ emissions_n \tag{14}$$

6.3 Results and discussion

6.3.1 Oil sands electricity demand and GHG emissions

Figure 6-5 presents oil sands electricity demand to 2050. Energy demand for surface mining, the three in situ extraction methods, and upgrading are illustrated. Surface mining energy demands will grow until 2024 and then decline slightly until 2050. In situ SAGD extraction will make up the largest share of electricity demand in 2050 due to steady growth through the study period. CSS and primary extraction will undergo slow growth over the projection period. Bitumen upgrading demands will reach a peak in 2030 and then remain steady. Total oil sands electricity demand will reach a peak in 2039 with 109 PJ, a growth of 45% from 2017 levels. The BAU electricity production from oil sands will not keep up with demand, especially after 2022.

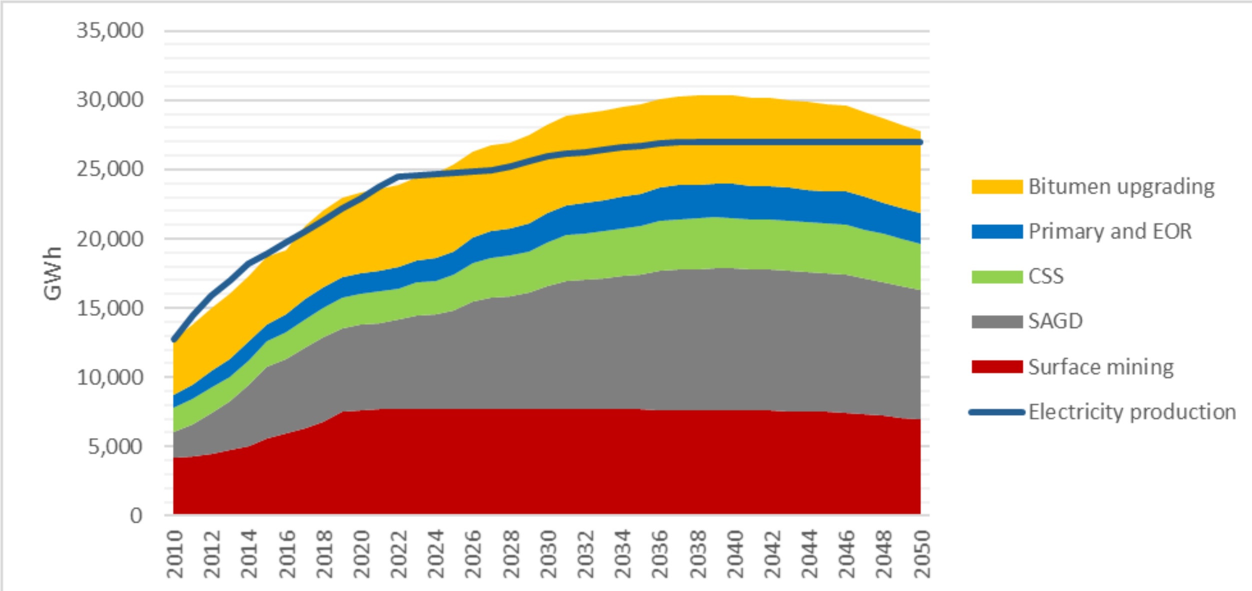

Figure 6-5: Oil Sands electricity demand projections based on the LEAP-Canada model

Figure 6-6 shows the oil sand's emissions as projected by the model. Surface mining emissions will reach a peak in 2024, due to approximately 38% diesel and 62% natural gas use. In situ mining emissions will experience considerable growth due to SAGD. Bitumen upgrading emissions will peak in 2030 and then decline slightly to 2050. Electricity generation emissions will average 7% of total oil sands emissions over the projection period. Total oil sands emissions will peak in 2040 with 103 MT, a 50% increase from 2017 levels. A breakdown of emissions by fuel use is provided in Figure 6-7.

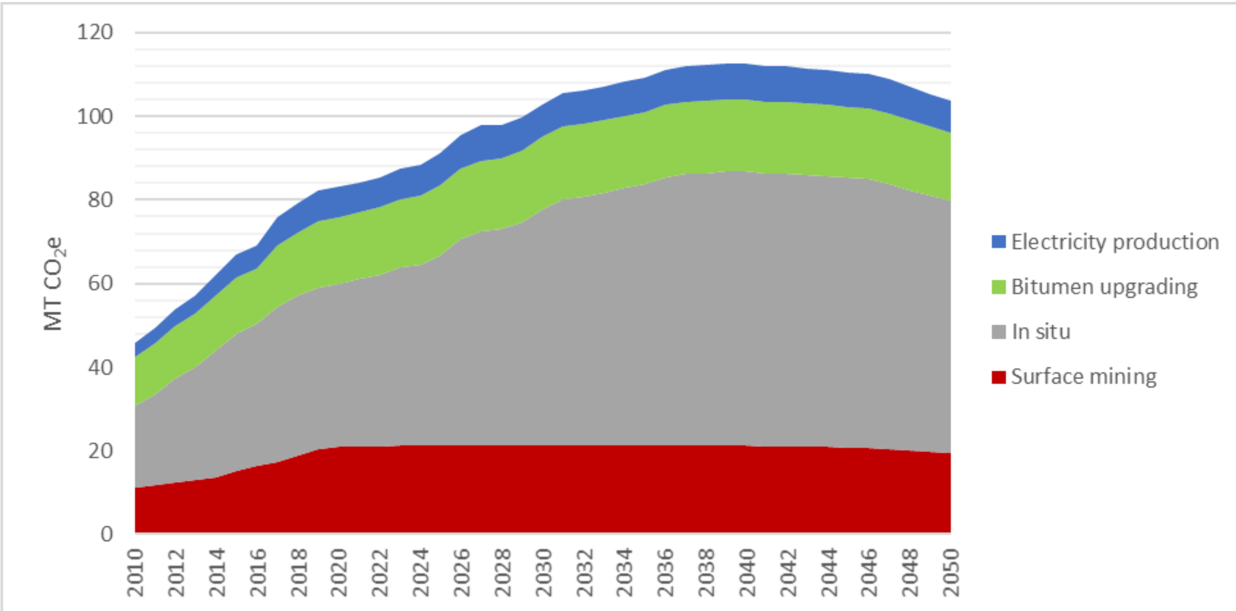

Figure 6-6: Oil sands GHG emission projections by process based on the LEAP-Canada model

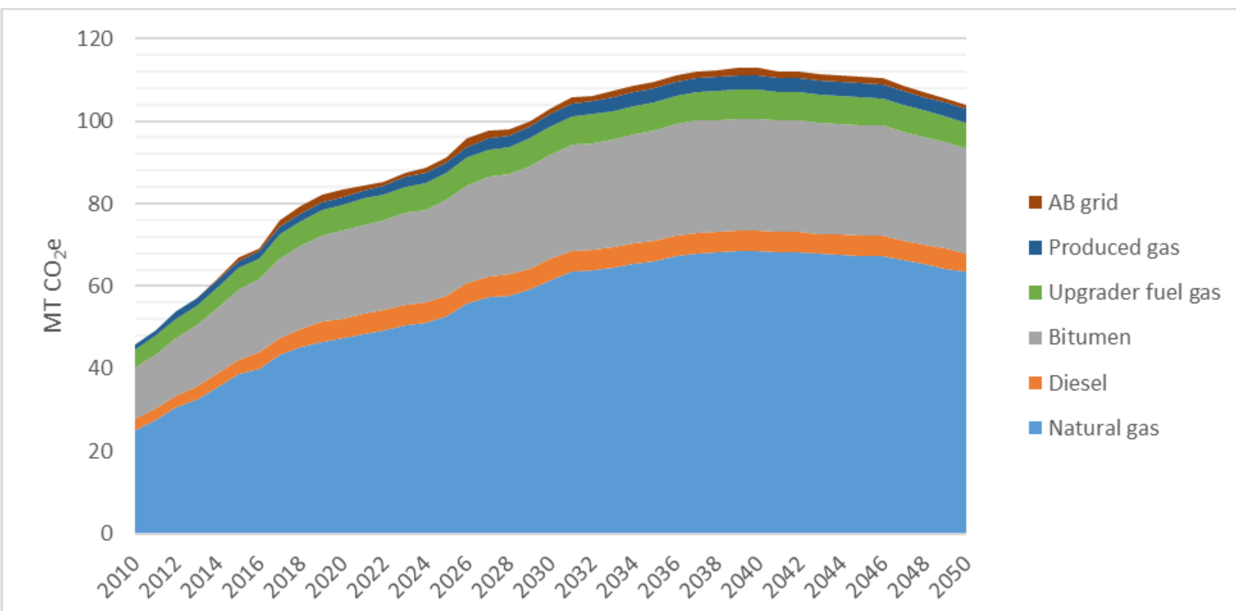

Figure 6-7: Oil sands GHG emission projections by fuel based on the LEAP-Canada model

6.3.2 GHG abatement cost curves

Figure 6-8 shows the cost curve for the intertie and Site C replacement of the oil sands' cogeneration scenarios. If the intertie option effectively replaces oil sands cogeneration capacity beginning in 2019, the oil sands will see 21 MT CO_2e mitigated between 2019 and 2050, an average of 0.7 MT per year. This would cost $1,552 million over the study period, giving an abatement cost of 72.5 $/tonne. If the Site C option effectively replaces oil sands cogeneration capacity beginning in 2025, the oil sands will see 24 MT CO_2e mitigated between 2019 and 2050, an average of 1 MT per year. This would cost $5,343 million over the study period, giving an abatement cost of 226 $/tonne.

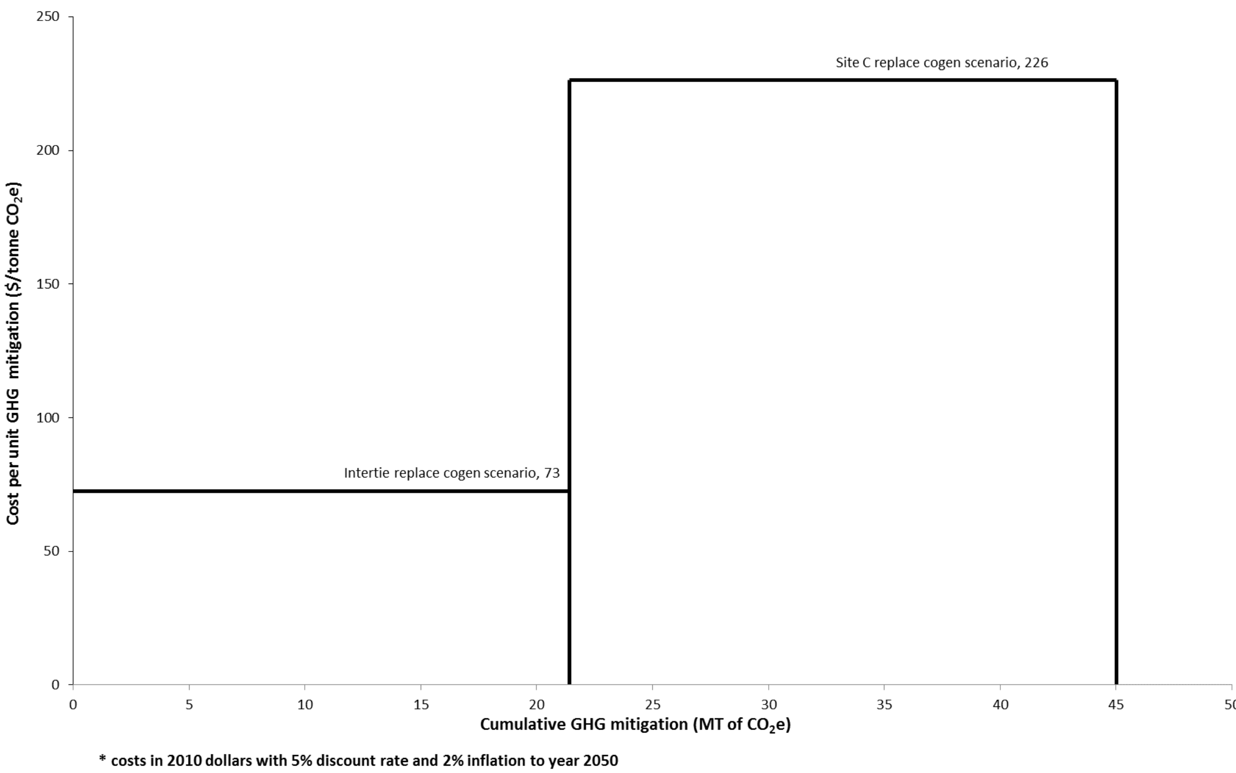

Figure 6-8: BC hydropower options replacing oil sands cogeneration cost curve based on the LEAP-Canada model

Figure 6-9 shows the cost curve for the intertie and Site C addition to the oil sands' cogeneration scenarios. If the intertie option is introduced in addition to the BAU oil sands cogeneration capacity beginning in 2019, Alberta would see 29.5 MT CO_2e mitigated between 2019 and 2050, an average of 0.92 MT per year. This would cost $1,816 million over the study period, giving an abatement cost of 61.5 $/tonne. If the Site C option is introduced in addition to the BAU oil sands cogeneration capacity beginning in 2025, Alberta would see 38 MT CO_2e mitigated between 2025 and 2050, an average of 1.46 MT per year. This would cost $5,343 million over the study period, giving an abatement cost of 171 $/tonne.

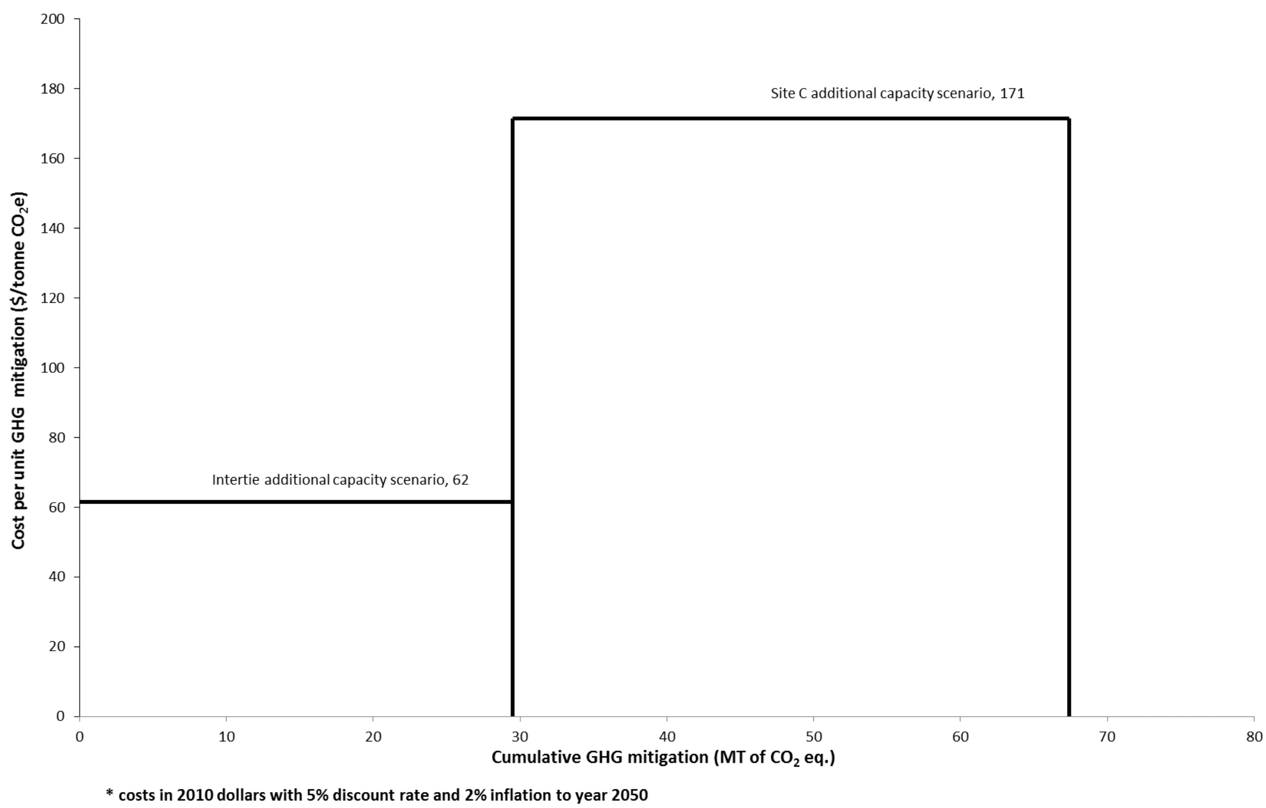

Figure 6-9: BC hydropower options addition to oil sands cogeneration cost curve based on the LEAP-Canada model

6.3.3 BC electricity supply adequacy

Figure 6-10 shows BC's electricity supply and demand outlook as projected by the model. Historical data are used for the years 2010-2015, and the model projects supply and demand to 2050 with Site C generation shown explicitly. The results show gross electricity production being greater than demand from 2017 onward. However, when considering annual peak load requirements, exporting BC hydropower to Alberta will increase BC's import requirements due to reduced BC Hydro reserve margins. All variables plotted adhere to the left y-axis except for the intertie and Site C additions (blue and brown lines). The blue line in Figure 6-10 represents the incremental increase in BC imports if the intertie was upgraded and used to supply the oil sands with power at full capacity. The dashed line in Figure 6-10 represents the incremental increase in BC imports if Site C was used to supply the oil sands with power at full capacity.

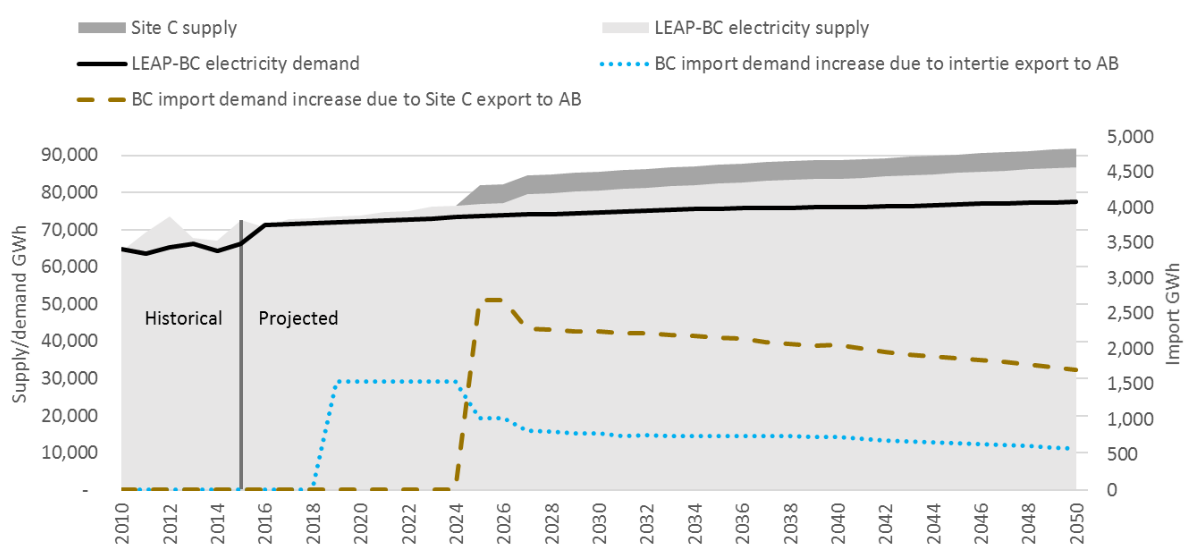

Figure 6-10: LEAP-BC electricity supply projection

6.3.4 Implications

Oil sands emissions will rise steadily from now to 2050. Electricity generation accounted for a relatively small portion of the oil sands emissions growth. The potential to reduce GHG emissions by using BC hydropower was found to be small and costly. Additionally, BC's domestic hydropower supply adequacy was shown to be compromised due to increased exports to Alberta's oil sands. If the 100 MT oil sands emissions cap stipulated by the Government of Alberta is going to be met, more drastic GHG emissions mitigation measures are needed.

7 Chapter VII: Conclusion and recommendations

7.1 Conclusion

The research presented in this thesis discussed Canada's current and future energy paradigm. The challenges of reducing GHG emissions to meet set targets were examined. Canada has a target to reduce emissions to 611 MT by 2020 [50]. With current and proposed climate and energy policy measures, the nation is expected to fall short of this goal with 727 MT [50]. This research provides further resources for decision makers to use to help achieve the large reductions needed.

Primary fuel to end use energy flows were mapped through Sankey diagrams for Canada's provinces and territories and for Canada as a whole for the year 2012. The macro view of the maps clearly shows the energy sources, energy conversion, energy consumption by economic sector, and finally useful and rejected energy. Crude oil was the dominant energy supply source (11,853 PJ) in Canada in 2012, and a major share of crude (63.60%, or 7,539 PJ) was exported. Among the provinces, Alberta exported the highest amount of crude oil (5,071 PJ), followed by the Atlantic provinces (957 PJ), Saskatchewan (868 PJ), Quebec (377 PJ), Ontario (204 PJ), Manitoba (83 PJ) and the territories (34.9 PJ). A significant amount of natural gas was exported by Alberta (2,773 PJ) and British Columbia (523 PJ). The entire coal stock from British Columbia (726 PJ) was exported, whereas the other provinces consumed nearly all of their coal. Every province exported NGLs (from 2 PJ to 78 PJ) for a total of 185 PJ. Nuclear energy was produced only in Saskatchewan (4,500 PJ). All of it was exported to Ontario for processing. Ontario consumed approximately 22% of the nuclear energy it processed and exported the rest. Electricity generation was found to be mostly based on renewable energy, led by hydro-electricity (1,356 PJ) and followed by biomass (650 PJ), wind (40 PJ), and a small amount of solar (1 PJ). On the demand side, the industrial sector consumed the most energy (4131 PJ) and the agriculture sector consumed the least (256 PJ) in Canada in 2012.

An analysis of the ratio of rejected to useful energy shows that the worst efficiency was observed in Saskatchewan (1.19) and Ontario (1.07) and best in the territories (0.55); other provinces held moderate efficiencies ranging from 0.69 to 0.83. The overall ratio of rejected and useful energy for Canada as a whole was 0.84. These variations of energy efficiency can be shown in Sankey diagrams. In Saskatchewan, about 80% of electricity was produced from coal, and 60% of crude oil was consumed in the transportation sector; and in Ontario, about 71% of crude oil was consumed in the transportation sector. (Both the transport sector and coal power plants have low energy efficiency). On the other hand, the Quebec transport sector rejected about 79% of its supplied crude oil energy (500 PJ) though its ratio of loss and useful energy was 0.77 due to the high amount of electricity (691 PJ, about 90%) the province produced through hydro-power, which minimized the overall loss of energy.

The maps clearly present the balance of energy flow from source to end use. The total available energy from different sources (fossils, renewables, and nuclear) is shown in the maps. There are two inflows of energy in the supply source, local production and imports. The outflows of energy from the supply source are local demand and exports. These maps can provide useful information to help understand the extent of energy consumption and the efficiency of the energy consumed in different sectors. The maps can help identify energy demand by economic sector in different forms of use. They can also help by providing information on a specific sector vulnerable to wasting energy that has the potential to improve in energy efficiency. The maps can also help formulate policy in the areas of energy conversion, refining, and end-use energy efficiency. A Sankey diagram of Canada's energy flow is provided in Figure 7-1.

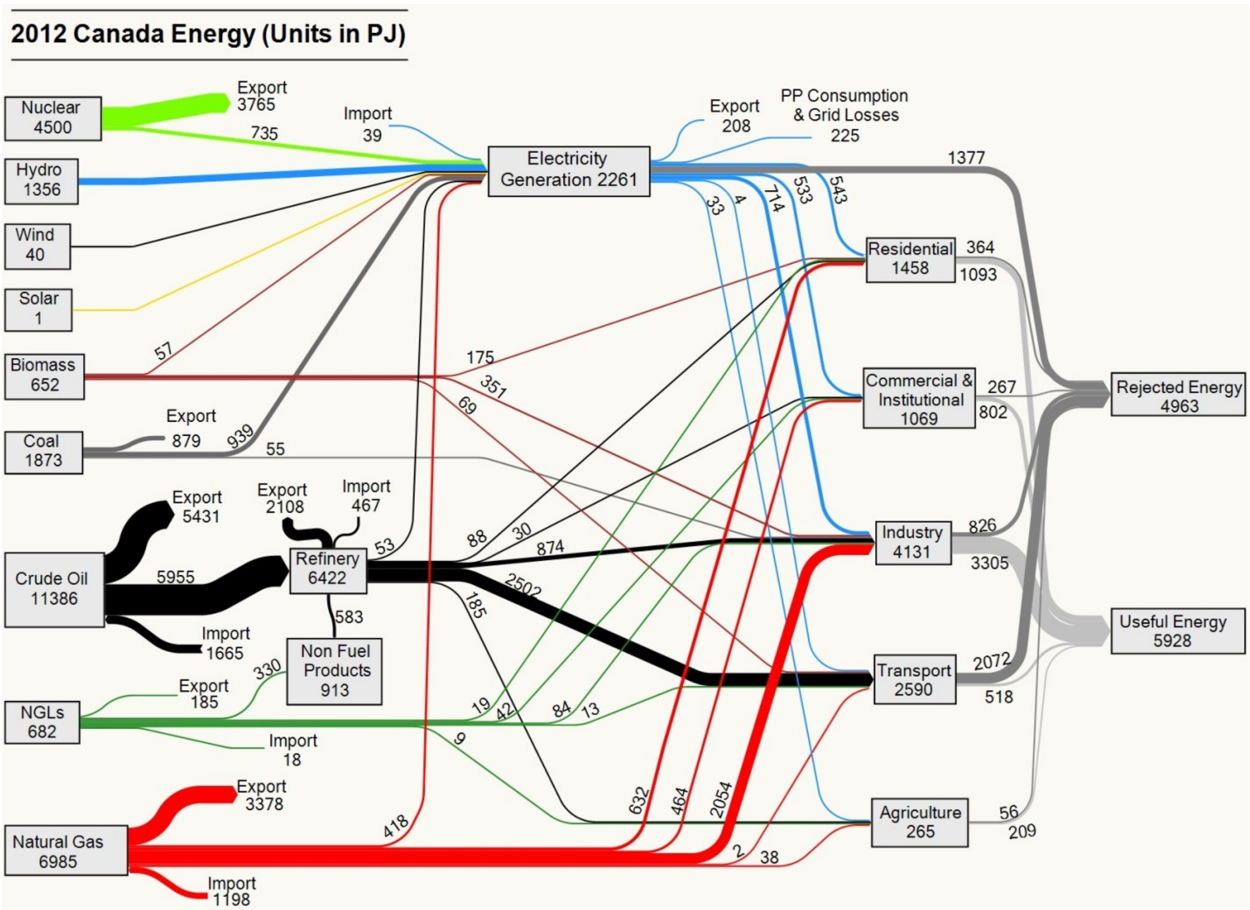

Figure 7-1: Integrated energy flow Sankey diagram for Canada, 2012

The primary purpose of the research was to develop a novel energy model (the LEAP-Canada model) that can serve as a platform for the growing climate change, energy efficiency, and emission concerns. A bottom-up, data-intensive, multi-regional, accounting-based energy model for Canada was created. The development process of the model has been described in detail for the residential, commercial and institutional, industrial, transportation, and agriculture demand sectors as well as for the transformation processes. Bottom-up detailed demand trees were presented. The energy intensity methodologies were explained for each demand sector. Figure 7-2 shows the high-level framework of the model. The reference scenario assumptions were outlined for each sector and supply module up to the year 2050.

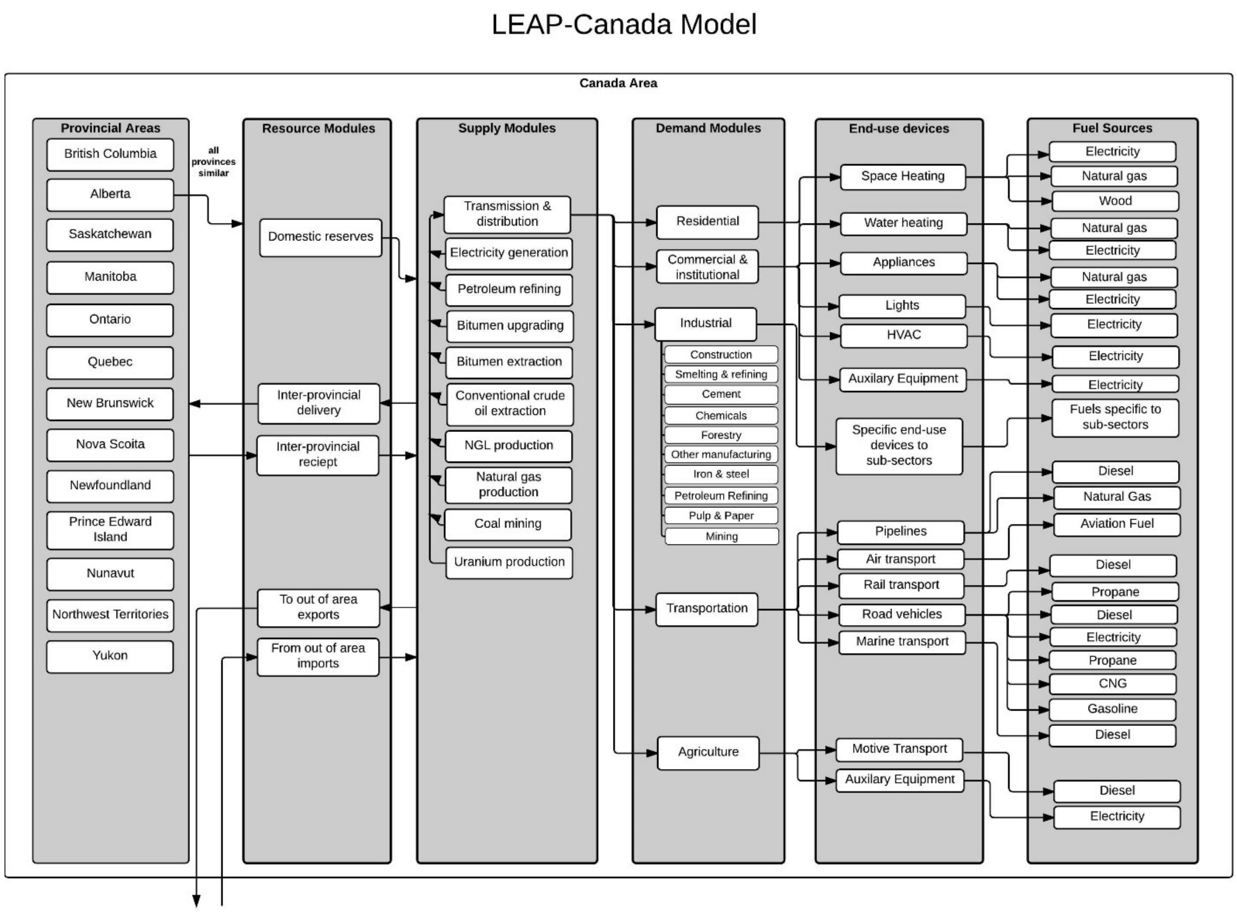

Figure 7-2: LEAP-Canada model methodological structure

Energy and GHG emission outlooks were provided for Canada and for 6 individual provinces and Atlantic Canada. The average percent growth in energy demand for Canada between 2010 and 2050 is 0.5% per year, bringing the total energy demand in 2050 to 12,878 PJ. A GHG outlook for Canada was also provided and shows that the total percent growth in emissions for Canada between 2010 and 2050 is 13%, bringing total emissions in 2050 to 799 MT CO_2e.

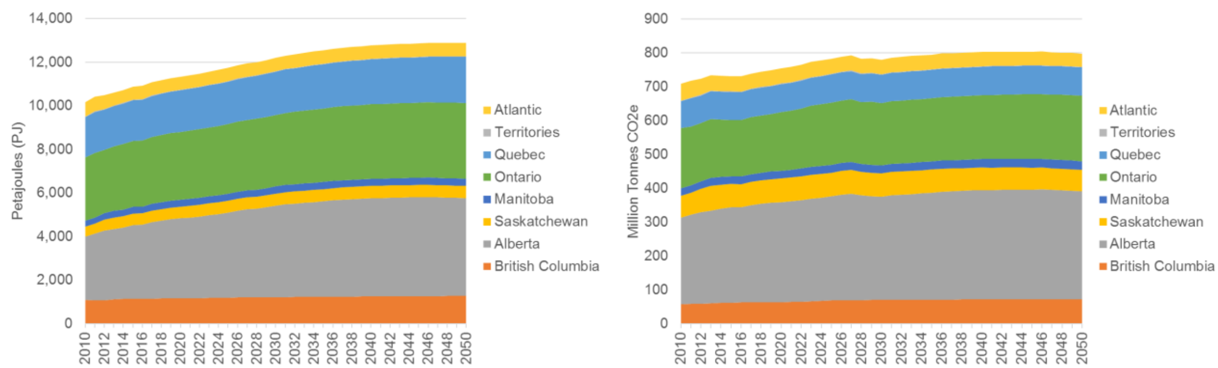

Figure 7-3: Energy (left) and GHG (right) outlooks by region

The model developed in this study can serve as a single point of reference for historical data from 2010 for all energy demand and supply statistics. In addition, it contains detailed energy intensities for many technologies and processes for each individual province that are not publically accessible. These details make the LEAP-Canada model a novel energy modelling approach representing the entirety of Canada's integrated energy system. Future development of the model will include additionally developed bottom-up industrial sub-sector demand trees. These will allow more accurate scenario analyses and outlooks. Numerous scenarios will be run to evaluate GHG mitigation options in all sectors and all regions of Canada.

This research also presented an analysis of Canada's GHG emissions using Sankey diagrams. Numerical data were obtained from the LEAP-Canada model. The diagrams clearly show the resources and fuels responsible for emissions and the economic sectors where the emissions are released. Combustion, fugitive, and non-energy emissions were included. An estimate of the emissions in exported resources was presented. Individual analyses were completed both nationally for the years 2014, 2030, and 2050 and by province/region for BC, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, and Atlantic Canada for the year 2014. Emission totals were compared with the NIR's 2014 totals and found to be agreeable.

In 2014, 734 MT of GHG emissions were estimated for Canada. The transportation sector made up the majority of emissions due to the use of gasoline. The mining and upstream oil and gas industry was the next largest emitter. Alberta was the largest emitter in Canada primarily due to mining and upstream oil and gas activity, natural gas use, and crude oil and oil products use. Ontario was the second largest emitter mainly due to the transportation sector and crude oil and oil products use. The most emission-intensive regions were Saskatchewan, Alberta, and Atlantic Canada. These regions were the only provinces to have above average per capita emissions intensity.

The GHG content of exported resources and fuels was estimated. In 2014, Canada exported approximately 741 MT of crude oil, natural gas, coal, oil products, and NGLs. It was estimated with the LEAP-Canada model that approximately 14% of in-Canada emissions was due to the production of resources that are exported. Alberta exported the most emissions in 2014 followed by BC and Saskatchewan. Figure 7-4 illustrates a GHG Sankey diagram for Canada's emissions in 2014.

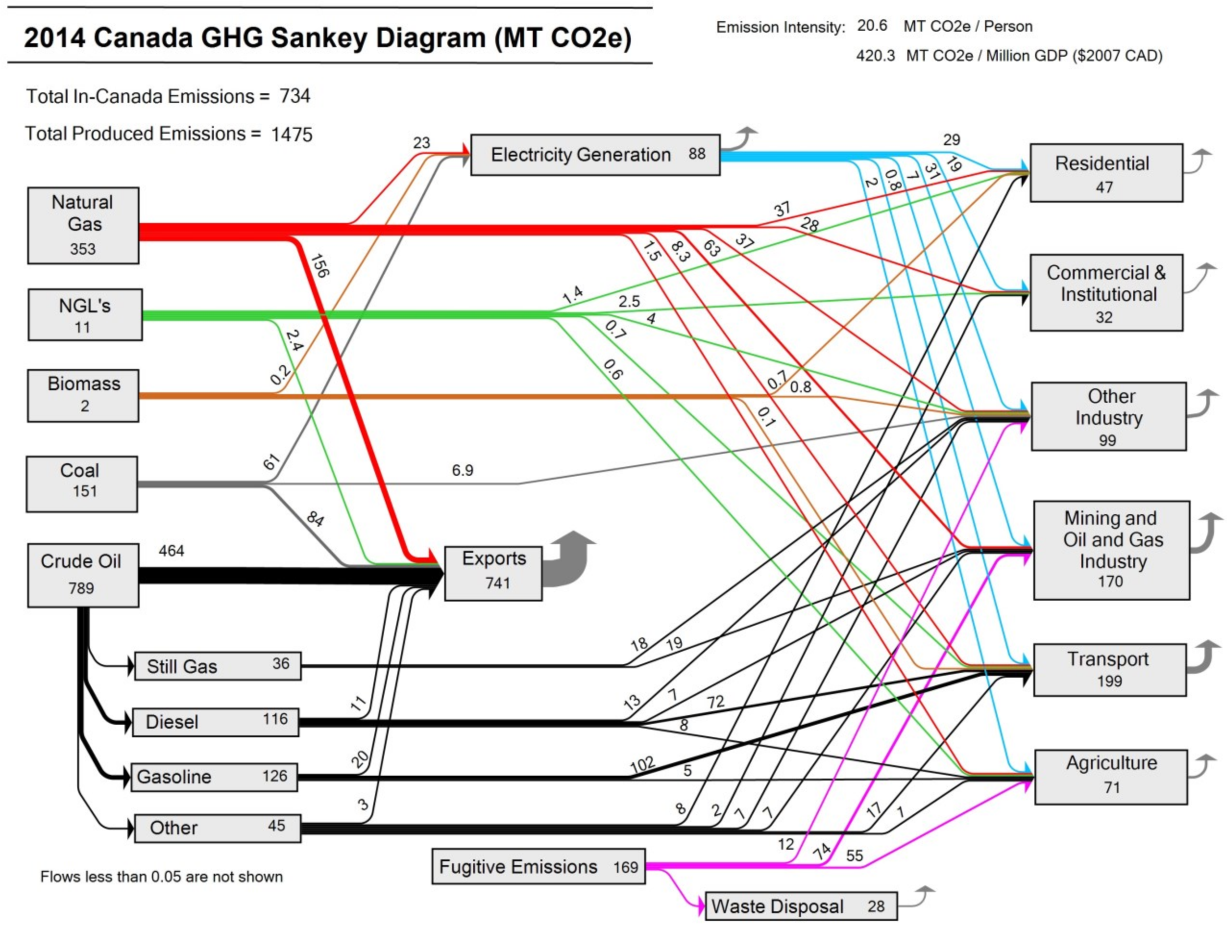

Figure 7-4: 2014 Canada GHG Sankey diagram with resources and sectors

The model shows that Canada will emit 780 MT of GHGs in 2030 and the largest GHG emission sector is the mining and upstream oil and gas industry, which will surpass the transportation sector, due to drastic projected growth in oil sands production. The majority of emissions will come from natural gas. Canada's emission intensity in 2030 is calculated to be 19.2 tonnes per person and 343.5 tonnes per million dollars of GDP. The LEAP-Canada model shows that Canada will emit 798 MT of GHGs in 2050, and Canada's largest GHG emission sector in 2050 is the mining and oil and gas sector. The second largest emitting sector is transportation sector. The majority of emissions in 2050 will come from natural gas. Canada's emission intensity in 2050 is expected to be 17.7 tonnes per person and 272 tonnes per million dollars of GDP.

Detailed diagrams of Canada's GHG emissions were created and show emissions by province, sector, and resource/fuel. These diagrams can provide a useful and easy-to-read breakdown of emissions in Canada. Policy makers can use these diagrams to understand emission sources and identify key focus areas for climate policy formulation specific to a province or region. 2030 and 2050 GHG Sankey diagrams are shown in Figure 7-5 and Figure 7-6.

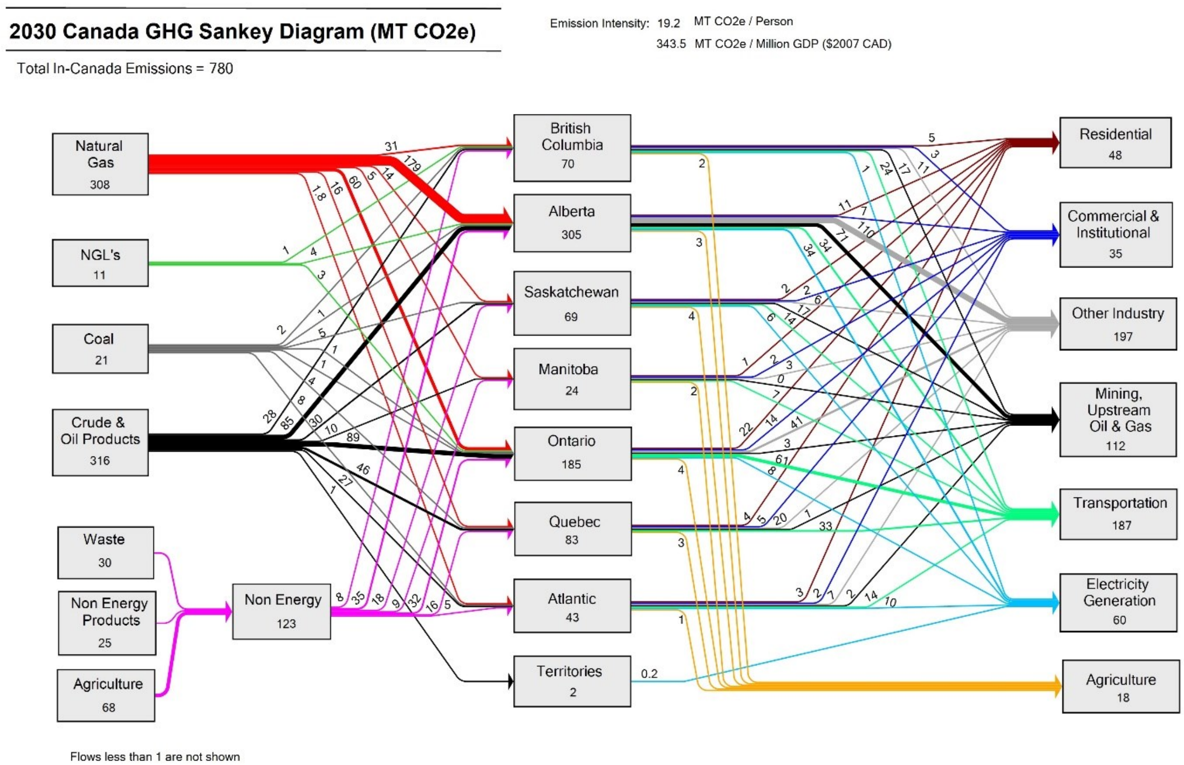

Figure 7-5: 2030 Canada GHG Sankey diagram with resources, regions, and sectors

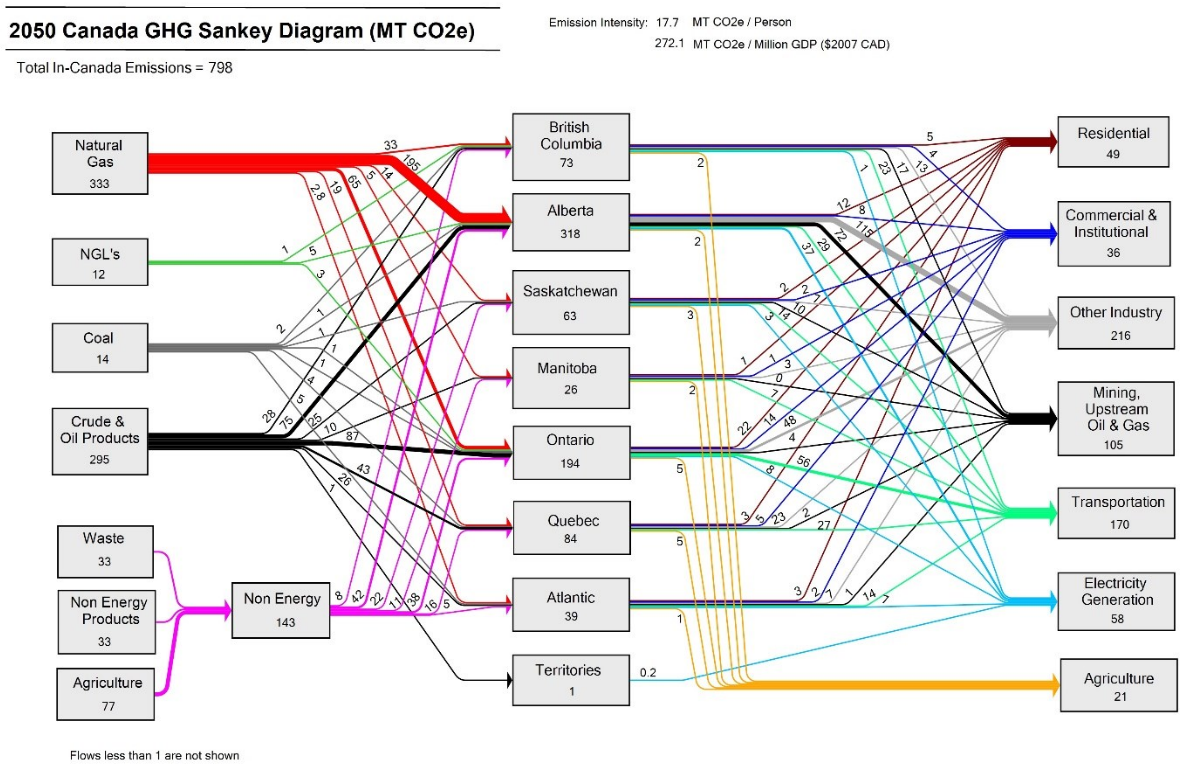

Figure 7-6: 2050 Canada GHG Sankey diagram with resources, regions, and sectors

The model was then used to quantify the energy and emission impacts of proposed pipelines on Canada's energy and emissions landscape. This involved finding the energy demands and emissions associated with the operation of the pipelines, if approved, through the LEAP-Canada model. Possible pathways were assessed in the event that pipelines are not approved, namely variations of crude-by-rail transport. The possibility of constrained oil production was discussed in the light of pipeline constraints.

Oil export projections were generated from the model, taking into account production projections from the NEB and LEAP-Canada's own developed supply-demand projections. Pipeline energy and emissions were evaluated with the LEAP-Canada energy model. A year-by-year outlook was presented illustrating provincial emission estimates from pipeline operations related to electricity generation for the proposed pipelines. From the literature review it was determined that a pipeline constraint might directly affect production through the higher transportation cost of rail, but only in a narrow price range, and thus investment decisions are not likely to be affected.

In terms of pipeline implications on GHG emission targets set forth by provincial and federal governments, the results of this study show that pipeline transport is a favorable alternative to crude-by-rail transport. It is not likely that upstream oil production will cease if pipeline capacity does not expand, and so energy demands and emissions would increase in all provinces through increased rail transportation of crude. A more effective means of reaching emissions targets would focus on reducing fossil fuel demand, not the transportation of the produced commodity, since the former drives the latter. Figure 7-7 shows the cumulative energy demands and emissions of the pipeline and rail scenarios to 2050.

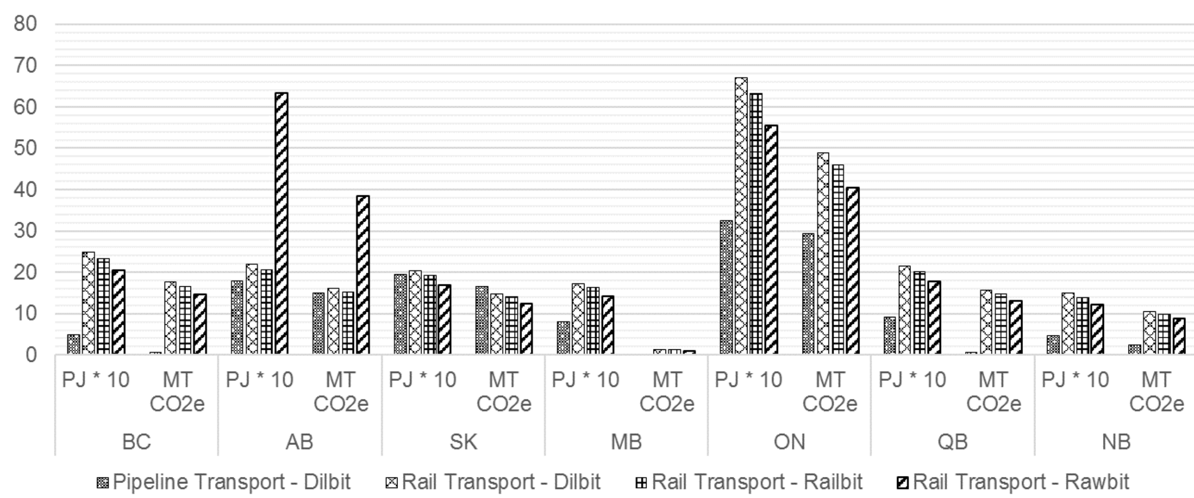

Figure 7-7: Cumulative energy and GHG emissions to 2050 by scenario based on the LEAP-Canada model

This research also evaluated BC hydropower import scenarios developed to satisfy oil sands electricity demands. GHG mitigation cost scenarios were quantified with the LEAP-Canada model. Oil sands electricity demands were projected with the model to the year 2050 and showed a 45% increase in peak electricity demand between 2017 and 2039. The BAU oil sands cogeneration electricity production GHG emissions were also projected to 2050 and showed a corresponding growth of 50% between 2017 and 2040.

Two options for importing BC hydro power were considered, increasing exiting intertie capacity by 500 MW and using the 1100 MW Site C dam exclusively for oil sands via DC transmission line. If the intertie or Site C option were to replace oil sands cogeneration capacity, the cost of GHG abatement would be 72.5 and 226 $/tonne, respectively. The average mitigation would be 0.7 and 1 MT per year, respectively. Figure 7-8 depicts the cost curves for the two cogeneration replacement scenarios. If the two options were considered in addition to oil sands cogeneration capacity, the mitigation cost fell to 61.5 and 171 $ per/tonne for the intertie and Site C options, respectively, an average of 0.92 and 1.46 MT mitigation per year, respectively. Figure 7-9 depicts the cost curves for the two in addition to cogeneration scenarios.

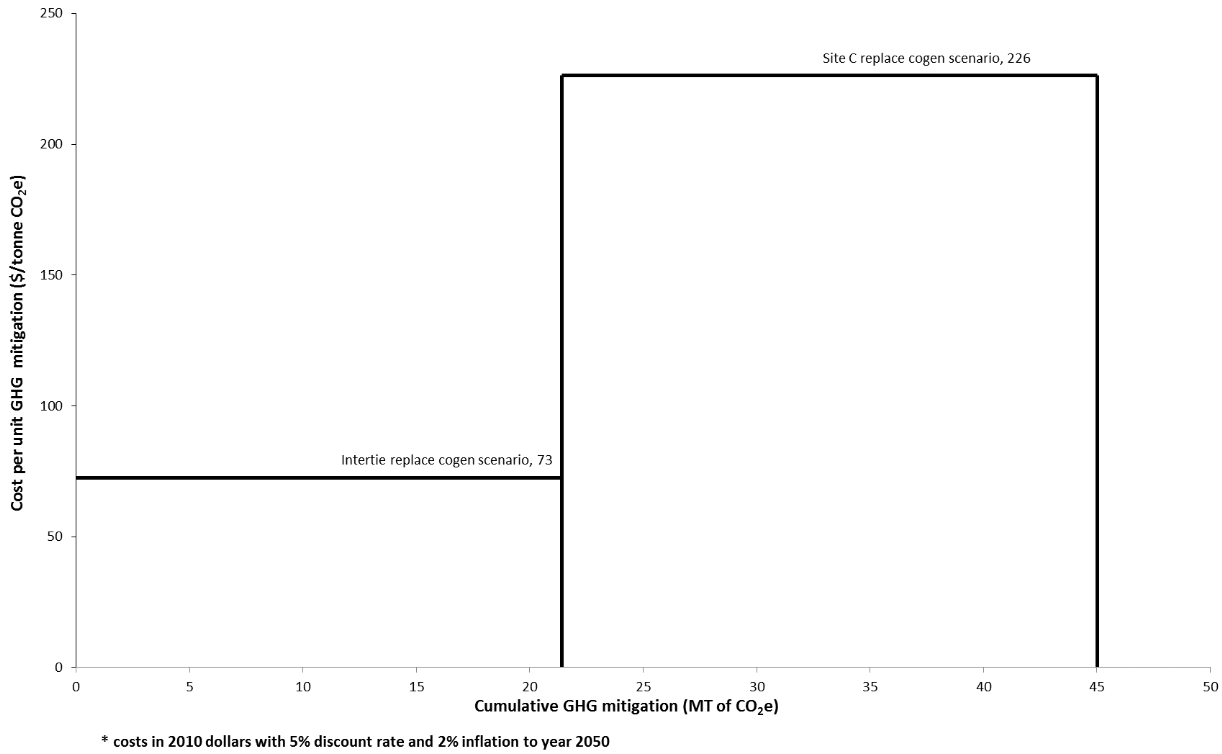

Figure 7-8: BC hydropower options replacing oil sands cogeneration cost curve

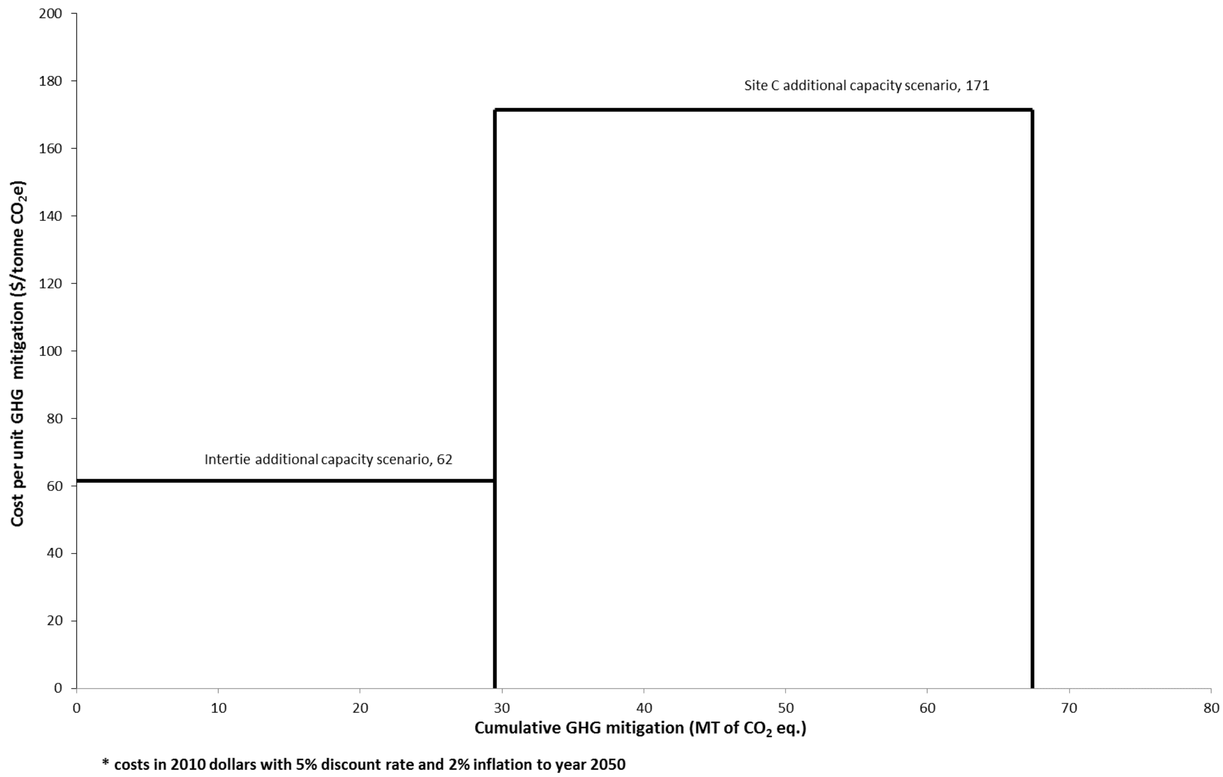

Figure 7-9: BC hydropower options addition to oil sands cogeneration cost curve

BC's electricity supply adequacy was analyzed to determine how increasing BC hydropower exports to Alberta would affect the domestic supply-demand balance. With hydropower additions, including Site C, annual gross electricity supply will meet domestic demands. However, due to peak load requirements, imports (from the U.S.) must be increased (up to 1,500 GWh in the peak year) with higher Alberta exports. This indicates that BC may not be in a position to provide reliable or cost-effective export capacity for oil sands operations.

7.2 Recommendations for Future Research

Continuing this work will involve further bottom-up sub-sector development for the industrial and agriculture sectors. The cement, smelting and refining, construction, chemical, forestry, manufacturing, iron and steel, and pulp & paper industrial sub-sectors require further work to develop their technology-specific energy demand trees. The agriculture sector also requires this development.

Abatement cost curves for energy efficiency measures have been developed for the residential, commercial and institutional, mining, and transportation sectors of Alberta. The method developed in the Alberta studies can be applied to all regions in Canada through the LEAP-Canada model and will give insight to those at the municipal, provincial, and federal levels on the techno-economic feasibility of various policy options.

It is recommended that scenarios be assessed to determine how to bring Canada to a net-zero emission and highly sustainably nation. This would involve electrification of the demand sectors. The model can be used to develop electrification cost curves to evaluate the most cost effective way to begin developing an electrification strategy. Examining natural resources potentials, energy storage and supply systems, and a horizontal (east-west) energy trading system should be evaluated to determine if Canada can be 100% energy self-sufficient. This can be done in a fully integrated manner with the model developed in this research.

Considering that electrification of the demand sector would impact the water system, it is also recommended to develop a corresponding multi-regional Water Evaluation And Planning model (WEAP-Canada model) to be integrated with the LEAP-Canada model. If Canada is to become a sustainable nation, water deserves the same level of planning and analysis as energy and emissions.

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Appendix

Table A- 1: Canada's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	1,435.6	1,512.8	1,539.1	1,531.5	1,516.8
Single Detached	1,011.9	1,065.9	1,086.0	1,082.2	1,073.8
Single Attached	135.1	143.0	145.9	145.5	144.1
Apartment	256.4	269.6	271.6	267.8	262.6
Mobile Homes	32.1	34.3	35.5	36.0	36.3
Commercial and Institutional	1,105.4	1,207.9	1,277.2	1,333.5	1,390.4
Wholesale Trade	52.6	55.6	57.6	58.9	60.2
Retail Trade	149.4	158.0	164.1	168.0	171.9
Transportation and Warehousing	35.2	37.1	38.5	39.3	40.2
Information and Cultural Industries	19.3	20.4	21.2	21.7	22.1
Offices	334.7	353.6	367.3	376.1	384.5
Educational Services	113.7	120.0	124.4	127.3	130.1
Health Care and Social Assistance	103.3	107.9	112.1	114.9	118.3
Arts and Entertainment and Recreation	24.3	25.2	26.1	26.7	27.4
Accommodation and Food Services	73.7	77.7	81.0	83.2	86.0
Other Services	15.6	16.6	17.2	17.6	18.0
Street Lighting	7.5	7.8	8.1	8.3	8.5
Non Energy Use	172.2	223.0	254.7	286.5	318.2
Aggregated Fuel Use	4.2	5.0	5.0	5.0	5.1
Industrial	4,661.6	5,533.2	6,324.9	6,895.8	7,103.7
Construction	206.5	192.6	216.1	237.3	253.8
Pulp and Paper	570.5	580.2	609.7	639.0	658.5
Smelting and Refining	236.1	251.5	284.4	318.9	345.5
Petroleum Refining	346.8	321.7	321.7	321.7	321.7
Chemicals	413.7	502.9	578.4	643.5	697.2
Iron and Steel	206.8	235.8	268.5	296.9	317.9
Other Manufacturing	533.1	649.7	738.0	819.1	881.8

Branches	2010	2020	2030	2040	2050
Forestry	18.9	19.2	21.5	23.8	25.5
Mining and Upstream Oil and Gas	967.1	1,541.9	1,877.0	2,036.1	1,919.4
Other Non-Energy Use	515.6	590.1	713.2	830.9	946.2
Aggregated Fuel Use	11.7	14.5	11.5	10.7	9.9
Producer Consumption	579.9	572.0	615.1	640.2	642.2
Cement	54.9	61.0	69.9	77.8	84.1
Transportation	2,727.5	2,807.2	2,751.0	2,672.4	2,512.6
Road	2,063.2	2,059.2	1,925.7	1,780.4	1,587.2
Air	228.3	252.1	274.1	292.1	309.1
Rail	83.7	94.2	104.1	122.5	120.6
Marine	121.1	130.2	138.4	144.9	150.7
OFF Road	103.0	113.3	122.4	129.4	135.7
Pipelines	122.6	152.2	181.0	197.8	204.0
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Aggregated Fuel Use	5.6	6.0	5.4	5.4	5.3
Agriculture	245.0	278.1	302.9	325.3	347.1
Electricity	33.9	38.7	43.1	47.4	52.1
Natural Gas	26.4	29.6	32.8	36.0	39.2
Gasoline	58.9	67.3	72.6	77.1	81.4
Diesel	105.5	120.0	129.3	137.1	144.2
Light Fuel oil	2.8	2.9	3.3	3.8	4.3
Heavy fuel oil	9.8	10.6	11.0	11.0	10.8
Propane	7.6	8.8	10.6	12.5	14.9
Lubricants	0.1	0.2	0.2	0.2	0.3
Total	10,175.2	11,339.2	12,195.0	12,758.4	12,870.6

Table A- 2: Canada's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	422	466	492	505	499
Residential	44	47	48	49	49
Commercial and Institutional	31	33	35	35	36
Industrial	144	177	203	221	223
Transportation	188	192	187	181	170
Agriculture	15	17	18	20	21
Transformation	184	177	167	165	155
Electricity Generation	94	80	60	60	56
Petroleum Refining	2	2	2	2	2
Bitumen Upgrading	5	5	6	6	6
Bitumen Extraction	8	16	20	22	20
Conventional Crude Oil Extraction	20	22	22	19	14
NGL Production	1	1	1	1	1
Natural Gas Extraction and Processing	53	50	55	56	56
Coal Mining	1	1	1	1	1
Non Energy	104	112	122	132	143
Agriculture	57	63	67	72	77
Waste	28	29	30	31	33
Non Energy Products	19	21	25	29	33
Total	709	755	781	803	797

Table A- 3: Canada's 2010-2050 GHG energy production results (PJ)

Branches	2010	2020	2030	2040	2050
Electricity Generation	2,002	2,273	2,463	2,557	2,580
Petroleum Refining	4,660	4,683	4,978	4,978	4,978
Bitumen Upgrading	2,542	2,863	3,046	3,046	3,046
Bitumen Extraction	4,002	7,992	9,845	10,788	9,907
Conventional Crude Oil Extraction	2,797	2,983	2,844	2,392	1,682
NGL Production	615	666	669	650	630
Natural Gas Extraction and Processing	5,802	5,943	7,004	7,092	7,218
Coal Mining	1,483	1,465	1,291	1,137	1,017
Uranium Production	5,770	7,855	7,855	7,855	7,855
Total	29,673	36,723	39,995	40,495	38,913

Table A- 4: British Columbia's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	149.5	164.9	170.3	173.3	174.5
Single Detached	104.3	114.3	118.1	120.2	121.0
Single Attached	15.1	17.0	17.6	17.9	18.0
Apartment	24.9	27.6	28.5	29.0	29.2
Mobile Homes	5.2	5.9	6.1	6.2	6.2
Commercial and Institutional	111.9	104.5	110.8	115.4	126.9
Wholesale Trade	4.1	3.8	4.0	4.1	4.5
Retail Trade	14.7	13.9	14.6	15.1	16.6
Transportation and Warehousing	3.1	2.8	3.0	3.1	3.4
Information and Cultural Industries	1.0	0.9	1.0	1.0	1.1
Offices	31.5	29.4	31.0	32.1	35.3
Educational Services	10.4	10.1	10.7	11.1	12.2
Health Care and Social Assistance	18.3	17.4	18.4	19.1	20.9
Arts and Entertainment and Recreation	3.4	3.2	3.4	3.5	3.8

Branches	2010	2020	2030	2040	2050
Accommodation and Food Services	16.0	16.2	17.0	17.7	19.4
Other Services	1.3	1.3	1.3	1.4	1.5
Street Lighting	0.4	0.4	0.4	0.4	0.5
Non Energy Use	7.8	5.2	6.0	6.8	7.6
Industrial	432.9	475.3	515.8	543.3	566.8
Construction	13.9	20.0	23.1	26.1	28.4
Pulp and Paper	192.7	185.5	178.4	171.6	165.0
Smelting and Refining	23.6	26.7	30.9	34.9	38.0
Petroleum Refining	7.2	8.9	8.9	8.9	8.9
Chemicals	5.8	6.5	7.5	8.5	9.3
Iron and Steel	0.9	1.2	1.4	1.6	1.7
Other Manufacturing	66.7	78.6	90.9	102.7	111.8
Forestry	6.2	7.3	8.5	9.6	10.4
Mining and Upstream Oil and Gas	52.7	67.9	80.7	87.3	94.8
Other Non-Energy Use	20.3	21.4	25.8	30.4	34.4
Producer Consumption	38.1	44.4	51.6	52.8	54.1
Cement	4.7	6.9	8.0	9.0	9.8
Transportation	375.9	382.6	377.4	370.6	359.6
Road	228.8	217.9	195.6	173.5	151.5
Air	62.9	69.2	75.3	80.7	85.5
Rail	6.4	7.1	7.7	9.0	8.7
Marine	47.6	52.4	57.0	61.1	64.7
OFF Road	12.6	13.9	15.1	16.2	17.1
Pipelines	17.5	22.2	26.7	30.1	32.0
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Agriculture	19.2	22.4	26.9	31.7	36.9
Electricity	2.7	3.1	3.8	4.5	5.2
Natural Gas	5.7	6.6	8.0	9.4	10.9
Gasoline	3.9	4.5	5.5	6.4	7.5
Diesel	6.6	7.7	9.2	10.9	12.7
Light Fuel oil	0.1	0.1	0.1	0.2	0.2

Branches	2010	2020	2030	2040	2050
Propane	0.2	0.2	0.3	0.3	0.4
Lubricants	0.0	0.0	0.0	0.0	0.0
Total	1,089.4	1,149.7	1,201.2	1,234.4	1,264.6

British Columbia's Table A- 5: 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	40	43	45	46	47
Residential	4	4	5	5	5
Commercial and Institutional	3	3	3	3	4
Industrial	8	10	12	13	13
Transportation	24	24	24	24	23
Agriculture	1	1	2	2	2
Transformation	9	12	17	17	17
Electricity Generation	2	1	1	1	1
Petroleum Refining	0	0	0	0	0
Conventional Crude Oil Extraction	0	0	1	0	0
NGL Production	0	0	0	0	0
Natural Gas Extraction and Processing	6	10	15	15	15
Coal Mining	0	0	0	0	0
Non Energy	8	8	8	8	8
Agriculture	2	2	2	2	2
Waste	5	5	5	5	6
Non Energy Products	1	1	0	0	0
Total	57	63	70	72	73

Table A- 6: Alberta's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	206.6	229.6	251.4	266.5	280.2
Single Detached	155.3	172.6	189.0	200.4	210.6
Single Attached	15.7	17.4	19.1	20.2	21.3
Apartment	24.1	26.8	29.4	31.1	32.7
Mobile Homes	11.4	12.7	13.9	14.8	15.5
Commercial and Institutional	260.7	329.0	364.2	395.8	424.3
Wholesale Trade	9.6	11.1	11.8	12.3	12.7
Retail Trade	28.4	32.9	35.0	36.5	37.5
Transportation and Warehousing	6.7	7.7	8.2	8.6	8.8
Information and Cultural Industries	3.8	4.4	4.7	4.9	5.0
Offices	61.0	70.6	75.2	78.5	80.6
Educational Services	19.4	22.4	23.9	24.9	25.6
Health Care and Social Assistance	15.5	18.0	19.2	20.0	20.5
Arts and Entertainment and Recreation	3.9	4.5	4.8	5.0	5.1
Accommodation and Food Services	13.8	16.0	17.0	17.8	18.2
Other Services	2.6	3.0	3.2	3.3	3.4
Street Lighting	1.1	1.3	1.4	1.4	1.5
Non Energy Use	94.9	137.1	159.9	182.6	205.3
Industrial	1,926.6	2,564.2	3,049.5	3,336.2	3,322.4
Construction	34.7	33.7	39.7	44.7	49.4
Pulp and Paper	78.3	77.4	77.2	77.0	76.9
Smelting and Refining	5.5	0.3	0.4	0.4	0.4
Petroleum Refining	68.5	68.1	68.1	68.1	68.1
Chemicals	151.4	183.1	215.7	242.9	268.7
Iron and Steel	2.9	2.6	3.1	3.4	3.8
Other Manufacturing	65.6	85.3	100.5	113.1	125.2
Forestry	0.9	0.9	1.1	1.2	1.3
Mining and Upstream Oil and Gas	780.7	1,321.3	1,631.0	1,771.5	1,631.9
Other Non-Energy Use	330.3	376.7	461.4	540.2	621.4
Producer Consumption	397.6	404.1	438.8	459.6	459.6

Branches	2010	2020	2030	2040	2050
Cement	10.3	10.7	12.6	14.2	15.7
Transportation	466.3	498.7	486.6	466.1	420.5
Road	361.0	371.3	333.7	289.9	229.0
Air	34.7	41.3	48.5	55.1	62.1
Rail	27.7	33.0	38.7	46.9	49.5
Marine	0.1	0.1	0.1	0.2	0.2
OFF Road	11.1	13.2	15.5	17.6	19.8
Pipelines	31.7	39.8	50.0	56.4	59.9
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Agriculture	48.2	54.6	52.0	47.1	40.0
Electricity	7.0	7.9	7.5	6.8	5.8
Natural Gas	3.5	4.0	3.8	3.4	2.9
Gasoline	13.0	14.8	14.1	12.7	10.8
Diesel	24.4	27.7	26.3	23.8	20.2
Light Fuel oil	0.0	0.0	0.0	0.0	0.0
Propane	0.3	0.3	0.3	0.3	0.2
Lubricants	0.0	0.0	0.0	0.0	0.0
Total	2,908.4	3,676.2	4,203.7	4,511.6	4,487.4

Table A- 7: Alberta's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	119	148	166	174	168
Residential	9	10	11	12	12
Commercial and Institutional	6	7	7	8	8
Industrial	68	93	111	120	117
Transportation	33	35	34	32	29
Agriculture	3	3	3	3	2
Transformation	109	116	104	109	107
Electricity Generation	48	52	34	37	36
Petroleum Refining	1	1	1	1	1
Bitumen Upgrading	4	5	5	5	5
Bitumen Extraction	8	16	20	22	20
Conventional Crude Oil Extraction	6	6	6	5	4
NGL Production	1	1	1	1	0
Natural Gas Extraction and Processing	41	36	37	38	40
Coal Mining	0	0	0	0	0
Non Energy	28	32	35	39	42
Agriculture	17	19	21	22	24
Waste	2	3	4	4	5
Non Energy Products	8	9	11	12	14
Total	256	296	305	322	317

Table A- 8: Saskatchewan's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	51.9	53.1	52.7	52.0	55.1
Single Detached	42.2	43.2	42.8	42.3	44.8
Single Attached	2.6	2.6	2.6	2.6	2.7
Apartment	5.6	5.7	5.7	5.6	5.9
Mobile Homes	1.5	1.6	1.5	1.5	1.6
Commercial and Institutional	65.4	71.7	72.1	72.4	75.9
Wholesale Trade	3.1	3.1	3.0	2.9	3.0
Retail Trade	7.0	7.0	6.8	6.5	6.8
Transportation and Warehousing	2.5	2.5	2.4	2.3	2.4
Information and Cultural Industries	0.7	0.7	0.6	0.6	0.6
Offices	14.0	13.9	13.5	13.0	13.6
Educational Services	6.0	5.9	5.8	5.6	5.8
Health Care and Social Assistance	5.2	5.2	5.0	4.9	5.1
Arts and Entertainment and Recreation	2.0	2.0	1.9	1.9	2.0
Accommodation and Food Services	2.1	2.1	2.0	2.0	2.0
Other Services	0.7	0.7	0.7	0.7	0.7
Street Lighting	0.3	0.3	0.3	0.2	0.3
Non Energy Use	21.8	28.3	30.0	31.8	33.5
Industrial	103.9	142.1	150.3	154.1	158.8
Construction	11.5	13.9	14.9	15.5	15.9
Pulp and Paper	3.9	9.3	10.0	10.4	10.6
Petroleum Refining	19.6	23.6	23.6	23.6	23.6
Chemicals	2.6	6.7	7.2	7.5	7.7
Iron and Steel	6.6	5.9	6.3	6.5	6.7
Other Manufacturing	12.0	23.4	25.1	26.1	26.8
Forestry	0.2	0.2	0.2	0.2	0.2
Mining and Upstream Oil and Gas	42.7	49.8	52.1	52.9	55.5
Other Non-Energy Use	2.7	6.9	7.7	8.3	8.9
Producer Consumption	2.1	2.3	3.1	3.1	3.0
Transportation	183.6	210.0	220.5	225.8	221.4

Branches	2010	2020	2030	2040	2050
Road	118.5	131.6	132.5	132.5	128.6
Air	3.6	4.0	4.3	4.5	4.8
Rail	9.0	10.1	10.7	12.2	11.9
OFF Road	3.5	3.9	4.1	4.3	4.5
Pipelines	49.0	60.4	69.0	72.3	71.6
Agriculture	55.1	60.6	60.5	57.1	50.7
Electricity	4.7	5.2	5.2	4.9	4.3
Natural Gas	1.7	1.9	1.9	1.8	1.6
Gasoline	11.9	13.1	13.1	12.3	10.9
Diesel	30.8	33.9	33.8	31.9	28.3
Heavy fuel oil	5.9	6.5	6.5	6.1	5.4
Propane	0.1	0.1	0.1	0.1	0.1
Lubricants	0.0	0.0	0.0	0.0	0.0
Total	459.8	537.5	556.0	561.5	561.8

Table A- 9: Saskatchewan's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	24.2	27.7	28.2	28.3	28.2
Residential	2.2	2.3	2.2	2.2	2.3
Commercial and Institutional	1.6	1.6	1.5	1.5	1.6
Industrial	4.6	6.2	6.5	6.7	7.0
Transportation	12.1	13.6	13.9	14.2	14.0
Agriculture	3.6	4.0	4.0	3.8	3.4
Transformation	28.6	26.6	22.7	18.4	13.0
Electricity Generation	12.1	9.6	5.7	4.4	2.5
Petroleum Refining	0.1	0.1	0.1	0.1	0.1
Bitumen Upgrading	0.1	0.1	0.1	0.1	0.1
Conventional Crude Oil Extraction	10.8	12.6	13.2	11.3	8.9
NGL Production	0.0	0.0	0.1	0.1	0.1
Natural Gas Extraction and Processing	5.2	4.0	3.3	2.3	1.2
Coal Mining	0.1	0.1	0.1	0.1	0.1
Non Energy	12.6	15.5	17.6	19.7	21.8
Agriculture	11.2	14.1	15.9	17.7	19.6
Waste	0.9	1.0	1.2	1.3	1.4
Non Energy Products	0.5	0.4	0.6	0.7	0.8
Total	65.4	69.8	68.5	66.4	63.0

Table A- 10: Manitoba's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	50.0	56.4	56.1	54.7	52.8
Single Detached	39.2	44.2	43.9	42.8	41.3
Single Attached	2.5	2.8	2.8	2.7	2.6
Apartment	7.1	8.0	7.9	7.8	7.5
Mobile Homes	1.2	1.4	1.4	1.4	1.3

Branches	2010	2020	2030	2040	2050
Commercial and Institutional	43.9	50.2	49.3	48.2	47.0
Wholesale Trade	2.7	3.1	3.0	2.9	2.8
Retail Trade	7.1	8.1	7.9	7.7	7.4
Transportation and Warehousing	2.1	2.3	2.3	2.2	2.1
Information and Cultural Industries	0.8	0.9	0.9	0.9	0.8
Offices	14.2	16.1	15.7	15.2	14.7
Educational Services	5.8	6.6	6.4	6.2	6.0
Health Care and Social Assistance	4.0	4.6	4.5	4.3	4.2
Arts and Entertainment and Recreation	0.7	0.7	0.7	0.7	0.7
Accommodation and Food Services	2.2	2.5	2.5	2.4	2.3
Other Services	0.8	0.9	0.9	0.9	0.8
Street Lighting	0.3	0.4	0.4	0.4	0.3
Non Energy Use	3.2	3.9	4.2	4.5	4.7
Aggregated Fuel Use	-	-	-	-	-
Industrial	65.0	76.1	82.8	88.7	92.8
Construction	6.8	11.5	12.5	13.5	14.1
Pulp and Paper	7.0	7.7	8.4	9.0	9.4
Smelting and Refining	6.4	5.9	6.4	6.9	7.2
Chemicals	17.0	20.4	22.2	23.9	25.0
Iron and Steel	2.2	2.3	2.5	2.6	2.8
Other Manufacturing	20.1	21.7	23.7	25.5	26.6
Forestry	0.1	0.1	0.2	0.2	0.2
Mining and Upstream Oil and Gas	4.7	5.5	5.6	5.8	6.1
Other Non-Energy Use	-	0.2	0.3	0.3	0.3
Aggregated Fuel Use	-	-	-	-	-
Producer Consumption	0.8	0.9	1.1	1.1	1.1
Transportation	92.6	106.1	110.3	113.2	111.1
Road	68.9	78.7	79.1	79.2	77.4
Air	9.2	10.2	11.0	11.6	12.1
Rail	8.0	8.9	9.6	10.9	10.6
Marine	-	-	-	-	-

Branches	2010	2020	2030	2040	2050
OFF Road	3.4	3.8	4.1	4.3	4.5
Pipelines	3.1	4.6	6.5	7.2	6.5
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Aggregated Fuel Use	-	-	-	-	-
Agriculture	18.7	24.2	25.3	26.4	27.5
Electricity	2.5	3.2	3.4	3.5	3.7
Natural Gas	0.1	0.1	0.1	0.1	0.1
Gasoline	6.7	8.7	9.1	9.5	9.9
Diesel	8.2	10.6	11.1	11.6	12.1
Light Fuel oil	-	-	-	-	-
Kerosene	-	-	-	-	-
Heavy fuel oil	0.6	0.8	0.8	0.8	0.9
Propane	0.6	0.8	0.8	0.8	0.9
Lubricants	-	0.0	0.0	0.0	0.0
Total	270.2	313.1	323.7	331.2	331.2

Table A- 11: Manitoba's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	12.0	13.8	14.2	14.6	14.6
Residential	1.1	1.2	1.2	1.2	1.2
Commercial and Institutional	1.4	1.6	1.5	1.5	1.4
Industrial	2.1	2.5	2.7	2.9	3.1
Transportation	6.2	7.0	7.2	7.3	7.2
Agriculture	1.2	1.5	1.6	1.7	1.7
Transformation	1.4	1.0	0.5	0.4	0.3
Electricity Generation	1.0	0.6	0.2	0.2	0.2
Conventional Crude Oil Extraction	0.3	0.4	0.3	0.2	0.2
Non Energy	8.1	8.3	9.1	10.0	10.9
Agriculture	6.4	6.5	7.1	7.7	8.3
Waste	1.1	1.2	1.4	1.6	1.7
Non Energy Products	0.5	0.5	0.6	0.7	0.8
Total	21.4	23.1	23.8	25.0	25.8

Table A- 12: Ontario's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	513.0	536.1	551.6	550.5	543.2
Single Detached	362.3	378.7	389.6	388.9	383.7
Single Attached	64.2	67.1	69.0	68.8	67.9
Apartment	83.7	87.5	90.0	89.9	88.7
Mobile Homes	2.7	2.8	2.9	2.9	2.9
Commercial and Institutional	372.5	410.1	428.8	442.3	451.3
Wholesale Trade	20.4	22.2	23.1	23.6	23.9
Retail Trade	56.3	61.5	63.8	65.3	66.0
Transportation and Warehousing	12.8	14.0	14.5	14.9	15.0
Information and Cultural Industries	7.2	7.9	8.2	8.4	8.5

Branches	2010	2020	2030	2040	2050
Offices	134.2	146.5	152.1	155.6	157.3
Educational Services	40.7	44.5	46.2	47.2	47.7
Health Care and Social Assistance	35.1	38.4	39.8	40.7	41.2
Arts and Entertainment and Recreation	7.8	8.5	8.8	9.0	9.1
Accommodation and Food Services	22.3	24.3	25.2	25.8	26.1
Other Services	6.4	7.0	7.3	7.4	7.5
Street Lighting	2.1	2.3	2.4	2.5	2.5
Non Energy Use	27.3	33.0	37.4	41.9	46.4
Industrial	1,061.3	1,195.7	1,348.0	1,480.9	1,581.4
Construction	58.1	42.5	48.6	53.7	57.4
Pulp and Paper	88.6	114.6	130.8	144.6	154.6
Smelting and Refining	19.2	21.0	24.0	26.5	28.4
Petroleum Refining	121.1	119.5	119.5	119.5	119.5
Chemicals	187.2	230.9	263.7	291.4	311.7
Iron and Steel	174.6	197.1	225.0	248.7	266.0
Other Manufacturing	216.6	253.4	289.3	319.7	342.0
Forestry	1.9	2.0	2.3	2.6	2.8
Mining and Upstream Oil and Gas	28.3	34.0	38.8	43.0	47.8
Other Non-Energy Use	97.6	111.2	132.1	151.8	168.8
Producer Consumption	40.1	39.0	39.1	41.0	41.3
Cement	28.1	30.4	34.8	38.4	41.1
Transportation	897.3	913.6	891.5	865.2	816.1
Road	746.8	745.1	708.0	668.4	614.4
Air	60.4	66.9	72.3	75.9	78.6
Rail	16.1	17.8	19.2	23.2	20.9
Marine	15.8	17.5	18.9	19.8	20.6
OFF Road	40.1	44.4	48.0	50.3	52.2
Pipelines	18.2	21.9	25.0	27.6	29.5
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Aggregated Fuel Use	-	-	-	-	-
Agriculture	59.8	65.2	71.8	78.5	85.3

Branches	2010	2020	2030	2040	2050
Electricity	9.1	9.9	10.9	11.9	13.0
Natural Gas	14.2	15.5	17.0	18.6	20.2
Gasoline	15.2	16.5	18.2	19.9	21.6
Diesel	15.4	16.8	18.5	20.2	21.9
Light Fuel oil	0.9	1.0	1.1	1.2	1.3
Heavy fuel oil	1.6	1.7	1.9	2.1	2.3
Propane	3.4	3.7	4.1	4.5	4.8
Lubricants	0.0	0.1	0.1	0.1	0.1
Total	2,903.9	3,120.7	3,291.7	3,417.4	3,477.2

Table A- 13: Ontario's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	133.4	140.7	145.2	147.8	147.6
Residential	20.5	21.4	22.0	22.0	21.7
Commercial and Institutional	12.2	13.4	13.9	14.2	14.3
Industrial	35.5	39.4	44.1	48.0	51.0
Transportation	61.7	62.7	61.0	59.1	55.7
Agriculture	3.5	3.8	4.1	4.5	4.9
Transformation	18.5	5.3	8.3	7.3	8.5
Electricity Generation	18.1	4.8	7.9	6.9	8.1
Petroleum Refining	0.4	0.4	0.4	0.4	0.4
Conventional Crude Oil Extraction	0.0	0.0	0.0	0.0	0.0
Natural Gas Extraction and Processing	0.1	0.0	-	-	-
Non Energy	26.8	28.2	31.6	35.0	38.3
Agriculture	10.6	10.9	12.0	13.1	14.1
Waste	9.4	9.8	10.4	11.0	11.6
Non Energy Products	6.8	7.6	9.3	10.9	12.6
Total	178.8	174.2	185.1	190.1	194.4

Table A- 14: Quebec's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	345.3	356.3	343.2	324.9	306.2
Single Detached	214.5	221.3	213.1	201.8	190.2
Single Attached	27.0	27.9	26.9	25.4	24.0
Apartment	98.9	102.0	98.2	93.0	87.7
Mobile Homes	5.0	5.1	4.9	4.7	4.4
Commercial and Institutional	196.1	183.5	189.4	193.3	195.5
Wholesale Trade	10.0	9.4	9.7	9.8	9.9
Retail Trade	28.4	26.6	27.3	27.7	27.8
Transportation and Warehousing	6.4	6.0	6.1	6.2	6.3
Information and Cultural Industries	5.0	4.7	4.8	4.9	4.9
Offices	65.0	60.9	62.6	63.4	63.7
Educational Services	24.7	23.2	23.8	24.1	24.2
Health Care and Social Assistance	19.4	18.2	18.7	19.0	19.1
Arts and Entertainment and Recreation	5.8	5.4	5.6	5.7	5.7
Accommodation and Food Services	14.1	13.2	13.6	13.8	13.8
Other Services	2.8	2.6	2.7	2.7	2.7
Street Lighting	2.3	2.2	2.2	2.2	2.3
Non Energy Use	12.2	11.0	12.4	13.7	15.1
Industrial	769.5	835.5	933.9	1,041.4	1,128.0
Construction	44.1	35.9	40.5	45.5	49.4
Pulp and Paper	140.4	138.2	155.9	175.2	190.2
Smelting and Refining	179.7	196.2	221.3	248.7	269.9
Petroleum Refining	47.0	36.9	36.9	36.9	36.9
Chemicals	47.1	51.4	57.9	65.1	70.7
Iron and Steel	19.5	26.8	30.2	34.0	36.9
Other Manufacturing	116.3	158.3	178.6	200.6	217.8
Forestry	5.3	4.6	5.1	5.8	6.3
Mining and Upstream Oil and Gas	35.2	39.4	44.4	50.0	56.4
Other Non-Energy Use	63.1	68.4	80.3	93.8	105.9
Producer Consumption	61.3	67.6	69.5	70.9	71.5

Cement	10.7	11.8	13.3	15.0	16.3
Transportation	506.4	494.8	463.9	430.6	386.1
Road	399.5	379.5	341.4	301.7	253.4
Air	37.8	40.7	43.2	45.0	46.6
Rail	10.8	11.6	12.3	13.8	13.3
Marine	33.0	35.6	37.7	39.3	40.7
OFF Road	22.3	24.0	25.5	26.6	27.5
Pipelines	3.0	3.3	3.8	4.2	4.6
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Agriculture	32.4	40.5	54.8	71.8	93.0
Electricity	6.4	8.0	10.8	14.2	18.4
Natural Gas	1.2	1.5	2.0	2.7	3.4
Gasoline	6.5	8.1	11.0	14.4	18.7
Diesel	14.9	18.6	25.2	33.0	42.8
Light Fuel oil	0.4	0.5	0.7	0.9	1.1
Heavy fuel oil	0.1	0.1	0.2	0.2	0.3
Propane	2.9	3.6	4.9	6.4	8.3
Lubricants	-	0.0	0.0	0.1	0.1
Total	1,849.8	1,910.6	1,985.3	2,062.0	2,108.9

Table A- 15: Quebec's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	62.6	64.9	65.5	66.1	65.9
Residential	3.8	4.0	3.8	3.6	3.4
Commercial and Institutional	5.5	5.2	5.3	5.4	5.4
Industrial	15.4	18.5	20.6	22.9	24.7
Transportation	36.0	35.0	32.7	30.1	27.0
Agriculture	1.9	2.3	3.2	4.2	5.4
Transformation	1.3	1.4	1.6	1.5	1.5
Electricity Generation	0.9	1.1	1.3	1.2	1.2
Petroleum Refining	0.3	0.3	0.3	0.3	0.3
Non Energy	15.0	16.3	16.3	16.2	16.2
Agriculture	7.8	8.0	8.1	8.1	8.1
Waste	6.5	6.3	6.3	6.2	6.1
Non Energy Products	0.7	1.9	1.9	1.9	1.9
Total	78.9	82.7	83.3	83.9	83.6

Table A- 16: New Brunswick's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	36.1	32.2	31.0	29.2	27.3
Single Detached	28.7	25.4	24.4	23.1	21.6
Single Attached	1.9	1.9	1.8	1.7	1.6
Apartment	3.5	3.2	3.0	2.9	2.7
Mobile Homes	2.0	1.7	1.7	1.6	1.5
Commercial and Institutional	15.0	15.3	15.7	16.4	16.9
Wholesale Trade	0.7	0.7	0.7	0.7	0.7
Retail Trade	1.9	2.0	2.0	2.0	2.1
Transportation and Warehousing	0.4	0.4	0.4	0.5	0.5
Information and Cultural Industries	0.2	0.2	0.2	0.2	0.2
Offices	3.7	4.0	4.0	4.1	4.1

Branches	2010	2020	2030	2040	2050
Educational Services	2.1	2.2	2.2	2.3	2.3
Health Care and Social Assistance	1.4	1.5	1.5	1.5	1.6
Arts and Entertainment and Recreation	0.2	0.2	0.2	0.2	0.2
Accommodation and Food Services	0.8	0.8	0.8	0.9	0.9
Other Services	0.2	0.2	0.2	0.2	0.2
Street Lighting	0.2	0.2	0.2	0.3	0.3
Non Energy Use	3.1	2.8	3.1	3.5	3.8
Industrial	131.8	116.6	120.7	123.6	126.3
Construction	28.4	31.3	33.0	34.4	35.2
Pulp and Paper	18.6	14.9	16.0	16.6	17.2
Smelting and Refining	0.5	0.5	0.5	0.5	0.5
Petroleum Refining	57.2	44.4	44.4	44.4	44.4
Chemicals	0.2	0.1	0.1	0.2	0.2
Other Manufacturing	11.5	8.8	9.5	9.8	10.1
Forestry	1.3	1.3	1.3	1.4	1.4
Mining and Upstream Oil and Gas	6.7	6.9	7.3	7.6	8.1
Other Non-Energy Use	-	4.1	4.5	4.9	5.2
Producer Consumption	7.2	4.0	3.7	3.6	3.6
Cement	0.4	0.3	0.4	0.4	0.4
Transportation	62.7	53.6	51.8	50.1	46.5
Road	48.4	39.1	36.8	34.4	31.3
Air	2.2	2.2	2.3	2.3	2.3
Rail	3.9	4.0	4.1	4.8	4.2
Marine	5.1	5.2	5.3	5.4	5.4
OFF Road	3.1	3.2	3.3	3.3	3.3
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Agriculture	3.7	3.4	3.7	4.0	4.4
Electricity	0.5	0.4	0.5	0.5	0.6
Gasoline	0.5	0.5	0.5	0.6	0.6
Diesel	1.7	1.5	1.7	1.8	2.0
Light Fuel oil	0.4	0.4	0.4	0.5	0.5

Branches	2010	2020	2030	2040	2050
Heavy fuel oil	0.5	0.5	0.5	0.6	0.6
Propane	0.0	0.0	0.0	0.0	0.0
Lubricants	-	0.0	0.0	0.0	0.0
Total	249.3	221.1	222.8	223.4	221.4

Table A- 17: New Brunswick's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	10.4	8.6	8.6	8.5	8.2
Residential	0.8	0.7	0.7	0.6	0.6
Commercial and Institutional	0.4	0.4	0.4	0.4	0.4
Industrial	4.5	3.5	3.5	3.6	3.6
Transportation	4.5	3.9	3.7	3.6	3.3
Agriculture	0.2	0.2	0.2	0.3	0.3
Transformation	4.2	3.7	3.6	3.5	3.4
Electricity Generation	3.9	3.4	3.3	3.2	3.2
Petroleum Refining	0.2	0.3	0.3	0.3	0.3
Natural Gas Extraction and Processing	0.1	-	-	-	-
Non Energy	2.4	2.3	2.5	2.8	3.1
Agriculture	0.5	0.5	0.5	0.5	0.5
Waste	0.7	0.7	0.7	0.7	0.6
Non Energy Products	1.2	1.0	1.3	1.7	2.0
Total	17.1	14.6	14.7	14.7	14.7

Table A- 18: Nova Scotia's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	48.4	48.9	48.0	45.4	42.4
Single Detached	37.4	37.7	37.0	34.9	32.6
Single Attached	3.2	3.3	3.2	3.1	2.9
Apartment	5.8	5.8	5.8	5.5	5.2
Mobile Homes	2.0	2.1	2.0	2.0	1.8
Commercial and Institutional	11.3	12.1	14.0	15.9	17.4
Wholesale Trade	0.7	0.7	0.8	0.9	1.0
Retail Trade	1.8	1.9	2.2	2.5	2.8
Transportation and Warehousing	0.4	0.4	0.5	0.6	0.6
Information and Cultural Industries	0.2	0.2	0.3	0.3	0.3
Offices	3.6	3.9	4.5	5.1	5.6
Educational Services	1.5	1.6	1.8	2.1	2.3
Health Care and Social Assistance	1.4	1.5	1.7	1.9	2.1
Arts and Entertainment and Recreation	0.2	0.2	0.2	0.3	0.3
Accommodation and Food Services	0.8	0.8	0.9	1.1	1.2
Other Services	0.2	0.2	0.3	0.3	0.3
Street Lighting	0.2	0.2	0.3	0.3	0.3
Non Energy Use	0.3	0.4	0.5	0.5	0.6
Industrial	67.1	53.8	56.5	55.8	55.4
Construction	6.3	2.2	2.4	2.4	2.3
Pulp and Paper	23.1	19.0	20.7	20.3	20.0
Smelting and Refining	0.7	0.6	0.6	0.6	0.6
Petroleum Refining	2.8	2.1	2.1	2.1	2.1
Chemicals	2.4	3.6	3.9	3.9	3.9
Other Manufacturing	13.5	11.9	13.0	12.8	12.6
Forestry	1.6	1.6	1.7	1.7	1.7
Mining and Upstream Oil and Gas	8.3	8.7	9.3	9.4	9.8
Other Non-Energy Use	0.7	0.5	0.6	0.6	0.6
Producer Consumption	7.2	3.0	1.7	1.5	1.3
Cement	0.5	0.4	0.5	0.5	0.5

Branches	2010	2020	2030	2040	2050
Transportation	70.3	73.2	74.1	74.2	73.3
Road	52.6	55.5	56.5	57.5	57.6
Air	6.1	6.1	6.1	5.8	5.4
Rail	1.7	1.7	1.7	1.6	1.5
Marine	6.4	6.4	6.3	6.0	5.6
OFF Road	3.5	3.5	3.5	3.3	3.1
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Agriculture	4.6	4.2	4.6	5.0	5.5
Electricity	0.6	0.6	0.6	0.7	0.7
Gasoline	0.7	0.6	0.7	0.7	0.8
Diesel	2.1	1.9	2.1	2.3	2.5
Light Fuel oil	0.6	0.5	0.6	0.6	0.7
Heavy fuel oil	0.6	0.6	0.6	0.7	0.8
Propane	0.0	0.0	0.0	0.0	0.0
Lubricants	0.0	0.0	0.0	0.0	0.0
Total	201.7	192.1	197.2	196.4	194.1

Table A- 19: Nova Scotia's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	9.1	8.9	9.0	9.0	8.9
Residential	1.7	1.7	1.7	1.6	1.5
Commercial and Institutional	0.3	0.4	0.4	0.5	0.5
Industrial	1.7	1.3	1.3	1.3	1.3
Transportation	5.0	5.2	5.3	5.2	5.2
Agriculture	0.3	0.3	0.3	0.3	0.3
Transformation	7.8	6.1	6.1	5.1	3.7
Electricity Generation	7.0	5.9	6.1	5.1	3.7
Petroleum Refining	0.1	-	-	-	-
NGL Production	0.0	0.0	0.0	0.0	0.0
Natural Gas Extraction and Processing	0.7	0.2	0.0	0.0	-
Non Energy	1.1	0.9	0.7	0.5	0.4
Agriculture	0.5	0.5	0.4	0.4	0.3
Waste	0.6	0.5	0.3	0.1	0.1
Non Energy Products	0.0	0.0	0.0	-0.0	-0.0
Total	18.0	16.0	15.8	14.5	13.0

Table A- 20: Newfoundland's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	24.4	24.5	23.6	23.6	24.1
Single Detached	20.2	20.3	19.5	19.4	19.8
Single Attached	2.0	2.0	2.0	2.0	2.1
Apartment	1.8	1.9	1.8	1.8	1.9
Mobile Homes	0.3	0.3	0.3	0.3	0.3
Commercial and Institutional	13.0	13.5	13.6	13.4	13.4
Wholesale Trade	0.7	0.7	0.7	0.7	0.7
Retail Trade	1.9	2.0	2.1	2.0	2.0
Transportation and Warehousing	0.4	0.5	0.5	0.5	0.4

Branches	2010	2020	2030	2040	2050
Information and Cultural Industries	0.2	0.2	0.2	0.2	0.2
Offices	3.8	4.1	4.1	4.1	4.1
Educational Services	1.5	1.7	1.7	1.7	1.7
Health Care and Social Assistance	1.4	1.5	1.6	1.5	1.5
Arts and Entertainment and Recreation	0.2	0.2	0.2	0.2	0.2
Accommodation and Food Services	0.8	0.9	0.9	0.9	0.9
Other Services	0.2	0.2	0.2	0.2	0.2
Street Lighting	0.2	0.3	0.3	0.3	0.2
Non Energy Use	1.6	1.2	1.2	1.2	1.2
Industrial	87.9	55.7	52.6	57.3	57.8
Construction	2.5	1.6	1.4	1.7	1.7
Pulp and Paper	17.6	13.2	11.7	13.8	14.0
Smelting and Refining	0.5	0.4	0.4	0.4	0.4
Petroleum Refining	23.5	18.2	18.2	18.2	18.2
Chemicals	0.2	0.1	0.1	0.1	0.1
Other Manufacturing	10.8	8.1	7.2	8.5	8.6
Forestry	1.2	1.1	1.0	1.2	1.2
Mining and Upstream Oil and Gas	6.8	6.9	6.5	7.1	7.3
Other Non-Energy Use	0.7	0.5	0.5	0.6	0.6
Producer Consumption	23.8	5.3	5.3	5.3	5.3
Cement	0.3	0.3	0.3	0.3	0.3
Transportation	56.2	56.9	57.6	59.2	60.7
Road	30.1	31.1	32.3	33.4	34.1
Air	11.2	11.1	10.9	11.0	11.4
Rail	0.0	0.0	0.0	0.0	0.0
Marine	11.8	11.7	11.5	11.7	12.1
OFF Road	3.1	3.0	3.0	3.0	3.1
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Aggregated Fuel Use	-	-	-	-	-
Agriculture	2.6	2.3	2.6	2.8	3.0
Electricity	0.3	0.3	0.3	0.4	0.4

Branches	2010	2020	2030	2040	2050
Gasoline	0.4	0.3	0.4	0.4	0.4
Diesel	1.2	1.1	1.2	1.3	1.4
Light Fuel oil	0.3	0.3	0.3	0.3	0.4
Heavy fuel oil	0.4	0.3	0.4	0.4	0.4
Propane	0.0	0.0	0.0	0.0	0.0
Lubricants	0.0	0.0	0.0	0.0	0.0
Total	184.0	152.9	149.9	156.2	159.1

Table A- 21: Newfoundland's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	8.3	6.9	6.9	7.1	7.3
Residential	0.4	0.4	0.4	0.4	0.5
Commercial and Institutional	0.4	0.4	0.4	0.4	0.4
Industrial	3.4	1.8	1.8	1.9	1.9
Transportation	4.0	4.1	4.1	4.2	4.3
Agriculture	0.2	0.1	0.2	0.2	0.2
Transformation	3.8	4.0	2.4	2.2	0.7
Electricity Generation	0.5	0.6	0.5	0.6	0.6
Petroleum Refining	0.1	0.1	0.1	0.1	0.1
Conventional Crude Oil Extraction	3.3	3.3	1.8	1.4	-
Non Energy	1.0	1.0	1.1	1.2	1.2
Agriculture	0.1	0.2	0.2	0.2	0.3
Waste	0.8	0.8	0.8	0.8	0.8
Non Energy Products	0.1	0.1	0.1	0.1	0.2
Total	13.1	11.9	10.4	10.4	9.2

Table A- 22: Prince Edward Island's 2010-2050 energy demand results (PJ)

Branches	2010	2020	2030	2040	2050
Residential	7.3	7.5	7.9	7.7	7.5
Single Detached	5.7	6.0	6.2	6.1	5.9
Single Attached	0.5	0.5	0.5	0.5	0.5
Apartment	0.7	0.7	0.7	0.7	0.7
Mobile Homes	0.4	0.4	0.4	0.4	0.4
Commercial and Institutional	11.7	12.9	14.2	15.4	16.7
Wholesale Trade	0.7	0.8	0.8	0.9	1.0
Retail Trade	1.9	2.1	2.3	2.5	2.8
Transportation and Warehousing	0.4	0.5	0.5	0.6	0.6
Information and Cultural Industries	0.2	0.2	0.3	0.3	0.3
Offices	3.8	4.2	4.6	5.0	5.5
Educational Services	1.6	1.7	1.9	2.1	2.3
Health Care and Social Assistance	1.5	1.6	1.8	1.9	2.1
Arts and Entertainment and Recreation	0.2	0.2	0.2	0.3	0.3
Accommodation and Food Services	0.8	0.9	1.0	1.1	1.2
Other Services	0.3	0.4	0.4	0.4	0.5
Street Lighting	0.2	0.3	0.3	0.3	0.3
Non Energy Use	0.0	0.0	0.0	0.0	0.0
Industrial	2.0	2.1	2.4	2.5	2.7
Construction	0.0	0.0	0.0	0.0	0.0
Pulp and Paper	0.4	0.4	0.5	0.5	0.5
Smelting and Refining	0.0	0.0	0.0	0.0	0.0
Chemicals	0.0	0.0	0.0	0.0	0.0
Other Manufacturing	0.2	0.2	0.3	0.3	0.3
Forestry	0.0	0.0	0.0	0.0	0.0
Mining and Upstream Oil and Gas	1.1	1.3	1.4	1.5	1.6
Other Non-Energy Use	0.1	0.1	0.1	0.1	0.1
Producer Consumption	0.0	0.0	0.0	0.0	0.0
Cement	0.0	0.0	0.0	0.0	0.0
Transportation	10.6	11.6	11.9	12.0	12.0

Branches	2010	2020	2030	2040	2050
Road	8.6	9.5	9.6	9.8	9.9
Air	0.3	0.3	0.3	0.3	0.3
Marine	1.3	1.4	1.5	1.5	1.4
OFF Road	0.4	0.4	0.5	0.5	0.4
Agriculture	0.7	0.6	0.7	0.8	0.8
Electricity	0.1	0.1	0.1	0.1	0.1
Gasoline	0.1	0.1	0.1	0.1	0.1
Diesel	0.3	0.3	0.3	0.3	0.4
Light Fuel oil	0.1	0.1	0.1	0.1	0.1
Heavy fuel oil	0.1	0.1	0.1	0.1	0.1
Propane	0.0	0.0	0.0	0.0	0.0
Total	32.2	34.8	37.1	38.3	39.7

Table A- 23: Prince Edward Island's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	1.6	1.7	1.8	1.8	1.9
Residential	0.4	0.4	0.4	0.4	0.4
Commercial and Institutional	0.4	0.4	0.5	0.5	0.5
Industrial	0.1	0.1	0.1	0.1	0.1
Transportation	0.7	0.8	0.8	0.8	0.8
Agriculture	0.0	0.0	0.0	0.0	0.1
Transformation	0.2	0.0	0.0	0.0	0.0
Electricity Generation	0.2	0.0	0.0	0.0	0.0
Non Energy	0.5	0.5	0.5	0.4	0.4
Agriculture	0.3	0.4	0.3	0.3	0.3
Waste	0.1	0.1	0.1	0.1	0.1
Total	2.2	2.2	2.3	2.3	2.3

Table A- 24: Nunavut's 2010-2050 energy demand results (TJ)

Branches	2010	2020	2030	2040	2050
Residential	1.0	1.1	1.2	1.3	1.3
Single Detached	0.6	0.7	0.8	0.8	0.9
Single Attached	0.1	0.2	0.2	0.2	0.2
Apartment	0.1	0.1	0.1	0.1	0.1
Mobile Homes	0.1	0.1	0.1	0.1	0.1
Commercial and Institutional	0.4	0.3	0.3	0.3	0.3
Aggregated Fuel Use	0.4	0.3	0.3	0.3	0.3
Industrial	1.6	2.5	3.2	3.3	3.5
Aggregated Fuel Use	1.6	2.5	3.1	3.3	3.5
Transportation	1.5	1.7	1.7	1.8	1.9
Aggregated Fuel Use	1.5	1.7	1.7	1.8	1.9
Total	4.4	5.6	6.4	6.7	7.1

Table A- 25: Nunavut's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	0.2	0.3	0.4	0.4	0.4
Residential	0.0	0.0	0.0	0.1	0.1
Commercial and Institutional	0.0	0.0	0.0	0.0	0.0
Industrial	0.1	0.2	0.2	0.2	0.2
Transportation	0.1	0.1	0.1	0.1	0.1
Agriculture	0.0	0.0	0.0	0.0	0.0
Transformation	0.1	0.1	0.1	0.1	0.1
Electricity Generation	0.1	0.1	0.1	0.1	0.1
Non Energy	0.0	0.0	0.0	0.0	0.0
Agriculture	0.0	0.0	0.0	0.0	0.0
Waste	0.0	0.0	0.0	0.0	0.0
Non Energy Products	0.0	0.0	0.0	0.0	0.0
Total	0.3	0.4	0.5	0.5	0.5

Table A- 26: Northwest Territories' 2010-2050 energy demand results (TJ)

Branches	2010	2020	2030	2040	2050
Residential	1.2	1.2	1.2	1.2	1.3
Single Detached	0.8	0.8	0.8	0.8	0.8
Single Attached	0.2	0.2	0.2	0.2	0.2
Apartment	0.1	0.1	0.1	0.1	0.1
Mobile Homes	0.1	0.1	0.1	0.1	0.1
Commercial and Institutional	2.5	3.2	3.2	3.2	3.3
Aggregated Fuel Use	2.5	3.2	3.2	3.2	3.3
Industrial	10.5	9.6	8.0	7.6	7.2
Aggregated Fuel Use	9.1	8.3	6.9	6.4	5.9
Producer Consumption	1.4	1.4	1.1	1.1	1.2
Transportation	2.7	2.6	2.5	2.4	2.4
Aggregated Fuel Use	2.7	2.6	2.5	2.4	2.4
Total	16.9	16.6	14.9	14.5	14.1

Table A- 27: Northwest Territories' 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	0.9	0.8	0.7	0.7	0.6
Residential	0.0	0.0	0.0	0.1	0.1
Commercial and Institutional	0.1	0.1	0.1	0.1	0.1
Industrial	0.6	0.5	0.4	0.4	0.3
Transportation	0.2	0.2	0.2	0.2	0.2
Agriculture	0.0	0.0	0.0	0.0	0.0
Transformation	0.4	0.3	0.2	0.2	0.2
Electricity Generation	0.2	0.2	0.1	0.1	0.1
Conventional Crude Oil Extraction	0.2	0.1	0.1	0.1	0.0
Natural Gas Extraction and Processing	0.0	0.0	0.0	0.0	0.0
Non Energy	0.0	0.0	0.0	0.0	0.0
Agriculture	0.0	0.0	0.0	0.0	0.0

Branches	2010	2020	2030	2040	2050
Waste	0.0	0.0	0.0	0.0	0.0
Non Energy Products	0.0	0.0	0.0	0.0	0.0
Total	1.2	1.1	0.9	0.9	0.8

Table A- 28: Yukon's 2010-2050 energy demand results (TJ)

Branches	2010	2020	2030	2040	2050
Residential	1.0	1.0	1.0	1.0	1.0
Single Detached	0.6	0.7	0.7	0.7	0.7
Single Attached	0.1	0.2	0.1	0.1	0.1
Apartment	0.1	0.1	0.1	0.1	0.1
Mobile Homes	0.1	0.1	0.1	0.1	0.1
Commercial and Institutional	1.3	1.5	1.5	1.5	1.5
Aggregated Fuel Use	1.3	1.5	1.5	1.5	1.5
Industrial	1.4	3.9	1.5	1.1	0.6
Aggregated Fuel Use	1.0	3.8	1.5	1.0	0.5
Producer Consumption	0.4	0.1	0.1	0.1	0.1
Transportation	1.4	1.7	1.2	1.1	1.0
Aggregated Fuel Use	1.4	1.7	1.2	1.1	1.0
Total	5.1	8.1	5.2	4.7	4.0

Table A- 29: Yukon's 2010-2050 GHG emission results (MT CO_2e)

Branches	2010	2020	2030	2040	2050
Demand	0.2	0.4	0.2	0.2	0.1
Residential	0.0	0.0	0.0	0.0	0.0
Commercial and Institutional	0.0	0.0	0.0	0.0	0.0
Industrial	0.1	0.2	0.1	0.1	0.0
Transportation	0.1	0.1	0.1	0.1	0.1
Agriculture	0.0	0.0	0.0	0.0	0.0

Branches	2010	2020	2030	2040	2050
Transformation	0.0	0.1	0.0	0.0	0.0
Electricity Generation	0.0	0.1	0.0	0.0	0.0
Natural Gas Extraction and Processing	0.0	0.0	0.0	0.0	0.0
Non Energy	0.0	0.0	0.0	0.0	0.0
Agriculture	0.0	0.0	0.0	0.0	0.0
Waste	0.0	0.0	0.0	0.0	0.0
Non Energy Products	0.0	0.0	0.0	0.0	0.0
Total	0.2	0.4	0.2	0.2	0.1