Development of Integrated Model for Assessment of Water and GHG Footprints for Power Generation Sector

by

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Abstract

Freshwater is a critical natural resource and is used in energy production, conversion and utilization. To ensure that the use of water today does not adversely affect the prospects for its use by future generations, there is a need to understand long term water demand and supply through energy production, conversion and utilization. This research presents the methodology for development of integrated water energy model for Alberta's power sector and simulates business-as-usual and alternative scenarios. This model also estimates long term impacts of alternative policies in Alberta's power sector on water demand and greenhouse gas (GHG) emissions. A bottom up demand tree for Alberta's power sector is developed using the Water Evaluation And Planning (WEAP) model for estimation of water demand and supply. Similarly, the demand tree is developed in the long-range energy alternative planning systems model (LEAP) model to understand GHG emissions footprint of the electricity generation in power sector under different technology implementation scenarios. This demand tree is further used to develop a scenario analysis. Based on expected growth in the power sector, a business-as-usual (BAU) scenario is developed for the years 2015 – 2050 to project water demand and GHG emissions of Alberta's power plants. Nine GHG mitigation scenarios and four water conservation scenarios are developed for Alberta's power sector, and water and emissions reductions are estimated with respect to the BAU scenario. The scenarios are also analyzed in terms of the cost-benefit aspects by developing two types of cost curves, i.e. water-carbon cost curves and water conservation cost curves. The water-carbon cost curves compare the scenarios in terms of net GHG mitigation achievable in each scenario, GHG abatement cost ($/tonne of CO_2 equivalent mitigation) and water demand compared to the BAU case. The water conservation cost curves compare the scenarios in terms of net water

savings achievable in each scenario and water savings cost ($\$/m^3$ of water saved) compared to BAU scenario.

In Alberta's power sector, for BAU scenario, GHG emissions and water demand decrease by around 44% and 34%, respectively, in 2030 due to the retirement of all the coal power plants by 2030. The overall increase in GHG emissions and water demand from 2030 to 2050 is 16% and 19.5%, respectively. Nine GHG mitigation scenarios were evaluated with the aim of mitigating carbon emissions and four scenarios were evaluated with the aim of reducing water demand. These scenarios were developed for planning horizons of 2010-2030 and 2010-2050. From the results of the integrated GHG mitigation scenarios, it can be deduced that for power sector, although the implementation of climate change scenarios will result in reduced GHG emissions but will increase the water demand. Out of all the technologies, in the long run, dry cooling technology will save the most water (15.6 million m^3 by 2030 for a cost of $\$7.8/m^3$ and 157.8 million m^3 by 2050 for a cost of around $\$4/m^3$). These different scenario outcomes can help to create awareness among the policy makers in understanding the water-energy nexus in a quantifiable way and to formulate policies towards sustainable development.

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List of abbreviations

AEP – Alberta Environment & Parks

AESO – Alberta Electric System Operator

AIL – Alberta Internal Load

AUC – Alberta Utilities Commission

AWRA - American Water Resources Association

BAU – Business-as-usual

BCM – Billion cubic meters

BTF – Behind-the-fence

CANSIM – Canadian Socio-Economic Information Management System

CAPP – Canadian Association of Petroleum Producers

CEP – Conservation, Efficiency, and Productivity

CLP – Climate Leadership Plan

CLRM – Climate Leadership Report to Minister

CO_x – Carbon Oxides

ECCC – Environment and Climate Change Canada

FGD – Flue Gas Desulphurization

GCAM – Global Change Assessment Model

GDP – Gross Domestic Product

GHG – Greenhouse Gases

GIS – Geographic Information System

GWh – Gigawatt Hour

HDI – Human Development Index

HRSG – Heat Recovery Steam Generator

IPCC – Intergovernmental Panel on Climate Change

LEAP – Long-range Energy Alternatives Planning system

MWh – Megawatt Hour

MWWS – Municipal Water and Wastewater Survey

NEB – National Energy Board

NGCC – Natural gas combined cycle

NGL – Natural Gas Liquids

NO_x – Nitrous Oxides

NPV – Net Present Value

NRCan – Natural Resources Canada

REP – Renewable Electricity Program

SO_x – Sulphur Oxides

TED – Technology & Environment Database

UNDP – United Nations Development Program

UNICEF – United Nations Children's Emergency Fund

US DOE – United States Department of Energy

USGS – United States Geographical Survey

WEAP – Water Evaluation And Planning

WHO – World Health Organization

Chapter 1: Introduction

1.1. Background

Water resource management is vital and includes protecting water bodies from pollution and exploitation. Water availability, quality and management are identified as three major challenges that must be addressed for a sustainable development [1]. Water resource management efforts are directed at optimizing the use of water among competing water demand sectors and in minimizing the environmental impact of water use. Water is one of the most critical resources driving the global economy. Although water covers nearly 70% of the earth, a mere 2.5% of it is freshwater. Of this 2.5%, more than 1.5% is locked up in ice caps, glaciers, or deep underground and the remaining 1% is accessible through surface sources and aquifers [2]. Competition for a clean, sufficient supply of water is growing yearly because the volume of freshwater has not changed but the population and economy has grown exponentially. The water supply worldwide is challenged by problems like deforestation, limits to water supply, and pollution. Protected forest areas provide a significant portion of drinking water to more than a third of the world's largest cities [3].

By 2030, globally there will be 40% shortfall between forecast demand and available supply of water [4]. According to a joint report by World Health Organization (WHO) and United Nations Children's Emergency Fund (UNICEF), global demand for water already exceeds supply -- about 1.1 billion people don't have access to clean water -- and the so-called water gap is increasing at an accelerating rate [5]. In many parts of the world like California and Venezuela, water demand already exceeds supply, and many more areas are expected to experience this imbalance in the near future [6]. In California, water has become the input constraining all agricultural output as it is suffering from several years of drought thereby, increasing the food prices across the state [7].

A nationwide water shortage is damaging Venezuela, leaving faucets dry and contributing to blackouts [8]. Due to exponential growth of world population from 4 billion in 1970 to over 7 billion by 2011, there is a growing competition for water, resulting in depletion of many of the world's major aquifers [9, 10]. According to World Bank report, a projected increase in population to 9 billion people by 2050 will require an increase of 60% in agricultural production which translates to 15% increase in water withdrawals [11]. These numbers show that the combined effects of growing populations, rising incomes and expanding cities will see demand for water rising exponentially while supply becomes more erratic and uncertain. Nearly 90% of the consumption of the world's freshwater supply is used for producing food and energy [12, 13]. When discussing water use and sectoral demand, it is important to distinguish between water withdrawal and water consumption. Water withdrawal (or water demand) represents the total water taken from a source, while water consumption represents the total amount withdrawal that is not returned to the source [14-16].

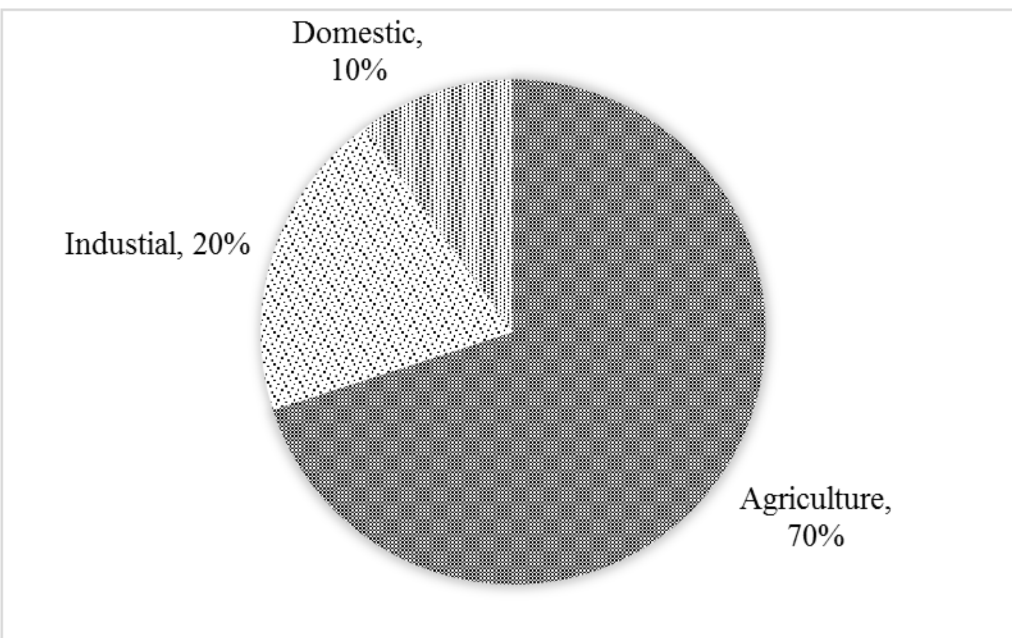

Figure 1: Sector-wise global water consumption *[12, 13]*

The agriculture sector, worldwide, accounts for 70% of all freshwater consumption, compared to 20% for industry and 10% for domestic use or direct human consumption as shown in figure 1 [17, 18]. However, in industrialized nations, more than half of the water (59%) available for human use is consumed by industries [17, 18]. Freshwater withdrawals have tripled over the last 50 years and the demand is increasing at a rate of roughly 64 billion cubic meters (BCM) a year [19]. It is expected to increase further due to growing world population, changes in lifestyle & eating habits[1] and accelerating energy demand impacting energy sector's reliability and costs. Canada is commonly perceived as a fortunate state for its abundant freshwater resources as it has one-fifth of the world's freshwater [20, 21]. The next section of the thesis discusses the state of water resources in Canada and its issues.

1.1.1. Canadian water resources overview

Canada's surface water sources are estimated to be about 7% of the world's renewable water supply [20, 21]. It is counted among the world's highest per capita users of water [21]. In 2013, approximately 38 billion cubic meters of water were withdrawn from Canada's surface (rivers and lakes) and groundwater sources [22]. Of the 38 billion cubic meters, thermal power generation was responsible for a significant share (67.6%), followed by the manufacturing (10.45%), residential (8.54%), agriculture (5.29%), and other sectors as shown in Figure 2 [23].

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[1] Requiring more water consumption per capita

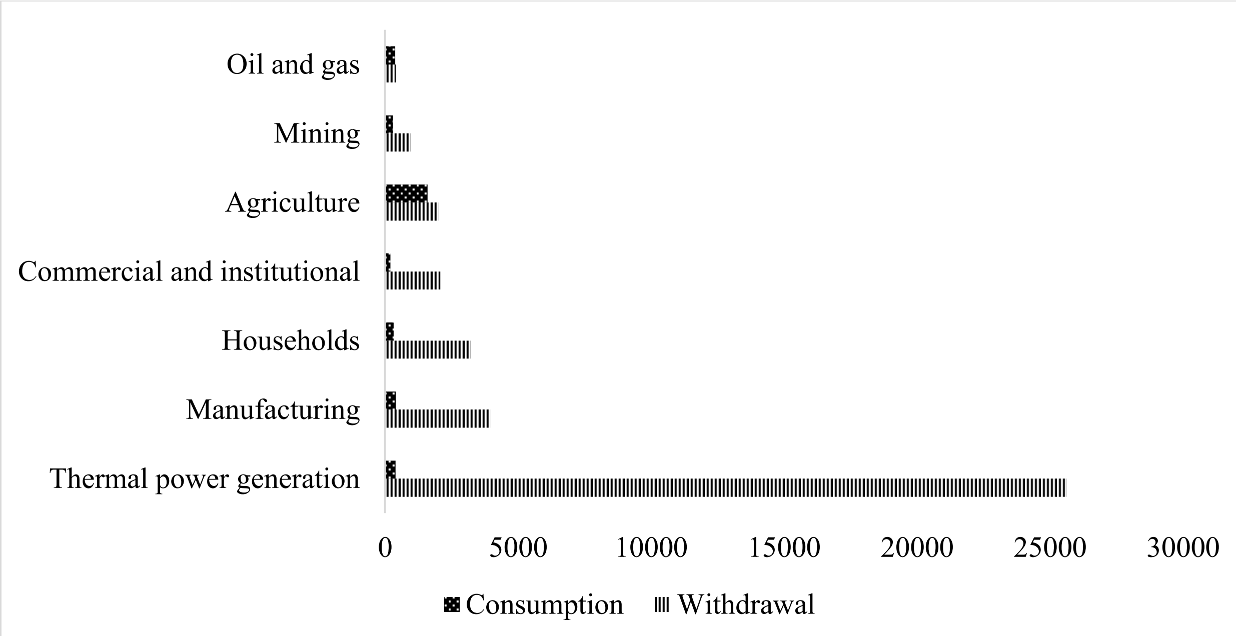


Figure 2: Sector-wise water withdrawal and consumption for Canada for 2013 (in million m^3) *[23]*

Despite being the largest user, thermal power generation and manufacturing sectors consume very little water with approximately 90% returned to the water source. The agriculture sector consumes approximately 84% (2 BCM) of the water it withdraws, and is the sector with the largest overall water consumption [23].

Although Canada is water-rich, demand for water is not uniformly distributed. There is a growing mismatch between sources of freshwater and areas of high demand, as Canada has a southern based population and a northern supply (84% of Canada's population resides within 300 kilometers of the southern border while about 60% of Canada's freshwater flows north) [21]. Because of climate change, water shortages may increase in frequency, duration, and severity in all regions of the country. Barnett et al., in a paper [24] on the impact of climate change and global warming on water availability, stated that earlier snow melt results in longer periods of low water flow during summer and will eventually lead to increased frequency and severity of droughts on the Canadian prairies [24]. A warming climate will have greater tendency to hold water in the atmosphere resulting in reduced surface water [25]. Urban expansion directly affects water availability for other sectors as municipal and commercial requirements exert heavy demand on freshwater [21]. The southern part of the Prairie region (Alberta, Saskatchewan and Manitoba) is historically known for dry and arid area where precipitation is low [26]. In this region of the country, the agricultural and thermoelectric power sectors are large users of surface water. Because of increased urbanization, Alberta Environment no longer accepts water allocation requests for the South Saskatchewan River Basin [27]. Canadian freshwater sources have been under pressure for many reasons, including population growth, pollution, growing industrial activity, rising food production, and climate change. Alberta is the fourth largest province. In Canada, in 2014, Alberta is the 2nd highest contributor to the national Gross Domestic Product (GDP) with a share of 19.04% ($375,756 million CAD) due to large oil and gas industry making it one of the most influential province in Canada [28]. Next section of the thesis presents a snapshot of water use in Alberta. A detailed review of Alberta's water resources has been discussed by Dar et. al. and AMEC Earth & Environmental Limited [29-31].

1.1.2. Water use in Alberta

In Alberta, energy (power and petroleum) sector is one of the key driver for provincial economy, accounting for about one-third of its GDP in 2012 [32]. The rapid economic growth requires better management of the province's resources to meet future needs. In Alberta, around 97% of water allocations are from surface water and the remaining 3% are from ground water sources. Interestingly, North and South Saskatchewan rivers, although has only 13% of the province's water, it fulfils 88% of the Alberta's water demand [21]. Figure 3 shows sector-wise Alberta's water withdrawal and consumption which depicts highest water withdrawal for thermal power generation sector whereas highest water consumption for agriculture sector [23, 33-37].

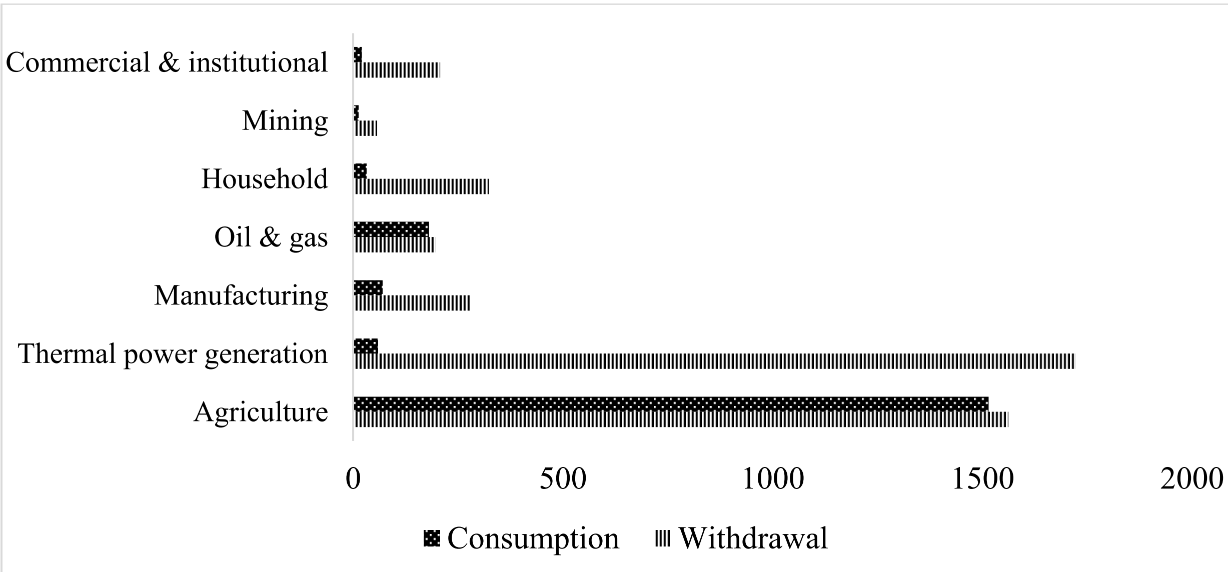


Figure 3: Sector-wise water withdrawal and consumption for Alberta for 2013 (in million m^3) *[23, 33-37]*

Following the Paris climate change conference, one of the major outcomes is mitigating Greenhouse gases (GHG) emissions [38]. In electricity generation sector, coal generation pathway is the main source of carbon emissions. Alberta is responsible for 65% of Canada's coal-fired electricity generation [39]. So, the success of Canada's move away from coal will be judged by Alberta's transition from coal to renewables. Also, Alberta has been the highest GHG emitter in the country since 2005 with 273 million tons of carbon emissions (out of 732 million tons) in 2014 [40]. In November 2015, Government of Alberta announced Climate Leadership Plan (CLP) which outlines the province's proposal to curb its emissions [41]. One of the key strategies outlined in the report is to end coal pollution by phasing out province's coal-fired power plants by 2030. Hence, Alberta's electricity generation sector is currently at an inflection point and a successful transition to cleaner sources of energy will set a guideline to upcoming states and countries for their transition. In Alberta, with the expected shift towards greener electricity grid (as highlighted in the Government of Alberta Climate Leadership Plan), it is critical to understand the impact of climate change mitigation efforts on water demand. Water use and consumption for the electricity generation sector will be highly influenced by proposed air emissions regulations and technology advancement to improve water intensity in power sector [42].

In 2016, American Water Resources Association (AWRA) conducted a survey on "Top 10 Water Issues for America's Leaders", in which aging infrastructure, climate change, water and energy nexus, flood and drought, and governance were derived to be the top 5 issues [43]. Given the importance of water as a criterion for assessing the physical, economic and environmental viability of power projects and water-energy nexus for sustainable climate and water resources planning, lately, there has been a lot of focus on reduction of water consumption in power plants [14, 44, 45].

1.1.3. Water energy nexus

Over the last two centuries water management connection with energy has been deepened due to development of complex and energy intensive societies. Energy and water are valuable resources that support human prosperity and are interdependent (for power generation, extraction, transport and processing of fossil fuels) [46, 47]. Water and energy have symbiotic relationship. Energy is needed for wastewater treatment, drinking water treatment, transmission and distribution of water and water is needed for fuel production like ethanol, hydrogen, extraction and refining, thermoelectric cooling, hydropower production etc.

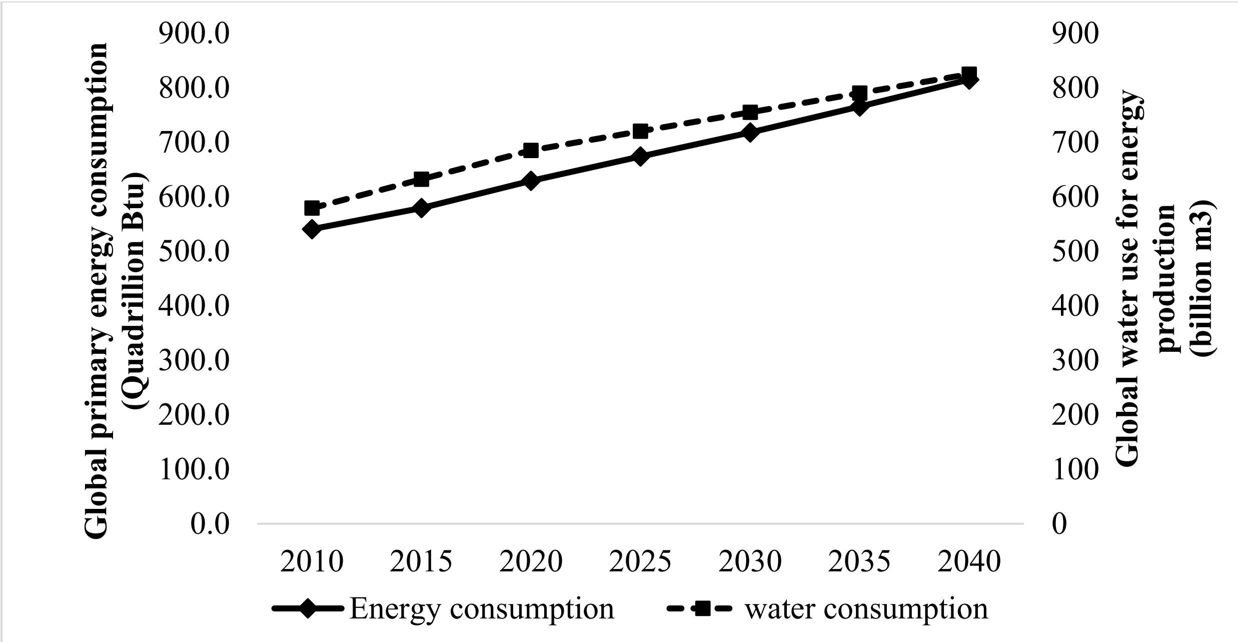


Figure 4: Global energy production and water consumption projection (2010 – 2040) *[13, 48]*

Figure 4 shows projection for global primary energy consumption and global water use for energy production which shows a 48% increase in energy consumption from 2012 to 2040 which translates to a 42% increase in water consumption [13, 48]. Key drivers behind this increase in energy use and water consumption are population growth and increase in income per person. A chart developed by United Nations Development Program (UNDP) shows a direct correlation between electricity use per capita and quality of life, i.e., human development index (HDI) [49]. So, as we are aiming to improve our quality of life globally, we will be increasing our energy use. Currently we rely primarily on fossil fuels which is increasing the threats of climate change. So, one of our biggest challenges is to maintain an improving quality of life while decreasing the emissions from fossil fuels (mitigating climate change). Some options to mitigate climate change are to decrease our energy use by consuming less energy or using energy efficient equipment or increasing our clean energy supply with renewables [50-53].

Water withdrawals for energy production globally in 2010 were estimated at 583 billion cubic meters (BCM) (15% of world's total water withdrawals) [13]. Of this withdrawal, 66 billion cubic meters is the water consumption – volume withdrawn but not returned to its source [13]. In United States in 2010, as estimated by United States Geographical Survey (USGS), about 41% of nation's available water was withdrawn by thermoelectric power plants [54]. In the energy sector, water requirement for fossil fuel-based and nuclear power plants are the largest. Condenser cooling represents the largest and most critical use of water at wet cooling based fossil fuel power plants (except simple cycle) accounting for approximately 95% of a plant's water consumption [55]. Smaller amounts of water are used consumptively for boiler feed, scrubbers for air emission and general plant water use (e.g. sanitary and cleaning) [55].

Further, under climate change mitigation, role of electricity generation mix is becoming more prominent, resulting in increased water demand for power plant cooling purposes [56]. This study focuses on water use for energy production primarily in electricity generation sector. A combination of technologies such as nuclear, fossils or biomass with carbon capture and storage and renewable sources characterized by diverse water requirements are the means for achieving decarbonization of electricity systems thus impacting the water resources [57-59].

1.1.4. Electricity generation sector in Alberta

Alberta as of December 2015 had 16,261 MW of installed generation capacity which produced 81,621 GWh of electricity and the demand is increasing at twice the rate as the rest of Canada [60, 61]. Recently, Alberta government launched Renewable Electricity Program (REP) to increase the use of renewables to generate electricity. This program aims to add 5,000 MW of renewable electricity capacity by 2030. This section presents the different types of power plants in electricity generation mix of Alberta including the water consumption processes, and water intensities for these different types of plants.

1.1.4.1. Coal based power plants

Globally, Coal plays a vital role in electricity generation. In coal-fired plants, water is turned into steam inside boiler using coal as heating agent, steam in turn drives turbine generators to produce electricity [62]. Coal fired-power plants currently fuels 41% of global electricity because of its inexpensive and plentiful availability of resource [63]. In Alberta, coal powered about 50.9% of total electricity generated in 2015 [60]. Coal power plants are used as base load in Alberta's generation because they are slow to start or to change output while operating [62].

In a conventional coal-fired power plant, cooling water for condensing exhaust steam from steam turbines is the largest use of water [13, 44, 54, 62]. A number of alternative cooling system exist and have been used [14]. Alberta uses only two types of cooling: once through and recirculating type [62]. Plants also use water for operation of flue gas desulfurization (FGD) devices, ash handling and wash water [62]. Figure 5 shows typical share of water use in a conventional coal power plant.

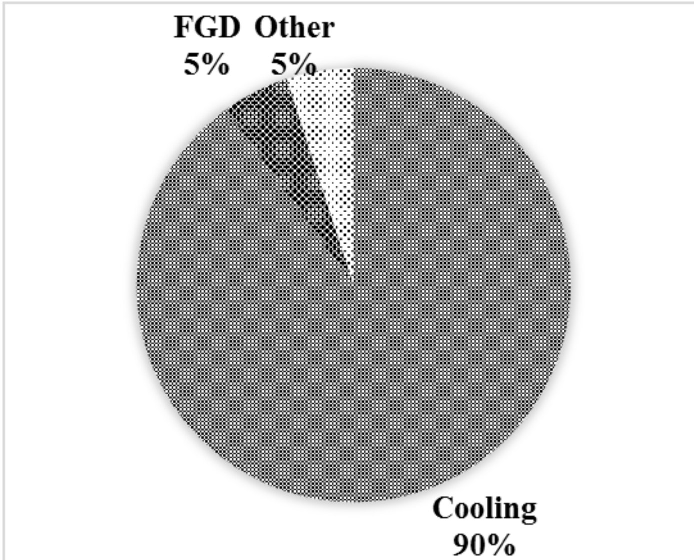


Figure 5: Share of water use in a conventional fossil fuel based power plant

For plants with wet cooling systems, the cooling tower make-up represents approximately 90 - 95% of the total power plant water requirements [55]. A large portion of this water is returned to the source. Smaller amounts of water are used consumptively for boiler feed and other process uses. At some plants, some water is consumed by scrubbers for air emissions (e.g. NOx, SOx control) to meet air quality requirements [55, 62]. Babkir and Kumar developed benchmark for water demand coefficients for coal based electricity generation [15]. Table 1 presents typical water withdrawal and consumption for coal power plant for wet cooling technology which are used in this study.

Table 1: Water demand coefficients for coal based power plants [15]

Water use parameter (water withdrawal)		
	m^3/MWh	Consumption %
Coal subcritical	2.33	84
Coal supercritical	2.19	74

1.1.4.2. Natural gas power plants

In Alberta, there are 3 types of natural gas power plants which are simple cycle, combined cycle and cogeneration [64]. In Alberta as presented in Figure 6, in 2015, 39.23% of electricity is generated by natural gas power plants (Simple Cycle: 0.79%, Combined Cycle: 7.53%, Cogeneration: 30.91%) [60]. A simple cycle power plant uses only combustion turbines and do not utilize heat recovery resulting in lower thermal efficiency [65]. In combined cycle power plant, a natural gas-fired combustion turbine and a steam turbine are used in combination to achieve greater efficiency [65]. Cogeneration power plants produce power and thermal energy simultaneously for the onsite industrial processes [65]. In Alberta, cogeneration plants are base loaded and are predominantly used in oil sands industry [62]. Simple cycle gas turbines have a short start-up time and this ability to ramp up and down rapidly makes them well suited for peaking load [62]. Combined cycle are well suited for an intermediate role between base load and peaking generation [62].

In terms of water use, combustion turbines do not require any cooling water. Simple cycle plants only use combustion turbines which greatly reduces the amount of water consumption required for operation. Therefore, water is used for basic plant operations (e.g. water used for equipment cleaning, drinking, sanitary uses) and control of air emissions (e.g. NOx, SOx control) to meet air quality requirements [55, 62]. Water consumption for combined cycle plants consists of cooling system make-up water, auxiliary cooling, turbine inlet cooling, Heat Recovery Steam Generator (HRSG) make-up water, environmental controls (such as NOx) and general plant water use (e.g. sanitary and cleaning) with largest use of water at cooling tower. Water use and consumption at cogeneration plants are similar to those in combined cycle power plants. Figure 5 shows a typical breakdown of water use at a wet cooling based conventional fossil fuel power plant (except simple cycle). Babkir and Kumar developed benchmark for water demand coefficients for natural gas based electricity generation pathways [16]. Table 2 presents typical water withdrawal and consumption for natural gas power plant categorized based on its cooling system type which are used in this study.

Table 2: Water demand coefficients for natural gas power plants with different cooling technologies [16]

Water use parameter (water withdrawal)		
	m^3/MWh	Consumption %
Natural gas simple cycle	0.38	80
Natural gas Combined cycle + cooling tower	0.96	75
Natural gas Combined cycle + Dry cooling	0.32	75
Natural gas cogeneration + cooling tower	0.69	65
Natural gas cogeneration + Dry cooling	0.25	65

1.1.4.3. Hydropower plants

In a hydropower plant, water is typically diverted from rivers into a reservoir through a penstock (i.e. pipe to the turbines) where it is directed through turbines to produce electricity and then returned to the environment downstream of the power house [66]. Hydropower energy is a renewable source which has no direct consumption of water. Significant amount of water, however, is lost at conventional hydropower facilities due to evaporation from the reservoir [67]. Currently, Alberta has a total installed hydroelectric generation capacity of 894 MW, or about 5.45% of the installed capacity in the province [60]. Most of the conventional hydropower plants (13 individual plants) are installed in the Bow and North Saskatchewan river basins [62]. The remaining hydro capacity is located at several separate plants ranging in size from small run of-river micro hydro projects (less than 1 MW) to larger hydroelectric projects such as the 32 MW Oldman River project [62]. Water demand coefficient for hydropower generation of 13.12 m^3/MWh was estimated based on average annual water consumption 30 million m^3 assumed for

Alberta and divided by actual hydropower generation based on AESO's current Supply Demand Report [62, 64].

1.1.4.4. Biomass power plants

Biomass fueled power plants are similar in design to conventional coal fired power plants where the difference is of fuel type, here biomass fuel is used as energy source [68]. Wood waste from pulp and saw mills is the primary fuel for biomass generation plants in Alberta. Landfill gas and a small amount of agricultural waste are also used for fuel. Alberta currently has biomass power facilities with a total capacity of about 424 MW and an additional 100 MW of other type of generation (Oil, diesel, Waste heat) [60]. Condensing exhaust steam from steam turbines is the largest use of water at biomass plants [62]. Water withdrawal coefficient for biomass generation of 2.53 m^3/MWh was used in this study [69].

1.1.4.5. Wind power plants

In wind power plants, power is generated by harnessing energy from wind using wind turbines. Wind power is an intermittent source of energy and the amount of power generated by wind turbines is highly dependent on the wind speed. A wind turbine is placed on top of a high tower and when the wind blows it spins a generator, creating electricity [62]. In Alberta, wind power has seen substantial growth in last few years. As of 2016, Alberta had 1,445 MW of transmission-connected wind power [64]. It is assumed that wind power generation does not consume water.

Based on Statistics Canada CANSIM Table*,* it is assumed that all the power plants in Alberta use freshwater either from river or water treatment plants [70]. The process variation in similar type of plants is not expected to be significant to have a major impact on final water demand. Table 3 summarizes the water use processes for different types of power plants in Alberta, respectively.

Table 3: Water consumption processes by generation type *[62]*

Water use process	Coal	Natural Gas			Hydro	Biomass	Nuclear	Wind	Solar
		Simple Cycle	Combined Cycle	Co-gen					
Boiler/makeup water	•		•	•		•	•		
Cooling water	•		•	•		•	•		
Pollution control/Ash handling	•	•	•	•		•			
General service water	•	•	•	•		•	•		
Potable water use	•	•	•	•	•	•	•		
Reservoir Evaporation					•				

1.2. Research Rationale

As discussed in the introduction section, a major challenge that Canada faces is effective water management [71]. It is essential to plan carefully, and to do this we need to understand freshwater intake and consumption. First section of this study attempts to identify water use by different demand sectors with the help of Sankey diagrams. These diagrams visually present water use patterns by sector for six Canadian provinces (Ontario, Quebec, Alberta, British Columbia, Saskatchewan, and Manitoba). These provinces are responsible for 90% of the water intake in Canada.

There are several different process visualization tools used and described in literature. ESSA Technologies, a Vancouver-based company, developed a water supply and demand viewer to illustrate current and future conditions of water use, availability, flow needs, and water licenses [72]. Best and Lewis developed a groundwater visualization tool that "bridges the gap between static and research based visualizations by providing an intuitive, interactive design that allows participants to view the model from different perspectives, infer information about simulations" [73]. Subramanyam et. al. used Sankey diagrams to analyze energy consumption for the five main energy demand sectors and map energy flow from primary fuel to end use for Alberta [74]. A Sankey diagram is a useful tool not only to analyze water use patterns but also to identify high water consuming sectors and areas in which policies can be implemented to improve water use efficiency.

For water systems, visualization tools have been predominantly used to study global water use to identify ways to reduce water consumption. Researchers at the Lawrence Livermore National Laboratory developed state-wise Sankey diagrams for freshwater withdrawals in U.S. that illustrated the breakdown of water consumption by sector for the years 1995, 2000 and 2005 [75]. In 2014, the U.S. Department of Energy (US DOE) published a report on the water-energy nexus and its challenges and opportunities which depicts interlink between energy generation and water consumption. [76]. These studies show the water footprint in different industries through Sankey diagrams. Fei-Ling Tseng conducted similar work that shows the distribution of the Colorado River water [77]. Curmi et al. conducted a stochastic analysis to assess the future supply of and demand for water resources in California and presented the results in Sankey diagrams [78].

Various government organizations have studies on water use for Canada. A recent study by Environment and Climate Change Canada (ECCC) presents detailed statistics on sector-wise water intake and consumption for Canada [23]. Yet water governance and policy formulation are regional; provincial governments own water resources and are responsible for the day-to-day management of the resources [79]. Hence it is important to understand province-wise water consumption for water demand sectors. There has been little research published on the water footprint of demand sectors by province for Canada.

Further, to make well informed long-term decisions, policy makers and resource managers need to fully understand the interconnections between energy production and water use, or water-energy nexus [80]. Planning and assessment issues require strategies to minimize the vulnerabilities around water and energy while mitigating the corresponding GHG emissions. Some studies on water energy nexus have been conducted in the past and a summary of literature review focused on water use and electricity production is described below.

Some of the papers discuss the impact of climate change mitigation scenarios on water demand or on energy sector indirectly affecting water demand. Climate change can impact energy sector (both demand and supply) in a number of ways such as changes in the efficiency of power plants, increased rainfall may enhance hydroelectricity output, but thermoelectric power may become vulnerable due to higher temperature and increases in peak demand due to higher cooling demand in hotter summers [81, 82]. Climate change mitigation scenarios include adoption of renewable technologies like wind, hydropower, solar, carbon capture & storage, reduction of fossil fuel based power plants etc. Mouratiadou et al. [83] present an integrated assessment model of water-energy-land-climate to assess the changes in electricity and land use, induced by climate change mitigation, impact on water demand under alternative socioeconomic and water policy assumptions. Nanduri and Otieno [84] propose a framework of a joint carbon and water cap-and-trade model to understand implications of electricity-water-climate change nexus and present a multi-agent reinforcement learning-based predictive model. Ciscar and Dowling [85] in 2014 presented a review on how integrated assessment models have estimated impacts of climate change and adaptation in the energy sector concluding that there is vast amount of work that needs to be done in order to understand the vulnerability of energy sector stating the fact that most important aspect is the adaptation options available in energy sector, their costs, effectiveness and potential.

Water-energy nexus for Middle East and North Africa region was reviewed by Siddiqui and Anadon [86] which highlighted a weak dependence of energy systems on freshwater, but a strong dependence of water extraction and production on energy. Most of the Arabian Gulf countries consume 5 to 12% of the total electricity consumed for water desalination. Based on these studies, it can be concluded that research focused on integrated GHG and water footprints for energy pathways are limited. A big challenge as discussed by Sovacool and Sovacool [87] is to improve quality of research related to electricity-water issues. This thesis attempts to address this gap by developing a framework to assess water use and GHG mitigated for various climate change scenarios.

Given the importance of water as a criterion for assessing the physical, economic and environmental viability of energy projects and water-energy nexus for sustainable climate and water resources planning, lately, there has been a lot of focus on reduction of water consumption in power plants [14, 44, 45]. Water efficient technologies can play a significant role in reducing the water consumption in the power sector.

Many of the studies examine integrating water resources and power generation and also evaluated the impact of shift in cooling technology and fossil fuel on water demand by power sector. Stillwell et al. [88] worked on the energy-water nexus and created a model to estimate the potential decrease in total water diversions in Texas river basins. This model simulated the implementation of three alternative cooling scenarios at thermoelectric power plants which showed that water diversion could be reduced by as much as 247 to 703 million m^3 annually [88]. Tidwell et al. [89] performed similar analysis for US freshwater resources discussing potential impacts of high penetration of natural gas and renewables along with cooling system options [89]. Bijl et al. [90] describe an end use-oriented model for future water demand in the electricity, industry and municipal sectors by developing 3 scenarios for 26 regions and the period 1971 – 2100. The authors conclude that thermal efficiency improvements in power plants could significantly reduce global electricity sector water withdrawal (54%) and consumption (63%), irrespective of any water efficiency improvements [90]. Kyle et al. [57] developed an integrated Global Change Assessment Model (GCAM) to analyze global water demand for electricity generation sector considering three climate change mitigation strategies and two technology strategies. Authors conclude that regardless of increase in electricity sector by five- to seven-fold, water withdrawals remain relatively stable due to retirement of water-intensive cooling technologies. DeNooyer et al. [47] worked on the energy-water nexus for the state of Illinois and concluded that shift in coal generated to natural gas generated electricity on average could decrease statewide water consumption by 0.10 billion m^3/year (32% decrease) and withdrawal by 7.9 billion m^3/year (37% decrease). They also performed an economic analysis of retrofitting open-loop cooling systems to closed-loop cooling, revealing an effective water price between \$0.03 and \$0.06/m^3 [47]. Tidwell et al [91] in its "Transitioning to zero freshwater withdrawal in the U.S. for thermoelectric generation" identified technical tradeoffs and initial cost estimates for retrofitting existing thermoelectric generation to achieve zero freshwater withdrawal. Results indicate that projected increase in levelized cost of electricity ranges from roughly \$0.20 to \$20/MWh with a median value of \$3.53/MWh [91]. On a similar theme, Maulbestch and DiFilippo [55] conducted a study to compare water requirements in combined cycle power plants and identified "effective cost[2]" of water ranges from \$3.40 to \$6.00 per 1000 gallons [55].

[2] Defined as the additional cost of using dry cooling expressed on an annualized basis divided by the annual reduction in water requirement achieved using dry cooling

While the previous studies discussed above provide useful information about the water requirements in power plants, little or no information was provided to inform electricity and water planners about more precise options which will be most effective and economic in terms of water and cost savings. The studies are also limited with respect to providing the full scope of applying these water conservation options such as actual potential and associated costs of new technologies implementation in a defined region. Currently economic assessment of comprehensive water efficient technologies for power generation sector does not exist for Alberta.

This current study attempts to address the issue of water and energy nexus by investigating the water savings potential in power generation sector by conducting a case study for a western Canadian province (i.e., Alberta) where currently about 51% of the power is generated by coal power plant. To address the gap, this work explains the methodology followed to develop an integrated water-energy system primarily for power generation sector. Also, as many countries are planning to move towards cleaner electricity grid to mitigate climate change, this work attempts to present the impact of various GHG mitigation scenarios on water use for the sector.

1.3. Objective of the research

The objective of this study is to develop an integrated water-energy model to quantify the impact of various climate change policies and water conservation options on water resources for Alberta. This will illuminate how exactly we are managing our water demand for power sector, and help show us where we need to focus our efforts to improve. From this, a scenario analysis was conducted to find impactful policy and technology alternatives to drive Alberta's level of sustainability forward without greatly sacrificing energy security or quality of life. These scenarios are also evaluated for economic suitability by developing a water-carbon cost curve for a comprehensive comparison of scenarios in terms of GHG abatement costs, GHG mitigation potential and water use. The goal is to better direct strategies for choosing the most effective water conservation pathways by assessing the different conservation options. The Long-range Energy Alternatives Planning system (LEAP) and Water Evaluation And Planning (WEAP) model has been used to evaluate these options. The LEAP and WEAP models have previously been used to study the integrated energy and water demand for Alberta's energy sector predominantly petroleum sector to demonstrate the capability the two models [29]. In this study, authors assessed the long-term impacts of various GHG mitigation scenarios which consider various renewable energy penetration in Alberta's electricity generation grid. This study takes a closer look at power generation sector of Alberta and assesses the impact of recent announcement of coal power phase out by 2030. The specific objectives of this study are as follows:

1. Identify the water-intensive sectors and quantify demand sector water intake and water consumption in the main water-using provinces of Canada
2. Develop a baseline energy supply and demand in the LEAP and water supply and demand scenario WEAP model for the Province of Alberta over a 35-year planning horizon
3. Identify GHG mitigation options and water conservation options in the electricity supply sectors of Alberta
4. Estimate the potential for GHG mitigation and water use in different scenarios over two planning horizons of 2030 and 2050.
5. Perform a cost-benefit analysis to evaluate various GHG mitigation and water conservation options.
6. Develop a cost curve to rank the identified pathways for the Province of Alberta.

1.4. Overall methodology

This section of the thesis summarizes the methodology used in this research. Water consumption and withdrawal for seven different demand sectors were estimated for six Canadian provinces. This estimation was based on the collected data on water intake and consumption for each demand sector and used it to develop Sankey diagrams. A detailed methodology for developing the Sankey diagrams is discussed in the Chapter 2 of the thesis. Further, to develop an integrated water-energy model for Alberta's power sector, data on electricity generated, water intensity, capacity factor, process efficiency and other key parameters for all the power plants in Alberta were collected and modelled in WEAP and LEAP software. A baseline scenario and alternative scenario were developed in the energy and water models and further long-term impacts of alternative scenario (GHG mitigation and water conservation options) were evaluated with respect to water demand and GHG emissions. Water consumption parameters for supply sources in Alberta were collected and modelled in WEAP. The detailed methodologies on development of integrated water-energy model are described in Chapter 3 and Chapter 4 of this thesis. A snapshot of overall methodology is presented in figure 6.

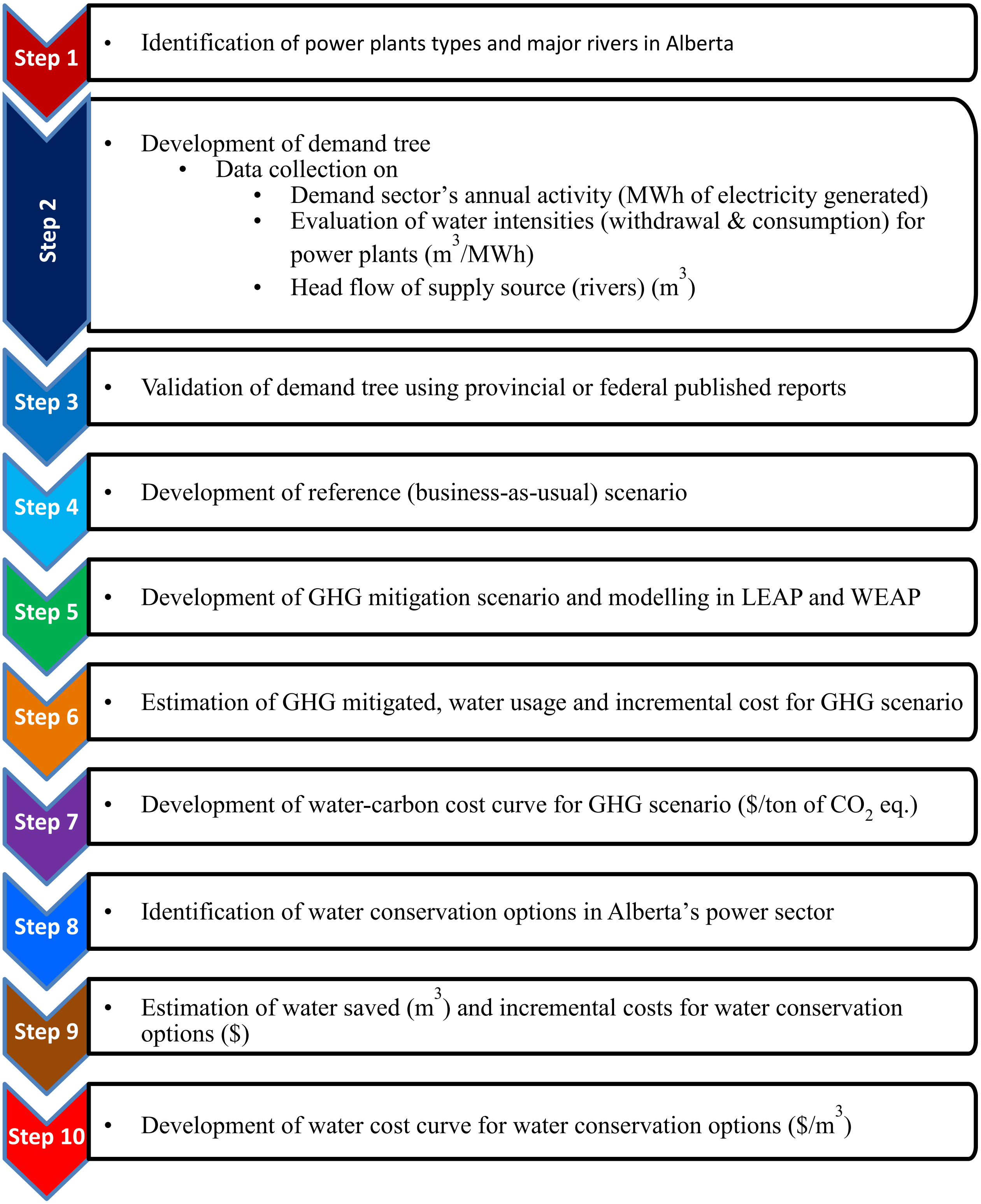


Figure 6: Overall methodology for development of water-energy model for Alberta's power sector

1.5. Limitations of the research

The current study and model are limited to following factors:

1. Only six rivers, namely, North Saskatchewan, Athabasca, Peace, Bow, Red Deer and South Saskatchewan river basins are considered for the study because of their current critical condition as explained in chapter 4.
2. The forecasting period comprises of 35 years (from 2015 to 2050) with 2015 as base year.
3. The water supply sector projections in WEAP model are based on climate model. In this research, monthly river flow data (m^3/s) for the last fifteen years (2001-2015) has been used to develop the supply side. The climatic conditions have not been taken into account for the supply side. The WEAP option for cyclic repetition of streamflow values has been followed in this research.
4. All the power plants in Alberta use freshwater either from river or water treatment plants.
5. Process variation in similar types of plants is not expected to be significant enough to have a major impact on final water demand or GHG emissions.
6. For the study period, water intensity and GHG emission intensity for the individual power plants in electricity sector will not change.
7. All the GHG mitigation scenarios assume the same load growth as the reference case but with a different generation mix.
8. The parameters of water quality are not within the scope of this study.
9. Suitable assumptions have been made where data are not available.

1.6. Organization of thesis

The thesis has five chapters with a table of contents, a list of tables, a list of figures, a list of abbreviations, references, and an appendix. The thesis is in a paper-based format. Chapters 2, 3 and 4 are expected to be published as separate papers. There might be some repetition in these chapters due to the format of the thesis.

Chapter 1 provides the introduction to water resource management, global issues on water use, sectorial water distribution in Canada and Alberta, water-energy nexus importance, Alberta's electricity generation sector, objectives, overall methodology and limitations of the scope of this study, and a detailed literature review.

Chapter 2 explains the development of Sankey diagrams for Canadian provinces to map water intake and consumption from source to demand. This chapter highlights the key water intensive sectors in Canada and sector-wise provincial water use.

Chapter 3 discusses integrated Alberta's WEAP-LEAP model structure, input parameters, modelling methodology, development of reference scenario and various GHG mitigation scenario for power sector. This chapter also discusses the validation of the output results of the model for the reference scenario. The results on cost benefit analysis and long-term impacts of GHG mitigation scenarios with respect to water demand and GHG mitigation conclude this chapter.

Chapter 4 comprises of the various water conservation options considered to evaluate changes in water demand patterns for the power sector. The methodology for developing the water conservation options, the input parameters, and the assumptions are described in detail. The water demand results estimated by the WEAP model and cost benefit analysis are presented in the form of water conservation cost curve. Key scenario in this chapter are integrated with LEAP to estimate the GHG emissions in the long run. This chapter is a continuation of the previous chapter.

Chapter 5 presents the study's conclusions and recommendations for future work in relation to this research.

Chapter 2: Development of water Sankey diagrams for six Canadian provinces to map water flow from source to end use

2.1. Introduction

As discussed in the Chapter 1, water demand is primarily distributed among three sectors – agricultural, industrial, and municipal. The industrial sector can be further subdivided into thermal power production, manufacturing, mining, and oil and gas. The municipal sector can be further divided into the residential and the commercial and institutional sectors. Accordingly, in this study the water demand sectors have been broken down into 7 categories. The scope of each demand sector is given in Table 4. On the supply front, water sources are of two types, ground and surface water. Surface water sources for different provinces are given in Table 5.

Table 4: Water demand sector categorization

Sector	Scope
Agriculture	Irrigation, feedlot, stock watering, animal production
Thermal power production	Electric power generation (coal, natural gas, nuclear, biomass etc.), transmission and distribution
Oil and gas[3]	Oil and gas exploration, conventional crude oil extraction, oil sands mining, oil sands in situ
Residential	Cities, towns, urban and rural villages, summer villages, hamlets, condominium/townhouses/mobile homes/complexes
Manufacturing	Chemical plants, fertilizer plants, paper manufacturing, primary metal manufacturing, food processing, petroleum and coal product manufacturing/ refining[4], other manufacturing industries
Mining	Coal mining, metal ore mining, non-metallic mineral mining
Commercial and Institutional	Natural gas distribution, water, sewage and other systems, construction, commercial buildings, transportation, recreation services, other activities

[3] Does not include the manufacturing/refining of oil, coal, and petroleum products
[4] Primarily transforming crude petroleum and coal into intermediate and end products

Table 5: Main surface water sources in six provinces

Province	Water Sources	Source
Ontario	St. Lawrence River, Great Lakes (Lake Huron, Lake Superior, Lake Ontario, Lake Erie, and Lake Michigan), Ottawa River	[79, 92, 93]
Alberta	Peace/Slave River, Athabasca River, North Saskatchewan River, South Saskatchewan River, Milk River, Beaver River, and Hay River	[94]
Quebec	St. Lawrence River, James Bay, Hudson Bay, Ungava Bay, Chaleur Bay, Laurentides Hannah and Rupert Bay, Bas-Saint-Laurent, Saguenay–Lac-Saint-Jean, James and Hudson Bay, Estrie, Côte-Nord, Hudson Strait and Ungava Bay, Outaouais, Lac Saint Louis, Lac des deux Montagnes, River des Prairies	[95]
British Columbia	Fraser River, Mackenzie River, Columbia River, Skeena River, Nass River, Stikine River, Taku River, Yukon River and Coastal Watershed	[96]
Saskatchewan	Souris River, Missouri River, Cypress Hills (North Slope), Old Wives Lake, Qu'Appelle River, South Saskatchewan River, North Saskatchewan River, Assiniboine River, Lake Winnipegosis, Saskatchewan River, Churchill River, Lake Athabasca, Tazin River, Kasba Lake	[97]
Manitoba	Seal River, Churchill River, Nelson River, Saskatchewan River, Lake Manitoba, Lake Winnipeg, Hayes River, Hudson Bay, Shoal Lake, Assiniboine River	[98]

The assumptions and input parameters are given in subsequent sections. U.S. Geological Survey (USGS) definitions of water-demand coefficients are used in this study. The USGS defines water intake as the water withdrawn from surface or groundwater sources. Water consumption is that portion of water intake that is expected to be consumed or lost. A schematic diagram on water flow as used in the study is presented in Figure 7. We collected inventory data on water intake and consumption for each demand sector and used it to develop Sankey diagram as discussed in the following sub-sections.

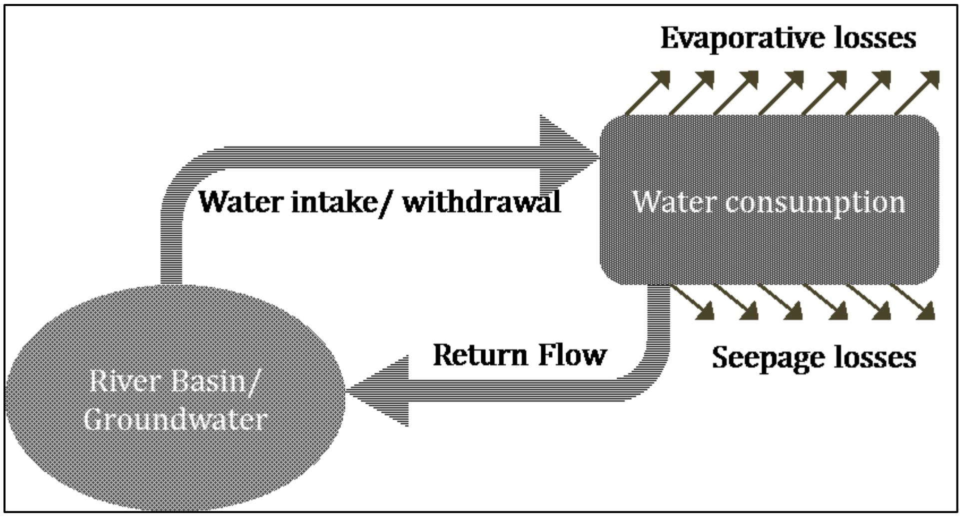


Figure 7: Schematic diagram of water flow

2.2. Methodology for developing a Sankey diagram

Sankey diagrams are figures illustrating flow from one direction to another with arrows. The width of the arrow is in proportion to the quantity of the flow, which in our case is the water intensity [99]. Sankey diagrams are used to demonstrate quantitative information about flows, their relationship, and their transformations [100]. We have used the diagrams to map water intake and consumption from source to demand for six Canadian provinces. Appendix A presents an overview of methodology of Sankey diagram development for different sectors.

2.2.1. Key assumptions and input parameters

Data for this study were taken from various government reports and databases Environment and Climate Change Canada's (ECCC) "Water Withdrawal and Consumption by Sector" [23], Statistics Canada's CANSIM tables [33], Canadian Association of Petroleum Producers' (CAPP) "Statistical Handbook for Canada's Upstream Petroleum Industry" [34], ECCC's "Municipal Water and Wastewater Survey" (MWWS) [35], The Mining Association of Canada's report titled "Facts and Figures of the Canadian Mining Industry, 2013" [36], and Natural Resources Canada's

"Water Use by the Natural Resources Sectors", [37]). The data from these reports were used to generate Sankey diagrams for six Canadian provinces, namely Ontario, Quebec, Alberta, British Columbia, Saskatchewan, and Manitoba, for the base year 2013. As evident from Figure 7, there are many components of water use for any process. For this study, a system boundary was defined as shown in Figure 8 and shows that new water added to and discharged from the system is considered. In the industrial sector, water recirculation parameters were not considered, as recirculation water is already present in the system and is not withdrawn from a supply source. In the mining sector, discharge volumes are higher than intake volumes because mine operators need to dewater their mines of any groundwater in order to carry out operations [23]. In this study, mining sector dewatering is termed mine water.

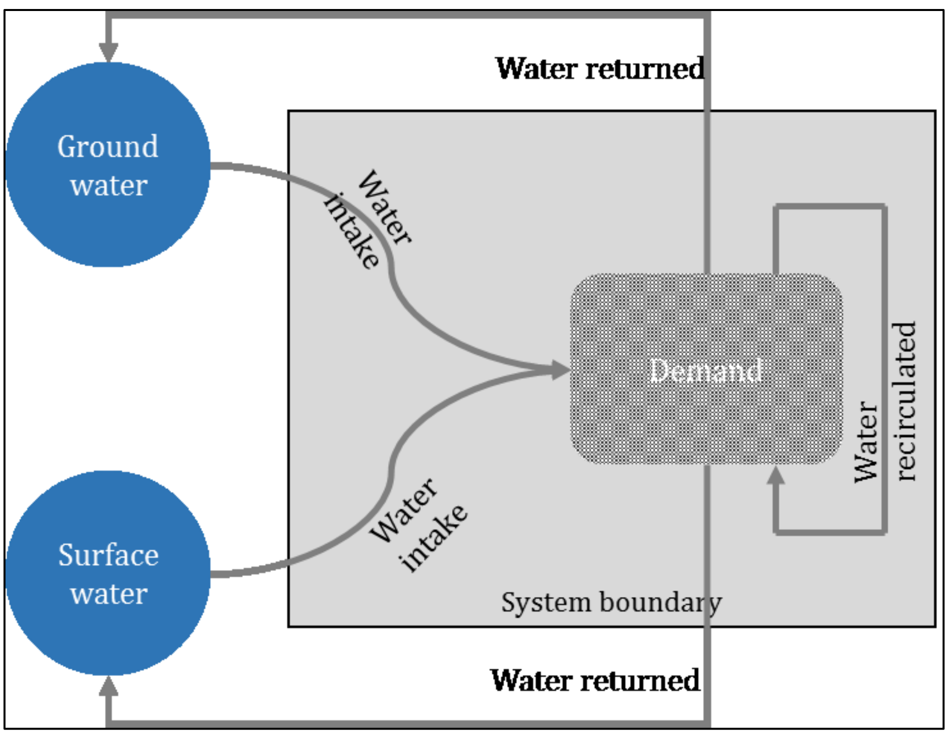


Figure 8: System boundary for Sankey diagram development

For each province, depending on the data available in the public domain, a top-down or a bottom-up approach was used to model water flow for each of the seven sectors. Water intake, consumption, and return were assessed based on annual activity, water intensity, provincial percentage share, etc., hence an elaborate and comprehensive province-wise database was created for each sector. The next section presents a detailed description of calculations.

2.2.2. Water intake and consumption

Province-wise water intake and consumption for demand sectors were estimated based on available Canada-wide water intake and consumption data. In the top-down approach, sector-wise national water intake and consumption were divided into water use by province. Further, provincial water intake was divided based on the water source (surface or groundwater). In the bottom-up approach, provincial intake and consumption were estimated using the demand sector's annual activity level and water intensity level. Province-wise estimated water intake and consumption for all the demand sectors are presented in Appendix B.

2.2.2.1. Agriculture sector water consumption estimates

In the agriculture sector, water is predominantly used for irrigation (crop production) and animal production. We calculated provincial irrigation water consumption for 2013. This was based on average consumption data for 2012 and 2014 from Statistics Canada's CANSIM database [101]. Statistics Canada's "Human Activity and the Environment" report shows that 84% of agricultural activity water is used for crop irrigation and production and the remaining 16% supports the livestock population (animal production) [102]. This figure (16%) was used to calculate the water consumption for animal production. Water consumption for both irrigation and animal production were added to calculate agriculture sector water consumption. Data provided by Statistics Canada for the year 2013 to estimate total water intake [23] was used. It was assumed that for each province, water intake is based on the percent share of water consumption for the province. Surface and groundwater shares for the agriculture sector were estimated using the water source information for irrigated land, which is included in Agriculture Water Use in Canada [103]. The following equations 1 to 5 show how we calculated water intake and consumption for Alberta's agriculture sector:

$$\alpha_{AB,surface} = \alpha_{Canada} * X_{AB} * Y_{AB,surface} \tag{1}$$

$$\beta_{AB} = \beta_{AB,Irrigation} + \beta_{AB,Livestock} \tag{2}$$

$$\mu_{AB} = \alpha_{AB} - \beta_{AB} \tag{3}$$

where

α = Water intake (m^3)

β = Water consumption (m^3)

μ = Water returned back to source (m^3)

X_{AB} = Provincial water intake/consumption share (%)

$$X_{AB} = \frac{\beta_{AB}}{\beta_{Canada}} \tag{4}$$

$Y_{AB,\ surface}$ = Water intake percentage share by surface water (%)

$\beta_{AB,\ livestock}$ = Water consumption by livestock (m^3)

$$\beta_{AB,Livestock} = \frac{\beta_{AB,Irrigation} * 0.16}{0.84} \tag{5}$$

2.2.2.2. Industrial sector water consumption estimates

The three industrial water users, as mentioned earlier in the paper, are thermal power production, manufacturing, and mining. Water intake and consumption parameters for all three sectors for the year 2013 were taken from Statistics Canada's CANSIM database, which provides region-wise water intake, recirculation, and discharge [104, 105]. For thermal power production and the mining sector, water parameters for the provinces of Manitoba, Saskatchewan, and Alberta are presented collectively as Prairie provinces. To estimate data for the Prairie provinces, it was assumed that the distribution was based on annual thermal electricity generation (MWh) and the number of mines in each province for the year 2013 [36, 106]. The percent shares of surface and groundwater were calculated from Statistics Canada's CANSIM database for the year 2013 [70, 107].

Crude oil production, oil sands mining, and oil sands in situ are the three activities in the oil and gas sector that consume water. To estimate the water footprint of the petroleum sector, a bottom-up approach was used and three key parameters were identified: activity level, water intake coefficient, and water consumption coefficient. Province-wise annual activity levels has been described by the Canadian Association of Petroleum Producers in its "Technical Statistical Handbook" [34]. Natural Resources Canada, in its 2009 report "Water Use by the Natural Resources Sectors – Facts", discussed the water intensity parameters for the oil and gas extraction sector [37]. Saline water plays an important role in conventional and in situ activities (enhanced oil recovery). Typical water intake shares, as given in the Alberta Energy Regulator's report, are 56.5% surface water 21.4% fresh groundwater and 22.1% saline groundwater (for enhanced oil recovery technologies) were used in this study [108]. The following equations 6 to 8 show the water intake and consumption calculations for Alberta's oil and gas sector:

$$\alpha_{AB,surface} = \left(\theta_{AB} * \Sigma_{AB,intake} + \varepsilon_{AB} * \Delta_{AB,intake} + \eta_{AB} * \Pi_{AB,intake}\right) * Y_{AB,surface} \quad (6)$$

$$\beta_{AB} = \left(\theta_{AB} * \Sigma_{AB,consume} + \varepsilon_{AB} * \Delta_{AB,consume} + \eta_{AB} * \Pi_{AB,consume}\right) \quad (7)$$

$$\mu_{AB} = \alpha_{AB} - \beta_{AB} \tag{8}$$

Where,

α = Water intake (m^3)

β = Water consumption (m^3)

μ = Water returned to source (m^3)

θ = Annual crude oil production (m^3)

Σ = Water coefficient for crude oil production (m^3/m^3)

ε = Annual oil sands mining (m^3)

Δ = Water coefficient for oil sands mining (m^3/m^3)

η = Annual crude oil sands in situ (m^3)

Π = Water coefficient for oil sands in situ (m^3/m^3)

$Y_{AB,\ surface}$ = Water intake percentage share by surface water (%)

2.2.2.3. Municipal sector water consumption estimates

The municipal sector includes the residential and the commercial and institutional sectors. Statistics Canada's 2013 report "Water Withdrawal and Consumption by Sector" was used to collect total water intake by these sectors. The provincial share of water intake was calculated from ECCC's MWWS for the year 2009 [23, 35]. It was assumed that provincial shares for municipal water intake will not change from 2009 to 2013. Environment Canada's 2016 Water Withdrawal and Consumption by Sector assumes water consumption for the municipal sector to be 10% of total water intake, based on consumption rates from ECCC's MWWS [23]. Distribution between surface and groundwater was estimated from Statistics Canada's 2011 Survey of Drinking Water Plants.

2.3. Results and discussion

In 2013, approximately 38,300 million m^3 of water were withdrawn from Canada's rivers, lakes, and groundwater [23]. Of this 38,300 million m^3, approximately 90% (34,085 million m^3) was withdrawn by six provinces: Ontario, Alberta, British Columbia, Quebec, Saskatchewan, and Manitoba. Figure 8 shows water intake trends by sector. It can be inferred that water intake for the thermal power, manufacturing, and residential sectors is decreasing and for other sectors withdrawals are increasing [23].

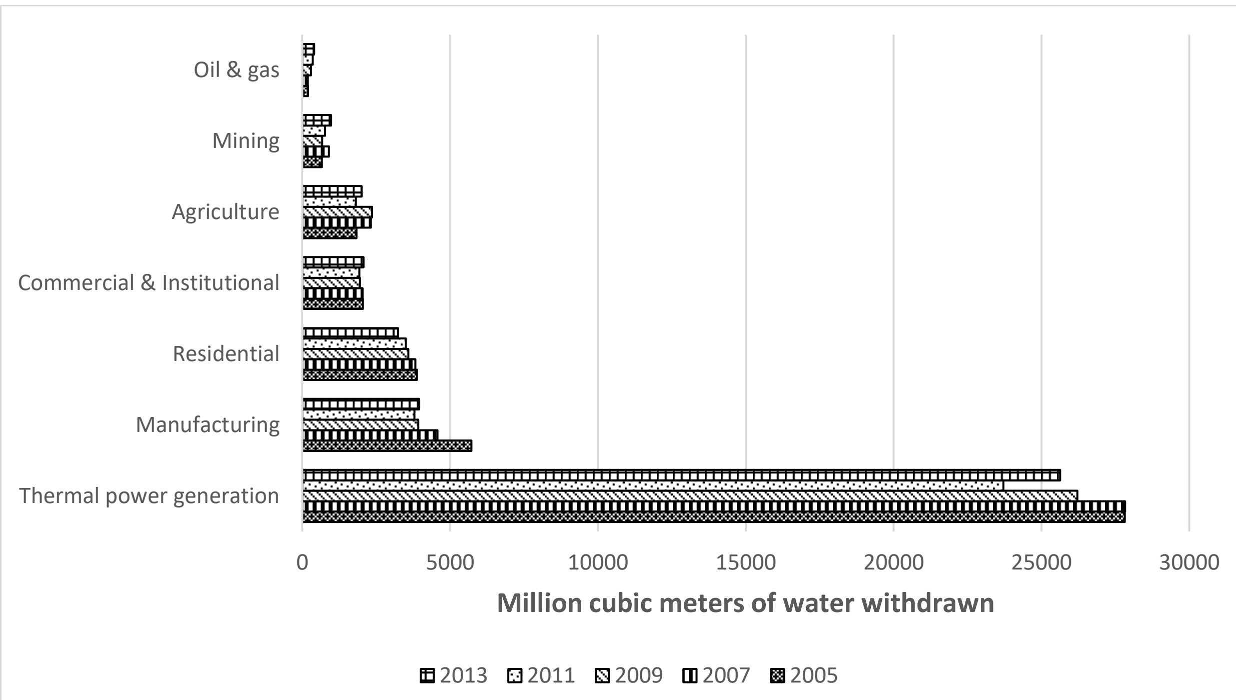


Figure 9: Water withdrawal by sector in Canada (adopted from [23])

In Sankey diagrams for provinces, the following convention is used to label the flow: the label above the arrow indicates the surface water and water consumption numbers for each demand sector. The label below the arrow indicates the groundwater and water returned to the source for each demand sector. Also, Sankey diagram scales are different for different provinces. Figure 10 illustrates province-wise water flow from source to end use and shows that Ontario is a major province with high water intake because of thermal power production and Alberta consumes the most water (1,892.26 million m^3) because of its irrigation activities.

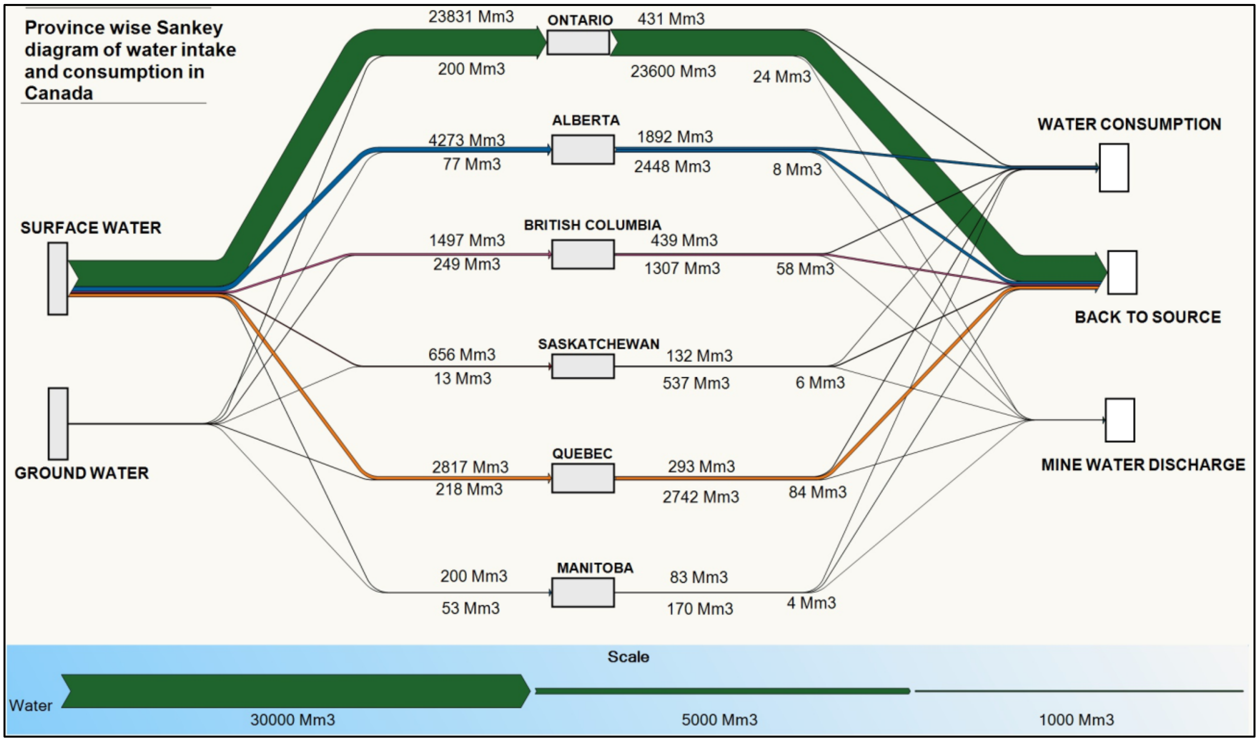


Figure 10: Province-wise Sankey diagram for water intake and consumption

2.3.1. Ontario's water Sankey diagram

In 2013, Ontario's surface and groundwater intake was 23,831.84 million m^3 and 200.01 million m^3, respectively. Total surface and groundwater consumptions were 404.12 million m^3 (1.7% of total intake) and 27.25 million m^3 (0.11% of total intake), respectively. The province's oil and gas activity is negligible, hence in the Sankey diagram only 6 demand sectors are shown. Total water intake and consumption for Ontario are given in Figure 11. In this province, around 98% (23,624.02 million m^3) of water is returned to the source.

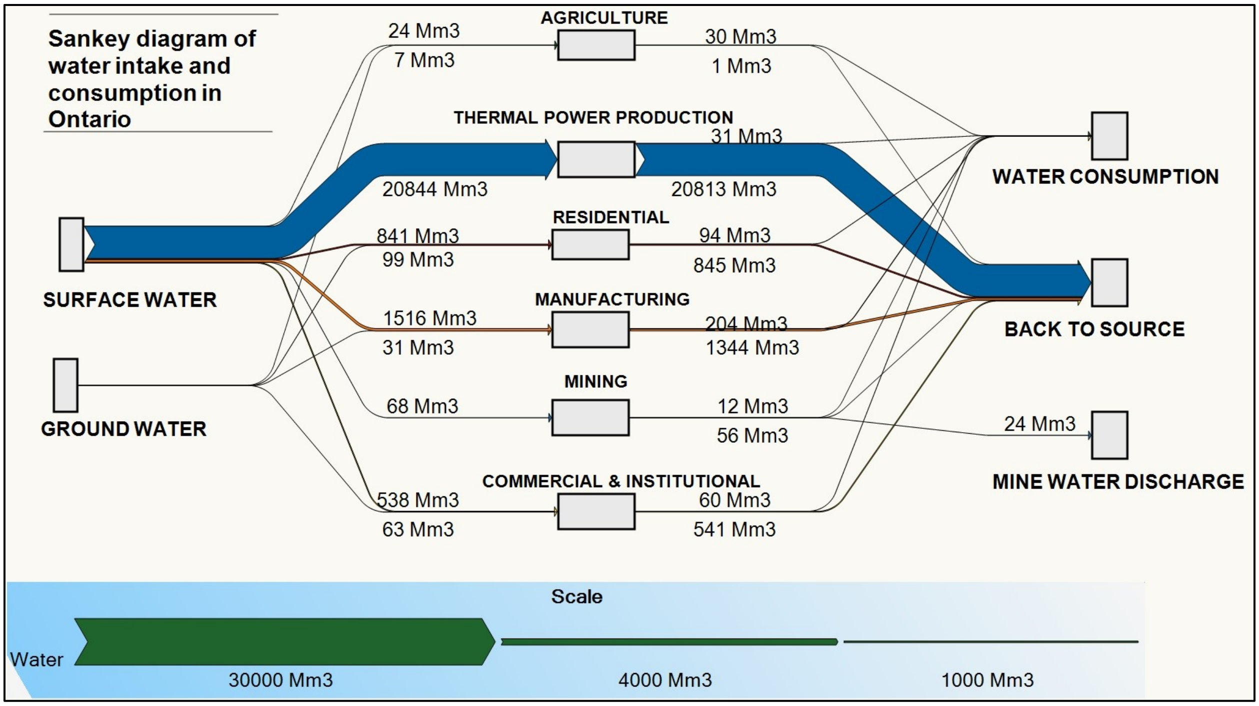


Figure 11: Water intake and consumption in Ontario

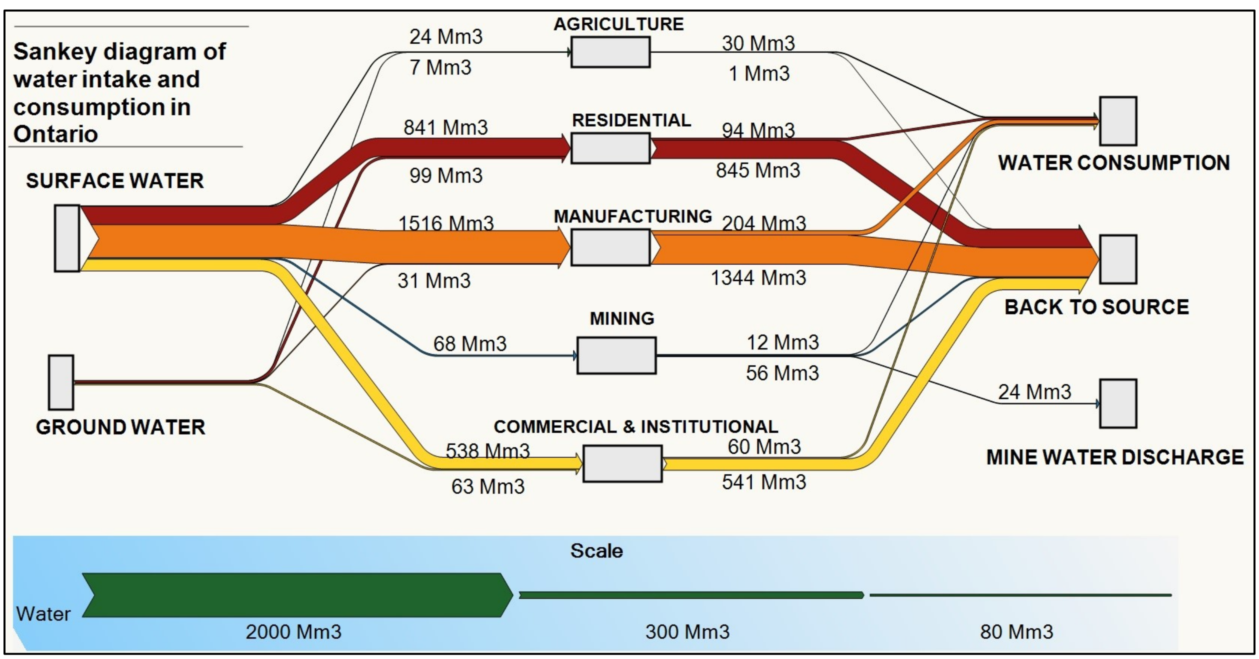


Figure 12: Water intake and consumption in Ontario without thermal power production

In our study, we found that Ontario’s thermal power production, despite having a huge water intake, consumes a mere 0.14% of its intake, i.e., 31 million m^3. To better understand this water intake and consumption of Ontario, a Sankey diagram was developed as shown in Figure 12 without thermal power production. It is evident from this figure that the manufacturing, municipal, and other sectors account for high water intake.

2.3.2. Alberta’s water Sankey diagram

Alberta’s intake from surface and groundwater was 4,272.56 million m^3 and 77.41 million m^3, respectively, for 2013 and is shown in in Figure 13. Total surface and groundwater consumption were 1,851.24 million m^3 (42.55% of intake) and 41.01 million m^3 (0.94% of intake), respectively, for Alberta.

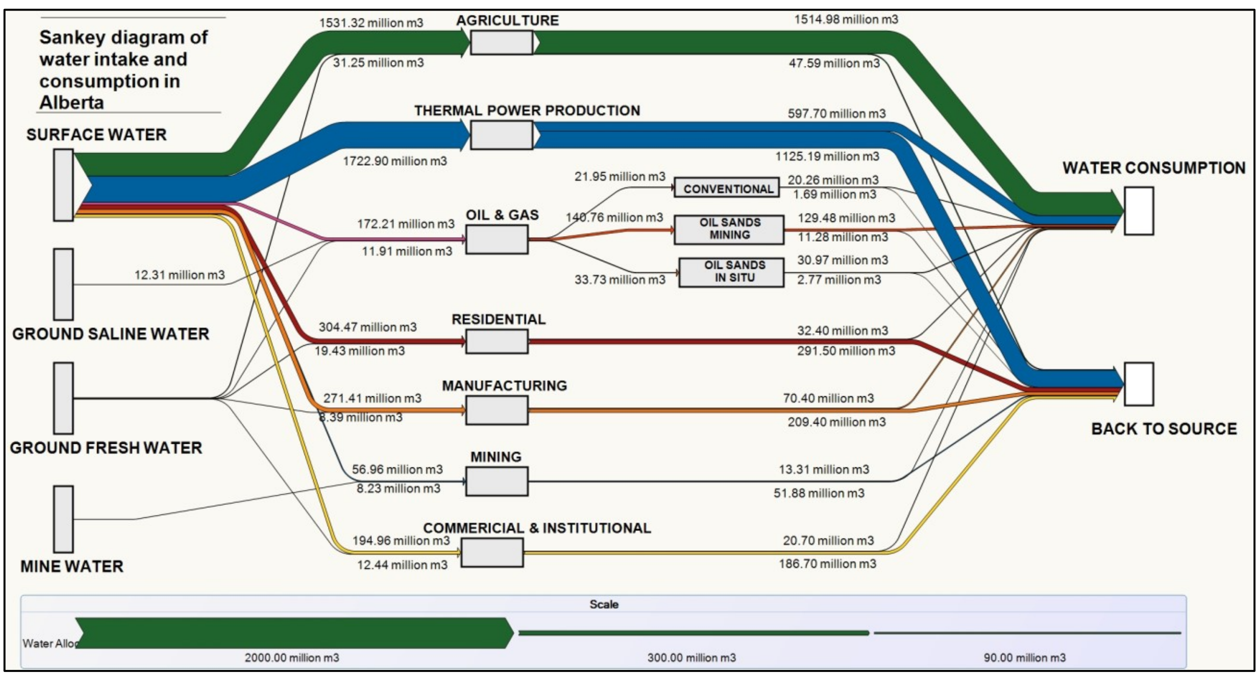


Figure 13: Water intake and consumption in Alberta

In this study, it was found that in Alberta only around 56.68% (2465.94 million m^3) of intake water is returned to the source. Water consumption in Alberta is higher than in Ontario due to Alberta’s high agricultural activity and thermal power production. Alberta's agriculture sector, the province's largest water consuming sector, consumes 90% (1,514.98 million m^3) of its total water intake and returns the rest 10% (47.59 million m^3). Alberta's thermal power production sector consumes 35% (597.97 million m^3) and returns the remaining 65%.

2.3.3. Quebec's water Sankey diagram

For Quebec, intake from surface and groundwater was 2,817.17 million m^3 and 217.96 million m^3, respectively, for the year 2013 (see Figure 14). The residential, manufacturing, and other sectors (commercial and institutional) are the main water demand sectors. Although water intake for Quebec is very high, only 9.6% (293.27 million m^3) is consumed; the rest goes back to the source.

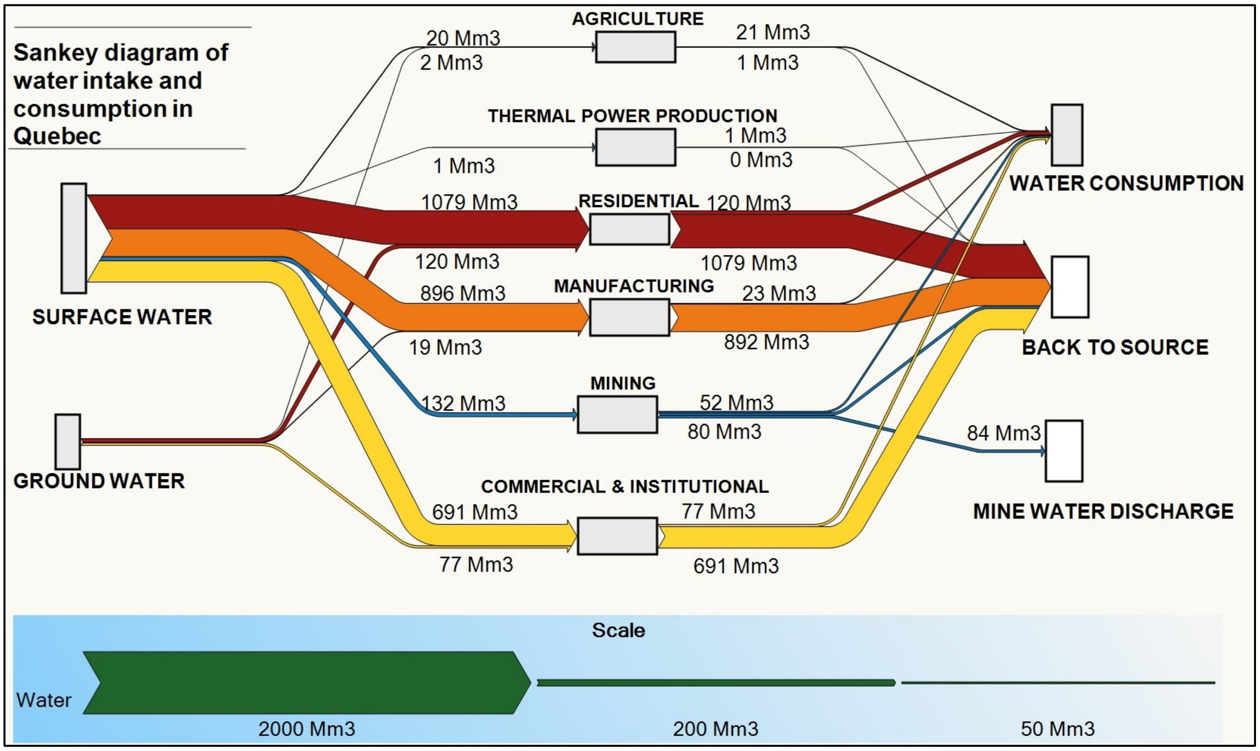


Figure 14: Water intake and consumption in Quebec

2.3.4. British Columbia's water Sankey diagram

British Columbia's of surface and groundwater intake was 1,496.56 million m^3 and 249.46 million m^3, respectively, in 2013 (see Figure 15). Total surface and groundwater consumption was 339.37 million m^3 (19.43% of intake) and 100.00 million m^3 (5.72% of intake), respectively. British Columbia has a small share of the petroleum sector, in conventional crude oil production.

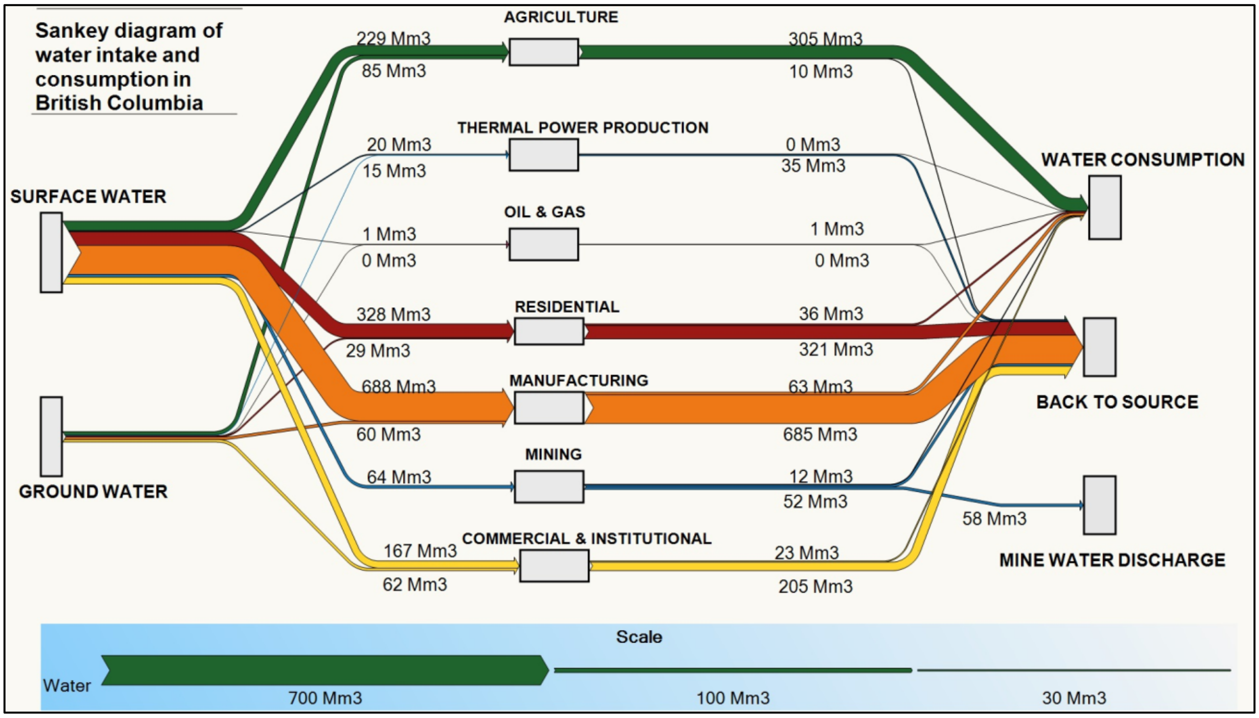


Figure 15: Water intake and consumption in British Columbia

In this study, it was found that for British Columbia, overall water consumption considering all the demand sectors accounts for 25.16% (439.37 million m^3), most of it in the agriculture and manufacturing sectors. The province has very little thermal power production or petroleum sector activity. For every sector except agriculture and oil and gas, more than 80% of the water withdrawn is returned to the source.

2.3.5. Saskatchewan's water Sankey diagram

Saskatchewan's intake of surface and groundwater was 656.02 million m^3 and 13.31 million m^3, respectively, in 2013 (see Figure 16). Total surface and groundwater consumption was 128.5277 million m^3 (19.2% of intake) and 3.59 million m^3 (0.53% of intake), respectively. Saskatchewan has a small share of the petroleum sector, in conventional crude oil production.

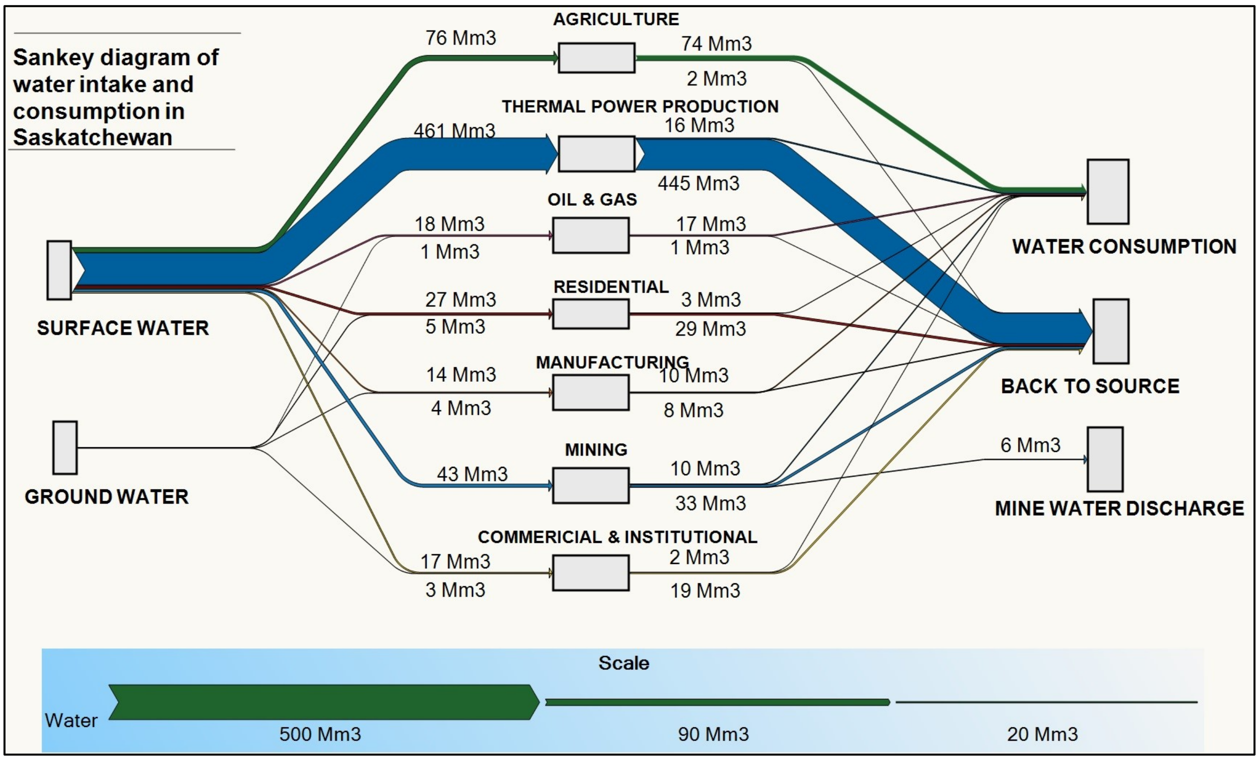


Figure 16: Water intake and consumption in Saskatchewan

In this study, it found that overall water consumption for Saskatchewan considering all the demand sectors accounts for 19.7% (132.11 million m3), most of it in the agriculture sector. Like Ontario, thermal power production is a key water demand sector for Saskatchewan and the sector returns about 96% of water intake back to the source.

2.3.6. Manitoba's water Sankey diagram

Manitoba's intake of surface and groundwater was 199.87 million m^3 and 53.37 million m^3, respectively, in 2013 (see Figure 17). Total surface and groundwater consumption was 567.51 million m^3 (22.31% of intake) and 26.45 million m^3 (10.44% of intake), respectively. Manitoba has a small share of the oil and gas sector, in conventional crude oil production.

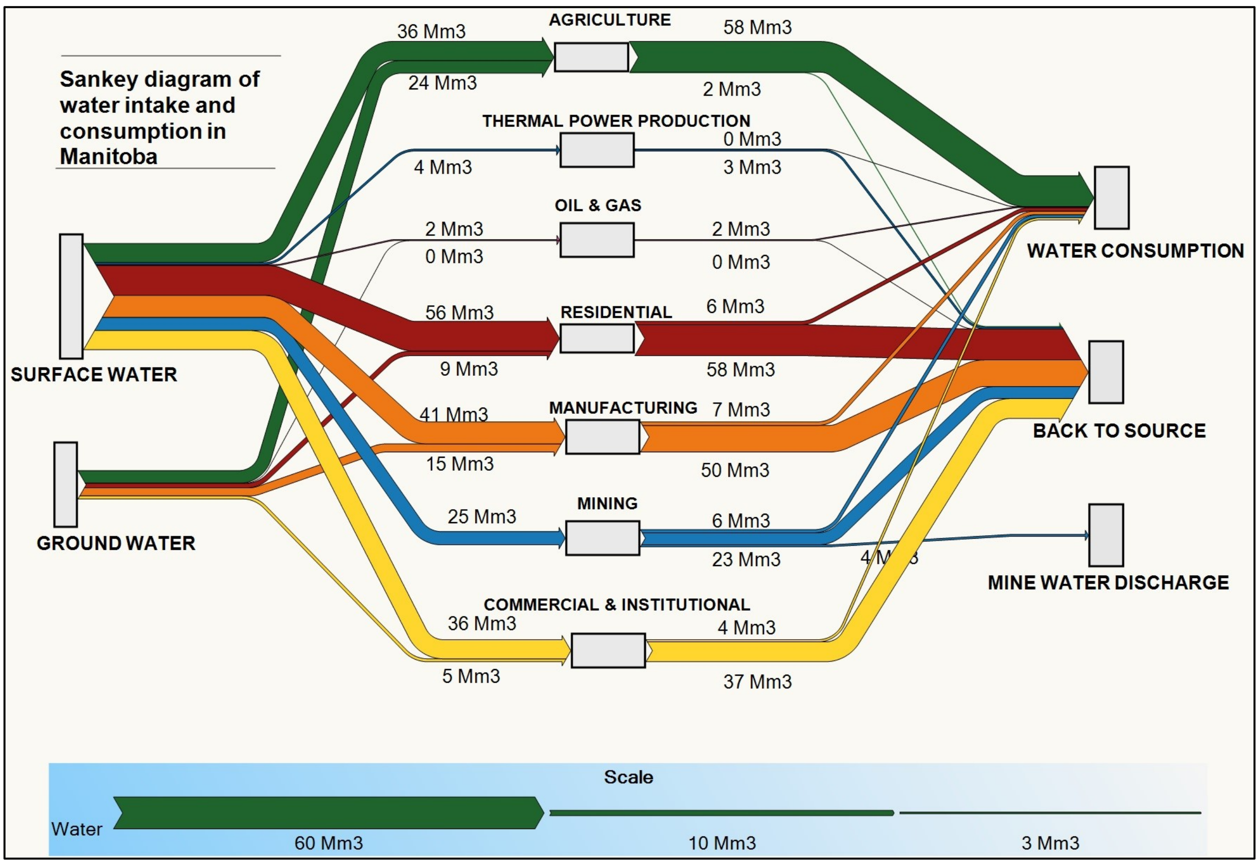


Figure 17: Water intake and consumption in Manitoba

For Manitoba, overall water consumption considering all the demand sectors accounts for 32.75% (82.95 million m^3) of intake, in large part because of the agriculture sector. Manitoba has very little thermal power production or oil and gas sector activity. For every sector except agriculture and oil and gas, more than 80% of the water withdrawn is returned to the source.

Figure 18 is an integrated water Sankey diagram for Canada. It shows that while the thermal power production sector is by far the highest water withdrawal sector, it consumes less than 0.5% of water withdrawn. The agriculture sector is the highest consumer of water (2,003.07 million m^3).

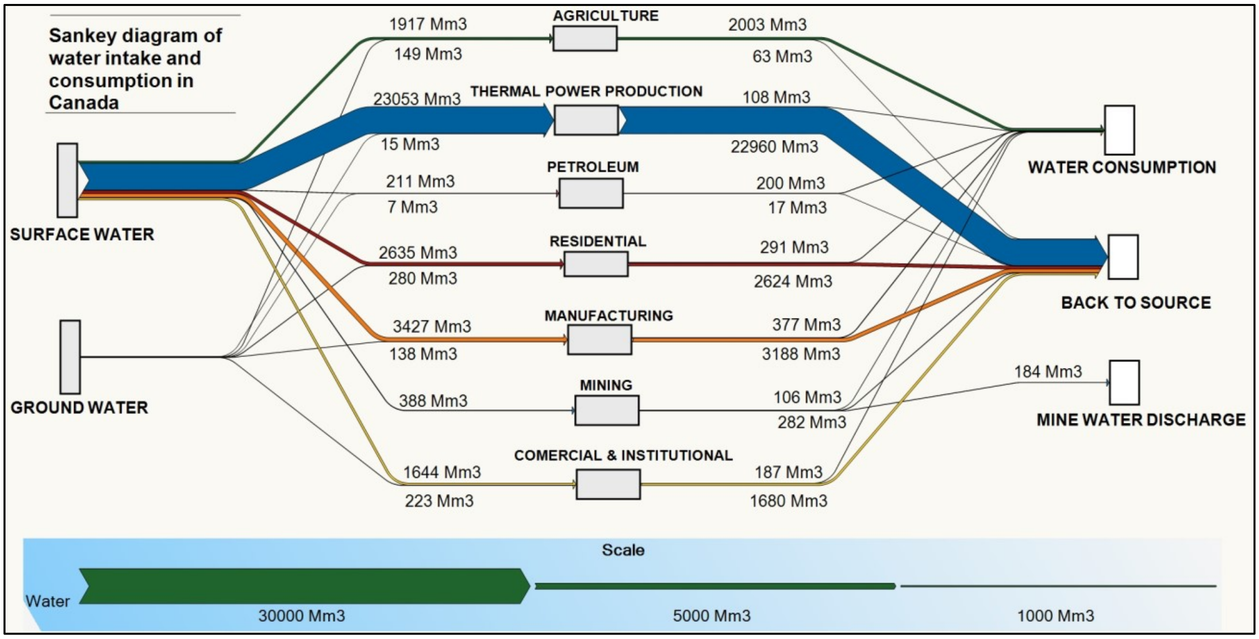


Figure 18: Integrated sector-wise water Sankey diagram for Canada

2.4. Conclusion

Water intake and consumption were mapped for six Canadian provinces and seven demand sectors: agriculture, thermal power production, oil and gas, residential, manufacturing, mining, and commercial and institutional. The Sankey diagrams show total water intake (surface and groundwater), consumption, and return to source. From these diagrams, the highest consumers of water in each province can be identified. It can also be determined where emphasis should be put to reduce water consumption and improve water use efficiency. In British Columbia, Alberta, and Saskatchewan, the agriculture sector is the largest consumer of water, both because of high crop production activity that requires large amounts of water and because very little water is returned directly to the source. In the Ontario and Quebec, the manufacturing sector is the major water consumer. In this study, province-wise water intake and consumption parameters for different water-consuming sectors for six Canadian provinces were developed. In a traditional sector-based management strategy, prospects for improving the management of water resources and connections with other resources are often overlooked. With the water flow maps we developed, it will be easier for policy makers to understand consumption in the competing water demand sectors.

Chapter 3: The Development of an Integrated LEAP-WEAP Model for the Assessment of Energy Scenarios for the Power Generation Sector

3.1. Introduction

This chapter details our methods for the development of a reference scenario and nine integrated LEAP-WEAP climate change scenarios for the power sector for the years 2015-2050 by forecasting water consumption and greenhouse gas emissions (GHGs). The economic aspects of the scenarios are discussed through cost curves that compare the scenarios in terms of GHG savings potential, water use, and the cost of mitigating GHG. Power generation sector policies primarily consider carbon emissions. Our LEAP-WEAP model results can help create awareness among policy makers to help them understand the water-energy demand and supply relationship in a quantifiable way.

3.2. Modelling methodology

To develop a baseline energy supply and demand scenario, annual activity levels of the electricity generation sector along with various parameters were entered into the LEAP model for the supply sector. To develop the water supply and demand scenario, annual activity levels (MWh) of the electricity generation sector along with end-use water intensities were entered into the WEAP model. Both models work on a demand and supply resource balance. A key benefit of WEAP and LEAP is their seamless integration, and for that reason they were used in this study [109]. A business-as-usual (BAU) scenario was also developed for the years 2005 to 2050 to project the GHG emissions and water consumption from Alberta's power sector; these projections act as references in our evaluations of the impacts of various climate change scenarios. A water-energy nexus diagram was developed using the integrated LEAP and WEAP results. In this study, cost-benefit analyses of the scenarios were developed to evaluate the incremental costs incurred in each scenario compared to the baseline scenario. The incremental costs, along with water use and GHG mitigation potential, were used to develop the water-carbon cost curve. The overall methodology for developing cost curves is given in Figure 19.

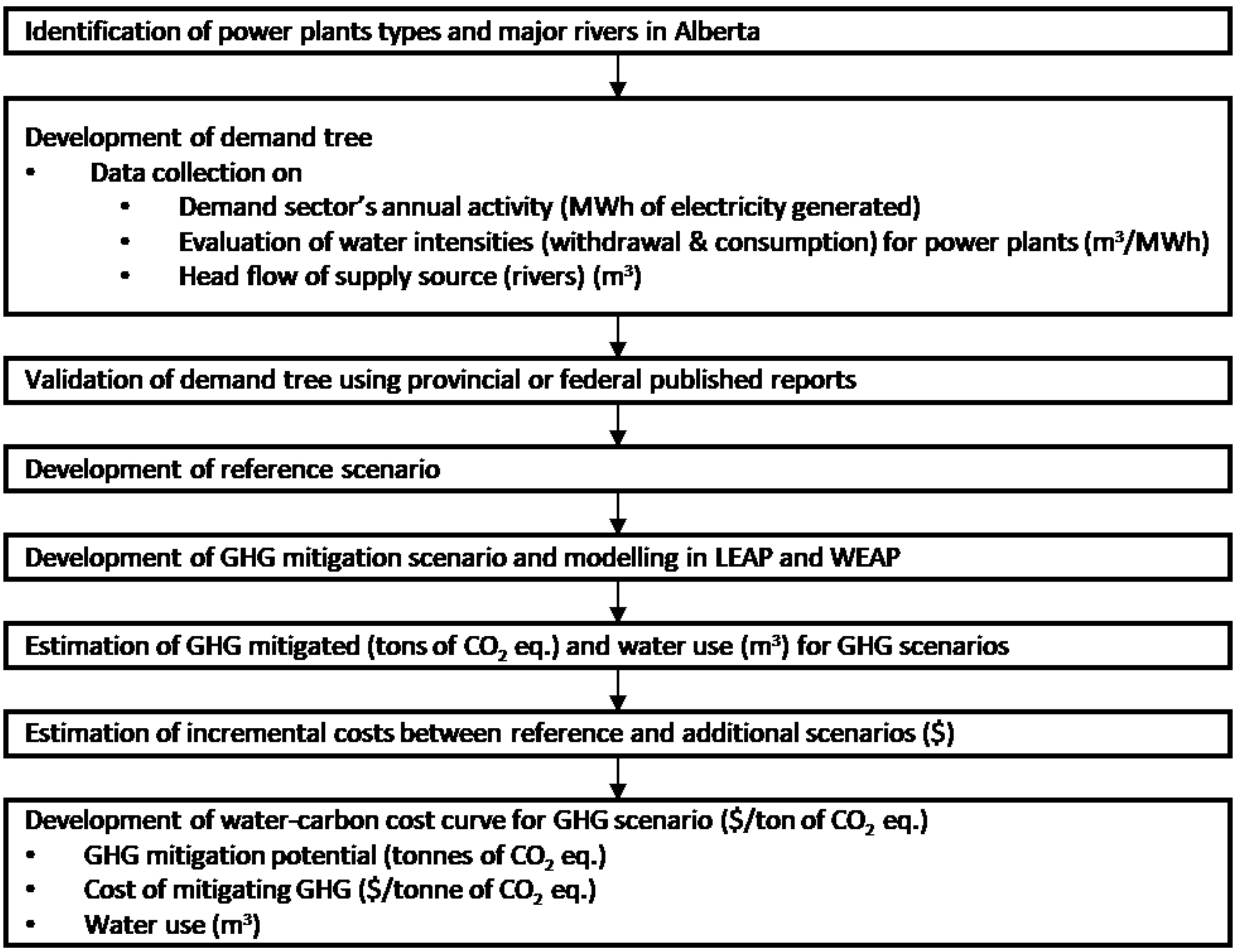


Figure 19: Methodology for the development of the water-carbon cost curve for Alberta

3.2.1. Water Evaluation and Planning (WEAP)

The WEAP model's graphical interface allows the user to develop a bottom-up demand tree, develop a business-as-usual scenario to forecast water consumption patterns, and evaluate water use impacts of climate change scenarios [109]. The model also allows the user to perform extensive cost analyses, and the results are provided in various formats (charts, tables, and summary reports). WEAP is a water demand and supply assessment tool with long-term water planning and forecasting capability [109]. It provides an efficient way to predict demand-source interactions and the effects of different parameter variations over time [109]. Appendix C presents an overall layout of WEAP model, various water demand sectors in Alberta and a detailed structure of one sector up to annual activity level.

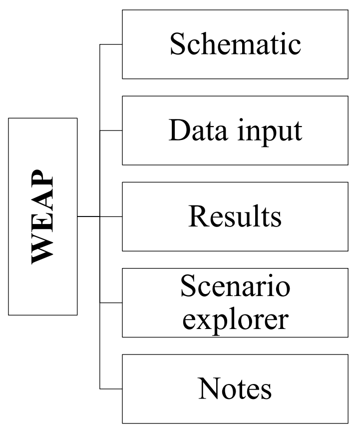


Figure 20: WEAP's modeling modules *[109]*

WEAP has a demand module that keeps all the considered demand sectors and sub-sectors and a supply module that simulates the supply resources. WEAP includes a schematic, data input, results, a scenario explorer, and notes (see Figure 20). The schematic graphically represents the rivers, reservoirs, demand sites, transmission links, return flows, and stream-flow gauges. Geographic information system (GIS) vector files were imported into WEAP [109]. For the demand and supply model developed for Alberta, the six main river basins, along with their tributaries, locations of the stream-flow gauges installed along the rivers, and reservoirs were identified through Google Earth [109]. These vector files were imported into WEAP and represent the course of the rivers.

The data view in WEAP consists of data input to the software that can build relationships between variables and user-defined assumptions for future projections [109]. Historical data from 2005 to 2015 were used to develop the reference scenario. The base year for this model is 2015 because this is the most recent year for which complete data are available. The model was built in WEAP considering the demand and supply sides of all the water consumers in each river basin with a key emphasis on the power generation sector.

3.2.2. Long-range Energy Alternatives Planning (LEAP)

LEAP is an integrated computer-based energy-environment modeling tool designed to provide support in evaluating energy policies and sustainable energy plans [74, 110]. It also allows the user to make projections of energy supply and demand over a custom-defined planning horizon (i.e., fifteen or thirty-five years). The model is data-intensive and can take into account the energy flow characteristics from reserves to final end use [110]. Appendix D presents an overall layout of LEAP model, various energy demand sectors in Alberta and a detailed structure of one sector up to device level.

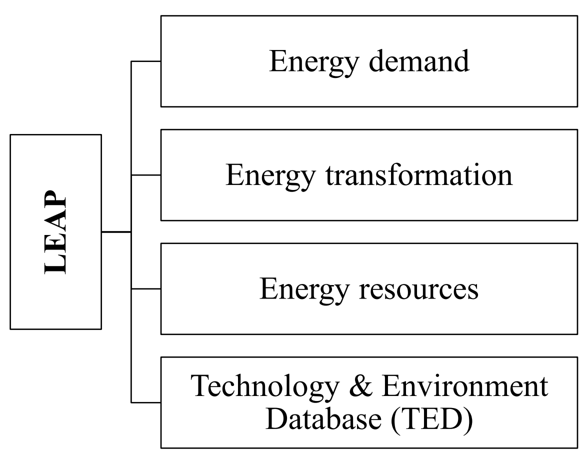


Figure 21: Framework of the LEAP model *[111]*

LEAP consists of four modules: demand, transformation, resource, and an environmental database, as shown in Figure 21 [112]. The demand module highlights all the energy demands for both primary and secondary fuels from sectors and sub-sectors to end uses and devices. The transformation module deals with the conversion of primary fuel to secondary fuel, i.e., the electricity generation, and this conversion is the focus of this study. The resource module is a record of all the primary and secondary fuels considered. The Technology and Environment Database (TED) is a database that keeps track of all the emission factors associated with primary and secondary fuels.

The electricity demand in Alberta's five sectors (residential, commercial & institutional, industrial, transportation and agriculture) developed by Subramanyam and Kumar [74, 113, 114] has been used as input in this LEAP-WEAP model. Along with this, the "behind-the-fence load" (BTF) was modelled to account for the total electric demand in Alberta that is served by onsite generation, typically in industrial cogeneration plants [115, 116]. Behind-the-fence load is an industrial load served in whole, or in part, by onsite generation built on the host's site [117]. In a transformation analysis, the LEAP model deals with the conversion and transportation of different forms of energy from the point of withdrawal of primary and imported fuels to the point of final fuel consumption. These modules are based on one or more processes that are further classified into input and output processes. These processes represent the individual technologies or a group of technologies that convert one form of energy to another or transmit energy [111]. Technology data such as fuel inputs to each process, capacities, efficiencies, capacity factors, and environmental loadings can be defined at this stage by linking Technology and Environmental Database (TED) to the process [74].

The input data for primary resources consist of reserves for the base year, resource imports, and exports for natural gas, coal, bitumen, crude oil, natural gas liquid (NGL), and pentanes [111]. The secondary resources include the fuels produced due to conversion of primary fuel to electricity, steam etc. which are further used by demand sectors. In LEAP's Alberta model, the secondary fuels are electricity, steam, and refinery-finished products [111].

Environmental data for different kinds of pollutants (e.g., CO_2 biogenic, methane NO_x, CO_2 equivalent, particulates, and SO_x) are built into the LEAP model's TED. The corresponding global warming effects are also listed in the LEAP's database. All the transformation and resource sectors were developed based on Alberta's resource development and are associated with the corresponding emissions [111].

The following guidelines were adopted for a successful integration of the LEAP and WEAP models [118]:

- Both LEAP's and WEAP's areas must have the same base and end years.
- Both LEAP and WEAP models must have the same set of time steps.

3.3. Demand tree for Alberta's power generation sector

3.3.1. WEAP demand tree

The demand tree for Alberta's power sector by identifying the types of power plants was developed, calculating their percentage share of electricity generation and modeling water use intensity data for the identified power plants in the WEAP model. All the power plants, from a 5 MW to 860 MW capacity were identified and included in WEAP model [64]. Based on Statistics Canada's CANSIM Table 153-0082*,* it was assumed that all the power plants in Alberta use freshwater either from rivers or water treatment plants [70]. Process variation in similar plants is not expected to be significant enough to have an impact on final water demand. When the base case was developed, 2015 was selected as the base year because of the availability of complete data. The demand tree for each subsector was developed based on water data collected from various sources, as explained in the following sections (see also Figure 22).

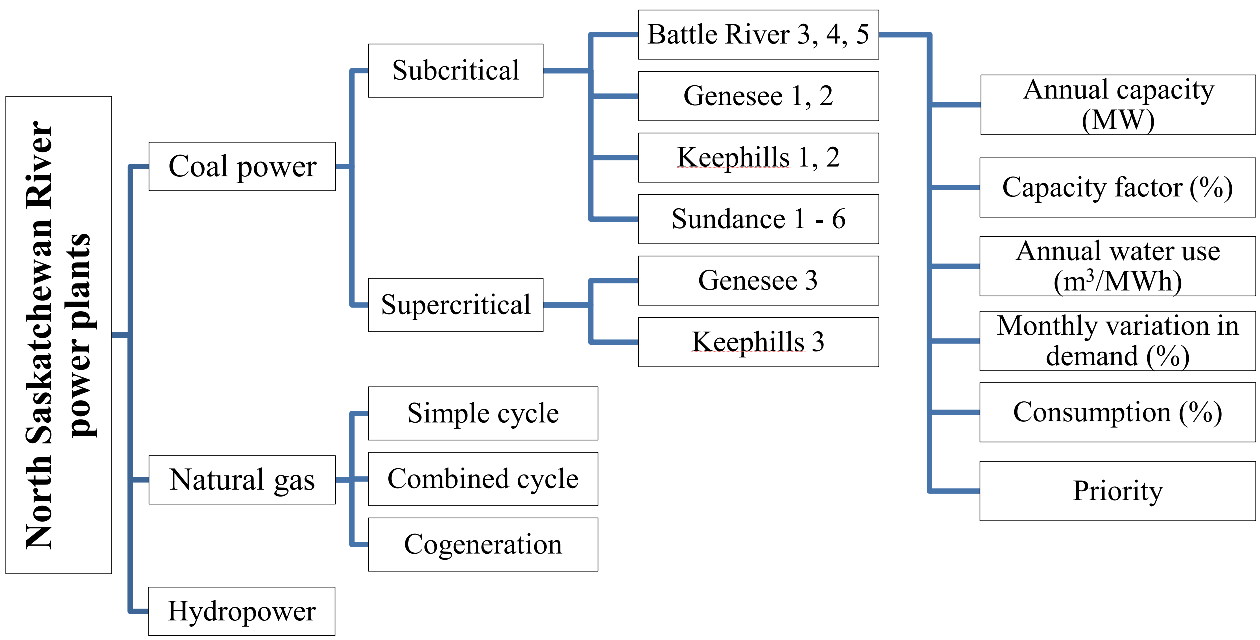


Figure 22: WEAP water demand tree and input parameters

Actual water-use by the power sector, in terms of water consumption (i.e., water withdrawal minus return flow), was estimated based on a combination of available water use reporting information and typical unit rates from the literature; these are discussed in the subsequent sections. This combination was necessary due to limited actual water use data available from Alberta Environment & Parks (AEP) [62]. As for the demand module, to satisfy water demand, WEAP has a supply module, which determines the amount, availability, and allocation of water supplies, and simulates monthly river flows. In the WEAP model for Alberta's power sector, the supply module was taken from an earlier study conducted by Dar et al. [31].

The water consumption results were calculated by WEAP model using a bottom-up demand tree based on equation 9:

$$\text{Annual power plant water consumption } (\mathrm{m}^3)_{\mathrm{i,j}} = \sum_{k=1}^{n} \text{power production } (\mathrm{MWh})_{\mathrm{i,j,k}} * \text{Annual water use rate } (\mathrm{m}^3/\mathrm{MWh})_{\mathrm{i,j,k}} \tag{9}$$

i types of power plants in Alberta

j number of years with 0 as the base year, corresponding to 2015 in our case

k the total number of power plants of type "*i*".

Table 6 shows water withdrawal and consumption parameters for different types of power plants.

Table 6: Water demand coefficients for power plants in Alberta *[15, 16, 62, 119]*

Power plant type	**Withdrawal (m^3/MWh)**	**Consumption %**
Coal subcritical	2.33	84
Coal supercritical	2.19	74
Natural gas simple cycle	0.38	80
Natural gas combined cycle + cooling tower	0.90	75
Natural gas combined cycle + dry cooling	0.32	75
Natural gas cogeneration + cooling tower	0.69	65
Natural gas cogeneration + dry cooling	0.25	65
Biomass + cooling tower	2.53	87
Nuclear + cooling tower	4.17	65
Hydropower	13.12	100

3.3.2. LEAP transformation tree

In the LEAP model, the electricity generation sector is a transformation sector where fuel like coal, natural gas, hydro, wind, etc., are converted into electricity, which is further used by the demand sectors. Figure 23 shows the input parameters for developing the power sector in the LEAP model.

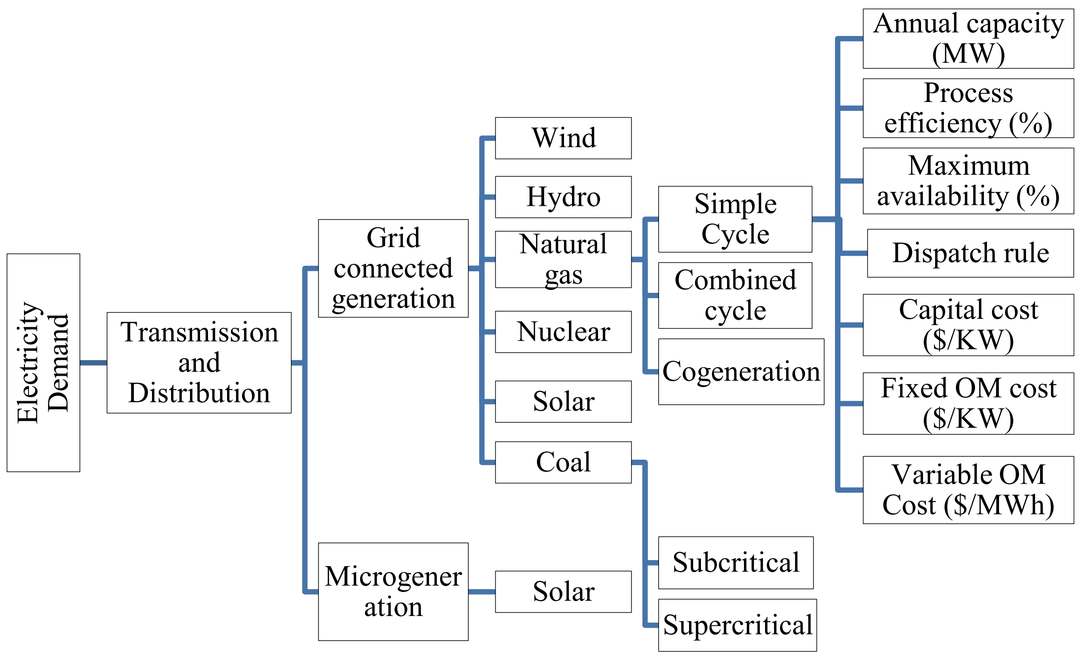


Figure 23: LEAP power sector transformation tree and input parameters

In this study, input parameters for the electricity demand module from 2005 to 2010 are based on the National Energy Board's report [39]. Electricity demand projections from 2010 to 2050 are based on the energy demand tree developed by Subramanyam and Kumar [74, 113, 114]. The electricity demand module includes electricity consumption in the residential, commercial & institutional, industrial, transportation and agriculture sectors. Additionally, the BTF loads for cogeneration power plants were modelled.

In 2003, total annual system losses were 2,765 GWh, or 4.45% of total energy transmitted – 62,089 GWh [120]. The Alberta Electricity System Operator (AESO) estimated electricity loss to be 3.84% on average in 2016 compared to an average system loss of 3.66% in 2015 [121]. Based on these figures, a system average loss of 3.5% was assumed for the future years in the LEAP model. The input data to the electricity generation module consist of plant availability, historical production, merit order, dispatch rule, system load curve, and process efficiency for each type of power generation unit selected. The total electricity production includes the MW generated in Alberta's oil sands for bitumen production and upgrading. The planning reserve margin for Alberta is assumed to be 30% based on AESO's 2015 long-term transmission plan [116]. Planning reserve margin represents the system generation capability in excess of that required to serve peak system load [117].

The emissions per unit of fuel consumed with respect to the technology considered were used for the demand sectors. TED module of LEAP contains a database of various sources on emission factors. The Intergovernmental Panel on Climate Change (IPCC) Tier 1 and Tier 2 emission factors for coal, natural gas, biomass, and wood are also specified in TED which were used in this study [111].

3.4. Reference scenario development

Using the demand tree, a reference (business-as-usual) case was developed in WEAP and LEAP models to understand the future water demand and GHG emissions in Alberta's power sector from 2015 to 2050. The reference scenario was developed based on the AESO 2016 report, which projects the generating capacity for each electricity generation type from 2015 to 2037. Although Alberta is currently suffering an economic slowdown due to low crude oil prices, this study's reference scenario assumes crude oil prices will recover and the oil sands industry and Alberta's economy will grow and increase the Alberta Internal Load (AIL). The AIL for the reference scenario is assumed to grow rapidly from 2016-2018 due to oil sands projects currently under construction (over 550,000 bbl/d of oil sands capacity under construction and an additional 3.7 million bbl/day of capacity announced [122]) and the assumption that Alberta's economy will recover with peak AIL increasing to 13,700 MW by 2022 from 9,162 MW in 2015 [115]. It is also assumed, based on third party forecasts, that by 2024 oil sands production will increase by approximately 1 million barrels per day from 2016 levels [39, 122]. Post-2022 peak AIL is assumed to grow at an average annual rate of 2.5% to 2027 and 1.9% to 2037.

As discussed by AESO in its 2016 Long-term Outlook report, the reference case assumes the Alberta Government will legislate the Climate Leadership Plan (CLP) and that the CLP will support the phase-out of coal-fired power plants by 2030 [41]. The Climate Leadership Report to Minister (CLRM) advises that 50-75% of retired coal capacity be replaced with renewables by 2030. The remaining 25-50% is assumed to be replaced by combined cycle and simple cycle gas-fired generation to support the integration of intermittent renewables and accommodate load growth. Further, in September 2016, the Alberta Government announced a target of 5,000 MW clean energy by 2030 that will be served by wind, solar, and hydro [123]. Because of the great resource potential and cost advantages of wind generation, it is assumed that wind will be an appropriate technology to support near-term renewable penetration targets. An addition of 385 MW solar capacity is modelled in the reference scenario based on solar PV projects under development (see Table 7) and assuming a 5,000 MW addition of wind, an amount that will be difficult to meet through wind alone [124].

Table 7: List of solar PV projects under development in Alberta *[124]*

Name of the project	Capacity
GTE Solar at Brooks	15 MW
BluEarth Renewables, Burdett	20 MW
BluEarth Renewables, Yellow Lake	19 MW
Electricite de France (EdF)	68 MW
Brownfield site of Imperial Oil's former Leduc Gas Conservation Plant, Devon	23 MW
Suncor, Handhills	80 MW
Suncor, Forty Mile	80 MW
Suncor, Schuler	80 MW

AESO reported 42 MW of biomass power in a connection queue and another 330 MW Amisk hydroelectric project currently in review phase that were modelled in a reference scenario [125, 126]. Geothermal and nuclear generation have large upfront capital costs and difficult regulatory processes, which makes them more suitable for long-term than near-term development [127]. After 2037, the growth rate for the years 2030-2037 was used to forecast the capacity addition for natural gas and wind-type power plants. For hydropower and solar type plants, projections are based on AESO's alternate mid-growth scenario. A 2013 report prepared for the Independent Power Producers Society of Alberta by EDC Associates projects 30,000 MW generation in Alberta by 2050 to cover growing demand, and the developed model projects it to be 31,111 MW [128]. Figure 24 shows the projection of capacity for various electricity generation types. In this figure, projections from 2016-2037 are based on AESO's 2016 LTO report [115] and projections for the years 2037-2050 are based on calculated growth rates.

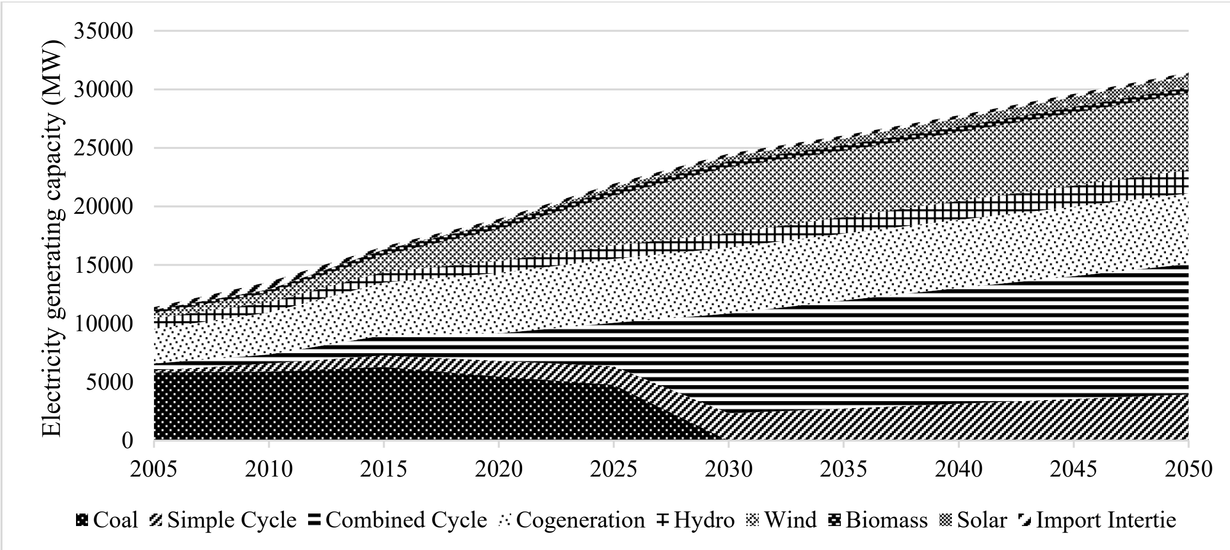


Figure 24: Technology-wise generation capacity projection from the reference scenario for the years 2005 - 2050

It is assumed that for the study period water intensity for the electricity sector will not change [62]. As 90-95% of the water is used for cooling purposes and until new technology (such as dry cooling) is implemented in the thermal power generation, water intensity will remain constant. Due to the unavailability of data, the projection of GHG emission intensity for power plants is assumed to be remain constant as well.

The capacity factor for various technologies is assumed to be constant over the study period except for natural gas combined cycle plants, as presented in Table 8, which are based on AESO's 2015 Annual Market Statistics [117].

Table 8: Technology-wise capacity factor for the forecast period *[117]*

Year	Coal	Simple Cycle	Combined Cycle	Cogeneration	Hydro	Wind	Biomass	Nuclear	Solar
2016 - 2050	80%	10%	32%, 72%*	60%	23%	32%	65%	90%	20%

*It is assumed that capacity factor of combined cycle power plant will increase from current 32% to 72% in year 2020 due to heavy coal retirement.

For combined cycle power plants, since coal power plants will be phased out and replaced by natural gas combined cycle plants and wind power plants, natural gas combined cycle power plant capacity factors must increase. In the reference scenario, there is a heavy coal capacity retirement in 2020 (794 MW), so it is assumed that the capacity factor for combined cycle plants changes to 72% in 2020, thereby acting as a baseload supply.

3.5. Alberta power sector validation

3.5.1. LEAP model validation

Model validation is an important step to assess accuracy. The values reported by the Alberta Utilities Commission (AUC) and the National Energy Board (NEB) differ because the AUC data is based on actual generation and the NEB data is based on demand met by the electricity sector; therefore, both are used for validation [39, 60]. The LEAP model uses the power plant's process efficiency, exogenous capacity, maximum availability, merit order, and dispatch rule to calculate Alberta's total electricity supply required to meet demand. Hence, it requires these input parameters from the past several years. The input parameters are given in Table 9 and Table 10.

Table 9: Net Installed Capacity (MW) by resource *[60, 64, 129, 130]*

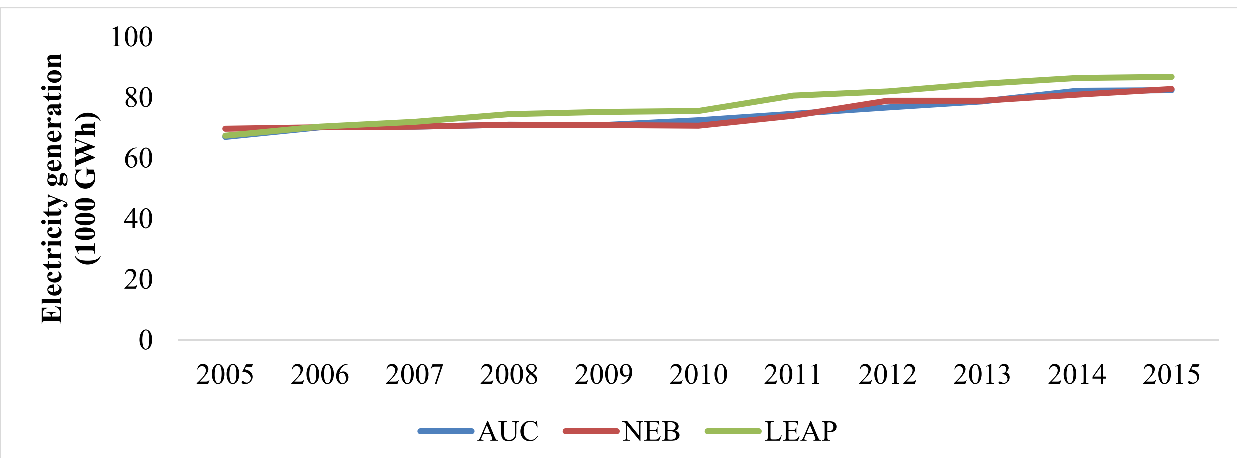
Year	Coal	Simple Cycle	Combined Cycle	Cogeneration	Hydro	Wind	Biomass	*Other	Total
2005	5,839.60	1,081.00	797.0	2,892.2	899.70	276.70	308.12	55.15	12,149.47
2006	5,863.60	461.60	797.0	3,065.9	899.70	386.20	313.10	54.05	11,841.15
2007	5,917.90	460.00	797.0	3,168.2	899.72	525.20	313.10	54.05	12,135.17
2008	5,918.30	572.90	797.0	3,453.5	899.70	525.20	313.10	74.10	12,553.80
2009	5,971.30	787.10	797.0	3,554.5	900.00	591.20	323.20	72.50	12,996.80
2010	5,735.30	787.90	797.0	3,632.6	900.00	723.20	340.20	73.30	12,989.50
2011	5,631.80	803.85	797.0	3,650.6	899.90	895.40	358.70	73.75	13,111.00
2012	5,690.33	834.66	797.0	4,051.1	899.92	1,113.30	413.80	97.75	13,897.84
2013	6,258.30	821.40	830.0	4,159.8	900.25	1,113.25	416.65	97.75	14,597.40
2014	6,258.00	1,165.63	830.0	4,165.0	900.25	1,458.90	438.33	97.75	15,313.86
2015	6,266.80	890.86	1690.0	4,372.1	902.20	1,490.80	423.73	96.75	16,133.24

*Oil, Diesel, Waste Heat

Table 10: Alberta power sector input parameters *[117, 120]*

Generation type	Process Efficiency	Maximum Availability	Dispatch Rule
Subcritical coal	33.60%	85%	Based on merit Order
Supercritical coal	39.50%	85%	Based on merit Order
Simple cycle	38.00%	79%	Based on merit Order
Combined cycle	51.00%	65%	Based on merit Order
Cogeneration	84.00%	67%	Based on merit Order
Hydropower	95.00%	25%	Based on merit Order
Wind	35.00%	32%	Based on merit Order
Biomass	25.00%	65%	Based on merit Order
Solar	15.00%	20%	Based on merit Order

The total annual electricity supply calculated by LEAP model shown in Figure 25. The LEAP model results and the electricity generation figures reported by provincial and federal agencies are shown in Figure 25.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AUC (Generation)	66.99	70.18	70.43	70.98	70.92	72.48	74.57	76.77	78.68	82.18	82.4
NEB (Demand)	69.7	70.2	70.4	71	70.9	70.7	74	78.9	78.9	80.9	82.8
LEAP Model	67.4	70.4	72	74.5	75.2	75.6	80.6	82	84.5	86.4	86.8

Figure 25: LEAP model validation

Figure 25 shows that the LEAP model closely follows the electricity generation pattern reported by the AUC and the NEB and thus can be used to forecast energy consumption in Alberta's power generation sector. Figures 26-30 show validation by plant type. In Alberta, there are around 125 individual power plants that operate at different generation levels every day; hence, the capacity factor of each power plant is different. In addition, the dispatch rule in Alberta is dynamic; it changes every hour based on the lowest bid price. Therefore, small variations in electricity generation from each power plant type can be seen.

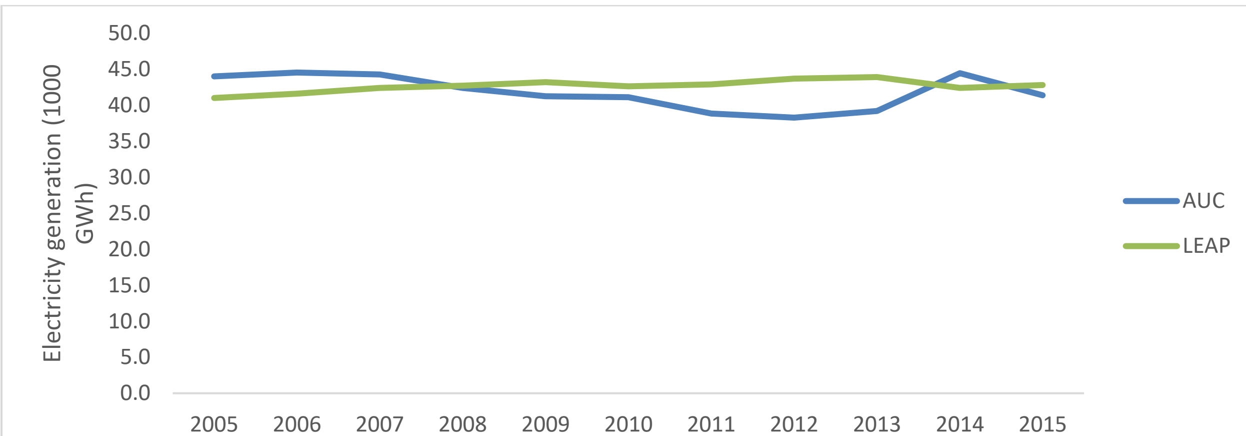


Figure 26: Coal power generation validation

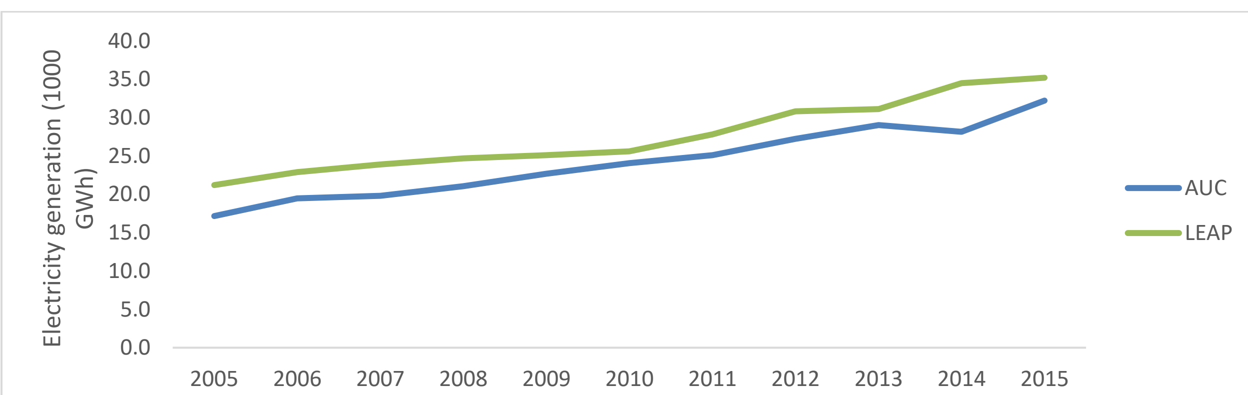


Figure 27: Natural gas power generation validation

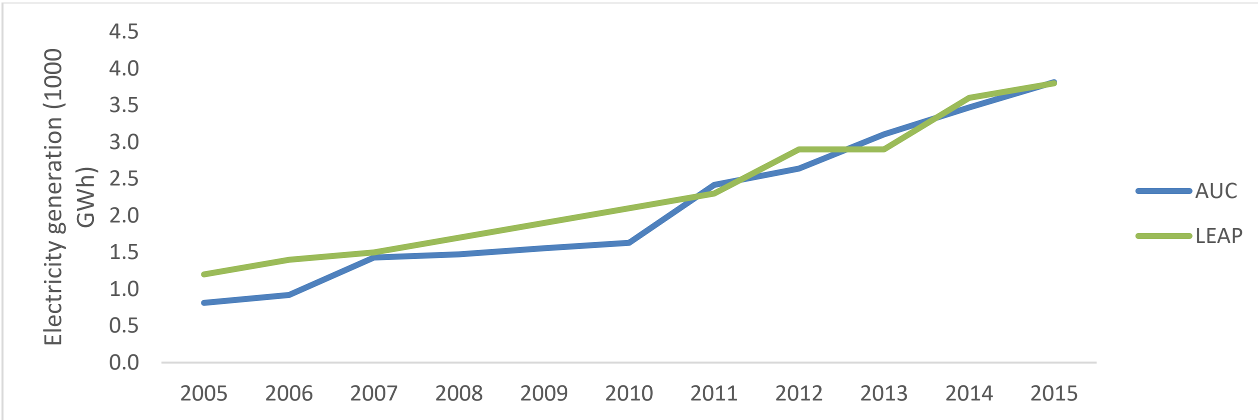


Figure 28: Wind power generation validation

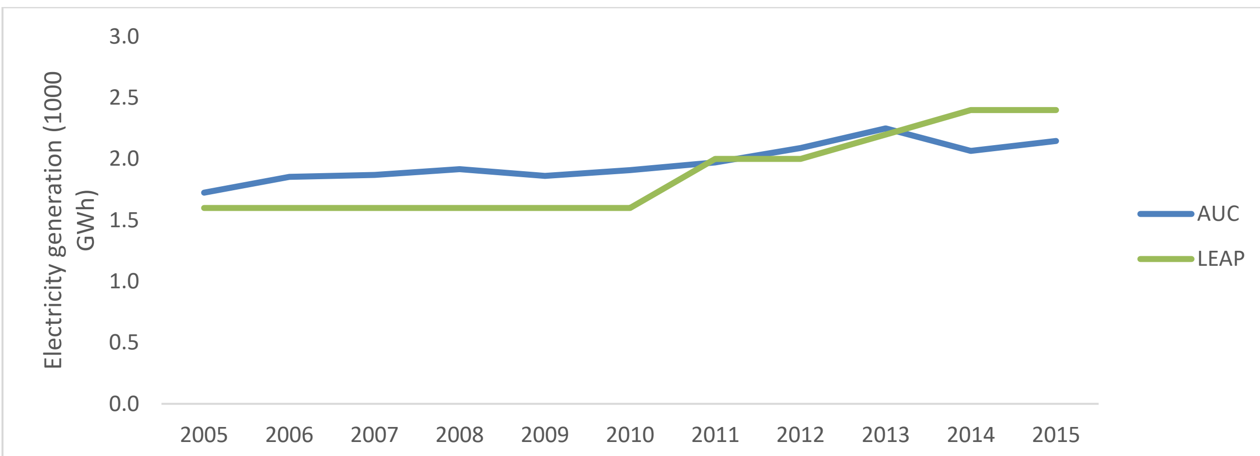


Figure 29: Biomass power generation validation

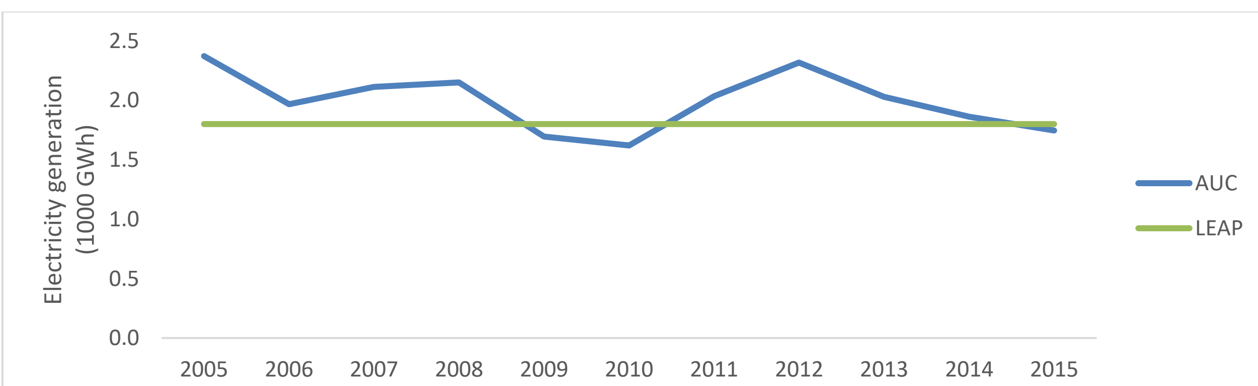


Figure 30: Hydropower generation validation

3.5.2. WEAP model validation

Model validation is an important step to verify correctness. AMEC Earth & Environmental Ltd. prepared a report for Alberta Environment that forecasts water use for all industrial sectors rather than for the electricity generation sector alone [30]. The total water consumption by power plants in Alberta was reported by ATCO Power, Capital Power Corporation, and TransAlta with the assistance of Golder Associates Ltd [62].

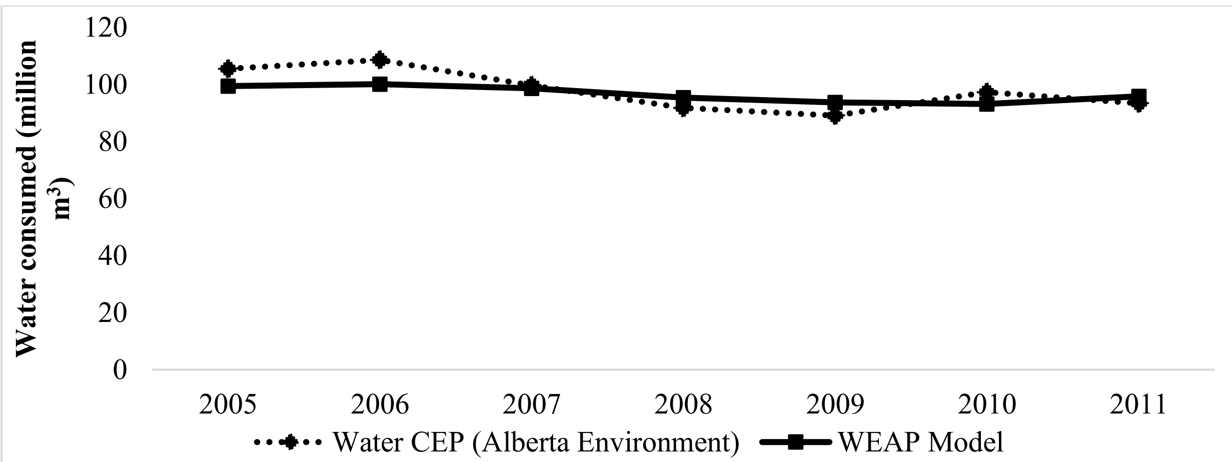


Figure 31: WEAP model validation

The results between the WEAP model and the Water Conservation, Efficiency, and Productivity (CEP) report are compared in Figure 31. The decreasing trend reported by the Alberta's Water CEP report can be attributed to the expected decline in coal-fired electricity generation. As evident from the figure, the model follows a similar trend to Alberta's CEP plan. Water consumption by cogeneration power plants is not included in the figure because it was not included in Alberta's Water CEP Plan.

Figure 31 shows that the results from the WEAP model closely follows the water consumption pattern report from the Water CEP Plan, and thus the model can be used as a base to forecast water consumption in Alberta's power generation sector.

3.6. Energy scenario development

Alberta's electricity generation sector in 2015 included 16.74% electricity generation capacity from renewables, which was 9.44% of Alberta's electricity in the reference scenario [64]. Based on various earlier studies from different organizations, several electricity generation mix scenarios are modelled to understand their impact on water sources in future.

The GHG mitigation scenarios for power plants were selected based on the literature review of the electricity generation mix and in discussion with experts and were developed in the WEAP and LEAP models. Water use and consumption for the electricity generation sector will be highly influenced by proposed GHG emissions regulations and technology advances to improve water intensity in the power sector [62]. Hence, climate change mitigation scenarios were developed to study the impact of regulations and technology improvements on water resources. These scenarios were developed using the reference scenario as the baseline with changes in the electricity generation mix as input parameters. The penetration rate for each scenario was selected on a case-by-case basis depending on its implementation potential in Alberta between 2016 and 2050. Stillwell et al. and Yazawa et al. concur that future water trends in the power sector will be driven by a shift towards more efficient power plants with more advanced cooling systems and low carbon energy technologies [131-133]. The integrated model provides GHG mitigation potential and impacts on water resources for each scenario compared to the BAU, which reflects the accurate outcome of the new generation mix. All the GHG mitigation scenarios assume the same load growth as the reference case but with a different generation mix. Nine scenarios were investigated in detail for this GHG emission and water analysis and are summarized in Table 11.

Table 11: GHG mitigation scenarios considered in this study and their key assumptions

Scenario	Acronym	GHG mitigation scenario considered	Assumption
Scenario 1	GHG1	Increased renewable penetration	9,300 MW of renewables added by 2037; (% renewables by 2030 = 40.9%) 600 MW of new wind added each year from 2018-2029 100 MW of solar generation capacity added annually from 2020-2029 and another 378 MW by 2050 330 MW and 770 MW of hydro generation in 2027 and 2036, respectively, and another 1,100 MW by 2050.
Scenario 2	NUC2	Nuclear energy penetration in Alberta's power sector replacing projected combined cycle	Two 650 MW reactors by 2028 (1,300 MW) replacing 1,625 MW NGCC Another 650 MW by 2044 replacing 812 MW NGCC
Scenario 3	NUC3	Nuclear energy penetration in Alberta's power sector replacing Athabasca cogeneration activity	Two 650 MW reactors by 2028 (1,300 MW) replacing 1,950 MW cogeneration Another 650 MW by 2044 replacing 975 MW cogeneration
Scenario 4	HYD4	Hydropower penetration in Alberta's power sector replacing projected combined cycle	330 MW and 770 MW of hydro generation in 2027 and 2029, respectively, replacing 352 MW NGCC by 2030 Another 1,100 MW by 2050 replacing 352 MW NGCC
Scenario 5	BIO5	Biomass - whole tree based biomass power penetration in Alberta's power sector replacing projected combined cycle	In Alberta, mixed hardwood and spruce are abundantly available and could be used to support a large power plant for 30+ years; assumed forest biomass yield of 84 dry tonnes of biomass per hectare 2,000 MW of whole tree biomass by 2030 replacing 1,805 MW of NGCC
Scenario 6	BIO6	Biomass - forest harvest residue based biomass power penetration in Alberta's power sector replacing projected combined cycle	Yield of forest harvest residue is 0.247 dry tonnes of residue per gross hectare. 2,000 MW of forest harvest residue biomass by 2030 replacing 1,805 MW of NGCC; forest residue potential = 2,655MW

Scenario	Acronym	GHG mitigation scenario considered	Assumption
Scenario 7	BIO7	Biomass-agricultural straw based biomass power penetration in Alberta's power sector replacing projected combined cycle	A study on biomass potential suggests an additional 6-7 million dry tonnes of straw is available per year that can support a ca. 2,000 MW power plant from uncollected straw alone. 2,000 MW of agriculture straw biomass by 2030 replacing 1,805 MW of NGCC
Scenario 8	CTG8	Late conversion of coal power plants to gas power plants	6 coal power plants that could continue to operate beyond 2030 are converted to natural gas power plants by 2029.
Scenario 9	CTG9	Early conversion of coal power plants to gas power plants	6 coal power plants that could continue to operate beyond 2030 are converted to natural gas power plants by 2025.

Table 12: Capacity additions for each scenario for 2030 and 2050

Scenario	Power plant type	2016	2030	2050
Reference	Coal subcritical	5351	0	0
	Coal supercritical	929	0	0
	Simple cycle	1065	2336	3953
	Combined cycle	1845	8528	11141
	Cogeneration	4632	5609	5953
	Wind	1713	5663	6573
	Hydropower	894	1224	1994
	Biomass	455	497	497
	Solar	14	385	1000
	Total	**16898**	**24242**	**31111**
GHG1: Optimistic	Coal subcritical	5351	0	0
	Coal supercritical	929	0	0
	Simple cycle	1065	3684	3931
	Combined cycle	1845	7176	8559
	Cogeneration	4632	5548	5953
	Wind	1713	8663	10223
	Hydropower	894	1224	3094
	Biomass	455	497	497
	Solar	14	1000	1378
	Total	**16898**	**27792**	**33635**
NUC2: Nuclear_NGCC	Combined cycle	1845	6903	8704
	Nuclear	0	1300	1950
	Total	**16898**	**23917**	**30624**
NUC3: Nuclear_Cogen	Cogeneration	4632	3659	3028

Scenario	Power plant type	2016	2030	2050
	Nuclear	0	1300	1950
	Total	**16898**	**23592**	**30136**
HYD4: Hydro_NGCC	Combined cycle	1845	8177	10790
	Hydropower	894	1994	3094
	Total	**16898**	**24661**	**31860**
BIO5: Whole tree_NGCC	Combined cycle	1845	6723	9336
	Biomass	455	2455	2455
	Total	**16898**	**24395**	**31264**
BIO6: Forest residue_NGCC	Combined cycle	1845	6723	9336
	Biomass	455	2455	3094
	Total	**16898**	**24395**	**31903**
BIO7: Agriculture Straw_NGCC	Combined cycle	1845	6723	9336
	Biomass	455	2455	3094
	Total	**16898**	**24395**	**31903**
CTG8: Gas_Coal_2030	Coal	6280	0	0
	Combined cycle	1845	8528	11141
	Total	**16898**	**24395**	**31903**
CTG9: Gas_Coal_2025	Coal	6280	0	0
	Combined cycle	1845	8528	11141
	Total	**16898**	**24395**	**31903**

The penetration of renewable technology assumes generation (MWh) replacement as well as different scenarios to meet demand. One of the key aspects is that, with capacity replacement, different power plants have varying capacity factors, so direct one-to-one capacity replacement will result in unmet demand. To estimate the replacement capacity of technology 1 with technology 2, capacity factor analysis is used. Equation 10 shows the estimation method:

$$CF_{T1} * GenCap_{T1} = CF_{T2} * GenCap_{T2} \quad (10)$$

where

CF_x = Capacity factor for Technology x

$GenCap_x$ = Generating capacity for Technology x

3.6.1. Scenario 1: AES1 – Alternate mid growth

The alternate-policy scenario assumes the same load growth as the reference case but with a strong interpretation of Alberta's Climate Leadership Plan. This scenario assumes that there is support for 9,300 MW of renewables by 2037 instead of the 5,000 MW assumed in the reference scenario [115]. Because of higher levels of intermittent renewable development, more simple cycle capacity is added than combined cycle due to its faster ramp up and down rates [62]. The capacity additions up to 2037 were adopted from the 2016 AESO Long-term Outlook report [115]. After 2037, for each generation type other than hydropower, the 2030-2037 growth rate is assumed for future years. For hydropower plants, in the alternate mid growth scenario, 1,100 MW is planned from 2015-2037 and it is assumed that 1,100 MW will be added from 2037-2050.

3.6.2. Scenario 2: NUC2 – Nuclear energy penetration in Alberta's power sector replacing combined cycle

Nuclear energy penetration was not modelled in the reference scenario because of its large capital investment and challenging regulatory processes [134]. Scenario 2 is based on a previous consideration of nuclear development by Bruce Power in Alberta [135]. In 2008, Bruce Power applied for a license to build a 4,000 MW capacity nuclear power plant 30 km north of Peace River [136]. As part of the decision making process, the Nuclear Power Expert Panel was set up to present facts on nuclear power to Albertans [137]. The results of the Alberta Nuclear Consultation report show that 45% of Albertans were in favor of nuclear power plants on a case-by-case basis, 19% said government should encourage proposals, and 27% were opposed to proposals [138]. In late 2011, Bruce Power deferred the plan because of local residents' worry of the impacts on wildlife and water in the area [139].

In scenario 2, nuclear power generation is considered as a feasible long-term option for Alberta's growing energy needs. Nuclear energy is a reliable energy source and provides on-demand baseload electricity. Hence, nuclear power is well suited to replace combined cycle power plants. Based on the capacity factor analysis for the two technologies, a 1 MW nuclear power plant can replace a 1.25 MW combined cycle plant because the capacity factor of a nuclear plant by 2027 is assumed to be 90% and of a combined cycle plant, 72%. In terms of nuclear energy penetration, it is assumed that 2 nuclear reactors of 650 MW each will come online in 2028 and a 650 MW nuclear reactor will be installed in 2044. Figure 15 shows the electricity generation growth profile for this scenario. By 2050, the capacity of nuclear power generation will increase to 1,950 MW and replace new combined cycle installations to meet 2,437 MW of combined cycle capacity. This is based on the maximum level of considered generation for Alberta as per a corporate announcement by Bruce Power reported by AESO's generation planning forecast [136].

3.6.3. Scenario 3: NUC3 – Nuclear replacing cogeneration plants, supporting oil sands growth

The background for the consideration of nuclear energy is discussed in the previous section. Although there are currently no plans to construct a nuclear power plant in Alberta, the oil industry has expressed interest in nuclear energy and considers it to be a serious option, provided that the technology meets industry technical requirements, such as steam pressure [140]. This scenario is modelled considering Canada's goal to reduce GHG emissions by 30% in 2030 from 2005 levels [141]. It is assumed that current cogeneration plants of 3,396 MW capacity in the Athabasca region are replaced by 1,300 MW nuclear energy in 2028 and another 650 MW in 2044, together replacing 2,925 MW of cogeneration capacity by 2050.

3.6.4. Scenario 4: HYD4 – Hydropower plants replacing combined cycle plants in Alberta

At present, Alberta has a hydropower capacity of 894 MW (1,745 GWh annually) of hydroelectricity [60]. The ultimate hydroelectric energy potential that could be extracted is about 42,000 GWh per year [55]. Approximately 75% of this potential is from northern Alberta (the Athabasca, Peace, and Slave river basins) and the rest is in the Red Deer, North Saskatchewan, and South Saskatchewan river basins. A 2010 report on Alberta's hydroelectric energy resources for the Alberta Utilities Commission states that major projects in the northern basin and smaller projects in the southern basin can be developed in the next 30 years [142]. According to the report, in this period total hydropower development could be as much as 20% of the ultimate potential, i.e., 10,600 GWh per year. Based on this 10,600 GWh, around 5,260 MW of hydropower plants can be developed by 2040 considering a 23% capacity factor. A new capacity of 5,260 MW hydropower seems overambitious due to the high capital investment; therefore, in this scenario, an increment of 1,100 MW hydropower is considered by 2037 (894 MW is planned for the reference scenario) based on AESO's alternate mid growth scenario and another 1,100 MW by 2050. Hydropower, a reliable source, is an ideal means of replacing 704 MW from combined cycle power plants, based on a capacity factor analysis. Hydropower in northern Alberta can be integrated with oil sands. The assessment was carried out by the Canadian Energy Research Institute [143, 144].

In the early 1980s, two large hydro projects in the province were investigated for Dunvegan hydro, one on the Peace River and the other on the Slave River along the Alberta-Northwest Territories boundary [142]. The projects were considered for prospective large hydro development by early 2000s. The Peace River project would develop an estimated 38.8 m of gross head with an installed capacity of about 900 MW. The estimated construction time is 9.25 years. Based on AESO figures, this converts to an annual production of just over 4,300 GWh (assuming a 54% capacity factor).

The Slave River project has an estimated head of about 35 m and a projected installed capacity of 2,000 MW. The Government of Alberta developed these estimates in the early 1980s but neither project has been developed, largely due to financial risk, high cost, long lead time, and concerns over environmental impact. The Dunvegan site was recently approved for a 100 MW low head run-of-river development that is not yet under construction [145].

3.6.5. Scenario 5: BIO5 – Whole tree biomass replacing combined cycle plants

Forest and agricultural biomass are the two main potential sources of biomass-based energy production in Alberta. According to earlier studies on the potential of biomass in Alberta, approximately 7 million bone-dry tonnes of forest biomass (e.g., forest residues) and 15 million bone-dry tonnes of agricultural biomass (e.g. crop residue or straw) are produced per year in Alberta for an energy content of about 380-420 petajoules [146]. In Alberta, mixed hardwood and spruce are abundantly available and could be used to support a large power plant over a period of 30+ years with a forest biomass yield of 84 dry tonnes of biomass per hectare [147]. A forest residue potential of 2,655 MW is identified based on research by Weldemichael [148].

This scenario considers of the use of whole trees for power generation. Biomass is considered to be a baseload power source ideal for replacing a combined cycle power plant [149]. In this study, a capacity replacement of up to 2,000 MW is assumed by 2030 based on 84 dry tonnes biomass replacing 1,800 MW of power from natural gas combined cycle plants.

3.6.6. Scenario 6: BIO6 – Agricultural straw biomass replacing combined cycle plants

Agricultural biomass in Alberta consists mainly of wheat and barley straw. A recent study suggests that about 6-7 million dry tonnes of straw is available per year after the current use of straw is considered [150]. This scenario considers the use of agricultural straw biomass for power generation. Biomass is considered to be a baseload power source ideal for replacing a combined cycle power plant [149]. In this study, the capacity replacement of up to 2,000 MW biomass power plant potential from agriculture straw is taken based on published yield data.

3.6.7. Scenario 7: BIO7 – Forest residue biomass replacing combined cycle plants

Forest residues are the limbs, tops, and branches that remain after the logging operations. The current practice for harvesting trees in Alberta involves felling the trees in the stand, dragging them to the roadside, delimbing them on the roadside, and transporting the main stem to pulp and lumber operations. The residue generated by delimbing is known as forest residue. It is forwarded, piled, and then burned to prevent forest fires. This residue is estimated to constitute about 15-25% of the total biomass of a tree [150]. In Alberta, forests have an average rotation period of 100 years; the yield of forest residue can be considered 0.247 dry tonnes of residue per gross hectare [147, 148]. This scenario considers the use of forest residue biomass for power generation. Biomass is considered to be a baseload power source ideal for replacing a combined cycle power plant [149]. In this study, a capacity replacement of up to 2,000 MW is assumed by 2030 replacing 1,800 MW of power in natural gas combined cycle plants.

3.6.8. Scenario 8: CTG8 – Conversion of coal power plants to natural gas by 2029

This scenario was developed based on the announcement by TransAlta to convert their coal power plants to gas in order to help meet Alberta's GHG emissions reductions target [151]. This scenario assumes the conversion of six coal power plants that could continue to operate beyond 2030 to gas plants [41]. The modifications needed to switch a coal boiler to natural gas include new gas burners and piping, combustion air ductwork and control damper modifications, air heater upgrades, gas recirculating fans, control systems modifications, and other site-specific modifications, as well as any pipeline installation that would be necessary to supply the unit's gas combustion following the conversion [152]. For this analysis, based on the United States Environmental Protection Agency's (US EPA) assumptions on cost and performance associated with coal-to-gas conversion, a 500 MW pulverized coal unit would have a capital cost of $137/KW (with the base year as 2014) to convert the boiler so that it could burn natural gas [152]. Further, it is assumed that due to a reduced need for operators, maintenance materials, and maintenance staff, fixed O&M costs would be reduced by 33% and variable O&M costs by 25% through reduced waste disposal, auxiliary power requirement, and other miscellaneous expenses [152]. The average capital cost of constructing new pipelines is assumed to be approximately $1 million per mile of pipeline built [152]. The pipeline requirement was estimated based on the nearest source of natural gas production, which is 50 miles for Genesee 1, 2, and 3, and Keephills 3 power plants and 20 miles for the Sheerness plant.

3.6.9. Scenario 9: CTG9 - Conversion of coal power plants to natural gas by 2025

This scenario considers an early conversion of coal power plants to natural gas plants and assumes the conversion of coal power plants to gas by 2025 with the same assumptions as those made for scenario 8.

3.7. Cost of mitigating GHG

The cost of GHG mitigation in each scenario was investigated. The analysis, carried out in integrated LEAP-WEAP model, is not intended to provide an analysis of financial viability. Instead, it is a detailed cost potential of each scenario throughout the proposed project's lifetime, converted to its present value, i.e., 2015. The scenarios developed for Alberta power plants to identify impacts on water consumption involve different technology implementation costs, i.e., capital and operating & maintenance. In the WEAP model, new data variables were created to model the capital costs, fixed and variable operating costs, and capacity factors of different power plants. Using these parameters, the cost of mitigating GHG considering the BAU scenario as the base was calculated, which allowed us to perform an incremental cost analysis with different electricity generation mixes. GHG mitigation costs are typically calculated by dividing the net present incremental cost by the total GHG mitigated (calculated in LEAP) in a timeframe with units of $/tonnes of CO_2 eq. Additionally, incremental water use for the scenarios with respect to the reference scenario was calculated from the WEAP model and combined in a water-carbon cost curve. Equations 11-14 show how the cost analysis was conducted in this study.

$$\text{Cost of GHG mitigated} = \frac{\text{Incremental cost of electricity production}}{\text{Total GHG mitigated}} \tag{11}$$

$$\text{Incremental cost of electricity production} = (\text{ACC} + \text{Fixed O\&M} + \text{Variable O\&M})_{\text{Scenario xyz}} - (\text{ACC} + \text{Fixed O\&M} + \text{Variable O\&M})_{\text{Reference}} \tag{12}$$

$$\text{Annualized Capital Cost (ACC)} = \text{CC} * \text{CRF} \tag{13}$$

$$\text{Capital Recovery Factor (CRF)} = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{14}$$

where

i = discount rate

n = life of the equipment/ power plant

Fixed O&M = Fixed Operating & Maintenance cost

Variable O&M = Variable Operating & Maintenance cost

Table 13 shows the input parameters used for calculating the cost of mitigating GHG. Cost parameters for each power plant were developed after data were gathered from the literature and harmonized and updated it to the 2015 Canadian dollar. Location factors of 1.08 and 2.16 were used for capital cost and fixed O&M cost for the conversion of cost data from the US Gulf Coast to Alberta, Canada [153]. Fuel prices were calculated based on Alberta's coal price (1$/GJ) and varying natural gas costs from NEB projections [39, 118, 154]. The cost data for various scenarios were converted to 2015 Canadian dollars and corrected to consider inflation based on Bank of Canada rates where applicable [155, 156]. The discount rate in the economic analysis was considered to be 5%, a figure used in similar recent studies on GHG mitigation [157, 158].

Table 13: Power plant input parameters for cost calculation and source in 2015 CAD

Power plant type	Overnight capital cost ($/KW)	Fixed O&M cost ($/KW)	Total Variable O&M cost ($/MWh)	Fuel cost ($/MWh)	Heat rate (GJ/MWh)	Source
Subcritical coal	1666.47	47.07	3.32	10.50	10.5	[118, 120, 159, 160]
Supercritical coal	2309.14	47.07	3.32	9.37	9.4	[118, 120, 159, 160]
Simple cycle	1258.07	18.98	18.50	36.00	9	[120, 153, 154, 161]
Combined cycle	1594.71	9.30	2.60	18.40	8	[39, 120, 156, 159]
Cogeneration	1499.03	8.72	3.32	44.00	11	[39, 120, 156, 159]
Nuclear	7302.34	246.35	2.62	3.50	-	[154, 161]
Biomass straw	3082.21	88.45	62.98	Included in O&M	-	[147, 162, 163]
Biomass whole tree	2854.40	80.41	56.28	Included in O&M	-	[147, 162, 163]
Biomass forest residue	2854.40	80.41	69.68	Included in O&M	-	[147, 162, 163]
Wind	2952.69	105.54	0.00	0.00	-	[120, 153, 154, 161]
Utility scale solar PV	4688.09	59.77	0.00	0.00	-	[120, 153, 154, 161]
Hydroelectric	4038.51	38.87	0.00	0.00	-	[120, 153, 154, 161]

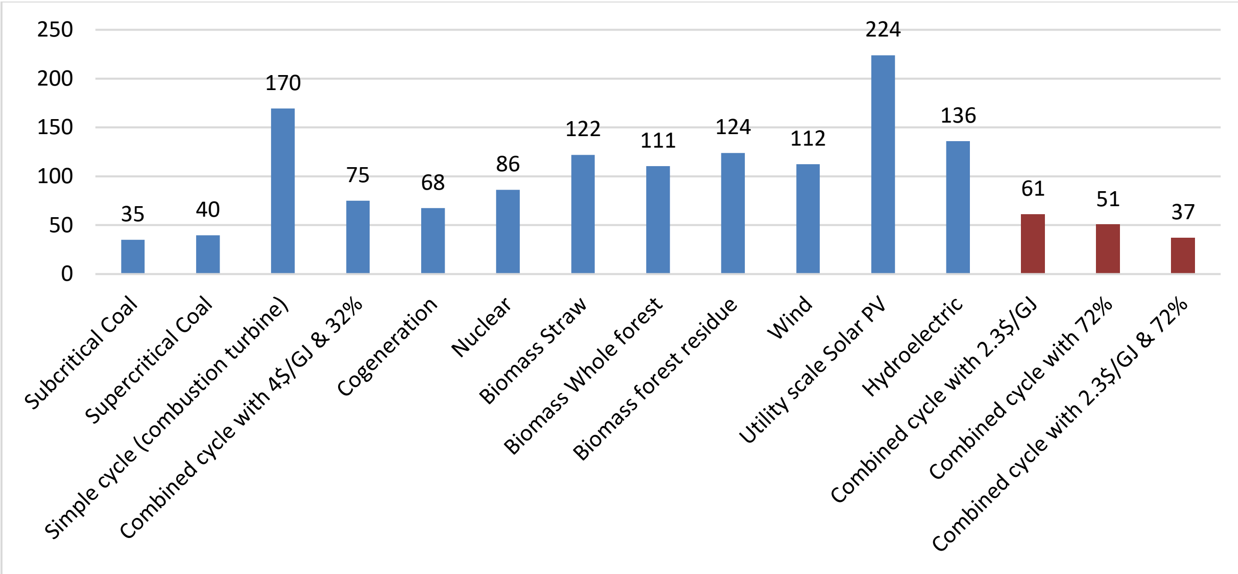


Figure 32: Levelized costs for different generation types for Alberta (2015 CAD $/MWh)

3.8. Results and Discussion

A demand tree was used to calculate the base year electricity supply, GHG emissions from power plants, and corresponding water withdrawal and consumption, on which the BAU scenario was developed for the study period (2005 to 2050). This section discusses the GHG emissions and water withdrawal profile considering projected power plant generation as calculated by the LEAP and WEAP models. The electricity supply from coal power plants in Alberta will be zero by 2030, and these plants will be replaced by natural gas and renewable plants. Combined cycle and wind will absorb 90% of the projected load in Alberta after 2030, as shown in Figure 33.

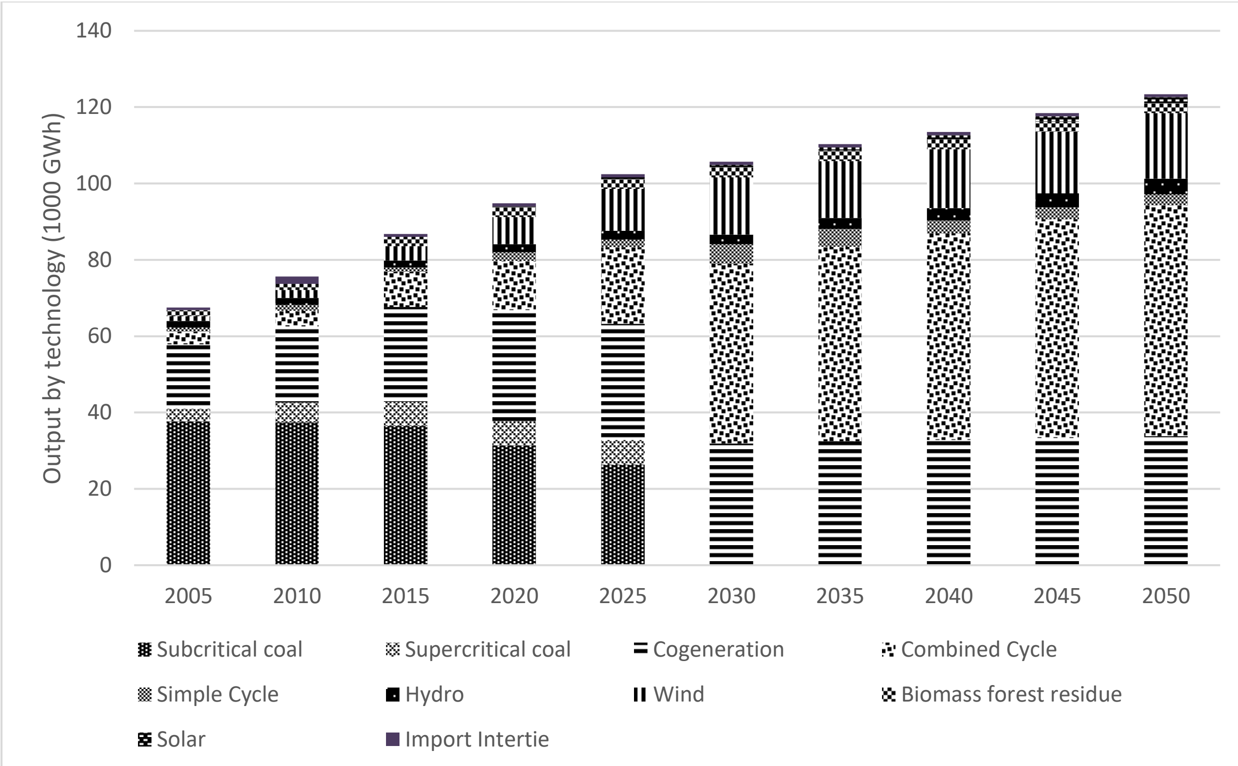


Figure 33: Technology-wise share of electricity supply as projected by LEAP for the business-as-usual scenario

For water demand, we used the generation levels from 2005-2015 and the water use intensities of power plants to calculate net water consumption for the base year in the WEAP model. Figure 34 shows the water consumption as calculated in the WEAP model for each technology.

The synergies and tradeoffs between water resources and power generation have interesting implications for integrated decision making and policy in Alberta. Total water consumption for the year 2015 was estimated to be 124.51 million m^3. In the base case year (that same year), coal power plants consumed the largest amount of water (64.81%) followed by hydropower plants (18.98%). The large amount of water consumption by coal power plants is partly due to larger electricity generation and a relatively high water consumption intensity.

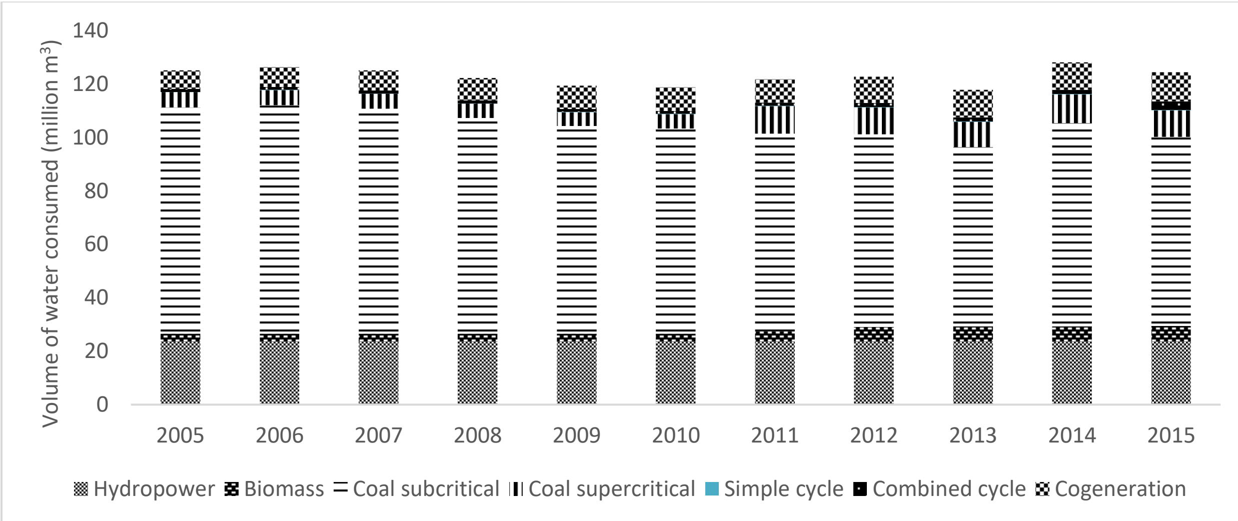


Figure 34: Technology-wise share of water consumption for base case years

Figures 35 and 36 show expected water consumption and GHG emissions, respectively, from 2015-2050 in the business-as-usual scenario. Water consumption is expected to decrease drastically from the base year value of 124.51 million m^3 to 98.08 million m^3 in 2050 and GHG emissions will also fall drastically, from around 52 million tonnes in 2015 to around 29 million tonnes in 2030 and 33.6 million tonnes of CO_2 eq. in 2050. This is predominantly because coal power plants are scheduled to retire by the end of 2030.

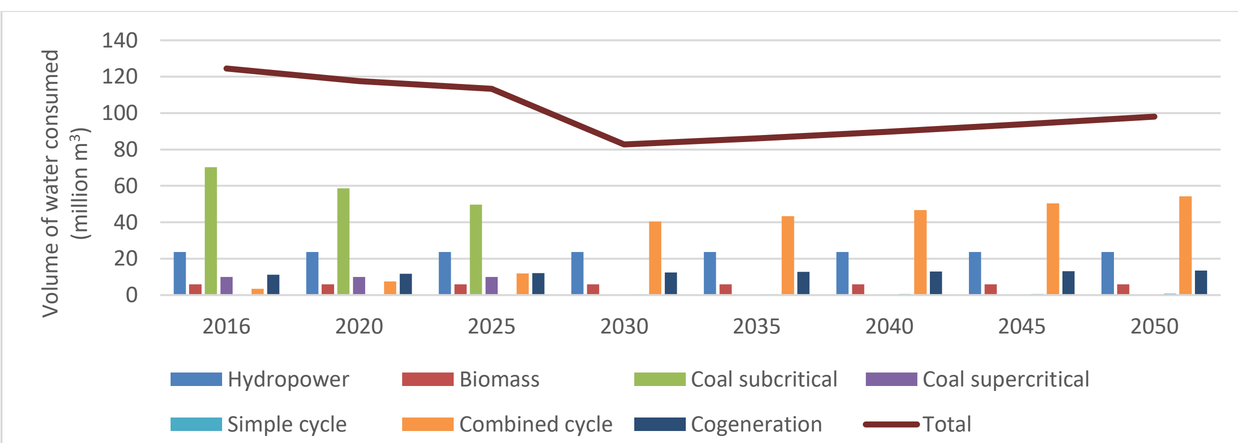


Figure 35: Technology-wise share of water consumption for the business-as-usual scenario

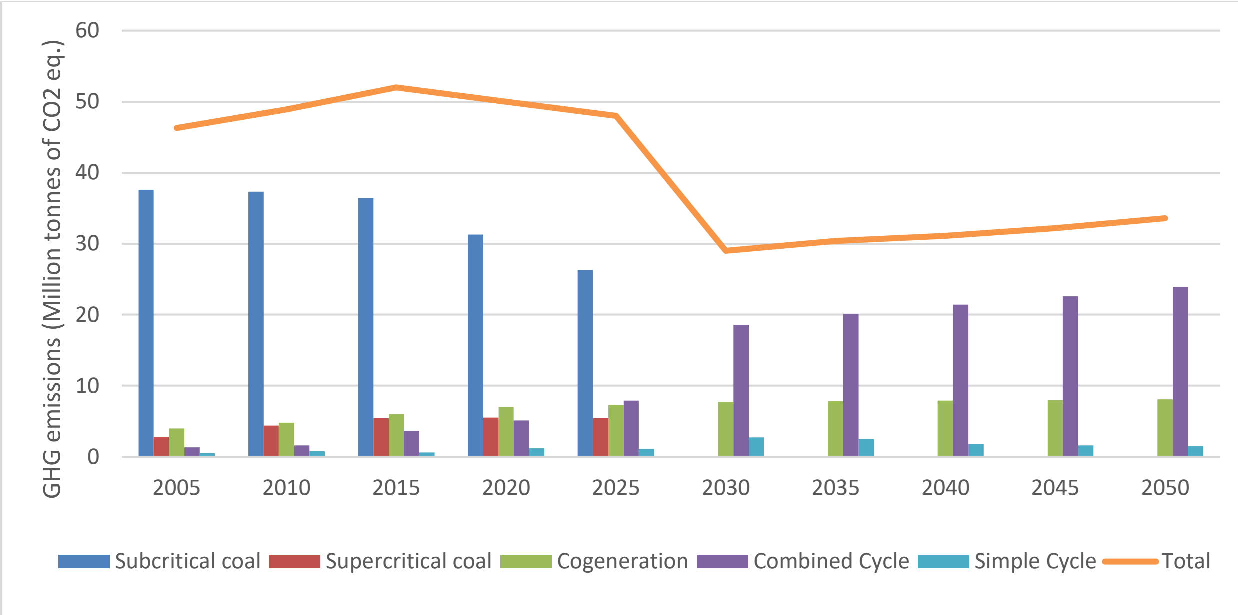


Figure 36: Technology-wise share of GHG emissions for the business-as-usual scenario

The results generated in the WEAP model on water demand for all developed scenarios compared to the reference scenario are summarized in Figure 37, and corresponding GHG emissions are shown in Figure 38. The results from the energy and water modeling and implementation of GHG mitigation scenarios for Alberta's power sector as developed in the LEAP and WEAP models were discussed in detail. The economic aspects are shown in cost curves that compare GHG savings potential, water use, and GHG mitigation costs.

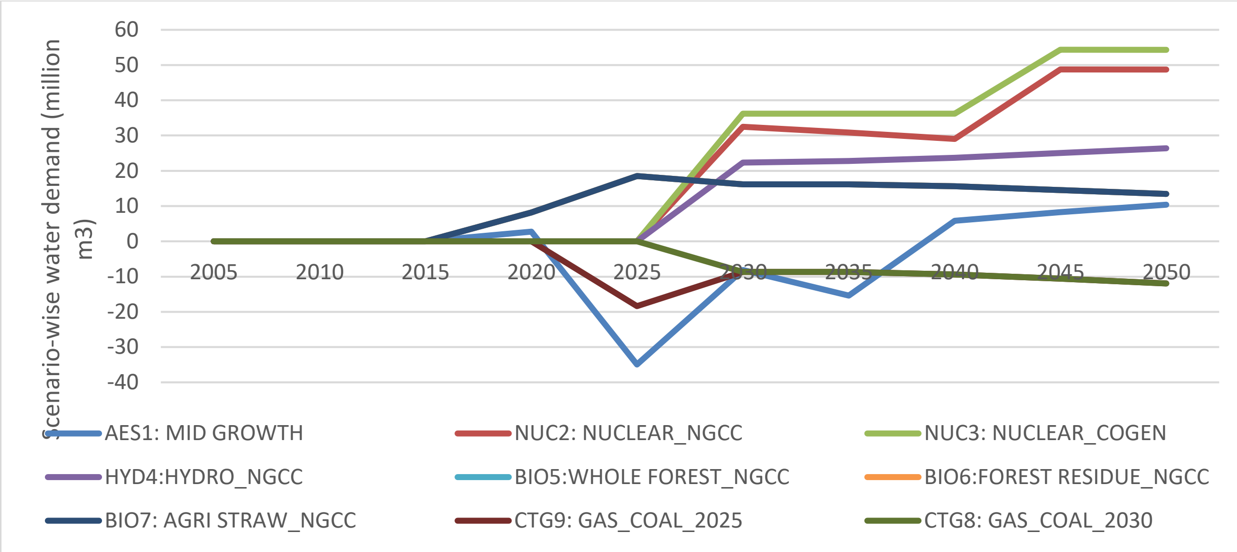


Figure 37: Water demand by scenario compared to the reference scenario

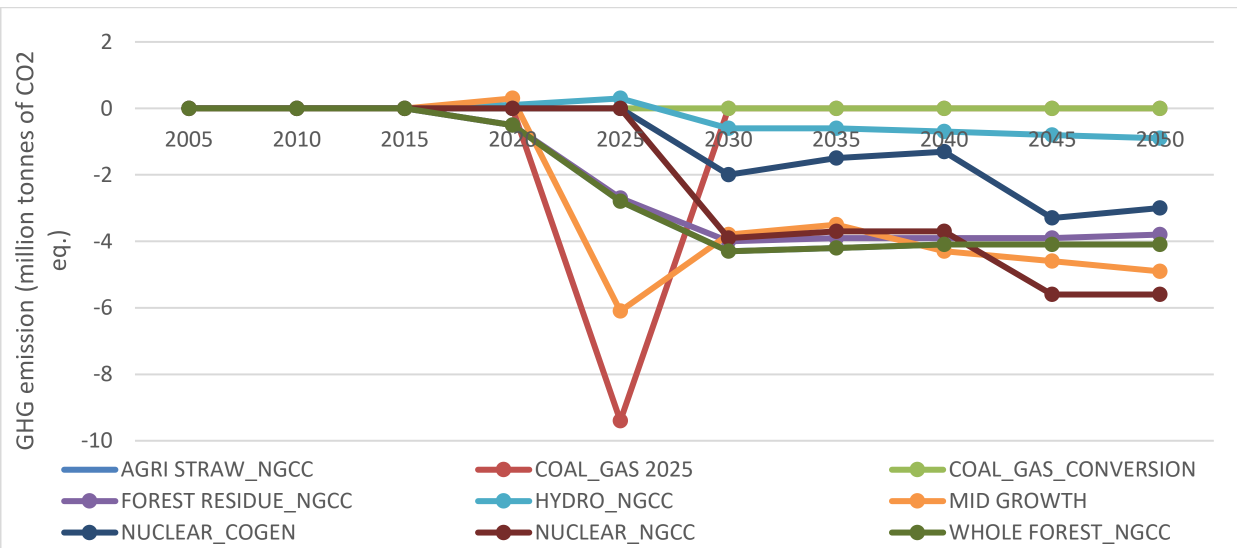
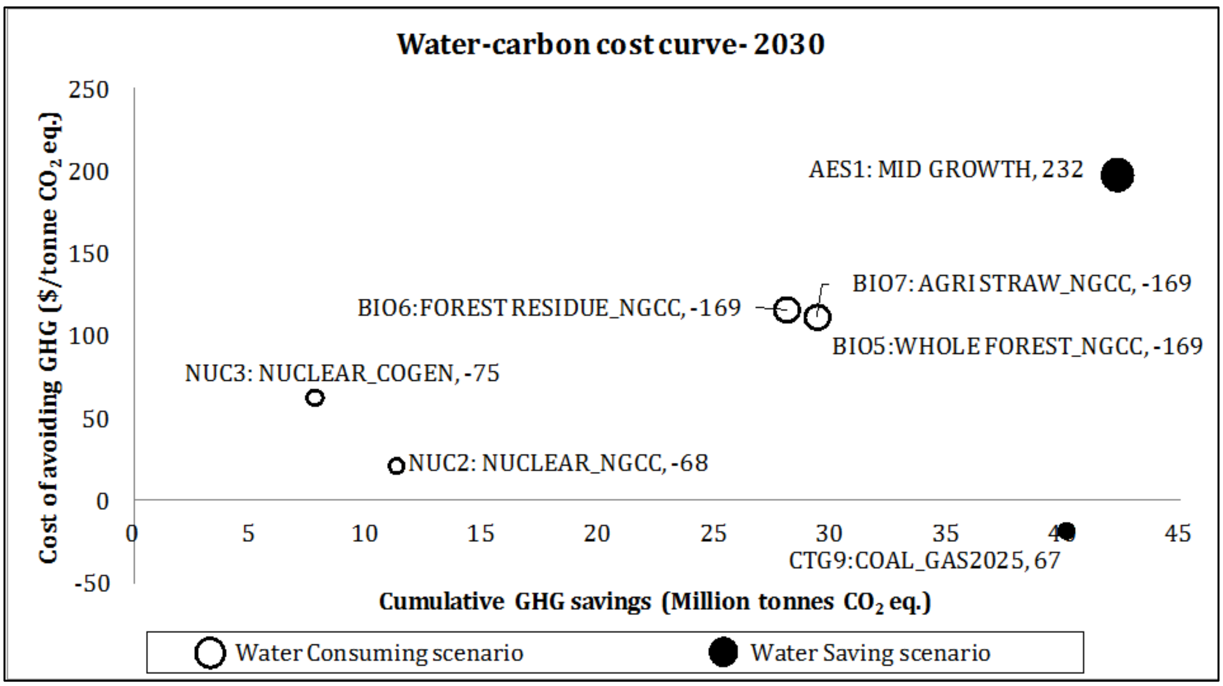


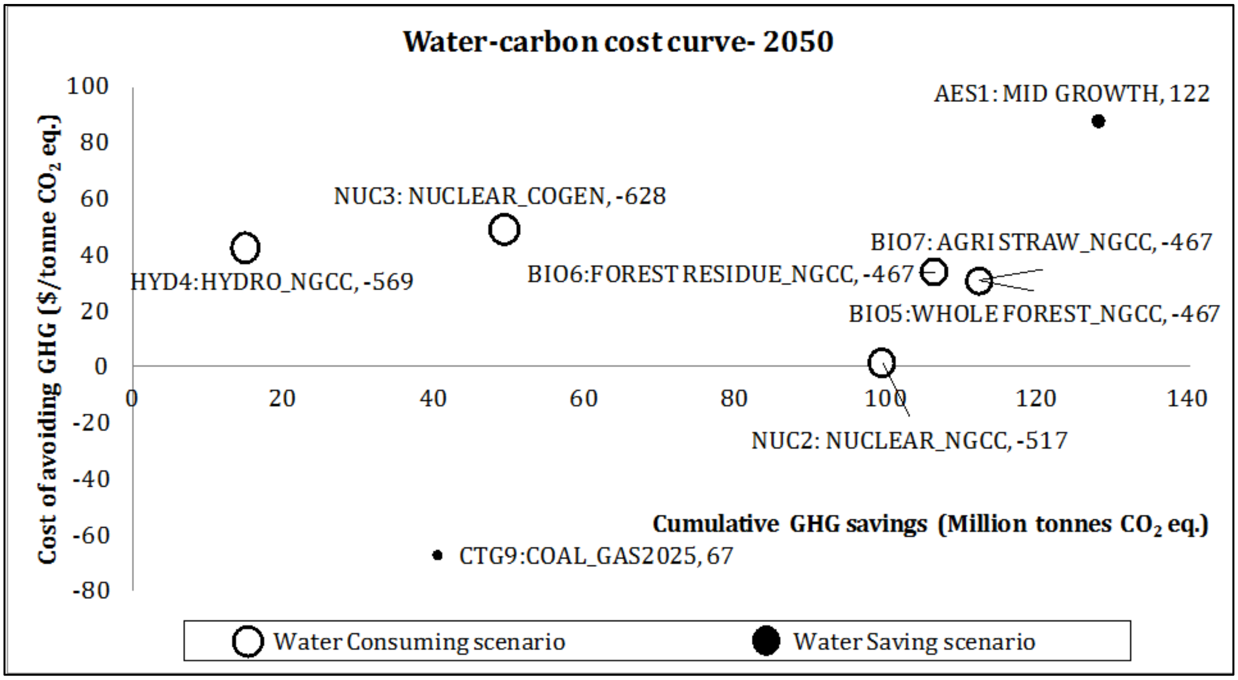
Figure 38: GHG emissions by scenario compared to the reference scenario

To make an informed decision and evaluate the potential of implementing multiple scenarios in Alberta's power sector, one should compare the scenarios in terms of cost as well as the potential to reduce water consumption. A comprehensive comparison of the costs and water savings potential of the scenarios developed in this study is presented through a cost curve developed from the LEAP and WEAP model results. The LEAP model simulates the GHG savings potential of various scenarios and estimates the net present value (NPV) of investment, and the WEAP model calculates the water use for each scenario, thus providing the water-carbon cost curve. In the cost curve shown in Figures 39 and 40, the x-axis value is scaled based on net GHG mitigated during the study period, i.e., planning horizons to 2030 and 2050, and the y-axis value indicates the cost per unit GHG mitigated. The bubbles in Figures 39 and 40 represent the water saved/lost with respect to the reference scenario. The hollow circle represents water lost and solid circle represents water saved. The size of the bubble signifies the magnitude of water lost/saved.



* Numbers in the graph represent water saved or lost

Figure 39: Water GHG cost curve for Alberta's power sector for a planning horizon ending in 2030



* Numbers in the graph represent water saved or lost

Figure 40: Water GHG cost curve for Alberta's power sector for a planning horizon ending in 2050

From the water-carbon cost curve, it can be inferred that the cost of mitigating carbon emissions for the power sector is high. This is predominantly because of a high investment cost for installing renewable power plants. Of all GHG mitigation scenarios, only the AESO mid growth and coal to gas conversion scenario saves water; all other scenarios consume more water than in the reference case. These results indicate that the implementation of climate change policies lead to higher water consumption in the power sector. The coal-to-gas conversion 2030 scenario results in approximately zero GHG mitigation, hence it is not included in the figures.

Chapter 4: The Development of a WEAP Model for the Assessment of Water Efficient Technologies in the Power Generation Sector

4.1. Introduction

Water use and consumption in the electricity generation sector will be highly affected by proposed air emissions regulations and technology advancement to improve water intensity in the power sector. Water efficient technologies are an effective means of reducing water consumption in the sector. In this study, emerging water efficient technologies in power plants were identified and their implementation potential was evaluated for Alberta's power sector. The options were assessed with respect to the extent of water savings and cost incurred over the short term (to 2030) and the long term (to 2050).

Water Evaluation and Planning (WEAP) software was used to develop data-intensive models with details on water use processes and associated water intensities for power plants in Alberta. A baseline scenario was developed for the years 2005-2050 based on current and predicted water demand growth rates in Alberta, which were discussed in Chapter 3. This scenario was then compared with various water conservation scenarios for the power plants. The cost effectiveness of these scenarios was then analyzed by developing cost curves, and water saving options were prioritized using indices such as the cost of saved water.

4.2. Modelling Methodology

To analyze water withdrawal and consumption projections for each river basin, a baseline water supply and demand network in the WEAP model was first established. The baseline was created by developing a bottom-up water demand tree for the power sector and modelling water intensities in terms of water required per unit of electricity generated for each power plant type. Input data were found through a literature review, in discussion with the experts and wherever it was not available it was developed based on fundamental principle. Water intensity values from Canadian data sources are preferred. The WEAP model was used to simulate a water demand tree and the results were validated by comparing them with net water consumptions of power plants in Alberta obtained from publicly available federal and provincial reports. A business-as-usual (BAU) scenario was also developed for the years 2005-2050 to project water consumption from Alberta's power sector that acted as reference to evaluate water savings through the implementation of new technologies. With the water demand tree and BAU scenarios, an accurate scenario analysis can be performed to evaluate future impacts of various scenarios on water at the river-wise plant level for the study period of 2015 to 2050. In this study, cost-benefit analyses of the scenarios were developed to evaluate the incremental cost for alternate scenarios compared to the reference scenario for the province of Alberta. The curves were developed for power sectors to evaluate various water conservation options [164, 165]. The overall methodology followed is given in Figure 41.

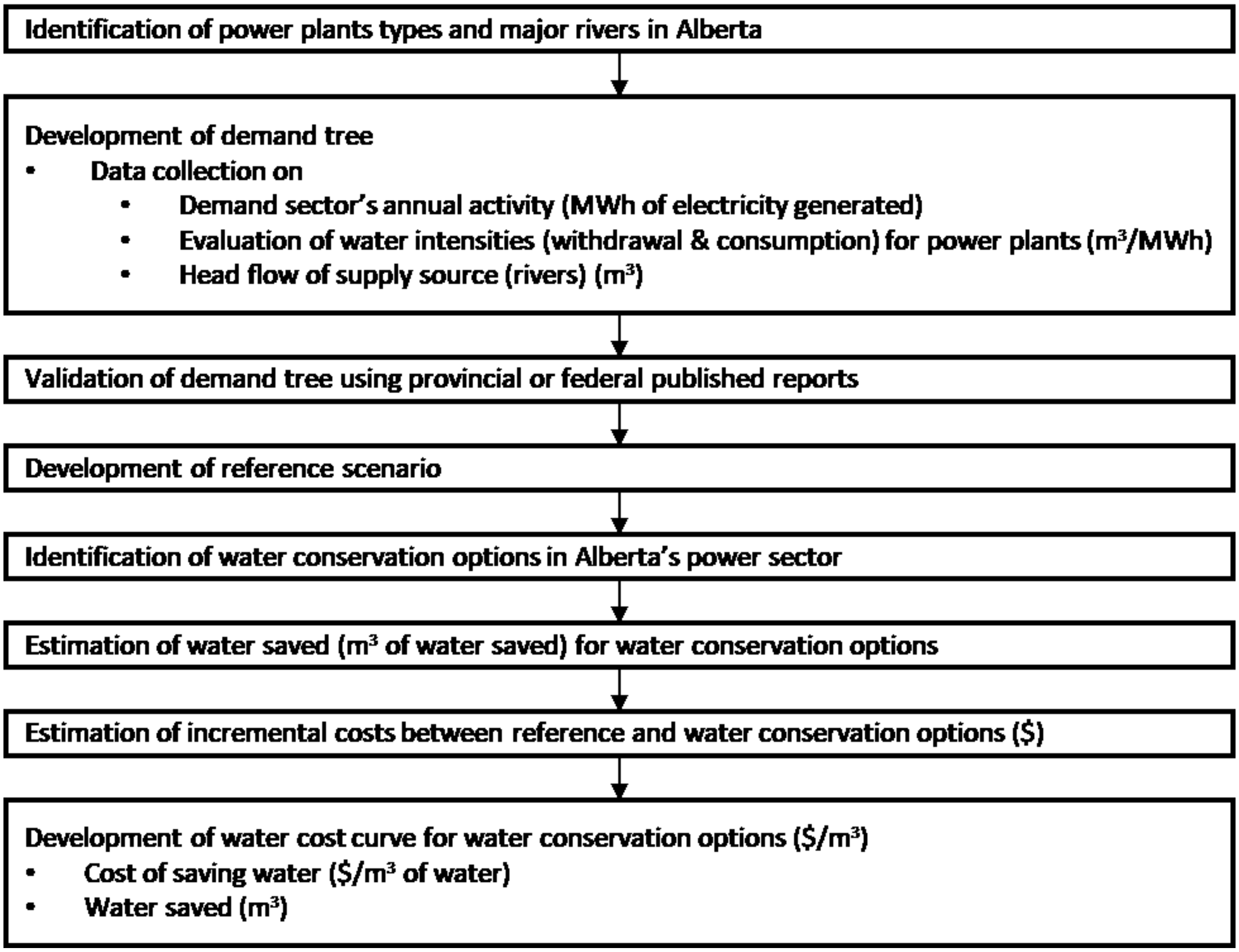


Figure 41: Methodology for the development of water conservation cost curves for Alberta

The subsections in this chapter discuss the water demand profiles of Canada and Alberta with a focus on the power sector, a brief overview of the WEAP model and the development of the water demand tree for Alberta's power sector. Further validation of the WEAP model and key assumptions in developing the BAU scenario are also discussed. In the subsequent section, water savings scenarios, the resulting cost curves and its inferences are discussed.

4.2.1. WEAP – A modelling tool

To develop the water demand tree and perform long-term water planning for the power sector in Alberta, a basic water demand and supply modelling tool is required, one that provides the flexibility of building a demand tree based on unit water consumption, analyzes water savings, and assesses water improvement scenarios (including a cost analysis). This tool is also able to predict demand-source interactions and the effect of different parameter variations over time.

For the current study, the WEAP model is used as it provides a graphical interface that allows the user to develop a bottom up demand tree, develop business-as-usual scenarios to forecast water consumption patterns, and evaluate water efficiency improvement scenarios. The model also allows the user to perform extensive cost analyses and provides the results in various forms (charts, tables, and summary reports). The WEAP model is a water demand and supply assessment tool with long-term water planning and forecasting capabilities [109]. It provides an efficient way to predict the demand-source interactions and the effect of different parameter variations over time [109]. Chapter 3 of this thesis provides more details on the WEAP model. Figure 42 presents the schematic of the WEAP model developed to simulate water use in Alberta.

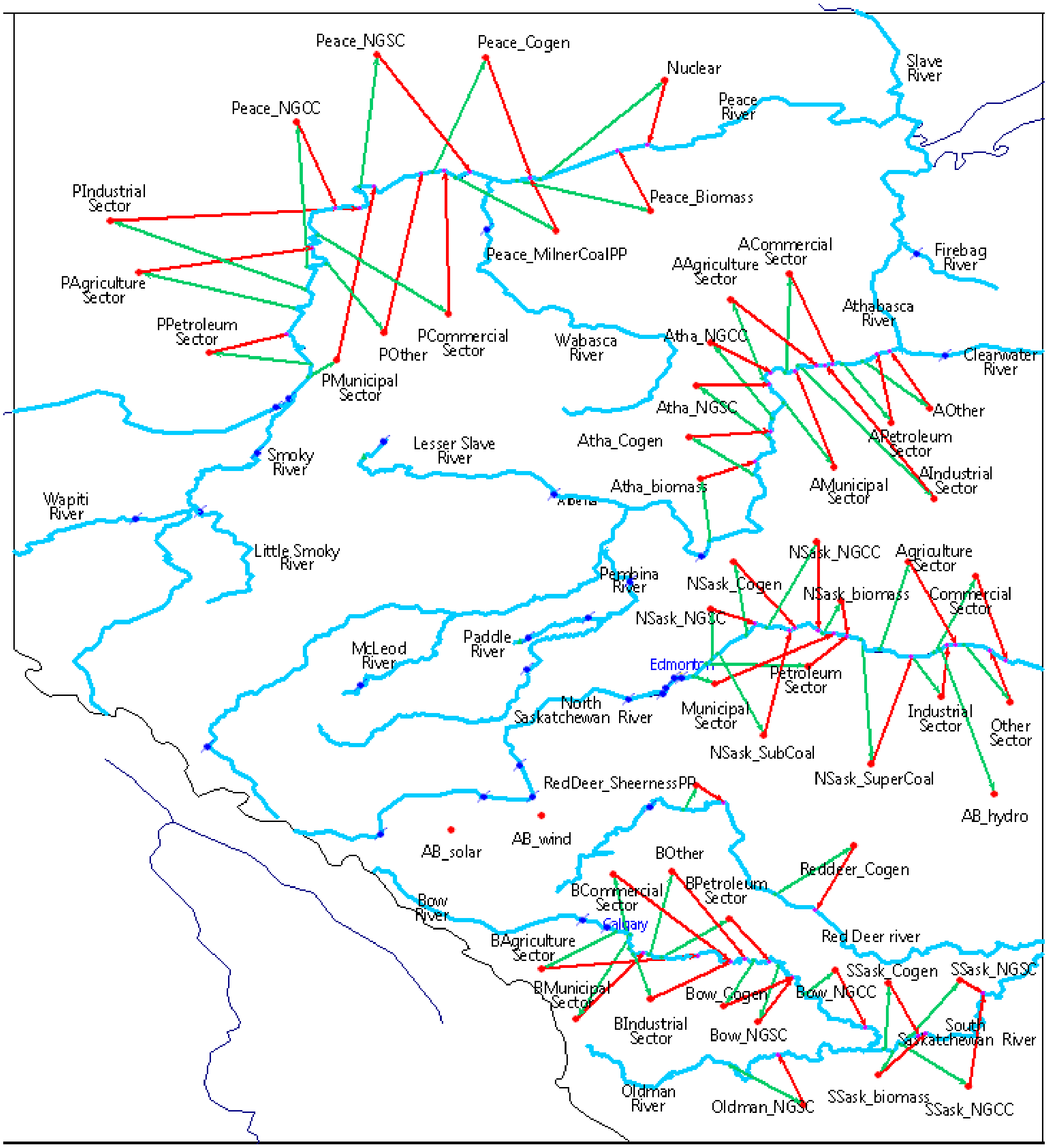


Figure 42: WEAP schematic for Alberta

4.3. Water demand tree for Alberta power plants

This section extends the demand tree development work in section 3.3 of Chapter 3 to illustrate river-wise water use in the electricity generation sector. The demand tree for Alberta's power sector was developed by identifying the types of power plants and their percentage share of electricity generation as well as the water use intensities of corresponding power plants. The demand tree for Alberta was developed in the demand module where data can be modelled based on end-use water consumption. Six major rivers were considered in this study, four of which (the North Saskatchewan, Athabasca, Peace, Bow) were chosen based on their criticality with respect to Alberta's economic growth as identified by Dar et al. [31]. The Red Deer and South Saskatchewan rivers were also considered because of power plant activity in those areas. To develop the demand tree, Alberta was divided into 3 regions based on the AESO 2016 Long-term Outlook (LTO) report (shown in Figure 43) [115]. All the power plants, from a 5 MW to 860 MW, were identified and categorized for 6 rivers considering power plant location in Alberta [64]. Each region corresponds to the river of its location, shown in Table 14. It is assumed that the river assigned to each region is the water source for the corresponding regional power plant.

Table 14: Major river categorization based on Alberta's planning regions

Planning Region	**River**
North (Northeast and Northwest)	Peace River and Athabasca River
Central + Edmonton	North Saskatchewan River and Red Deer River
South + Calgary	Bow River and South Saskatchewan River

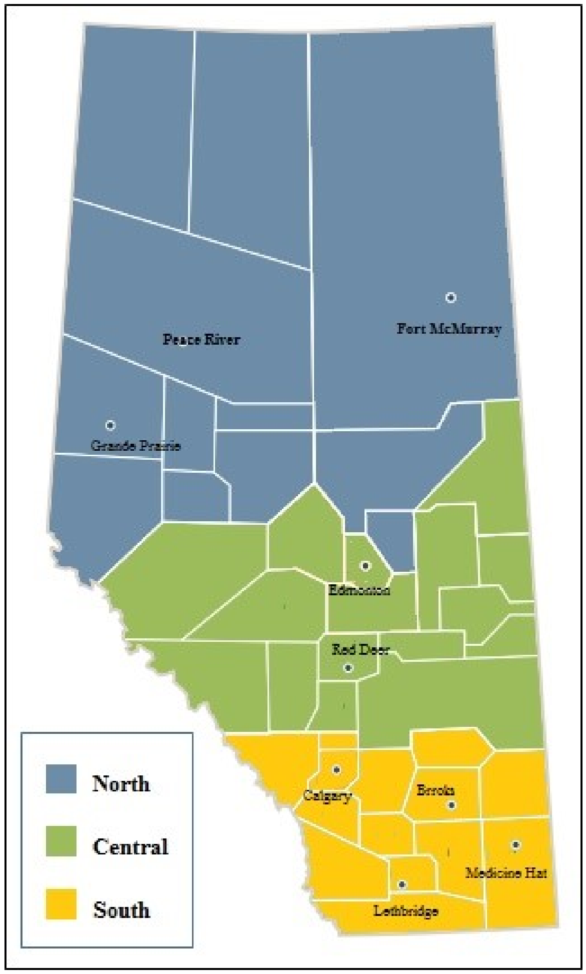


Figure 43: Alberta's electricity generation planning regions based on the AESO 2016 LTO report *[115]*

The year 2015 was selected as base year due to availability of complete data when we developed the base case. The demand tree for each subsector was developed following careful study of the process and the collection of unit water data from various sources as explained in the following sections. Available water use studies were used to calculate actual water consumption (i.e., water diversion minus return flow) by power different power plants, which are discussed in the subsequent section [15, 16, 69]. Similar to the demand module, to satisfy demand, WEAP has its supply module, which determines amount, availability, and allocation of water supplies, and simulates monthly river flows. In the WEAP model for Alberta's power sector, the supply module was taken from a study by Dar et al. [31]. In this module, stream flow data for the years 2009 to 2015 were incorporated to simulate the river flow patterns. In addition, river flow patterns for the Red Deer and South Saskatchewan rivers were added into the model because of their significant power sector activity.

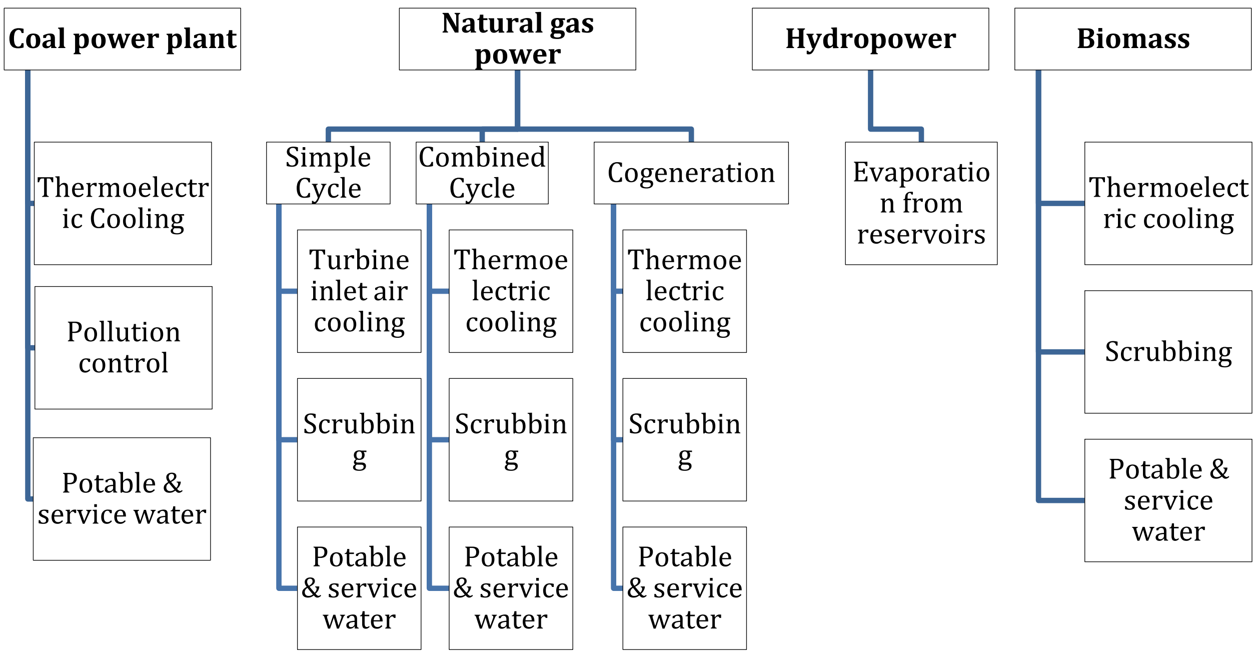


Figure 44: Alberta's power sector demand tree

The WEAP model uses bottom-up water intensities to calculate annual power plant water consumption and it requires annual electricity generation as input. The power plant production capacity and generation[5] for the years 2005-2015 were obtained from studies by government agencies like AUC and AESO [60, 64, 129, 130] and are shown in Table 15. The table also shows

5 Includes the behind-the-fence load. The behind-the-fence load is the total electric demand in Alberta that is served by on-site generation.

corresponding average capacity factors from 2005-2015 for the various types of power plants as calculated from AUC data [120]. In the WEAP model, generation capacity (MW) was entered as annual activity and capacity factor was modelled with water intensity to account for electricity generation (MWh). Thus, historical capacity and generation data were used to validate the demand tree.

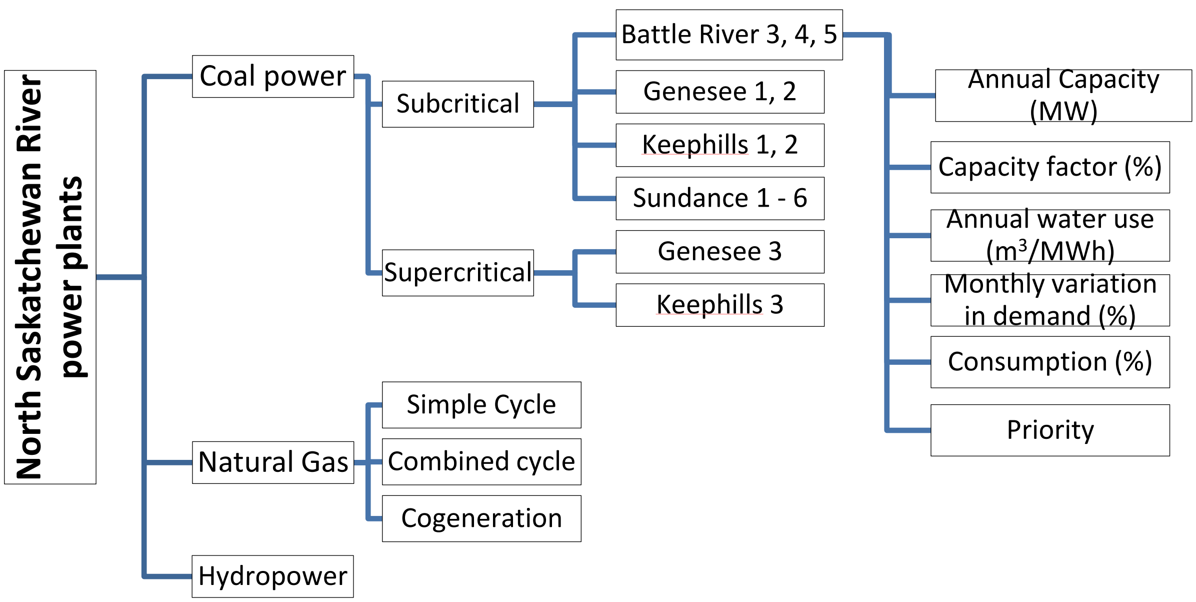


Figure 45: River-wise demand tree and input parameters

Table 15: Alberta's electricity generation base case parameters

Power plant type	Generating capacity (MW)	Generation (GWh)	Capacity factor
Coal	6,300	41,378	80%
Simple cycle	996	644	10%
Combined cycle	1,703	6121	32%
Cogeneration	4,527	25,450	60%
Wind	1,445	3,816	32 %

Power plant type	Generating capacity (MW)	Generation (GWh)	Capacity factor
Hydro	894	1,745	23%
Biomass	394	2,149	65%
Others	43	318	20%
Total	16,261	81,261	

When developing the bottom-up demand tree, the water consumption results were calculated using equation 9:

$$\text{Annual power plant water consumption } (\mathrm{m}^3)_{\mathrm{i,j}} = \sum_{k=1}^{n} \text{power production } (\mathrm{MWh})_{\mathrm{i,j,k}} * \text{Annual water use rate } (\mathrm{m}^3/\mathrm{MWh})_{\mathrm{i,j,k}} \quad (9)$$

i types of power plants in Alberta

j number of years with 0 as the base year, corresponding to 2015 in our case

k the total number of power plants of type "*i*".

Table 16: Water demand coefficients for power plants in Alberta *[15, 16, 62, 119]*

Power plant type	Withdrawal (m^3/MWh)	Consumption %
Coal subcritical	2.33	84
Coal supercritical	2.19	74
Natural gas simple cycle	0.38	80
Natural gas combined cycle + cooling tower	0.90	75
Natural gas combined cycle + dry cooling	0.32	75
Natural gas cogeneration + cooling tower	0.69	65
Natural gas cogeneration + dry cooling	0.25	65
Biomass + cooling tower	2.53	87
Nuclear + cooling tower	4.17	65
Hydropower	13.12	100

4.4. Power generation water demand – business-as-usual case scenario

The WEAP model was further used to forecast water consumption in the power sector depending on expected annual power generation. Using the demand tree, a reference (business-as-usual) case in the WEAP model was developed to understand future water demand in Alberta's power sector for the years 2015 to 2050. The reference scenario was developed based on the AESO's 2016 projections, which specifies the generating capacity for each electricity generation type from 2015 to 2037. The development of Alberta's power generation sector business-as-usual scenario and its validation were discussed in detail in Chapter 3. Figure 46 shows the projection of capacity for various electricity generation types. In this figure, projections from 2016 to 2037 are based on the AESO 2016 LTO study and from 2037 to 2050 on the calculated growth rate. For each river, a proportional increment in power plant capacity is considered.

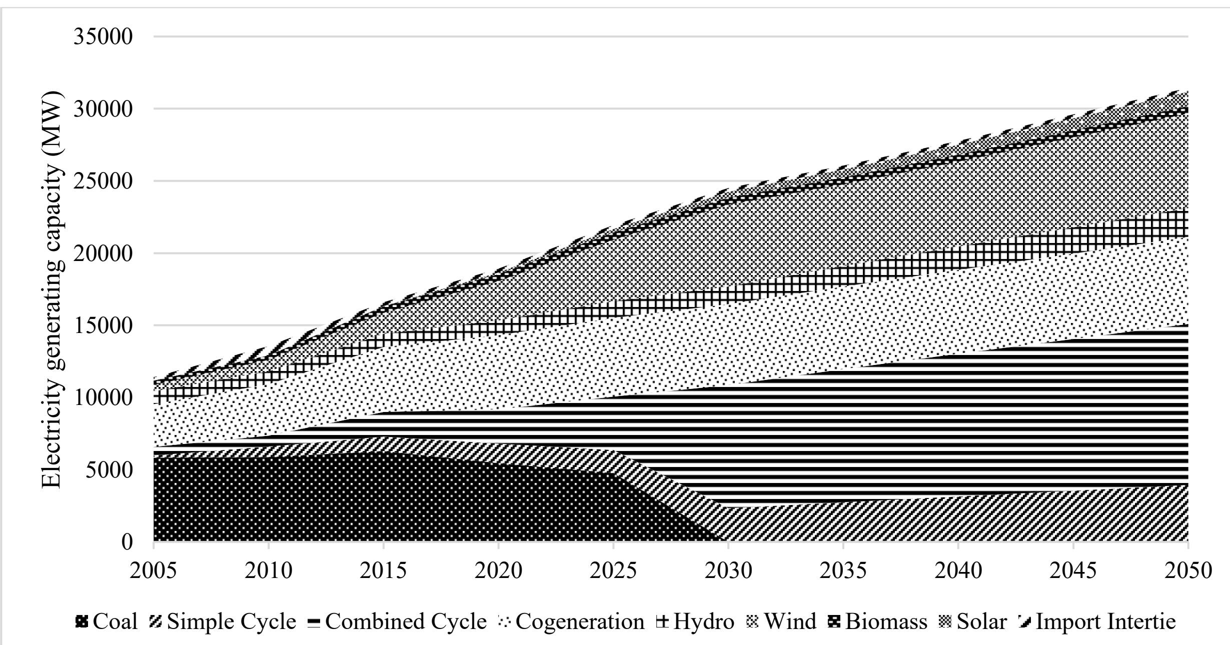


Figure 46: Technology-wise generation capacity projection for the reference scenario, 2005-2050

It is assumed that over the study period, water intensity for the electricity sector will not change [62]. As 90-95% of the water is used for cooling purposes and until new technology (like dry cooling) is implemented, water intensity will remain constant. Due to the unavailability of data, GHG emissions intensity for power plants is also assumed to remain constant for future years.

The capacity factor for various technologies is also assumed to remain constant over the study period except for natural gas combined cycle plants (see Table 17). The data in this table are from the AESO 2015 Annual Market Statistics [117].

Table 17: Technology-wise capacity factor for the forecast period *[117]*

Year	Coal	Simple Cycle	Combined Cycle	Cogeneration	Hydro	Wind	Biomass	Nuclear	Solar
2016 - 2050	80%	10%	32%, 72%*	60%	23%	32%	65%	90%	20%

*It is assumed that capacity factor of combined cycle power plant will increase from current 32% to 72% in year 2020 due to heavy coal retirement.

Since coal power plants will be phased out and replaced by natural gas combined cycle and wind power plants, natural gas combined cycle power plant capacity factors must increase. In the reference scenario, there is a heavy coal capacity retirement in 2020 (794 MW), so it is assumed that the capacity factor for combined cycle plants will change to 72% in 2020 and act as a baseload supply.

4.5. Water conservation options for Alberta's power sector

The water conservation scenarios for power plants were selected based on the comprehensive literature review of emerging technologies and developed in the WEAP model for Alberta power plants. The scenarios were developed using the reference scenario as the baseline with water saving potential and the penetration rate of new water efficient technologies as input parameters. The penetration rate was selected on a case-by-case basis depending on technology status (development, pilot, or commercial stage) for the years 2015 to 2050. Stillwell et al. [131] and Yazawa et al. [132, 133] concur that future water trends in the power sector will be determined by a shift in technology from the current wet cooling towers to more advanced dry or hybrid cooling systems, low carbon energy technologies, and higher efficiency power plants. The model shows water saving potential for each scenario compared to the BAU; the saving potentials reflect accurate outcomes of implementing new technologies in power plants.

All the scenarios consider replacing coal or natural gas power plants because these thermal power plants consume water along with the hydropower plants. In addition, in hydropower plants, the evaporation of water is natural and have not been considered in the scope of this study. In thermal power plants, water use can be reduced by:

- Providing alternate sources of cooling water make-up
- Enhancing the concentration rate (increase concentration cycles for wet recirculation systems, thereby decreasing wet cooling tower blowdown requirements)
- Using advanced cooling technologies
- Reclaiming water from combustion flue gas for use in cooling water make-up
- Reducing cooling tower evaporative losses

Water saving scenarios were developed and modelled in this study based on the technology's applicability in Alberta. Four scenarios were investigated in detail and are summarized in Table 18.

Table 18: Water conservation options considered in this study and their key assumptions

Scenario	Acronym	Water conservation scenario considered	Assumption
Scenario 1	WCO1	Dry cooling penetration in Alberta's electricity generation sector	25% of natural gas plants use dry cooling
Scenario 2	WCO2	Transport membrane condenser technology penetration in Alberta's power sector	25% of natural gas plants use transport membrane condenser technology
Scenario 3	WCO3	Heat exchanger condensing technology penetration in Alberta's power sector	25% of natural gas plants use heat exchanger condensing technology
Scenario 4	WCO4	Liquid desiccant based absorption condenser technology penetration in Alberta's power sector	25% of natural gas plants use liquid desiccant-based absorption condenser technology

4.5.1. Scenario 1: WCO1 – Dry or hybrid cooling technology penetration in 25% of natural gas power plants

All thermal power plants in Alberta use wet cooling technology to cool the steam turbine exhaust [62]. Accounting for 85-90% of a plant's water consumption, this cooling is the largest and most critical use of water at power plants [55]. While in the power generation sector water-based cooling is the most cost effective and efficient method available, due to increasing economic growth, water demand in the other sectors (agriculture, municipal, and industrial) is increasing. This growth is the motivation for pursuing large-scale dry cooling plants. Dry cooling penetration in the US increased from 9,012 MW in 2010 to 20,952 MW in 2016 [166]. Regulatory and public pressure can significantly increase market penetration of dry cooling technology [164].

In this scenario, it is assumed that by 2050, 25% of combined cycle and cogeneration power use dry cooling. This scenario is based on a National Energy Technology Laboratory study that considered a 25% addition in dry cooling use by 2030 [167]. Based on earlier estimates, it is assumed that natural gas power plant efficiency will decrease by 10% with dry cooling technology due to the parasitic load and the lower efficiency of dry cooling than wet cooling [168, 169].

4.5.2. Scenario 2 – 4: Flue gas water recovery

This scenario applies to all thermal power plants and the various technologies used to recover boiler flue gas. In a thermal power plant, there are three sources of boiler flue gas moisture: fuel moisture content, water vapor formed from oxidation of fuel hydrogen, and water vapor carried into the boiler along with combustion air. Feeley et al. estimated the reduction in water consumption from combustion flue gas for natural gas combined cycle plants to be 8.8% [14]. As the penetration rates of different technologies were not available for thermal power plants, a 25% penetration by 2050 was assumed. In this scenario, it was assumed that this recovered water is used to replace a portion of cooling tower makeup.

- **Transport membrane condenser:** In this scenario, a membrane separation technology developed by the Gas Technology Institute is used to recover water vapor from power plant flue gas [170]. Cannon Boiler Works Inc. has commercialized this technology under the name Ultramizer.
- **Heat exchanger condensing:** This technology was adopted from DOE-funded NETL Water Reuse & Recovery projects. In this scenario, a condensing heat exchanger is used to recover water from power plant flue gas [171].
- **Liquid desiccant-based absorption:** In this scenario a liquid desiccant-based absorption process is used to remove water from flue gas [172].

4.6. The cost of saving water

The costs of the additional scenarios were developed to investigate the potential of technology implementation from both water- and cost-saving perspectives. The analysis done in WEAP is not intended to analyze financial viability of a technology; rather, it provides water-saving cost potentials for a technology throughout its life-time. The scenarios developed for Alberta power plants to identify impacts on water consumption involve different types of technology implementation costs. In the WEAP model, new data variables were created to model the capital cost, fixed and variable operating costs, and capacity factors of different power plants. Using these parameters, the cost of saved water (CSW) was calculated with the BAU scenario as the base, which allowed to perform incremental cost analyses that considered the different electricity generation mixes, or, for the water savings scenario, associated efficiency improvement measures. The CSW is typically calculated by dividing the net present incremental cost of annual water savings by units of $/m^3.

The cost curves developed for various scenarios help determine the relative cost per m^3 of water saved in a particular timeframe. The actual cost of a technology/plant and its characteristics are used as input for developing the cost curves. The cost factor used to develop the cost curves are the net present value (NPV) of the electricity generation cost over a 15-year (2030 horizon) and 35-year (2050 horizon) study period compared to the reference scenario. The total discounted cash flow of the scenario considers the annualized capital cost, actual operating & maintenance costs and fuel costs incurred due to the operation of the plant. The total amount of water saved (given in million m^3) is then used to generate water conservation cost curves for each of the scenarios.

These curves were generated to provide insight into the comparative techno-economic assessment of the additional scenarios under consideration, in particular to evaluate various GHG mitigation scenarios in energy-intensive sectors [164]. Equations 16-19 show the methodology used to perform the cost analysis conducted in this study.

$$\text{Cost of water saved} = \frac{\text{Incremental cost of electricity production}}{\text{Total water Savings}} \qquad (16)$$

$$\text{Incremental cost of electricity production} = (\text{ACC} + \text{Fixed O\&M} + \text{Variable O\&M})_{\text{Scenario A}} - (\text{ACC} + \text{Fixed O\&M} + \text{Variable O\&M})_{\text{Reference}} \quad (17)$$

$$\text{Annualized capital cost (ACC)} = \text{CC} * \text{CRF} \quad (18)$$

$$\text{Capital recovery factor (CRF)} = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (19)$$

where

i = discount rate

n = life of the equipment/ power plant

Fixed O&M = Fixed Operating & Maintenance Cost

Variable O&M = Variable Operating & Maintenance Cost

Table 19 shows the input parameters used to calculate the cost of water saved. Cost parameters for each power plant type were developed after gathering data from comprehensive literature review, and harmonizing and updating the figures to the 2015 Canadian dollar (CAD). Location factors of 1.08 and 2.16 were used for capital and fixed O&M costs to convert cost data from the US Gulf Coast to Alberta, Canada [153]. Fuel price for the study were calculated based on the Alberta coal price (1 $/GJ), and the varying natural gas price was based on a National Energy Board report [118, 154]. The cost data were converted to Canadian dollars and corrected to consider inflation based on Bank of Canada rates where applicable [155, 156]. The discount rate used to perform the economic analysis is 5%, a rate used in recent similar studies on GHG mitigation [157, 158]. For water saving technologies, an increment in levelized cost was calculated based on the available capital and O&M costs for different technologies (see Table 20).

Table 19: Power plant input parameters for cost calculations and sources in 2015 CAD

Power plant type	Levelized Cost ($/MWh)	Source
Subcritical coal	35.06	[118, 120, 159, 160]
Supercritical coal	39.53	[118, 120, 159, 160]
Simple cycle (combustion turbine)	169.59	[120, 153, 154, 161]
Combined cycle	74.92	[39, 120, 156, 159]
Cogeneration	67.53	[39, 120, 156, 159]

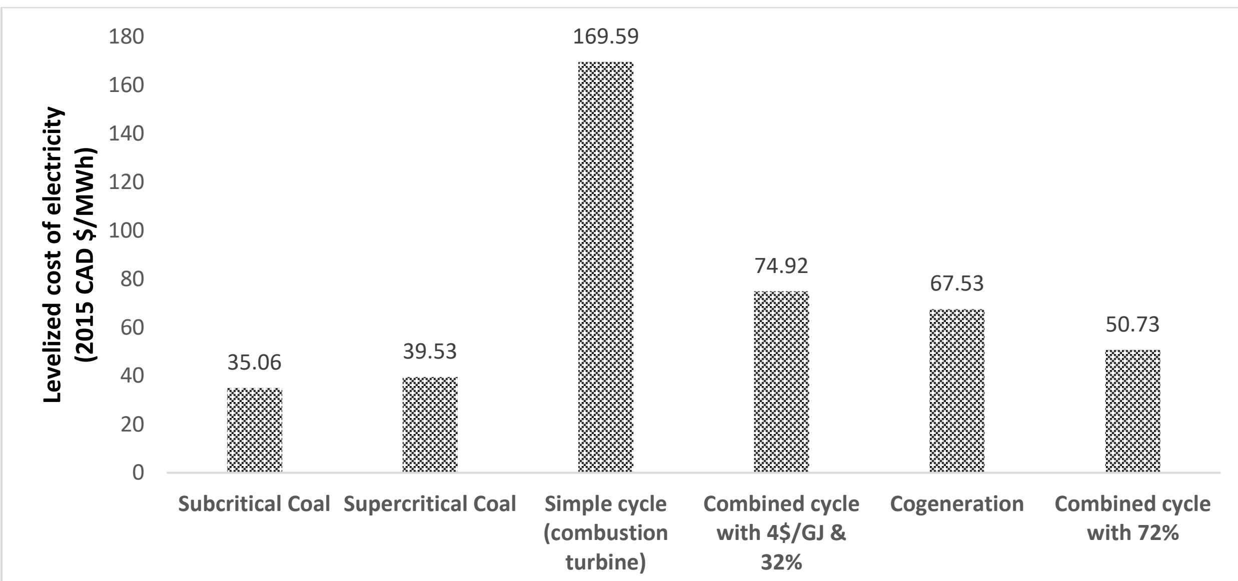


Figure 47: Levelized cost for generation types in Alberta (2015 CAD $/MWh)

Table 20: Cost parameters for water saving technologies

Water saving technology	Capacity (MW)	Capital cost ($/kW)	O&M cost ($/kW)	% increment in levelized cost	Source
Dry or hybrid cooling	500	182	-	7 – 9%	[62, 167, 173-175]

Water saving technology	Capacity (MW)	Capital cost ($/kW)	O&M cost ($/kW)	% increment in levelized cost	Source
Transport membrane condenser	223	0.74	0.00	0.02 – 0.04%	[170, 176]
Heat exchanger condensing	500	21.18	0.30	0.8 – 1.5%	[171]
Liquid desiccant absorption	270	32.49	2.31	2.3 – 3.7%	[172]

4.7. Results and Discussion

In this section, the results from the water modeling and implementation of water conservation options for Alberta's power sector as developed in the WEAP model are discussed in detail. The economic aspects are discussed in the form of cost curves that compare the scenarios in terms of savings potential and cost for one m^3 water saved. Water demand for the North Saskatchewan River decreases from 95.4 million m^3 in 2005 to 42.5 million m^3 in 2050.

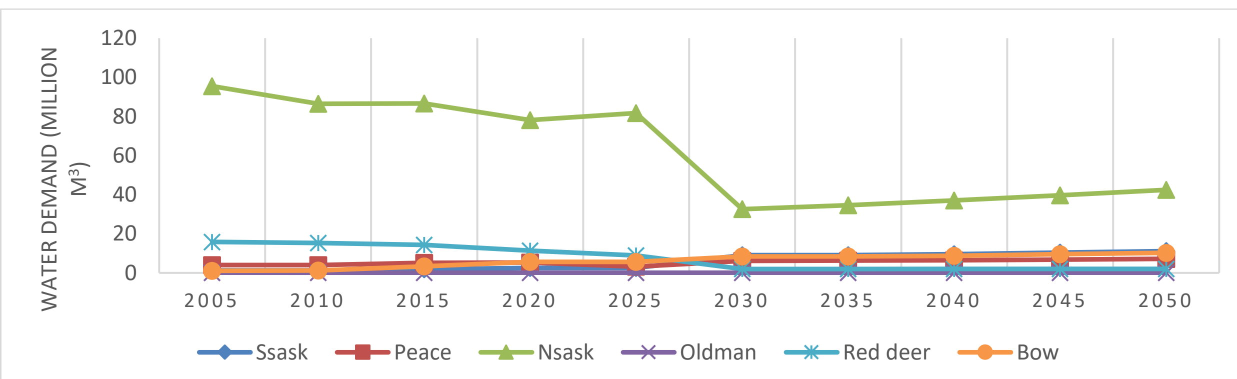


Figure 48: River-wise water demand for Alberta's power sector for the reference scenario

From Figure 48, it is evident that water demand from Alberta's power sector will decrease in future following the coal phase-out. This phase-out will predominantly affect the North Saskatchewan River as most of the province's coal power plants withdraw water from this river. Water withdrawal beyond 2030 is expected to increase at a uniform rate because of combined cycle power plants' capacity addition in Alberta's electricity generation grid. Figure 49 shows the withdrawal and return flow of water from all the rivers that provide water to Alberta's power sector along with consumption. It is interesting to note that although the total water withdrawal by Alberta's power sector will decrease following the coal power phase-out, consumption will increase from 118.8 million m^3 in 2005 to 127.68 million m^3 in 2050. This increase is primarily because of increased electricity production (from 67.4 TWh in 2005 to 123.4 TWh in 2050).

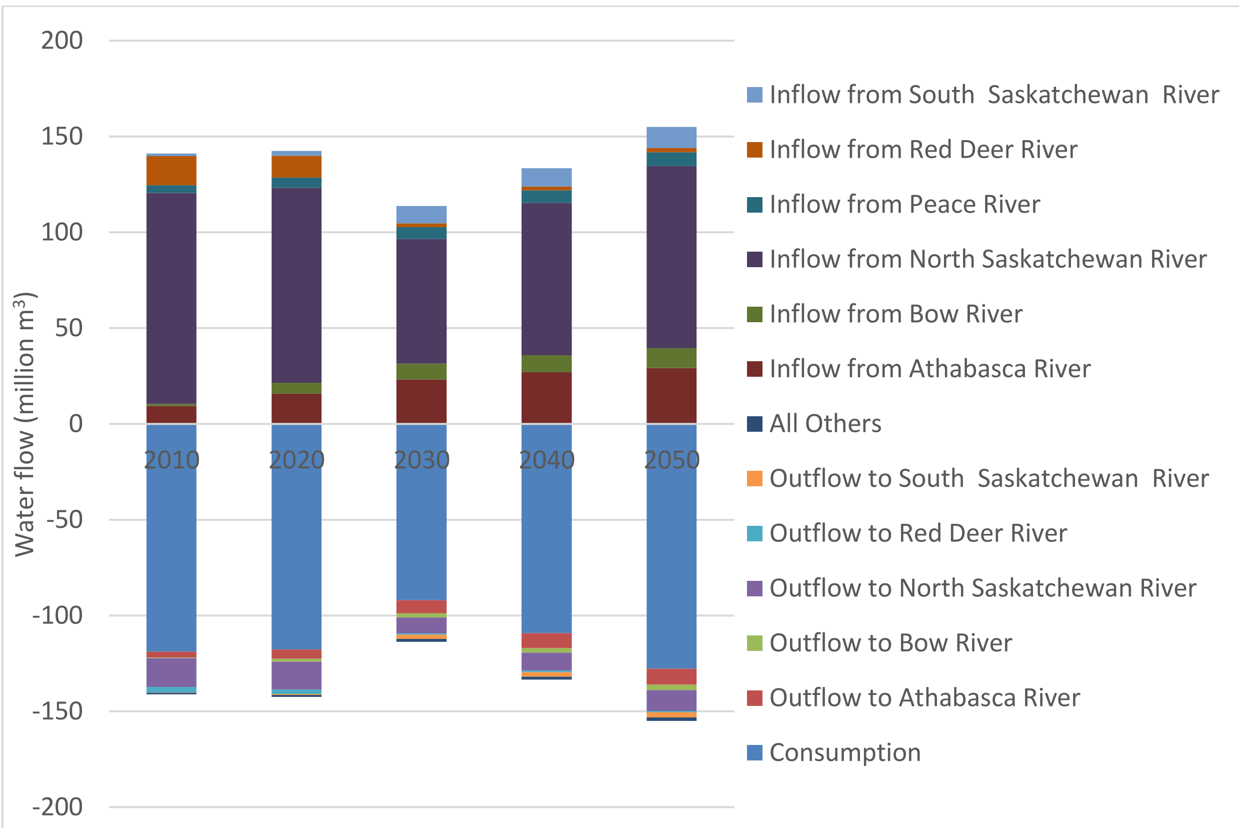


Figure 49: Demand site inflows and outflows for all sectors for the reference case

The WEAP model results on water demand for all the scenarios were compared to the reference scenario (see Figure 50). The water savings for the three scenarios of water recovery from the boiler flue gas are the same because these have the same penetration level and water saving potential, as discussed by Feeley et al. [14].

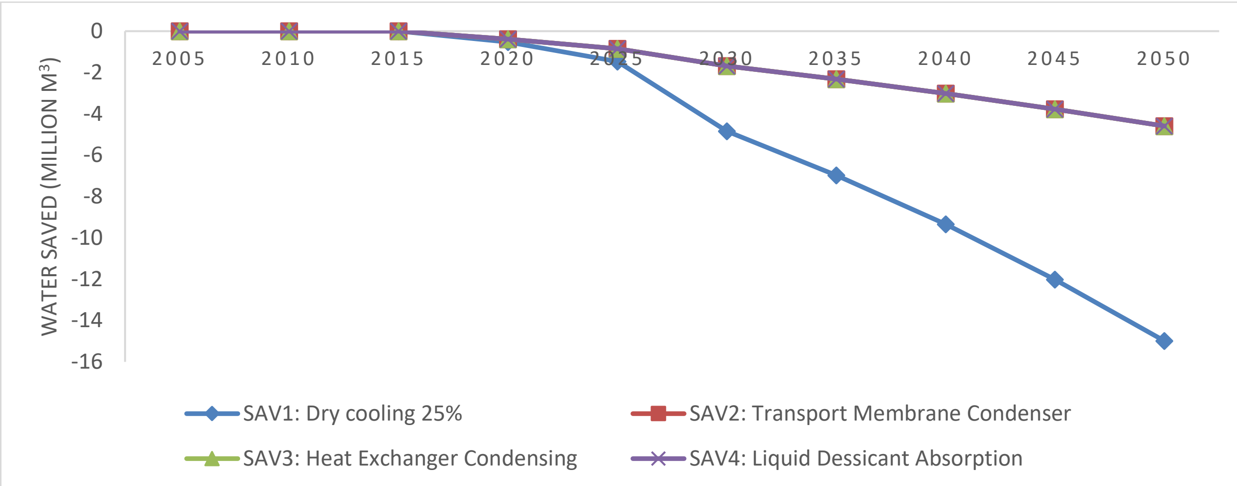


Figure 50: Comparison of water saving potential for the water efficient scenario

To make an informed decision and to evaluate the potential to implement several scenarios simultaneously in Alberta's power sector, the scenarios should be compared in terms of cost along with the potential to reduce water consumption. A comprehensive comparison of the costs and water savings potential scenario is presented as a cost curve with the WEAP model results. The WEAP model simulates the water savings potential of various scenarios and estimates the net present value (NPV) of investment, thus providing the water conservation cost in terms of dollar per m^3 of water saved. The net water savings, NPV, and water savings costs for each scenario are shown in Figures 51 and 52. Cost curves show the estimates of incremental costs ($/$m^3$ of water saved) incurred if a scenario is implemented. The x-axis indicates m^3 of water saved and y-axis indicates incremental NPV of costs in a water conservation option compared to a baseline scenario. The height of the y-axis indicates the intensity of costs ($/$m^3$ of water) and the width on the x-axis indicates the total amount of water saved. Different bars in Figures 51 and 52 represent different scenarios. All the scenarios have 25% penetration by 2050 with around 10% penetration by 2030.

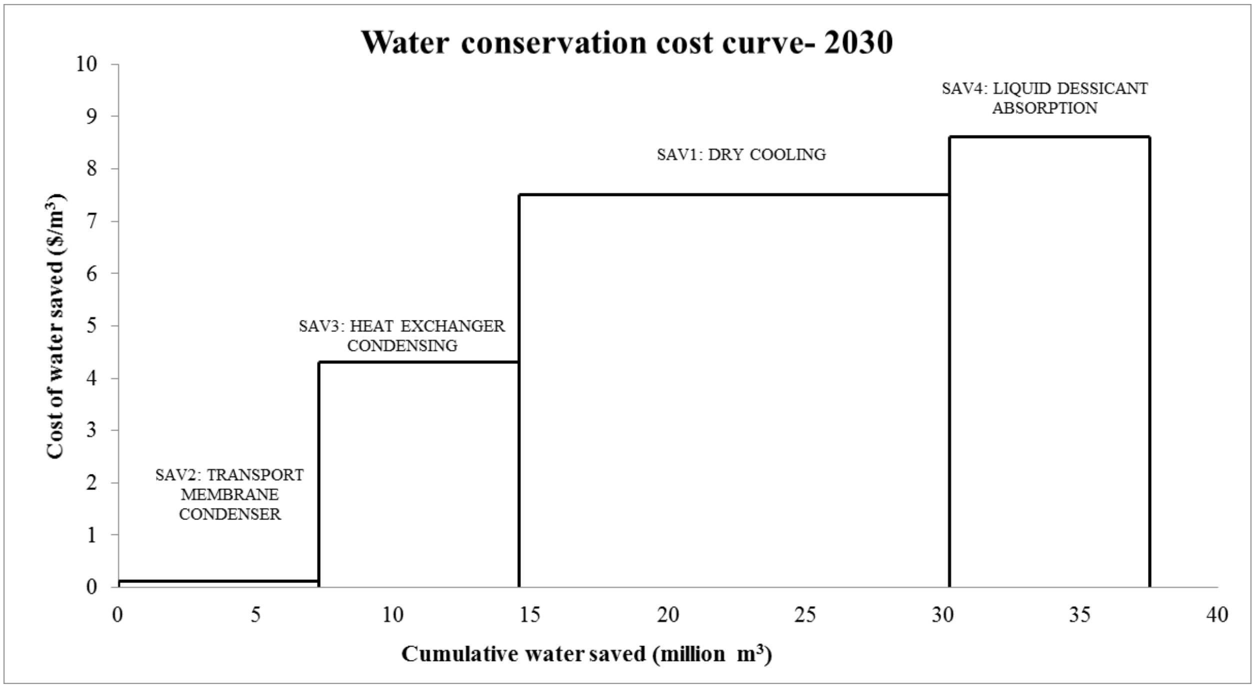


Figure 51: Water conservation cost curve for Alberta's power sector, 2030 scenario

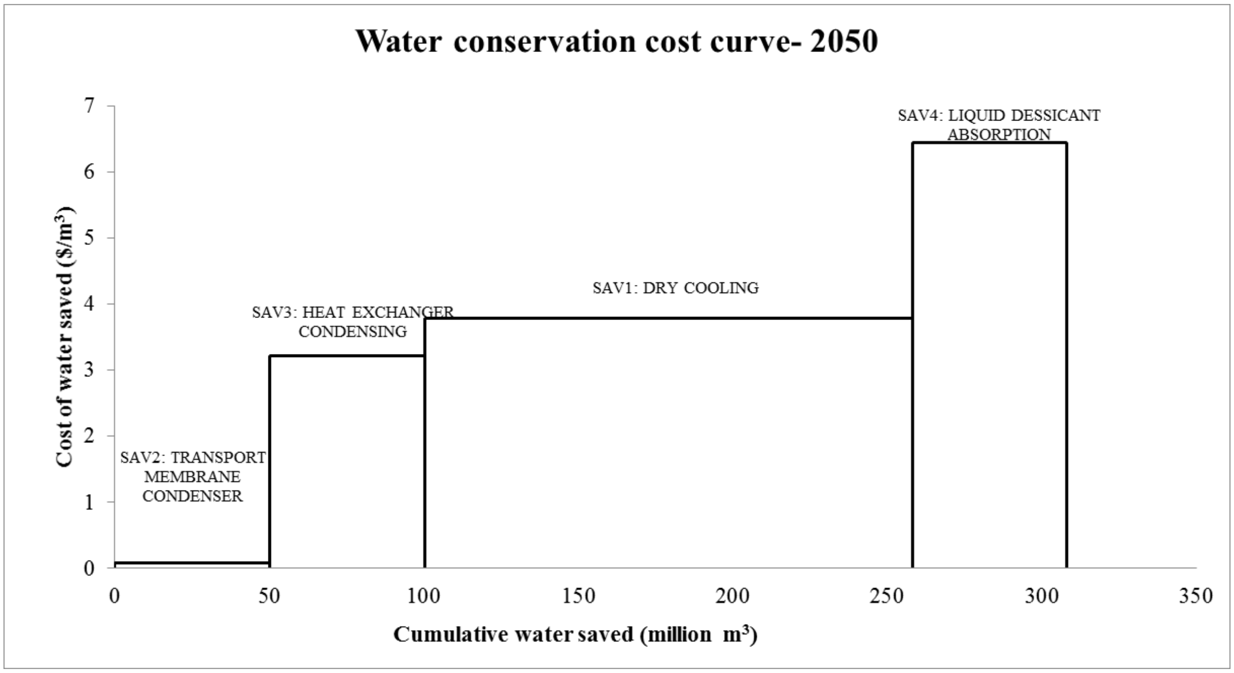


Figure 52: Water conservation cost curve for Alberta's power sector, 2050 scenario

In the cost curve, all the scenarios are on the right side of y-axis, which indicates that these scenarios are water saving scenarios. In the long run, the dry cooling scenario will save the most water (15.6 million m^3 by 2030 and 157.8 million m^3 by 2050). Every scenario is above the x-axis, which implies that additional costs will be incurred to save water in each case. The dry cooling scenario was integrated with the LEAP model to estimate the impact of dry cooling technology penetration on GHG emissions in the electricity sector considering a 10% efficiency loss in power generation. The results indicate that a 25% penetration of dry cooling technology will result in an increment of 2.2 million tonnes of carbon equivalent by 2030 and 16.2 million tonnes by 2050 due to parasitic load and efficiency loss.

Chapter 5: Conclusion and Recommendation

5.1. Conclusion

Alberta is the fourth largest province in Canada and is a major contributor to the country's GDP due to its heavy oil and gas activities. Alberta is the highest GHG emitter in the country since 2005 and emitted 273 million tons of GHG in 2015. Approximately 40% of Canada's emissions are associated with increased economic activity. In 2015, Government of Alberta launched its Climate Leadership Program to reduce its emissions. One of the major recommendation in this report was phase out of coal power plants by 2030. In 2015, 90% of Alberta's electricity production (81.62 TWh) was from fossil fuel consuming 94.5 million m^3 of water. Power sector plays a vital role in Alberta's economy and have potential to reduce its water consumption. Alberta's power sector is at a major crossroads with shift towards cleaner grid. Currently, economic assessment integrated with water demand and GHG emissions for comprehensive water efficient technologies and climate change policies in power generation sector does not exist for Alberta. This current study attempts to address the issue of water and energy nexus by investigating the water savings potential in power generation sector by conducting a comprehensive analysis for a western Canadian province (i.e., Alberta) where currently about 51% of the power is generated by coal power plant.

The developmental method and the results achieved for the integrated WEAP and LEAP scenarios are discussed. Authors drew on a wide range of data, built computer models and used them to visualize future energy scenarios. An integrated water-energy model developed for power sector in Alberta provides a customized water-energy analysis based on various climate change scenario. For the same input data of the annual activity of the power sectors, the two integrated models provide the water demand results along with the variations in electricity supply and GHG emissions under the scenarios considered.

The objective of this study included detailed water-energy nexus model development for Alberta's power sector from 2015 to 2050. This study provides a detailed analysis to understand the pattern of future water and electricity supply for power sector. In order to achieve this, a detailed water demand tree is required. Such bottom-up energy demand tree allows for accurate scenario analysis. A demand tree for various power plant technologies operating in Alberta has been developed by collecting plant level water intensity data and plants annual electricity generation. The model is validated for case of Alberta by comparing the WEAP model results with annual water consumption reported by available government report and the LEAP model results with historical data on electricity generation as shown in Figure 53. A BAU scenario is also developed based on projection of existing electricity generating capacity by 2050. The development of BAU scenarios allows for accurate scenario analysis for reduction in water consumption in a long-term study period.

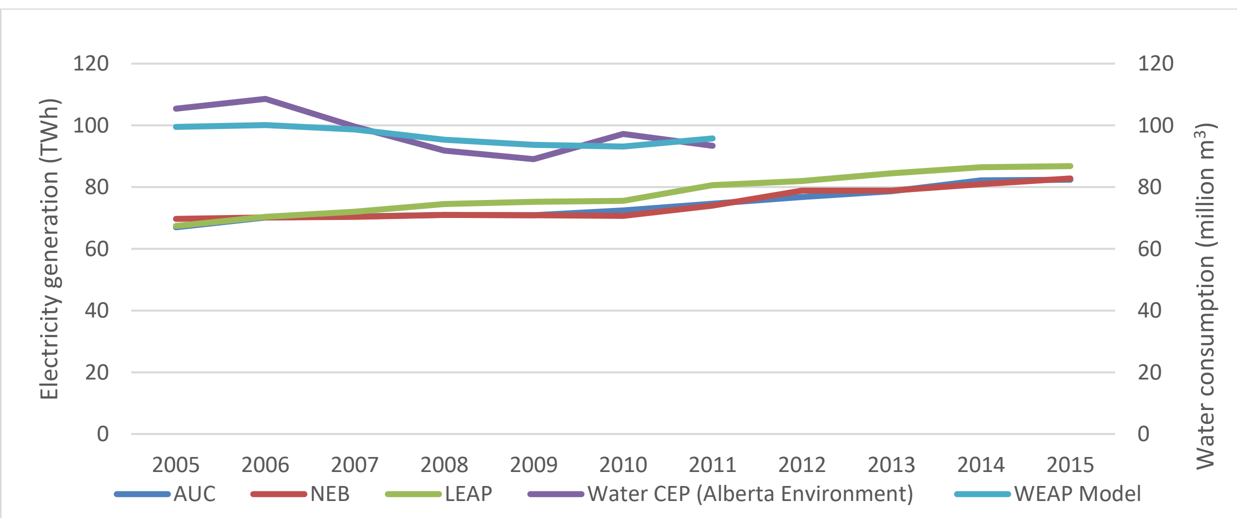


Figure 53: LEAP model and WEAP model validation

It can be summarized that for reference scenario GHG emissions and water demand decrease by around 44% and 34%, respectively, in 2030 due to the retirement of most of all the coal power plants by 2030. The overall increase in GHG emissions and water demand from 2030 to 2050 is 16% and 19.5%, respectively as shown in figure 54 and figure 55. The demand site coverage for all the sectors of all the river basins under study is 100% in WEAP model.

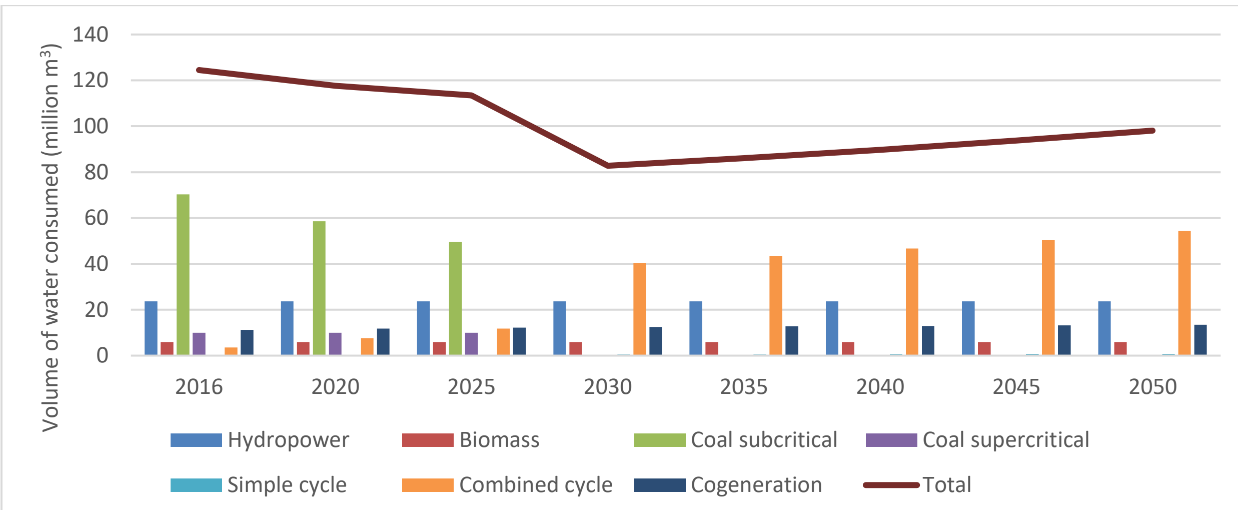


Figure 54: Technology wise share of water consumption for business-as-usual scenario

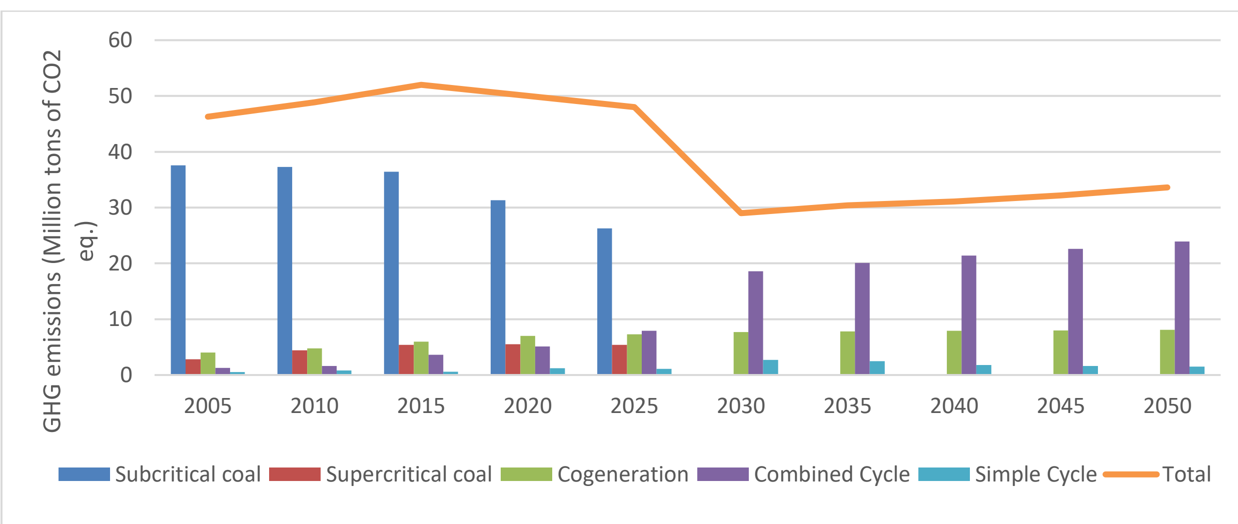
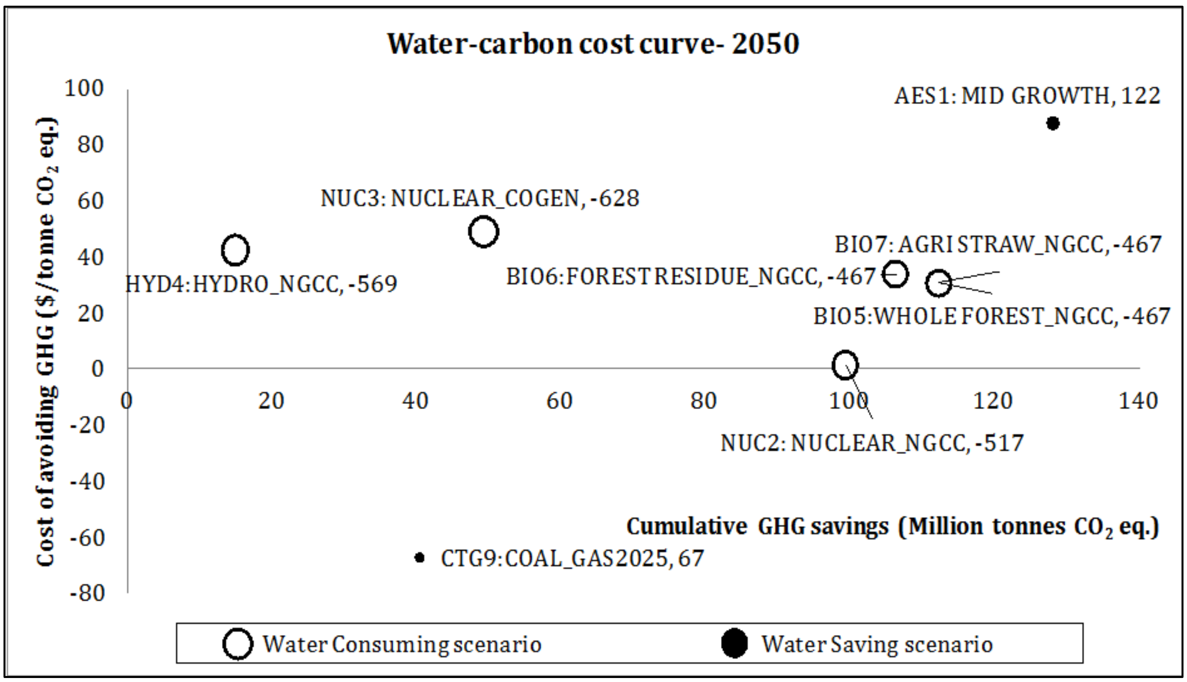


Figure 55: Technology wise share of GHG emissions for business-as-usual scenario

From the results of the integrated energy scenarios, it can be deduced that for power sector although implementation of climate change scenarios will result in reduced GHG emissions but will increase the water demand. For the power sector, coal power plants are more GHG and water intensive than natural gas power plants. Since the coverage is 100%, it can be deduced that the water resources have enough water to fulfil the needs for different energy scenarios, if the river flow pattern in future remains same as from 2005 – 2015.



* Numbers in the graph represent water saved or lost

Figure 56: Water GHG cost curve for Alberta's power sector for planning horizon 2050

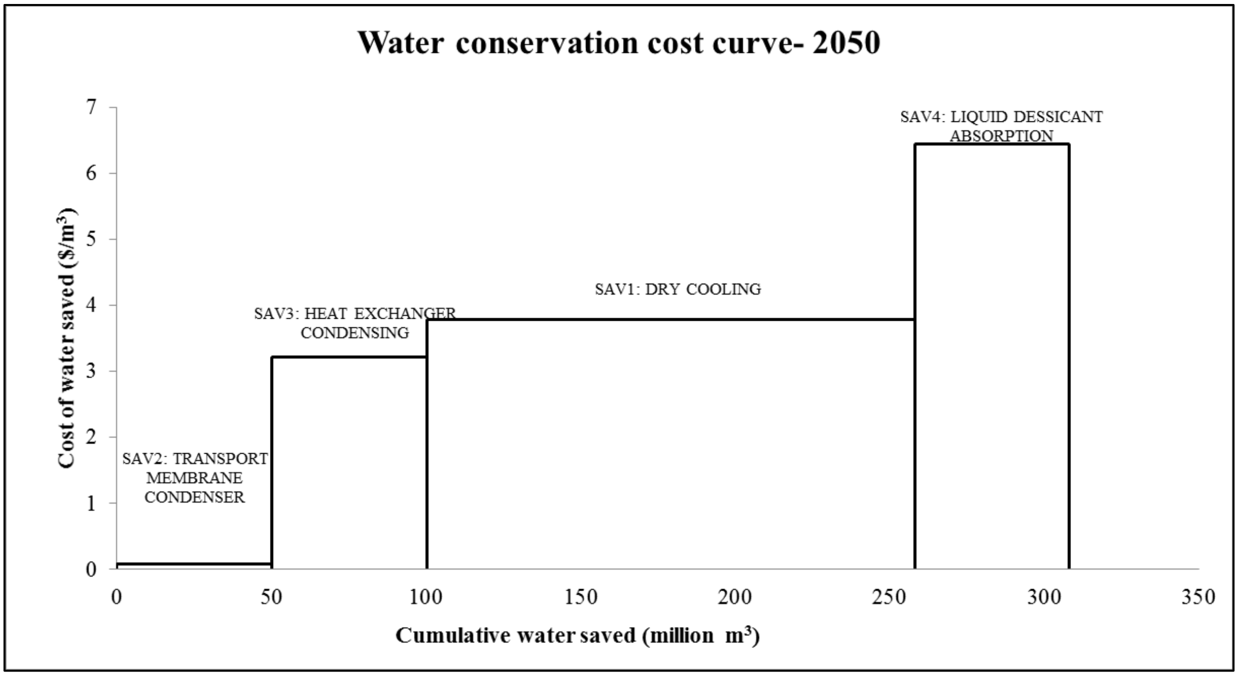


Figure 57: Water conservation cost curve for Alberta power sector 2050

Further to evaluate various water efficient and emerging technologies implementation in power plants, a framework for water demand has been developed for Alberta's power sector along with the economic analysis. Four new scenarios for water savings i.e. dry cooling technology penetration and water savings from boiler flue gas have been analyzed in the form of scenarios to estimate their impact on water demand. Out of all the technologies, in the long run, dry cooling technology will save the most water (15.6 million m^3 by 2030 for a cost of $\$7.8/m^3$ and 157.8 million m^3 by 2050 for a cost of around $\$4/m^3$). Cost curves are developed based on net water savings achievable from each scenario and corresponding water savings cost in terms of dollar per unit m^3 saved. The cost curve provides a comprehensive comparison of scenarios in a specific sector in terms net water savings potential and associated costs. The model is based on Alberta power industry and can be adopted to analyze other regions with necessary modifications in input parameters.

5.2. Recommendation for future work

This research work developed GHG mitigation options and water conservation options for Alberta's power sector by developing a water demand tree and evaluating thirteen scenarios. Some of the recommendations to extend this work are:

1. A similar model can be developed for other important sectors like oil & gas and agriculture sector for Alberta and the results can be combined together to evaluate best water saving technology across all the sectors in Alberta.
2. This study assumes a constant water intensities and GHG emission intensities for power plants. Different methods can be considered and explored to forecast water coefficients' future trends. This addition can help achieve more realistic results from the WEAP model.
3. Water quality module of the WEAP model has not been considered in this model. This parameter can be coupled to electricity sector in the WEAP model to track water pollution and contaminants in WEAP.
4. An integration model for Canada as a whole, can be developed using the methodology presented in this thesis to assist policy makers and industrial stakeholders make an informed decision with respect to electricity generation sector in Canada.

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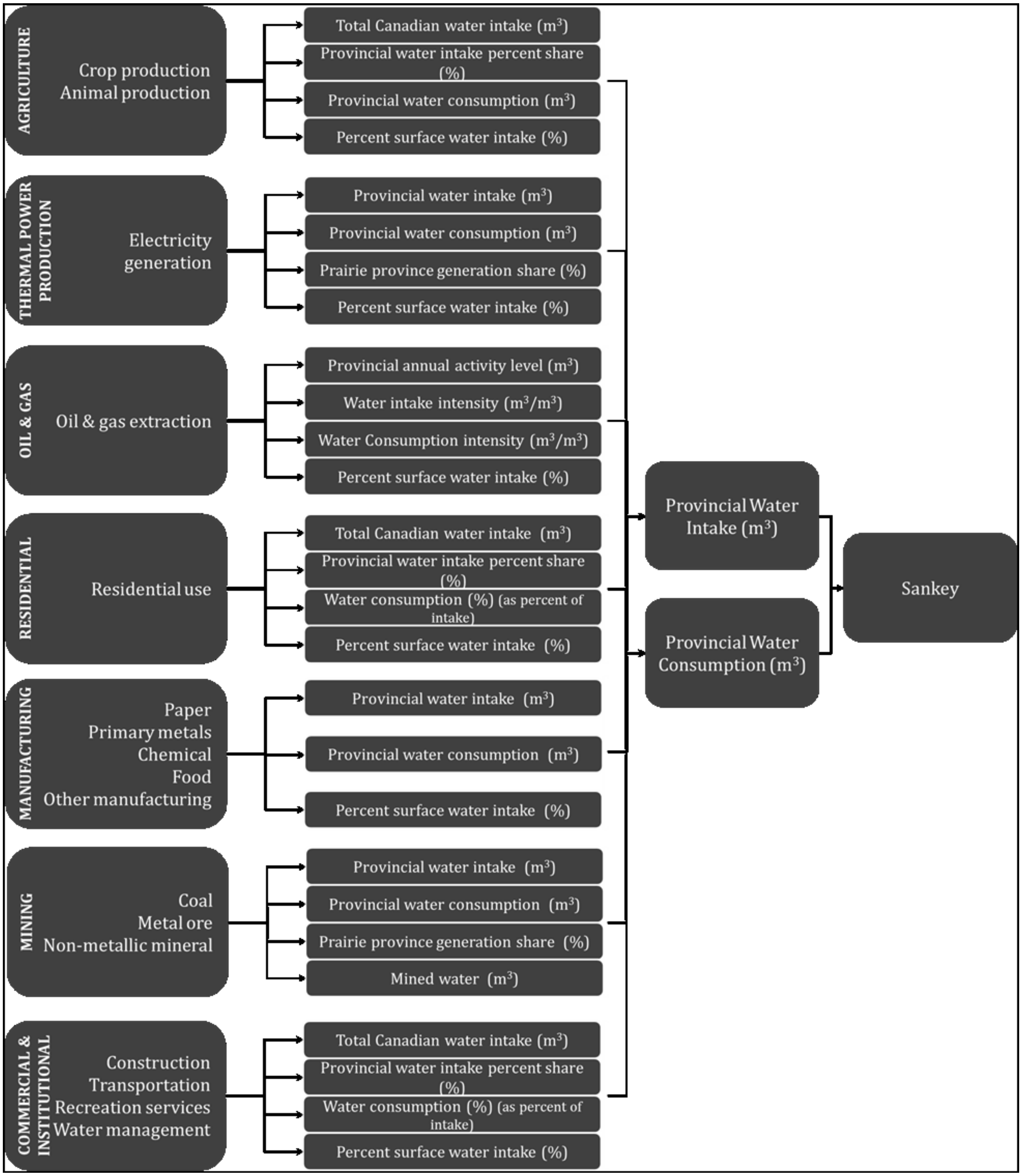
Appendix A: Sankey diagram development



The data for all sectors were organized hierarchically and in the form of a tree as presented above.

Appendix B: Province-wise water intake and consumption estimates for demand sectors

Ontario	Water intake (million m^3)	% Surface water	Surface water (million m^3)	Groundwater (million m^3)	Water consumption (million m^3)	Water discharge (million m^3)	Mine water (million m^3)
Agriculture	31	77	24	7	30	1	
Thermal power	20844	100	20844	0	31	20813	
Manufacturing	1547	98	1516	31	204	1344	
Oil & gas	0	0	0	0	0	0	
Residential	939	89	841	99	94	845	
Mining	68	100	68	0	12	80	24
Commercial	601	89	538	63	60	541	
Total	**24032**	**-**	**23832**	**200**	**431**	**23624**	**24**

Alberta	Water intake (million m^3)	% Surface water	Surface water (million m^3)	Groundwater (million m^3)	Water consumption (million m^3)	Water discharge (million m^3)	Mine water (million m^3)
Agriculture	1563	98	1531	31	1515	48	
Thermal power	1723	100	1723	0	60	1663	
Manufacturing	280	97	271	8	70	209	
Oil & gas	196	87	172	24	181	16	
Residential	324	94	304	19	32	292	
Mining	57	100	57	0	13	52	8
Commercial	207	94	195	12	21	187	
Total	**4350**	**-**	**4273**	**77**	**1892**	**2466**	**8**

British Columbia	Water intake (million m^3)	% Surface water	Surface water (million m^3)	Groundwater (million m^3)	Water consumption (million m^3)	Water discharge (million m^3)	Mine water (million m^3)
Agriculture	314	73	229	85	305	10	
Thermal power	35	58	20	15	0	35	
Manufacturing	748	92	688	60	63	685	
Oil & gas	1	97	1	0	1	0	
Residential	356	92	328	29	36	321	
Mining	64	100	64	0	12	110	58
Commercial	228	73	167	62	23	205	
Total	**1746**	**-**	**1497**	**249**	**439**	**1365**	**58**

Saskatchewan	Water intake (million m^3)	% Surface water	Surface water (million m^3)	Groundwater (million m^3)	Water consumption (million m^3)	Water discharge (million m^3)	Mine water (million m^3)
Agriculture	76	100	76	0	74	2	

Thermal power	461	100	461	0	16	445	
Manufacturing	18	78	14	4	10	8	
Oil & gas	18	97	18	1	17	1	
Residential	32	83	27	5	3	29	
Mining	43	100	43	0	10	39	6
Commercial	21	83	17	3	2	19	
Total	**669**	**-**	**656**	**13**	**132**	**543**	**6**

Quebec	**Water intake (million m^3)**	**% Surface water**	**Surface water (million m^3)**	**Groundwater (million m^3)**	**Water consumption (million m^3)**	**Water discharge (million m^3)**	**Mine water (million m^3)**
Agriculture	22	90	20	2	21	1	
Thermal power	1	100	1	0	1	0	
Manufacturing	915	97	896	19	23	892	
Oil & gas	0	0	0	0	0	0	
Residential	1198	90	1079	120	120	1079	
Mining	132	100	132	0	52	164	84
Commercial	767	90	691	77	77	691	
Total	**3035**	**-**	**2817**	**218**	**293**	**2826**	**84**

Manitoba	**Water intake (million m^3)**	**% Surface water**	**Surface water (million m^3)**	**Groundwater (million m^3)**	**Water consumption (million m^3)**	**Water discharge (million m^3)**	**Mine water (million m^3)**
Agriculture	60	60	36	24	58	2	
Thermal power	4	100	4	0	0	3	
Manufacturing	57	73	41	15	7	50	
Oil & gas	2	97	2	0	2	0	
Residential	65	86	56	9	6	58	
Mining	25	100	25	0	6	23	4
Commercial	41	86	36	5	4	37	
Total	**253**	**-**	**200**	**53**	**83**	**174**	**4**

Appendix C: WEAP model framework

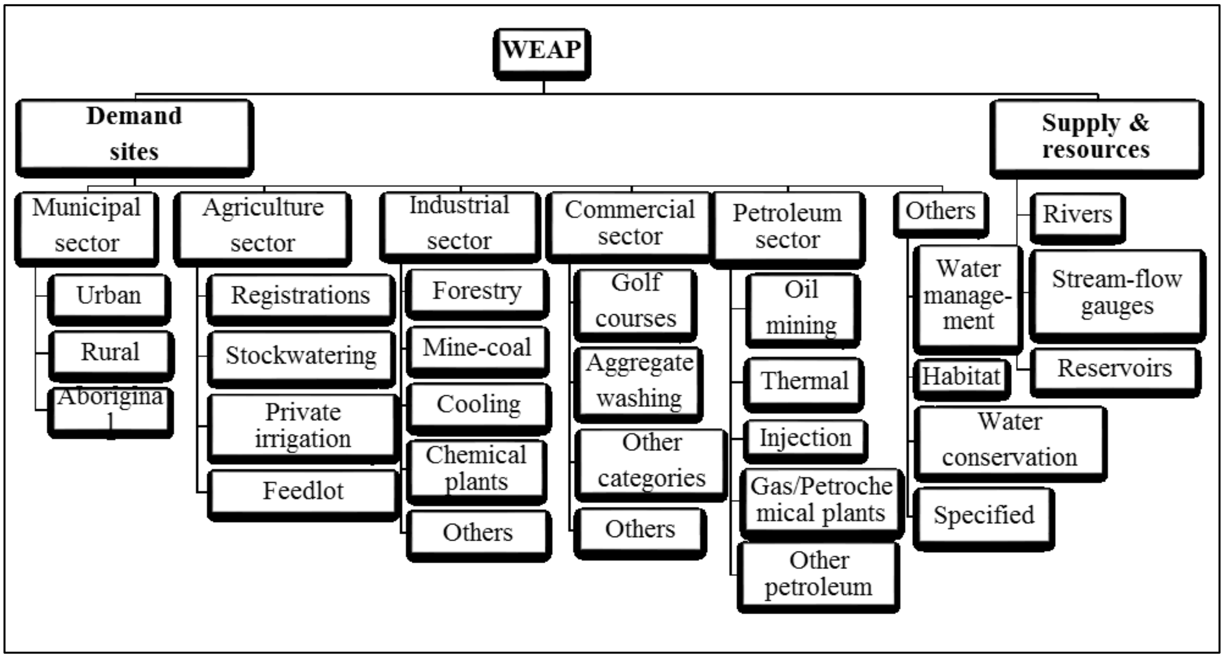


Figure 58: WEAP model framework for Alberta (Adopted from [31])

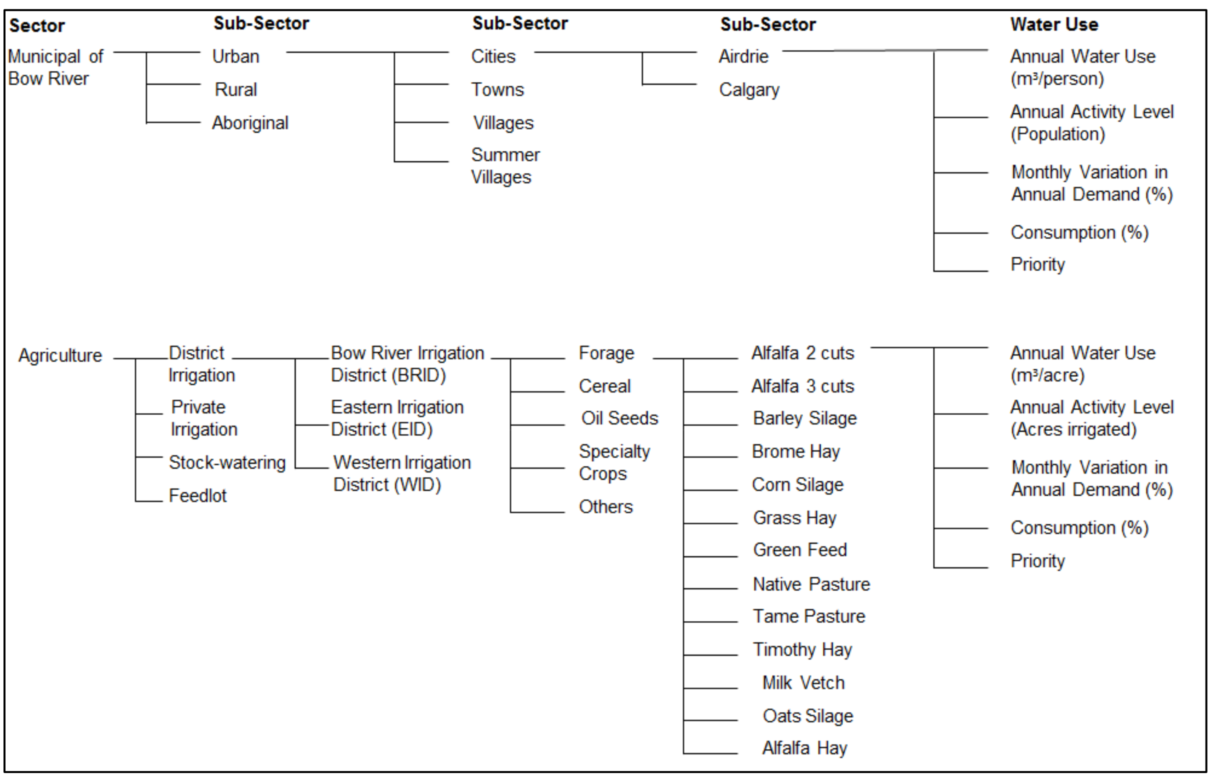


Figure 59: WEAP methodology for the municipal and agriculture sectors of the Bow River Basin [31]

Appendix D: LEAP model framework

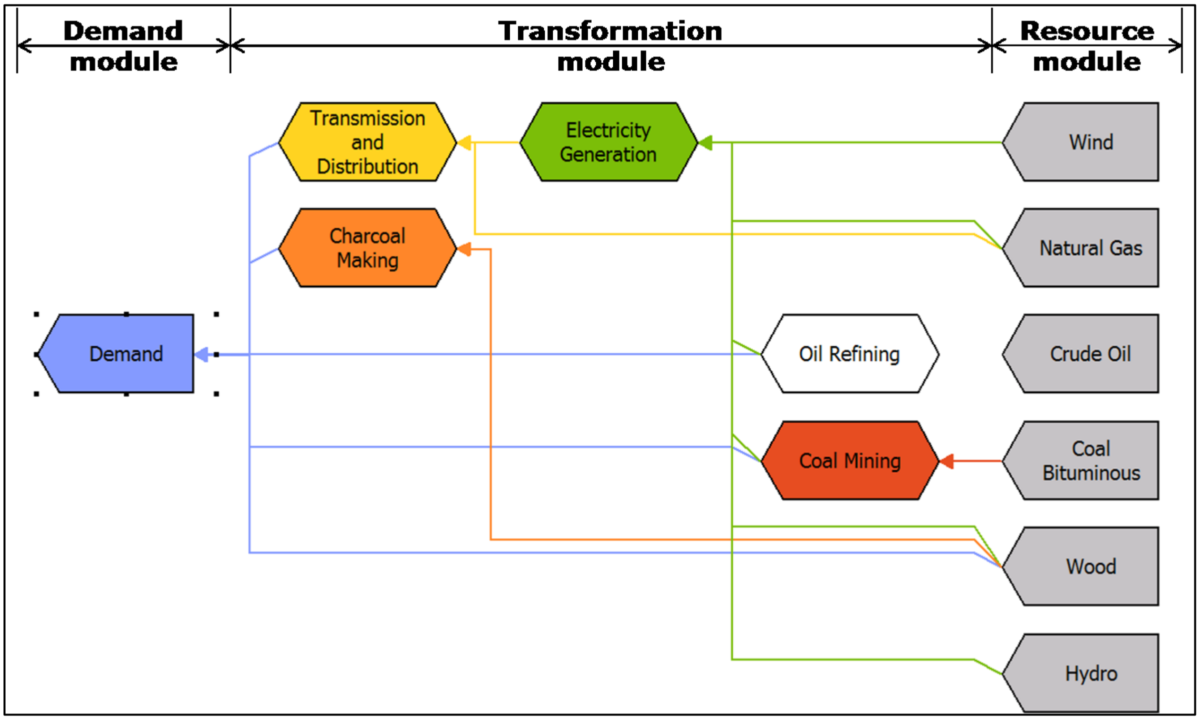


Figure 60: LEAP Overall Layout

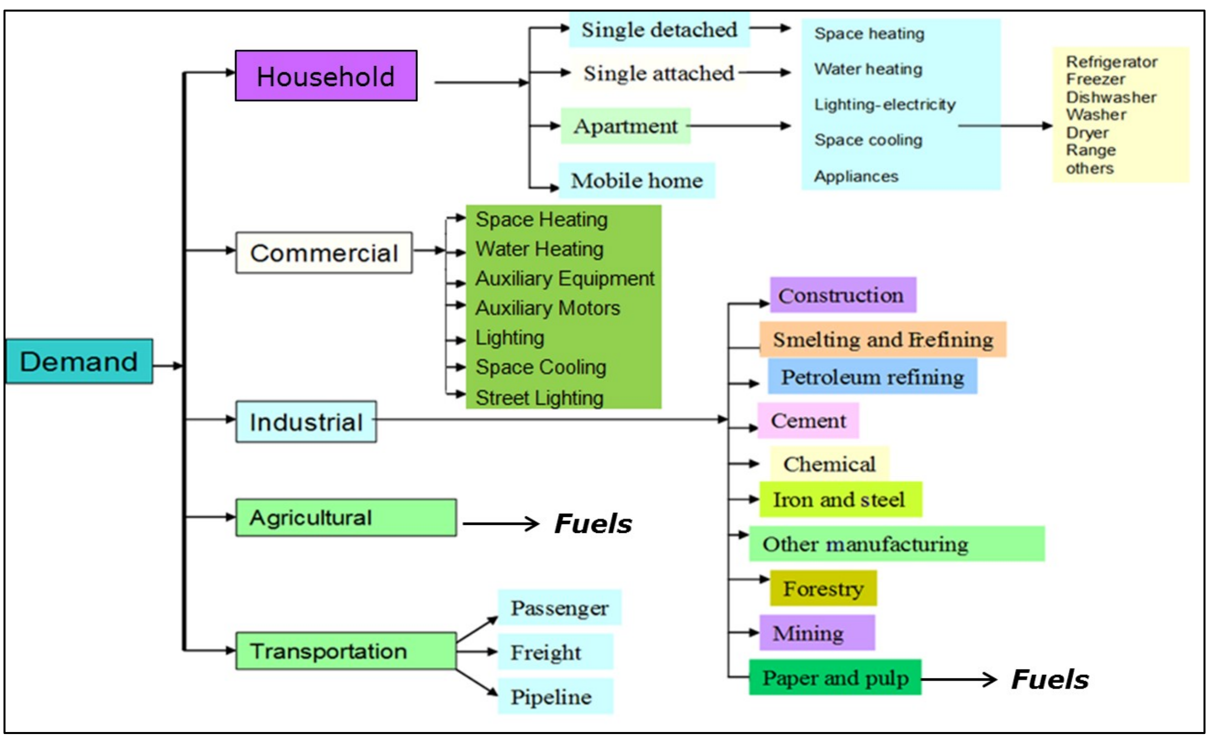


Figure 61: Energy Demand Sectors in Alberta

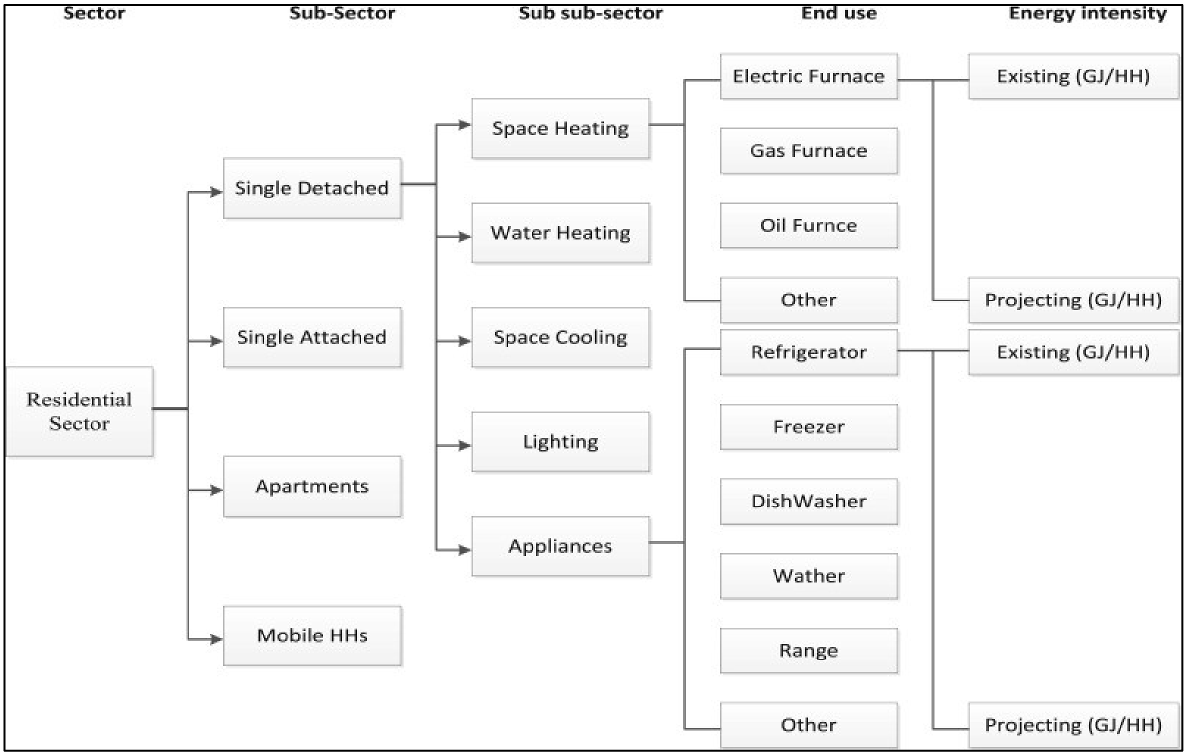


Figure 62: Detailed structure of Residential sector up to device level (Adopted from [114])

Appendix E: Base year input data for WEAP Model

Table 21: Power plants with their corresponding capacity in Alberta, 2016

ASSET	MC
COAL (MW)	
Battle River #3 (BR3)	149
Battle River #4 (BR4)	155
Battle River #5 (BR5)	385
Genesee #1 (GN1)	400
Genesee #2 (GN2)	400
Genesee #3 (GN3)	466
H.R. Milner (HRM)	144
Keephills #1 (KH1)	395
Keephills #2 (KH2)	395
Keephills #3 (KH3)	463
Sheerness #1 (SH1)	400
Sheerness #2 (SH2)	390
Sundance #1 (SD1)	288
Sundance #2 (SD2)	288
Sundance #3 (SD3)	368
Sundance #4 (SD4)	406
Sundance #5 (SD5)	406
Sundance #6 (SD6)	401
GAS (MW)	
Simple Cycle	
AB Newsprint (ANC1)	63
AltaGas Bantry (ALP1)	7
AltaGas Parkland (ALP2)	10
Carson Creek (GEN5)	15
Cloverbar #1 (ENC1)	48
Cloverbar #2 (ENC2)	101
Cloverbar #3 (ENC3)	101
Crossfield Energy Centre #1 (CRS1)	48
Crossfield Energy Centre #2 (CRS2)	48
Crossfield Energy Centre #3 (CRS3)	48
Devon	10.5
Drywood (DRW1)	6
House Mountain (HSM1)	6
Judy Creek (GEN6)	15
Lethbridge Burdett (ME03)	7
Lethbridge Coaldale (ME04)	6

Lethbridge Taber (ME02)	8
Maxim APP	11.1
Mazeppa (MFG1)	16
NPC1 Denis St. Pierre (NPC1)	11
NPC2 JL Landry (NPC2)	9
Northern Prairie Power Project (NPP1)	105
Poplar Hill #1 (PH1)	48
Rainbow #1 (RB1)	30
Rainbow #2 (RB2)	40
Rainbow #3 (RB3)	20
Rainbow #5 (RB5)	50
Ralston (NAT1)	16
Valley View 1 (VVW1)	50
Valley View 2 (VVW2)	50
West Cadotte (WCD1)	20
Cogeneration	
ATCO Scotford Upgrader (APS1)	195
Air Liquide Scotford #1 (ALS1)	96
AltaGas Harmattan (HMT1)	45
Base Plant (SCR1)	50
Bear Creek 1 (BCRK)	64
Bear Creek 2 (BCR2)	36
BuckLake (PW01)	5
CNRL Horizon (CNR5)	103
Camrose (CRG1)	10
Carseland Cogen (TC01)	95
Christina Lake (CL01)	101
Conacher Algar	12.7
Dow Hydrocarbon (DOWG)	326
Edson (TLM2)	13
Firebag (SCR6)	473
Foster Creek (EC04)	98
Grizzly Algar	15.3
Joffre #1 (JOF1)	474
Kearl (IOR3)	84
Lindbergh (PEC1)	16
MEG1 Christina Lake (MEG1)	202
MacKay River (MKRC)	197
Mahkeses (IOR1)	180
Muskeg River (MKR1)	202
Nabiye (IOR2)	195

Nexen Inc #2 (NX02)	220
Poplar Creek (SCR5)	376
Primrose #1 (PR1)	100
Rainbow Lake #1 (RL1)	47
Redwater Cogen (TC02)	46
Shell Caroline (SHCG)	19
Syncrude #1 (SCL1)	510
U of C Generator (UOC1)	12
University of Alberta (UOA1)	39
Combined Cycle	
Cavalier (EC01)	120
ENMAX Calgary Energy Centre (CAL1)	320
Fort Nelson (FNG1)	73
Medicine Hat #1 (CMH1)	210
Nexen Inc #1 (NX01)	120
Shepard (EGC1)	860
HYDRO (MW)	
Bighorn Hydro (BIG)	120
Bow River Hydro (BOW1)	320
Brazeau Hydro (BRA)	350
CUPC Oldman River (OMRH)	32
Chin Chute (CHIN)	15
Dickson Dam (DKSN)	15
Irrican Hydro (ICP1)	7
Raymond Reservoir (RYMD)	21
Taylor Hydro (TAY1)	14
WIND (MW)	
Ardenville Wind (ARD1)	68
BUL1 Bull Creek (BUL1)	13
BUL2 Bull Creek (BUL2)	16
Blackspring Ridge (BSR1)	300
Blue Trail Wind (BTR1)	66
Castle River #1 (CR1)	39
Castle Rock Wind Farm (CRR1)	77
Cowley Ridge (CRE3)	20
Enmax Taber (TAB1)	81
Ghost Pine (NEP1)	82
Halkirk Wind Power Facility (HAL1)	150
Kettles Hill (KHW1)	63
McBride Lake Windfarm (AKE1)	73
Oldman 2 Wind Farm 1 (OWF1)	46

Soderglen Wind (GWW1)	71
Summerview 1 (IEW1)	66
Summerview 2 (IEW2)	66
Suncor Chin Chute (SCR3)	30
Suncor Magrath (SCR2)	30
Wintering Hills (SCR4)	88
BIOMASS AND OTHER (MW)	
APF Athabasca (AFG1)	131
Cancarb Medicine Hat (CCMH)	42
DAI1 Daishowa (DAI1)	52
Drayton Valley (DV1)	11
Gold Creek Facility (GOC1)	5
Grande Prairie EcoPower (GPEC)	27
NRGreen (NRG3)	19
Slave Lake (SLP1)	9
Weldwood #1 (WWD1)	50
Westlock (WST1)	18
Weyerhaeuser (WEY1)	48
Whitecourt Power (EAGL)	25

TOTAL GENERATION (MW)	
GROUP	**Maximum Capacity**
COAL	6299
GAS	7384
HYDRO	894
OTHER	437
WIND	1445
TOTAL	**16459**

Table 22: Water use parameters for different electricity generation pathways

Water use parameter (water withdrawal)		
	m^3/MWh	Consumption %
Coal subcritical	2.33	84
Coal supercritical	2.19	74
Natural gas simple cycle	0.38	80
Natural gas Combined cycle + cooling tower	0.90	75
Natural gas Combined cycle + Dry cooling	0.32	75
Natural gas cogeneration + cooling tower	0.69	65
Natural gas cogeneration + Dry cooling	0.25	65

Hydro	13.12	100
Wind	0.0	-
Nuclear	4.17	65.46
Solar	0.0	-
Biomass	2.53	87

Table 23: Capacity factor of different power plants for forecast period

Year	Coal	Simple Cycle	Combined Cycle	Cogeneration	Hydro	Wind	Biomass	Nuclear	Solar
2016 - 2050	80%	10%	32%, 72%	60%	23%	32%	65%	90%	20%

*It is assumed that capacity factor of combined cycle power plant will increase from current 32% to 72% in year 2020 due to heavy coal retirement.

Table 24: Power plant input parameters for cost calculations (in 2015 CAD)

Power plant type	Levelized Cost ($/MWh)	Source
Subcritical coal	35.06	[118, 120, 159, 160]
Supercritical coal	39.53	[118, 120, 159, 160]
Simple cycle (combustion turbine)	169.59	[120, 153, 154, 161]
Combined cycle	74.92	[39, 120, 156, 159]
Cogeneration	67.53	[39, 120, 156, 159]

Table 25: Cost parameters for water saving technologies

Water saving technology	Capacity (MW)	Capital cost ($/kW)	O&M cost ($/kW)	% increment in levelized cost	Source
Dry or hybrid cooling	500	182	-	7 – 9%	[62, 167, 173-175]
Transport membrane condenser	223	0.74	0.00	0.02 – 0.04%	[170, 176]
Heat exchanger condensing	500	21.18	0.30	0.8 – 1.5%	[171]
Liquid desiccant absorption	270	32.49	2.31	2.3 – 3.7%	[172]

Appendix F: Base year input data for LEAP Model

Table 26: Net Installed Capacity (MW) by resource *[60, 64, 129, 130]*

Year	Coal	Simple Cycle	Combined Cycle	Cogeneration	Hydro	Wind	Biomass	*Other	Total
2005	5,839.60	1,081.00	797.0	2,892.2	899.70	276.70	308.12	55.15	12,149.47
2006	5,863.60	461.60	797.0	3,065.9	899.70	386.20	313.10	54.05	11,841.15
2007	5,917.90	460.00	797.0	3,168.2	899.72	525.20	313.10	54.05	12,135.17
2008	5,918.30	572.90	797.0	3,453.5	899.70	525.20	313.10	74.10	12,553.80
2009	5,971.30	787.10	797.0	3,554.5	900.00	591.20	323.20	72.50	12,996.80
2010	5,735.30	787.90	797.0	3,632.6	900.00	723.20	340.20	73.30	12,989.50
2011	5,631.80	803.85	797.0	3,650.6	899.90	895.40	358.70	73.75	13,111.00
2012	5,690.33	834.66	797.0	4,051.1	899.92	1,113.30	413.80	97.75	13,897.84
2013	6,258.30	821.40	830.0	4,159.8	900.25	1,113.25	416.65	97.75	14,597.40
2014	6,258.00	1,165.63	830.0	4,165.0	900.25	1,458.90	438.33	97.75	15,313.86
2015	6,266.80	890.86	1690.0	4,372.1	902.20	1,490.80	423.73	96.75	16,133.24

*Oil, Diesel, Waste Heat

Table 27: Power plant input parameters for cost calculation and source in 2015 CAD

Power plant type	Overnight capital cost ($/KW)	Fixed O&M cost ($/KW)	Total Variable O&M cost ($/MWh)	Fuel cost ($/MWh)	Heat rate (GJ/MWh)	Source
Subcritical coal	1666.47	47.07	3.32	10.50	10.5	[118, 120, 159, 160]
Supercritical coal	2309.14	47.07	3.32	9.37	9.4	[118, 120, 159, 160]
Simple cycle	1258.07	18.98	18.50	36.00	9	[120, 153, 154, 161]
Combined cycle	1594.71	9.30	2.60	18.40	8	[39, 120, 156, 159]
Cogeneration	1499.03	8.72	3.32	44.00	11	[39, 120, 156, 159]
Nuclear	7302.34	246.35	2.62	3.50	-	[154, 161]
Biomass straw	3082.21	88.45	62.98	Included in O&M	-	[147, 162, 163]
Biomass whole tree	2854.40	80.41	56.28	Included in O&M	-	[147, 162, 163]
Biomass forest residue	2854.40	80.41	69.68	Included in O&M	-	[147, 162, 163]
Wind	2952.69	105.54	0.00	0.00	-	[120, 153, 154, 161]
Utility scale solar PV	4688.09	59.77	0.00	0.00	-	[120, 153, 154, 161]
Hydroelectric	4038.51	38.87	0.00	0.00	-	[120, 153, 154, 161]