2060 Project

ENERGY PATHWAYS FOR BRITISH COLUMBIA AND CANADA

Two-Year Progress Report

22/01/2015

Pacific Institute for Climate Solutions
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University of Victoria | Institute for Integrated Energy Systems

EXECUTIVE SUMMARY

The 2060 Project is studying the future of Canada's energy system through the lens of long-term large-scale models. With a focus on low-carbon transition pathways, the 2060 Project explores the intersection of technology, policy, economics, society and the environment on the decarbonisation of Canada's electrical sector.

The 2060 Project uses techno-economic models to study energy system transitions under a range of policy, technology and economic scenarios. In addition to custom numerical approaches, two key modelling and simulation tools are used for this work: OSeMOSYS and PLEXOS. OSeMOSYS is a long-term energy system model well-suited for analysis and planning purposes, chosen for its open and accessible nature. PLEXOS is an industry-trusted simulation software that provides a high-performance, robust simulation platform, particularly at short time scales.

A number of studies have been completed and the resulting manuscripts are now either under review or in-press with peer reviewed journals.

The impacts of carbon policies and intertie capacity on combined BC-AB emissions from electricity generation from 2010 to 2060 are quantified using a model developed in OSeMOSYS. Results indicate no benefit from increasing BC-AB intertie capacity under current (July 2015) policies. Under more stringent carbon policies, greater intertie transmission capacity lowers both overall costs and emissions. An 80% reduction in emissions from 2007 levels is achievable with a 10% increase in the net present cost of electricity generation. In all scenarios, natural gas generation replaces Alberta's coal facilities - this gas-fired generation serves as a bridge between Alberta's current coal-dominated generation mix and future low-carbon mixes.

The impacts of carbon policies on GHG emissions and overall system costs in AB are examined using a second OSeMOSYS model. Findings show that carbon taxes accelerate decarbonisation - although with decreasing effectiveness – as the tax increases. Alternative tax scenarios settle on similar carbon intensities by 2060. Modest carbon taxes ($30/t$CO_2$) accelerate the transition from coal to natural gas for base load generation, providing cost-effective reductions. Natural gas-fired capacity provides valuable dispatchable generation, even if substantial build-out of wind and solar power occurs. Additional methane leakage from increased use of natural gas does not negate the GHG benefits of reduced coal combustion. Near-term carbon policy in Alberta and other coal-based power systems should focus on accelerating the retirement of coal plants.

The opportunity for large-scale wave energy integration on Vancouver Island is assessed using a detailed PLEXOS model. Results show that development of 500 MW of wave energy generation can decrease the energy dependency of Vancouver Island on the Mainland by 15% but capacity expansion of four on-island transmission lines is required. In addition, results show that wave energy integration leads to periodic and, therefore, predictable reductions in the monthly energy demand from non-wave sources.

The impacts of climate change on electricity demand and hydroelectric generation in BC are investigated to determine what capacity would be necessary to provide adequate operational flexibility taking into account climatic uncertainties. Results suggest that shifts in regional stream flow characteristics are likely to increase BC's annual hydropower potential by more than 10%. When combined with an estimated decrease in electricity demand by 2%, due to warmer temperatures, an additional 11 TWh of annual energy will be available. Ensuring system robustness to climatic change uncertainties comes with an increase in cumulative operating costs of between 1 and 7%.

In addition, work in progress is assessing the regional potentials of wind energy, geothermal energy, solar energy, and renewable energy-driven "power to gas" in decarbonising strategies for BC and Alberta. To further quantify the impacts of intertie capacity, a GIS-based tool has been developed to provide a wind energy supply stack for BC and AB. To provide validation of the OSeMOSYS results, a high resolution PLEXOS model of BC and AB has been developed. An assessment of fuel substitution using forest biomass residues in place of coal is underway in collaboration with the Forest Carbon Management Project. Valuing alternative pathways to low-carbon systems using risk metrics is being explored for both planning and operational models.

The 2060 Project is actively engaging with industry, government, academia and NGOs to ensure that: (1) models are informed by up to date and consistent data sets; (2) ongoing and future research questions are relevant and timely; and, (3) research findings are disseminated to the relevant parties. Engagement activities include: workshops with industry and government stakeholders, full day meetings with our Advisory Board; presentations to government officials; invited seminars hosted at UVic; ongoing informal discussions between individual researchers and external experts; blog posts on the 2060 website and social media activity. Through direct engagement with electrical utilities, provincial ministries and academia, the findings of the 2060 Project provide both the qualitative and quantitative insights to guide the migration of the Canadian energy system through the transition to carbon neutrality.

CONTENTS

BACKGROUND

An energy system uses high quality *energy sources* to provide *services* such as heating, communication, transport, hygiene, and sustenance. A common framework depicting the extraction, conversion and use of *energy sources* to provide *services* is shown in Figure 1. While primary energy source options are relatively unchanging, the technological systems to *harvest* these sources and efficiently *convert* primary energy into functional secondary energy carriers, or currencies, are under continuous development. Innovations in the *harvesting* and *conversion* of energy sources have allowed urbanization, increased productivity in agriculture, and increased longevity.

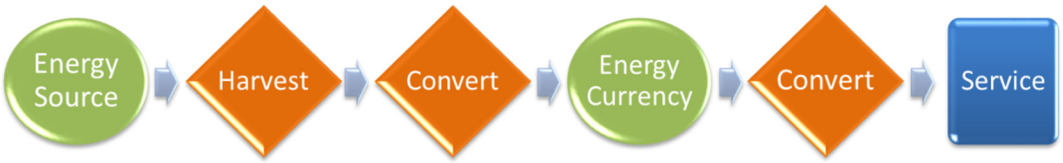


Figure 1: New processes and technologies allow services to access alternative sources and currencies.

Industrialization over the last two centuries was enabled by using global fossil fuel supplies accumulated over millions of years. The resulting anthropogenic movement of stored carbon into the atmosphere has resulted in changes to the earth's natural energy balance and energy flows. If potentially catastrophic climate change is to be avoided or its effects mitigated, net carbon emissions to the atmosphere must be slowed, stopped and possibly even reversed.

Electrical systems provide two ways to meet this goal – one through decarbonisation of the energy harvesting and conversion systems, the other through the use of low-carbon electricity as a substitute for carbon emitting currencies[1].

> *"The most plausible way to reduce global CO_2 emissions is … to increase the role of very low carbon technologies in electricity generation and to increase the use of electricity in transportation and heating."*
>
> *(Schmalensee, 2015)*

Electricity is one of many energy currencies which can be generated from a broad range of sources. Modern electrical systems are reliable, pervasive and complex. As a technical construct, electrical infrastructure can be deployed in any jurisdiction. However, the energy sources used to power the electrical system vary with location due to non-uniform distributions of resources and the desire to provide service at least cost. When considering the electrical system, it is important to understand that the physical connection of energy sources to energy services is only one aspect of what this infrastructure does. A second and equally important aspect is the dynamic coordination of supply with demand. Electricity presents a unique challenge in that supply must be *dispatched* to instantaneously meet time varying demand. To fully utilize generation sources that cannot be dispatched (*i.e.* whose output is variable and cannot be controlled) requires additional technical resources, such as storage or

[1] Schmalensee, *Energy Economics*, 52 (2015).

dynamic system management. The latter may include load control, trading, and increased use of flexible capacity.

In a conventional electrical system, energy sources (such as fossil fuels) are characterized by their energy content while the rate at which this energy is used (*i.e.* power) is determined by demand. Sources such as hydro, wind, solar, and other renewables are *sources of power*. The rate at which these sources can be harvested is determined by the availability of the source itself and the instantaneous demand for power. Unfortunately, in most variable renewable energy (VRE) cases, the availability of the source is not synchronous with demand.

A technical chain that links a time-varying and non-dispatchable supply with a time-varying load is represented in Figure 2. Given the non-synchronous nature of the source availability and the demand, storage elements are implemented to ensure that the balance is maintained. In the case of British Columbia, we harvest precipitation and glacial run-off using large storage hydroelectric dams and convert this to electricity as required by the demand.

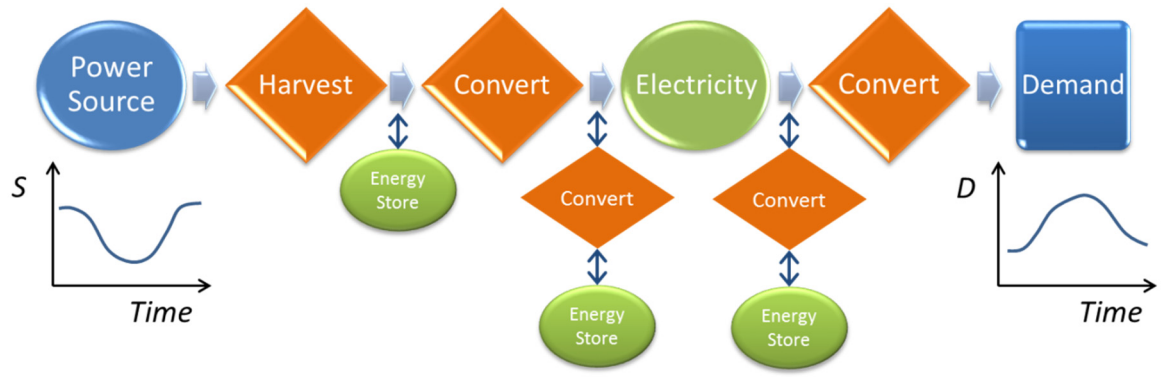


Figure 2: Renewable supplies may not be dispatchable. Balancing electricity demand may require additional technologies for storage and an additional level of control.

The differences between energy and power may seem small, but the technical infrastructure needed to provide electricity is largely determined by these two aspects of demand. In addition, the desire to reduce cost and improve reliability requires the transmission and distribution infrastructure we rely on today. The ability to move electricity regionally is another way to manage temporal mismatches between supplies and demands and to reduce installed capacity. Sufficient transmission infrastructure is a critical element to enabling large-scale renewable penetration.

> *"…there is no single technology that can be said to be the cheapest under all circumstances. […] system costs, market structure, policy environment and resource endowment all continue to play an important role in determining the [value] of any given investment."*
>
> *(IEA, Projected Costs of Generating Electricity 2015 edition)*

Transitioning global electrical systems to low-carbon energy sources is essential to reducing emissions. Renewable energy sources are increasingly being utilized; however, many of these renewable energy sources are naturally variable and the inherent fluctuations create challenges for utilities and governments tasked with ensuring system reliability and cost-effectiveness. Some experts feel that solving the energy-power-emissions problem is simply a matter of deploying existing technologies, while others feel new technologies must be developed to accelerate the pace and scale of decarbonisation. Either perspective may be supported depending on what is assumed with regards to acceptable cost and social license.

PROJECT OBJECTIVES

The 2060 Project examines transition pathways to future, low-carbon energy systems in Canada. The broad goals are to quantify and understand how technology, policy, economics and social license combine to drive decarbonisation. Our specific research objectives are as follows:

1. Quantify the impacts of policy on electrical system decarbonisation
2. Determine the costs and benefits of regional integration through transmission interconnections
3. Cost pathways to carbon emission targets under various scenarios
4. Assess the impacts of climate change on water supply and energy demands
5. Assess potential of fuel substitution in the delivery of transportation and thermal energy services
6. Value trade-offs amongst emissions, costs, and long-term system resilience

As shown in Figure 3, Canada is in an enviable position with regards to our electricity generation mixture. There are ample energy supply options, the carbon intensity is low, and the costs are amongst the lowest in the world. As a result, fully decarbonising the Canadian electricity system is a feasible goal and there is a clear opportunity to use the electrical system to decarbonize other sectors, transportation in particular.

The components of our electricity infrastructure are large, designed to have long working lifetimes and require long lead times for alteration, additions or decommissioning. While future supply mixes, or energy sources, can be easily prescribed, the financial and political conditions needed to transition from today's system to the future system are more difficult to determine. The 2060 Project aims to provide an understanding of the necessary intermediate steps, technology requirements, and supporting policies required to reach these long term goals.

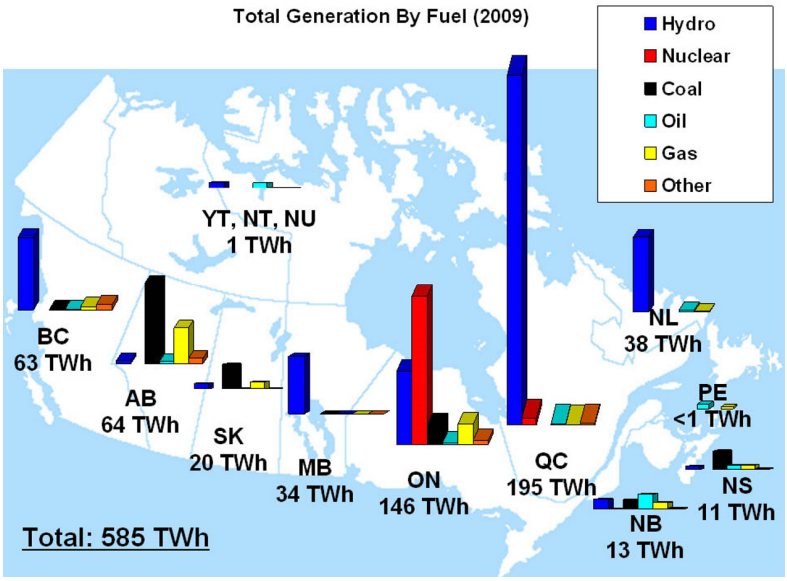


Figure 3: Regional electrical generation and energy sources (Environment Canada).

In the initial stages of this research, the focus is on British Columbia (BC) and Alberta (AB). As shown in Figure 4, the Alberta electrical system is heavily dependent on carbon intensive generation but has tremendous potential for development of renewable resources while the British Columbia system is hydroelectric dominated and features unique multi-year energy storage capabilities. This complementary pairing of jurisdictions is representative of similar pairings elsewhere in Canada (i.e. SK-MB, QC-NB-NS, MB-USA, QC-USA, NL-USA). Therefore, the findings of this research will have application beyond these two provinces.

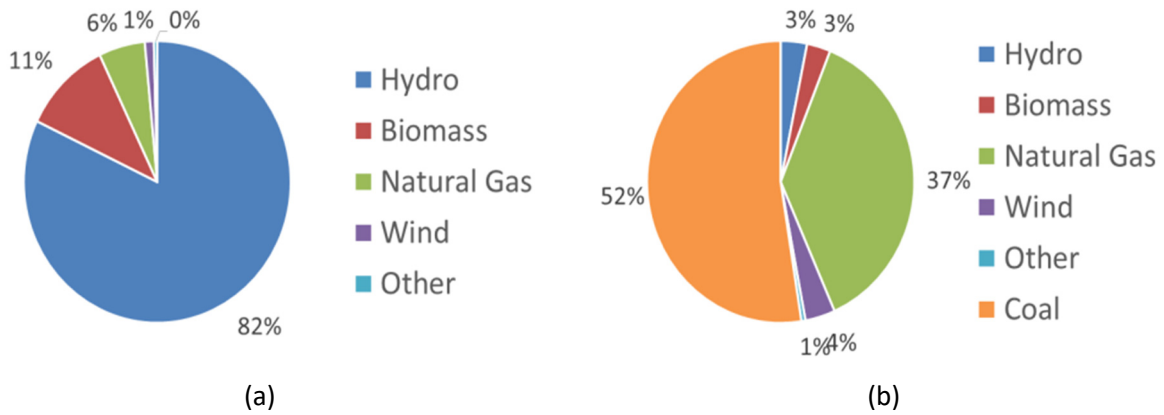


Figure 4: Generation mixes in (a) BC and (b) AB.

Over the coming decades, AB is expected to see increasing demand in conjunction with retirement of coal facilities and increasingly stringent emission caps. In relative terms, this challenge is fundamentally similar to the global challenge, as illustrated in Figure 5. Elements of this research that focus on policies to address this challenge will, therefore, have relevance beyond Canada.

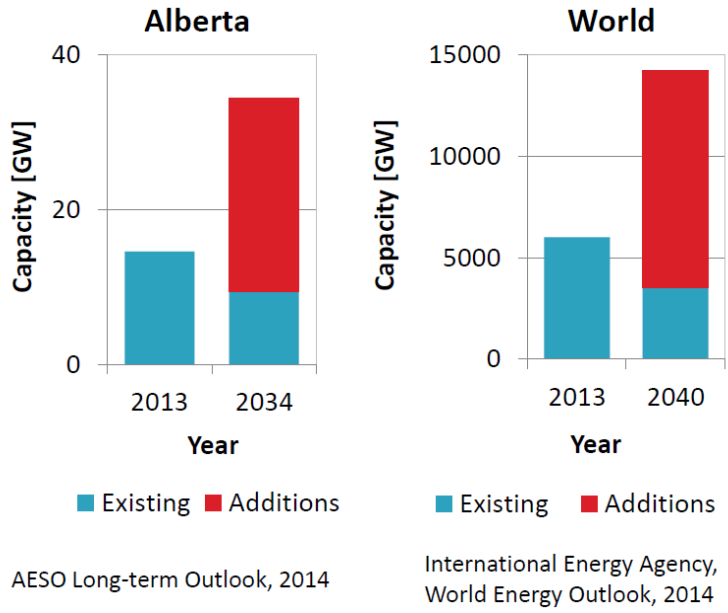


Figure 5: Generation retirements and additions for Alberta and the world.

APPROACH

The 2060 Project uses techno-economic models to study energy system transitions under a range of scenarios. A planning approach for supply uses least-cost optimization to determine generation mixtures, timing of capacity retirements and additions, and emissions intensity. The evolution of system structure and performance is determined such that the net present value of the system is minimized for a fifty year period extending from the year 2010 to 2060. In addition to planning, operational characteristics of systems are tested using simulations. These studies are shorter term, incorporate more technical detail, and consider shorter time-scale variability and uncertainty.

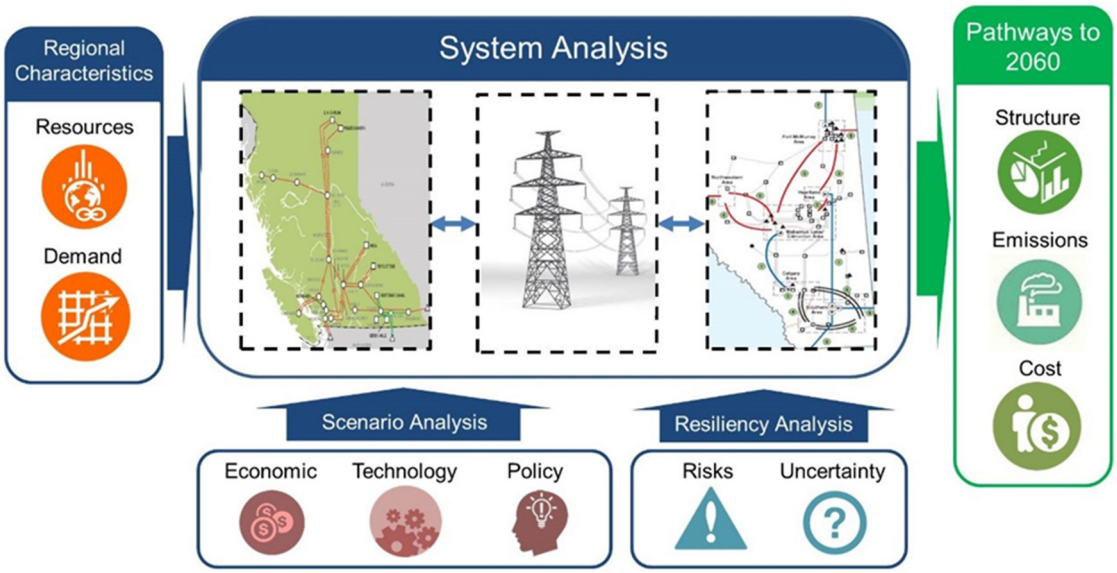


Figure 6: Electrical system structure, costs, and emissions in western Canada are determined using regional supply and demand characteristics under a range of scenarios.

The modelling framework is shown schematically in Figure 6. Planning models are initialized to reflect regional system characteristics including existing energy resources, demand profiles, and current infrastructure. Constraints to reflect policy and social factors are applied. Projected costs, resource characteristics, supply options and demand patterns are defined for the 50 year time period. Scenarios are defined to investigate impacts of policy, future fuel costs, climatic change effects, and technology learning curves. The main outputs are the structure, emissions, and cost of the least-cost system.

The 2060 Project is technology-neutral. All available generation options are considered unless removed for a specific scenario. The team recognizes that there is inherent uncertainty in data and that regional characteristics lead to different costs for equivalent types of technologies. These uncertainties are partially accounted for by focusing on the relative differences between pathways instead of absolute values. A scenario-based analysis is also used to bound possible outcomes and provide a quantitative measure of the sensitivity of emissions, cost and structure under economic, technology and policy changes.

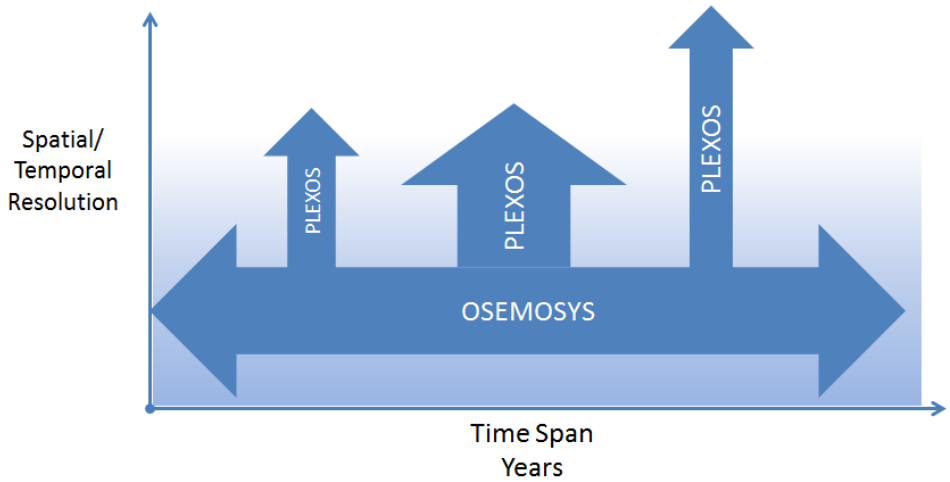


Figure 7: A stylized representation of the coupling of long-term and short-term models; OSEMOSYS determines least cost generation mixtures and timing of infrastructure changes over a 50 year window, while PLEXOS allows for detailed regional and temporal simulation and optimization over shorter time frames.

A key guiding principle of the 2060 approach is to *add value through simplicity*. This idea is represented in Figure 7. Planning and operational studies use a "soft coupling" of two energy modeling tools – OSEMOSYS and PLEXOS – which address long and short terms aspects of energy system performance, respectively. Instead of relying on an integrated assessment model, our analysts decide which outputs from one model will be used as inputs to another. By avoiding more sophisticated "black box" numerical models, the 2060 Project aims to bring more comprehensive understanding to the interactions and outcomes that result from alternative policy assumptions, technology advances or economic changes.

OSEMOSYS (Open Source Energy Modeling System) is used for long term system optimization. As open source software, OSEMOSYS allows researchers to "lift the hood" on the code to add or modify functionality. The long duration of OSEMOSYS studies necessitates relatively coarse spatial and temporal resolution. OSEMOSYS has been used by other researchers to investigate integrated energy system optimization with multiple fuels and loads in sectors such as transportation and heating for buidings. This allows for studies of substitution effects and penetration of new technologies such as electric vehicles.

Shorter term and higher resolution studies use PLEXOS, a commercial software which can be used for academic research at no charge. PLEXOS has market simulation, economic dispatch, and stochastic optimization capabilities. Detailed transmission and distribution networks can be easily implemented to assess spatial impacts of supply, demand, and cost. A broad range of analytic capability exists including tools for risk analysis – a feature of particular interest to the 2060 project. PLEXOS can also be used to simulate water and natural gas systems. In future, the project scope is to expand to include a broader energy system picture. PLEXOS appears to have sufficient flexibility to allow this to happen by building off current activities.

ENGAGEMENT

The research team are actively engaging industry, government, NGO's and academia. This engagement has been undertaken to ensure that: (1) our research questions are relevant to public policy and/or industry decision making; (2) our analyses are based on the up to date, consistent and unbiased data; (3) our modeling methods are based on current best practices; (4) our research findings are accessible to the public and to key actors in industry, government and NGOs; and, (5) that our on-going research is informed by discussions with these key actors. Appendix A provides a comprehensive list of organisations and individuals with whom we are engaged.

A key element in our engagement strategy is the support provided by our Advisory Board. Our Advisory Board provides guidance on current and future research directions, insights on policy directives and assists in ensuring that we are engaging with the correct political, industrial and academic players. The 2060 Project hosts an annual meeting with the full Advisory Board, and organises workshops with individual members to help disseminate research results and to collect commentary on findings. Advisory Board members include members of provincial governments in BC and AB, provincial utilities and market surveillance authorities.

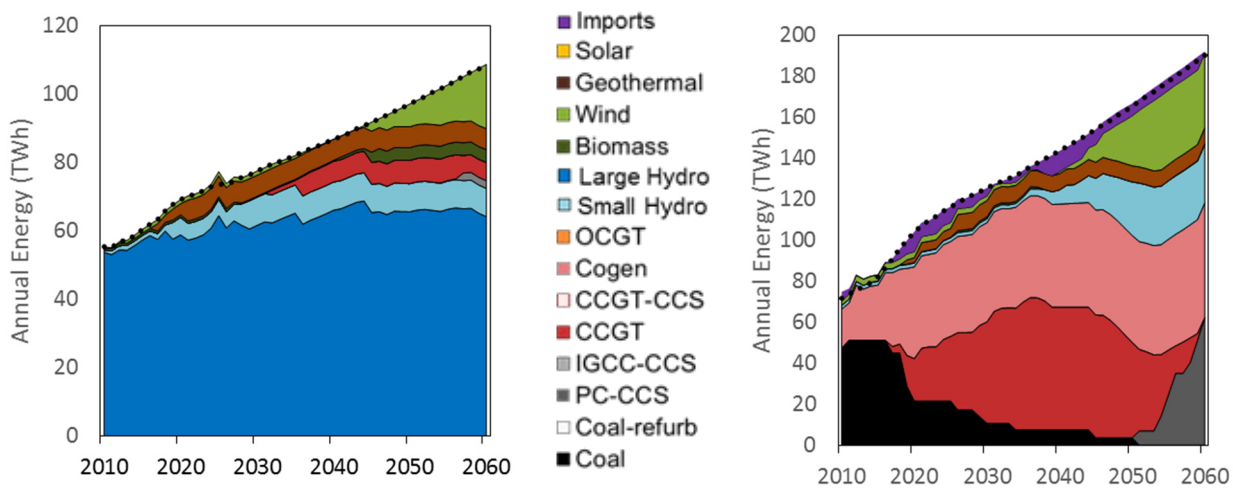
Realising the need to convey project findings beyond traditional academic channels, the 2060 Project has developed an interactive website (www.uvic.ca/2060project) and maintains an active presence on Twitter (@2060Project). These digital channels have allowed the 2060 Project findings to be widely distributed to government policy developers on relevant time scales. The benefits of these efforts were well represented by the uptake the 2060's review of Alberta's new Climate Leadership Plan and the resulting face-to-face meetings and on-line discussions.

In addition, our researchers are involved in outreach activities that contribute to public literacy on climate-energy issues. These activities include participation in public dialogue on issues to which this research has relevance, and development and implementation of educational activities.

RESEARCH FINDINGS

BRITISH COLUMBIA / ALBERTA INTEGRATION

Toward addressing Research Objectives 1, 2 and 3, the 2060 Project is initially focused on the electricity systems of British Columbia (BC) and Alberta (AB). Models of the AB electrical system and of the integrated BC-AB electrical system have been developed in OSEMOSYS. These models are used to explore the transition to lower carbon electricity in Western Canada, including the implications of a more integrated electrical system. The existing generation technologies in the provinces are included in the models, as well as a suite of options for the future, for example, solar PV, geothermal, and increased BC-AB intertie capacity. Key assumptions for the model are drawn from historical data, BC Hydro and AESO load forecasts, as well as projections from the US Energy Information Administration for technology costs and performance. Annual demands are represented by thirty-six time-slices representing season variations and daily peak, shoulder, and off peak periods. The models minimize net present cost over several decades, accounting for capital, O&M, fuel, and carbon costs. Potential carbon policies, such as a range of taxes and caps, are applied in several scenarios to evaluate their impact on generation mix, carbon emissions, and costs.

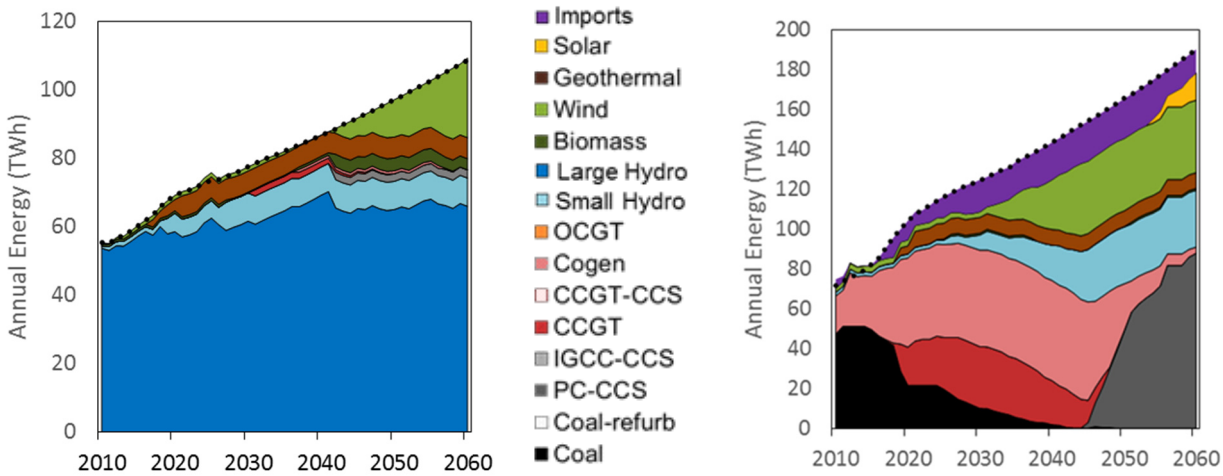


(a) (b)

Figure 8: Baseline energy generation for (a) BC and (b) AB.

A baseline scenario for the joint BC-AB electricity system was created based on BC Hydro and Alberta Electric System Operator (AESO) demand forecasts and resource availability projections. Generation cost estimates are based on data from the Energy Information Administration (EIA). Figure 8 shows the evolution of generation types for the two provinces as determined by the model for this baseline scenario. Also represented are imports into AB from BC and the United States, the latter wheeled through BC. The model predicts a slow transition away from coal in AB to a predominantly natural gas and renewable mix. BC remains hydro-dominated with increasing contributions from natural gas and wind after 2045.

The 2007 BC Greenhouse Gas Reduction Target Act stipulates an 80% carbon emissions reduction below 2007 levels by 2050. This policy scenario has been applied to the baseline BC/AB system and the resulting changes in costs, emissions and generation mix have been determined. An option for increased intertie transmission capacity between the provinces was introduced.



(a) (b)

Figure 9: Energy mix evolution under 80% reduction scenario for (a) BC and (b) AB

Under the 80% reduction scenario, the Alberta system features a faster transition from coal and natural gas and an earlier adoption of renewable generation than in the baseline scenario (Figure 9 b). After 2040, coal with carbon capture and sequestration (CCS) becomes a major contributor to the Alberta generation mix. While this technology is currently unproven and the associated costs uncertain, the model results indicate the requirement for a low-carbon, widely available energy source in order to meet the carbon cap requirements. This may include a mix of solar, coal with CCS, enhanced geothermal or some other source. It is important to note this future scenario arises only when the necessary supporting policies are in place.

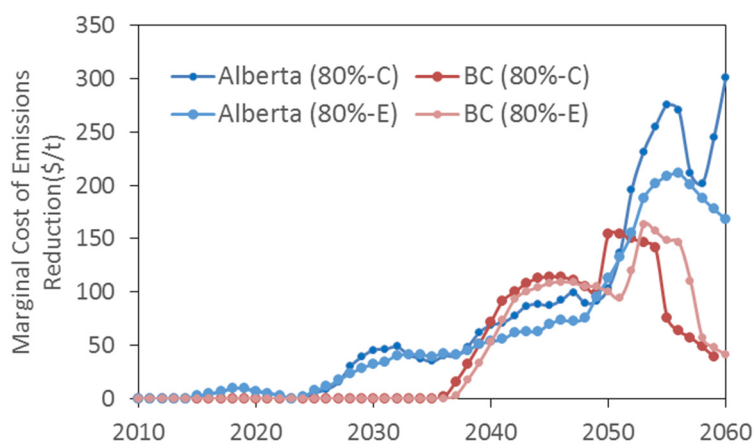


Figure 10: Marginal cost of emission reductions under Current (C) and Expanded (E) transmission intertie capacity.

The cost of emissions under the 80% cap in both provinces with the current (80%-C) and with expanded (80%-E) intertie capacities are shown in Figure 10. The expanded capacity, 3.1GW versus the current 1.2GW, facilitates expansion of low-cost generation options and, thus, reduces the cost of emissions. For both intertie capacities, the marginal cost of the emission reductions increases significantly toward the end of the model timeframe because more expensive resources must be used to meet the carbon cap. As a result, it may be more economically efficient to reduce electricity consumption or reduce emissions from other sources rather than developing these resources.

i. An 80% reduction in combined BC/AB CO2 emissions is possible with a 10% increase in net present cost
ii. Increasing intertie capacity lowers the cost of carbon abatement policies.
iii. Intertie capacity alone does not reduce carbon emissions

This study is presented in a manuscript submitted to *Energy Policy*.

IMPACT OF CARBON PRICING IN ALBERTA

Further addressing Research Objectives 1 and 3, an Alberta only OSEMOSYS model was subjected to a range of carbon pricing scenarios. For this work the baseline or Reference Scenario is consistent with anticipated load growth and carbon policy outlined by the June 25, 2015 update on the *Specified Gas Emitters Regulation*.

As seen in the Reference Scenario in Figure 11(a), the carbon intensity of Alberta's power system is predicted to decrease as coal generation is phased out. As expected, increasing carbon prices reduce annual carbon emissions in all scenarios. However, the cumulative emissions in Figure 11(b) show the value of reducing carbon intensities in the near-term to achieve significant long-term reductions.

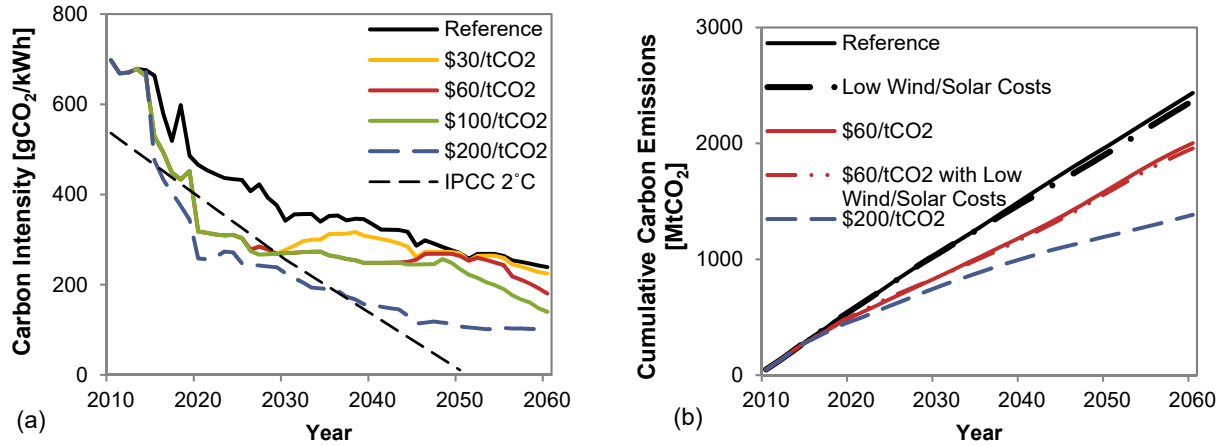


Figure 11: Simulated 2010-2060 carbon emissions. (a) Carbon intensity of select scenarios. IPCC 2˚C line is the median value outlined by the Intergovernmental Panel on Climate Change for the set of 430-530 PPM scenarios contained in the AR5 database. (b) Cumulative CO_2 emissions of selected scenarios.

Carbon pricing accelerates decarbonisation by making it economic to retire coal plants early and install combined cycle natural gas generation. Wind power is built-out to maximum capacity in all scenarios, but not before 2030. Wind power cannot be dispatched so it does not count towards meeting the reserve margin, meaning additional back-up capacity must also be installed. From the system perspective, this makes wind – and solar PV – uneconomic for decades until fuel prices and/or carbon taxes increase.

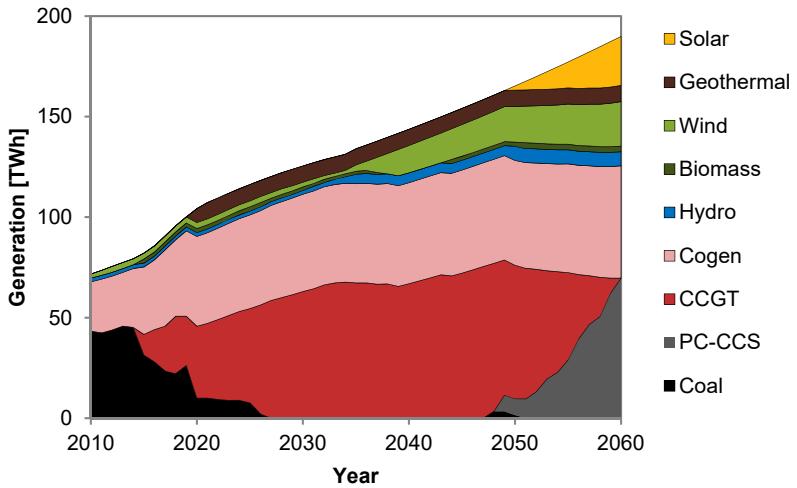


Figure 12: Stacked generation by type for the AB $100/TCO2 scenario.

Figure 12 presents the annual generation mix under a $100/t$CO_2$ scenario. Natural gas plants, including cogeneration, continue to replace coal plants as base load generation and provide a transition to lower carbon-intensity generation. After 2050, solar PV and coal with carbon capture and storage become cost effective and begin replace retiring natural gas plants. Although not included in the scenarios, nuclear or some other technology, could fill this role of low-carbon generator.

In Alberta 99.7% of natural gas is produced by conventional sources, nevertheless increased use of natural gas does cause additional fugitive emissions. Assuming a leakage rate of 2% and global warming potential of 25, the impact of fugitive methane is relatively minor and it is still beneficial to replace coal plants with natural gas.

i. $30/tCO$_2$ is sufficient to meet IPCC 2˚C carbon intensity through to 2030
ii. Dispatchable generation remains essential with extensive variable renewables
iii. Shift from coal to natural gas for baseload provides most cost-effective emission reductions
iv. Fugitive methane from natural gas generation does not negate its GHG benefits

This study is presented in a manuscript that is under review with *Energy Strategy Reviews*.

ALBERTA CLIMATE LEADERSHIP PLAN

Toward addressing Research Objective 1, 2060 researchers analysed the ambitious new Climate Leadership Plan announced by the Alberta government on November 22, 2015. Part of the plan targets electricity generation, where it aims to phase out coal plants by 2030 and simultaneously increase the share of electricity from renewables to 30%. Initial details indicate two mechanisms will be employed to achieve these goals: a carbon tax (the "stick"), and subsidies in the form of renewable energy credits (the "carrot"). Using the previously developed OSeMOSYS model of the Alberta system, a brief analysis was conducted on the new policy indicating that both the carrot and the stick are required to meet the 2030 goals. The carbon tax is effective at driving much of the coal out of the system, but renewable energy credits (RECs) are necessary to incent investment in renewables. Simulations indicate that in spite of significant load growth, annual emissions in 2030 will be less than half of the current system. The province may have to use carbon tax revenue from other sectors such as the oil sands to fund the RECs if the policy is to remain revenue neutral.

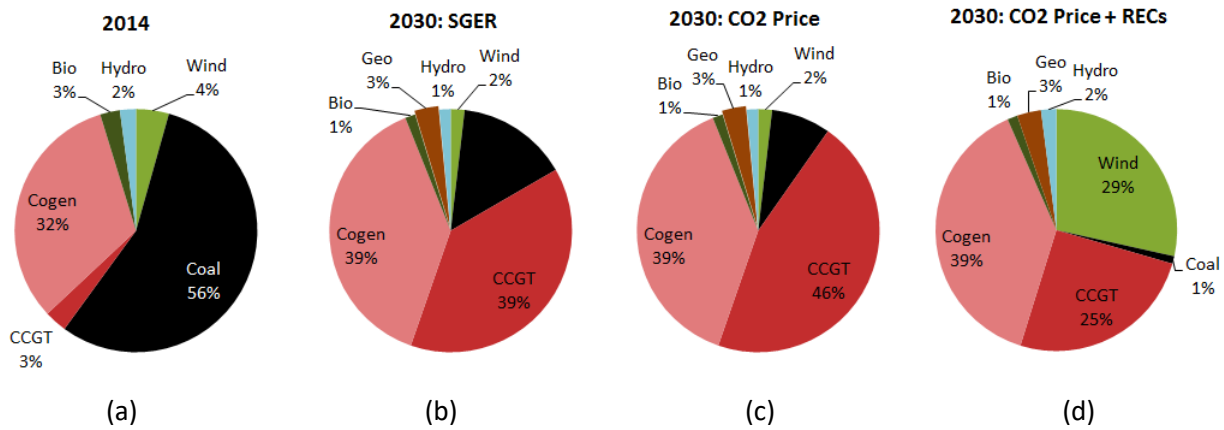


Figure 13: Generation share by type (a) historic 2014, (b) 2030 under existing SGER policy, (c) 2030 under new $30/t carbon price on emissions over best-in-class standard, (d) 2030 under new $30/t carbon price on emissions over best-in-class standard and $25/MWh RECs. Under the existing SGER policy, new combined cycle gas natural gas plants (CCGT) replace retiring coal plants. The new carbon price pushes additional coal plants out for new CCGT, but RECs are required to incent a build out of renewables.

i. The new Alberta policy transitions the system away from coal power and reduces CO_2 emissions

ii. RECs are required for renewables to make significant contribution to the energy mix

This study is posted on the Project 2060 website and has been submitted to *Policy Options*.

WAVE ENERGY INTEGRATION ON VANCOUVER ISLAND

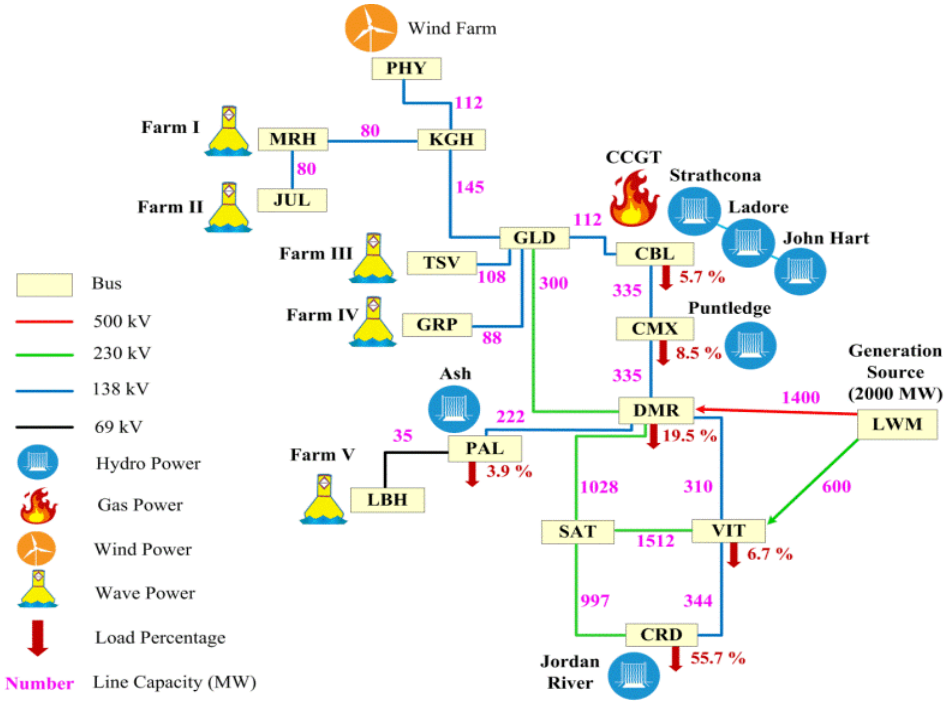


Figure 14: Model of Vancouver Island electrical grid with theoretical wave energy generation

As part of Research Objective 6, wave energy generation and integration was investigated as a means to increase energy security on Vancouver Island. Wave energy resources are vast but largely unexploited due, in part, to uncertainty with respect to reliability, costs and grid integration. Utilizing the PLEXOS® Integrated Energy Model software, a model was developed to assess large-scale wave energy integration on Vancouver Island. As shown in Figure 14, the model incorporates the current transmission grid, the existing fleet of generation stations and ten potential wave farm sites with a total generation capacity of 500 MW.

Three scenarios are investigated: Business As Usual (BAU) - current transmission grid/no wave energy; Infinite Transmission (ITW) – current grid topology with no capacity limits/500 MW of wave energy; Existing Transmission (ETW) – current grid topology with existing capacities/500 MW of wave energy. Figure 15 shows the breakdown of energy sources for the island in each scenario over a seven year period.

Wave generation reduces monthly energy dependency on the lower mainland by up to 15% if infinite transmission capacity is assumed. In the ETW scenario, the available wave power is frequently curtailed due to transmission capacity limitations on the island. As a result lower mainland demand is reduced by only 11%. Comparing the peaks in wave generation, shown in Fig. 15 (b) and (c), it is apparent that this curtailment occurs predominantly during the winter months when the BC load peaks. The current transmission grid is only able to support ~250 MW of wave energy without curtailment.

It is further demonstrated that wave integration leads to a periodic and predictable reduction in the monthly energy demand. In hydro-dominated grids, such as BC's, reservoir levels are managed on monthly and yearly basis and this periodic trend may be a useful feature of wave energy for this system.

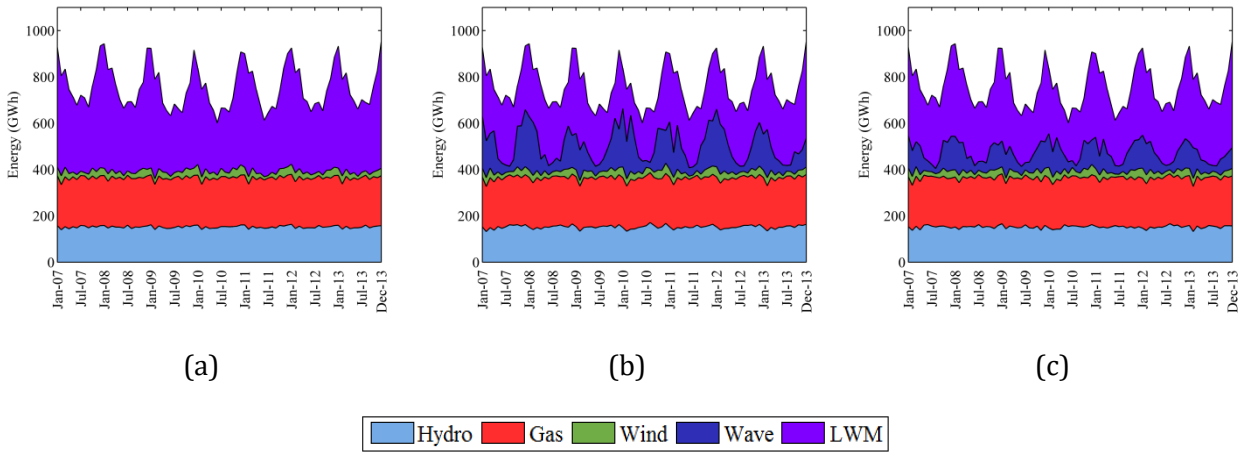


Figure 15: Monthly generation by type across seven years for the 3 scenarios (a) BAU, (b) ITW, (c) ETW. Note: LWM=Energy from cable to Lower Mainland

i. Wave energy integration increases the energy security of Vancouver Island and reduces energy dependence on the mainland by 11% annually.
ii. Current grid infrastructure can support ~250 MW of wave capacity.
iii. Winter peaking wave generation correlates well with provincial load.
iv. Additional transmission capacity on Northern Vancouver Island would facilitate higher VRE levels.

This study is has been posted on the 2060 website and has been published in the *Journal of Renewable Energy* (DOI: 10.1016/j.renene.2015.11.049)

IMPACT OF HYDRO-CLIMATIC CHANGE ON ELECTRICITY GENERATION PLANNING

Climate change is occurring, and as part of Research Objective 4, the project aims to assess the impacts of climate change on water supply and energy demands. This is particularly important in the context of British Columbia where the bulk of the electricity supply relies on hydro resources that are climate-sensitive. As a result, it is important to understand what generation capacity would be necessary, in the 2050 horizon, to provide adequate operational flexibility taking into account climatic uncertainties. An electricity generation planning framework incorporating adaptation to hydroclimatic change was developed to address this question.

The planning framework internalizes both the risks and opportunities associated with alternative hydro-climate scenarios to identify a long-term system configuration that is robust to uncertainty. The implications of a robust response to hydro-climatic change are then examined for the BC electricity system.

As shown in Figure 16, analysis of results suggest that shifts in regional stream flow characteristics by the year 2050 are likely to increase BC's annual hydropower potential by more than 10%. These effects combined with an estimated decrease in electricity demand by 2%, due to warmer temperatures, could provide an additional 11 TWh of annual energy. Uncertainties in these projected climate impacts indicate technology configurations offering significant long-term operational flexibility will be needed to ensure system reliability.

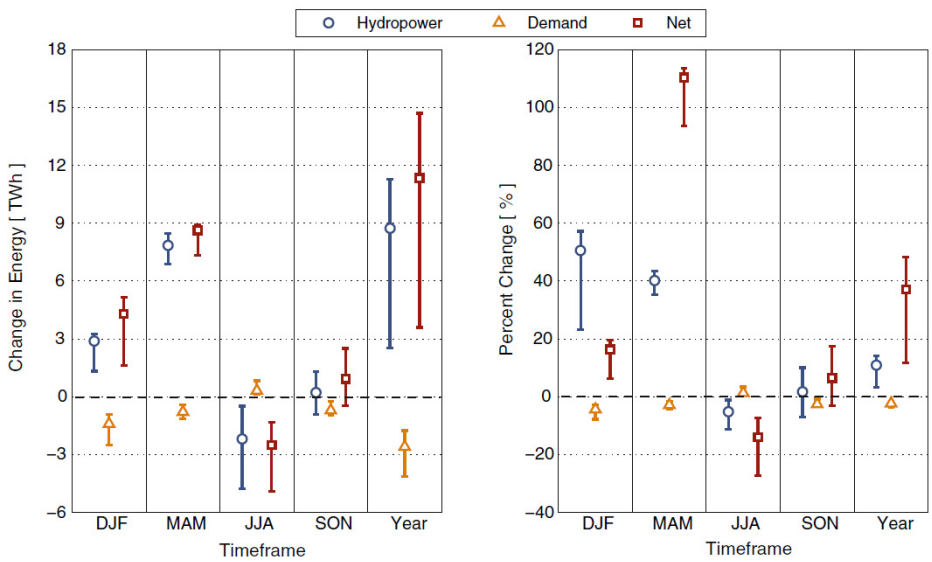


Figure 16: Hydroelectric generation, demand and net energy in 2050; magnitudes presented in (a) and percent change in (b). Error bars indicate uncertainties associated with climatic change models

Results from the regional long-term electricity generation model show that ensuring system robustness can increase cumulative operating costs between 1% and 7%. An analysis of technology configurations involving high-penetrations of wind generation was also performed to highlight interactions between flexibility requirements occurring over multiple temporal scales.

An extension of this work examined the issue of risks in meeting environmental performance (EP) requirements in a long-term energy planning framework. EP risk was found to be particularly important in situations where environmental constraints become increasingly stringent.

Model results indicate allocation of a modest risk premium in these situations can provide valuable hedging against EP risk.

i. Climate change projections will increase hydro generation by 10% and decrease local demand by 2%.
ii. Ensuring electrical grid resilience against climate change will require up to 7% additional investment in the electrical sector

This study is posted on the Project 2060 website and has been published in *Climatic Change* (DOI: 10. 1007/s10584-015-1359-5)

RENEWABLE ENERGY AND STORAGE POTENTIAL

Studies projecting impractically high energy penetrations of variable energy resources have been published in the literature and subsequently reported in the popular media. For example, Myhrvold and Caldeira reported that worldwide coal-fired generation capacity, approximately 1 TW, could be replaced by approximately 5 TW of solar PV with a 20% capacity factor[2]. To examine the practicality of these claims, 2060 Project researchers developed an OSEMOSYS model to determine specifications for a hypothetical integrated solar PV and energy storage facility, located in Arizona, to provide 1 GW of continuous baseload.

Results indicate that 22.3 GW of solar PV capacity, in conjunction with a 30 GWh storage facility having 70% round-trip efficiency, is required to meet this load. The efficiency of this storage facility is equivalent to the largest utility-scale energy storage facility in the world, the Bath County Pumped Storage Station. The ratio of PV capacity to load for this facility is 22:1 whereas, in the study by Myhrvold and Caldeira, this ratio is 5:1, indicating that this estimate of required PV capacity is impractically low. Furthermore, Myhrvold and Caldeira make no mention of the scale or cost of energy storage infrastructure required to smooth this PV generation which we estimate to be orders of magnitude greater than the capacity of the Bath County facility. Impractical estimates of feasible levels of energy penetration by variable energy resources, such as that proposed by Myhrvold and Caldeira, foster misconceptions that are not helpful in the public discourse.

A widely cited paper projecting high energy penetrations of solar PV shown to underestimate the required installed capacity and fails to account for storage infrastructure.

This study is posted on the Project 2060 website and has been published in the Journal of Clean Energy Technologies (DOI: 10.7763/JOCET.2016.V4.248)

CONTROL STRATEGIES FOR REAL-TIME PRICE DEMAND RESPONSE

[2] N. P. Myhrvold and K. Caldeira, 'Greenhouse gases, climate change and the transition from coal to low-carbon electricity', *Environ. Res. Lett.*, vol. 7, no. 1, p. 014019, Mar. 2012.

This study focuses on thermostatically controlled electrical loads. These loads are automatically recruited for fast acting demand response (DR) to provide "virtual storage" and mitigate highly variable renewable power generation without adding costly ramping resources. When conventional thermostats are retrofitted for real-time price DR control, significant control errors can arise, particularly in the form of dispatch control drift. This work identified the underlying causes and proposed a new residential thermostat design that eliminates drift and enables accurate aggregate load control. The thermostat maintains consumer comfort by allowing them to specify a comfort preference for each occupancy mode. The performance of the proposed thermostat was illustrated by detailed simulation and performance studies coupling a residential house and feeder models. Cities in three different climatic zones were examined. During peak times, the new thermostat was found to impart the entire residential load an energy demand elasticity of about 10–25%. The new thermostat's demand response implementation allows operation in the real-time distribution capacity auction system and can provide all the benefits associated with transactive systems, and in particular environmental benefits associated with increased integration of renewable resources.

i. *Novel thermostat designs aggregate demand response resources; allowing utilities to utilize them for short-duration fast-acting reliability services.*
ii. *New residential HVAC equipment design allows consumers to control their participation level in utility demand response services.*

This study is posted on the Project 2060 website and has been published in *Applied Energy* (DOI: 10.1016/j.apenergy.2015.06.048)

RESEARCH IN PROGRESS

WIND RESOURCE ASSESSMENT IN BC/AB

Currently, wind generation is represented in energy systems models using a combination of general cost estimates, historical wind measurements, and external predictions of available capacity. This introduces several implicit assumptions: the entirety of future wind generation has the same generation pattern, no further capacity is available at higher prices, and all generation has the same capital cost. A GIS model of available wind energy and development cost is being developed to better understand the amount, location, and characteristics of wind energy in British Columbia and Alberta.

The model estimates available wind energy from Environmental Canada wind speed models and manufacturers' wind turbine power curves on a 5 km grid covering the entire province. Each point on the grid has an associated capacity factor and costs for roads and transmission. These are combined to determine the levelized cost of energy at each site, allowing a provincial wind supply stack to be made. This supply stack will be used to inform energy models.

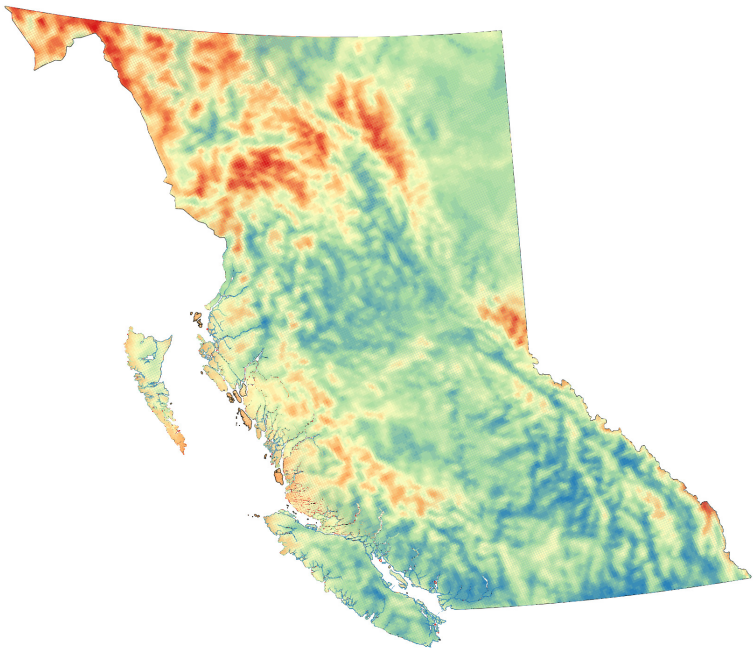


Figure 17: Map of wind turbine capacity factor in British Columbia. Red indicates high capacity factors, blue indicates low capacity factors.

HIGH RESOLUTION PLEXOS MODEL OF BC/AB

PLEXOS allows short term, high time resolution simulations of energy system dynamics. Based on infrastructure development and technology deployment projections from the long term OSEMOSYS models, PLEXOS is being used to create a short term model with higher temporal and spatial resolution. This model will be used to investigate the variability of solar, wind and wave resources; the capacity of

projected future transmission networks to adequately meet loads; storage dynamics of cascading hydro-systems, which dominate in BC; and the resilience of the energy system to unforeseen shocks or failures. Additionally, using both Monte Carlo and stochastic methods, PLEXOS will be used to investigate the implicit trade-offs between risk and uncertainties in future projections.

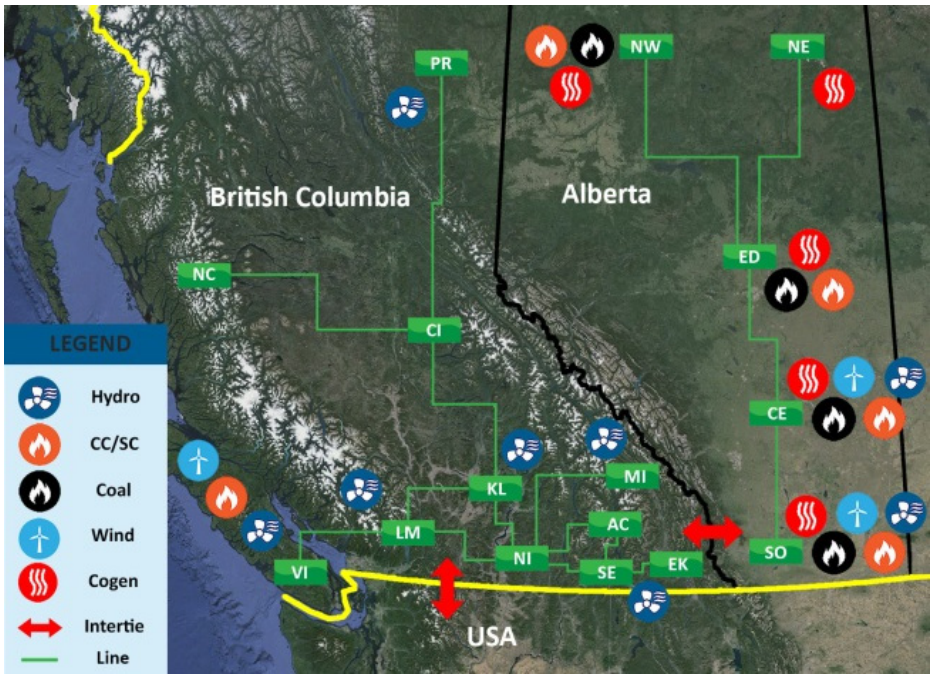


Figure 18: Schematic representation of BC & AB PLEXOS model

POWER-TO-GAS ENERGY STORAGE

Power-to-gas (PtG) is the process of producing hydrogen by water electrolysis. It is being researched for its potential to assist the integration of renewables, like wind and solar, by providing balancing and storage services for the system. PtG can be used for daily arbitrage, but is particularly well suited for seasonal storage, and, unlike compressed air and pumped hydro storage, is not dependent on requisite geography. Another interesting application of PtG is that the hydrogen, generated by renewables, could be used as a fuel for hydrogen vehicles, bridging the power and transportation sectors.

Preliminary research on this topic was presented at the *Energy Systems Conference* in London, UK.

FUTURE RESEARCH

The specific objectives in the initial project proposal for years one and two were:

1. creation of a long-term optimization model of the BC electrical system (Year 1);
2. creation of an electrical system planning model for Alberta (Year 1);
3. creation of a coupled BC-AB electrical system model (Year 2);
4. generation of long-term energy demand scenarios for BC-AB (Year 1);
5. analysis of BC and AB system evolution to 2060 with carbon constraints (Year 2);
6. analysis of climate change induced hydrology and energy demand scenarios (Year 2); and,
7. assessment of renewable power additions to 2060 in a coupled BC-AB electrical system (Year2).

The above milestones have been achieved and the group has worked to ensure findings have been conveyed to industry, academic and government sectors.

Much of the effort during 2016 will focus on analysis of electrical system transitions for BC and Alberta. Future generation mixtures, forecast by our long-term planning studies, will be assessed using short term high resolution methods. The impact of variable renewable energy supplies on wholesale market prices and on the resulting value of this energy will be quantified. Ramping requirements for dispatchable generators and the flexibility benefits of large hydroelectric supplies will be determined in relation to intertie capacity. The regional diversity of supply options will be considered in greater detail so as to quantify the system requirements for inter- and intra-provincial transmission and flexible capacity. Cutting across all of this work, we will continue to explore impacts of uncertainty on risk and system robustness. In addition, we will continue our detailed assessments of the scale, distribution and temporal character of geothermal, wind and solar resources in BC and AB. This work will support the ongoing development of supply stacks which are central to our models.

Also in 2016, we propose to initiate a study to investigate the extent to which demand response (DR) can contribute to maintaining the balance between demand and generation and what impact it would have on interregional trade. An optimal scheduling model will be developed to determine hourly tieline flows between system control areas. The model will be applied and tested for the Western Interconnection operated under the jurisdiction of the Western Electricity Coordinating Council (WECC). The potential contribution of DR in enabling control areas to utilize slow-ramping generation units for system control in the presence of intermittent renewable resources will be analyzed.

A joint study with the PICS Forest Management project is underway to analyse the impacts of using residual forest biomass in retrofitted coal units in AB. The impacts of carbon tax and renewable energy credits on feasibility will be determined and the potential benefits of the addition of CCS technology will be explored. This pathway for carbon mitigation will be compared to alternative uses of forest biomass such as in long lived wood products or in direct heating.

Through combined efforts with the PICS Transportation Futures project, the 2060 Project will explore electrification of the transportation sector. In 2015, the 2060 team initiated a study of a process known as “power-to-gas” to couple the electrical, natural gas and transportation systems. This process incudes the potential for hydrogen use in fuel cell electric vehicles.

Broad objectives for years three to five include:

- Assess impacts of technology diffusion and electrification of transportation and thermal energy services;
- Examine demand changes and the use of residential and industrial loads for demand response;
- Increase scope to examine the broader energy system where interactions between electrical, gas, and liquid fuels are considered.

More detailed short term objectives will be developed with input from the Advisory Board through regular meetings.

In conjunction with our Advisory Board and collaborators, the 2060 Project has developed a much greater understanding on the long term issues and concerns surrounding the Canadian energy system. With Advisory Board input, the 2060 Project is able to ensure future research directions are relevant and inform future policy decisions aimed at mitigation of the effects of our energy systems on the climate.

APPENDIX A: ENGAGEMENT

ENGAGEMENT WITH PICS PROJECTS

FOREST CARBON MANAGEMENT PROJECT

Werner Kurz, Biomass Resource Assessment

TRANSPORTATION FUTURE FOR BRITISH COLUMBIA

Walter Merida and Curran Crawford, Transportation Energy Requirements

ENGAGEMENT WITH INDUSTRY

BC HYDRO

ENERGY PLANNING

David Ince
Sanjaya De Zoysa
John Rich
Kathy Lee
Susan Burton
Pat Harrington
Amir Amjadi
Edlira Gjoshe

POWEREX

Rob Campbell
Brian Moghadam

GENERATION RESOURCE MANAGEMENT

Alaa Abdalla
Raquel Mazariegos
Wun Kin Cheng
Doug Robinson
Jian Li

BUSINESS DEVELOPMENT

Warren Bell

POLICY AND REPORTING

Brenda Goehring

TECHNOLOGY PLANNING AND INNOVATION

Alex Tu

ALBERTA MARKET SURVEILLANCE ADMINISTRATOR

Derek Olmstead, Senior Economist and Market Co-ordinator

ELECTRIC POWER RESEARCH INSTITITUTE

Warren Frost, Energy System and Canadian Manager

SEABREEZE POWER

James Griffiths, Wind Resource and Project Feasibility

SOLAS ENERGY CONSULTING

Paula McGarrigle, Present and Future Wind Development in Alberta

CANADIAN GEOTHERMAL ENERGY ASSOCIATION

Alison Thompson, Chair

WHAT IF TECHNOLOGIES

Michael Hoffman, CEO

ENGAGEMENT WITH ACADEMIA

UNIVERSITY OF VICTORIA

West Coast Wave Initiative, Wave Energy Resource Assessments

Kara Shaw, Environmental Studies

Adam Monahan, Earth and Ocean Sciences

UNIVERSITY OF BRITISH COLUMBIA

Laura Irvine, Civil Engineering

Ziad Shawwash, Civil Engineering

Walter Merida, Mechanical Engineering

UNIVERSITY OF CALGARY

David Layzell, Canadian Energy Systems Analysis Research

UNIVERSITY OF ALBERTA

Jonathan Banks, Earth and Atmospheric Sciences

Brian Fleck, Mechanical Engineering

UNIVERSITY OF ALBERTA

Jonathan Banks, Earth and Atmospheric Sciences

PACIFIC CLIMATE IMPACTS CONSORTIUM

Markus Schnorbus, Lead, Hydrologic Impacts

POTSDAM INSTITUTE FOR CLIMATE IMPACT RESEARCH, GERMANY

Paul Nahmmacher, Research Domain III: Sustainable Solutions

UNIVERSITY COLLEGE CORK: ENERGY POLICY AND MODELLING, IRELAND

John Paul Deane, Large-scale Energy Modelling Efforts in EU

ENGAGEMENT WITH GOVERNMENT

BC PROVINCIAL GOVERNMENT: MINISTRY OF ENERGY AND MINES

Les McLaren, Assistant Deputy Minister

Paul Wieringa, Alternative Energy Policy Branch

Julie Chase, Transmission and Inter-Jurisdictional Branch

Warren Walsh, Geothermal Resource Assessments

Michael Rensing, Transportation Fuels

Amy Sopinka, Electricity Policy Analyst

Jennifer Davison, Transmission and Inter-Jurisdictional Branch

Alan Barber, Transmission and Inter-Jurisdictional Branch

Oswald Dias, Transmission and Inter-Jurisdictional Branch

Jack Buchanan, Electricity Generation and Regulation Branch

BC PROVINCIAL GOVERNMENT: BC CLIMATE ACTION SECRETARIAT

Suzanne Spence, Executive Director

Tim Lesuik, Executive Director

ALBERTA ENERGY

Tim Weiss, Ministerial Assistant

Steve Flavell, Public Policy

Katie Rowe, Public Policy

ENGAGEMENT WITH PUBLIC

"MEGAWATTS AND MARBLES: HOW DOES OUR ELECTRICITY SYSTEM WORK?"

St. Andrew's High School, February 5, ~20 students

IdeaFest, March 4, ~50 people

UVic Science Venture, summer programs 2015, 500-600 participants

BC Hydro, December 15, ~ 15 participants

IdeaFest, March 10, 2016, upcoming

CONFERENCES AND WORKSHOPS

Uncertainty and Risk-Based Resource Planning: New Orleans (Feb, 2015)

Technology Transfer Workshop between the Carbon Capture & Storage and Geothermal Industries: Calgary (May, 2015)

Geothermal Policy Mechanisms and Levelized Cost of Energy: Calgary (June, 2015)

International Clean and Green Energy Conference: Amsterdam (February, 2015)

Energy Systems Conference: London, UK (June, 2014)

UVic Sustainability Forum – Oct 7, 2014

Climate Change Technology Conference: Montreal (May, 2013)

APPENDIX B: PUBLICATIONS

Listed below are journal and conference publications arising from this research. Where these publications are not discussed in Research Findings (above), a full abstract is included.

JOURNAL PUBLICATIONS (*Presented in "research findings"):*

English, J., Niet, T., Lyseng, B., Palmer-Wilson, K., Moazzen, I., Pitt, L., Wild, P., Rowe, A. (2016). Impact of Electrical Intertie Capacity on Carbon Policy Effectiveness. Manuscript under review with Energy Policy.

Lyseng, B., Rowe, A., Wild, P., English, J., Niet, T., Pitt, L. (2016). Decarbonising the Alberta power system with carbon taxes. Manuscript under review with Energy Strategy Reviews.

Moazzen, I., Robertson, B., Wild, P., Rowe, A., Buckham, B. (2016).Impacts of Large-Scale Wave Integration into a Transmission-Constrained Grid. Journal of Renewable Energy, 88, 408 – 417.

Niet, T., Pitt, L., Rowe, A., Wild, P. (2016). Storage and the Shift to Low Carbon Energy. Journal of Clean Energy Technologies, 4(1), 26 – 31.

Parkinson, S. C., & Djilali, N. (2015). Robust response to hydro-climatic change in electricity generation planning. Climatic Change, 130(4), 475-489.

Chassin, D., Stroustrup, J., Agathoklis, P. & Djilali, N. (2015). A new thermostat for real-time price demand response: Cost, comfort and energy impacts of discrete-time control without deadband. Applied Energy, 155(4), 816-825.

JOURNAL & CONF. PUBLICATIONS WITH ABSTRACTS (*Not presented in "Research Findings"):*

Parkinson, S. C., & Djilali, N. (2015). Long term energy planning with uncertain environmental metrics. Applied Energy, 147(4), 402-412.

Environmental performance (EP) uncertainties span a number of energy technology options, and pose planning risk when the energy system is subject to environmental constraints. This paper presents two approaches to integrating EP uncertainty into the long-term energy planning framework. The methodologies consider stochastic EP metrics across multiple energy technology options, and produce a development strategy that hedges against the risk of exceeding environmental targets. Both methods are compared within a case study of emission-constrained electricity generation planning in British Columbia, Canada. The analysis provides important insight into model formulation and the interactions with concurrent environmental policy uncertainties. EP risk is found to be particularly important in situations where environmental constraints become increasingly stringent. Model results indicate allocation of a modest risk premium in these situations can provide valuable hedging against EP risk.

Reikard, G., Robertson, B., & Bidlot, J. R. (2015). Combining wave energy with wind and solar: Short-term forecasting. Renewable Energy, 81, 442-456.

While wind and solar have been the leading sources of renewable energy up to now, waves are increasingly being recognized as a viable source of power for coastal regions. This study analyzes integrating wave energy into the grid, in conjunction with wind and solar. The Pacific Northwest in the United States has a favorable mix of all three sources. Load and wind power series are obtained from government databases. Solar power is calculated from 12 sites over five states. Wave energy is calculated using buoy data, simulations of the ECMWF model, and power matrices for three types of wave energy converters. At the short horizons required for planning, the properties of the load and renewable energy are dissimilar. The load exhibits cycles at 24 h and seven days, seasonality and long-term trending. Solar power is dominated by the diurnal cycle and by seasonality, but also exhibits nonlinear variability due to cloud cover, atmospheric turbidity and precipitation. Wind power is dominated by large ramp events irregular transitions between states of high and low power. Wave energy exhibits seasonal cycles and is generally smoother, although there are still some large transitions, particularly during winter months. Forecasting experiments are run over horizons of 1e4 h for the load and all three types of renewable energy. Waves are found to be more predictable than wind and solar. The forecast error at 1 h for the simulated wave farms is in the range of 5e7 percent, while the forecast errors for solar and wind are 17 and 22 percent. Geographic dispersal increases forecast accuracy. At the 1 h horizon, the forecast error for large-scale wave farms is 39e49 percent lower than at individual buoys. Grid integration costs are quantified by calculating balancing reserves. Waves show the lowest reserve costs, less than half wind and solar.

Sopinka, A., & Pitt, L. (2014). Taming WECC's Carbon Diet: Are We Losing Weight Yet?. The Electricity Journal, 27(8), 96-104.

The North American bulk power system is comprised of four interconnected regions: the Western Interconnect, the Eastern Interconnect, Texas, and Quebec. Arguably, the largest and most diverse of those areas is the Western Interconnect, which spans from northern Alberta and British Columbia in Canada to the Baja California peninsula in Mexico and includes all or part of 14 U.S. states in between. The varied geography and geology of the region creates a wide range of possible energy sources. The Pacific Northwest is dominated by mountains and rivers and therefore has many large storage hydroelectric facilities. The interior portion of the Western Interconnect that runs from Alberta southward has substantial coal and natural gas deposits and these areas tend to have a higher proportion of fossil fuel capacity and generation. Several U.S. states within the region have nuclear generating capacity; however, the use of this technology is prohibited in British Columbia and the province of Alberta currently has no plans to introduce nuclear electricity production into its generation mix. Low-carbon energy sources, particularly the variable energy resources (VER) of wind, solar, and run-of-river technologies, are increasingly the focus of WECC policymakers, fostered by the underlying conviction that adding zero-carbon resources will reduce emissions in the electricity sector. In the work that follows, we roughly estimate the quantity of carbon abatement expected from state and provincial policies that are designed at increasing low-carbon capacity and generation. We do not consider the carbon production impacts of connecting VERs to the grid or of firming their output once they enter service, both of which would have the effect of raising the cost of CO_2 abatement with the addition of VERs. In addition, we provide a lower bound on the cost of reducing emissions in a system with significant low-carbon assets.

Ouellette, A., Rowe, A., Sopinka, A., & Wild, P. (2014). Achieving emissions reduction through oil sands cogeneration in Alberta's deregulated electricity market. Energy Policy, 71, 13-21.

The province of Alberta faces the challenge of balancing its commitment to reduce CO_2emissions and the growth of its energy-intensive oil sands industry. Currently, these operations rely on the Alberta electricity system and on-site generation to satisfy their steam and electricity requirements. Most of the on-site generation units produce steam and electricity through the process of cogeneration. It is unclear to what extent new and existing operations will continue to develop cogeneration units or rely on electricity from the Alberta grid to meet their energy requirements in the near future. This study explores the potential for reductions in fuel usage and CO_2 emissions by increasing the penetration of oil sands cogeneration in the provincial generation mixture. EnergyPLAN is used to perform scenario analyses on Alberta's electricity system in 2030 with a focus on transmission conditions to the oil sands region. The results show that up to 15–24% of CO_2 reductions prescribed by the 2008 Alberta Climate Strategy are possible. Furthermore, the policy implications of these scenarios within a deregulated market are discussed.

Sopinka, A., & Pitt, L. (2014). The Columbia River Treaty: Fifty Years After the Handshake. The Electricity Journal, 27(4), 84-94.

The Columbia River Treaty requires coordinated water flows between Canada and the U.S. to improve power generation and provide flood control. In September 2014 either country can announce their desire to terminate participation in the Treaty. Already there appears to be a significant chasm between the entities with respect to how they will allocate the costs and benefits associated with future coordinated operations. The Columbia River is the fifteenth-longest river in North America, winding its nearly 2,000 km length through both Canada and the U.S. Approximately 15 percent of the river's 669,300 km2 basin is located in Canada, although due to the elevation and geography, the Canadian portion of the river contributes approximately 35 percent of the annual average flow and up to 50 percent of total annual peak flows. In all, the Columbia River discharges 244 billion cubic meters or 198 million acre feet (Maf) annually, which makes it the third-largest in North America in terms of river mouth flow rate, after the Mississippi and St. Lawrence rivers (Dai and Kevin, 2002). However, its unregulated flow rates are highly variable; flow at the Canadian border can range from 14 to 555 thousand cubic feet per second (kcfs). U.S. measurements are taken at The Dalles, Ore., and can vary from 36 to 1,240 kcfs (BPA, 2011).

APPENDIX C: PROJECT 2060 RESEARCHERS

Dr. Andrew Rowe

Principal Investigator

Dr. Peter Wild

Principal Investigator

Dr. Ned Djilali

Co-Investigator

Dr. Bryson Robertson

Programme Manager

Dr. Karena Shaw

Co-Investigator

Dr. Iman Moazzen

Post-doctoral Fellow

Mr. Benjamin Lyseng

PhD Candidate

Mr. Taco Niet

PhD Candidate

Mr. Jeff English

PhD Candidate

Mr. David Chassin

PhD Candidate

Mr. Kevin Palmer-Wilson

PhD Candidate

Mr. Victor Keller

PhD Candidate

Mr. Simon Parkinson

PhD Candidate

James Donald

PhD Candidate