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Optimal electricity system planning in a large hydro jurisdiction: Will British Columbia soon become a major importer of electricity?

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HIGHLIGHTS

- ▶ Within two decades, BC will need to import substantial power to meet demand.
- ▶ Operating Burrard Thermal and the Site C dam will delay imports by only 6 years.
- ▶ A \$30/t CO_2 tax causes closure of the Burrard Thermal plant on economic grounds.
- ▶ Closure of Burrard Thermal reduces export revenue to BC by at least \$5B by 2040.

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ABSTRACT

An energy-system model incorporating generation, transmission and integrated management of hydroelectric reservoirs in British Columbia (BC) is used to explore approaches to meeting load projections to 2040. The model includes electricity trade between BC, Alberta and the US, the influence of a carbon emissions tax, contributions from the aging gas-fired Burrard Thermal plant and production from a proposed dam called "Site C" on the Peace River in northern BC. Model results suggest: If load increases as anticipated at 1.4%/year, BC will need to import significant amounts of electricity within two decades. Operating the Burrard plant at full capacity to 2025 and bringing Site C on line in 2020 delays the need to import by only 6 years, while realizing net electricity export sales of \$5.9 billion by 2040. Bringing Site C on line but imposing a tax of \$30/t of CO_2 emitted on gas-fired generation causes immediate closure of the Burrard plant on economic grounds and reduces net export revenue to \$0.63 billion by 2040. BC has options, however, including demand side management and development of additional generation capacity. In the absence of these measures, imported power may be more significant in BC's electricity future.

1. Introduction

Canada's westernmost province, British Columbia (BC), will face an increasing demand for electricity over the next 30 years should population increase by 25% and industrial growth continue as expected. Energy and carbon pricing policies, as well as greenhouse-gas-emissions targets that are unique to the province, severely constrain the range of energy options available to meet the anticipated demand. British Columbia produces over 90% of its electricity via hydroelectric generation, one of the highest proportions in the world. Growing concern about global climate change has reinforced the importance of this 'clean' source. Indeed, the province requires that 93% of its indigenous electricity be produced from non-fossil-fuel generation, a requirement that maintains the focus on hydroelectricity while giving BC one of the highest effective renewable portfolio standards in North America (Government of British Columbia, Clean Energy Act, 2010). But demand continues to grow; meeting the average annual increase of 1.4% forecast for the next 20 years (B.C. Hydro, 2008a) will require an additional 30 TW h to be supplied yearly by 2030. Meeting this additional load from clean energy sources will be a challenge.

At present ~65 TW h of electricity are distributed annually in BC, produced by a generation mix of ~86% hydro, 9% biomass and 6% natural gas (BC Ministry of Energy and Mines, 2012). BC is part of the Western Interconnect, the synchronous grid that comprises BC, Alberta, all or part of 14 western states in the USA and a small portion of North Mexico. Electricity trade within this market generates revenue that is important to British Columbia's

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economy. Complicating the future picture is the status of the Columbia River Treaty between Canada and the US that impacts the operation of the hydro assets in the Columbia Basin. Signed in 1964 as a 60-year agreement, this famous trans-boundary pact will likely undergo major revision by 2024 (Columbia River Treaty Blog, 2012). Finally, climate variability, mainly driven by Pacific Ocean influences and long-term, century-scale climate change, introduces a range of potential hydrologic regimes into the scenario mix, an important consideration given the large hydroelectric capacity of the province.

BC Hydro, a provincially owned corporation and the principal electrical utility in the province, has expansion plans for some of its major hydroelectric dams and has signaled its intent to build a large new dam on the Peace River (Site C) in northern British Columbia. Should electricity demand increase at a constant 1.4% annual rate, however, the analysis in this paper shows that demand is likely to outstrip supply within two decades, even if the proposed new capacity is added to the grid. Enhanced importation of power from proximal extra-provincial suppliers, much of which is generated through the burning of fossil fuels, could become a must, albeit one limited by existing intertie capacity with the Alberta grid to the east and lines into the US to the south. This begs a key question: Given the imperative of reducing CO_2 emissions from the Canadian power-generation system, and the province's avowed intent to remain a non-emitting clean-energy powerhouse, how can – or should – BC's growing electricity requirements for the future be met?

Integrated reservoir management offers one approach to meeting future demand, wherein the power potential of the province's multiple-dam hydro system is maximally exploited through optimized operation of water storage and release in response to load requirements. Alternatively, should that approach be insufficient to meet demand – as will be shown to be the case – additional supply or enhanced importation will be needed. What implications will this have on the scale of extra-provincial transmission infrastructure? Other approaches to meeting the demand, such as the large-scale addition to the grid of renewable resources including windpower, will be explored in subsequent studies.

In this study, we address these issues using a mixed-integer mathematical optimization model that simultaneously controls generation, manages reservoir levels and expands and/or retires generation and transmission capacities (Kiani et al., 2011a, 2011b, 2011c).. Alternative modeling frameworks have been studied (Connolly et al., 2010) and, for the current investigation, MESSAGE (Model for Alternative Energy Supply Strategies and their General Environmental Impacts) has been chosen as an appropriate framework due to its ability to deal with long-term planning horizons based on high-resolution short term system dynamics.

Related work that has been done internationally includes Connolly et al. (2011), Lund (2007), Shawwash (2000) and IAEA (2007a). Connolly et al. (2011) optimise energy storage based on day-ahead electricity prices, while Lund (2007) utilises EnergyPLAN software to simulate renewable penetration on an hourly basis. Shawwash (2000) describes the hourly optimisation of British Columbia's hydroelectric system including reservoirs over 168 operational hours. All these models employ short-term hourly-based approaches. EnergyPLAN simulates a defined scenario with limited flexibility and does not optimize based on an LP method. IAEA (2007a) utilises MESSAGE as an LP optimization approach for the Baltic states energy system on a long-term basis. As hydroelectricity capacity in the Baltic states is low, reservoir management is not required in that model.

In the current study, electricity supply throughout the hours of the day, for different types of days (i.e., weekdays, holidays) and for each season is optimized, over the extended time frame that is necessary for long-term energy planning. MESSAGE uses quasi-chronological time slices[1] to enable fine temporal resolution (i.e., hours of the day) over a planning time horizon of several decades, all in a single optimization. In this way, long-term capacity requirements are based on hourly peak loads. Time slices can be aggregated according to different criteria. For example, time slices can be sorted according to power requirements or demand patterns (summer/winter, day/night). The latter (semi-ordered) load representation creates the opportunity to model energy storage as the transfer of energy (e.g., from night to day, or from summer to winter). In this study, this feature is used to track reservoir levels in a chronological manner across quasi-chronological time slices.

The model yields economically optimal integrated configurations of the BC–Alberta energy system over the next three decades, assuming the Alberta system has no generation limits and new transmission can be built. We include discussion of the impact of the BC carbon tax on generation sources and the incremental influences on capacity of the gas-fired Burrard Thermal plant – the operation of which is currently prohibited except for special circumstances – as well as the proposed Site C dam.

The results of this analysis indicate BC will be forced to import increasing amounts of "non-clean" energy within a few decades in the absence of demand side management (electricity conservation) or the incorporation of substantial new sources of renewable (non-carbon-emitting) electricity into the provincial grid.

2. The modeled energy system structure and parameters

For modeling purposes, British Columbia is divided into six geographic regions (Fig. 1). Estimated electricity demand in each is based on proportionate population (Broeer et al., 2009). Transmission lines connect buses located in each region; single tie lines to Alberta and the US are connected at buses 5 and 6, respectively (Fig. 1). Limits of 1300 and 900 MW for respective electricity imports from and exports to the US are imposed in the model, and are based on 2010 transmission data. The current transmission capacity between BC and Alberta is 780 MW, and the model allows intertie capacity expansion between BC and Alberta if necessary. A fixed import/export price of \$50.88/MW h is used for Alberta interties, and import (\$30.75/MW h) and export (\$43.25/MW h) prices are used for the US interties. The market prices are based on 2010 data.

Ninety-six per cent of British Columbia's hydroelectricity is generated by facilities on the seven river systems listed in Table 1 (Shawwash, 2000). To include the full hydroelectric potential in the model, the remaining 4% is defined as a single supply variable called "other hydro" that comprises mostly small run-of-river hydroelectric plants. An additional generation asset, the aging gas-fired Burrard Thermal plant located near Vancouver, has a 950 MW capacity, but has been used only sporadically to meet peak demand in recent years. Existing current policy allows the plant to be used in emergencies only, but this constraint is removed in some of the modeled scenarios discussed later in the paper.

For each hydroelectric facility, inflows are defined as the mean 50-year historical inflows for six two-month seasons per year, based on the Environment Canada hydrology database (Environment Canada, 2010) (Fig. 2).

Load growth projections to 2029 are based on the 2008 BC Hydro Electric Load forecast (B.C. Hydro, 2008a). The projected

[1] These time slices are referred to as "load regions" within MESSAGE.

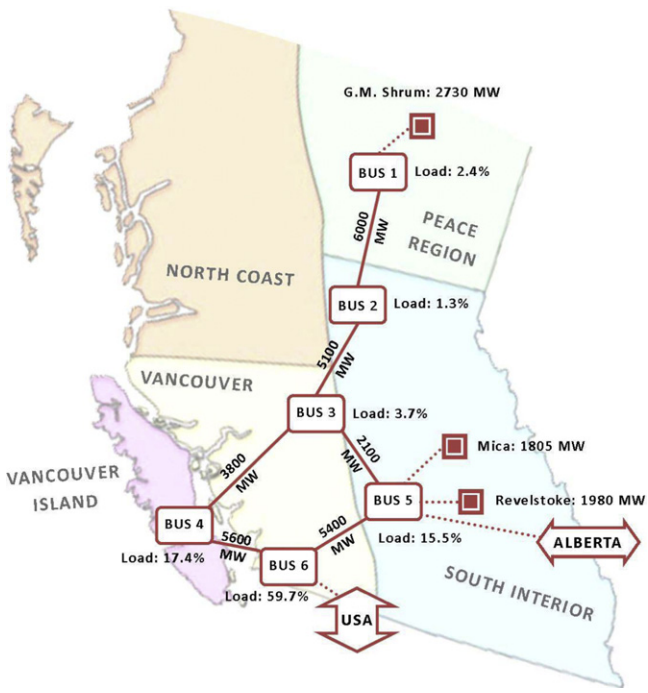

Fig. 1. The six-region network for BC used in the model. Load percentages are based on proportionate population in each region and the major line capacities between the regions are labeled. Note that most of the load in BC (~60%) is located in the Greater Vancouver region. For clarity, only three major hydroelectric plants (red squares) are shown on the map. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Table 1
Hydroelectric generation facilities represented in the model. Aggregate capacities are listed for the multiple installations on each of the Pend d'Oreille, Bridge and Campbell rivers.

River system	Reservoir	Plants	Capacity (MW)
Peace	Williston	G.M. Shrum (GMS)	2730
	Dinosaur*	Peace Canyon (PCN)	700
	Site C**	(Site C)	(1100)
Columbia	Kinbasket	Mica (MCA)	3840
	Revelstoke*	Revelstoke (REV)	
Pend D'Oreille	Seven Mile	Seven Mile (SEV)	954
		Waneta (WAN)	
Bridge	Carpenter	Lajoie (LAJ)	548
		Bridge (BR)	
		Seton (SON)	
Kootenay	–	Kootenay Canal	570
Campbell	–	Strathcona (SCA)	229
		Ladore (LDR)	
		John Hart (JHT)	
Nechako	Nechako	Kemano	960

* Downstream reservoirs.
** Planned.

growth rate for 2029 (1.4% annually, compounded) is applied in the model from 2030 to 2040. Fig. 3 shows the peak load growth in the six regions up to year 2040 and the load share of each bus, based on the estimated future population within each region. Demand Side Management (DSM) is not considered in these forecasts, and its potential for load amelioration is not discussed in this paper.

3. The energy supply model

A multi-objective mathematical programming tool, MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental Impacts), is used in this work. MESSAGE is an optimization model designed for medium to long-term energy system planning, energy policy analysis and scenario development. The model provides a framework for representing an energy system that includes imports and exports and energy flows from resources that respect inherent resource limitations. Different conversion technologies, transmission, distribution, and provision of energy end-use services are included in the model, descriptions of which are provided in IIASA (2001), IAEA (2007b), Messner (1984), and Messner et al. (1996).

Adoption of strategies for the supply of energy from alternative sources are evaluated in MESSAGE so that they are consistent with limits on new investment, fuel availability and trade, environmental regulations and market penetration rates for new generation technologies. Environmental aspects are analyzed by accounting for and, if necessary, by limiting the emissions of pollutants at each step in the energy supply chain. This approach yields insights into the impact that environmental regulations have on energy system development (Kiani et al., 2004).

Fig. 4 shows the BC energy system structure, as defined in this work for application of the MESSAGE model. Six energy levels, from resources to end-use, are considered. At the resource level, natural gas and renewables such as hydroelectricity, wind and biomass are defined. Reservoirs for each river system are defined independently. Because this paper focuses on optimizing reservoir management to maximize electricity production, supplementary generation via additional wind or biomass resources is not considered; the potential for accommodating more wind power into the grid will be examined in detail in a subsequent

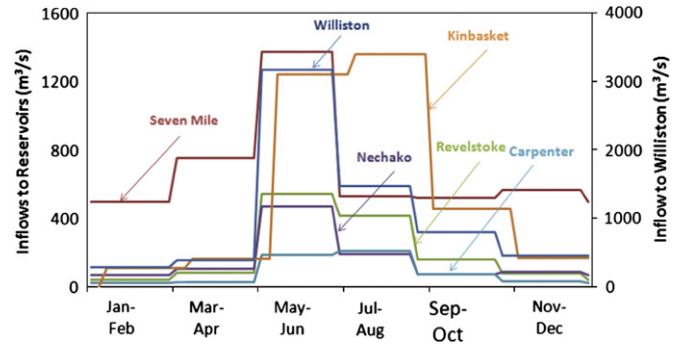

Fig. 2. Fifty-year mean inflows to reservoirs in each of the six two-month-duration seasons defined for each year in the model. The right-hand axis refers only to the large Williston Reservoir (B.C. Hydro, 2006, 2007a, 2007b, 2011).

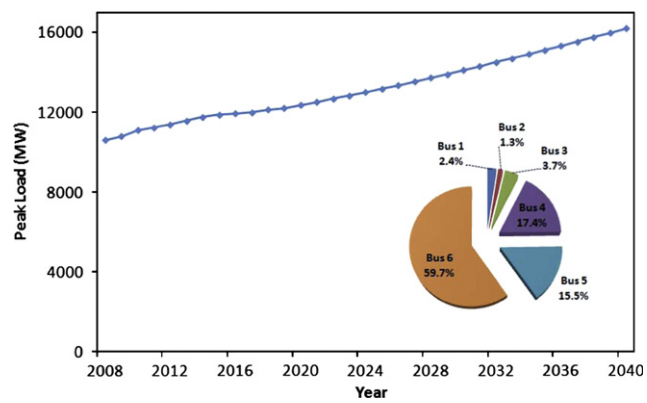

Fig. 3. British Columbia peak load projection to 2040, excluding DSM (B.C. Hydro 2008b). The pie chart shows the current load distribution across the six regions (Broeer et al., 2009) outlined in Fig. 1. The majority of the load demand will continue to sit in the bus 6 region, the Greater Vancouver area in the southwest corner of the province.

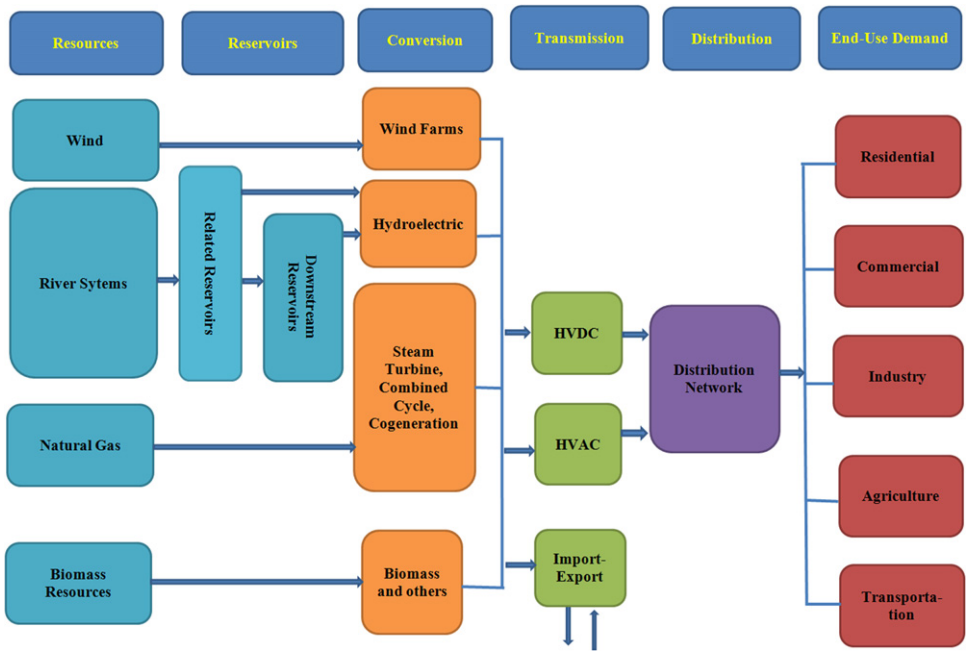

Fig. 4. A schematic of the energy system for British Columbia as implemented in MESSAGE. In this work, the system is analyzed up to and including transmission. Distribution and end-use are not resolved.

publication. At the energy conversion level, different technologies such as hydroelectric turbines and gas- and wind-powered turbines are introduced. The transmission level used in the model includes the different transmission technologies that are currently used among the six load and generation regions defined for BC, as well as for transmission across provincial boundaries via import and export to Alberta and the US. Both high-voltage AC and DC transmission lines are variously used in the existing distribution network in this region of North America. Finally, MESSAGE can accommodate various end-use loads; for this paper, however, a single aggregate load is used—no discrimination among load components has been applied.

Three types of variables and a variety of equation types are used in MESSAGE. The variables are: (a) technology output, which refers to the energy supplied during a specific time slice (see Section 3.1 below) from a given type of power source (e.g., hydro or gas-fired generation); (b) annual new installations of generation technologies; and (c) renewable resource variables which are constrained by renewable resource limitations during daily hours or across seasons and/or years.

The equations applied in MESSAGE can be grouped as follows: (a) demand equations that ensure that the exogenous demand is satisfied by the appropriate technologies; (b) balancing equations that guarantee that consumption of electricity equals production; (c) capacity equations that relate production by a generating source in each time slice to the overall capacity existing in that year; (d) dynamic constraints that relate the output in one year to the output in the previous year; and (e) renewable resource equations that limit the resource availability based on historical regimes in different hours and seasons of a year (this can apply, for example, to water inflows to the reservoirs or wind regimes in different geographical locations). Minima are set with respect to anticipated resource extraction of, for example, water from reservoirs. All variables and most of the constraints are attributed to a specific time slice. Only the dynamic constraints link consecutive years to each other. Capacity equations accommodate the sum of new installations over the lives of specific generation sources (e.g., hydro dams or gas-fired power plants).

Each model year is divided into six two-month seasons – referred to here as time slices[2] – to capture seasonal variations in reservoir inflows and load. Daily load patterns and resource fluctuations are captured by defining two types of days: weekdays, and weekends or national holidays. To reduce computational complexity, while being able to optimize the energy system with hourly-resolution, only the individual hours around the daily load peak are resolved in the model. For this purpose, in a 24 h load pattern, the 3:00 pm to 10:00 pm interval is considered on an hourly basis. For the remaining time, we have defined the daily base load and night-time load, yielding a collective total of nine time slices in a day. Also, because the load is lower on weekends and national holidays, weekend days are characterized by two time slices only.

Our aim is to minimize the objective function which is the net present value of the total costs of the system, including investment costs, fixed and variable operating and maintenance costs, fuel costs, water rental rates, external costs and carbon costs, if applicable. Carbon taxes or external costs associated with carbon-emitting technologies are included in the objective function by taking into account the emission factors multiplied by the fuel consumption of each generation source, as appropriate.

The demand equations satisfy load requirements in each time slice and in each geographic region by providing adequate energy from lower levels (energy levels that provide the required energy input for the next level as illustrated in Fig. 4). In this way, the model provides the minimum energy required to meet demand in each time slice and region over the studied multi-decadal time interval. Energy balance is maintained in the model by requiring adequate energy to be carried from primary resources to end-use demand.

3.1. Hydroelectric generation

Historical inflow data are used here to define seasonal constraints on inflows to reservoirs (Fig. 2). Variations in seasonal

[2] In MESSAGE, these time intervals are denoted as *load regions*.

inflows in future years are assumed to be the same as historical means. This assumption is, of course, not likely to be valid on long multi-decadal time scales, given the anticipated influence of climate change on hydrology in British Columbia. This influence will be explored in a subsequent paper. For the purposes of the analysis presented here, hydrological steady-state is assumed for the next several decades.

The storage can be used to support all the regional loads defined in the model. The remaining amount of the water stored at the end of the year is put forward to the next year. Each reservoir is defined with an initial and final volume of water, an allowable maximum and minimum volume of water (live storage), inflows from the watershed or upstream reservoir(s), and an outflow that is used to generate electricity. To ensure sustainability and to avoid boundary effects at the end of model runs, water volume in the final year is constrained to equal the volume at the start of the first year. Maximum rates of outflow from reservoirs are defined, as are maximum storage capacities. In meeting the energy-generation requirements needed to satisfy the demand, the model optimizes the rates of depletion or accumulation of water in the various reservoirs and the storage capacity of each.

The power produced from each dam is defined by a linear equation that relates water density, dam height, outflow, turbine efficiency and the number of installed turbines. The optimal outflow of each hydroelectric plant at each time slice is computed based on the minimum cost to satisfy the load, considering contributions from all generation sources, including coal and gas plants in Alberta and existing wind turbines, the number of which is fixed. Note that while outflows reduce water volumes in upstream reservoirs, they act as inflows – thus, exploitable generation capacity – to downstream reservoirs such as Peace Canyon and Site C.

3.2. Other inputs and constraints

In addition to physical limitations on installed capacity, such as maximum storage volume in a given reservoir, other constraints are stipulated in the model. Maintenance of fisheries habitat, for example, requires minimum rates of release from some reservoirs at certain times of year, typically in late summer. The costs of decommissioning old plant and construction of new are specified according to the schedule listed in Table A.1 (Appendix A).

All model scenarios span 43 yearly periods (2008–2050), with the base year being 2007. One of the characteristics of the BC system is the very large storage capacity; this, and the constraint that reservoir levels in the final period be the same as the initial condition, can produce some unusual behaviors in the final years of simulation (boundary effects) that are removed by simulating over a timeframe that is longer than the planning period. Thus, all model runs discussed here were computed over 43 yearly periods (2008–2050), with the base year being 2007, but end effects are avoided by considering results to 2040 only.

Additional economic variables are specified in MESSAGE (see Tables A.1 and A.2 in Appendix A), and a discount rate of 4% is used in all economic calculations. A marginal water rental rate of \$7/MW h is applied to outflow, as per BC Hydro practice (BC Ministry of Energy and Mines, 2011). The price of natural gas is constant at \$5.36/MMBtu over the 43-year duration of the runs, and an emissions factor of 56.9 kg/GJ is assumed for CO_2 emissions calculations.

4. Results and discussion

Fig. 5 shows the modeled optimal generation up to the year 2040, along with the projected increase in provincial load demand (B.C. Hydro, 2008a). Seasonal demand peaks in winter in BC, a direct consequence of the use of electricity for space heating, and reaches its minimum in mid-summer each year. Note that the 950 MW gas-fired Burrard Thermal plant is allowed to operate in this Base scenario until the end of its scheduled lifetime, assumed to be 2025 (Appendix J3 of B.C. Hydro, 2008a), because it provides economically competitive power. As discussed below, however, when BC's CO_2 emissions tax is imposed, the Burrard plant is immediately rendered uneconomic. Note also that the proposed 1098 MW Site C dam is brought onstream in the model in 2020, although its construction has not yet been approved by the province. The difference between hydroelectric production and demand, shown in white in the figure from about 2028 on, grows with time primarily because of limited hydro capacity to meet the increasing demand.

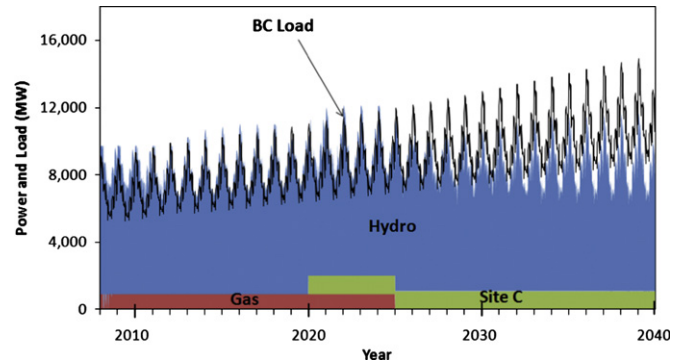

Fig. 5. Optimal generation mix and load growth for British Columbia to 2040. Note that this scenario allows the gas-fired Burrard Thermal plant to operate at full output until 2025. The power contribution from the Site C dam commences in 2020 and for clarity is shown in the first 5 years stacked on top of the Burrard Thermal output.

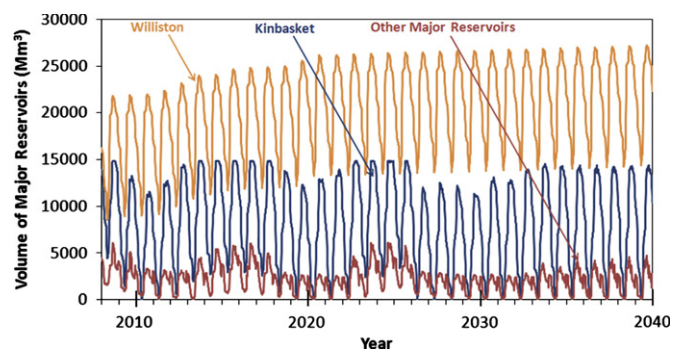

Fig. 6. Time series of the volume of water stored in the Williston and other major reservoirs to 2040 in units of millions of cubic metres (Mm^3). The Williston and Kinbasket reservoirs (respectively behind the Shrum and Mica dams) are shown separately as they have higher live storage capacity than all the other reservoirs (Dinosaur, Site C, Revelstoke, Seven Mile, Carpenter and Nechako), which are aggregated for simplification here as "Other Major Reservoirs" (see Table 1).

Fig. 6 illustrates the optimal management of the reservoirs in BC associated with the generation mix shown in Fig. 5. Having the Burrard Thermal plant operate to 2025 allows water to be stored in the Kinbasket and other reservoirs in the early 2020s. That additional storage is then progressively depleted to generate hydroelectricity in the late 2020s, an operational aspect that delays the need to bring power into the province from external sources. Future scheduled increases in generation capacity in 2014 and 2015 via addition of turbine units to the Mica and Revelstoke dams on the Columbia River are included in this scenario.

Fig. 7 shows the energy annually exported from and imported to BC given the optimal generation mix shown in Fig. 5. Net imports commence in about 2025 from both Alberta and the US.

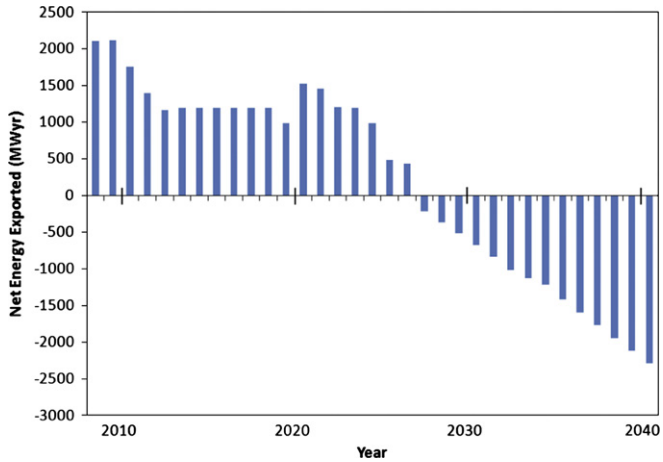

Fig. 7. Time series of electricity exports from and imports into BC to 2040, for the base-case generation mix shown in Fig. 5. Over the time period shown (2008–2040), a net aggregate of 6885 MWyr would be exported from BC. Note that negative values indicate net imports.

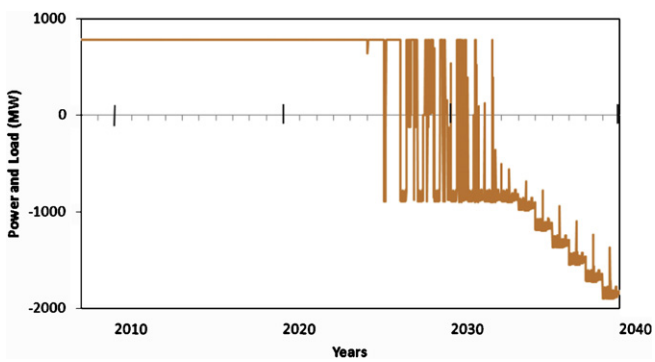

Fig. 8. Time series of transmission across British Columbia–Alberta tie lines (MW) in the base scenario. Positive values represent exports from BC and negative values represent imports to the province. Elimination of power from the Burrard Thermal plant in 2025 leads to pronounced seasonal shifts in import–export, until the demand for power exceeds available indigenous supply in BC, starting in about 2033.

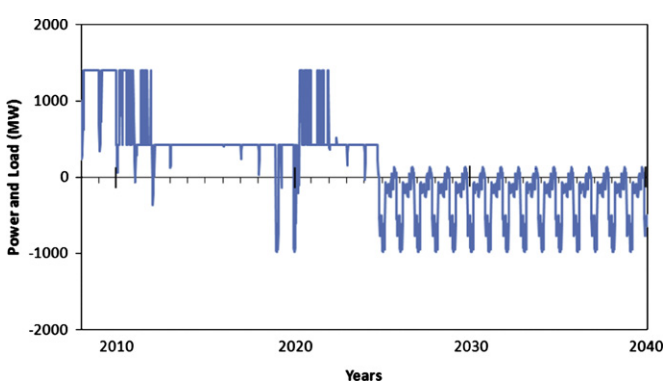

Fig. 9. Time series of transmission across British Columbia–US tie lines (MW). Positive values represent exports and negative values are imports to BC. The seasonal minima in 2019 and 2020 (power imports) occur because progressively increasing provincial demand in BC cannot be met by supply during peak winter loads in those years. MESSAGE chooses to import electricity from the US while continuing to export to Alberta (see Fig. 8) as this is most economically beneficial. From 2020 when Site C starts production, exports to the US recommence. But when Burrard is shut down in 2025, imports from both the US and Alberta (Fig. 8) dominate during peak winter demand in BC. Export is then possible only from July to October, and only during some non-peak hours.

Forecast transmission across BC–Alberta and BC–US tielines, respectively, is shown in Figs. 8 and 9. In this base scenario, the existing tieline capacity (780 MW) with Alberta is inadequate to service anticipated transmission from that jurisdiction as of about 2030 and additional capacity will need to be constructed if the ongoing demand for electricity is to be met via imports. Note that this scenario does not include demand side management (i.e., conservation) nor addition of non-hydro renewable power into the BC grid.

Modeled transmission to and from the US (Fig. 9) is much more predictable than that in the BC–Alberta case. Net annual imports commence in 2025 and cycle in each year between 100 and −1000 MW. The differences in the transmission time series between BC and the two adjoining jurisdictions is a reflection of price difference and allowing the model to expand imports from Alberta while limiting imports from the US to current maximum capacity.

5. Sensitivity analysis and additional scenarios

The sensitivity of the model to two supplementary scenarios is considered. The first assigns a tax on the carbon emitted from fossil-fuel powered plants, and the second assumes that the proposed Site C dam is not constructed prior to 2040.

In the first case, a tax is imposed on CO_2 emissions identical to that currently in place in British Columbia: \$15 CAD per tonne of CO_2 emitted as of July 1, 2009 rising \$5 per year to \$30 per tonne as of July 1, 2012. In this scenario the tax is imposed only in BC and it is assumed that BC can purchase electricity from Alberta and/or Washington generation assets at 2010 prices. The tax is held constant at the \$30 per tonne CO_2 level to 2040. An immediate consequence of this imposition is that the gas-fired Burrard Thermal plant becomes uneconomic and is not chosen by the model as a source of power from 2010 on. A second impact is more subtle: A total of 7373 MWyr of accumulated energy will need to be imported by 2025, a result of the loss of the Burrard Thermal asset.

In the second case, if we show the total existing power (MW) from all hydro facilities as a function of time as $W_{\text{Hydro}}^{\text{BaseCase}}(t)$ in the Base Case and $W_{\text{Hydro}}^{\text{no Site C}}(t)$ in the no-Site-C scenario, then ΔW_{Hydro} represents the difference in the total hydro production at any time between these two options, via:

$$\Delta W_{\text{Hydro}} = W_{\text{Hydro}}^{\text{BaseCase}}(t) - W_{\text{Hydro}}^{\text{no Site C}}(t) \tag{1}$$

This difference is shown in Fig. 10.

From 2010 on, when the tax has rendered the gas-fired Burrard Thermal plant uneconomic, seasonal negative values to 2033 reflect more intensive drawdown of stocks of water in BC's reservoirs. That drawdown is used to produce electricity that was

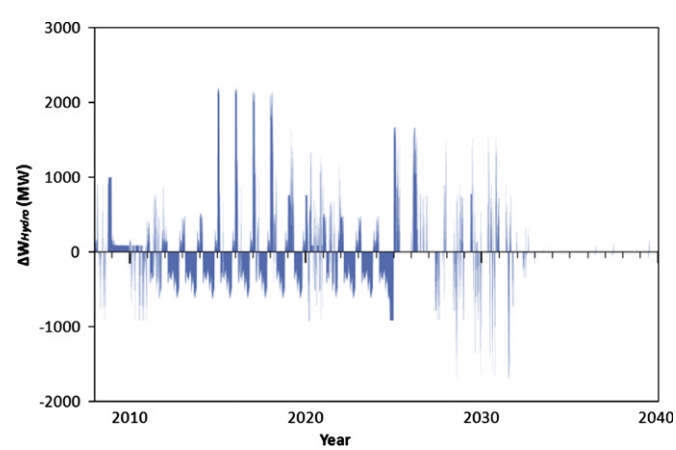

Fig. 10. The difference in supply of hydropower to 2040 relative to the Base Case, when the carbon tax is applied to fossil fuels combusted in BC. The loss of the Burrard gas-fired plant increases the peaking duty of hydro.

formerly supplied in the Base Case scenario by the Burrard plant. Note that Site C comes onstream in 2020 and, for about 2 years, offsets some of the deficit. After 2033, no "excess" water remains in the reservoirs that can be used to offset the power deficit caused by the combination of the 'missing' Burrard plant and progressively increasing load demand.

The impact of the carbon tax on water volume in the major reservoirs is shown in Fig. 11. In the Base Case, with no carbon tax (Fig. 6), excess water accumulates in Williston after about 2013, and in the Kinbasket and other major reservoirs (OR) during 2013–2016 (in part because Mica and Revelstoke add turbines to increase their generation capacity) and in the early-mid 2020s when Site C produces power during the final years of Burrard's operation. But when the carbon tax is implemented and Burrard Thermal shuts down in 2010, the immediate need for increased hydroelectric production depletes the water accumulated prior to 2013 in Kinbasket, OR and Williston.

The impact on energy trade of the carbon tax and associated closure of Burrard Thermal relative to the Base Case (Fig. 7) is shown in Fig. 12. Less electricity is available for export until 2027 beyond which there is little difference between the two scenarios. This is because Burrard Thermal is shut down in 2025 at the end of its design life, a requirement independent of the carbon tax. By 2040 the integral of the difference in Fig. 12 amounts to 7373 MWyr of imported power.

In the second sensitivity test, the Site C dam is not constructed, no carbon tax is imposed and the Burrard Thermal plant is allowed to run at maximum output until the scheduled end of its life in 2025. The loss of the 1098 MW capacity of Site C from 2020 on, relative to the Base Case (Fig. 6), has one obvious consequence as shown in the difference plot (Fig. 13): More electricity must be imported to meet demand, beginning several years earlier—in about 2019 instead of 2027 as in the Base Case. Net power imports increase to 14349 MWyr by 2040.

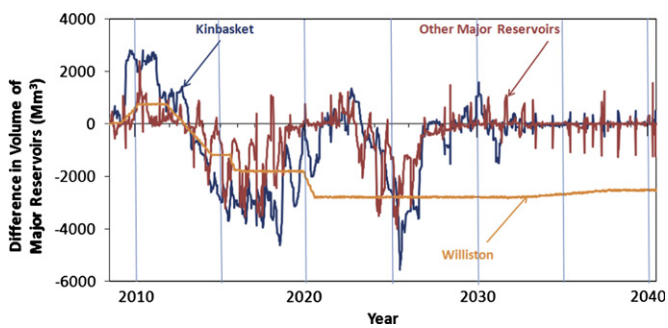

Fig. 11. The difference in British Columbia's reservoir volumes to 2040 when a carbon tax is applied, compared to the Base Case (no tax) (Fig. 6). Note the minima for Kinbasket and Other Major Reservoirs during the 2013–2016 and early-mid 2020s intervals, and the low relative volume in Lake Williston beyond 2013, a reflection of the persistent need to withdraw water for power production after the closure of Burrard Thermal.

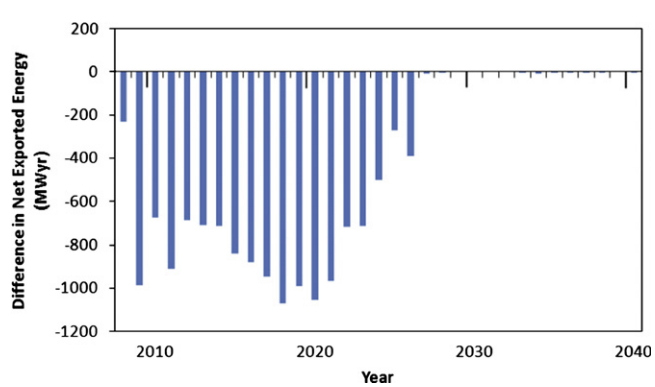

Fig. 12. The difference relative to the Base Case (Fig. 7) in yearly net energy exported when the BC carbon tax implemented. Negative values indicate less net electricity available for export relative to the Base Case when the carbon tax is imposed. Little difference is seen after 2027, when in both scenarios Site C is operational (as of 2020) and Burrard Thermal is shut down (as of 2025 in the Base Case).

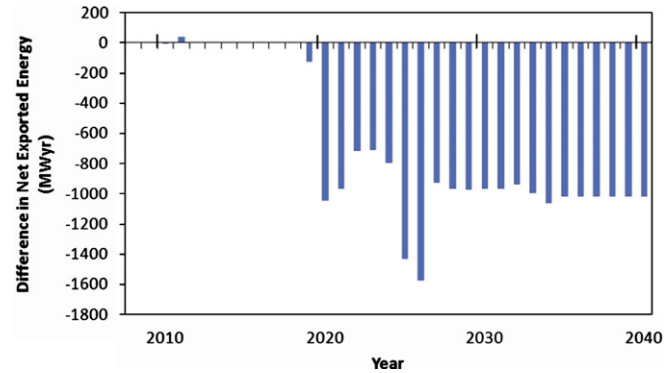

Fig. 13. The difference in yearly net energy exported, relative to the Base Case (Fig. 7) when no Site C dam is allowed in the model. No net exports occur after 2018. Notable imports in 2025 and 2026 reflect compensation for Burrard Thermal immediately after its shutdown in 2025.

6. Economic and CO_2 emissions outcomes

Optimal solutions obtained by MESSAGE are based on minimizing the total cost of the entire modeled electrical system. Shadow prices are defined as being equivalent to the marginal cost of commodities in an open market, and decisions regarding imports, exports, increases or decreases of production from each defined technology in the model, or capacity expansion at different time slices and years, are based on the optimum marginal cost or benefit over the period considered.

Using the electricity import–export and gas prices noted earlier, operating the Burrard Thermal plant to 2025 and bringing Site C on line in 2020 results in a net positive revenue for British Columbia by 2040 of $5.9 billion from electricity trade with the US and Alberta. Bringing Site C onstream but imposing the carbon tax (thus, causing Burrard Thermal to shut down) reduces the net revenue to $0.63 billion by 2040. If Site C is not built and the carbon tax is imposed, $3.2 billion net will flow out of the province by 2040 to pay for imported power.

The existing intertie capacity between BC and Alberta (780 MW maximum) limits the ability of the province to import significant amounts of power across its eastern border. Full accommodation of the projected scale of import will require expansion of the intertie capacity to 1900 MW by the year 2040. Meeting this requirement will require substantial investment, on the order of $896 million according to the MESSAGE results, using the cost factors listed in Table A1. If the Site C dam is not built, intertie capacity would need to be expanded to 2900 MW to meet the demand for imported power, at an estimated capital cost of $2.32 billion.

Net emissions of carbon dioxide increase as a direct consequence of importing to BC electricity generated by fossil-fuel combustion in Alberta. Assuming that the current fossil fuel generation mix in Alberta – 46% coal and 39% gas – remains the same to 2040, and further assuming that no carbon tax is applied in that province, an additional ~15,000 kt of CO_2 will be emitted when the carbon tax is imposed in BC and Burrard Thermal is shut down. In the second scenario – no Site C dam – 30,000 additional kt of CO_2 will be emitted by 2040 in Alberta.

7. Conclusions and implications

A mixed-integer mathematical optimization approach has been used to investigate the minimum cost of electricity supply in the context of increasing long-term demand in BC. Optimal generation schedules for each hydro facility, gas power plant, regional transmission of electricity, reservoir management, are used with high temporal resolution over a multi-decade planning horizon. The model includes expansion of both generation and transmission capacity to meet the forecast increase in demand.

The novelty of the modeling tool developed here lies in our ability to analyze, in the public domain, emerging issues to help inform discussion and decision-making on major infrastructure choices. The tool compares well to other state-of-the-art modeling approaches used recently (B.C. Hydro, 2012, BPA, 2012).

The principal findings are clear: Despite optimizing operation of the BC hydro reservoir system to maximize production of non-carbon-emitting electricity, within two decades BC's hydroelectric supply will be insufficient to meet the province's demand. Running the 912 MW gas-fired Burrard Thermal plant at full capacity to the scheduled end of its lifetime in 2025 would eliminate the need to import about 7400 MWyr of energy prior to 2025. Similarly, construction of the Site C dam and its subsequent production of an additional 1098 MW of power beginning in 2020 would delay importation of significant amounts of electricity for about 6 years. Under business-as-usual consumption patterns and with anticipated growth in demand, imported power will most likely be needed by the late 2020s (from 2028 without Site C and from 2034 with Site C).

BC has options to reduce imports, including the introduction of vigorous demand side management, load-leveling approaches that incorporate adoption of smart appliances and a smart grid, realization of energy efficiency gains by improving building codes and shifting, for example, from baseboard heaters to air- or ground-source heat pumps for residential heating. The broad-scale introduction of such initiatives would offer scope to lessen growth in demand. Enhanced installation of renewable power from wind, solar, wave, tidal, and run-of-river resources would also contribute to meeting future needs while eliminating the need to import power from external sources. While beyond the scope of the current study, efforts in neighboring jurisdictions in the western interconnect to satisfy their own loads can be expected to have long-term impacts on the assumed prices for electricity trade. Large amounts of new renewable generation in places like Alberta and California will likely increase the spread in electricity prices which may add value to the storage available in BC and make imports of electricity less costly. Such broader perspectives will be discussed in subsequent papers in which the addition of renewables in both BC and Alberta is explicitly modeled.

Appendix A. Major input parameters defined in British Columbia energy model

Table A1.
Table A2.

Table A1
Technical and economic specifications for installed new capacity.

Parameter	Coal	Gas turbine	Combined cycle	Wind	Hydro
Availability (%)	92	94	92	100	100
Capital cost ($/kW)	3500	1000	1500	2000	3000
Annual fixed Cost ($/kW/year)	67	57	60	25	4
Variable O&M cost ($/kW/year)	8.76	4.38	8.76	0	0
Fuel cost ($/GJ)	2.78	5.52	5.52	0	0
Efficiency	0.31	0.36	0.45	1	0.9
Plant life (year)	35	35	35	25	100
Transmission expansion ($/MW km) GE Energy (2010)	1000				
Transmission losses (%/100 km)	0.625				

Table A2
Major supply technologies and hydroelectric data used in the model.

Bus no.	Electric power plant	Related reservoir	Capacity[a](MW)	Outflow max/min[c] (m/s)	Operating drawdown[b] (m)	Live storage[c] (Mm[c])	Head (m)
1	GM Shrum	Williston	2730 (5 × 310) (90)		12	32,410	18 3
	Peace Canyon	Dinosaur	700	1982/283	3	24	61
	Site C	Site C	1100	–	–	20	60
	Wind	–	200	–	–	–	
2	Nechako	Nechako	960	−/36.8	10	8,700	33
4	Campbell	–	237	–	–	–	–
5	Mica	Kinbasket	1840 (2 × 500)	–	47	14,800	244
	Revelstoke	Revelstoke	2000 (2 × 500)	1750/−	15	1,850	175
	Kootenay	–	528	−/142	–	–	–
	Seven Mile	Seven mile	594	–	Summer 4	16	80
			(1 × 200)	–	Winter 6	25	
	Other hydro	–	1187	–	–	–	–
6	Bridge	Carpenter	480	–	45	1,011	60
	Burrard Thermal Gas plant	–	912	–	–	–	–

[a] Capacity includes existing capacity and BC Hydro's planned expansion, listed in parentheses as new installed turbines times their capacity. For GM Shrum, five 310 MW turbines are expected to be added; a further 90 MW increase is planned.

[b] Calculation of operating drawdown includes consideration of publicly available information on operating constraints, be they environmental requirements, harvested-log transportation needs, and pulp mill or tourist industry requirements.

[c] Live storage calculations reflect operating constraints listed above.

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