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2022

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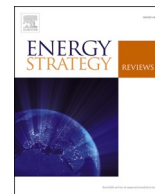
This article was originally published at:

<https://doi.org/10.1016/j.esr.2022.100882>

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Citation for this paper:

Palmer-Wilson, K., Bryant, T. S., Wild, P., & Rowe, A. (2022). Cost and capacity requirements of electrification or renewable gas transition options that decarbonize building heating in Metro Vancouver, British Columbia. *Energy Strategy Reviews*, 42, 100882. <https://doi.org/10.1016/j.esr.2022.100882>



# Cost and capacity requirements of electrification or renewable gas transition options that decarbonize building heating in Metro Vancouver, British Columbia

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## ARTICLE INFO

### Keywords:

Electrification  
Renewable gas  
Hydrogen  
Peak demand  
Power-to-gas  
Building heating

## ABSTRACT

Northern countries face a unique challenge in decarbonizing heating demands. This study compares two pathways to reduce carbon emissions from building heating by (1) replacing natural gas heaters with electric heat pumps or (2) replacing natural gas with renewable gas. Optimal annual system cost and capacity requirements for Metro Vancouver, Canada are assessed for each pathway, under nine scenarios. Results show that either pathway can be lower cost but the range of costs is more narrow for the renewable gas pathway. System cost is sensitive to heat demand, with colder temperatures favouring the renewable gas pathway and milder temperatures favouring the electrification pathway. These results highlight the need for a better understanding of heating profiles and associated energy system requirements.

## 1. Introduction

Governments across the globe are facing a variety of challenges in their efforts to mitigate greenhouse gas (GHG) emissions from energy use. In the buildings sector, energy-use caused 17.5% of global GHG emissions in 2016 [1], presenting a substantial need for reduction. Strategies to reduce emissions include replacing fossil fuels with low-carbon fuels and electricity [2–4]. For example, electric heaters can replace natural gas and oil consuming heaters at relatively low cost. However, in colder climate regions these technologies add significant electric energy demand because heating energy needs can exceed all present-day electricity generation in some industrialized countries [5]. Technologies like heat pumps can substantially reduce delivered energy requirements depending on their efficiencies.

Air-source heat pumps reduce primary energy consumption in comparison to fossil fuel or electric resistance heaters, but their coefficient of performance declines with ambient air temperature. Ground-source heat pumps are less affected by cold weather, but their underground complexity often prevents retrofitting existing building stock. Due to coincidence with other loads, electrification of building heating in cold northern climates causes the peak electricity demand to increase more significantly than the average demand [6,7]. Where variable renewable energy sources are expected to replace carbon-intensive but

dispatchable electricity generation [8], or where renewable energy resource availability misaligns with heat demand [9], electrification of the building heating system requires additional dispatchable capacity. This may be provided in a number of ways, such as the addition of intermittent renewable generation coupled with storage. However, when serving long-duration cold weather events, the required electricity storage capacity might not be the most cost-effective option for heating electrification.

Where natural gas serves a significant fraction of heating demand, energy system transition pathways that can utilize the existing stock of gas infrastructure are of interest. Replacing fossil fuels with biogas or electrolytic hydrogen is an alternative to direct electrification and may mitigate impacts on winter-peak electricity demand. Coupled to electricity systems, power-to-gas technologies facilitate use of low-cost gas storage capacity to indirectly store electricity from variable renewable sources, reduce electricity storage requirements, use existing gas infrastructure, and increase resilience to energy demand and supply variability [10].

This study compares two transition pathways that reduce greenhouse gas emissions in the building heating sector. The study considers Metro Vancouver, British Columbia, Canada, a region where the electricity system is already decarbonized and policies encouraging substitution are in place; hence, new electricity demands are expected. The

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electrification pathway substitutes natural gas with electricity directly, whereas the renewable gas pathway allows for biogas and electrolytic hydrogen to replace natural gas. The analysis starts by developing a representation of the region’s building heat demand profile by fuel and equipment type. Next, the model cost-optimizes energy production and storage capacities able to supply space heat, water heat, and electricity for a one-year period at hourly resolution. To quantify energy system requirements for a range of possible futures, nine scenarios are developed to evaluate different assumptions on technology costs, performance characteristics, energy demand, and renewable resource supply.

## 2. Background

The Metro Vancouver Regional District houses 2.5 million persons or 53% of British Columbia’s (BC) population. In BC, delivered energy for heating in residential and commercial buildings is primarily from natural gas (>50% and >75% respectively.) While fossil fuels dominate the heating sector, British Columbia generates 98% of its electricity from renewable sources; hydro power contributes the largest share at 91%, biomass and wind provide another 6% and 1%, respectively [11]. Natural gas combustion for space and water heating makes the building sector the second largest source of greenhouse gases, behind transportation [12]. This work chooses to investigate electrification in Metro Vancouver because the existing low carbon electricity supply offers immediate and significant emission reduction potential.

Seasonal variability and capacity constraints limit the BC power system’s ability to accommodate additional electricity demand in winter in the Metro Vancouver region. Only one third of annual hydroelectric energy supplies can be dispatched flexibly in British Columbia, and the majority of water inflows occur in early summer when electricity demand is low [13]. In addition to space and water heating, electrification of road transportation (the sector responsible for most emissions) and industry would further increase electricity demand and require significant investments in generation, transmission and distribution infrastructure. Efficiency improvements will mitigate the intensity of energy demand, but can be offset by increases in population and floor area.

Comparing energy consumption and sectoral greenhouse gas emissions highlights the large challenge of decarbonization via electrification. In the residential, commercial and institutional building sectors of British Columbia, natural gas provided 68% (124 PJ) of space and water heating in 2018, or 45% of the total secondary energy consumption in those building sectors [14]. These 124 PJ of natural gas caused 12% (6.1 MtCO<sub>2eq.</sub>) of the province’s overall emissions related to fossil fuel combustion (51.1 MtCO<sub>2eq.</sub>), but the energy contained in that natural gas would equate to 46% (34.4 TWh) of the province’s total electricity generation in that year [11,14]. An energy-equivalent replacement of that natural gas with zero-carbon electricity would eliminate a relatively small fraction of combustion emissions (12%) while significantly increasing electricity demand (by 46%).

The dynamics of the BC electricity system are reflected in Fig. 1 where load and trade statistics are shown on a weekly basis. Fig. 1 suggests that installed electricity generation capacity in British Columbia is constrained in peak demand hours during winter. Between 2007 and 2018, the all-time peak hourly load on the integrated transmission system (ITS) approached the 2018 load carrying capability. The comparison demonstrates lack of significant surplus capacity to accommodate additional peak loads. Meeting peak electrification demands in the absence of other dispatchable capacity will likely require installation of designated electricity storage facilities like batteries or pumped hydro.

## 3. Methods

This study cost-optimizes a combined electricity and gas system model for two distinct transition pathways meant to compare electrification and renewable gas alternatives. The model determines system costs, emission reductions, and electricity and gas production and storage capacity requirements. Along each transition pathway, nine scenarios with varying technology costs, energy demand, and renewable energy resource availability are considered. These scenarios delineate potential upper and lower energy system bounds for a range of possible futures.

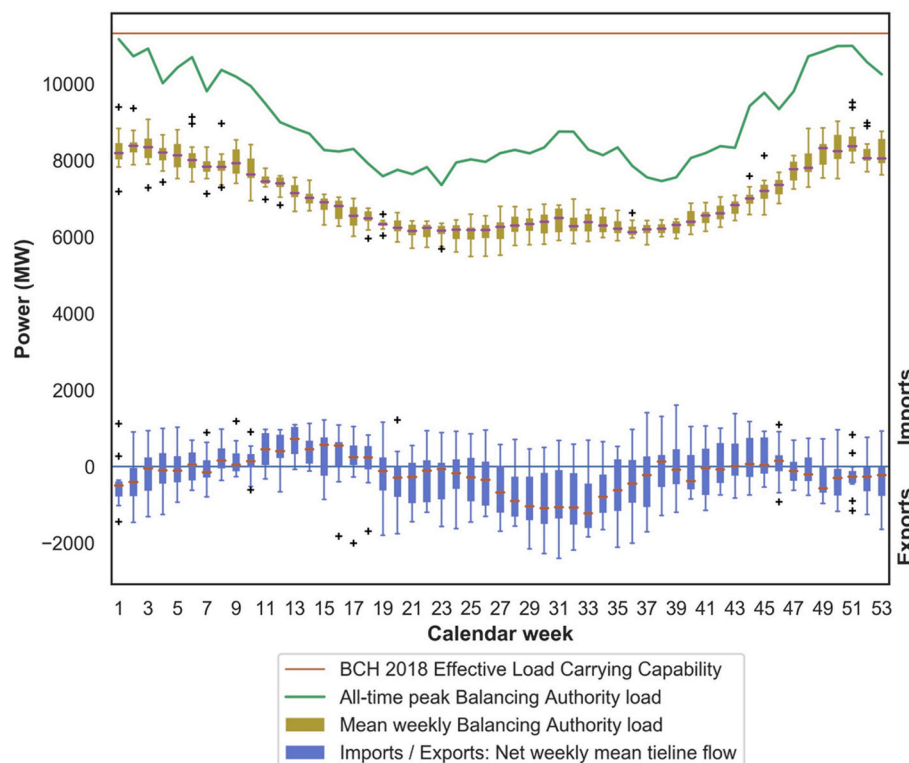


Fig. 1. Comparison of electric load and load-carrying capability highlights the capacity constraint in winter peak-demand periods in British Columbia. The red straight line shows BC Hydro’s 2018 Effective Load Carrying Capability of 11,315 MW [15], Ch. 3, Tables 3–9). The green line shows all-time peak load between 2007 and 2018 on the Integrated Transmission System of British Columbia [16]. Yellow boxplots show the weekly mean loads. Blue boxplots show net electricity import/export [17] across the borders with Alberta and Washington State. Note that the electricity system in British Columbia may be able to accommodate a larger additional peak load than this figure suggests because load on the Integrated Transmission System is likely not equivalent to loads “carried” exclusively by BC Hydro.

The model serves discrete energy demand profiles comprised of space heat, water heat, and residual electricity (non-heating). To overcome limited data availability, existing annual end-use energy demands are calculated from historic secondary energy consumption and technology efficiency records. Aggregated hourly demands are constructed by estimating normalized profiles and scaling these profiles to match annual demands (Section 3.2). Residential profiles are derived from proprietary electricity consumption data recorded at the household level. Commercial and institutional profiles are derived from building models. Correlating temperature records and space heat demand produces profiles for varying climate conditions. The resulting hourly data enables the investigation of supplying demand with variable renewables like wind and solar power, and related storage requirements. The following sections provide further detail on methods.

Although BC population growth is expected to remain near 1% per year for the next two decades, this study does not consider any load growth that may result. Instead, the analysis investigates the supply of historic end-use energy demands through technology and fuel substitution. This approach is chosen to avoid the additional uncertainty related to forecasting energy demand at hourly resolution. Building efficiency improvements might reduce energy intensity, population growth might increase demand, and climate change might shift the demand profile. These factors and their effect on energy system requirements are not included here but warrant further study.

### 3.1. Energy system optimization and transition pathway implementation

This study applies the Open Source Energy System Model OseMOSYS [18]. This linear programming framework expands and dispatches gas and electric energy production and storage to supply energy demands at minimum total annualized costs (Fig. 2). The model determines the necessary capacities to substitute from 0 to 100% of natural gas over a one-year period at hourly resolution.

The electrification and the renewable gas pathways each substitute for natural gas using two different methods. In the electrification pathway, air-source heat pumps and electric resistance water heaters exogenously replace natural gas-consuming space and water heaters. Baseboard heaters are not replaced. In the renewable gas pathway, biogas and hydrogen replace natural gas via exogenously mandated renewable gas consumption rates.

A single year with hourly time steps is optimized for technology capacities and dispatch. For each pathway, incremental reductions in natural gas are modelled from 0% to 100% substitution. Iterating over the same one-year model period with varying electrification and renewable gas rates reveals energy system expansion trends.

Water heating and space heating are specifically investigated for electrification and renewable gas substitution. In addition, a residual electricity demand serves non-heating loads, and, in the case of vehicle electrification, transportation demand. Air-source heat pumps and baseboard resistance heaters consume electricity, and furnaces consume gas to provide space heat. Electric and gas water heaters provide hot water.

For the case of 0% substitution of natural gas, the model uses existing hydro electricity and natural gas production to supply demands. At higher substitution rates, the model can choose to expand wind and solar electricity generation, biogas production, electricity and gas storage, and hydrogen production via electrolysis. This substitution reduces greenhouse gas emissions endogenously.

### 3.2. Annual energy demands and hourly profiles

The end-use space heat, end-use water heat, and non-heating electricity demands shown in Fig. 3 are each constructed from an annual demand and a normalized profile. The total annual space and water heat demands are population-scaled from provincial secondary energy consumption records for the year 2016 [14]. Space heat and water heat

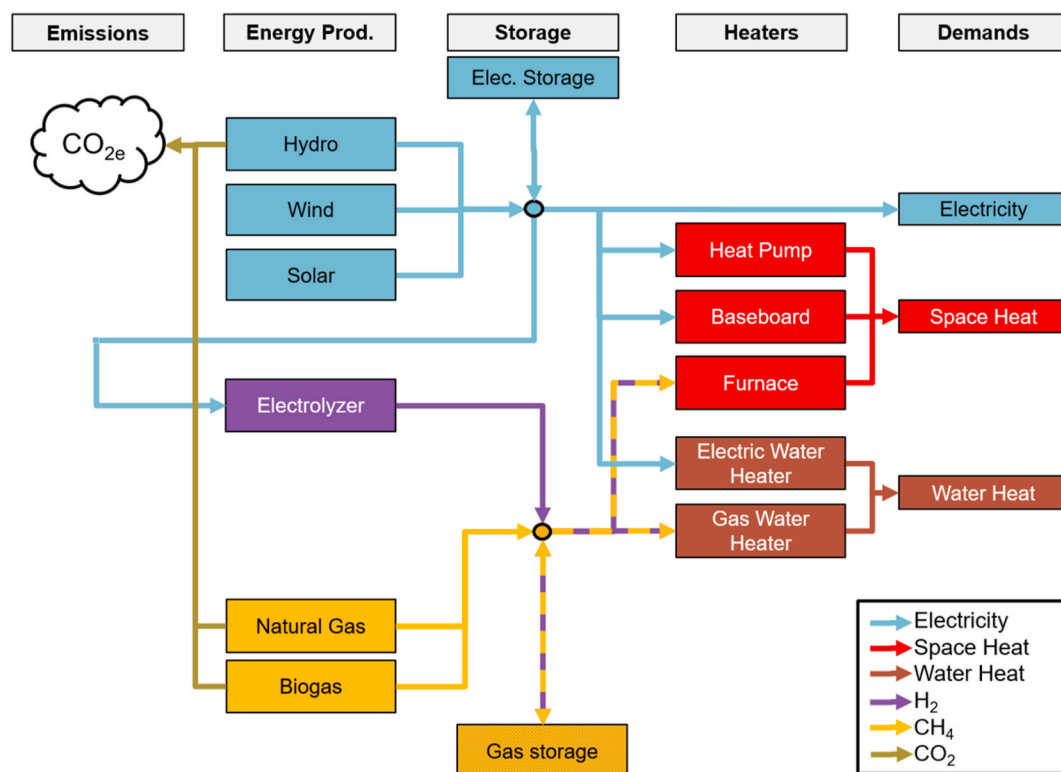
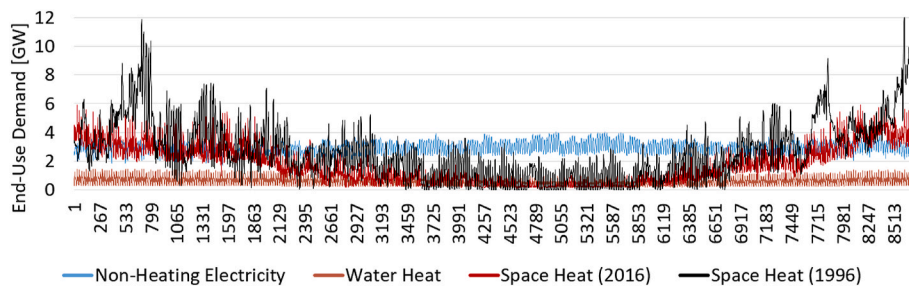


Fig. 2. Energy system model used to investigate electrification and renewable gas pathways for Metro Vancouver. In the electrification pathway furnaces and gas water heaters are replaced by electric heat pumps and electric water heaters. In the renewable gas pathway, natural gas is replaced by biogas and electrolyzed hydrogen.



**Fig. 3.** Estimated hourly end-use energy demands for Metro Vancouver are the product of annual secondary energy demand records, heater efficiencies, and normalized hourly demand profiles. The 2016 space heat demand profile is based on residential sector data recorded in 2016, and modelled commercial sector data produced from typical meteorological year (TMY3) temperatures. The 1996 space heat demand profile is hindcast using 1996 temperatures and represents the demand that Metro Vancouver – as it existed in 2016 – would have experienced under a 1996 temperature profile.

include natural gas and electricity consumed in the residential and commercial sectors. Annual electricity demand is based on the BC Hydro fiscal 2016 total electricity supply [15]. Space heater efficiencies [14] and water heater efficiencies [19] are used to estimate end-use energy demands from the available secondary energy consumption data.

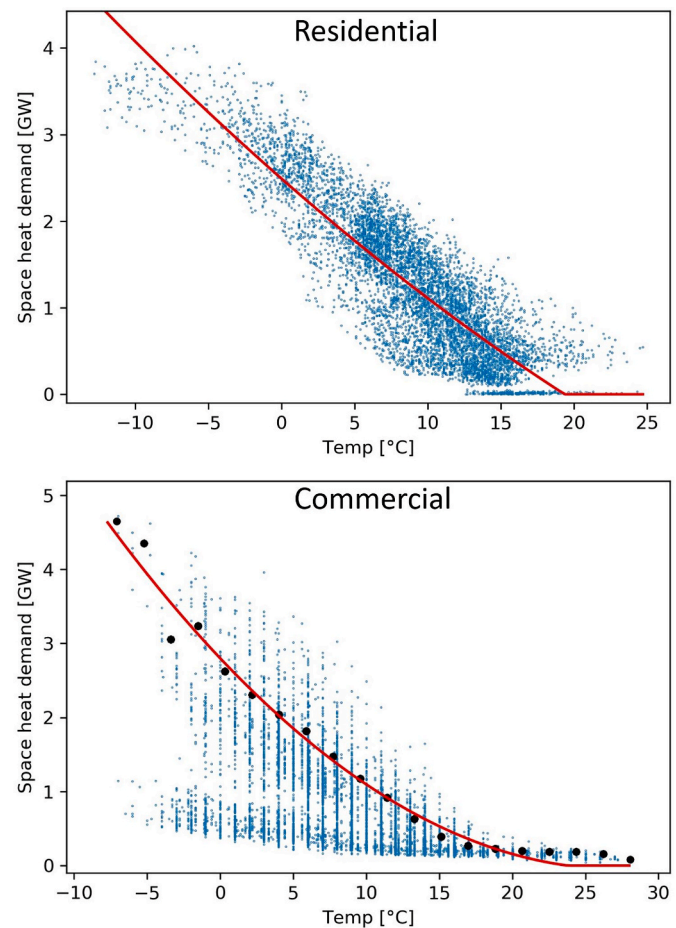
The energy demand profiles determine the fraction of annual energy demand that the model must provide in each hour of the year. The commercial space and water heat demand profiles are based on 15 commercial reference building models that represent ~70% of the commercial building stock in the United States of America [20]. The residential water heat demand profile is based on data in the Cost Effectiveness tool published by Ontario's Independent Electricity System Operator [21]. The residential space heat demand profile is derived from proprietary residential electricity demand data provided by the utility BC Hydro, as described by [22, chapter 5.6]. This dataset provides two years of hourly loads for over 5000 metered residences (five building types in four regions) with each building flagged as electric or non-electric heat. The non-heating electricity demand profile is the difference between the provincial electricity demand profile [16] and the space and water heat demands served by electricity.

### 3.3. Space heat demand

Based on 2016 residential demand and typical mean year commercial demand, the estimated hourly end-use space heat energy demand in Metro Vancouver peaks at 5.9 GW of heat. That demand may underestimate the peak under low temperature conditions. Natural gas delivery in British Columbia reached over 18 GW of secondary energy above baseload during a minimum temperature weather event in 2020 [23].

To represent energy system requirements for other climate-years, a regression analysis between space heat demand and ambient temperature is performed using hourly temperatures (Pitt Meadows Climate Station between 1995 and 2019.) In that dataset, the lowest temperature of  $-16\text{ }^{\circ}\text{C}$  occurs in 1996 when the number of heating degree days (HDD) is 3197. While 1996 has the lowest hourly temperature, the annual heating degree days in that year are only the third highest in the dataset. For comparison, the lowest temperature in 2016 is  $-12.8\text{ }^{\circ}\text{C}$  with 2568 heating degree days.

To hind cast a low-temperature space heat demand profile, the regression analysis is applied to the residential and commercial sectors separately (Fig. 4). For the residential sector, a second-degree polynomial minimizes the sum of squared errors between hourly end-use space heat demand and ambient temperature for temperatures below  $18\text{ }^{\circ}\text{C}$ . For the commercial sector, the equation was fitted onto the 90th percentiles of 20 temperature bins of equal width. This adaptation is chosen because the bottom-up method that created the commercial heat demand data for separate building types does not produce normally distributed residuals around the equation of best fit. The right panel in Fig. 4 shows this heteroscedasticity and that the error between the equations of best fit increases as temperatures decrease. Nevertheless, this fitting onto 90th percentiles was chosen because the resulting demand profile better matched the expected peak space heat demand during low temperature events.



**Fig. 4.** End-use space heat demand versus temperature in the residential and commercial sectors. The red curve shows the second-degree polynomial equation of best fit. The residential equation is fitted directly onto the temperature data and results in a Coefficient of Determination  $R^2 = 0.84$ . The commercial equation is fitted onto the 90th percentiles (black dots in right graph) of 20 temperature bins of equal width to better capture peak space heat demand during low temperature events.

Next, the residential and commercial equations of best fit are applied to the 1996 hourly temperatures to estimate hourly space heat demand. The resulting demand profile peaks at 12 GW of end-use demand. Capacity for heating is critical for a reliable energy system, hence, 1996 is used as a reference climate-year, one that captures a possible case of HDD and peak demand.

### 3.4. Space and water heater performance

Heating efficiencies listed in Table 1 are constant throughout the modelling period for all technologies except heat pumps. Instead, heat

**Table 1**

Space and water heater efficiencies or coefficient of performance (COP). The efficiency determines the quantity of secondary energy that the model must supply to heating technologies in order to meet end-use demands.

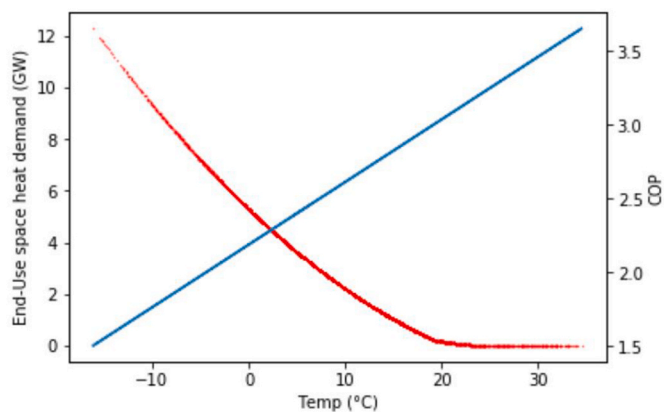
Technology	Efficiency/COP	Rationale
Heat Pump Space Heater	1.5 to 3.0 (−16 to +20 °C)	Temperature-dependant average coefficient of performance observed on 23 residential non-cold-climate heat pumps [24]
Baseboard Space Heater	1.0	Assumed
Furnace Space Heater	0.95	Annul Fuel Utilization Efficiency energy performance standard for gas furnaces without an integrated cooling component [25]
Electric Water Heater	0.95	Assuming 5% standby losses for electric tank water heaters
Gas Water Heater	0.735	Mean Energy Factor of storage and tankless gas water heaters [19]

pump coefficient of performance (COP) varies with ambient temperature to better reflect actual technology performance during colder weather events.

The COP is derived from data collected for several different non-cold-climate heat pump models in Massachusetts and Rhode Island in the winter of 2016 [24]. A linear interpolation between the known COP of two temperatures creates an hourly COP profile. The COP ranges from 1.5 at −16 °C to 3.0 at +20 °C where the latter is the highest temperature at which space heat demand occurs. Fig. 5 shows COP and end-use space heat demand within the recorded temperature range. For explanation, at −16 °C the heat pumps with a COP of 1.5 consume 8 GW of electric power to supply 12 GW end-use space heat demand.

### 3.5. Electricity generation

Hydro power generation capacity (12.9 GW) and annually available energy (60 TWh) in British Columbia are based on the BC Hydro load-resource balance for fiscal year 2015 [26, Tables 2 and 3]. Hydro power capacity is fixed and cannot be expanded by the model. The energy and power available to the model are population-scaled to Metro Vancouver. The available energy is dispatched on a partially flexible, partially pre-determined profile (Fig. 6) to simplify the complex operating constraints observed by British Columbia’s large hydro and run-of-river power stations. These constraints include snowmelt-driven water inflows, minimum water discharge rates, or flood control. This study estimates that approximately 41 TWh are dispatched to meet operating constraints; approximately 19 TWh are dispatchable at any time of the year [13]. The assumed cost of hydroelectric energy is 60



**Fig. 5.** Coefficient of performance (blue line) and hourly end-use space heat demand using the 1996 temperature profile (red dots).

**Table 2**

Nine scenarios determine low-carbon energy system costs and capacity requirements for a broad range of future technology costs, technology performance, energy demand, and renewable energy resource potential. The (\*) indicates biogas resource availabilities assessed for all of British Columbia which have been scaled to Metro Vancouver via the 53% population ratio.

Scenario	Description	Rationale
Reference	a) 2030 Li-Ion battery cost	a) [38]
	b) BC Hydro Wind/Solar cost	b) [41]
	c) 2030 Biogas target 30 PJ (*)	c) Personal correspondence with FortisBC Inc.
	d) 1996 temperature profile (high heat demand)	d) Section 3.2
LowRNG	a) Lower Biogas availability 11.9 PJ (*)	a) [32]
	b) Electrolyzer efficiency of 50%	b) [37]
LowCost	a) 2050 Battery ≈ pumped storage cost	a) [38]
	b) NREL 2050 Wind/Solar cost	b) [42]
	c) 2050 Electrolyzer cost	c) [35]
MuchBiogas	High biogas availability 93.6 PJ (*)	[32]
LowHeatDemand GasHeatPump	2016 temperature profile Gas heating efficiency increases from 95% to 140%	Section 3.2 Estimated gas heat pump efficiency
Resilient	No wind and solar electricity generation during five-day peak space heat demand event	Determines hydro + storage capacity requirements when electrified demand exceeds hydro’s load carrying capability
ResilientLowRNG	Equivalent to Resilient scenario except:	
	a) Lower Biogas availability 11.9 PJ (*) b) Electrolyzer efficiency of 50%	a) [32] b) [37]
Transport	Light- and heavy-duty road transport is electrified: −60% annual electricity demand increase -Doubles peak electricity demand	Electrification of additional sectors increases storage demand. Electrified demand estimate taken from [22]

**Table 3**

Installed energy and power capacity for electric energy storage in the electrification pathway of each scenario at 100% natural gas substitution.

Scenario	Power Capacity [GW]	Energy Capacity [GWh]
Reference	6	80
LowRNG	6	80
LowCost	6	123
MuchBiogas	6	80
LowHeatDemand	1	4
GasHeatPump	6	80
Resilient	7	357
ResilientLowRNG	7	357
Transport	12	87

\$/MWh. The assumed emissions intensity of 29.9 gCO<sub>2,eq</sub>/kWh is based on the published grid emissions factor of the integrated transmission system [27]. That factor accounts for non-hydroelectric imports from outside of British Columbia. For clarification, electricity trade is not otherwise represented in this study.

The model installs wind power capacity at scenario-dependant costs between 1219 and 2395 \$/kW. The exogenous wind generation profile is based on the hourly mean capacity factor of 30 potential sites located in southern, central, coastal, and eastern British Columbia [28]. The aggregated annual mean capacity factor is 33.2%.

The model chooses to install solar power capacity at scenario-

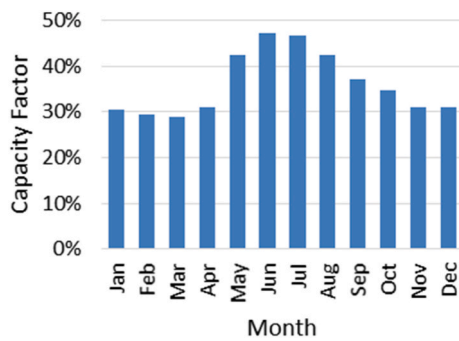


Fig. 6. Estimated monthly minimum capacity factors define the profile shape of ~41 TWh generated by British Columbia's hydroelectric power stations on a pre-determined schedule [13]. Generation peaks in June and July when snowmelt-freshet inflows dominate.

dependant costs between 669 and 2021 \$/kW. The exogenous solar generation profile is based on single-axis tracking potential in Vancouver as published by NREL's PV Watts [29]. The annual mean capacity factor for Metro Vancouver is 24.3%.

### 3.6. Gas production options

Gas production includes natural gas, biogas, and hydrogen produced from electrolysis. In this study, biogas and hydrogen substitute natural gas on an energy-equivalent basis. Natural gas is assumed to cost 1.19 \$/GJ [30] and emits 50.3 gCO<sub>2</sub>/MJ [31].

The assumed biogas resource supply for British Columbia ranges from 11.9 to 93 PJ [32]. The lower bound derives from feedstock resource potentials of municipal organics, landfill gas, agricultural waste, pulp mill residue, and waste water treatment. The upper bound adds industrial forest process by-products and anticipates significant improvement in wood gasification technology. For reference, FortisBC plans to procure 30 GJ of biogas, as prescribed by the 15% renewable gas target in the provincial government's CleanBC Roadmap [33]. Biogas emits 11 gCO<sub>2</sub>/MJ and costs of 23 \$/GJ were estimated by the authors. Specific costs are confidential, but FortisBC confirmed that this estimate reasonably aligns with their portfolio average.

Beyond biogas, the energy system model can choose to produce hydrogen by installing electrolyzer capacity at a scenario-dependant cost of 1400 \$/kW [34] or 500 \$/kW [35]. The electricity-to-hydrogen conversion efficiency of 50% or 78% is representative of lower present-day efficiencies or estimates that assume some technological improvement in Proton Exchange Membrane (PEM) electrolyzers [35–37].

### 3.7. Costs and performance

The model can choose to install electricity and gas storage technologies. Electricity storage has a round-trip efficiency of 86% [38]. Installation costs are scenario dependant to reflect battery storage costs in 2030 (156 \$/kW and 184 \$/kWh) or in 2050 (95 \$/kW and 112 \$/kWh) as forecast by Schmidt et al. [38]. Gas storage capital costs (1 \$/kW and 0.1 \$/kWh) are fixed across all scenarios, with assumed operating costs being nil. Gas storage has an assumed round-trip efficiency of 100% to limit computational complexity. (Note that this assumption is addressed in the discussion.)

Two parameters determine the ability of a storage technology to balance energy supply and demand. First, the installed energy capacity limits the quantity of energy that can be stored. Second, the installed power capacity limits the charge and discharge rates. The model optimizes installed energy and power capacities independently of each other.

### 3.8. Scenario assumptions and rationale

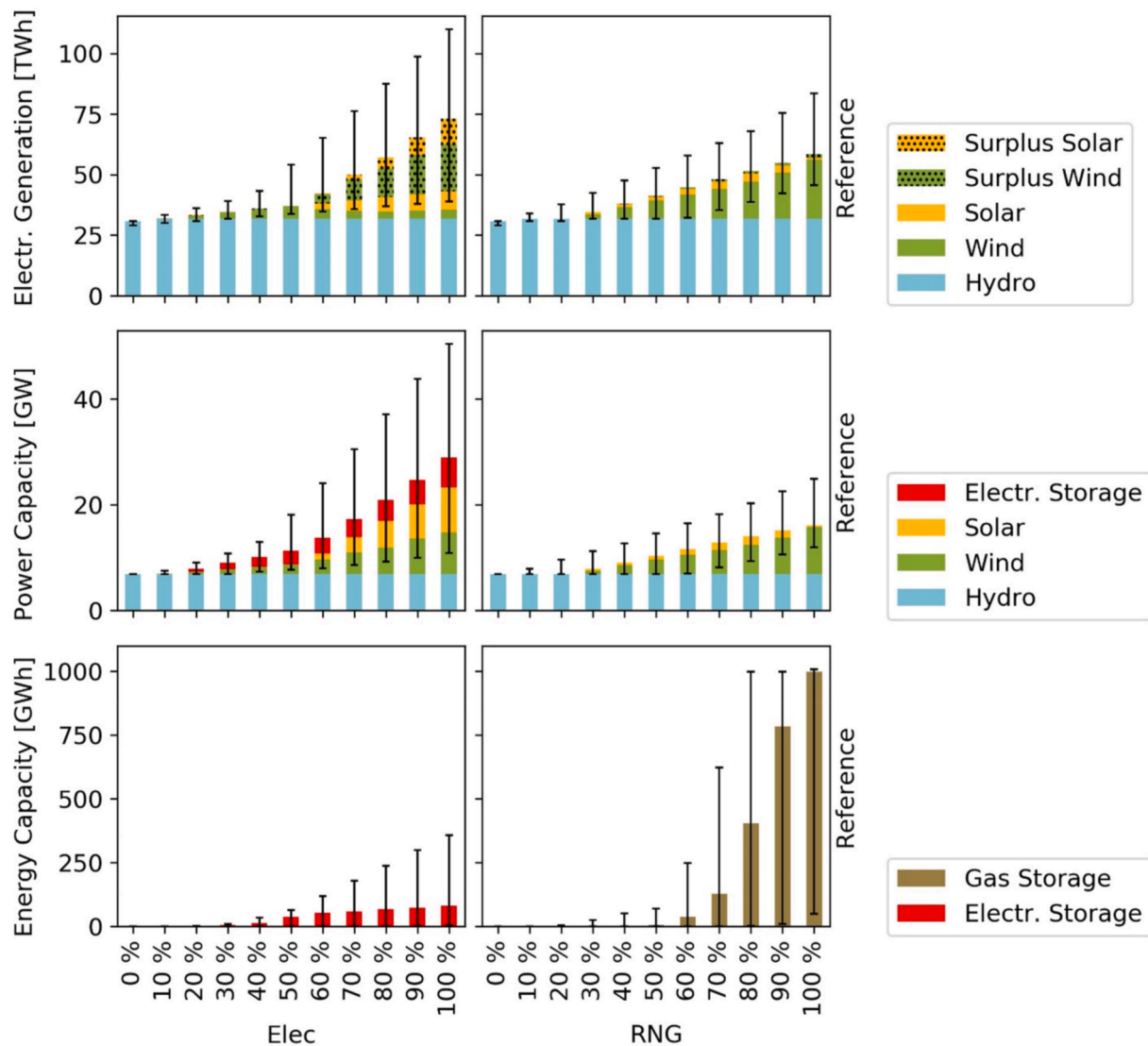
Motivated by initial results found across three scenarios investigated in related work [39], this study constructs nine scenarios to investigate energy system costs and capacity requirements across a range of possible futures. Technology costs, technology performance, energy demand, or renewable energy supply varies between each scenario. Table 2 and the following list summarize the defining variations from the *Reference* scenario. The (\*) indicates the value for British Columbia that, in the model, is scaled to Metro Vancouver by population ratio.

- The *Reference* scenario applies 2030 lithium-ion battery storage costs, and present-day wind and solar costs determined by the latest resource options report performed by BC Hydro. Biogas availability aligns with FortisBC's provincial biogas target of 30 PJ (\*). The space heat demand is based on historic temperature correlation and hind cast for the 1996 temperature profile.
- The *LowRNG* scenario reduces biogas availability to 11.9 PJ (\*) and reduces electrolyzer efficiency to 50%.
- The *LowCost* scenario applies 2050 capital costs for battery, wind, solar, and electrolyzer installation. The assumed 2050 battery cost is approximately equivalent to present-day pumped storage costs.
- The *MuchBiogas* scenario applies a large availability of biogas resources. The 93 PJ (\*) include estimated wood gasification supplies in British Columbia.
- The *LowHeatDemand* scenario applies 2016 space heat demand data. That data has a lower peak and lower overall energy demand than the hind cast 1996 demand applied in all other scenarios.
- The *GasHeatPump* scenario replaces all gas furnaces with gas heat pumps. The replacement increases gas-based space heating efficiency from 95% to 140% and consequently reduces natural gas and biogas consumption.
- The *Resilient* scenario forces the model to install sufficient energy storage capacity to supply energy demand during a five-day peak space heat demand event where no wind or solar generation is available. In the absence of other dispatchable technology alternatives, all capacity demand that exceeds the existing capacity of hydro power must be supplied by energy storage during that event.
- The *ResilientLowRNG* combines the *Resilient* and *LowRNG* scenarios. Wind and solar generation is not available during the five-day peak demand event. Biogas availability is 11.9 PJ (\*) and electrolyzer efficiency is 50%.
- The *Transport* scenario assumes full electrification of the road transportation sector and increases the electricity demand equally in the renewable gas and electrification pathways. Adding this demand serves to investigate the simultaneous electrification of sectors beyond the heating of buildings. The additional electricity demand derives from five vehicle classes. Fossil fuel and electric efficiency estimates for each vehicle class convert the 2016 gasoline and diesel consumption of passenger cars, passenger trucks, light freight trucks, medium freight trucks, and heavy freight trucks [14] to an electricity equivalent energy consumption of 14.4 TWh over the one-year modelling period. The hourly profile for this additional electricity demand peaks at 5 p.m. and 6 p.m. and repeats in 24 h cycles [40]. A description for deriving the electricity demand, profile, and conversion efficiencies is detailed in [22, Chapter 5.6].

## 4. Results

### 4.1. Generation and storage capacity

Fig. 7 shows annual electricity generation (top row), generation capacity (center row), and energy storage capacity (bottom row). Electrification (left column) or renewable gas (right column) gradually substitute natural gas in 10% increments. The stacked vertical bars show results for the *Reference* scenario. Whiskers show the range of values



**Fig. 7.** Reference scenario energy system transition in the electrification (Elec) and renewable gas (RNG) pathways. Horizontal axes show natural gas substitution rates ranging from 0% to 100% in 10% increments. The top row shows electricity generation and potential surplus for the one-year modelling period. The center row shows installed electric power generation capacities. The bottom row shows energy storage capacity. Gas storage capacity reaches ~1000 GWh; the axis range highlights the electric energy storage capacity because gas storage is low cost in comparison. Whiskers show the range of values observed across all scenarios.

across all nine scenarios. This figure reveals three important findings.

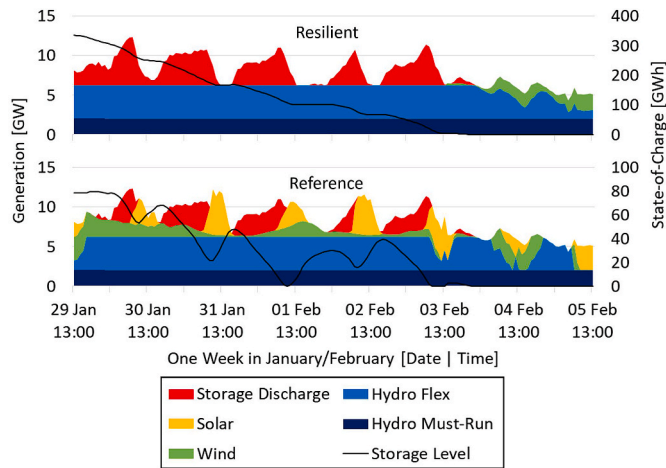
First, both pathways require installation of additional wind and solar generation capacity with storage to fully substitute natural gas. The available hydroelectric energy cannot substitute all natural gas consumed in the building heating sector, but partial substitution is possible with existing energy supply. The electrification pathway requires additional generation capacity beyond 10% substitution in the *Reference* scenario, and beyond 30% substitution in the *LowHeatDemand* scenario. In the renewable gas pathway, biogas supplies substitute up to 30% of natural gas in the *Reference*, and up to 60% in the *MuchBiogas* scenario.

Second, installation of electric storage capacity is sensitive to peak demand and to availability of variable renewables during this peak. In the electrification pathway, storage capacities range from 4 to 357 GWh (Table 3).

The 4 GWh needed in the *LowHeatDemand* scenario indicate that hydroelectric capacity provides close to sufficient flexibility to accommodate electrified heating in warmer years. In contrast, the colder temperature and higher heat demand of the *Reference* scenario exceeds hydropower capacity. This scenario installs 80 GWh of electric energy

storage capacity while large wind and solar capacity installations generate electricity surplus off peak. That large capacity installation is chosen by the model to meet peak space heat demand during a five-day cold period in January/February due to lack of dispatchable generation technology alternatives. The excess capacity generates surplus electricity in the remaining year, but is lower cost than installing additional high-cost electricity storage.

The magnitude of capacity installation is sensitive to the exogenous wind and solar profiles that, by coincidence, provide small amounts of power during the peak demand period. The *Resilient* scenario highlights this sensitivity by exogenously reducing wind and solar availability to zero for the five-day peak demand event. Fig. 8 compares electricity generation and storage levels in the *Resilient* scenario to the *Reference* scenario. During the five-day peak period, demand exceeds the installed hydro power capacity. In the *Reference* scenario, wind, solar, and electricity storage supply demand in excess of hydro capacity. In doing so, the 80 GWh of electric energy storage drain from maximum to nil within the first three days; the installation of 8 and 9 GW of wind and solar power result from the relatively low exogenous capacity factors during that period. In the *Resilient* scenario, 357 GWh of electric energy storage



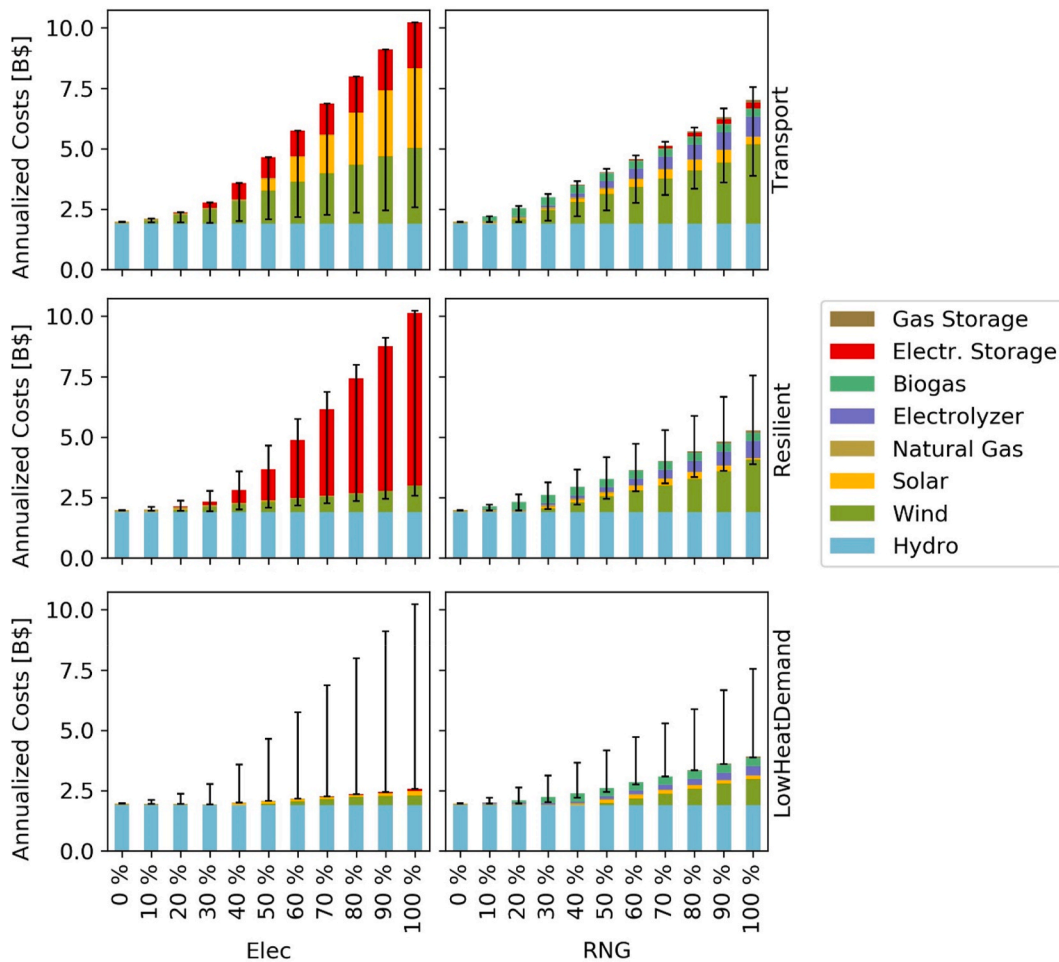
**Fig. 8.** Electricity generation and storage level during the five-day peak demand event in the Resilient (top) and Reference (bottom) scenario of the electrification pathway. The top of the stacked areas delineates the electricity demand. Note that the 168 h time period shown in this figure represents only an excerpt of the full 8760 h modelled in each scenario and pathway.

meet all demand that exceeds hydropower capacity during the five-day period. Lower wind and solar capacity installation almost eliminates surplus electricity generation.

Third, the renewable gas pathway balances supply and demand between seasons. The *Resilient* scenario requires 4.6 GW of electrolyzers and 1000 GWh of gas storage capacity. The electrolyzers operate at an annual average capacity factor of 66%. In this configuration, gas storage drains to nil from a full state-of-charge only once during the 1-year modelling period. Less biogas supply and lower electrolyzer efficiency in the *ResilientLowRNG* scenario require 11 GW electrolyzer capacity while using 1000 GWh of gas storage capacity. That configuration reduces the electrolyzer capacity factor to 48%.

#### 4.2. Costs

The large range of storage capacity installation leads to significant total system cost differences between the electrification and the renewable gas pathways. While either pathway can result in lower overall costs, the range of costs observed across all scenarios is more narrow in the renewable gas pathway. The whisker lengths in Fig. 9 highlight the large range of total annualized system costs. In absolute terms, the *LowHeatDemand* scenario has the lowest overall costs in both pathways because the low demand requires the least amount of energy production. The *Transport* scenario has the highest costs in the electrification pathway and the second-highest costs in the renewable gas pathway because the additional transportation-related energy demand increases costs in both pathways. The *ResilientLowRNG* scenario has the highest costs in the renewable gas pathway because the lower biogas availability and lower electrolyzer efficiency require significant



**Fig. 9.** Annualized total system costs in the electrification (Elec) and renewable gas (RNG) pathways in the Transport, Resilient, and LowHeatDemand scenarios. Horizontal axes show natural gas substitution rates ranging from 0% to 100% in 10% increments. Whiskers show the full range of annualized costs observed across all scenarios.

electrolyzer and electricity generation capacity. Note that costs include the annualized capital costs, and operation and maintenance costs for gas production, electricity generation, and electricity and gas storage. We do not include any costs associated with space and water heaters, and do not include costs for gas and electricity transmission and distribution.

To compare relative pathway costs, Fig. 10 shows the percentage difference for the lower cost pathway relative to the higher cost when 100% of natural gas is substituted. The renewable gas pathway is most cost-favourable (−48%) in the *Resilient* scenario because the lower-cost storage of electrolytic hydrogen avoids the 357 GWh of electric energy storage required in the electrification pathway. The electrification pathway is most cost-favourable (−52%) in the *LowHeatDemand* scenario because the lower peak electricity demand requires relatively little electricity storage.

#### 4.3. Greenhouse gas emissions

Substituting natural gas with electricity or renewable gas significantly reduces but does not eliminate greenhouse gas emissions from British Columbia's electricity system. Fig. 11 shows *Reference* scenario emissions in the electrification pathway (Elec) on the left and the renewable gas pathway (RNG) on the right. The whiskers delineate the range of emissions observed across all seven scenarios. The annual emissions decline as natural gas substitution rates increase from 0 to 100%. At a substitution rate of 100%, the remaining emissions result from the BC grid factor that takes into account non-renewable electricity imports. The renewable gas pathway retains additional emissions from biogas combustion.

The *MuchBiogas* scenario has the largest emissions (top whiskers) because the larger biogas resource-availability enables larger emissions by combusting more biogas. The *LowHeatDemand* scenario has the lowest emissions (bottom whiskers) because of lower overall energy production.

## 5. Discussion

This study quantifies costs and energy system capacities required to eliminate natural gas consumption in the residential, commercial and institutional building heating sectors of Metro Vancouver. Both direct electrification or substitution via renewable gas provide feasible solutions to supply space heat, water heat, and electricity for non-heat demands. Scenario analysis reveals that energy storage capacity requirements and resulting annualized system costs are sensitive to technology costs, resource supplies, and energy demand profiles.

Both transition pathways require the installation of additional electricity generation capacity to accommodate direct electrification or production of electrolytic hydrogen. In the absence of other dispatchable generation technologies, the installation of wind and solar power requires installation of energy storage. Consequently, the peak electricity

demand that exceeds present-day dispatchable capacity is the largest cost driver in the electrification pathway.

In Metro Vancouver, replacing all natural gas heating with air source heat pumps using the 1996 temperature profile increases peak electricity demand by 112%. That finding is consistent with other studies; in the absence of other efficiency improvements, heat pump deployment would increase peak electricity demand by 95% in Newcastle, United Kingdom [6]. A suite of efficiency improvements that mandate heat pump deployment and lead to net-zero emissions by 2050 is estimated to increase peak demand by 74% in Ontario, Canada [7].

Electrification of space and water heating in the BC building sector requires vast amounts of storage. To accommodate the additional peak demand, the *Reference* scenario uses 80 GWh of electricity storage to support wind and solar installations of 7.9 and 8.6 GW. If wind and solar power were not available during a five-day cold weather event, as in the *Resilient* scenario, 357 GWh of electricity storage is needed to meet demand. The probability of such a scenario occurring requires further study.

In the context of present and planned global storage capacities, installing the required storage infrastructure to supply Metro Vancouver appears to be challenging. Currently installed pumped storage facilities provide a total energy capacity of about 1400 GWh [38] worldwide. Using batteries instead of pumped hydro, the *Resilience* scenario would require ~10% of the global lithium-ion capacity (3200 to 4200 GWh [38]) forecast to be installed for residential and utility applications until 2050.

Comparing storage capabilities of gas and electricity systems demonstrates the immense challenge of fully electrifying heat energy demand. The compressibility and energy density of natural gas facilitate the supply of large peaks that occur during cold weather events. Natural gas transmission and distribution systems can vary gas pressure, or *line pack*, to accommodate demand fluctuations. In British Columbia, line pack in gas distribution systems provides 40 GWh of storage capacity. In the larger gas network of the United Kingdom, line pack has been shown to provide 690 GWh within a 24 h period during the heating season [43]. Dedicated gas facilities can store orders of magnitude more energy; the existing underground Aitken Creek gas storage facility in northeastern British Columbia can store 80,000 GWh of natural gas.

Implementing a suite of improvements will be critical to decarbonize the heating of buildings. Alongside demand side and energy efficiency measures, replacing natural gas with renewable gas can help limit the increase in peak electricity demand and, thus, storage capacity requirements. In the *Resilient* scenario, installing 4.5 GW of electrolyzer capacity and 1000 GWh (3.6 PJ) of hydrogen storage sufficiently supplements the 30 PJ of biogas supply that Fortis BC expects to procure annually by 2030. Low-cost biogas (or lack thereof) is the largest cost driver in the renewable gas pathway because hydrogen production requires installing electrolyzers, additional electricity generation capacity, and hydrogen gas storage. Nevertheless, the *ResilientLowRNG* scenario shows that conservative assumptions for biogas supply coupled with no advancement in electrolyzer efficiency can still result in the renewable gas pathway being cost effective.

This cost effectiveness will depend on developing low-cost large-scale hydrogen storage. Although underground natural gas storage is a mature technology, underground hydrogen storage (UHS) presents numerous challenges, including: lower compressibility and volumetric energy density, leakage due to low viscosity, chemical reactivity with media present in depleted oil and gas caverns, dissolution in water, microbial reactivity, and contamination of pure hydrogen [44]. Although, the energy penalty for natural gas storage is relatively low – only 1.4% of stored energy was lost or consumed over the 50 year operational life of the Aitken Creek natural gas storage facility in northeastern British Columbia – the challenges of hydrogen storage make such high efficiencies unlikely [45].

Review of the geological criteria suggests abundant UHS potential throughout Canada, especially in the Western Canada Sedimentary

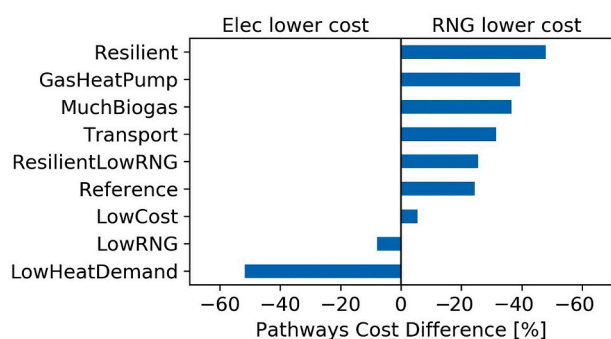
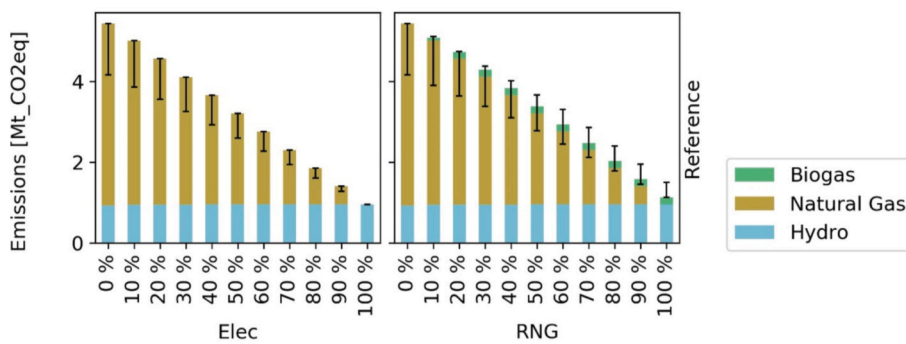


Fig. 10. Percentage cost difference between electrification and renewable gas pathways at 100% natural gas substitution across all scenarios.



**Fig. 11.** Greenhouse gas emissions related to all-sector electricity generation and gas combustion in the building heating sector of Metro Vancouver. Each stacked bar on the horizontal axes shows total emissions in the Reference scenario for the one-year modelling period as natural gas substitution rates increase from 0% to 100% in 10% increments. Whiskers denote emissions observed across all scenarios. The electrification pathway (Elec) is shown on the left, and in the renewable gas pathway (RNG) on the right.

Basin that extends through northeastern British Columbia [46]. To realize this potential, policy measures such as subsidies for research and development and price guarantees (e.g. feed-in-tariffs), may be needed to mitigate investment risk, reduce costs, and expedite installations [47, 48].

In this analysis, electrolysis provides the only source of hydrogen; fossil fuel feedstocks are not considered. Natural gas, coal, and oil presently feed 96% of global hydrogen production at costs of 1.26 \$/kg while emitting 13.2 kg<sub>CO2eq</sub> per kg<sub>H2</sub> [49,50]. Carbon capture and sequestration (CCS) could reduce direct emissions by 58% at double the cost. In contrast, wind, solar, or nuclear powered electrolysis is expected to increase hydrogen costs by a factor of 4–14 [51]. These economics favour hydrogen from CCS, but fugitive methane emissions from natural gas feedstock production could negate emission reduction [50].

Both direct electrification and renewable gas pathways reduce the combined electricity and heating emissions by about 80%, but these sectors represent a fraction of overall emissions in BC. The BC power grid emissions factor of ~30 t<sub>CO2eq</sub>/GWh [27] produces the majority of remaining emissions because of non-renewable electricity imports. Remaining emissions will decline if the neighbouring jurisdictions of Alberta and Washington State decarbonize their electricity generation. Note that emissions embodied in wind and solar power plants are not included in this study.

In the renewable gas pathway, substituting natural gas with biogas reduces the emission intensity by 78% (from 50.3 to 11 g<sub>CO2</sub>/MJ) but some biogas related emissions remain. The quantity of those emissions depend on available biogas supply. Achieving net-zero greenhouse gas emissions by mid-century to limit global warming to below 2 °C will require additional emission reduction. If negative emission technologies like direct air capture are to be deployed, additional expansion of zero-carbon energy sources will be required thereby compounding the energy supply challenge.

Metro Vancouver is somewhat unique in the context of Canada, being in a moderate climate zone with relatively low heating demand. The magnitude of heating demand, the temporal attributes, and the infrastructure needed suggests a potential for greater value for renewable gas in other Canadian locations. Note that our findings are consistent with a recent study examining delivery of power and heat in a warmer jurisdiction [52]. That study assesses the value of renewable gas (including hydrogen) injection into the Italian natural gas grid and finds electrolysis and hydrogen injection offer significant value when renewable energy accounts for more than 50% of the energy mix. That result is attributed to the ability of the gas network to provide long-term, cost-effective storage.

### 5.1. Limitations

This study is a first pass to directly compare electrification with renewable gas technology transition alternatives in the building heating sector of a metropolitan area where hydropower-dominant generation provides flexible and low carbon electricity. There are a number of

assumptions and key limitations that warrant further investigation.

First, this study models both transition pathways to be mutually exclusive. Either pathway can reduce greenhouse gas emissions and supply all energy demands in the building heating sector, but a combination of electrification and renewable gas adoption will likely prove the cost-optimal solution for simultaneously substituting fossil fuels in several economic sectors. The *Transport* scenario provides initial insight into decarbonizing additional sectors, but this study's investigation is limited to a single electric-vehicle charging profile and assumes full electrification of all passenger and freight transportation vehicles. Alternative charging profiles might utilize the otherwise surplus electricity generation. Incentives to electrify specific vehicle classes while converting others to hydrogen may prove to balance utilization of energy production and storage infrastructure cost effectively. Furthermore, the electrification pathway deploys heat pump technology to serve space heating; space cooling is enabled with this deployment and increased summer electricity demand would be expected. Extending this study's analysis to include more detailed, sector-specific energy demands across the economy could help identify where and which low-carbon fuel provides the most benefit in each sector.

Second, the costs of transitioning either the gas or electric delivery systems to align with significant fuel substitution of natural gas have not been explored in detail in this study. New infrastructure, modifications, and upgrades will be needed to connect either new electric loads or to move large volumes of hydrogen. Other drivers of change, including climate change, will also increase investment requirements to improve resilience and reliability. With this in mind, overall cost implications of transitioning energy delivery systems are still uncertain. Future work could reduce that uncertainty by, for example, increasing the spatial resolution of the energy system model. The completed study represents Metro Vancouver as a single node without energy transmission requirements. Increasing the spatial resolution could reveal cost-effective upgrades and geospatial configurations needed to accommodate increased electricity demand and hydrogen concentrations.

## 6. Conclusions

This analysis highlights the challenge of addressing greenhouse gas emissions in the building heating sector. The existing natural gas system provides three services that a future low-carbon system will need to replicate. These services include 1) provision of a large quantity of energy that 2) can be stored for long durations at relatively low cost and 3) be dispatched to provide a large quantity of power when cold weather events cause large heat demand. British Columbia's low-carbon hydroelectric system provides those services, but its ability to accommodate additional demand from natural gas substitution is limited. The variable renewable energy sources wind and solar power provide energy, but they lack dispatchability and require separate storage capacity installation. Considering the scale of fossil fuel combustion that will need to be eliminated in all sectors of the economy, enabling the gas system to continue to provide its services via renewable gas adoption may be a

cost-effective strategy to mitigating climate change.

The scenario analysis shows that costs of the electrification and renewable gas transition pathways are sensitive to assumptions around heat demand and variability of energy supply. Electrification is cost-effective when milder temperatures enable existing generation capacity to supply peak demand. In contrast, an extended period without wind and solar availability during a historic cold weather event requires a prohibitive quantity of electric energy storage. Overall, either pathway can be lower cost, but the range of costs is narrower in the renewable gas pathway.

Although the existing hydroelectric energy system of British Columbia provides flexible and low carbon electricity, these results highlight the value of dispatchable generation capacity and the cost-sensitivity to increasing peak electricity demand. Electrifying the building heating sector causes peak demand to increase more rapidly than average demand. Policy should support efficient technologies that limit peak increases and enable peak demand management. Prioritizing electrification of sectors that avoid increasing the winter-peaking load could more cost-efficiently use available renewable energy capacity.

### Credit author statement

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### Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: The second author of this manuscript is an employee of FortisBC Inc. This investor-owned organisation provides natural gas and electricity to customers across British Columbia.

### Acknowledgement

Funding for this research was provided by FortisBC Inc., MITACS, and the Energy Modelling Initiative.

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