Towards Net Zero Heating: An Analysis of Technology and Policy Pathways for Decarbonizing Building Heat in British Columbia

by

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Abstract

The Province of B.C. has committed to reducing greenhouse gas emissions from residential and commercial buildings, but little information is available on 1) the technology-energy pathways to cost effectively reach emission targets and 2) the impacts of heat decarbonization on gas distributers. This study uses the partial equilibrium energy economy model CIMS to assess the impacts of announced policies to decarbonize building heat under two possible visions of the evolution of the gas system: a maintained gas grid, and a pruned gas grid. In both scenarios, heat decarbonization results in high gas costs that cause gas grid defection and favour a shift to electric heating in both residential and commercial buildings. Additional insight is provided into future technology heating stock, forecasted gas costs, electricity sector impacts, and other considerations for policy makers.

Keywords: climate policy; energy economy modelling; building sector; gas distribution; scenario analysis

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Table of Contents

List of Tables

List of Figures

List of Acronyms

ASHP – Air source heat pump

B.C. – British Columbia

CER – Canada Energy Regulator

COP – Coefficient of Performance

HDD – Heating Degree Day

GGRS – Greenhouse Gas Reduction Standard

GHG – Greenhouse gas emissions

GJ – Gigajoule

GSHP – Ground source heat pump

HVAC – Heating Ventilation Air Conditioning

IPCC – Intergovernmental Panel on Climate Change

LCC – Life Cycle Cost

MtCO2e – Megatons of carbon dioxide equivalent

NRCAN – Natural Resources Canada

RNG – Renewable Natural Gas

PJ – Petajoule

UNFCC – United Nations Framework Convention on Climate Change

1.0 Introduction

1.1 Context

In light of irrefutable evidence documenting the drivers and effects of anthropogenic climate change, international efforts to limit warming as outlined at the Paris Agreement have led Canada and many other countries to declare net zero by 2050 emission targets. Net zero emissions refers to an energy and economic system where the difference between total emissions released into the atmosphere and emissions removed from the atmosphere through negative emissions technology or nature based solutions equals zero net emissions (Canadian Climate Institute, 2021). Preventing the worst impacts of climate change is largely dependent on the mitigation of greenhouse gas (GHG) emissions, as well as adapting to the locked-in effects of past emissions. Despite international efforts to establish warming limits of 1.5°C, and national commitments from the 193 Parties to the United Nations Framework Convention on Climate Change (UNFCCC), global anthropogenic emissions have risen across all major sectors since 2010 (UNFCCC, 2022). With global pressure mounting and the effects of climate change already being felt, there is an urgent need for Canada to decarbonize.

The energy sector is a primary focus of decarbonization efforts, since it is responsible for over 80% of Canada's GHG emissions (ECCC, 2022). Research into decarbonization pathways shows that electrification and fuel switching away from fossil fuels will play a large role in short term decarbonizing, but that there is more uncertainty as to how Canada's energy system will be structured when looking longer term to 2050 (Bataille, C. et al., 2015).

Pathways to decarbonization in the residential and commercial building sector threaten to disrupt the status quo of the energy system. The primary reason for this is a reliance on carbon intensive heating fuels like natural gas derived from fossil fuels ("fossil gas").[1] Fossil gas is a reliable and relatively low-cost fuel that is the dominant provider of heating services across Canada. Thus, gas systems are deeply embedded in

[1] After discussion with energy experts, I use "fossil gas" in this study to refer to those gases whose consumption must decrease or end entirely to achieve net-zero targets. These include "natural gas" extracted from porous geological strata in isolation or in association with oil, "shale gas" extracted from fracturing shale rock, and "town gas" produced from coal gasification. These are distinguished from "biomethane" (also called "renewable natural gas") and "hydrogen" produced from renewables or from fossil fuels with carbon capture and storage.

Canada's energy landscape, and a shift away could impact gas users and gas utilities. However, the general nature of these impacts is uncertain and may benefit from research that explores plausible long-term pathways to sectoral decarbonization.

In this research paper, British Columbia (B.C.) is used as a case study to explore the uncertainty associated with decarbonizing gas dominated building heat. The province has legislated GHG reduction targets of 40% by 2030, 60% by 2040, and 80% by 2050, from a 2007 baseline. To that end, in 2021, the Province of B.C. released the *CleanBC Roadmap to 2030* outlining key measures to achieving provincial emissions targets while supporting the development of a clean economy (CleanBC, 2021). To decarbonize building heat, the province announced a policy to cap emissions from the gas distribution system, a mandate to require 100% efficient heating equipment in future sales, and an intention to financially and institutionally support building electrification. Despite a suite of announced policies, there is a lack of publicly available modelling that analyses the effects of these policies on British Columbia's energy landscape, including the impact on emissions, the cost of energy for end users, and the impact to gas systems and distributers.

1.2 Analytical Framework

I used a partial equilibrium hybrid energy economy mode, CIMS, to investigate the lowest cost pathway to decarbonize building heating in British Columbia (B.C.) in the 2020 to 2050 timeframe under two possible visions of the gas system. Given the degree of uncertainty involved in modelling technology uptake and policy implementation decades into the future, I establish several principles here to define the scope and approach that I took in approaching this research topic.

- I limited my exploration of decarbonized heating pathways strictly to known technology and energy options. A pathway that is not technically or economically feasible is not included in this study.
- I considered emissions from the residential and commercial building sector only. I considered several policy scenarios to constrain technology and energy usage, including 1) policies to achieve current GHG targets of 40% by 2030 and 80% by 2050 and 2) policy to achieve net zero emissions by 2050 GHG targets. I assumed that any remaining emissions could be offset by negative emissions elsewhere.

- A partial equilibrium model like CIMS allowed me to capture the price dynamics and market responses within a subset of the economy and was therefore an appropriate tool to track how the impacts of changing costs affect the expansion or contraction of each competing technology-energy option explored.
- I assessed competing low carbon pathways to building heat decarbonization, and allowed CIMS to compare the relative costs of each pathway in order to predict how emissions from fossil gas in residential and commercial buildings would decline as competing energy sources became more cost competitive.
- I endogenously simulated the increase in cost per unit of gas caused by a decline in gas consumption, then drew conclusions about the impact of heat decarbonization on gas distributers. I used a cost curve for biomethane to approximate the rise in price associated with an increase in quantity of biomethane supplied. Hydrogen price and quantity is solved for endogenously. Thus, the final cost of gas is determined by a price competition between fossil gas, biomethane gas, and hydrogen gas.
- I assumed that B.C.'s hydro endowed electricity system would be able to absorb additional generation demand but would require investment in transmission capacity or electricity storage to meet peak demand. I reflected this impact on electricity prices by exogenously adjusting electricity costs.
- In this work I do not consider full scale adoption of hydrogen heating, as this pathway would require the conversion of all end user heating equipment and pipeline infrastructure to hydrogen-compatible materials and equipment.

1.3 Research Objectives

The specific objectives of my research are to:

1. Identify plausible technology, fuel, and policy pathways for reducing emissions from heat in residential and commercial buildings to meet B.C.'s emission reduction targets.
2. Determine how the pathways modelled impact the cost of gaseous fuel delivery and subsequently the viability of gas distribution companies in a decarbonized future when in competition with alternative zero-emission options.
3. Provide recommendations to policy makers to support a pathway to decarbonized building heat.

The results of my study may help guide decision makers in British Columbia and other Canadian jurisdictions by identifying technology, fuel, and policy pathways for decarbonizing building heating services, and illuminating the impacts of decarbonization on the gas distribution system.

In the following section I provide background information on the gas system and policy landscape in British Columbia, as well as pathways that have been explored in other literature focused on decarbonization of building heating. In section 3 I outline the methodology I applied in this study, including the model improvements made to CIMS to simulate the evolution of the gas system. In section 4, I outline the scenarios that I developed and modeled. I present the results of my modelling efforts and discusses their implications for policy makers, gas utilities, and the public in section 5. Finally, in section 6 I summarize the findings and policy implications of this study and identifies limitations and directions for future research.

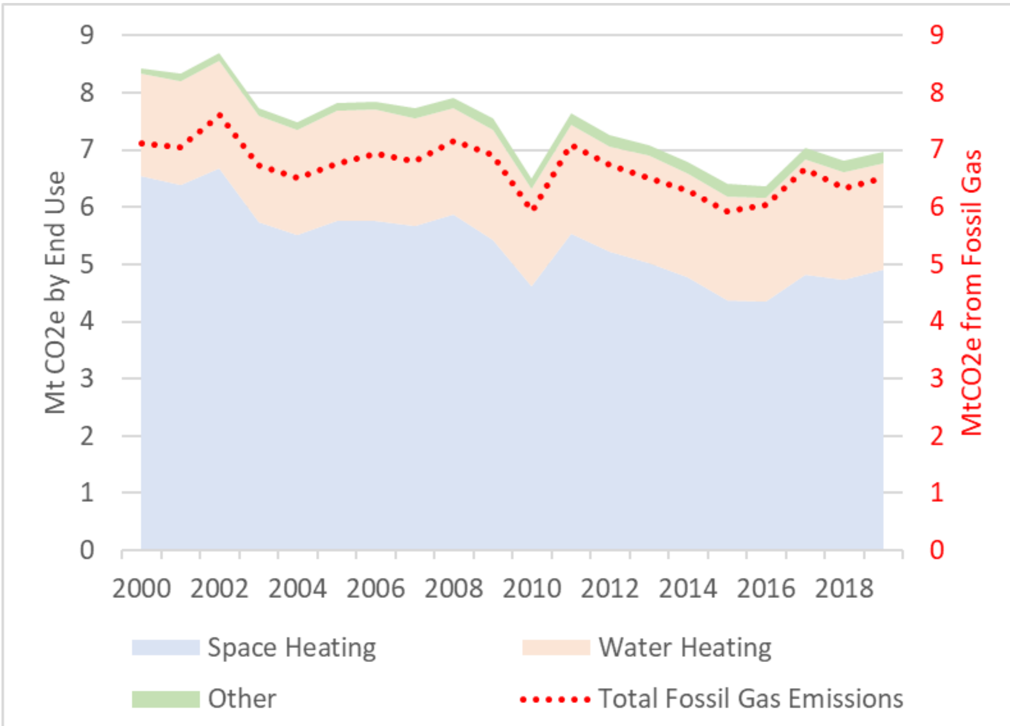
2.0 Background

2.1 Building Sector Emissions

Canada has committed to a net zero emission target, and the Province of British Columbia to an 80% emission reduction target by 2050. However, both jurisdictions currently continue to emit greenhouse gases as a result of business-as-usual activities, and historically many such governments have had a bad track record with achieving GHG pathways consistent with their (safely distant) long-term promises. Nationally, 74Mt of emissions from energy use (14%) can be traced back to residential, commercial, and institutional buildings, largely due to burning natural gas, heating oil, and biomass for heat (ECCC, 2022). Year-over-year analysis shows a 6.1% increase in building sector emissions from 1990 to 2020, driven by growth in population and floor space per capita that were not proportionately offset by energy efficiency improvements (ECCC, 2022). This growth occurred during a 30-year period when Canada's federal and most provincial governments had commitments to dramatically reduce GHG emissions, with unfulfilled targets in 2000, 2010 and 2020 (Simpson, J. et al., 2008).

In 2020, emissions from residential and commercial buildings made up 11% of British Columbia's emissions (Province of British Columbia, 2020b). B.C.'s dependence on fossil gas for heating services results in a disproportionate amount of emissions relative to energy use: in 2019 space and water heating accounted for 66% of energy consumption in B.C.'s buildings, but over 97% of building emissions (NRCAN, 2019). In addition to space and water heating, fossil gas is used in limited cooking and clothes drying applications. Figure 1 summarizes on the left axis the role that space and water heating play in B.C.'s emissions profile, and on the right axis highlights how fossil gas combustion is responsible for the majority of building sector emissions.

Figure 1: B.C. Building Sector Emissions by End Use and Fuel



2.2 Fossil Gas Fuel and Distribution Systems

Fossil fuel formation occurred over millions of years through high pressure and high temperature geological processes that compressed decaying organic materials into hydrocarbon dense products. These processes resulted in three forms of fossil fuels: coal in solid form, oil in liquid form, and natural gas in gaseous form. The latter, "fossil gas", is formed from methane (CH_4), and contains four hydrogen molecules for every one carbon molecule. Fossil gas extraction and processing requirements vary by reserve type. Reserves may be conventional (i.e. occurring in porous and impermeable rock formations) or unconventional (i.e. occurring in impermeable rock formations and requiring hydraulic fracturing extraction processes) (Natural Resources Canada, 2011).

Prior to being injected into the gas grid, raw fossil gas must be processed to remove water, crude oil, CO_2, and other impurities (Ivanenko, 2012).

In B.C., the main applications of fossil gas are to power industrial processes and as a fuel for heating in residential and commercial buildings (Natural Resources Canada, 2011). Nationally, fossil gas is also used as a fuel to generate electricity, although this is not the case in B.C. due to the province's hydro endowed electricity system. Fossil gas is transported via high pressure transmission pipelines that connect to lower pressure local distribution pipelines owned and managed by Local Distribution Companies (LDCs) servicing residential, industrial, and commercial gas users (Ivanenko, 2012). Residential and commercial gas users rely on a subsurface pipeline network that transports gas from local delivery pipes into buildings, where it is combusted using heating equipment such as furnaces and boilers.

Like many commodities reliant on network-like systems for distribution, the final cost of gas is comprised of both fixed cost and variable cost components. The fixed cost captures capital investment in construction, operation, and maintenance on the pipeline distribution system that transports gas to end users (Ong et al., 2021). In addition to fixed costs, gas end users also pay a variable charge per gigajoule (GJ) of fuel that they consume (Ong et al., 2021). In Canada, a carbon surcharge is levied on all hydrocarbon-based fuels, including fossil gas.

Fossil gas has remained an attractive and dominant fuel across Canada for several reasons. For one, compared to many renewable energy sources such as wind or solar energy, fossil gas is a dispatchable and non-intermittent energy source that can reliably provide energy during periods of peak demand (van der Zwaan et al., 2022). Additionally, the extensive global network of fossil gas transportation and distribution makes its continued usage convenient. Finally, fossil gas has lower emission impacts than either coal or oil, leading some gas proponents to suggest a role for gas as a transition fuel from more carbon intensive fossil fuels (Fortis BC, 2022; van der Zwaan et al., 2022). Despite global recognition of the need to move away from fossil fuel usage, gas distributers across Canada continue to propose and build pipeline expansion projects that lock in fossil gas dependency and emissions for the length of the system's lifetime – typically about 50 years (Intergovernmental Panel on Climate Change, 2022) although in reality these systems, with upkeep, can last indefinitely. The prevalence of fossil gas firmly entrenches it in Canada's energy system, and a transition away from it would require a significant overhaul of existing energy infrastructure and system planning. Path dependency on infrastructure that supports fossil fuel combustion can delay progress towards emission reduction targets, and has been shown to increase the cost of pathways towards net zero emissions (Bataille, C. et al., 2015; Canadian Climate Institute, 2021).

Despite the GHG emissions associated with fossil gas usage, proponents of fossil gas maintain that it has a role to play in the decarbonization challenge. B.C.'s largest gas utility, FortisBC Energy Inc. ("Fortis") states in its *Clean growth pathway to 2050* that it sees a role for fossil gas as a "low-carbon and affordable energy source" (Fortis BC, 2022). Fortis envisions a critical role for gas in a decarbonized future, proposing that gas will provide a reliable and affordable fuel in difficult to decarbonize building sector end uses, and leveraging biomethane and hydrogen blending as tactics to reduce gas system emission intensity (Fortis BC, 2022).

As the Province of B.C. advances towards its GHG targets, the future of the gas system is uncertain. The possibility of a growing share of gas users shifting to electricity for heating services raises concerns of a "grid defection" event, also known as a "utility death spiral" (Then, Hein, et al., 2020). A death spiral is a cyclical process whereby a reduction in sales of a product drives an increase in the per unit cost of producing that product, leading to price increases that further reduce its demand. These events have been heavily studied and theorised in the context of electrical systems where, decades ago, a rapid increase in nuclear plant construction costs triggered rate increases in parts of the U.S., which in turn reduced demand, forced additional rate increases to cover the high fixed costs, and caused utility bankruptcies – hence, the utility death spiral. More recently, a rise in renewable energy systems like rooftop solar has allowed electricity users to lower their dependency on the centralized grid. Such actions reduce total grid demand and increase energy prices for remaining electricity users, who must share system wide fixed costs among fewer kilowatt-hours of consumption. The impact of rising fixed costs borne by remaining system users increases overall energy costs, causing demand to fall. This feedback loop threatens the financial viability of the utility (Laws et al., 2017). While the concept of the utility death spiral is less often applied to the gas distribution system, research shows that grid defection could also take place in the gas system spurred by the "perfect storm" of rising utility costs, the adoption of competing energy sources, and rising costs for gas customers that increase the incentive for yet additional fuel switching (Laws et al., 2017; Then, Spalthoff, et al., 2020). My research investigates the extent to which B.C.'s announced decarbonization policy may pose a death spiral threat to its gas distributers.

2.3 Pathways to Decarbonized Heating

Achieving B.C.'s GHG targets necessitates the development of an energy system that can provide a reliable and consistent supply of low carbon energy. A low carbon energy system consists of any combination of measures including a significant reduction in the use of fossil fuels, the deployment of low emitting energy sources such as electricity, and the use of alternative energy carriers such as biofuel or hydrogen. In a net zero energy system, energy conservation and efficiency measures alone do not drive any reduction in emissions but can play a role in reducing investments in the supply of zero emission energy that is needed to power a low carbon transition. Below I provide a background the three measures considered in my study: low carbon gas blending, electrification, and energy efficiency.

Low Carbon Gases

Blending low carbon gases such as biomethane and hydrogen into the gas grid displaces fossil gas usage and lowers the overall carbon intensity of the gas system. Low carbon gas production pathways are summarised in Figure 2.

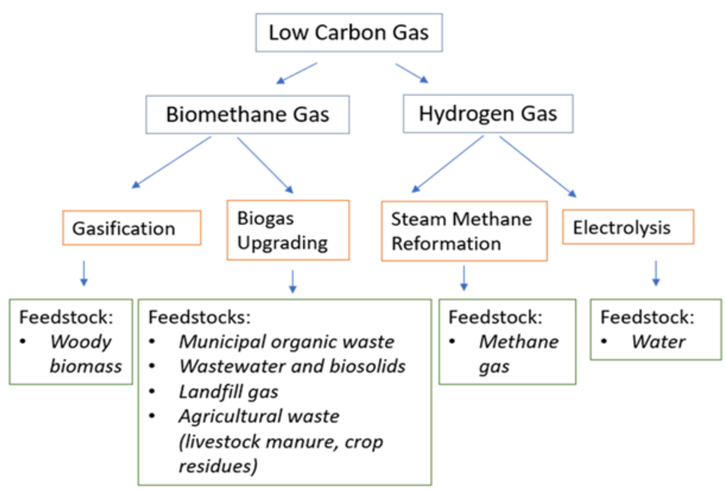


Figure 2: Low Carbon Gas Production Pathways

Biomethane (also called Renewable Natural Gas or RNG) in its processed form is chemically identical to fossil gas and can be used in the same way despite differences in its feedstocks. Biomethane is produced from a variety of feedstocks including livestock manure, biosolids, wastewater, urban organics, crop residues, and woody biomass (Stephen, J. et al., 2020). Conventional biomethane is produced either through anaerobic digestion or the capture of landfill gas, both of which produce an impure biogas that is upgraded into biomethane (Laszlo, R. & Short, T., 2021; Tampier, M., 2022). The resulting gas is near-pure methane that can be blended into the gas grid. A co-benefit of conventional biomethane production is the associated reduction in livestock and landfill methane emissions (Stephen, J. et al., 2020).

A second biomethane production pathway comes from the gasification of woody biomass. This production pathway takes woody biomass feedstock (i.e. forest residues) and applies a thermo-chemical conversion to produce a synthesis gas, followed by a water-shift reaction to increase the ratio of hydrogen to carbon molecules (Tampier, M., 2022). Biomethane produced through gasification is high cost compared to alternative zero emission options (Stephen, J. et al., 2020; Tampier, M., 2022). The scale up of biomethane from both biogas upgrading and woody biomass gasification is limited by the availability of organic feedstocks. As jurisdictions around the world turn to biomethane as a low carbon alternative to fossil gas, the competition to supply this fuel will intensify (van der Zwaan et al., 2022).

Hydrogen is an abundant and light-weight element that can be used as an energy carrier and fuel (Mazloomi & Gomes, 2012). Hydrogen can be produced through several processes. For example, electrolysis uses electricity to split water into hydrogen and oxygen (Canada Energy Regulator, 2021). The source of electricity used to fuel this process has an impact on the final Scope 2 emissions associated with hydrogen production. A second hydrogen production process, steam methane reformation, reacts steam with methane to produce hydrogen and CO_2 (Canada Energy Regulator, 2021). When paired with carbon capture and storage, the hydrogen gas produced through steam methane reformation is considered low carbon.

Use of hydrogen as a low carbon gas introduces new opportunities to decarbonize heat in buildings. However, there are several technical and practical challenges associated with hydrogen blending into the gas grid. For example, hydrogen, and biomethane for that matter, are both GHGs, and pipeline leakage prior to combustion is a concern associated with blending these gases into the gas system. Melaina et al. (2013) detail how the presence of hydrogen can increase corrosion of gas system infrastructure due to metal embrittlement, which can cause cracks, leaks, and potential safety hazards. These risks rise as the percentage of hydrogen in the gas blend increases, and significant system upgrades and modifications would be required to accommodate hydrogen blending levels above 20%. A second challenge is the compatibility of gas combustion equipment with hydrogen. Most gas appliances are not designed to operate with hydrogen gas, and may experience reduced performance, require increased maintenance, or risk safety hazards as a result of hydrogen blending. Gas system maintenance costs would likely be higher with hydrogen service due to increased inspection frequency and the need for leak detection systems. Due to these challenges, the range of hydrogen blending typically considered acceptable within existing gas systems is between 5% and 20% (Baldwin et al., 2022; Melaina et al., 2013). For the purposes of my research, I considered 15% hydrogen as a blending limit.

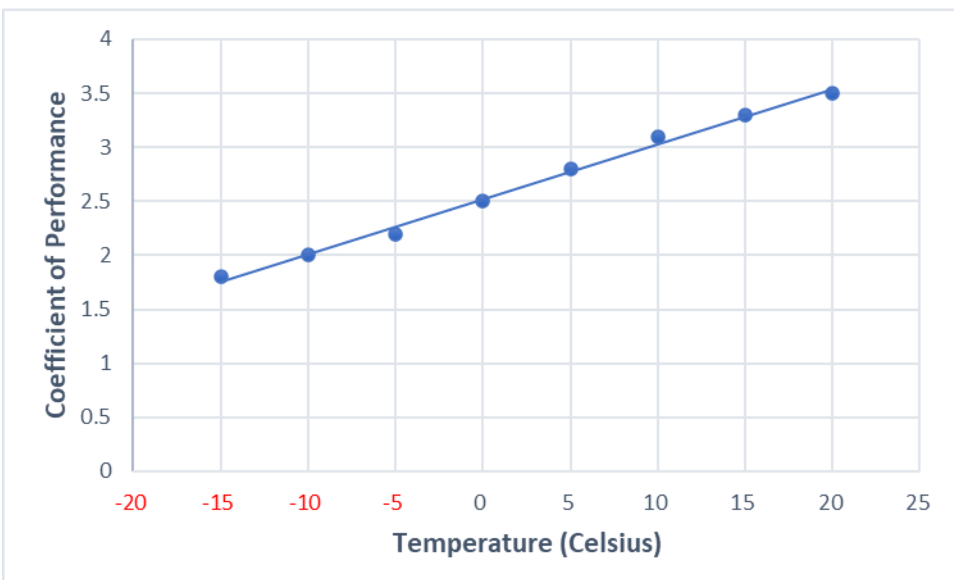
Blending low carbon gases into the gas grid reduces the carbon intensity of gas throughput while allowing gas distributers to use existing infrastructure and end users to continue to use their gas burning equipment. Fortis asserts that “decarbonizing the gas flowing through the system while maintaining the use of that system is a prudent and low-cost strategy to ensure that B.C. achieves its climate targets” (Fortis BC, 2022). However, as GHG reduction targets rise towards 2050, the proportion of fossil gas in the gas system must continue to decline if targets are to be achieved. My study investigates the likelihood that eliminating fossil gas combustion in buildings through low carbon gas blending will be the most economically competitive approach to decarbonize building heat.

Electrification of Heating End Uses

Another approach to decarbonizing heat in the residential and commercial building sector is through the electrification of end uses currently supplied by carbon derived fuels. Electrification has been classified as a “safe bet” technology by the Canadian Climate Institute, meaning that it is technologically available, cost effective, and a low risk pathway to transition to net zero in the building sector (Canadian Climate Institute, 2021). Heat electrification is driven by switching from gas powered space and water heating equipment towards electric baseboard heaters or electric heat pumps.

Heat pumps operate by extracting latent heat from the outdoors and transferring it indoors, functioning like an air conditioner in reverse (Deetjen et al., 2021). Despite being highly efficient, residential heat pump market share in Canada currently sits at about 5%, with commercial uptake even lower (Corbett et al., 2023). Ground source heat pumps (GSHP) draw their heat from below ground where there is a relatively stable temperature all year, but are less common than air source heat pumps (ASHP) due to being capital intensive and complex to install in existing buildings (Palmer-Wilson et al., 2022). In contrast to GSHP, air source heat pumps draw their heat from the air. Unlike conventional space heating equipment that has constant heating efficiencies, the efficiency of an ASHP is impacted by seasonal fluctuations in ambient temperatures. In other words, at temperatures above 10° Celsius, an ASHP can operate above 300% efficiency. However, as ambient temperature declines there is less heat available for an ASHP to extract and transfer indoors. This results in a decline in the heat pump's coefficient of performance (COP) that correlates with a decline in temperature (Palmer-Wilson et al., 2022). While heat pump efficiency by temperature varies according to the heat pump model considered, for my research I based my representation of an ASHP on a cold climate heat pump that can continue to operate down to -15° Celsius at a COP of at least 1.8. Due to declining efficiencies at temperatures below -15° Celsius, less heat available in ambient air, and the increased need for defrosting heat exchanger fins, buildings that rely on air source heat pumps require supplementary heating in climates that experience very low temperatures. Figure 3 depicts the effect of temperature on the efficiency of a cold climate heat pump.

Figure 3: Average Efficiency of Cold Climate Heat Pumps by Temperature



There is consensus that electrification is a core component of all credible net zero pathways and will drive a switch from fossil fuels to electricity in the building, transportation, and industrial sectors. However, achieving widespread electrification presents many challenges. Increases in the peak demand for electricity – the time when extra investment is needed to power sparingly-used generation – will present challenges for system management to cost effectively match electricity demand with electricity supply. For example, the Canadian Climate Institute predicts that widespread heat pump adoption would shift peak electricity demand from summer to winter months when heating demand is highest (Canadian Climate Institute, 2021). It is expected that nationally, electricity generation will need to double or triple in size in order to meet electricity demand by 2050 (Canadian Climate Institute, 2022), though this is not the case in B.C. due to surplus electricity capacity from mega dams like the Site C.

Energy Efficiency Measures

In addition to energy substitution approaches to decarbonize the energy used in residential and commercial buildings, energy efficiency approaches on the demand side can reduce the energy intensity of the built environment and delay the need for investment in new clean energy. Demand side measures play a role in BC Hydro's electricity system planning by pushing the need for new transmission and generation investments to the 2030's. In a low carbon energy system, energy efficiency measures are *not* a driver of GHG abatement, but can play a role in reducing the total amount of zero emitting energy supply necessary to power a decarbonized energy system. Energy efficiency measures include behavioural change, the adoption of efficient end use technology, and building retrofits. In Canada, studies have shown that retrofit measures such as window replacements, insulation upgrades, and building design improvements can reduce building energy intensity by 45-55% by 2050 (Canadian Climate Institute, 2021). However, efficiency measures have been found to be economically unattractive due to actual or perceived financial barriers, and uptake often relies on government subsidies (Murphy & Jaccard, 2011; Toronto District 2030, 2021). My study captures improvements in building shell efficiency over time driven by building code improvements.

2.4 Gas System Impacts of Heat Decarbonization

Several studies worth noting have also investigated pathways to decarbonised building heat and associated impacts on the gas system. The Canadian Climate Institute conducted rigorous modelling and found heating electrification to be a critical step in a net zero building transition, supported by energy efficiency measures and low carbon gases (Canadian Climate Institute, 2021). Their study found that a net zero transition could be achieved without a rise in energy costs. Other research focusing on the effects of blending biomethane and hydrogen into existing gas grids have found that the end user cost of gas typically rises in those scenarios due to the higher relative cost of low carbon gases compared to fossil gas (Aas, D. et al., 2020; Ong et al., 2021). A paper from the University of Victoria published in collaboration with Fortis assessed electrification and renewable natural gas as two pathways to decarbonized building heat. The paper found that both pathways can be low cost under the right conditions, but argued that the gas system might be able to store gas and dispatch power to meet demand in ways that the electricity grid cannot (Palmer-Wilson et al., 2022). It should be noted that storage as an approach to meet demand is not limited solely to the gas system; electricity system capacity can also be increased through storage built near demand – for example by leveraging electric vehicles as batteries or constructing hydrogen or compressed underground air storage for conversion into electricity. Additional investments in storage would ease any transmission strains on B.C.'s electricity system associated with an increase in demand of electricity.

There is little research that considers the implications of decarbonized building heat on the gas system. Instead, several studies have considered possible visions of what the gas system might look like in a decarbonized energy system. One outcome is the partial decommissioning of the gas grid, known as *selective grid pruning*. In this scenario, portions of the gas grid with low utilization rates would be retired and replaced with targeted electrification. Grid pruning has been identified as a relatively low cost approach to reducing emissions (Ong et al., 2021). Another outcome identified in the literature is a *hybrid system*, also called an integrated energy system, made up of two or more energy sources. In my research, I consider an electricity-gas hybrid system that is made up of a strengthened low emitting electricity system coupled with gas infrastructure to accommodate peak demand (ICF, 2019). Research from the Canadian Gas Association and the Canadian Climate Institute suggests that an electricity-gas hybrid system is a more cost effective approach to reducing emissions than total electrification (ICF, 2019; Seguin, H. & Bigouret, A., 2023). However, a system of this nature might require gas distribution to be linked and dependent on electricity system operators which can be challenging to operationalise (Then, Hein, et al., 2020). An electric-gas hybrid heating system approach has recently been taken in the Province of Quebec via the partnership of the local gas distributer Énergir and Hydro-Quebec.

2.5 Need for Analysis

Fossil gas is the dominant heating fuel in B.C and uses long lived infrastructure that will be challenging to move away from without policy direction. In 2021 B.C.'s provincial government released the *CleanBC Roadmap to 2030,* which included several policies to reduce building sector emissions. Despite the urgent need for gas distributers, utility regulators, and provincial policy makers to proactively plan for a low carbon energy system or risk locking in infrastructure that supports fossil fuel combustion, there is little data publicly available on the implementation timelines of announced policies, the impacts to B.C.'s gas system, or the effect on costs for gas users (Then, Spalthoff, et al., 2020). Past research on the energy system's transition to net zero has focused on the decarbonization of end uses and the role of the electricity system, rather than analyzing the effects of decarbonization on the integrated system. Proponents of the gas system claim gas is a reliable heating fuel that can be made compatible with net-zero through energy efficiency and low carbon gas blending (Fortis BC, 2022; ICF, 2019). However, few studies have investigated whether this pathway is cost competitive against other technology-energy pathways, particularly ones that foresee fuel switching towards electricity. Analysis using CIMS, a tool that can trade off different decarbonization options in an integrated framework of prices and costs, can help illuminate how the energy system may evolve given various emission and price constraints.

While there is an unavoidable degree of uncertainty when planning for a net zero energy system, any delay in planning constitutes locking in of additional emissions. As the Canadian Climate Institute states it in their Net Zero Pathways report: "Uncertainty and disagreement regarding the future shape of a net zero economy and energy system cannot justify delay" (Canadian Climate Institute, 2021). This study recognises the uncertainty inherent in planning for a decarbonized future and explores potential pathways and policy levers to support that transition. The results of this work may be useful to policy makers who must plan for the energy transition and ensure that energy systems remain affordable and reliable amidst their decarbonization trajectory.

3.0 Methodology

To conduct my research, I used the CIMS model to assess the options and system wide impacts of building heat decarbonization. In this section I will provide an overview of CIMS and describe the updates that I made to the model.

3.1 Overview of the CIMS model

An energy economy model is an evaluative tool that simulates how the implementation of energy or climate policies might cause the adoption of new technologies that reduce GHG emissions (Jaccard, 2009). The Canadian Integrated Modeling System (CIMS), developed and housed by the Energy and Materials Research Group at Simon Fraser University, is a partial equilibrium hybrid energy economy model. Unlike conventional top-down or bottom-up models, CIMS can capture both technological explicitness and behavioural realism, as well as certain macroeconomic impacts (Jaccard, 2009). Being a partial equilibrium model, CIMS can simulate the dynamics within a specific sector or subset of the economy – in this case the residential and commercial building sector – and the energy markets that support that sector. Partial equilibrium models capture detailed interactions, price dynamics, and market responses that might be difficult to isolate in general equilibrium models. CIMS represents sectors in the Canadian economy that demand energy, such as the residential, commercial, or transportation sectors, and sectors that supply energy, such as the electricity sector. Additionally, CIMS represents the price and fuel demands of over 1,000 technologies that use energy. For my research project, I modelled only the province of British Columbia, and focused on technologies demanding energy within the residential and commercial buildings sectors, as well as the sectors supplying that energy.

The CIMS model simulates the purchase, retirement, and retrofit of capital stock in 5-year periods from 2000 to 2050. Each year, technologies in the model compete for market share to provide services, while requesting a given amount of energy. A similar logic is used for sectors providing energy. Technologies compete to provide the requested amount of energy resulting in a weighted-average price for the energy product. The model iterates between the demand and supply sectors until the quantity and price of each energy product calculated within each type of sector equilibrates.

The CIMS model uses a number of equations to simulate energy demand and supply. The competition of new capital stock at each node of the economy is solved for by comparing the life cycle costs (LCC) of competing technologies using the market share equation in CIMS, shown in Figure 4.

Market share is determined by several parameters that capture the effect of financial cost and the microeconomic behaviour of economic agents when acquiring capital stock. For instance, in addition to the capital cost (CC), maintenance cost (MC) and energy cost (EC) dictating the market share of a given technology (j) relative to its competition (k), so too does its intangible costs (i). Intangible costs represent perceived non-financial costs to adopting a technology such as costs related to risk differences, information availability, and subjective preferences about the quality of service provided by a technology relative to its competitors. The equation also includes the time preference of technology acquirers (parameter r) and the heterogeneity of their preferences (parameter v).

$$MS_j = \frac{\left[CC_j * \frac{r}{1-(1+r)^{-n_j}} + MC_j + EC_j + i_j\right]^{-v}}{\sum_{k=1}^{K}\left\{\left[CC_k * \frac{r}{1-(1+r)^{-n_k}} + MC_k + EC_k + i_k\right]^{-v}\right\}},$$

Figure 4: CIMS Market Share Equation

The cost of newer technologies evolves over time due to economies of learning and economies of scale, which can manifest as a decline in intangible costs or capital costs. For my modeling, I used the declining annual intangible cost function in CIMS that links future intangible costs to cumulative market uptake to represent the decline in the perceived risk of purchasing a relatively new technology such as a heat pump as awareness grows.

3.2 CIMS model updates

A significant amount of model development was necessary for CIMS to model technology and policy pathways to decarbonizing heat in B.C.'s residential and commercial buildings. As outlined below, I updated CIMS to delineate between regional climate zones, added new heating technologies, introduced a blended low carbon gas fuel, and disaggregated the fixed and variable costs of gas.

3.2.1 Cold and Temperate Climate Zones

I simulated building heat demand in two distinct climatic regions to capture the impact of regional climate differences on the demand for and supply of heat across British Columbia. I based the climate zones in CIMS on the correlation between heating degree day (HDD) data and January design temperature data reported in the BC Building Code (Province of B.C., 2018). Heating degree days are a measure of the amount of heating required to maintain a comfortable indoor temperature and are based on the cumulative number of degrees of heating per year required to reach a reference temperature of 18°C. Buildings in regions with higher HDD ratings will have a higher heat demand. Meanwhile, January design temperatures report the temperature below which 2.5% of hourly outside air temperatures in a municipality will occur. For example, Nakusp has a value of -20°C, indicating that 2.5% of hours in January will have air temperatures below that value.

I looked at municipalities with a 2.5% January design temperature of equal to or less than -15°C, to approximate municipalities where air source heat pump users would require supplementary heating for some portion of the year. I found a correlation between January 2.5% design temperatures of equal to or less than 15°C and HDD values of greater than or equal to 4,000. Thus, municipalities with an HDD value of greater than or equal to 4,000 HDD serve as an approximation of the municipalities that would require supplementary heating for some portion of the year. As shown in Table 1, I classified municipalities in climate zones with 3,999 HDD or less as “Temperate”, and municipalities in climate zones with greater or equal to 4,000 HDD as “Cold”.

Table 1: Climate Zone Classification Methodology

Climate Zone	Heating Degree Days	Sample Municipalities	Classification in CIMS
CZ4	<3,000 HDD	Delta, New Westminster, Sechelt, Vancouver	Temperate
CZ5	3,000-3,999 HDD	Kamloops, Kelowna, Nanaimo, Power River	Temperate
CZ6	4,000-4,999 HDD	Fernie, Prince George, Revelstoke, Whistler	Cold
CZ7 A, CZ7 B	5,000-6,999 HDD	100 Mile House, Dawson Creek, Smithers, Fort Nelson	Cold
CZ8	>7,000 HDD	Smith River	Cold

Using publicly available data from the *Community Energy and Emissions Inventory (CEEI)* (Province of British Columbia, 2020a), I calculated the annual historical residential and commercial energy demand for all municipalities in Cold and Temperate regions of the province. I used these values to calculate updated heat load demand for commercial and residential buildings in each climate zone for use in CIMS.

A second consideration and reason for implementing climate zones within CIMS is the difference in heat pump system compatibility and efficiency between cold and temperate regions of B.C. At temperatures below -15° C, air source heat pumps require a supplementary heating source: commonly a gas furnace, electric baseboard, or wood heater. By disaggregating heating into the Cold and Temperate climate zones I was able to control which heat pump systems were available in each zone to better approximate primary and supplementary heating systems in the cold region of B.C. My approach will be discussed further in Section 3.2.2.

3.2.2 Residential & Commercial Sector Technology Updates

My technology updates were focused on space and water heating equipment servicing residential and commercial buildings. I updated the costs, efficiencies, and lifetimes of existing technologies and added new technologies where applicable. My primary source for this work was the U.S. Energy Information Administration's *Updated Buildings Sector Appliance and Equipment Costs and Efficiencies* (U.S. Energy Information Administration, 2023).

Table 2: Air Source Heat Pump Availability by Climate Zone

Heat Pump	Temperate	Cold
Electric ASHP	x	
Electric ASHP with Electric Backup		x
Electric ASHP with Gas Backup		x
Gas ASHP	x	x

Table 2 summarizes the air source heat pump technologies that I added to the residential and commercial building heating nodes in CIMS, as well as their availability according to climate zone. I parameterised the electric ASHP to represent a cold climate ASHP that can operate at greater than 100% efficiency down to -15°C. Since CIMS often combines different equipment models into an archetypal technology, I elected to represent improvements in electric ASHP efficiency exogenously rather than by adding more efficient versions of the technology in later years. So, electric ASHP efficiency starts at a COP of 1.9 in 2000 and rises over time to reach a COP of 3.5 by 2025. I made the electric ASHP available in residential and commercial buildings in the Temperate climate zone, where a supplementary heating source would not be necessary. In the Cold climate zone, I added two dual fuel heat pump technologies, both of which use an electric ASHP as their primary heating technology and either gas or electricity as a supplementary fuel. I excluded wood as a supplementary heating option to limit complexity and focus my study on the trade-off between gas and electricity, however it should be noted that wood stoves are another option for supplementary heat. I used publicly available climate and temperature data to assess the proportion of time that the temperature in B.C.'s Cold climate zone falls below -15°C. I assumed that supplementary heating would be necessary to meet 5% of total heating demand, and the other 95% would be met by the electric ASHP.

Finally, I added a fourth heat pump technology fueled by gas with a COP of 1.3 that is available in both climate zones. The gas ASHP is being promoted by gas utilities including Fortis. The question of whether gas air source heat pumps, which are more than double the capital cost of an electric ASHP, can be part of a low carbon future depends on the cost competitiveness of low carbon blending into the gas grid.

3.2.3 Low Carbon Gases Supply Curve and Node Development

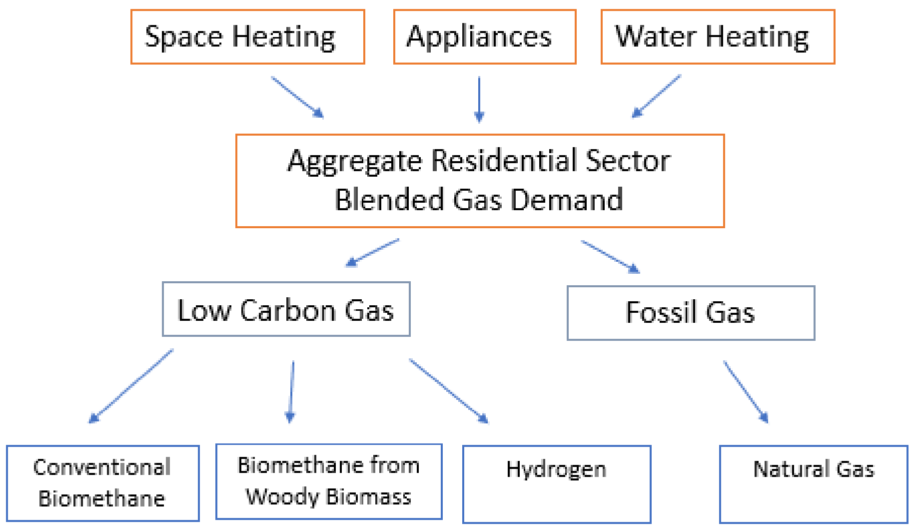
Blending low carbon gas into the gas system reduces the carbon intensity of gas delivery. To simulate this in CIMS, I conducted a literature review of supply quantity and cost estimates for biomethane fuel derived from key feedstocks (Appendix A). Based on my literature review, I limited the annual quantity of total biomethane availability to just over 90 PJ, with a price that rises until it reaches that quantity. This supply limit is based on biomethane feedstock availability in B.C. only. It is likely that with an increase in price, additional supply would be made available from alternative feedstocks or through imports from other jurisdictions. Table 3 shows the parameters I used for low carbon gases in CIMS, based on my literature review.

Table 3: CIMS Low Carbon Fuel Parameterization

Fuel	Year Available	Quantity Available	Raw Price	**Blending Allowance**
Conventional Biomethane	2010	Maximum annual supply of 9.65 PJ	Ranges from \$15/PJ to \$45/PJ depending on quantity supplied	No set maximum
Biomethane from Woody Biomass	2030	Maximum annual supply of 81.7 PJ per year	Fixed at \$28 per GJ	No set maximum
Hydrogen	2025	Quantity is determined endogenously in CIMS	Price is determined endogenously in CIMS	15% blending maximum

To allow low carbon gas to be blended into the gas system, I built new gas supply nodes that provided a blended gas fuel to the residential and commercial building sectors. The blended gas fuel nodes consist of a competition between fossil gas, conventional biomethane, biomethane from woody biomass, and hydrogen gas. The demand chain for blended gas fuel is depicted for the residential building sector in Figure 5. The same structure applies to the blended gas fuel supplying gas in the commercial building sector.

Figure 5: CIMS Demand Chain for Residential Sector Blended Gas Fuel



3.2.4 Gas System Fixed Costs

The third objective of my research involves determining how the cost of gaseous fuel delivery is impacted by various policy and technology scenarios. I simulated and parameterised a cost function for the delivery of gaseous fuel to represent how capital costs per service unit will change as buildings opt away from the gas grid. The CIMS model uses end user price forecasts from the Canada Energy Regulator (CER) for oil, natural gas, and electricity. The CER's price forecasts combine the variable commodity cost of fuel with the fixed costs of delivery and storage. To capture how the fixed cost of gas borne by gas users will change in response to climate policy and electric technology adoption, I used publicly available data to approximate the fixed and variable costs of fossil gas on a per GJ basis. I first used fossil gas billing rates from FortisBC to determine the variable and fixed cost of fossil gas that end users pay (FortisBC, 2023), and then used data from the *Community Energy and Emissions Inventory (CEEI)*

(Province of British Columbia, 2020a) to calculate the historical total fixed cost of delivering gaseous fuel to residential and commercial buildings in B.C. To ensure gas prices aligned with historical prices, I distinguished between fixed costs for gas servicing the residential sector from fixed costs for gas servicing the commercial sector. My approach to estimating gas system fixed costs yielded residential sector gas system costs of $153.8 million, and commercial sector gas system costs of $80.2 million for the year 2020. I used the same approach to calculate historical fixed cost values in five-year increments going back to 2000. Fixed costs assumptions for the years 2025 to 2050 depended on the scenario I modelled. The addition of gas system fixed costs to CIMS is critical to my research question as it allows me to simulate the impacts of declining gas demand on end user gas prices and to draw conclusions as to possible futures of the gas system.

3.2.5 Electricity Sector Price Feedbacks

Unlike other Canadian provinces, B.C.'s electricity system uses mainly hydro power for both base and peak loads. Since hydro power is dispatchable, B.C.'s generation capacity can be adjusted to match electricity demand. According to BC Hydro's Integrated Resource Plan, future increases in electricity generation capacity are likely to come from wind power, which could be absorbed into the grid whenever it is generated without a significant impact on the cost of electricity generation. However, transmission capacity – the ability to get electricity from the point of generation to end users – would be strained by an increase in electricity demand, particularly in south-western B.C. where most of the province's population resides. Improving transmission capacity could be achieved by building additional transmission infrastructure, or by investing in electricity storage to meet peak demand. A range of storage options exist including load shifting using electric vehicles, batteries, heat storage, and hydrogen storage. Investments in these options would increase average prices slightly.

I did not model the cost impacts of increased transmission capacity or electricity storage that would assist in providing electricity to end users at times of peak and shoulder demand. Instead, I estimated an increase in electricity rates to build price feedbacks into my work. The version of CIMS I used does not capture electricity supply and price feedbacks endogenously, so I adjusted the ratio between base, shoulder, and peak load after 2025. As a result, electricity prices increased by 10% to 20% from 2025 to 2050 compared to prices without this adjustment. This price rise corresponds to an increase of approximately $0.02/kWh, varying slightly by sector and scenario.

3.3 Calibration

I calibrated CIMS against Canada's National Inventory Report and the Canadian Energy Use Database to ensure the historical accuracy of emissions and energy demand. Emissions and energy demand outputs for the residential and commercial building sector are reported in Table 4.

Table 4: Comparison of CIMS and CEUD Emissions and Energy by Sector

	2000			2010			2019/2020		
	CIMS	CEUD	% Diff.	CIMS	CEUD	% Diff.	CIMS	CEUD	% Diff.
Commercial Sector Energy Use (PJ)	119.4	120.8	-1%	107.3	115.9	-7%	101.2	120.2	-16%
Commercial Sector Emissions (Mt CO2e)	3.7	3.6	2%	2.7	2.8	-5%	2.7	2.8	-6%
Commercial Sector Gas Energy Use (PJ)	62.5	60.9	3%	48.2	49.9	-3%	52.7	52.7	0%
Commercial Sector Gas Emissions (Mt CO2e)	3.2	3.1	2%	2.4	2.6	-7%	2.5	2.6	-2%
Residential Sector Energy Use (PJ)	162	157	3%	138	143	-3%	154	158	-3%
Residential Sector Emissions (Mt CO2e)	4.6	4.8	-4%	3.4	3.7	-8%	4.0	4.2	-3%
Residential Sector Gas Energy Use (PJ)	83.1	78.7	6%	64.5	67.2	-4%	81.4	79.5	2%
Residential Sector Gas Emissions (Mt CO2e)	4.2	4.0	6%	3.2	3.4	-6%	3.9	3.9	0%

4.0 Scenarios

I simulated several scenarios that represent existing, announced, and net zero policies under key sensitivities relating to the future of the gas grid. I assessed decarbonization pathways, emission impacts, and energy costs in each scenario modelled. Scenarios are summarized in Table 5.

4.1 Reference Scenario

The reference case, *Ref_BC*, represents a baseline scenario for emissions and energy demand in B.C.'s residential and commercial building sector. This scenario simulates existing conditions in the residential and commercial building sector and serves as a point of comparison for additional scenarios that I simulated. In *Ref_BC* , a carbon tax is levied on fuels listed in Schedule 1 of B.C.'s *Carbon Tax Act*, including gasoline, light and heavy fuel oil, and natural gas (Carbon Tax Act, 2008). Gas users pay a carbon levy per unit of fossil gas, but do not pay a tax on low carbon gases blended into the grid. The second policy simulated in my *Ref_BC* scenario is a set of rebates targeting electric heat pump technologies for space and water heating systems in residential buildings. There are several rebate programs available through BC Hydro, CleanBC, and the federal Greener Homes grant program with amounts that vary depending on the system installed and the existing fuel source in a building (BC Hydro, 2023).

In my *Ref_BC* scenario I make several assumptions regarding gas system growth to 2050. These assumptions are captured via the system wide fixed costs that are simulated in CIMS. I assume that the gas system grows at a slower rate after 2020 until 2035, at which point there is no new investment in system growth, but the existing system continues to be maintained. This assumption aligns with my model results which do not project any growth in gas demand after 2020. In 2035, a 3% amortization rate on existing capital investment is applied until 2050, causing total fixed cost to decline annually. The rate of declining growth investment as well as depreciation rates were based on values reported by Fortis in the utility's *Application for Approval of a Multi-Year Rate Plan for 2020 through 2024* (FortisBC Energy Inc., 2019).

4.2 Announced Policy Scenarios

For my study I modelled B.C.'s announced policies in two scenarios, which differed according to my assumptions of how the gas system would evolve. My first announced policy scenario, the *Anncd Pol_Maintained Grid* scenario, used the same assumptions regarding the fixed cost as in my *BC_Ref* scenario, where the gas system continues to be maintained but does not grow after 2035. My second announced policy scenario, *Anncd Pol_Pruned Grid,* considers an alternative future where utility costs do not favour continued service delivery, and the utility decommissions a portion of the gas system as a cost minimizing approach. There are many possibilities for how the gas grid could be pruned, each depending on costs to the utility. For example, cold regions in B.C. are less densely populated and have longer distances between urban centres, so gas system transmission costs may be higher. Alternatively, temperate regions in B.C. may be better suited to adopt heat pumps, leading more customers in these regions to move away from gas sooner. The costs associated with and likelihood of each of these alternatives is challenging to accurately estimate.

I developed assumptions for the pruned scenario that I modeled in my study after reviewing the results of my *Anncd Pol_Maintained Grid* scenario. To assess whether a dramatic cut in system wide costs would be enough to prevent a utility death spiral from transpiring, I reduced gas system wide fixed costs by 50% in 2030 and did not simulate any gas system growth in subsequent years. I also made all gas fueled heating technology unavailable in the Cold climate zone based on preliminary results indicating that the demand in the province's Cold zone would decline more than in the Temperate zone. The resulting model run represents a scenario where after 2030 the gas system has been fully decommissioned in B.C.'s cold zone and serves a reduced customer base in B.C.'s temperate zone.

Both scenarios modelled the same set of announced policies. In 2018, the Province released the *CleanBC Plan* to lay out its approach for achieving emission reduction targets while supporting the growth of a clean economy (CleanBC, 2021). The most recent version of the plan, the *CleanBC Roadmap to 2030*, lists policies and actions intended to achieve the province's 2030 emissions target of 40% below 2007 levels. The *CleanBC Roadmap to 2030* includes two policies intended to reduce emissions from residential and commercial building heat. As of 2023, these policies remain under development and have not been implemented, and therefore are modelled as part of my announced policy scenarios.

The first policy is an equipment standard requiring that "by 2030, and earlier where feasible, [….] all new space and water heating equipment sold and installed in B.C. will be at least 100% efficient" (CleanBC, 2021). I modelled the announced equipment standard by making space and water heating technologies that were less than 100% efficient unavailable by the year 2030 – effectively banning the installing of new gas or oil furnaces, HVAC systems, and water heaters. Instead, from 2030 to 2050, residential and commercial buildings in my simulation may only install space and water equipment powered by either an electric baseboard, an electric heat pump, or a gas heat pump.

The second policy is the *Greenhouse Gas Reduction Standard* (GGRS). The GGRS is an emissions cap on fossil gas that shifts the responsibility of reducing residential, commercial, and industrial customer emissions onto the utilities themselves. The Province announced that the cap would be set at 6.1Mt of CO2e annually by 2030, and that gas utilities will have flexibility in how they meet the target (CleanBC, 2021). Compliance mechanisms include capitalising on existing grid infrastructure by blending low carbon gases into the grid or by pursuing energy efficiency measures (CleanBC, 2021).

I simulated the emissions cap required by the GGRS by levying an additional carbon tax onto fossil gas. While the GGRS applies to residential, commercial, *and* industrial buildings, industrial end uses of gas are beyond the scope of my research. As a result, I used only the proportion of the 6.1Mt cap on emissions that would apply to the residential and commercial building sector as the building sector cap on fossil gas emissions. I calculated this value to be 4.5Mt CO2e, and applied additional carbon pricing to fossil gas used in residential and commercial buildings to reduce emissions in line with the cap. The carbon tax schedule followed the announced rate until 2025, when I doubled the announced rate so that the tax equaled $175/tCO2e in 2025 and $290/tCO2e in 2030.[2] There has been no announcement regarding a decline in the emission cap associated with the GGRS beyond 2030, and so from 2030 to 2050 the carbon price modelled was held constant at $290/tCO2e.

4.3 Net Zero Scenarios

My announced policy scenarios focus on policy to reach B.C.'s existing GHG targets, including an 80% reduction in emissions by 2050. However, many jurisdictions around the world are targeting ambitious net zero by 2050 targets, and it is plausible that a climate sincere provincial government would also adopt this target. I ran two additional scenarios that modelled B.C.'s announced policies while reflecting stringent carbon pricing that would achieve net zero emissions by 2050. I based my carbon price

[2] All carbon prices are in $2020 CAD

trajectory on modelling done for Stanford University's Energy Modelling Forum (EMF 37), which uses a carbon price that rises to \$545/t CO_2e by 2050.

Table 5: Scenario Overview

<table>
<tr><th>Scenario</th><th>Sensitivities/Assumptions</th><th>Policies Represented</th></tr>
<tr><td>Reference Scenario (Ref_BC)</td><td>Maintained Gas Grid, with no system growth after 2035</td><td>- B.C. Carbon Tax
- Subsidy on residential space ($3000) and water ($1000) air source heat pumps, in place from 2020-2050</td></tr>
<tr><td>Maintained Gas System: Announced Policy Case (Anncd Pol_Maintained Grid)</td><td>Maintained Gas Grid, with no system growth after 2035.</td><td rowspan="2">Same as in Ref_BC, in addition to:
- Equipment standard requiring new space and water heating equipment to be ≥ 100% efficient by 2030.
- A 4.5Mt CO2e cap on emissions from fossil gas distributed to residential and commercial buildings, achieved through additional carbon pricing</td></tr>
<tr><td>Pruned Gas System: Announced Policy Case (Anncd Pol_Pruned Grid)</td><td>Pruned Gas Grid. System wide fixed costs fall by 50% in 2030 as grid is partially decommissioned</td></tr>
<tr><td>Maintained Gas System: Net Zero Scenario (NZ_Maintained Grid)</td><td>Maintained Gas Grid, with no system growth after 2035.</td><td rowspan="2">Same as above, with a more stringent carbon price that rises to $545/t CO2e by 2050</td></tr>
<tr><td>Pruned Gas System: Net Zero Scenario (NZ_Pruned Grid)</td><td>Pruned Gas Grid. System wide fixed costs fall by 50% in 2030 as grid is partially decommissioned</td></tr>
</table>

5.0 Results and Discussion

The purpose of this study was to assess how B.C. could reduce emissions from building heat to align with announced GHG targets, and to explore the possible impacts of heat decarbonization on the province's gas system. My analysis compares several sets of policy and gas system scenarios with one reference case to assess technological change, energy change, and emissions. My results focus specifically on the difference between scenarios in the years 2030 and 2050.

5.1 Emission Results

5.1.1 Building Sector Emissions

At the time of writing, the Province of B.C. is working towards legislated targets to reduce GHG emissions by 40% by 2030, 60% by 2040, and 80% by 2050. While these are economy wide targets, I used them as a benchmark against which to assess emission reductions in the building sector in each of my scenarios. The results of my study indicate that under existing policies (*Ref_BC*), building sector emissions in B.C. will fall short of all three of these targets, and that the emissions gap will widen over time (Table 6). However, with the additional policies modelled in the *Anncd Pol_Maintained Grid* and *Anncd Pol_Pruned Grid* scenarios, GHG emissions from the building sector will meet or exceed provincial targets (Table 6). Both announced policy scenarios achieve 2050 GHG reductions of greater than or equal to 95% of 2007 emissions. The remaining GHG reductions could be achieved by a higher carbon tax to drive emissions to zero (*NZ_Maintained Grid, NZ_Pruned Grid)*. Conversely, true offsets, such as direct air capture with carbon storage are also a possibility.

Table 6: Emission Results by Scenario

	2030 % Reduction	**2040 % Reduction**	**2050 % Reduction**
Provincial GHG Target (from base year of 2007)	40%	60%	80%
Ref_BC	24%	45%	55%
Anncd Pol_Maintained Grid	41%	76%	95%
Anncd Pol_ Pruned Grid	51%	81%	96%
NZ_ Maintained Grid	42%	77%	99%
NZ_Pruned Grid	52%	82%	99%

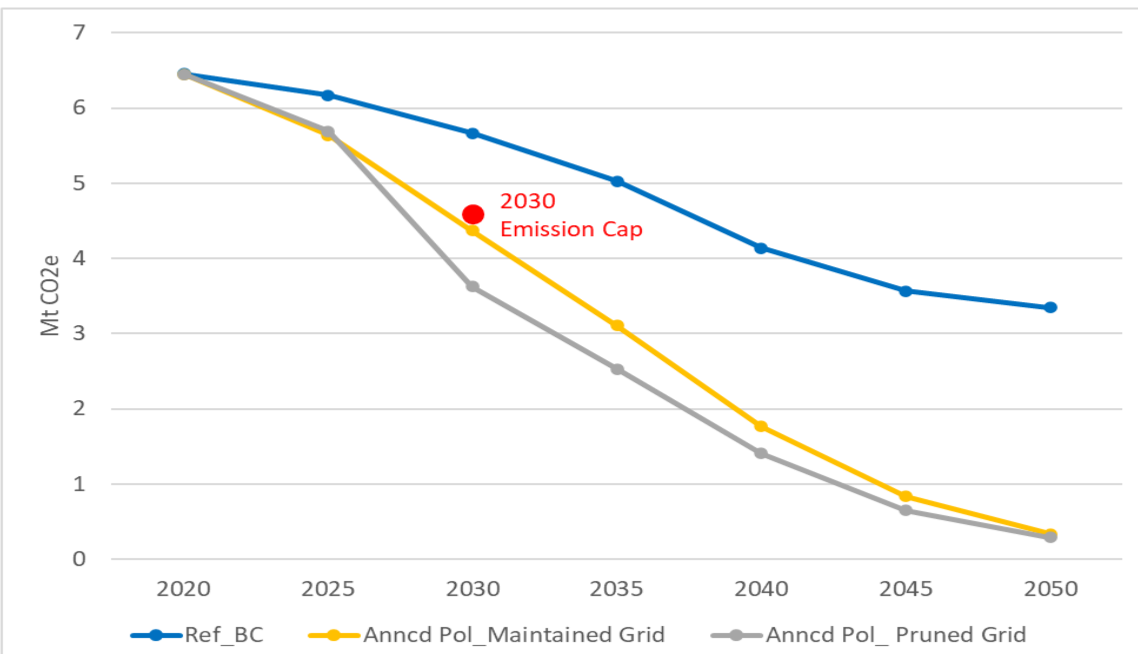
5.1.2 Building Sector Gas Emissions

The results I present in the following section highlight the impact of existing and announced policies on emissions from gas in B.C.'s residential and commercial building sector. I focus my analysis solely on building emissions from gas, as gas constitutes

99% of emissions from commercial and residential buildings after 2020 in all of my scenarios.

In both announced policy scenarios if the Province of B.C. implements announced and existing policies, building sector gas emissions are projected to decline to below 4.5 MtCO2e in 2030, and reach near zero by 2050 (0.3Mt C02e). Figure 6 shows building sector emissions from gas in my reference case and announced policy scenarios. While not included in Figure 6, the emission trajectory for my net zero scenarios follows the trajectory of the announced policy scenario but diverges after 2045 to reach 0.06 Mt CO2e by 2050 (99% reduction). In the reference scenario (*Ref_BC*), existing policies result in a 12% decrease in emissions from 2020 to 2030, and a 48% decrease in emissions from 2020 to 2050, falling short of the 4.5 Mt CO2e cap established by the GGRS. The principal driver of emission reductions under *Ref_BC* is the announced carbon price. As the carbon price rises it raises the end user price of fossil gas compared to alternatives, making fuel switching to low carbon heating more attractive.

Figure 6: Building Sector Emissions from Gas by Scenario Modelled

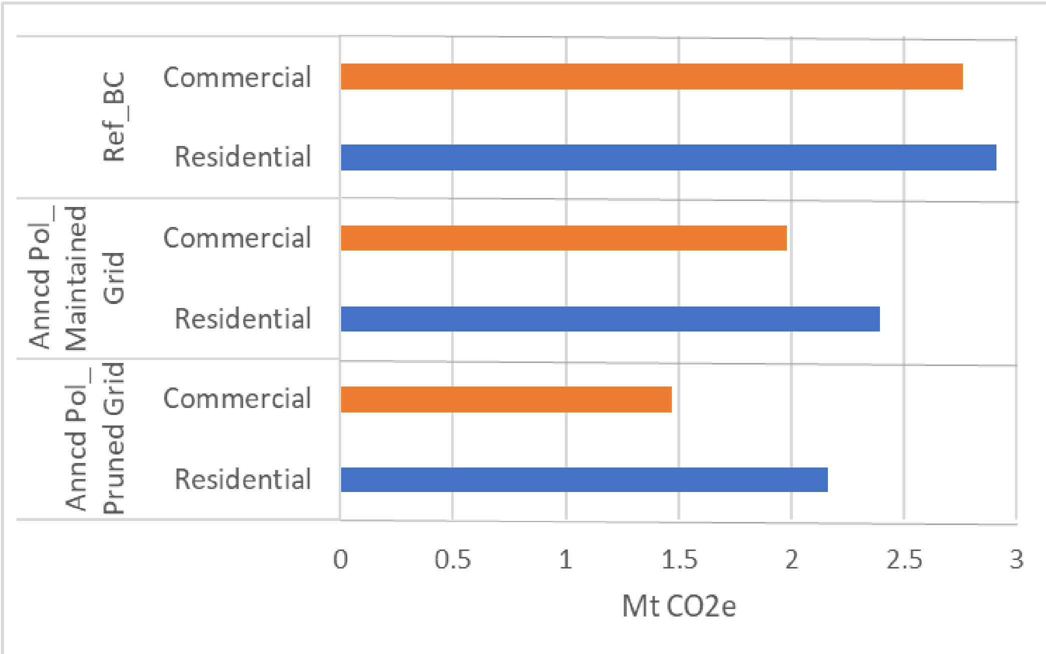


In contrast, both announced policy scenarios (*Anncd Pol_Maintained Grid* and *Anncd Pol_Pruned Grid*) achieve emission reductions in line with the province's emission targets (Figure 6). In these scenarios, I subjected the residential and commercial sector to a carbon price of more than double that of the *Ref_BC* scenario to achieve sectoral fossil gas emissions of equal to or less than 4.5 Mt CO2e. Carbon pricing was set to reach $175/t CO2e in 2025 and $290/t CO2e from 2030 to 2050. The impact of additional carbon pricing on fossil gas fuel as well as an equipment standard banning the installation of heating equipment less than 100% efficient resulted in a sharp decline in emissions by 2030. In the *Anncd Pol_Maintained Grid* scenario, gas emissions from buildings reach 4.4 Mt CO2e in 2030, representing a 41% decrease from a 2007 baseline. By 2050, emissions in this scenario had fallen 95% from 2007 levels to 0.3 Mt CO2e.

The *Anncd Pol_Pruned Grid* scenario represents a dramatically different future where the gas distribution system servicing B.C.'s Cold climate zone is decommissioned by 2030, perhaps due to a phased exit by the gas utility. As expected, the accelerated shift away from gas in this scenario results in a steeper initial decline in emissions than was seen in the *Anncd Pol_Maintained Grid* (Figure 6). Gas emissions fall an additional 10% in 2030 compared to the *Anncd Pol_Maintained Grid* and converge with emissions in the maintained grid scenario towards 2050. One note here is that I held the carbon price constant between the two announced policy scenarios and adjusted gas system assumptions only. Therefore, if low-cost emission reductions were a policy priority, the carbon price modelled in the *Anncd Pol_Pruned Grid* scenario could be adjusted downward so that the 4.5Mt CO2e sectoral cap is achieved at a lower cost of abatement.

The impact of announced policies becomes apparent in 2030. Figure 7 shows forecasted 2030 emissions in each scenario for the residential and commercial building sectors. In the *Ref_BC* scenario, gas emissions from both residential and commercial buildings are just below 3Mt CO2e each. In both announced policy scenarios emissions fall, but as expected the *Anncd Pol_Pruned Grid* projects higher abatement than the *Anncd Pol_Maintained Grid* scenario. Looking at the difference in results between sectors, both announced policy scenarios project that gas emissions from the commercial building sector will fall more steeply than gas emissions from the residential building sector by the year 2030. This is due to the difference in the end user price of electricity between the two sectors. CIMS electricity prices are based on projections from the Current Policies case of the CER's Energy Future report. In 2030, electricity prices in CIMS are $35.35/GJ in the residential sector and $29.74/GJ in the commercial sector. The lower relative price of electricity in the commercial sector results in a lower life cycle cost for commercial electric heating equipment than in the residential sector, inducing a higher rate of initial electric heat adoption in the commercial sector than the residential sector, and explaining the steeper decline in commercial sector emissions.

Figure 7: 2030 Emissions from Gas by Sector and Scenario



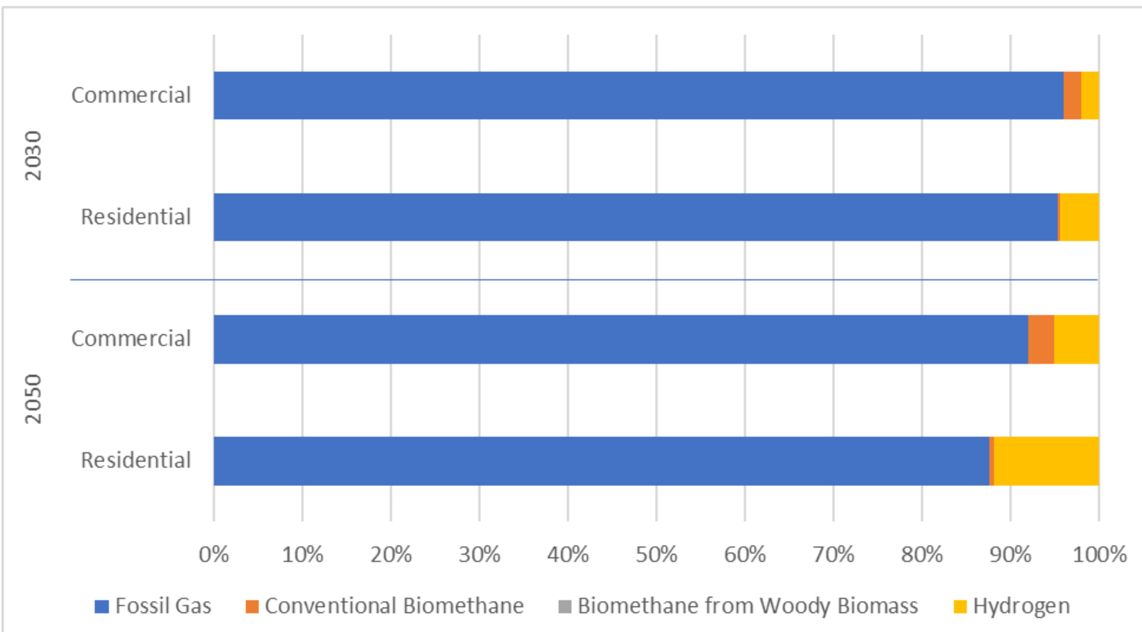
5.2 Fuel and Technology Pathways

5.2.1 Low Carbon Gas Blending

My first research objective entailed identifying technology, policy, and fuel pathways to reduce building sector emissions from heat. The results I present in section 5.1 indicate that it would be possible for the Province of B.C. to reduce building sector emissions in line with its 2030 and 2050 emission reduction targets, and that the 2030 cap on emissions from gas utilities could be achieved under both the *Anncd Pol_Maintained Grid* and *Anncd Pol_Pruned Grid* scenarios. The results I present in section 5.2 highlight the specific pathways that make those GHG reductions possible.

My results indicate that electrification will be a key driver of building heat decarbonization, and that low carbon gases have a minimal role to play. Despite assertions from gas proponents that low carbon gas blending is a cost-effective approach to decarbonizing the gas system, my results show that biomethane and hydrogen are not able to compete against the price of fossil gas unless a higher carbon price is levied. Figure 8 shows blending rates in 2030 and 2050 in my announced policy scenarios under a carbon tax of $290/t CO2e. To understand gas blending results, I compared the variable and tax component of each gas type and excluded fixed costs. Fixed costs are applied to all gases blended into the system, but the carbon tax is applied only to fossil gas. Of the three low carbon gases I modeled, hydrogen is most able to compete against fossil gas. In the residential sector, 4% of the grid is comprised of hydrogen gas in 2030, and that percentage rises to 12% by 2050. The average life cycle cost (LCC) of hydrogen is $30/GJ compared to $22/GJ for fossil gas after 2030. In contrast, the residential gas grid is comprised of less than 1% conventional biomethane and 0% biomethane from woody biomass. These low carbon gases have higher LCCs (upwards of $35/GJ and $55/GJ respectively) and are not able to compete against lower cost alternatives.

Figure 8: Grid System Gas Blend in Announced Policy Scenarios

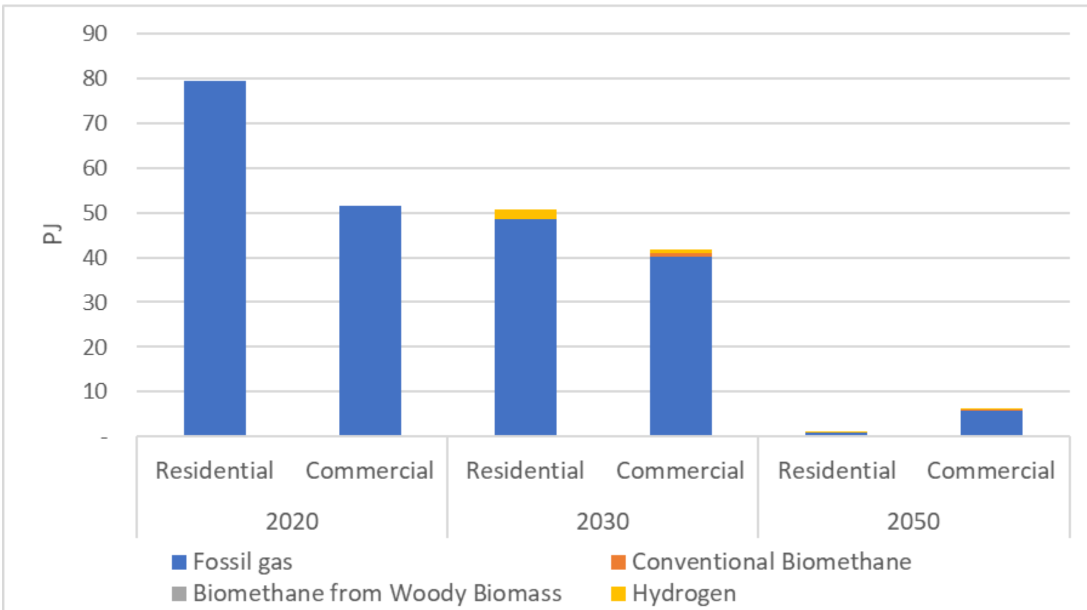


For additional details on the impact of carbon pricing levied onto fossil gas in my announced policy scenarios, see Appendix B which includes the variable, fixed, and tax portion of end user gas prices in both the residential and commercial building sector.

While the relative proportion of low carbon gas in the grid rises by 2050, on an absolute basis the total quantity of low carbon gases blended into the grid declines after 2030 due to a reduction in total pipeline utilization. In the *Anncd Pol_Maintained Grid* scenario, just over 2PJ of hydrogen is blended into the residential gas system in 2030

(4% of total throughput). In 2050, that amount declines to 0.1PJ of hydrogen (12% of throughput). For context, 0.1PJ of hydrogen blended into the gas grid in 2020 would constitute only 0.12% of total throughput. So, while blending rates appear to increase as fossil gas price rises towards 2050, the absolute quantity of low carbon gas blending falls (Figure 9)

Figure 9: Absolute Quantity of Gas Throughput by Gas Type



When building the conventional biomethane supply curve that CIMS uses to determine the price and quantity of biomethane that is blended into the grid, I established a 9.65PJ annual maximum supply of conventional biomethane, of which 2.1PJ is low cost. I also established a maximum annual availability of just below 81.7PJ of biomethane derived from woody biomass, available after 2030. My results show that annual demand for conventional biomethane after 2020 is less than the total amount of low cost conventional biomethane gas that is available, and that the annual demand for biomethane derived from woody biomass is negligible. This leaves nearly 8PJ of conventional biomethane and 81.7PJ of biomethane from woody biomass available as low carbon fuel for use in other sectors or jurisdictions.

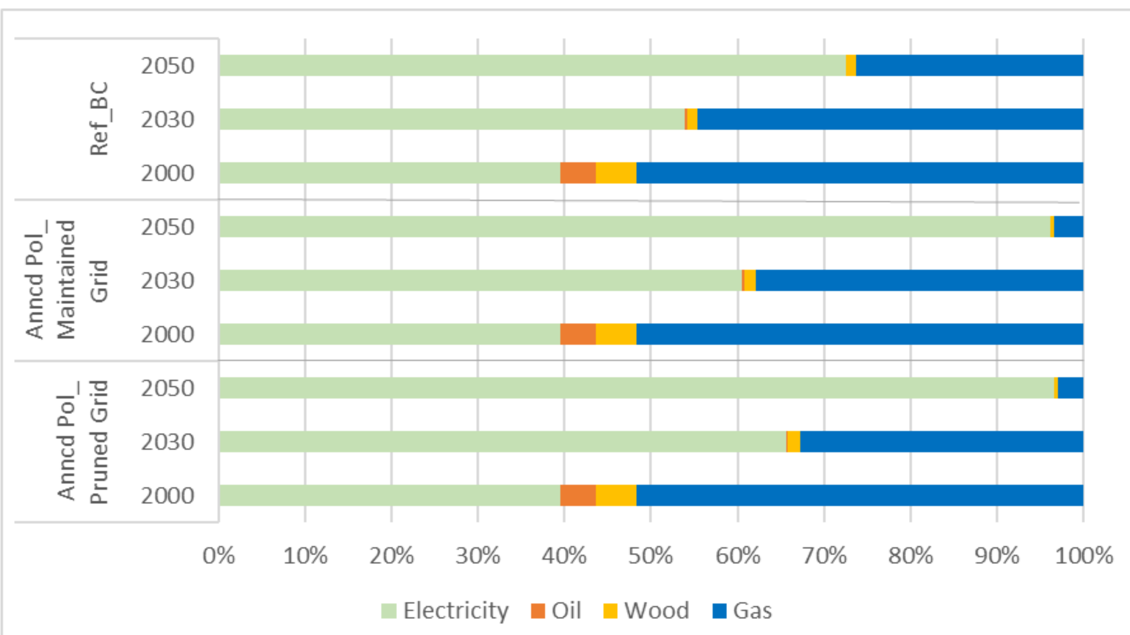
Despite some blending of low carbon gas into the grid, my results suggest that in 2050 fossil gas will still comprise the majority share of gas, and that a higher carbon price would be needed for low carbon gas to drive any significant GHG reductions from gas. That possibility is explored further in section 5.4.

5.2.2 Electrification

My results suggest that low carbon fuel blending will not play a significant role in decarbonizing building heat, and that fuel switching to electricity will drive the carbon reductions necessary for B.C. to align emissions from the building sector and fossil gas distribution system with provincial GHG targets.

A shift in the energy used to generate building heat over time is depicted in Figure 10. In the *Ref_BC* scenario, electricity rises from 39% of total energy for heating in 2000 to 72% in 2050. The addition of announced policies accelerates the shift to electricity, with 96% of energy for heating being provided by electricity in both announced policy scenarios in 2050. In both announced policy scenarios, electricity demand increases by 85% in 2050 relative to 2020. This shift towards electricity occurs in my modelling even with electricity price feedbacks that forecast electricity costs rising by 10-20%, to represent spending on electricity storage or additional transmission capacity. Both policy scenarios maintain relatively stable average heating costs on a $/GJ of heat provided basis in both climate regions relative to the reference.

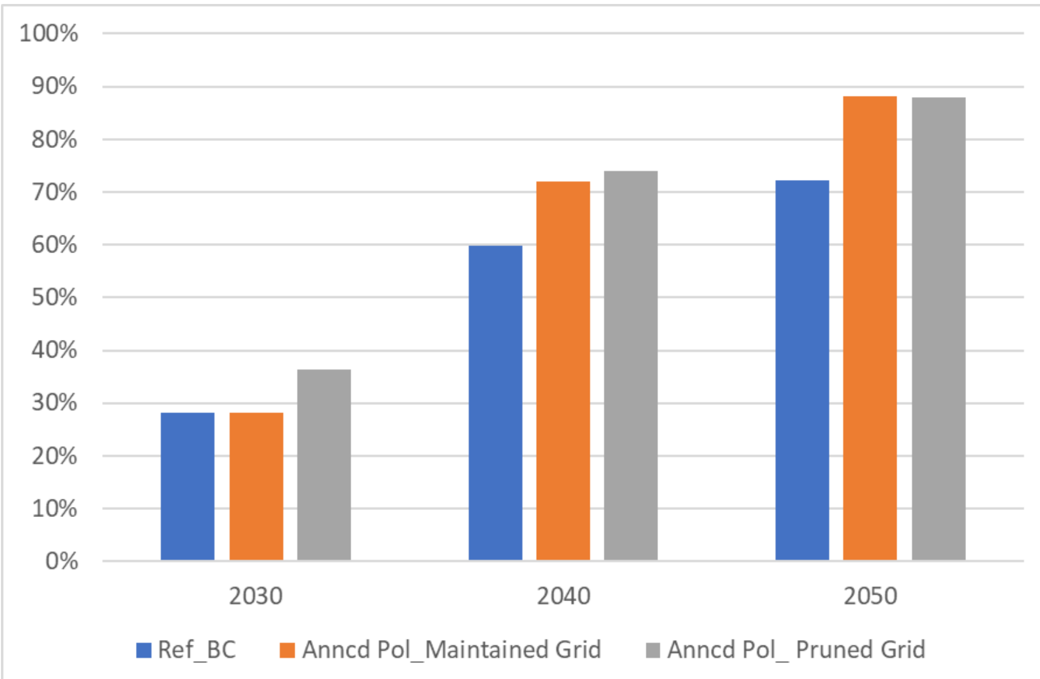
Figure 10: Heat by Energy Source in B.C. Buildings



Residential Sector Technology Results

In the Residential building sector, electric air source heat pumps become the dominant space heating technology in both announced policy scenarios. Figure 11 shows the proportion of total heat demand provided by ASHP across B.C. Both announced policy scenarios accelerate the uptake of ASHP when compared to the reference scenario.

Figure 11: Residential Heat Load Provided by ASHP



There is a distinction between space heating technology stock in the Cold and Temperate zones of B.C. In both announced policy cases, electric ASHPs in B.C.'s Temperate zone provide more than 85% of residential space heating demand in 2050. However, electric air source heat pumps in the Cold zone require a supplementary heating source that adds to the capital cost of the heating equipment. The electric ASHP with a back up electric heating system provides the majority (62%) of residential Cold zone space heating load in 2050. The remaining heating demand is met by conventional electric heating such as an electric baseboard. My results indicate that in the *Anncd Pol_Maintained Grid* scenario, the life cycle cost of the electric ASHP technology with a supplementary gas furnace is too high to compete against other heating options and will play a negligible role in heating B.C.'s Cold zone. While about 38% of heat demand in B.C.'s Cold zone will be provided by electric baseboard, in B.C.'s Temperate zone there will be virtually no role for conventional electric heating, and instead the majority of heating services will be provided by electric ASHP. The difference in heating technology between climate zones is driven by the difference in life cycle costs between technologies available in each zone. Dual fuel electric ASHP have higher life cycle costs than single fuel AHSP, and electric ASHP are less competitive against electric baseboards in the Cold zone than the Temperate zone.

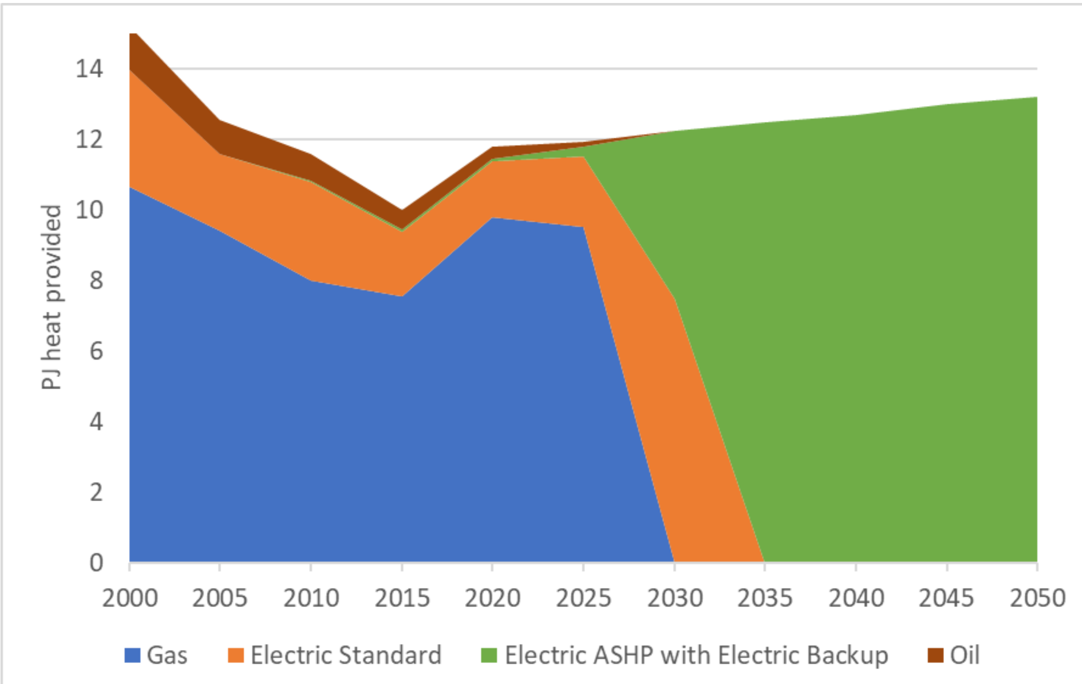
Lastly, the 100% efficient equipment standard I applied in my *Anncd Pol_Maintained Grid* and *Anncd Pol_ Pruned Grid* allowed gas heat pumps to continue to be installed after 2030. My results show that gas heat pumps will play a negligible role in space heating technology, largely due to the capital costs of gas heat pumps being more than double that of electric ASHP. To test the sensitivity of demand for gas heat pumps relative to price, I ran a sensitivity assessing the effect of FortisBC Energy Inc.'s rebate on gas heat pump adoption. The results of this sensitivity indicated that even with a $3,000 rebate applied to the capital cost of gas heat pumps, gas heat pumps remained an uncompetitive heating technology.

Commercial Sector Technology Results

In the *Ref_BC* scenario my results suggest that fossil gas will continue to provide most of the fuel for heat in commercial buildings in B.C.'s Cold and Temperate zones until 2035. In temperate regions, ASHP become cost competitive after 2035, and provide 41% of heat by the year 2050. In cold regions, the higher capital cost associated with electric air source heat pump systems that have supplementary electric or gas systems limits uptake. Instead, the reference scenario suggests that by 2050, commercial buildings in cold regions will continue to be heated largely by gas (90% of Cold zone heat).

The results differ dramatically in the announced policy scenarios. In the Temperate zone, electric ASHP begin to replace gas and standard electric equipment starting in 2030. Unlike in the reference scenario, in the *Anncd Pol_Maintained Grid* scenario electric ASHP uptake is not limited to just Temperate zones. In the Cold zone, new stock is dominated by an electric ASHP with a supplementary standard electric system that out-competes an electric ASHP with a supplementary gas system and a gas ASHP. This finding aligns with the heating stock results from the Residential sector. However, remaining gas heating stock continues to provide about 50% of Cold zone space heating until 2045 when the majority of gas heating equipment is retired. The *Anncd Pol_Pruned Grid* scenario shows similar results in the Temperate climate zone but differs in the Cold zone where an electric ASHP with supplementary electric heating provides all space heating services by 2050 due to the decommissioning of the gas system (Figure 12).

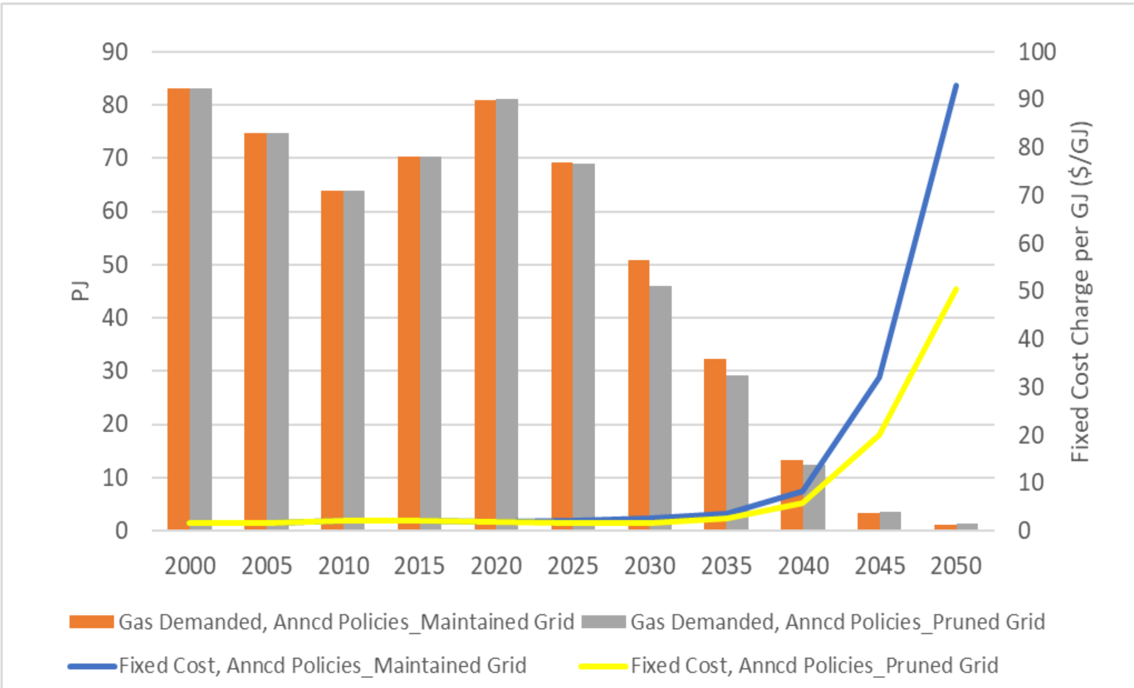
Figure 12: Commercial Sector Space Heating by Technology in B.C.'s Cold Zone under Anncd Pol_Pruned Grid Scenario



5.3 Gas System Viability and End User Gas Prices

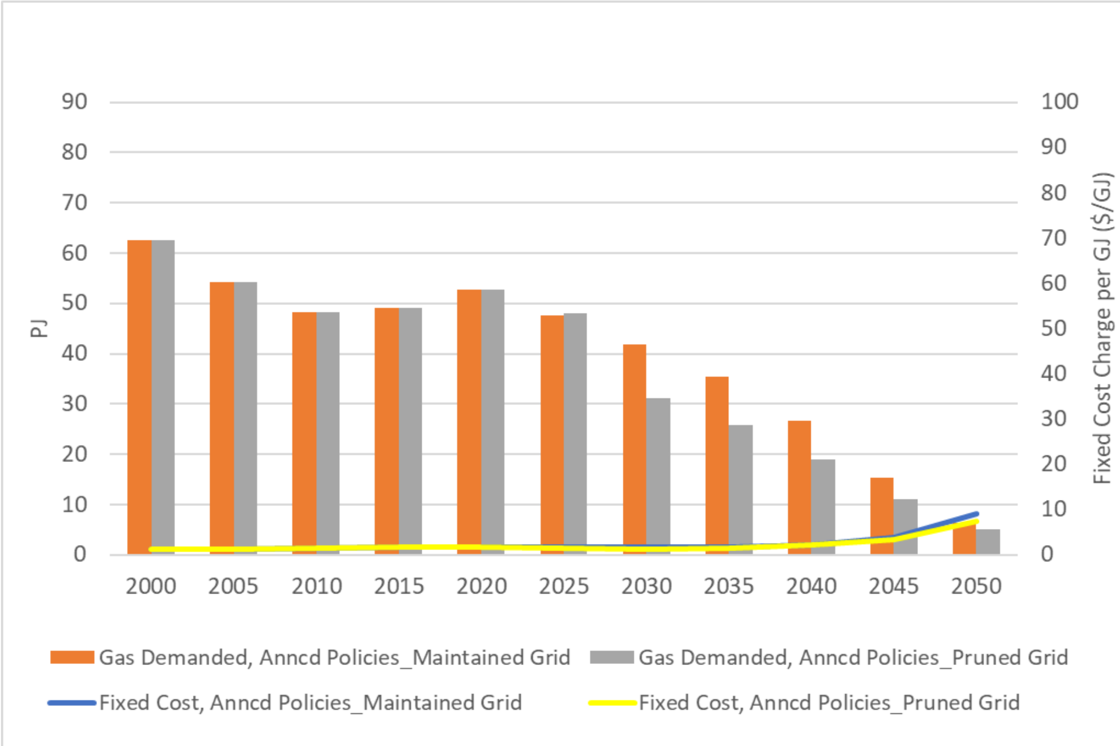
The second objective of my research involved assessing the impacts of building heat decarbonization on gas utilities and the cost of gaseous fuel delivery. My results suggest that announced policies drive customer costs that favour a shift to electric heating. The shift to electricity is large enough to threaten the viability of the gas system. As heat is increasingly electrified in both the *Anncd Pol_Maintained Grid* and *Anncd Pol_Pruned Grid* scenario, the total fixed cost of the gas system must be recouped from fewer and fewer end users of gas. End user gas prices, in particular the fixed cost component of gas, quickly become unaffordable. The relationship between total gas demanded and fixed cost in the residential sector is depicted in Figure 13. As gas demand falls, the fixed charge per GJ of gas delivered rises from under $2 before 2020 to $93 in 2050 in the maintained grid scenario, and $50 in the pruned grid scenario. The *Anncd Pol_Pruned Grid* scenario is associated with lower per GJ fixed costs than the *Anncd Pol_Maintained Grid* scenario because of the lower total fixed cost simulated in this scenario.

Figure 13: Total Gas Demand and Fixed Cost per GJ in B.C.'s Residential Building Sector



Fixed costs also rise in the commercial sector, but to a much lesser degree (Figure 14). The fixed charge per GJ of gas delivered rises from under $1.5 before 2020 to $9 in 2050 in the maintained grid scenario, and $7 in the pruned grid scenario. The less dramatic impact on fixed costs seen in the commercial sector is a product of the much lower total fixed cost I calculated in that sector. It was necessary for me to simulate the gas system servicing the residential and commercial sectors separately to correctly calibrate energy price differences between the residential and commercial sectors. In reality, these sectors are serviced by the same gas network, and the impact of a reduction in demand on system wide fixed costs would be shared between residential and commercial gas users.

Figure 14: Total Gas Demand and Fixed Cost per GJ in B.C.'s Commercial building sector



The shift to electricity as a heating fuel and the impact of announced decarbonization policy causes *each cost component* of gas to rise in the next few decades. The commodity cost of gas rises based on projections from the CER, as well as from the impacts of blending higher cost hydrogen and biomethane into the gas fuel blend. The component of gas price associated with the carbon tax also rises, particularly in my announced policy scenarios where the carbon price stringency was more than doubled from 2025 onwards (see Appendix B). Lastly, the fixed cost component of gas has the largest impact on gas prices. As end users of gas switch to electricity for building heating, the total fixed costs of the gas system are borne by fewer end users, and the competitive position of gaseous fuel is undermined. Table 7 shows forecasted annual household gas bills for a residential household using 80GJ of gas per year for space and water heating. The addition of B.C.'s announced policies raises gas bills by 45-51% in 2030, and 300-600% in 2050, relative to a reference scenario. The additional rate impacts seen under the maintained grid scenario suggest that delaying gas system decommissioning may adversely impact end users of gas. However, proactively decommissioning underutilized portions of the grid, as was simulated in the *Anncd*

Pol_Pruned Grid, reduces household gas bills compared to a scenario where the entirety of the gas system is maintained amidst declining utilization rates.

Table 7: Forecasted Annual Household Gas Bills, 2020-2050

		Annual Gas Costs ($)			% Increase from *Ref_BC*
		Variable Cost *	Fixed Cost	Total Cost	Total Cost
2030	*Ref_BC*	$1,143	$179	$1,322	
	Anncd Pol_Maintained Grid & NZ_Maintained Grid	$1,783	$208	$1,991	51%
	Anncd Pol_Pruned Grid & NZ_Pruned Grid	$1,783	$133	$1,916	45%
2050	*Ref_BC*	$1,092	$405	$1,498	
	Anncd Pol_Maintained Grid	$1,786	$7,448	$9,234	517%
	Anncd Pol_Pruned Grid	$1,786	$4,032	$5,818	289%
	NZ_Maintained Grid	$2,754	$7,883	$10,638	610%
	NZ_Pruned Grid	$2,754	$4,349	$7,103	374%

*includes carbon price. Note – numbers may not add to total due to rounding.

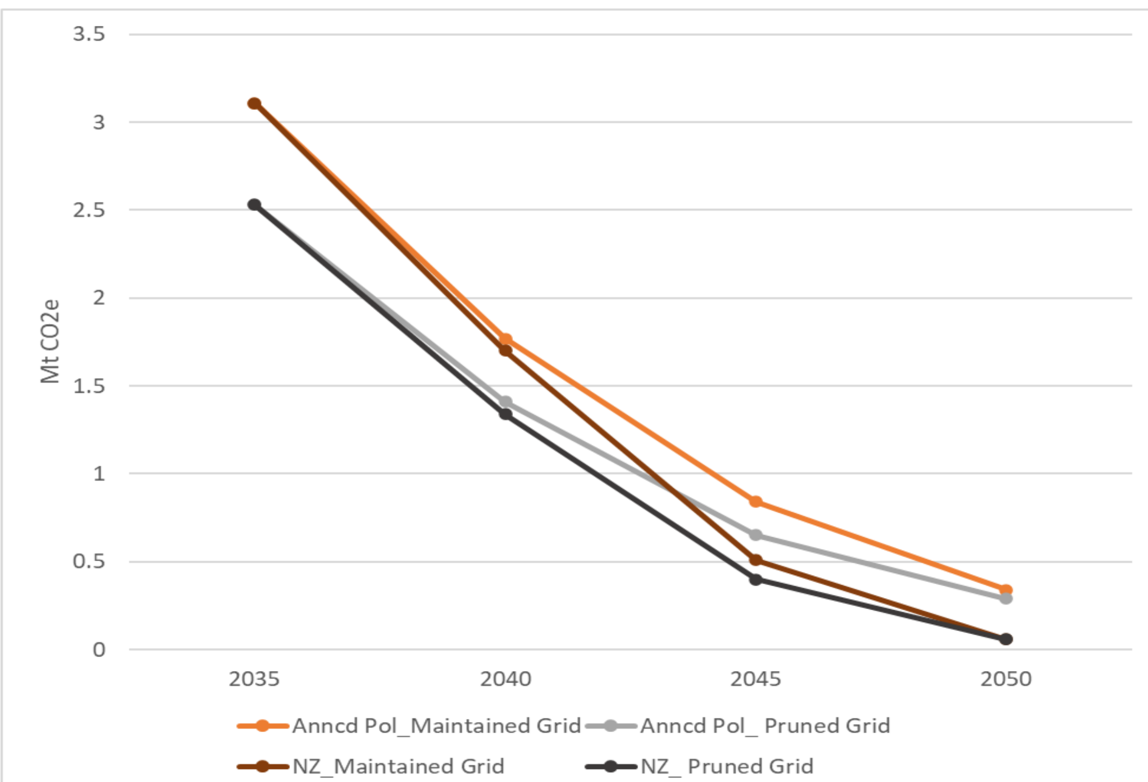
The purpose of my second announced policy scenario was to assess whether a partially decommissioned gas grid would reduce rising fixed cost impacts by enough to offset cost impacts on remaining gas system users. While energy price impacts from fixed costs are less drastic than in the *Anncd Pol_Maintained Grid* scenario, my results suggest that even with a pruned grid the resulting fixed cost price increase is enough to push gas users away from the gas grid. In other words, the grid would need to be pruned by more than 50% to offset the price impacts of lower gas utilization.

5.4 Net Zero Scenario Results

My results so far have considered technology-energy pathways to decarbonize building heat given B.C.'s current GHG policies – including a GHG reduction target of 80% by 2050. I also ran two additional scenarios where I increased the stringency of carbon pricing after 2040 so that B.C. achieves net zero emissions in 2050. Like the distinction between the two announced policy scenarios I modelled, the two net zero scenarios differ only in their assumptions of how the gas system will evolve: either maintained with no future growth after 2035 (*NZ_Maintained Grid)* or pruned by 50% in 2030 (*NZ_Pruned Grid).* The results of these two scenarios share many similarities to previously discussed results, and I will focus on key differences in my analysis.

Compared to the announced policy scenarios that I modeled, the net zero carbon pricing trajectory differed in the years 2045 and 2050 when it rose to $397/t CO2e and $545/t CO2e respectively, compared to a constant value of $290/t CO2e in the announced policy scenarios. My net zero scenario results suggest that with a more stringent carbon price emissions from gas will decline to 0.06 Mt CO2e by 2050. Figure 15 shows a comparison of emissions in each policy scenario after 2035. The stringent carbon price in the *NZ_Maintained Grid* scenario results in a steeper decline in emissions (dark orange) than the less stringent policy modelled in the *Announced Policy_Maintained Grid* scenario (light orange). This holds true for the net zero pruned grid compared to the announced policy pruned grid scenario. The higher carbon price levied in the net zero scenarios induces emission reductions that lower the total

Figure 15: Emissions Trajectory of Announced Policy and Net Zero Simulations

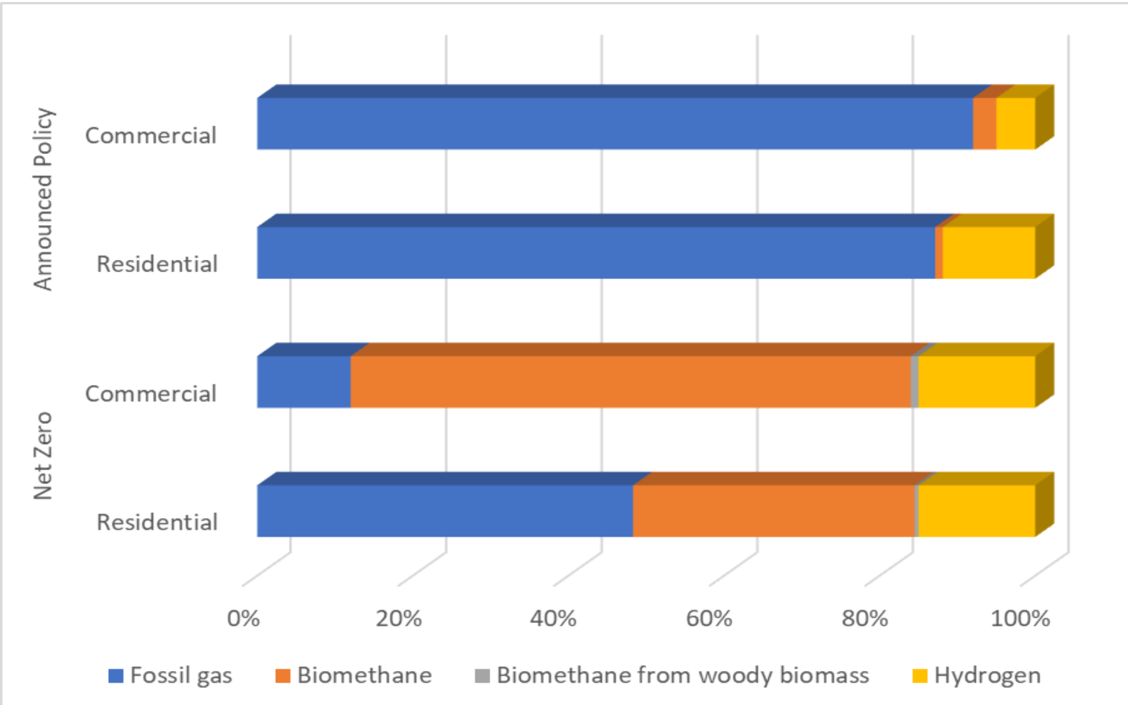


emissions costs paid by emitters by $20-$30 million in 2045 and $46-$57 million in 2050 compared to the announced policy scenarios. This indicates that the marginal cost of abatement for gas users is lower than the carbon price simulated in the net zero scenarios.

A more stringent carbon price does not result in greater fuel switching effects than the announced policy scenario. My results show that with a carbon price of $545/t CO_2e in 2050, electricity will provide the same percentage of heat in the net zero scenarios as in the announced policy scenarios. These results suggest that a higher carbon price would not cause additional gas grid defection. Additionally, while end user gas prices in the net zero scenario are forecast to be 15-30% higher than in the announced policy scenarios in the years 2045 and 2050, this is not due to either higher tax or fixed costs impacts. On a per GJ basis, fixed costs in the net zero scenarios are only about 2-7% higher than the announced policy scenarios, and in fact the tax component falls slightly. The main driver of end user prices, and the reason for a lower tax component on end user gas, is that the carbon price has risen such that fossil gas is less competitive than low carbon gases. Hydrogen and biomethane are now more cost competitive than fossil gas, increasing the commodity cost of gas relative to the announced policy scenarios.

Figure 16 depicts the low carbon gas blending rates in the net zero scenarios compared to the announced policy scenarios in the year 2050. Hydrogen reaches its 15% blending constraint in both the residential and commercial sectors, and biomethane makes up the remainder of blended low carbon gas. Low carbon gas blending makes up 88% of commercial gas throughput and 52% of residential gas throughput in 2050. The difference in uptake between sectors is due to higher price multipliers affecting the price of low carbon gas in the residential sector, which make it less able to compete against fossil gas. These results indicate that a carbon price of greater than $500/t CO_2e would need to be in place in order for low carbon gases to compete against fossil gas, but that at this carbon price most gas users would fuel switch to electricity as their source of heat energy.

Figure 16: 2050 Gas Blend in Announced Policy versus Net Zero Simulations



5.5 Policy Considerations

My results indicate that if B.C.'s 100% efficient equipment standard and gas distribution emissions cap are successfully implemented, the province will be on track to achieving its 2030 and 2050 GHG targets. However, achieving provincial emission targets drives gas demand low enough to threaten the viability of the gas system. The final objective of my research was to provide policy recommendations to support progress towards B.C.'s GHG targets and guidance on what the future of building heating will look like. Below I include several key recommendations stemming from my results.

1. Blending low carbon gas into the grid does not appear to be a cost-effective approach to decarbonising heat from gas at the announced carbon price. Instead, my data and modelling suggest that wholesale electrification is likely the lowest cost pathway to decarbonizing building heat. If policy makers wish to use low carbon gas as a pathway to decarbonise the gas system, consideration must be given for how to offset price impacts on gas users. B.C.'s *Greenhouse Gas Reduction Regulation* currently allows gas utilities to

blend low carbon gas into the grid and recover costs through customer rates. To prevent cost pressures on rates, the maximum cost of low carbon gas that can be blended into the system is currently limited to $31 per GJ. Continued regulation of gas blending price impacts would ensure that rate increases driven by low carbon gas blending do not adversely affect gas users. Additionally, there is a limited amount of woody biomass, agricultural waste, and landfill gas available each year to upgrade into biomethane. Consideration should be given to allocating these resources to the application where they can achieve the highest level of GHG abatement. Low carbon gas alternatives may find more cost-effective applications in other sectors that are difficult to decarbonize such as industry, although this is still an open question.

2. Electricity is a known pathway to decarbonization, but achieving heat decarbonization via electrification will increase electricity demand and may stretch the ability of B.C.'s transmission system to meet that demand. My results suggest that building sector electricity demand will double from 2020 to 2050. The version of CIMS I used does not yet endogenously model end use load curves, and so despite my attempt to represent these impacts through higher electricity prices my results cannot predict the impact of rising building electricity demand on base, shoulder, and peak generation. Some estimates indicate that total heat electrification could increase peak demand by between 70% and 100% (Waite & Modi, 2020), though total electricity system impacts would likely be higher as this estimate excludes demand impacts from electrification in other sectors such as transportation, where the *CleanBC Roadmap to 2030* has set a target for zero-emission vehicles to account for 90% of new light-duty vehicle sales (CleanBC, 2021). As previously mentioned, it is likely that additional electricity demand can be absorbed into the grid through B.C.'s plentiful hydro resources or by supplementing hydropower with wind power. However, ensuring the transmission system can adequately meet an increase in electricity demand without impacting average prices warrants early investments in electricity storage or transmission upgrades. While my results did not find a role for supplementary gas heating in Cold zones of B.C., other studies suggest that retaining fossil fuel equipment for backup during cold weather could avoid the

need for electricity system capacity upgrades (Waite & Modi, 2020). However, the cost of continuing to maintain a gas system solely for supplementary heating would be very expensive, particularly if system costs are borne by gas users.

3. My announced policy and net zero scenarios indicate that gas is unlikely to continue as the dominant fuel source of building heating, even in a vision of the gas system where a portion of the grid is decommissioned. As gas grid utilization falls, remaining gas users will experience a rise in gas bills that further induce fuel switching to electric heating. My study explores only two visions for the gas system's evolution. There are many other alternative scenarios for gas utilities and the province to consider, and approaches taken in other jurisdictions may serve as guidance for alternative models of gas usage in a net zero future. For example, the Quebec government has taken an approach to hybrid heating where gas is subsidized by the electricity utility so that it is available as a stable supplementary heating source on cold days or during times of peak demand. Another alternative is for gas distributers to evolve to deliver hydrogen gas to industrial customers. Additional exploration of these potential futures is beyond the scope of this study but could be undertaken as a next application of the data I have gathered and the recent developments of the CIMS model.
4. Finally, policy makers should consider supportive policies to ease the transition from gas to electric heating. All scenarios I modeled forecast a dramatic increase in gas prices stemming from the rising carbon tax and an increasing fixed cost charge borne on remaining gas users. While electric heating technology can be more affordable from a life cycle cost perspective, the upfront capital costs of electric ASHP are significantly higher than conventional gas heating equipment and might present a barrier to decarbonizing residential and commercial buildings owned and operated by people of lower socioeconomic status. When exploring decarbonization policy, decision makers should consider the affordability impacts of the decarbonization challenge and the disproportionate impact that rising energy costs can have on lower income people. Decision makers should continue to provide subsidies to support heat pump adoption, but also tailor subsidies to help low-income households overcome the initial higher cost of electrification

to ensure that all British Columbians can participate in a net zero transition. Consideration should also be given to subsidizing heat pump purchase and installation in regions of the province where gas system decommissioning is being considered.

6.0 Conclusions

6.1 Summary of Findings

The purpose of my research was to explore pathways towards and effects of announced building decarbonization policy in British Columbia's building sector under two possible visions of the evolution of the gas system. Fossil gas is currently B.C.'s dominant heating fuel and causes 97% of building sector emissions. The implications of gas system decarbonization include a grid defection event driven by the shift in building heat from gas to electricity, but this possibility has not been carefully researched. To explore the future of building heat in B.C. I used the partial equilibrium model CIMS to simulate five scenarios: a reference case, and four policy cases that model a future under announced policies and net zero policies in both a maintained gas grid and a partially decommissioned gas grid. The scenarios explored two distinctly different examples of what the future of the gas system might look like.

The first objective of my research was to identify if and how announced policies would achieve B.C.'s GHG targets. My results suggest that the implementation of announced policies, including a carbon price of \$175-\$290/t CO2e after 2025, will decarbonize building heat in B.C. to align with provincial GHG targets. Despite claims that low carbon gas constitutes an affordable and reliable approach to decarbonizing emissions from building heat, modelling finds that low carbon gas blending is limited by its high cost in comparison to fossil gas and does not drive any significant GHG reductions. Only at a carbon price of greater than \$500/t CO2e is low carbon gas able to compete against fossil gas, but even in this scenario, electricity remains a lower cost heating option. In both announced policy scenarios, electricity supplies 96% of energy demand in the building sector by 2050. Fuel switching from gas to electricity will likely drive reductions in GHG emissions from space and water heating. Heating technology stock is likely to be dominated by electric air source heat pumps after 2040, with a role for electric rather than gas supplementary heat systems in cold regions of the province.

The second objective of my research was to determine the impact of heat decarbonization on gas distributers. My results indicate that B.C.'s announced policies will achieve the province's GHG reduction targets, but at the cost of the gas system. All of the policy scenarios modelled resulted in widespread customer defection from the gas grid and significantly higher costs for the remaining end users of gas. According to my results, if the gas system continues to service remaining gas users in 2050, total gas system throughput will have declined by 95%, spelling the near certain death of the gas system.

Based on my results I propose several considerations for policy makers to support a smooth transition to building decarbonization. My research shows that in the absence of any additional policy, gas customers will largely abandon the grid in favor of electric heating. A delay in gas system decommissioning could result in higher gas prices, pointing to the need for proactive planning to shape a net zero energy system that is both reliable and affordable. Rebate programs subsidizing heat pump adoption, particularly for low-income building owners, can ensure that all British Columbians can participate equally in the energy transition. Electricity system planning will be necessary to ensure adequate electricity transmission capacity to meet the doubling of building sector electricity demand that is projected by 2050. As low carbon gas may not play a significant role in heat decarbonization, decision makers might explore alternative applications for biomethane and hydrogen in other sectors that are difficult to decarbonize.

6.2 Limitations and Directions for Future Research

As with any modeling exercise the results of my research are not without their limitations. The findings of my study are the result of a series of assumptions that I built into the model which were based on a thorough literature review and grounded by input from various experts. Due to the significant amount of model developments that were necessary to simulate gas blending and the fixed costs of the gas system, I limited my simulations to two announced policy scenarios and two net zero policy scenarios. My study could benefit from an additional analysis assessing the sensitivity of my results to my assumptions. For example, future research could include an additional sensitivity where the production costs of biomethane or hydrogen decline over time as technologies improve. In addition, while I assumed a fixed annual quantity of biomethane, future research could represent the additional supply that would be stimulated by an increase in willingness to pay for biomethane gas, and could also capture price dynamics on biomethane demand as gas distributers in other jurisdictions also pursue low carbon gas blending.

Another potential limitation is that meeting increased electricity demand would necessitate investments in transmission upgrades or electricity storage, which would impact the price of electricity. I did not endogenize this price feedback within CIMS, but rather estimated and exogenously adjusted peak and shoulder electricity prices. My modelling assumes that average electricity prices will rise by 10-20% ($0.02-$0.03/kWh) from 2025 to 2050. Future research could endogenize electricity price feedbacks to validate the assumption that an increase in peak load would stress B.C.'s transmission system and increase electricity prices, and even compare the cost of doing so with an alternative scenario where gas is the dominant provider of supplementary heat energy.

My research constitutes a preliminary assessment of potential futures of the gas system under a set of assumptions and policy scenarios. I modeled only two potential futures and recognize that there are many other system outcomes not captured by my work. There is additional work that could be done to build out my assumptions regarding changes in the rate base of the gas system as well as exploring alternative models for building sector heat. Future research could consider additional outcomes such as a fully hybrid heat system, a fully decommissioned gas system, or a selectively pruned grid servicing regional or user segments.

Finally, all the scenarios I modelled assumed that the provincial government is climate sincere and continues to prioritise climate as a policy priority. My research does not consider a change in policy priorities or a shift from a climate sincere to a climate insincere government. Additionally, in both of my announced policy scenarios I assume the perfect implementation of both the GGRS (emission cap) and the equipment standard. The target implementation date for the equipment standard is 2030, nearly a decade after it was announced in the *CleanBC Roadmap to 2030*. A likely reason for past policy failure is governments setting the date of regulatory implementation well into the future, without the assurance of still being in power by that point. Political uncertainty of this nature undermines the plausibility of the policies simulated in my modelling.

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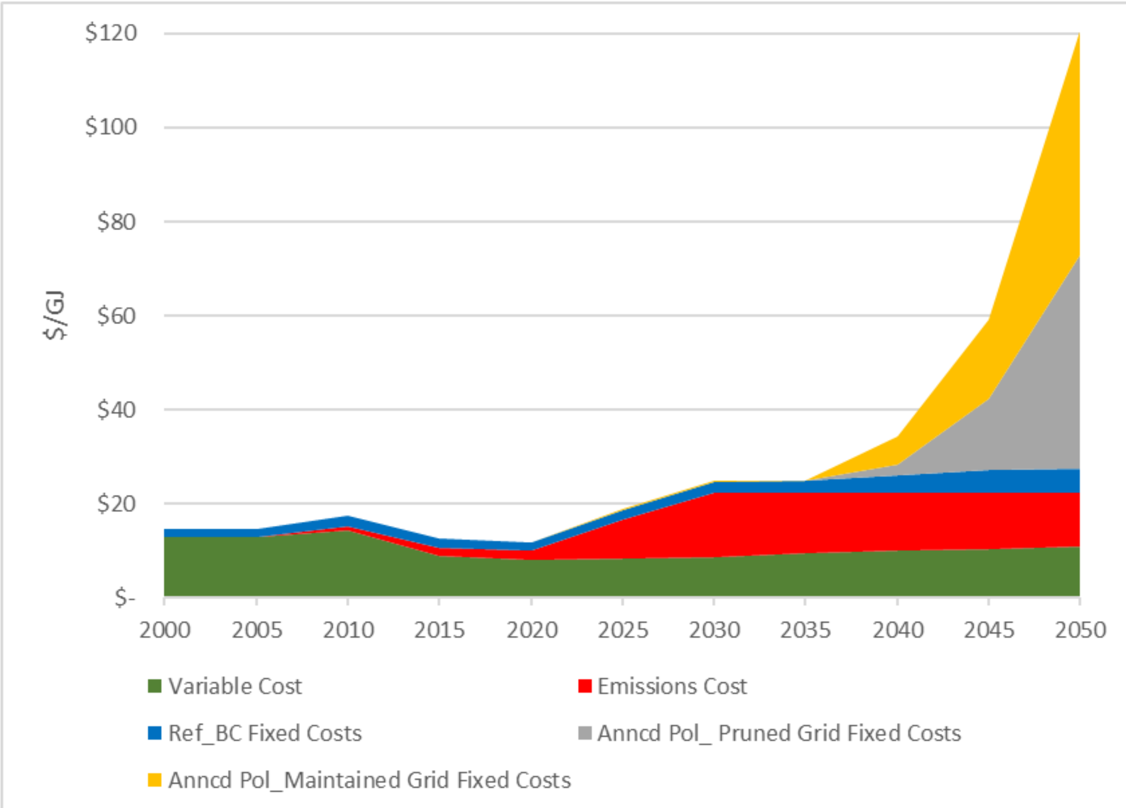
Appendix A. Literature Review of Low Carbon Gas Production Pathways

Low Carbon Gas Production Pathway	Jurisdiction	Estimated supply potential	Estimated cost	Date commercially available	Source
Conventional biomethane	British Columbia	9.65 PJ per year	$15-$45 per GJ depending on feedstock	2010	(Tampier, M., 2022)
Biomethane from gasification and methanation of woody biomass	British Columbia	39.4 to 81.7 PJ per year	$28 per GJ	2035	(Hallbar Consulting, 2017) Page 18, 22
	British Columbia	Maximum of 145 PJ/year. Noted to be an unlikely scenario.	$30-$40 per GJ	2030 Estimates that Technology Readiness Level is between 3-7.	(Tampier, M., 2022)
	Canada	149.6 PJ per year	n/a	Commercial deployment unlikely before 2030 due to technology readiness levels estimated at 6 to 7.	(Stephen, J. et al., 2020)
	Global	n/a	Average of $34 per GJ	n/a	(International Energy Agency, 2020)
	GoBiGas plant in Gothenburg, Sweden	n/a	Approximately $57 per GJ	n/a	(Thunman et al., 2019)
	California	n/a	Approximately $35 per GJ	n/a	(Seiser et al., 2020)

Appendix B. Gas Prices by Scenario and Sector

Residential Sector Gas Prices



Commercial Sector Gas Prices