THE ADOPTION OF GROUND SOURCE HEAT PUMPS AT MULTIPLE SCALES IN NORTH AMERICA

by

Thor Jensen

A THESIS SUBMITTED IN PARTIAL FULFILLMENT OF

THE REQUIREMENTS FOR THE DEGREE OF

Doctor of Philosophy

in

THE FACULTY OF GRADUATE AND POSTDOCTORAL STUDIES

(Resource Management and Environmental Sciences)

THE UNIVERSITY OF BRITISH COLUMBIA

(Vancouver)

December 2015

THESE DE DOCTORAT
DE
L'UNIVERSITE DE COLOMBIE BRITANNIQUE (RESOURCE MANAGEMENT AND ENVIRONMENTAL SCIENCES)
ET DE
L'UNIVERSITE PARIS-SACLAY
PREPAREE A L'UNIVERSITE VERSAILLES SAINT-QUENTIN EN YVELINES

Spécialité de doctorat : Sciences économiques

Par

M. Thor Jensen

L'adoption de géothermique à des échelles multiples en Amérique du Nord

Thèse présentée et soutenue à REEDS (Bergerie Nationale) Université de Versailles Saint Quentin-en-Yvelines, le 11 Décembre 2015:

Composition du Jury :
François Pascal NEIRAC, Professeur, Ecole de Mines (Mines-Paris-Tech) - Rapporteur
Ines AZEVEDO, Professuer et Co-directuer, au centre of Excellence in Climate and Energy Decision-Making - Rapporteur
Hadi DOWLATABADI, Professeur, à l'Université de Colombie Britannique - Directeur de thèse
Martin O'CONNOR, Professeur des Universités, à l'Université de Versailles Saint-Quentin-en-Yvelines - Co Directeur de thèse
Tim McDANIELS, Professeur, à l'Université de Colombie Britannique - Examinateur
Samir ALLAL, Maître de conférences, à l'UIT de Mantes - Examinateur
Isabelle NICOLAÏ, Professeure, Université de Versailles Saint-Quentin-en-Yvelines - Examinateur

Abstract

In North America, space heating, hot water, and air conditioning use more secondary energy than any other activity within buildings, thus emitting the majority of scope 1 and scope 2 Greenhouse Gases (GHG). The Ground Source Heat Pump (GSHP) uses one-third the energy of traditional technologies to provide space conditioning and hot water services.

While GSHP is a well-established technology, the energy savings and lower GHG emissions have not translated into their widespread adoption. Public policy measures and financial incentives adopted to promote GSHP have failed to lead to broad adoption or lower costs. This thesis examines the adoption of GSHP in response to supportive policies among residential, institutional, and city-scale adopters.

Detailed site-level and panel data permit natural experiments on the response of residential adopters in Canada and the US to changing incentives. At higher scales, regulatory proceedings concerning the offering of Thermal Energy Services (TES) has provided a case study for analysis of utility models to finance GSHP for commercial and institutional clients.

In Canada and the US, financial incentives failed to sustain the adoption of GSHP throughout or after the period of subsidy among residential households. Neither did incentives lead to a decrease in price over time. Free-ridership problems in Canada and an inability to make inroads to areas served by natural gas have stranded GSHP technology. Further, the capital cost of GSHP results in a higher lifecycle cost than most alternatives. The economy-wide benefits of financial incentives for GSHP are limited in Canada, where most heat pumps are imported.

TES provide compelling innovations to bridge barriers at higher scales. TES overcome balance sheet constraints on debt common to public sector organizations by financing capital equipment and renovations as utility payments. TES can overcome capital constraints faced by developers by financing equipment inside the building lowering construction costs. However, our case study of public procurement reveals TES to be a costly approach in the long run. The insights from this research are translated into best practices and policy advice to improve contracting, increase awareness, and align incentives for greater efficiency.

Preface

Parts of Chapter 1 were first published as "Improving the economics of ground source heat pumps through a community energy utility," authors Thor Jensen and Hadi Dowlatabadi, at the American Council for an Energy Efficient Economy, in Monterey California, 2012. I wrote 90% of the manuscript, with guidance on structuring the paper from Hadi Dowlatabadi. The model contained in Appendix B has been completely restructured. The authors hold copyright.

The findings for Chapter 5 titled "Determinants of public sector green investments," were presented in Montreal in April of 2013, at the 11th International Energy Agency Heat Pump Conference. I developed the financial model and presentation with support from Hadi Dowlatabadi, and wrote the entire resultant chapter with his editorial guidance.

The initial findings of Chapter 4 titled "Federal tax credits and residential investment in renewable energy" were presented by Hadi Dowlatabadi in Carnegie Mellon, April 2013. The initial model findings emphasized tax credit rents and windfalls. I shifted the focus of the chapter towards average price movements over time, investment based on income groups, and economy-wide benefits of investment. Hadi Dowlatabadi and myself developed the technology framework collaboratively, and I wrote 90% of the present chapter.

I applied for and received approval of a minimal risk ethics certificate from the UBC Research Ethics Board titled "Development models for community scale heating utilities (H13-01071). The certificate was required for a series of interviews I conducted with industry stakeholders and interveners during the thermal energy service regulatory proceedings. The interviews guided research with no direct quotations. All quotations are taken from publicly available transcriptions and reports filed as evidence with the British Columbia Utilities Commission.

Table of contents

List of tables

List of figures

List of abbreviations

AES	Alternative Energy Services
ASHP	Air Source Heat Pumps
BC	British Columbia
BC G.A.	British Columbia General Legislative Assembly
BCPSO	British Columbia Pensioners' and Seniors' Organization
BCSEA	British Columbia Sustainable Energy Association
BCUC	British Columbia Utilities Commission
CGC	Canadian GeoExchange Coalition
CIAC	Contribution In Aid of Construction
CO2e	Carbon Dioxide Equivalent
COS	Cost of Service
CPCN	Certificate of Public Convenience and Necessity
CRCE	Canadian Renewable Conservation Expense (tax credit)
DSB	Delta School Board #37
EIO-LCA	Economic Input Output Lifecycle Analysis
EPC	Energy Performance Contracting
ESAC	Energy Services Association of Canada
ESCO	Energy Savings Company
FAES	Fortis Alternative Energy Service
FortisBC	Fortis British Columbia
GCOC	Generic Cost of Capital Proceeding
GGRTA	Green House Gas Reduction Targets Act
GHG	Greenhouse Gases
GSHP	Ground Source Heat Pump
HEGB	High Efficiency Gas Boilers
HRAI	Heating Refrigerating and Air Conditioning Institute of Canada
ICBC	Independent Contractors and Businesses Association
kWh	Kilo Watt Hour
MCABC	Mechanical Contractors Association of British Columbia
MUSH	Municipalities Universities Schools Hospitals
MWh	Mega Watt Hour
O&M	Operations and Maintenance
PSECA	Public Sector Energy Conservation Agreement
PV	Solar Photovoltaic
RDA	Rate Disclosure Agreement
RMDM	Retail Markets Downstream of the utility Meter
SCBC	Sierra Club of British Columbia
ST	Solar Thermal
tCO2e	Ton of Carbon Dioxide Equivalent
TES	Thermal Energy Services
UCA	Utilities Commission Act

Acknowledgements

Above all, I offer my enduring gratitude to Hadi, my committed mentor and friend. I am continually grateful to Dr. Culver who saw me through to the end of a journey he started me on, and to Dr. Tansey for his counsel throughout my PhD. I owe a special thanks to Dr. Sutherland for years of guidance and seize at Le Passy.

To my family, thank you for your love and support on my quest to study everything, everywhere. Our weekly conversations were as much a part of my PhD as the writing. Tania, thank you for sharing in this life changing endeavor with me throughout Amsterdam, Kalimantan, Paris, Manila, Brussels, Vancouver, and Jakarta.

I wish to thank Dr. O'Connor and Professor Bürgenmeier of the Econoving Chaire for their support and resolve for this thesis from its earliest iteration. Thank you Claudie and Elizavetta, without you this thesis would have ended before it began.

This research benefited greatly from the assistance of Denis Tanguay, President of the Canadian GeoExchange Coalition.

The Pacific Institute for Climate Solutions and the Econoving Chaire of the Université de Versailles provided financial support for this research.

For Tania,
who makes my life an adventure,
and brings colour to my days.

Chapter 1: Introduction

Climate change and GHG reductions and energy security are an ever-growing public policy concern. Therefore, the promotion of technologies that bring about energy efficiency and economic GHG reductions across all sectors of the economy is receiving more and more attention. In Canada, as in most industrial nations, space heating and hot water provision dominate secondary energy use (61.8%, 19.1%, respectively) (NRCAN 2011a), making these services the greatest source of greenhouse gases from the built environment (NRCAN 2012a; NRCAN 2009).

The most energy efficient space conditioning technology available to reduce energy consumption and emissions is the Ground Source Heat Pump (GSHP), using less than one third the energy of systems we have traditionally used to provide space heating (DOE 2012). GSHP can use electricity or natural gas as input and, except for where the electricity is coal-based GSHP offers significant carbon savings compared to all other fuel types throughout North America (Hanova 2008).

Despite these advantages, GSHP systems serve only a small fraction of the market for space heating in the United States and Canada (0.5% and 4.6% respectively) (Thorsteinsson 2008; Natural Resources Canada 2012h). Commonly identified barriers to their adoption are: higher capital costs (Goetzler et al. 2009), limited awareness (Huttrer 1997), and availability of low cost energy substitutes (Newell et al. 1999; CRM 2005). A review of barriers to the wider adoption of GSHP by Tanguay (2011) revealed that these same challenges have persisted over time.

GSHP has predominantly been adopted in the residential sector (NRCAN 2011a). However, it has favorable economies of scale and can be designed for hotels, hospitals, building clusters, or even communities (PICS 2012). Given GSHP's strong returns to scale as the size and diversity of load increases, the dearth of larger systems suggests the existence of other barriers to adoption at larger scales – especially when needing to combine the demand of different customers.

Two key questions arise:

1. GSHP has been adopted in the residential sector, but can we be more specific about by whom and under what conditions? What has been the impact of the enabling policies?
2. There is a dearth of GSHP at higher scales, despite economies of scale; could there be other barriers and enablers at higher scales?

This thesis examines the adoption of GSHP and response to supportive policies in the US and Canada. These natural experiments provide empirical evidence for a number of studies in technology adoption at different scales by heterogeneous actors under changing economic regulations and political interests. In the next five chapters I explore the adoption of GSHP among residential, institutional, and district-scale actors, paying close attention to the barriers and bridges to wider adoption of this technology.

Chapter 2 reviews the economics of GSHP, emphasizing the advantages of moving beyond single developers to pursue economies of scale among larger installations. Chapters 3 and 4 use econometric techniques to study residential GSHP installations with micro-level and panel data. Chapter 5 presents a case study of a school district renovating several buildings for GSHP via a Thermal Energy Services (TES) contract, evaluating the proposed cost of service contract to a

public sector comparator and alternative rate designs. Chapter 6 reviews the Alternative Energy Service and Thermal Energy Service Regulatory proceedings, reviewing how the British Columbia Utilities Commission (BCUC) treats challenges of scale and coordination.

Three appendices provide context and support for this thesis. Appendix A contains technical detail describing the components and operation of GSHP. Given the longevity of the building stock, it highlights key issues of building compatibility and system performance among renovations. Appendix B contains an engineering-economic model to calculate the lifecycle cost of GSHP and a reference system served by gas and electricity. Appendix B also contains a sensitivity analysis identifying parameters most likely to reduce costs, and a separate profitability analysis for GSHP under utility ownership. I extend the sensitivity analysis for the utility model under different rate designs. Appendix C contains orders and decisions filed with the BCUC, which are relevant to the regulatory proceedings discussed in chapter 6.

Lessons learned help in the design of better policies to reduce the energy intensity of and GHG emissions from the built environment, and the remainder of this introduction maps the thesis contents.

GSHP exhibits strong returns to scale, and Chapter 2 uses the outputs from the engineering-economic model contained in appendix B to demonstrate quantitatively the fall in unit costs as the size and diversity of load increases. I then describe network economies available to GSHP at higher scales. Pursuing larger more diversified loads requires approaching new classes of customer and its associated challenges of coordination. I offer technical and social innovations for overcoming these barriers. Technical innovations include thermal energy storage, while

social innovations require partnering with the municipality and perhaps third-party finance with utility ownership.

In Chapter 3, I examine the largest proprietary database of residential GSHP installations in Canada, including detailed information on the type of heating system being replaced, housing type, previous fuel source, installation conditions, and price. I ask what is GSHP replacing within the heating stock, is it gaining market share, and what was the effect of policies designed to encourage its adoption. I also use observed prices to calculate the lifecycle cost of GSHP. Most academic studies have assumed installed system prices in their engineering-economics lifecycle analyses of GSHP. Using this unique dataset on actual prices as installed, I conduct an econometric analysis on key drivers of capital costs, including compatibility constraints.

The CGC database permitted an examination of cost, but did not answer why there have been no learning economies, and system price have remained stable or increased over time in Canada. To explore this issue, I needed to compare GSHP to other renewable technologies. This was made possible by examining the US Residential Energy Tax Credit claims. These data shed light on adoption of GSHP and other renewable technologies and their costs.

In Chapter 4, panel data from tax returns provided by the Internal Revenue Service permit a comparison on residential investment behaviour among multiple renewable technologies. I examine the performance of investment tax credits (ITC) in promoting residential sector adoption of renewable energy technologies in the United States. The tax codes of 2005, 2008 and 2009 changed the caps on investment credits for Solar Photovoltaic (PV), Solar Thermal (ST) and GSHP. This natural experiment, created by the evolving terms of the ITC, provides valuable insights into residential sector responses to tax incentives.

The second major theme in my thesis is adoption of GSHP by institutional actors. Institutions, such as schools and hospitals, tend to have larger loads, occupy their own buildings, rely on centralized decision-making bodies, and supportive of environmental objectives. Within BC, the environmental objective for Public Sector Organizations is explicit, with a Carbon Neutral Mandate imposed since 2009.

In British Columbia, The Delta School Board #37 (DSB) provides an opportunity to study the adoption of GSHP at the institutional scale for Chapter 5. The DSB had previously been denied financing for renovations by the Province, and yet were able to renovate 19 of their buildings at no upfront cost. The DSB did so through a Thermal Energy Services (TES) contract, the very first of its kind in North America, which would be regulated as a public utility by the British Columbia Utilities Commission (BCUC). The thermal plants, consisting of geothermal and high-efficiency natural gas equipment, are financed, owned and operated by the TES provider, FortisBC.

I examine the key factors influencing decision-making by DSB regarding their space conditioning and water heating needs at the point at which they needed to renovate their existing infrastructure. Using standard economic criteria I compare the TES contract to four counterfactuals including: a regulated alternative, two public procurement alternatives, and a 'status quo' scheme of ongoing energy payments. I draw lessons from experiments with alternative methods of infrastructure provision to improve public procurement for TES.

Although an original method of service delivery, the DSB project followed the normal pattern of installing independent GSHP systems for each building (foregoing potential economies of scale and scope). Chapter 6 considers the regulatory proceedings of TES in British Columbia,

examining scenarios where multiple classes of customer are involved, customers inherit utility contracts signed prior to their arrival, and when the system grows by connecting multiple buildings over time.

TES are defined as public utilities by the BCUC, but were previously omitted from regulatory oversight. The provision of TES by FortisBC has sent ripples through the energy services market in British Columbia. Other industry actors were concerned their services would henceforth require regulation by the British Columbia Utilities Commission (BCUC, Commission), and feared the entry of a large, regulated utility in what they considered to be an unregulated market. The promulgation of TES prompted a regulatory review, including several ad hoc rulings, two regulatory proceedings spanning 2011-2014, and the development of a scaled regulatory framework for TES in British Columbia.

I describe intervener arguments presented during the Alternative Energy Service and Thermal Energy Service Inquiries. I then summarize the scaled regulatory framework for TES in British Columbia, and the relevant BCUC orders and decisions to the TES market. I illustrate how the regulator chose to handle issues of scale and coordination, and how a long-term contract can be used to maintain a cost of service rate of return in an unregulated market. I offer policy recommendations to improve transparency, encourage efficiency, and achieve a better balance in risk sharing among parties.

I conclude by revisiting the key questions of this thesis, and summarizing the findings for each chapter. The broader implications of how to improve the technology adoption, supplier responses and investments in energy efficiency through better policies are illustrated by

connecting the key lessons from each chapter. I then propose future research to answer important questions unaddressed by this thesis.

Chapter 2: The economics of GSHP at higher scales

Outside of technical manuals, there is not a great deal of academic writing on ground-source heat pumps (GSHP) at higher scales. Their technical potential of GSHP to provide space heating, air conditioning, and hot water with one third the energy of conventional heating systems, however, has been well documented for residential homes (Bayer et al. 2011; Blum et al. 2009). The benefits of successful application of this technology for reducing the energy intensity of the built environment has been extolled by many (Huovila et al. 2007; Stern 2007).

As with most energy efficient technology, higher capital costs are offset by in-use energy savings under reasonable assumptions about discounting (Frederick et al. 2002; Self et al. 2012). Yet the capital cost of GSHP is considered prohibitive by most developers and homeowners (Goetzler et al. 2009; Kantrowitz & Tanguay 2011). They both worry that they will not be able to recover a sufficient return on their investment (Brown 2001; Gintis 2000).

The economic benefits of GSHP are greatest where energy prices are high and significant demand for heating and cooling services is found (Self et al. 2012; Kegel et al. 2012; Hanova & Dowlatabadi 2007). Most residential heat pumps are powered by electricity although recent low gas prices have led to the emergence of competitive gas-fired heat pumps (Garrabrant 2013). Low energy prices (and price expectations) depress the economic motive for heat pump based systems.

Engineering-economic models are often used in feasibility studies and technology briefs to estimate lifecycle costs, net benefits, payback period, energy savings, marginal cost and abatement cost curves (Ozgener & Hepbasli 2007). Comparisons of lifecycle costs for

residential GSHP identify the conditions where it is competitive with alternative heating systems, and where the potential for carbon savings is greatest (Hemmera 2007; CRM 2005; MRC 2007).

There have been two recent studies on the economics of residential GSHP in Canada. Self (2012) compared ground-source heat pumps to air-source heat pumps, electric baseboard, and a natural gas furnace. For Ontario, Alberta, and Nova Scotia, Self (2012) assumed identical capital costs, but reflected regional differences in energy prices. The total cost over a 20-year period was compared to air source heat pumps, electric baseboard heating, high and mid-range efficiencies for natural gas.[1] In this assessment the GSHP was the least costly alternative in each location over a time horizon of 20 years with the exception of Ontario where the low-price of electricity made air source heat pumps less costly.[2] This analysis was extended to Europe, where high electricity prices led to natural gas being the least costly alternative in Germany, Ireland, Luxembourg, Spain, and the United Kingdom.[3]

The analysis by Hanova and Dowlatabadi (2007) emphasized the value of energy savings as an indicator of how much more a financially motivated homeowner would be willing to pay upfront for the benefits of GSHP. The amount a homeowner is willing to invest upfront increases as the heating load, price of energy, and the efficiency of a heat pump increase. Further, it showed heat pumps to always provide carbon savings compared to electricity, fuel oil, and wood, however, when compared to high efficiency natural gas boilers the carbon intensity of electricity

---

[1] The study does not indicate whether there was any adjustment for seasonal variation on the efficiency of air source heat pumps.

[2] It did not include an analysis of Quebec, where residential electricity prices are lower than in Ontario.

[3] Varying climactic conditions were not considered for European cases.

consumed by the heat-pump must be less than 762t/GWh.[4] The study also indicated that while GSHP demonstrates favorable economies of scale, economies of scale and scope are rarely exploited.

GSHP is most prevalent among detached housing units, however, GSHP can be designed for hotels, hospitals, building clusters, or even communities (RETScreen 2005; OEE 2011b; PICS 2012). Given their novelty, the economic advantages of GSHP at these scales are rarely discussed, let alone demonstrated.

The primary objective of this chapter is to introduce the economics of GSHP at higher scales that may be observed among building clusters or communities. I then discuss potential barriers and suggest technical and social innovations for overcoming them. Further, I argue the municipality has an unparalleled advantage in creating community-scale GSHP, and suggest utility ownership as one means to overcome capital constraints faced by municipalities and developers.

2.1 Economics of GSHP at higher scales

Moving beyond residential detached housing to multiple buildings and or district scales may provide the opportunity to lower lifecycle costs. This may be achieved by increasing the system load through the combination of divergent demand profiles of heating and cooling, and the opportunity to incorporate heat ejected from mechanical loads during their operation.

The above economies are demonstrated quantitatively using an engineering-economic model described in Appendix B. Table 2.1 shows the outputs of the model, namely, the levelized cost

[4] Renewables are close to 50t/GWh, 60% efficient gas turbine ~300t/GWh and a typical coal powered system over 1000t/GWh.

of two 500m^2 buildings collocated on the same property, served either by a gas furnace with an electric cooling tower or a GSHP system, with and without the economies described in the upcoming Sections 2.1.2 and 2.1.3. Levelized costs are a useful proxy for lifecycle costs because they represent the constant price of heating over the lifetime of the technology, balancing capital and operating costs.[5]

Separate systems	**$/kWh**
Gas furnace with electric cooling tower	0.1203
GSHP system	0.221
Two interconnected buildings with GSHP (500m^2)	
Divergent demand profiles	0.188
GSHP incorporating waste heat	0.166
GSHP combining both network economies	0.155

Table 2.1 Lifecycle cost of GSHP with network economies

The sensitivity analysis in Appendix B shows the relative advantage of GSHP improves as demand and energy price assumptions increase or installation costs decrease. The sensitivity analysis also identifies the system demand and capital costs as most influential to lifecycle costs, both of which are effected by the network economies. Divergent loads increase system demand and incorporating waste heat may lower capital costs. Unlike energy prices or climate, the network economies can be created wherever complementary loads are found. I explain how these economies are realized in the next two sections.

The reference system of using natural gas for heating and electricity for air conditioning has a lower levelized cost than GSHP. This is due to the assumptions made for the engineering-

[5] Levelized costs are superior to indicators of investment duration, such as payback periods, which do not consider the time value of money, or the magnitude of costs. When profitability of investment is the deciding factor then either rate of return or net present value metrics should be used.

economic model. The lifecycle cost of GSHP is higher because of the relatively mild climate and low energy prices found in the lower mainland of British Columbia.

2.1.1 Divergent demand profiles

A heat pump can provide heating and cooling within the same unit, creating an opportunity for more favorable economies among larger systems. If a heating dominant building is collocated with a cooling dominant building, then they have divergent demand profiles and GSHP can serve both simultaneously. Essentially, demand for a heat pump can double so long as the two loads are divergent in their heating and cooling needs.

Differences in building use patterns are an excellent opportunity to utilize divergent heating loads. The space conditioning demand of residences and offices are complementary, allowing higher capacity utilization of any system that serves both. The heat ejected into the ground during the daytime hours warms the earth, recharging the ground loop before evening use. This improves energy efficiency of the system, while maintaining a higher rate of output.

The simultaneous need for heating and cooling, offers an additional economy. For example, within larger buildings demand for heating and cooling can occur simultaneously due to building orientation. North facing rooms may require heating at the same time as south facing rooms require air conditioning. GSHP systems can be designed to shift heat between the two sides of the building by having the condenser flowing to the heating side and the evaporator to the cooling side, greatly increasing system performance to over 500% (see Appendix A). In other settings, the constant cooling load of data centres and supermarkets are an excellent pairing with the continuous heating load of hospitals and laboratories. Such systems not only benefit from

using heat-pumps to move energy around the system, but also have need of smaller heat-exchange fields in the ground and therefore lower capital costs.

Long-distance transport of heat is both expensive and inefficient. Hence, spatial concentration is highly desirable for GSHP. The dispersed nature of detached housing, where GSHP has been most prevalent, does not lend itself to economies of divergent loads or scale. Divergent loads are found in mixed-use developments, where residential and commercial loads are found in close proximity. Among commercial buildings, buildings with large hot water loads, such as hotels and hospitals, can be paired with cooling dominant retail and office space.

2.1.2 Networking GSHP with waste heat rejection

Mechanical loads, such as IT data centers, supermarkets and water treatment facilities, must ventilate heat as part of their normal operation. The thermal energy is wasted unless a suitable sink can be found.

It is possible to connect these sources of low-grade heat to a GSHP system as a substitute or supplement to the ground loop. In such applications, the thermal energy is either ejected into the ground loop for circulation or connected directly to hot water tanks. Thermal energy ventilated by a mechanical load is often 10°C or more warmer than the ground loop and can significantly improve the operational efficiency of GSHP systems (Lund et al. 2010).

When the waste heat source can be relied upon, the system can rely on a smaller ground loop reducing capital costs. Thermal energy from mechanical systems displaces energy that would have been extracted from the ground permitting the installation of a smaller ground loop for the same amount of work.

2.1.3 Coordination challenges and the value of storage

The reliability of mechanical sources of heat and the timing of divergent demand creates a coordination challenge. Coordinating integrated systems may be perceived as risky. Sizing for redundancy or avoiding any shared mechanical systems is the status quo (Lovins 1992). If the perceived benefits of coordination do not outweigh their risks, these partnerships will not go forward. Two immediate challenges to coordination are proximity and timing.

As noted earlier, mixed-use developments or dense urban areas are much more likely to contain the diversity of loads in close proximity to one another. Timing may prevent coordination when waste heat is only available outside peak demand. Waste heat produced by mechanical loads must be ejected for the system to function correctly. If waste heat were produced primarily outside periods of demand, then it would be a difficult resource to rely on. Storing this heat, even inefficiently (e.g., in the ground), is the only way to resolve the timing issue.

There are three main ways to store heat. The first is to store heat in residential hot water tanks. This is not unlike demand side management programs where residential hot water systems are programmed by utilities to turn on prior to peak periods. The second is to treat the ground loop as storage, where the ground is warmed up during the day to the advantage of evening heating loads. The third option is to actually invest in a thermal storage facility, such as a glycol tank.

For whichever technological storage solution, it is only as valuable as the avoided cost of supplying energy on demand. If half of the waste heat is produced outside peak demand, then this is the amount that could be stored for later use. The value of storage can be calculated as the avoided cost of producing thermal energy on demand less the price of storage and any thermal losses.

2.2 Municipal power and third party finance

The municipality has an unassailable advantage in assisting with the creation of large-scale GSHP, offering social innovations to overcome challenges of load coordination. The municipality may engage in active permitting, whereby zoning requirements are written to favor mixed-used developments. Mixed-use developments are more likely to contain a diversity of loads that would benefit from connection to a community GSHP system, such as condominiums nearby supermarkets, hotels, data centers or even hospitals.[6]

Secondly, municipalities have eminent domain within city limits allowing them to facilitate the installation of much less costly horizontal ground loops on public lands where building densities are too high to permit economic installation of ground loops among high-rises. A significant fraction of all urban areas are paved and, if willing the municipality can grant easements for ground loops beneath pavements, roadways, playgrounds, or in property setbacks and utility corridors. These relatively abundant lands may allow the installation of horizontal ground loops, further lowering capital costs. Therefore, private developers willing to cooperate or partner with the municipality can realize great reductions in lifecycle costs (Jensen & Dowlatabadi 2012).

The size and diversification of the municipality's revenue streams allows them to borrow at a lower rate than almost any private entity. Many municipal governments have severe fiscal constraints and may be unable to incur the capital costs that permit them to benefit from the long-term benefits of GSHP (economic and environmental). Developers are also unlikely to

---

[6] The objective of active permitting is not only to design interconnected GSHP, which puts the cart before the horse, but to create the conditions where buildings could be connected to a larger interdependent system. For example, electric baseboard installations frustrate future renovations for energy systems of any kind, so requiring either forced air or low temperature hydronic heating systems within buildings preserves the opportunity for GSHP, district heating, or other new fuels or technologies. See appendix A.

shoulder the capital cost of a system sized beyond their need without remuneration (P. J. Hughes 2008). Developing GSHP at higher scales may well be ideal for Private-Public-Partnership, leveraging the combined powers of zoning and access by the municipality with third party finance.

There are two primary methods for financing GSHP at higher scales: utility ownership and Energy Performance Contracting (EPC). EPC offer renovations and capital equipment to commercial and institutional clients in exchange for a stream on ongoing payments based on previous energy usage. The company offering the EPC uses its expertise in energy services to extract a rent on the difference between the initial prices paid for energy and the energy payments following the renovation (GAO 2005a). Ownership of the equipment is transferred at contract terminus. EPC contracts incorporating GSHP are common in some parts of the US (DOD 2007), whereas EPC contracts for GSHP in British Columbia are unknown to the author.[7]

In British Columbia, utility models for financing GSHP at higher scales are growing in popularity (PICS 2012). Utilities finance, own, and operate equipment indefinitely in exchange for utility rates. As if often the case with utilities, the sheer size of an investment limits the number of firms able to undertake the investment to monopolies or governments. If privately owned, regulators intervene to limit the market power firms and oversee the rates charged. Thus, investment in a GSHP utility will likely occur in a regulated environment.

---

[7] GSHP systems installed in the US under EPC for the Department of Defense were concentrated in the Southern, South Western and North Eastern United States where a combination of climate and energy prices shortened the payback period of investment. To improve the return on investment, an EPC can bundle other improvements with shorter paybacks together with GSHP, such as insulation, lighting etc.

2.3 Conclusion

The primary objective for this chapter was to introduce the economies available to GSHP at higher scales. The financial benefits for GSHP are greatest where installation conditions lead to lower capital costs, where energy substitutes are costly, and demand for heating and cooling services are high. The ability to pair divergent loads and network externalities increase demand and decrease capital costs, respectively. Unlike other difficult to manipulate parameters, such as energy prices, these economies can be created wherever complementary loads among buildings are found.

The economies of GSHP improve as the overall system load increases with scale and diversity of demand meaning, from an engineering-economic perspective, GSHP is more compelling among larger or multi-unit buildings. These economies are unavailable to detached housing units, where GSHP are most commonly found.

Three immediate challenges to collective GSHP are coordination, timing of demand, and capital. I introduced both technical and social innovations as potential bridges. Technical innovations for timing of demand include the storage of heat. Social innovations include the exercise of municipal power over land use for assisting in the coordination of loads, and third party finance as a means to overcoming capital constraints. In the remaining thesis chapters, I will return to the barriers and bridges to the adoption of GSHP at residential, institutional, and community scales.

Chapter 3: Incentives and the adoption of GSHP among residential buildings in Canada

This chapter examines the adoption of residential GSHP in Canada using the Canadian GeoExchange Coalition's Database (CGC Database). This proprietary database is the largest of its kind in North America, with over 15,000 CGC certified systems installed between 2007-2015. The sample was taken during a period of generous provincial and federal subsidies permitting a detailed look at the response of residential households to incentives.

3.1 Background

In Canada, from 2007 through 2012, generous financial incentives were available encouraging homeowners to adopt energy efficient improvements and technologies. In some provinces, GSHP systems were eligible for $10K when provincial and federal incentives were combined. Table 3.1 lists the major incentive programs in Canada.

Region	Incentive	Availability	Amount	Eligibility	Stipulations
Canada wide	ecoEnergy	2007 - 2012	$1,750-$4,375	Renovations	Audit CGC Certification
Ontario	HESP	2007 - 2011	$5,000	Renovations	Audit CGC Certification
Quebec	RénoClimate	2007 - 2017	$2,000-$2,800	New and Renovation	Prior electric CGC Certification
Saskatchewan	EnergGuide for Houses	2007 - 2013	$5,000	Renovation	Audit

Table 3.1 Financial incentives in Canada from 2007 onwards

The ecoEnergy Retrofit program (ecoEnergy) for home renovations was made available across Canada by Natural Resources Canada (NRCan). Homeowners that went through the energy

efficiency audits of their home, and chose to adopt a GSHP system could be eligible for $4,375, or $1,750 for upgrading to a newer, more efficient heat pump (Natural Resources Canada 2014).

Three other provinces offered large incentives during the same period that could be used in conjunction with the ecoEnergy program. Ontario offered the Home Energy Savings Program (HESP) and Saskatchewan offered the EnerGuide for Houses program through SaskEnergy (Sullivan 2011; SaskEnergy 2011).[8] In both cases, the incentive was available only for renovations, and homeowners willing to undergo an energy audit were eligible for $5,000 on top of the federal ecoEnergy incentive.

Quebec offered ecoRenov program for GSHP for which new and renovated homes were eligible (VIGeothermal 2013). The primary motivation in Quebec was demand side management, so the renovation subsidy was only available to homeowners that had previously used electricity for heating or air conditioning.

Given the inherent promise of GSHP and a chequered early history with GSHP installations, the need for a professional training and certification program was seized by a group of industry advocates. They formed the Canadian GeoExchange Coalition (CGC) to try and bring about transformative change to the GHP industry. The CGC is a network of industry professionals dedicated to expanding the market for GSHP and reducing greenhouse gases within the built environment. The CGC facilitates industry development by working with educators to offer training and accreditation programs to installers, and working to develop trust among customers and contractors (CGC 2015b).

---

[8] Given the carbon intensity of electricity in Saskatchewan and Alberta, switching from natural gas to GSHP would not result in carbon savings.

How then, did the incentive programs affect the adoption of GSHP among residential homeowners in Canada? Is the share of GSHP growing, what is it replacing, and are impediments to its growth being overcome? The answers to these questions test the persistence of commonly identified barriers to GSHP, and the efficacy of financial incentives as policy tools for changing the energy intensity of the built environment. To answer these questions I use the CGC dataset containing over 15,479 CGC-certified systems installed between 2007-2014 (CGC 2015a).

Using the CGC dataset to interpret the wider adoption patterns in Canada has two countervailing sources of bias. It underestimates the level of GSHP adoption by only considering systems certified by CGC and overestimates the market dynamics by focusing on a period of strong financial subsidies for its adoption. The dataset can, however, be used to provide valuable information on the characteristics of homes persuaded to adopted GSHP, such as fuel switching.

Certain incentive programs requiring CGC certification enforce the likelihood of the CGC database being indicative of actual residential adoption in those areas. To be eligible for financial assistance CGC certification was required by the federal ecoEnergy incentive, and provincial incentives in Ontario (HESP), and Quebec (Rénoclimat) (VIGeothermal 2013; Natural Resources Canada 2014). A homeowner that did not select a CGC-certified installer would sacrifice between $5-10K in these areas.

The CGC dataset itself is the largest proprietary dataset of residential GSHP in North America, and the only source for site level detail and pricing information known to the author. This presents a unique opportunity to observe the adoption of GSHP in response to financial incentives. First, I trace the path of renovations through the building stock showing what types of

systems are most often being replaced, to answer whether GHSP is blocked by compatibility constraints and fuel substitutes. I then compare the rate of adoption to the growth of the residential building stock to estimate whether the financial incentives led to an increase in market share. I use ordinary least squares to examine the determinants of price for GSHP, and conduct a lifecycle analysis using actual capital cost estimates. I conclude with a discussion of whether lack of awareness, a recurring explanation in previous reviews of barriers to GSHP adoption (CGC 2015b), is stifling its adoption in Canada during the period of study.

3.2 Path of adoption

To assess the potential of GSHP, I use the CGC Dataset to trace its adoption through the building stock. Information on the types of heating systems, and possible fuel switching, allows us to assess whether GSHP is gaining ground on the dominant heating system types and fuels, or occupying a small niche. Furthermore, I examine whether the returns to scale of GSHP lead it to be more prevalent among buildings with larger heating loads.

3.2.1 Compatibility

Whether GSHP is an effective technology for mitigating climate change is dependent on how quickly, and how widely it is adopted within the building stock. The process of a technology spreading through a population is known as diffusion (Rogers 2004). There are two means by which GSHP can diffuse through the building stock; when new dwellings are built and when existing buildings are renovated. Site requirements dictate whether GSHP can be installed. Renovations for GSHP are more challenging, considering the previous heating system can frustrate or even block a renovation. This technological lock in makes it difficult to reduce the energy intensity of the building stock (Arthur 1989).

Buildings outlast their original heating system by many decades. Most buildings are served by several generations of heating systems each typically lasting 15 to 25 years. Within the CGC dataset, 91% of all systems were installed through a renovation (CGC 2015a). This is why compatibility with space conditioning systems in existing buildings is critical for GSHP's potential contribution to climate change mitigation and adaptation (see Appendix A for a discussion of heating systems and compatibility).

In Canada, the most common type of heating system is a natural gas furnace connected to forced-air distribution system (Table 3.2). The second most common heating type is electric baseboard, followed by boilers with radiators, heating stoves, electric radiant heating, and other types, including GSHP (NRCAN 2011a).

As shown in Table 3.2, GSHP is readily compatible with most residential buildings in Canada, and only blocked by electric baseboard among 16.6% of detached homes. This leaves more than 80% of the building stock suitable for conversion to GSHP. Table 3.2 also shows the heating system types renovated for GSHP from the CGC Dataset. Most systems were installed in homes that would have required minimal adjustment inside of the building, such homes with furnaces or heat pumps. None of the renovations for GSHP were in homes previously heated by electric baseboard.

System Type	Canada (%)	GSHP Renovations (%)
Furnace	66	37
Electric baseboard	17	0
Boiler	6	13
Heating stove	4	1
Electric radiant heating	2	15
Heat pump	3	25
Other*	1	-
NA	1	9

Source: NRCan (2011), CGC Dataset (2015)

Table 3.2 A comparison of heating systems in Canada to the share of homes that renovated for GSHP in the CGC dataset

A substantial number of buildings converted from electrical plinth and boilers to GSHP. These types of system can require some additional work inside the building. The CGC dataset does not describe the extent of work inside of the building. However, 95% of the buildings in the CGC dataset used forced air. This means it is likely boilers were connected to water-to-air fan coils for distributing heat through a forced air system, which is compatible with GSHP. I will now consider other factors, such as fuel types, as further constraints to the adoption of GSHP.

3.2.2 Availability of fuel substitutes

Renovating for GSHP is most worthwhile when energy costs are high. The availability of low-cost fuel alternatives, such as natural gas, reduces the value of energy savings

Fuel Type	Canada fuel mix (%)	GSHP conversions (%)
Natural Gas	50	6
Electricity	36	43
Heating Oil	8	40
Wood	4	2
Other/Propane	2	9

Source: NRCan (2012), Table 27: Heating system stock by building type and heating system type.

Table 3.3 A comparison of energy sources used for heating in Canada to the share of homes with that fuel type that renovated for GSHP in the CGC dataset

Electricity is the only energy category where the fraction of renovations for GSHP (42.8%) closely resembles the fraction of Canadians using that fuel type (36.1%). There is a clear economic incentive for replacing electricity with GSHP as it provides energy savings and doubles as demand side management. In Canada, Electricity is more common than natural gas for heating in Quebec (79.9%), New Brunswick (59.9%), and Newfoundland and Labrador (71%) (NRCAN 2012a).[9]

Most homeowners adopting GSHP in Quebec and New Brunswick heated their homes with electricity (see Table 3.4). In Ontario, natural gas is dominant, and homeowners renovated away from fuel oil most of the time. The pattern of GSHP displacing electricity in regions where electric heat is most common and fuel oil in all other provinces holds throughout the dataset. Alberta is the only region where homeowners renovated away from natural gas more often than any other fuel type (29 out of 38 installations). Alberta is exceptional for having less than 1% of homes heated with fuel oil and 94% of homes heated with natural gas (*ibid*).

(%)	**Ontario**		**Quebec**		**New Brunswick**	
	Fuel mix %	***GSHP Reno %***	***Fuel mix %***	***GSHP Reno %***	***Fuel mix %***	***GSHP Reno %***
Electricity	17	38	80	67	60	52
Natural Gas	73	5	4	1	4	1
Heating Oil	7	42	9	29	13	32
Other/Propane	2	13	0	2	3	1
Wood	1	2	7	1	20	14

Source: NRCan (2012) Heating system stock by building type and heating system type.

Table 3.4 A comparison of energy sources used for heating by province to the share of homes with that fuel type renovating for GSHP

9 Fuel oil is more common in Prince Edward Island and Nova Scotia (76% and 54% respectively).

3.2.3 Compatibility and fuel type

The market share of GSHP is currently too small for its growth to be held back by compatibility constraints. Over half of all buildings in Canada are served by forced-air furnaces, which can easily be substituted for GSHP (see Appendix A). Homeowners rarely switched away from furnaces with electricity or natural gas as fuel (6% and 4% of GSHP renovations, respectively).

Grouping renovations based on previous fuel source and heating system is a telling indicator of residential motivations for adopting GSHP. Electricity and fuel oil were the most common fuels during a renovation, combining for almost 80% of all renovations. Electricity is one of the most common energy sources for heating in Canada, which appears conducive for the long-term diffusion of GSHP. Table 3.5 groups GSHP renovations from the CGC dataset among homes heated with electricity by their previous heating system.

Heating system	No. GSHP	Share GSHP (%)
Heat Pump*	2313	40
Electrical Plinth (convector)	2018	35
Furnace	965	17
Boiler	111	2
Wood stove (fireplace)**	11	0
NA	361	6

* Water 1581, Ground 131, Air Source 601

**Wood stove with electric heating

Table 3.5 The most common heating systems found among buildings adopting GSHP that had previously used electricity as a heating source

Table 3.5 shows most of the renovations for electricity was from homeowners replacing heat pumps. Thus where electricity was the existing energy source, 40% of GSHP installations were free-riders of the government subsidies. These installations did not increase awareness about GSHP nor increase their market share. They may have conferred private benefits arising from the need to replace older units and benefit from incrementally higher efficiency of newer units.

Customers who switched from an electric plinth constituted 35% of GSHP adoptions where there is a technology switch. A closer examination of electric plinth reveals the motivation for a GSHP renovation. Table 3.6 groups the electrical plinth renovations based on whether or not they had air conditioning in their homes. Approximately 88% of homeowners switching from electrical plinth to GSHP gained air conditioning.

Air Conditioning	No. GHSP	Share (%)
None	1774	88
Yes	84	4
NA	160	8

Table 3.6 The share of air conditioning among homes renovating for GSHP, which were previously heated by an electric plinth heating system

The tendency to renovate for GSHP and gain air conditioning is consistent throughout the sample. Of the 5,813 buildings previously served by electricity, 35% were heat pump replacements. Of the remaining 3,793, only 7% had previously used air-conditioning, 73% reported no air conditioning and 20% did not report.

The preference for air conditioning with GSHP aligns with a growing trend towards air conditioning among residential buildings in Canada. In 1990, only 22% of all floor space was air-conditioning compared to 46% in 2011 (NRCAN 2012d; NRCAN 2012e). Air conditioning increases comfort, along with summer space conditioning costs. This indicates homeowners were considering comfort at least as much as energy savings when renovating their homes away from electricity.

3.2.4 Site conditions

Space limitations outside of the building constrain GSHP among new and existing buildings alike. Vertical ground loops are costlier, but can be installed compactly in most locations,

whereas horizontal ground loops are less costly, but require access to land far larger than the building footprint. Pond and open loop systems are less costly still, but dependent on the availability of water features (see Appendix A).

Where economics drive decision making, less costly ground loop types should be more prevalent. Rural areas have more space for the installation of ground loops than urban, and Table 3.7 ranks ground loops based on their prevalence in rural or urban areas. Rural areas were identified as such using their postal code.[10]

Rural			Urban		
Loop	***No.***	***Percent %***	***Loop***	***No.***	***Percent %***
Horizontal	5,302	62	Vertical	2,886	42
Vertical	1,645	19	Horizontal	2,704	39
Open	1,051	12	Open	870	13
Pond	540	6	Pond	352	5
Diagonal	22	1	Diagonal	54	1
Total	8,560		Total	6,866	

Table 3.7 A comparison of the GSHP systems types[11] found in rural and urban areas

The most common type of loop in the CGC dataset is horizontal (8006), followed by vertical (4531), open (1921), pond (892), and diagonal loops (76). In rural areas horizontal GCHE are five times more common than vertical loops. Vertical GCHE were most common in urban areas, followed closely by horizontal GCHE. More often than not, homeowners elected for less costly system types wherever site conditions permitted.

It appears GSHP is more likely to be installed by homeowners in rural locations. Compared to the entire population of Canada, only 17% (5.6M) of Canadians live in rural areas, whereas, over

[10] A zero in the second digit placeholder of the FSA denotes a rural location, any other number is urban.

[11] Vertical, horizontal and diaganol GSHP are based on geothermal energy, whereas open and pond loops require and aquifer or other water source.

55% of the CGC dataset reports system installations in a rural setting. Closer inspection reveals costlier fuel types such as fuel oil, wood, and propane have also been more prevalent in these areas where natural gas distribution networks have been less profitable due to low load density.

3.2.5 Returns to scale

From an energy-economics perspective, GSHP should be most compelling in larger homes and multi-unit housing where demand for energy services would yield higher returns to investment (see Appendix B). Ideally, comparing the size and heating load of the CGC dataset to a representative population of buildings in Canada could test this, but no such dataset is available.

As a substitute, homes with and without an incentive can be compared. The economics of thermal technologies improves with scale so one should expect to see renewable thermal technologies found among larger buildings first.[12] Incentives reduce the capital cost making heat pumps compelling where they may not have been before, such as in smaller homes.

In the CGC dataset, size is measured using area (sq-ft), total cost ($), and design heat load (Btu). Design heat load measures building heat loss, including considerations for climate and insulation.

Over 90% of the installations reflected in the CGC database occurs during a period of subsidy so t-tests were used to compare the characteristics of the sample with and without an incentive.

[12] Income is likely also a factor. If persons with higher income occupy larger homes, then the capital cost barrier to GSHP may be less constraining.

Missing values were replaced with the sample mean, following the exclusion of outliers (e.g., buildings areas greater than 10,000 sq-ft).[13]

(x1000)	**Without Incentive**	**With Incentive**	**P-value**
Area (ft sq)	2.597	1.943	0.00
Total cost ($)	34.556	24.958	0.00
Design heat load (Btu)	55.549	52.748	0.01

Table 3.8 A comparison of the primary indicators of system size reported in the CGC dataset, taken during and after the availability of the federal financial incentive

Table 3.8 confirms the area, total cost, and design heat load were all smaller during periods of subsidy, with statistical significance at the 1% level. This may indicate that homes adopting GSHP tend to be larger as the technology exhibits returns to scale, and the presence of financial incentives led to smaller homes, or homes on the edge of profitability, more willing to consider adopting the technology.

3.3 Growth of GSHP

In North America, industry advocates claim the past decade has seen rapid growth for GSHP driven by the availability of financial incentives (CGC 2012a; Groff 2014; P. J. Hughes 2008). An industry survey of GSHP installations for both residential and commercial systems indicated the market for GSHP in Canada grew by 40% in 2005, and 60% annually from 2006-2008. At the peak in 2009, there were almost 16,000 GSHP systems shipped, although this estimate did not distinguish between residential and commercial systems (CGC 2012b).

Did the financial incentive lead to an increase in the share of homes heated by GSHP? Finding estimates to confirm changes in the rate of adoption for GSHP is difficult. There is no reliable, comprehensive estimate for GSHP in Canada, and NRCAN does not distinguish between GSHP

[13] Careful review of the database suggests some confusion between building area and building design heat load.

and Air Source Heat Pumps (ASHP) in its annual reporting (NRCAN 2012g).[14] The 2007 and 2011 National Household Surveys do distinguish between GSHP and Air Source Heat Pumps (ASHP). In 2011, responding to the NHS survey became optional lowering the quality of data (see Table 3.9) (NRCAN 2007; NRCAN 2011a). For this reason, I estimate the share of GSHP among detached housing units using the 2007 survey.

(000's)	**2007**	**2011**
Detached housing units	7,630	7,950
Heat Pumps	1,123	564
ASHP	460	413
GSHP	104	93[b]
Don't know	200	U
Not stated	358	U
Share of GSHP (%)	1.4%	1.1%

[b]Use estimate with caution, U refers to unreliable data

Table 3.9 Best estimates for the share of heat pumps among detached housing units in Canada as reported among the National Household Survey[15] in 2007 and 2011

The CGC dataset offers a partial sample for GSHP adoption. However, I can use this estimate to establish a floor on total adoptions and compare it to the number of systems that must be installed annually for the share of GSHP to be growing.

If the building stock were not constantly growing through new construction, the market share of GSHP would increase with every home renovation that substituted GSHP for another system. For GSHP to increase its share, the total number of GSHP systems (renovations and new construction) must be greater than its current cumulative share. Otherwise the share of GSHP is eroded by the addition of other heating system types.

[14] The annual report no longer surveys for heat pumps, but instead imputes an estimate for heat pumps by subtracting other heating system types.

[15] The year 2007 was the last year the National Household Survey was part of a mandatory census, and therefore was better estimates than the 2011 survey.

The primary source for data on new construction activity is the change in detached housing from Statistics Canada, calculated as the year over year change from the detached housing survey of energy use (Natural Resources Canada 2012f; Natural Resources Canada 2012g).[16] To increase the share of GSHP, the total number of GSHP adopted divided by new construction each year must exceed its cumulative total or lose ground to other heating types. The best estimate of pre-incentive GSHP adoptions is the 2007 NHS survey, with 104K systems. In 2007, there were around 7.63M detached housing units Canada wide, so approximately 1.3% of buildings were served with GSHP.

As shown in Table 3.10, the numbers of CGC installations in Canada and in Quebec are compared to the rate of new construction. GSHP is starting with a very small base of installed units, so to maintain or exceed their current share only 1.2K GSHP systems need be installed each year. As shown in Table 3.10, the fraction of CGC certified buildings exceeds this amount for almost every year. Even using the limited sample of the CGC database, the share of GSHP was increasing for a time.

[16] The CGC database is a residential certification program, and is predominantly populated by detached housing. The database distinguishes among building types, including: bungalow, chalet, cottage, farm house, single-family home, town house, row house, apartment bloc, and condominium. Most of these categories qualify as detached housing with the exception of apartments, and the attached housing groups of row housing, condominiums, and town housing. Approximately 84% of the installations in the CGC sample are identified as single detached houses, ~1% are categorized as attached housing and apartments, and 15% are identified as other or were unlabeled.

Canada	2008	2009	2010	2011	2012	2013
Δ Detached Housing	74,900	66,000	62,100	54,200	53,900	-
CGC Installations	3,469	4,336	2,811	1,841	401	39
Fraction of GSHP	*4.6%*	*6.6%*	*4.5%*	*3.4%*	*0.7%*	-
Quebec						
Δ Detached Housing	17,100	15,000	16,900	13,800	14,100	-
CGC Installations	454	521	399	410	484	86
Fraction of GSHP	*2.7%*	*3.5%*	*2.4%*	*3.0%*	*3.4%*	-

The 2007 NHS Survey reported GSHP to be 1.4% of all detached housing units in Canada, there was no reliable estimate for GSHP in Quebec contained in the survey (NRCAN 2007).

Table 3.10 Trends in new detached-house construction by year for Canada[17] and Quebec[18], and the number of GSHP installations certified by CGC

While the subsidy from the federal government expired in 2011, the provincial incentive in Quebec remains valid until 2017. It appears as through the subsidy for renovations led to a short-lived increase in adoptions, but the appetite was limited. In Quebec (and Canada although the CGC sample may not be representative) the number of CGC-certified systems has declined prior to the conclusion of incentive programs (Raymond et al. 2015).

3.4 The cost of GSHP in Canada

Like other energy-efficient technologies, the economic incentive to invest the higher capital cost of a GSHP system is the savings it offers in lower operating costs over time. The energy savings give the adoption an investment quality. Most academic engineering-economic studies of residential GSHP have extolled its virtues without access to empirical data on cost of installed systems (see Table 3.11).

[17] The 2007 NHS Survey reported GSHP to 1.4% of all detached housing units in Canada, there was no reliable estimate for GSHP in Quebec contained in the survey (NRCAN 2007)

[18] GSHP installations in new new were offered financial incentives in Quebec, but not the rest of Canada

Source	Country	2008 USD
Goetzler (2009)	US	9,000-15000
Self (2012)	CAD	8,900
Long (1993)	US	10,900
IRS Credit Claims (Ch. 3)	US	8,300-17,000
Heat pump replacement[19]	CGC Dataset	13,000
Closed vertical renovation	CGC Dataset	28,000
Closed horizontal renovation	CGC Dataset	24,000
New closed vertical	CGC Dataset	38,000

Table 3.11 Capital cost estimates for GSHP from the literature[20] and CGC dataset

The observed prices in the CGC dataset are much higher than reported in the literature. In this section I use empirical data on costs to calculate a homeowners willingness to pay for GSHP in Ontario (where most of the installations occurred), as well as the homeowners implicit discount rate compared other heating alternatives. I then develop an evidence-based model for estimating capital cost, under different installation conditions.

Using an approach similar to Hanova (2008), I use NRCAN energy intensity estimates (2012a) for calculating residential energy demand. Table 3.12 shows the total demand for a residential building in Ontario calculated by multiplying the energy intensity of the buildings by its area. Energy intensity includes appliance loads and lighting, so I separate space heating and hot water requirements by multiplying total energy demand by the share of energy devoted to these services. A home adopting GSHP would also gain air conditioning services so I assume a re-bound effect in energy use for three months for cooling among homes adopting GSHP.

[19] The cost of a heat pump, inclusive of installation labour, was calculated as the price paid by homeowners replacing heat pumps in water and ground-based GSHP systems.

[20] Where per ton estimates were offered, I assume a 3ton system, the median system size of CGC dataset.

Region	Area	Energy use	Space heating	Water heating	Air conditioning
Ontario	200 m^2	0.68 GJ/m^2	85GJ	30 GJ	21 GJ

Table 3.12 Demand for space heating and hot water for a detached housing unit

The efficiency of the system determines that actual energy required. GSHP is assumed to have a Coefficient of Performance (COP) of 4 (400% efficient), which holds constant for heating and cooling. I assume the GSHP system is able meet 75% of energy demand, with the remainder served with a 100% efficient auxiliary unit. The alternative electric heating system is 100% efficient, while fuel oil, propane, and natural gas systems are 95% efficient.

For operating costs, I assume energy prices from 2009 (the year with the greatest number of installations in Ontario). Most homeowners in Ontario use Time-of-use pricing that increases during peak hours (Ontario Energy Board 2015a). I estimate demand profiles based on the sample bill supplied, which shows ¾ of demand off-peak. Natural gas rates are more challenging, considering third-party vendors can sell natural gas under a variety of pricing schemes bundling charges together. Here I used rates and sample bills from Enbridge in Ontario (Ontario Energy Board 2015b), and a sales tax including HST is included. Propane and fuel oil prices include a fixed fee of $200 per year for re-filling fuel tanks. The capital cost for GSHP is $28,000 (median price of a vertical GSHP renovation), and $10,000 for natural gas, fuel oil, and propane heating sytstems. The capital cost of electric heating is $5,000.

Table 3.13 shows the fuel mix for heating in Ontario compared to the proportion of homes with that fuel type that switched to GSHP. Next to each fuel type it shows the difference in costs between GSHP and each alternative over 15 years including the cost of additional air conditioning. The last two columns calculate the implicit discount rate with and without the combined provincial and federal rebates totalling $10,000.

	Fuel mix for heating		Difference compared to GSHP over 15 years		Implicit discount rate for GSHP over 15 years	
	Ontario	GSHP Reno	Premium/ Discount	AC Rebound	$28K CAPEX	$10K rebate
Natural gas	73%	5%	-17,000	-2,200	-27%	-20%
Electricity	17%	38%	-3,000	-2,200	-2%	6%
Fuel Oil	7%	42%	14,300	-2,200	9%	26%
Propane	1%	13%	16,800	-2,200	10%	28%
Wood	2%	2%	-	-	-	-

Table 3.13 The difference in lifecycle cost between GSHP and the implicit discount rate with and without $10,000 incentive over 15 years

Compared to electricity or natural gas, a homeowner would pay between $5,000-$19,000 more for GSHP. These homeowners adopting GSHP either had very low, or negative, discount rates, or were willing to pay a premium for the green attributes or air conditioning features of the technology. In stark comparison, the costly fuel types of fuel oil and propane permit homeowners to adopt GSHP and still save money with the rebound effect of air conditioning. These homes could have discount rates as high as 9-28% depending on whether the $10,000 rebate was available.

When comparing to the prices observed in the US, it appears Canadian installers are pursuing a pricing strategy that makes GSHP compelling only to homeowners served by costly fuel types or those willing pay a premium for the green attributes. This strategy may not succeed in the long run considering the homeowners with these attributes are in limited supply, and once this group has been exhausted, the growth possibilities for high-priced GSHP are limited.

3.4.1 Drivers of capital costs

The CGC dataset provides a valuable opportunity to examine the relationship between system cost, site, and system characteristics. This includes issues of backwards compatibility with the previous heating system, the importance of site conditions on the cost of the ground loop, and

homeowners' willingness to pay when switching from costlier fuels. The variables and their parameters are described below, followed by an ordinary least squares measurement of their relationship to total system costs.

The CGC dataset contains indicators for size, such as building area (sq-ft) and whether the system contains any additional loads, such as adjacent buildings, pools, or saunas. The fraction of total heating met by the ground loop is also included. Ground loops can be sized to meet anything from 60-100% of the peak demand – depending on the customers' willingness to use an auxiliary unit to meet peak heating a small fraction of the time. Under typical conditions, a ground loop capable of serving 70% of the demand would be capable of meeting >90% of all demand (see Appendix A).[21]

Compatibility constraints outside the building are described by the ground loop and soil conditions. There is a dummy variable for closed pond, open loop, horizontal, vertical, and diagonal ground loops. Beneficial soil conditions, such as conductivity or porosity, are indicated with a dummy variable identifying if soil was described as damp or contained clay.

For compatibility constraints inside the building, I include dummy variables for the previous heating system type including: forced air, boiler, stoves, electric plinth, and heat pumps. I also include a dummy variable for new or existing buildings, as a new building may require more materials inside the building.

[21] Given the prevalence of GSHP systems in rural areas, customer choice about the loop size is also informed by the reliability of electricity supply in their location and availability of secondary heating (such as wood fireplaces).

A dummy variable is used for each previous fuel type to test whether homeowners are willing to pay more for GSHP in areas where fuel substitutes are costly. Dummy variables are present for wood, fuel oil, propane, natural gas and electricity.

Other factors that might increase costs include the heat pump characteristics, such as the efficiency of the heat pump. I also included dummy variables for add-ons such as desuperheaters, thermostats, and insulation.

3.4.2 Data and results

As shown in Table 3.14, the Ordinary Least Squares (OLS) model was statically significant, explaining 40% of variance with 9,070 observations. Almost all of the parameters selected were significant at the 1% level, and at least one variable from each of the above groups was found statistically significant.

The model essentially calculates the implicit price, or effect on price, for certain features of GSHP system. It illustrates how conditions favouring economic installations and compatibility concerns can greatly affect system costs. Persons with access to water sources, space for trenching, and minimal work requirements with the building's inner mechanics, clearly benefit. Added features, such as auxiliary heaters or desuperheaters increase investment upfront, but will reduce operating costs.

All of the five variables related to system sizing were all found to have significant, positive relationships with total costs, and so were all of the variables describing site conditions. The dummy variable for new construction increases price by $16.5K, compared to a renovation. This

large price step fits the dataset, considering mean price of a new building is greater than a renovation in the CGC dataset ($37.7K and $24K on average, respectively).

On average, every loop type was costlier than an open loop, which was the reference for comparison. The availability of space for horizontal loops or nearby water features can result in significant savings. Vertical or diagonal loops come at a premium of $5-$3K more than horizontal loops while having favourable soil characteristics decreased costs by about $800.

The prior heating system is a major determinant of compatibility and of cost. The reference system was a boiler, which operates at a higher system temperature than GSHP so would require some additional work within the building. Renovations among furnaces, air source, ground, and water heat pumps were all less costly considering they require the least amount of work inside or outside of the building.

Of the key energy variables, electricity was the reference fuel and neither wood nor fuel oil was found to have statistically different price from electricity. Only propane was found to be costlier on average than electricity.

Among variables describing the technology and additional work, the heat pump's coefficient of performance did have a statistically significant effect on prices.

In general, persons with access to water, space for trenching, and minimal inner-building work requirements can realize substantial cost reductions. Conversely, persons without these characteristics will find the capital cost of GSHP to markedly increase along with the payback period of investment.

	Coefficients	*Estimate*	*Std. Error*	*Sign.*
Size				
	Design Heat Load (btu)	0.2	0	***
	Area (sqft)	0.9	0.1	***
	Load Factor (%)	3626.5	523.9	***
	Domestic Hot Water	636.4	523.9	***
	Pool Water	6337.4	741.4	***
	Adjacent Building	33326.8	1171.5	***
Site Conditions				
	Loop Type			
	Vertical	10492.8	359.5	***
	Horizontal	5876	357.9	***
	Diagonal	9601.6	1566.6	***
	Pond	5189.6	421.1	***
	New Construction	16553	3602.4	***
	Good Soil	1229.4	198.3	***
Housing Characteristics				
	Heating Before			
	Hydronic Heating	825.3	535.2	
	Electric Plinth	553.6	361.6	
	Stove (fireplace)	-1654	956	*
	Furnace	-901.2	251.7	***
	Heat Pump - Air	-1664.3	330.3	***
	Heat Pump - Ground	-9813.6	788.6	***
	Heat Pump - Water	-9324.1	379.7	***
Energy				
	Fuel Before			
	Fuel Oil (mazout)	520	262.2	**
	Fuel Oil & Wood	316.5	668.5	
	Fuel Oil & Electricity	365.7	855.5	
	Wood	65.4	732.9	
	Wood Pellets	554.6	1230.5	
	Propane	1185.5	334.9	***
	Natural Gas	815.8	368.9	**
System Characteristics				
	Performance Coefficient	1165	251.6	***

	Coefficients	*Estimate*	*Std. Error*	*Sign.*
Other Work				
	Auxilliary Heater	515.6	209.9	
	Desuperheater	1019.4	256.3	**
	Antivibration	77.3	336.6	***
	Insulation	422.8	161.8	
	PumpingKit	473.3	230.6	***
	Filter	-384.8	328.8	**
	Thermostat	885	270.7	
(Intercept)		-2624.8	1480.2	***
				*
	R2	**0.402**		
	Adj. R2	**0.4**		
	n	**9070**		
	Signif. codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1			

Table 3.14 The relationship between independent variables and total cost

Comparison of pricing behaviour with another dataset of GSHP installations outside of Canada could yield new insights on drivers of costs. As indicated earlier, the cost of GSHP is higher in Canada than in the US despite the same capital equipment, most of which is imported from the US. If installers are engaging in strategic behaviour by increasing prices in areas where competition is limited or when incentives are available, comparing this dataset with the US could identify such opportunistic pricing behaviour. Alternatively, this could be analyzed within the CGC dataset through a cross-sectional analysis comparing the price of GSHP in areas with multiple installations compared to underserved regions.

One of the potential advantages of a financial stimulus is a decrease in prices, as industry actors learn by doing (see Chapter 4). In Table 3.15, I have divided the cost of GSHP by the size of the

heat pump in refrigeration tons to calculate the price per ton (PPT) of GSHP for the years 2006-2014, distinguishing between horizontal and vertical loops. For vertical loops, the median PPT of GSHP increased steadily, with a slight plateau in 2011. Among horizontal loops, the price did decrease slightly, but rebounded in 2013. Future research comparing the pricing strategies of installers in response to financial incentives might explain this trend.

Vertical	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
No.	2	120	856	1,081	670	575	374	63	3
Median	9,352	11,315	9,258	9,702	9,922	9,651	11,219	11,921	13,645
Mean	9,352	12,184	9,701	10,182	10,281	10,275	11,751	12,179	13,254
Horizontal	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
No.	4	39	1715	2182	1384	905	232	27	1
Median	8,392	7,075	6,729	6,865	6,750	6,789	6,607	7,778	6,250
Mean	7,858	8,260	7,091	7,281	7,174	7,111	7,146	8,420	6,250
Median Difference	960	4,240	2,529	2,837	3,172	2,862	4,612	4,143	7,395

Table 3.15 The price per ton of GSHP over time

3.5 Awareness

Lack of awareness is a commonly identified barrier to broad adoption of GSHP (Kantrowitz & Tanguay 2011; P. J. Hughes 2008; CGC 2015b). The awareness barrier can refer to both negative perceptions of GSHP among developers and the lack of awareness about benefits and long-run savings among potential end users. The CGC dataset does not measure awareness from either perspective, however, it does provide insight into the awareness barrier.

Federal and provincial incentives were clearly an important motivator for adopting GSHP, however, incentives for GSHP adoption did not lead to growth among ineligible homeowners. The federal incentive, and most other provincial incentives, was only available for building

renovations. There were 14,075 installations for GSHP as a retrofit technology and only 1,372 among new construction. The only province offering an incentive for new construction was Quebec, which is where over 1,085 (79%) of new homes adopting GSHP were located.

The scarcity of new construction is a worrying indicator of the struggles for GSHP gaining market share. If awareness is a major barrier to GSHP then the increase in renovation activity should have led to some spillover in new construction outside of Quebec.

It is also possible that different persons are responsible for making decisions during renovation and new construction activity. If the majority of homes are not commissioned by homeowners but built for sale by developers, then it may be the developers who are unwilling to invest in GSHP. Absent a market capitalizing the benefits of energy efficiency upfront in the sales price, developers must absorb this higher cost. Unfortunately, the Canadian Housing Mortgage Corporation does not track whether homes are built for sale or commissioned by homeowners, which could explain the gap between new construction and renovation.

As shown in Chapter-section 3.4, the capital cost of GSHP is greater than most techno-economic models assume. The awareness barrier pertaining to the technology's long-term economic benefits may be overstated among residential homeowners in Canada. For homeowners with access to natural gas, increased awareness on the financial considerations of GSHP could harm or hinder its adoption.

3.6 Conclusion

In Canada, GSHP was supported by federal incentives from 2007-2012. To assess the efficacy of financial incentives on residential investment behaviour, I used site level data from the CGC dataset.

The market share of GSHP is currently too small to be frustrated by compatibility constraints, however, homeowners rarely switched away from furnaces with electricity or natural gas as fuel (~6% and 4% of GSHP renovations, respectively). Homes heated by electricity and renovated for GSHP were most often already served with heat pumps, making these installations free-riders on the subsidy. Air conditioning may have motivated technology changers from electrical plinth, with 88% of home renovators gaining this service.

Other economic considerations influenced the adoption of GSHP. GSHP tends to diffuse more readily in rural areas, where space for less costly ground loops is abundant and natural gas is rare. GSHP exhibits returns to scale, and absent financial incentives, I found the homes adopting GSHP are on average larger, with larger design-heating loads.

Using the NHS 2007 survey, I estimated the share of GSHP in Canada to be small (approximately 100K units or 1.3% of detached housing). For the share of GSHP to increase total adoption needs only exceed 1.4% of new construction meaning GSHP was growing, albeit from a small base. The financial incentives in Canada gave GSHP a temporary edge, but declined after 2009, and plummeted once incentives were removed.

Most engineering-economic studies of GSHP assume capital costs. The capital costs revealed by the CGC dataset are much higher than estimates published in other peer-reviewed articles. I

recalculated the lifecycle cost of GSHP using capital cost estimates from the CGC data. The capital cost of GSHP was the most costly alternative over 20 years, with the exception of electric baseboard in Ontario. I then used ordinary lease squares to model the effect different factors had on the price of GSHP. In short, GSHP is a high-price durable good, with a capital cost greatly influenced and compatibility with the previous heating system and site conditions. Further, the price per ton of GSHP did not achieve any sizeable reductions in cost during the incentive period.

Although this was not directly addressed in the CGC dataset, there are at least two reasons awareness may not be the barrier it seems. The widespread availability of incentives for renovations did not lead to an increase among ineligible homeowners. If awareness was a primary concern some spillover should have been observed in the market for new homes outside of Quebec. Secondly, the long-term economic benefits that ought to encourage adoptions are overstated in Canada. GSHP is costlier than other conservation measures. Thus, homeowners with better information concerning prices might be discouraged to invest in GSHP.

The financial incentives were unable to sustain the adoption of GSHP beyond the incentive period, and neither were the incentives able to persuade homeowners served by natural gas or central heating (furnaces) with electricity to convert in meaningful proportions. Instead the incentive likely accelerated future adoptions while incentives were available, leading to a drop after these households had been removed from the market. Designers of public policy should consider the limited traction of GSHP when offering incentives.

The dataset provides many other opportunities for future research. For instance, I did not order the importance of these factors on decision-making when tracing the path of adoption for GSHP.

A logistic regression, in conjunction with a comparator dataset, could identify the most important factors for adopting GSHP.

The differences in price between Canadian and American prices are great despite often using the same capital equipment. Considering the capital equipment is sold on either side of the border the differences in price must be due to another factor, and a close investigation of installer behaviour could illuminate these differences.

Chapter 4: Federal tax credits and residential investment in renewable energy

Tax incentives are a popular mechanism for encouraging private investments in specified target areas. The focus of this paper is to explore the performance of investment tax credits (ITC) in promoting residential sector adoption of renewable energy technologies. The tax codes of 2005, 2008 and 2009 changed the caps on investment credits. Tax return data is used to analyze investment patterns in: Solar Photovoltaic (PV), Solar Thermal (ST) and Ground Source Heat Pumps (GSHP) in the residential sector. The natural experiment created by the evolving terms of the ITC provides valuable insights into residential sector responses to tax incentives. Investment patterns are also examined across income groups, revealing a bias towards wealthier households. Key factors determining the economic multipliers associated with renewable energy investment are demonstrated.

4.1 Changing economic regimes

Governments have often used Investment Tax Credits (ITC) to shape investment patterns. In the US, Federal and state tax credits for renewable energy conservation improvements and renewable technologies have been used since the 1970s.

The Energy Policy Act of 2005 established the current Residential Energy Conservation Tax Credit. The tax credit was introduced during a period of economic prosperity, and its impetus was to address the joint concerns of climate change and energy security through stimulation of the domestic market for private investment in energy efficiency and renewable technologies. The bulk of private investments were expended on energy efficiency measures (95% of $8.3B in 2005). Yet in the 2005-2008 period, there was substantial investment in renewable technologies eligible for the ITC: solar photovoltaic, solar thermal, and fuel cells. The ITC, as originally

conceived supported energy efficiency measures to the end of 2007 and renewable energy technologies until the end of 2008.

However, the second half of 2008 witnessed the onset of a severe economic recession unprecedented since the Great Depression. In response, the federal government passed The Emergency Economic Stabilization Act (EESA) on October 3, 2008. The EESA was an omnibus bill with many components from the Troubled Assets Relief Program to the Energy Improvement and Extension Act.

The Energy Improvement and Extension Act of 2008 (EIEA 2008) amended the tax credit for energy efficiency improvements and renewable energy technologies. To stimulate private investment, the Energy Improvement and Extension act would renew the tax credit for some technologies another eight years and expand the list of eligible renewable technologies to include any small wind and geothermal systems installed as of January 1, 2008. This was a substantial increase in incentives for geothermal, which had previously been eligible for $300 credit as an energy efficient technology (EIA 2014).

The subprime crisis deepened, and a much larger stimulus package was enacted through the American Recovery and Reinvestment Act of 2009 (Recovery Act of 2009; ARRA). The ARRA containing provisions for business, households, and for strategic investments in education, health care, and clean energy (Aldy 2011).

Greater changes to the tax credit for renewable energy technologies under the ARRA of 2009 were foreshadowed by the EIEA of 2008. Under the EIEA of 2008, all renewable technologies were eligible for a tax credit equal to 30% of initial costs but capped at $2,000 ($4,000 for wind).

The EIEA of 2008 also announced that beginning in 2009, the $2,000 ceiling on the tax credit would be lifted for PV. However, less than four months later the ARRA of 2009 would remove the $2,000 ceiling for all renewable technology. For the first time, there would be no ceiling on the tax credit.

Effectively, the Residential Renewable Energy Tax Credit straddles two economic regimes. One during a period of prosperity where incentives were offered to the adoption of renewable technologies, and the other during a crisis where incentivizing green technologies could stimulate job growth and economic recovery. This chapter illustrates how the changing incentives affected investments among different renewable technologies.

These changing economic regimes facilitate a natural experiment on residential investment in renewable technology using panel data from IRS Form 5695 through 2008-2012. Of the five technologies eligible for the ITC, three of the technologies had sufficient adoptions to warrant examination: solar photovoltaic (PV), solar thermal (ST), and Ground Source Heat Pump (GSHP).[22] These three technologies can be characterized along two dimensions: energy form (electric cf. thermal) and installation type (modular cf. site-specific).

4.2 Review

The first federal tax credit directed at residential investment in energy efficiency, the Residential Energy Conservation Tax Credit of 1977-1986, was motivated by the energy crisis of the

[22] There was insufficient uptake to study: fuel cells and small wind.

1970s.[23] Under these ITC regimes, there was very little investment in renewable energy. Therefore, the focus of early academic studies was conservation investment.

Initially, tax credits appeared to be largely ineffective for influencing investment in energy conservation at the residential scale. Pitts & Wittenback (1981) surveyed 146 homeowners having recently made conservation improvements. Only 37% of respondents correctly understood how the tax credit worked, and 18% of those eligible for a tax credit did not claim one. Chester & Carpenter (1984) found similar results with a much larger survey with IRS Form 8369 voluntary responses. Even though 87% of respondents were aware of the federal tax credit, 95% of respondents reported they would have made the investment in energy conservation with or without the ITC. Therefore, the ITC was seen as a policy tool prone to free-rider behaviour, and less effective than other policies for influencing behaviour.

Using a sample of 2,911 households from the 1982 Residential Energy Consumption Survey, Walsh (1989) was unable to find any positive significant relationship between the federal and state tax credits and qualitative measures of energy conservation improvement.

However, Hassett and Metcalf (1995) observed positive and statistically significant relationships and energy conservation improvements after correcting for heterogeneous preferences for conservation at the state level. Using panel data on 37,659 individual tax returns from the University of Michigan Tax Research database from 1979-1981, they reported a 10% increase in state and federal tax credits would increase the probability of investment in conservation

[23] Eligible taxpayers could file Form 5695, and be eligible to deduct 15% initial costs for investing in energy conservation capital, and 40% for renewable energy technologies. The conservation improvements included insulation, storm window, weather stripping and other efficiency improvements. The renewable technologies were solar photovoltaic, solar thermal, and geothermal. The tax credit also came with a ceiling on the deductible amount of $300 for energy conservation and $4,000 for renewable energy.

improvements by 25%. Long (1993) also found tax credits to be positive and highly significant for energy conservation investments with a sample of 6,364 households from the Internal Revenue Services' Tax Model File for 1981, which indicated whether respondents had filed IRS Form 5696.

In further contrast to energy conservation improvements, tax credits were unambiguously important for shaping residential investment in renewable energy. Both initial and follow-up surveys found the importance of the tax credit to increase with more costly purchases, such as solar space and hot water heaters (Carpenter & Durham 1985; Carpenter & S Theodore Chester 1984; Petersen 1985).

The current experiment with federal investment tax credits and renewable energy is well underway. Special interest groups have followed closely the evolution of the ITC, and its implications for the cost of adopting individual technologies (Bolinger 2014; Bolinger et al. 2008; P. J. Hughes 2008). Much attention in the policy arena has focused on the amount and partitioning of investment (Gold & Nadel 2011a; Gold & Nadel 2011b), and the efficacy of ITC incentives compared to other approaches (Metcalf 2008; Metcalf 2009). However, no studies on either the first or current federal tax credit have differentiated among the individual renewable energy technologies using the panel data available on Form 5695.

4.3 Renewable technology characteristics

In which I anticipate different responses to changing financial incentives for residential renewable technology investments. These expectations are informed by whether the technology produces electricity or thermal energy and its modularity. I also reflect on each technologies price trends over time and its average initial price.

4.3.1 Marginal investments and sizing criteria

The marginal investment for homeowners considering a renewable technology is the installation lying on the border of profitability. Prior to subsidy, one should expect the majority of renewable technologies to be installed in areas where they are most profitable (inframarginal). Likewise one should expect fewer marginal installations, or renewable installations bordering on profitability.

A targeted fiscal incentive will increase marginal investments in renewable energy technology, but may have a substantial number of claims filed for inframarginal investments, resulting in free-ridership. This free-ridership problem is known as additionality, when inframarginal investments absorb government credits on projects that are already profitable without subsidy (Aldy 2011).

As shown in Table 4.1, the marginal installation is larger or smaller depending on whether the renewable technology produces electricity or thermal energy. In short, the marginal installation for renewable technologies producing electricity is larger, but smaller for technologies producing renewable thermal energy.

Characteristics		Pricing	
		Fixed	**Variable**
Modular	Solar PV Solar Thermal	A large fraction of system cost. Rapid rates of technical change. Global suppliers compete on price.	A small fraction of total system cost. Low rates of technical change. Local suppliers face little competition
Custom	GSHP	A small fraction of system costs. Low rates of technical change. Global suppliers compete on price.	A large fraction of total system cost. Low rates of technical change. Local suppliers face little competition.

Table 4.1 Renewable energy technology characteristics

All of the technologies covered by the ITC can de described as renewable, but they utilize different sources of energy and provide different outputs. Both solar PV and ST technologies rely on solar radiation, but the former produces electricity and the latter hot water. GSHP provides thermal energy by using electricity (or gas) to energize a heat-pump moving energy between the earth and the home.

Electricity and thermal energy offer different utilities to the homeowner. Electricity can be transmitted over great distances and where net metering or feed-in tariffs are available returning additional electricity to the grid can generate revenue and kudos to the investor. This investment quality differentiates renewable electricity from renewable thermal energy. By comparison, the US lacks thermal energy grids through which one could transmit energy captured in excess of on-site demand for financial remuneration. The value of thermal energy is not what is sold, but what is saved. The ability to sell electricity back to the grid differentiates renewable electricity from renewable thermal energy, resulting in different sizing criteria.

Electrical systems can be sized to meet all or a fraction of household needs, depending on the homeowners preferences or affordability of the technology. A homeowner can try the

technology, installing one or many solar PV modules at a time. If a homeowner can install a larger solar PV system returning more electricity to the grid for the same price or less, it makes sense to do so. It follows that the marginal installation for renewable electricity following a decrease in price is larger.

By contrast, residential thermal systems are sized based on the needs of the dwelling. Building a larger GSHP system or installing an extra ST system that could produce more than what is needed result in excess thermal energy. Increasing the size of a system beyond what is required will only increase costs, and so thermal energy systems are most valuable when they can displace the greatest amount of on-site energy. One should therefore expect GSHP systems to be more prevalent where demand is highest, such as in large homes and climates with hot summers and cold winters. It follows that the marginal installation for renewable thermal systems following a decrease in price is in an area where demand is lower, making the marginal installation smaller.

However, removing the ITC ceiling allows its value to increase in a straight line with the size of investment, and as the ITC value increases the homeowner cost net of taxes will fall, and one could observe an increase in the average size of all renewable technologies. If the majority of solar installations for solar PV are larger, it can be assumed they are on average marginal installations. However, larger installations of ST and geothermal technologies are likely inframarginal. Limitations on inferences based on average prices and size are discussed in the next section.

4.3.2 Differentiating module based and custom built technology

Making inferences based on observed investment patterns in residential renewable energy is more difficult for some technologies than others, depending on their custom-built or module

nature. ST and solar PV are module based, whereas GSHP is characterized as custom built. Table 4.2 groups the technologies based on whether they are characterized as module-based or custom built by nature, and the implications for their pricing environments.

Type of renewable energy		**Sizing criteria**	**Marginal installation**
Electric	Solar PV	Upper bound of investment is defined by opportunity to export power and investor budget.	Larger, given that more electricity can be exported for the same level of investment.
Thermal	GSHP Solar Thermal	Upper bound on sizing is defined by own demand.	Smaller, given that the marginal installations are located in areas with lower demand.

Table 4.2 Type of renewable energy and sizing criteria

The fixed-cost components of modular systems make up a greater fraction of their total cost. Fixed costs include hard costs like capital equipment, but also soft costs such as overhead, permit fees, financing and profit. These costs are typically based either on unit costs (modules), or spread evenly over multiple installations (overhead, etc.). These characteristics are conducive to market transparency, and readily comparable pricing information facilitates competition among installers who can innovate in service delivery. Furthermore, competition among global manufacturers has driven down prices of capital equipment due to manufacturing experience and technical progress.

The variable component of the initial installation for module-based renewable technologies makes up a smaller fraction of the total costs.[24] Prices will vary among installers and local

[24] Variable cost referring to the discretionary cost, as opposed to the fixed cost components. Variable cost is not to be confused with operating cost.

conditions, but given how installation or variable costs make up a relatively low fraction of their total investment, competition can reduce any adverse price effects in the long run.

In contrast, GSHP is custom built by nature, with their capital equipment or fixed costs making up a lower fraction of their total costs. The greater share of costs lies in the installation of the ground loop, which can be upwards of one third to half of total costs. The price of the ground loop can vary widely depending on the availability of space, and heat reservoir (water, or ground) (see Appendix A). This leads to high variability in geothermal system pricing depending on site conditions. These conditions increase the value of local knowledge, limit competition amongst installers, and where pricing information is incompatible increase the threat of local capture by installers.

When making inferences based on average prices charged, module technologies are likely to be indicative of the size of installation charged. These can be confirmed by average installed prices over time via price trends, for example. The prices for custom-built technologies are more heavily weighted towards installation, and may be indicative of size, higher installation costs, or even capture by local contractors.

4.3.3 Price trends and homeowner cost net of taxes

Renewable technologies for residential applications are high-priced durable goods. Their high initial costs are offset over time through energy savings or avoided utility bills through net metering programs. However, in the absence of assumed high future energy prices, many such investments do not have compelling private economics benefits. Yet from a personal perspective, their adoption confers significant non-economic benefits, such as: demonstrating socially

responsibility, achieving greater energy independence and working to reduce GHG emissions (Roe et al. 2000).

Homeowners considering adopting solar PV, ST, and GSHP faced very different pricing environments. Three primary factors have shaped the price trends for the renewable technologies examined here. Service innovations have reduced the cost homeowners face and increased the attractiveness of the technology. Technical progress has increased the efficiency and performance of solar energy systems, both for thermal and electrical energy production. Manufacturer learning curves (and offshore manufacturing) have driven down the cost of the component parts of modular systems (DOE 2012; Barbose et al. 2013). These trends do not apply equally to the three technologies in this study.

Homeowners considering purchasing PV were faced with rapidly falling prices. Policies, such as net metering and feed-in-tariffs, have further incentivized investment in certain states. Manufacturing learning and research and development have led to declining photovoltaic cell costs from $5/W in the 1990s to $1/W in 2012 (EIA 2012b). The cost of installing a system, inclusive of service and installation costs, has also halved since the 1990s (Barbose et al. 2013). Third party ownership, another service innovation reducing the initial outlay of capital, has grown to ~70% of solar PV installations in recent years (Margolis et al. 2013).[25]

ST panel prices have been dropping due to manufacturing experience but the component parts are relatively simple, and prices have largely stabilized within the past decade (EIA 2012a).

---

[25] In this case the homeowner leases back the solar panel over time, and the installer loans back the value of the tax credit by reducing their lease payments.

There have not been any widespread service innovations for ST, such as third party financing or net metering schemes.

GSHP is a mature technology that has not benefited from either technological progress or learning through production leading to manufacturing cost declines. The installed price per refrigeration ton has shown fairly consistent prices on average over time. The average price per ton in 2008 USD from three different sources is set on the left, and to the right the average amount claimed for the Federal ITC in 1981 and 2008 are shown in Table 4.3.

	$/ton			Average Reported Cost IRS	
Sources*	**1 ton**	**2 ton**	**3 ton**	**1981**	**2008**
EIA	3,000	6,000	9,000	$10,923	$8,276
Kavanaugh	4,236	8,472	12,708		
Rafferty	4,400	8,800	13,200		
*(Defense 2007)					

Table 4.3 Price per ton of GSHP in 2008 USD

All things held equal, a decrease in the price of adopting the technology should lead to an increase in the number of installations. The federal ITC is designed to reduce the investment cost, whereby eligible homeowners can later claim back a fraction of the initial cost from their federal taxes. In this way, the total investment cost to the homeowner includes both a consideration for payments made for the technology itself and for taxes payable to the federal government. This is why household cost net of taxes represents the actual homeowner cost when adopting a renewable technology.

Removing the ITC ceiling lowers the homeowner cost net of taxes for renewable technology installations costing greater than $6000. The average initial price for installing PV and GT technologies is great enough for a 30% ITC to be limited by the $2,000 ceiling, however, the

average initial cost of ST is below $6,000 (~$5K in 2008). Removing the ITC ceiling leads to an increase in incentives for PV and GSHP yet provides no additional economic incentives for ST.

4.4 Data

Taxpayers claiming the Residential Renewable Energy Tax Credit (ITC) must fill out Form 5695. Panel data for estimated line items on income tax returns, including Form 5695, are available on the Internal Revenue Service's (IRS) website (IRS 2014). These are records of the number of taxpayers who claimed the credit, and so are conservative estimates of the actual investment in conservation and renewable technologies.

Pooled estimates on the number and total initial cost of installed PV, ST, and fuel cell technologies are available from 2006-2011. Data on GSHP and small wind installations are available beginning in 2008. Energy conservation improvements, such as storm windows and insulation, are also available during this period, with the exception of 2008 when the ITC for energy conservation was allowed to expire.

Renewable energy installations are a fraction of total items claimed on Form 5695, by both number and value. In 2009, there were ~14B credits claimed for energy conservation improvements worth ~25,000M. By comparison there were only ~212K renewable technology investments worth ~$2.5B (see Figure 4.1).

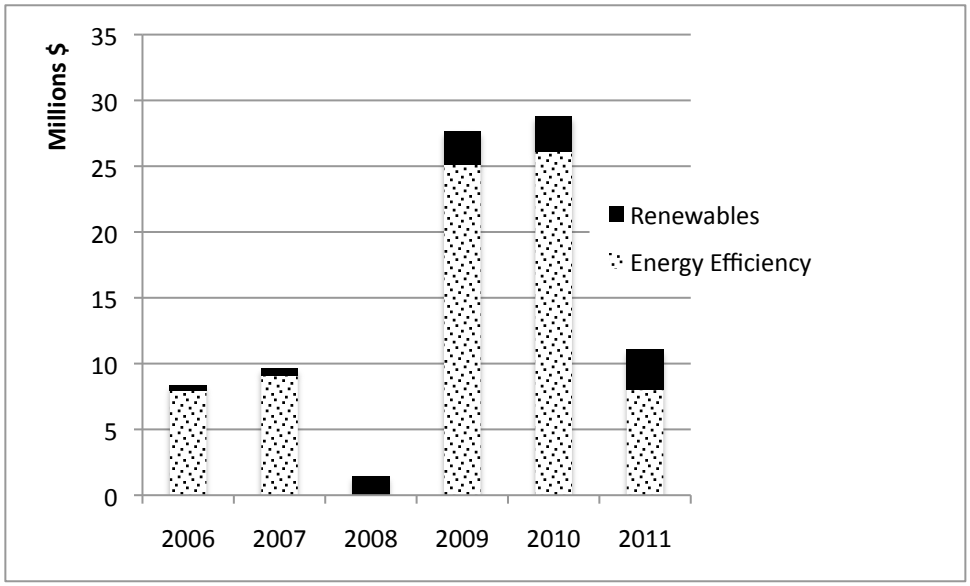

Figure 4.1 Total investment in energy conservation and renewable energy technologies

Unfortunately, Form 5695 does not indicate the average size of installation in terms kilowatts or refrigeration tons, and no median estimates are available. Micro-data on the size or geographic location of renewable energy installations is unavailable. Inferences on size are based on the average initial price and technology characteristics.

The primary observations calculated annually for each technology are the total investment value, number of adoptions, average initial price, and homeowner cost net of taxes. Dividing the initial cost of the technology by the number of installations yields the average initial price across the population of installations. The homeowner cost is calculated by subtracting the value of the ITC from average initial price. The average cost to the homeowner is calculated by subtracting the value of the tax credit from the initial price. The tax credit is equal to the lower of $2,000 or 30% of average initial price from 2006-2008, and 30% from 2009 onwards. ST is the exception, with the subsidy equal to 30% of initial costs without exceeding $2,000.

4.5 Observations of residential investment in renewable energy

The observations of residential renewable energy investment span two economic regimes, wherein the ITC was due to expire but was instead increased and expanded to include new technologies. The change in incentives clearly affected the overall investment patterns, however, there were some counterintuitive movements by PV and ST in 2008.

The year 2008 demonstrated a sharp increase in terms of the number of renewable energy technology installations compared to previous years. The average initial price claimed for these investments were also, on average, lower than previous years. This was also the first year for GSHP to be included on the renewable ITC ticket.[26]

The spike in adoptions by persons interested in capitalizing on the tax credit coincides with a dip in reported average initial prices. This creates a V-formation for average initial prices for PV and ST observed in the next section (see Figure 4.2 and Figure 4.3).

The parallel movements of PV and ST are perhaps explained by the uncertainty surrounding renewal of the ITC in 2008. The pronounced increase of installations in 2008 may have been due to homeowners and marketers anticipating the sunset of the ITC, rushing to benefit prior to expiration. For PV and ST this may also explain the slight dip in adoptions for 2009, if in a rush to claim the ITC prior to expiration a large number of potential adopters were removed from the market.

[26] GSHP was previously considered energy efficient technology eligible for a $300 tax incentive.

The rush to benefit from the ITC prior to its expiration led to many small installations by laggards wanting to test the technology, or renovate their system, while the ITC was available.[27] The consequence for this study is a need to focus on the greater price trends prior to and before 2008 for PV and ST.

4.5.1 Solar photovoltaic (PV)

There was an immediate financial benefit when the ITC ceiling was removed in 2009. The average installed cost of PV is greater than $6K, therefore the amount the homeowner can deduct from taxes increased on average. As expected, there was an increase in total PV residential investment and number of PV adoptions in the years following removal of the ITC ceiling. As shown Table 4.4 there are almost 4X as many installations in 2010 as 2006.

Solar PV	2006	2007	2008	2009	2010	2011
Number	25,854	33,822	92,052	78,329	101,932	105,554
Value ($000)	285,077	379,031	497,185	1,095,004	1,471,535	1,488,515

Table 4.4 Number and total investment in solar photovoltaic

The average initial price increased with average initial prices resting around ~$12,000 prior to the removal of the ITC, and increased to ~$14,000 afterwards, and remained at this level.[28] Consistent with a technology producing renewable electricity, this is likely indicative of an increase in marginal investments. There is no hard cap on the benefits for returning electricity to the grid, and given its modular characteristics, larger prices are on average indicative of larger (marginal) installations.

[27] It is possible to install small PV systems and expand them over time due to their module nature.

[28] During this period the module and non-module costs of installing residential solar photovoltaic systems were still falling.

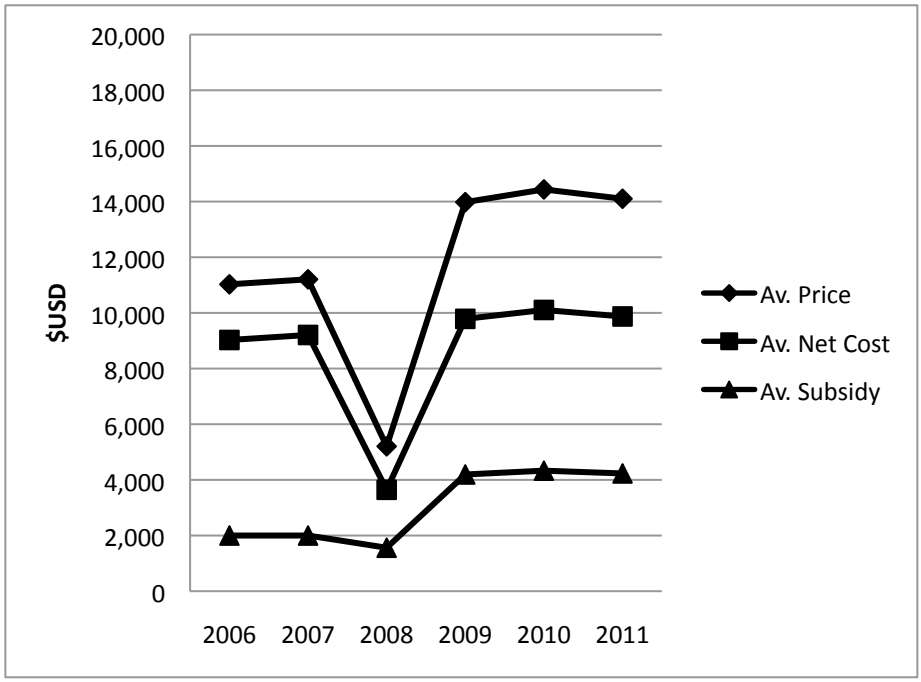

Figure 4.2 Solar PV investment observations

Even though homeowners could claim back a greater proportion of their investment, the price and homeowner cost net of taxes did not continue to climb. Figure 4.2 shows initial prices increasing by almost the same amount as the deductible tax credit at ~$2,000 in 2007 and then ~$4,000 in 2010. This increase was approximately equal to the change in value of the ITC, meaning the homeowner cost net of taxes remained relatively flat at ~$10,000 (excluding 2008). Homeowners were willing to go-out-of-pocket ~$10,000 for PV meaning their willingness to pay for PV was unaffected. Effectively, homeowners treated PV as a fixed budget decision and used the ITC to expand the capacity of the system increasing their return on investment.

4.5.2 Solar thermal (ST)

There should not have been any financial benefit for ST resulting from the ITC ceiling removal. The average cost of an ITC installed was less than $6,000, so only a minority of installations could claim an ITC exceeding $2000. Furthermore, the financial benefits for ST are capped, so

these systems are sized to meet domestic demand only. If only economic factors were considered, then there should not have been a marked change in total investment, number of adoptions, or size (price) of ST.

The average price and homeowner cost net of taxes was, as one might expect, relatively flat in the years before and after the ITC ceiling was removed. ST is a modular technology scaled based on need, and if average initial prices are indicative of average system size in the short run, homeowners did not increase the size of their systems.[29]

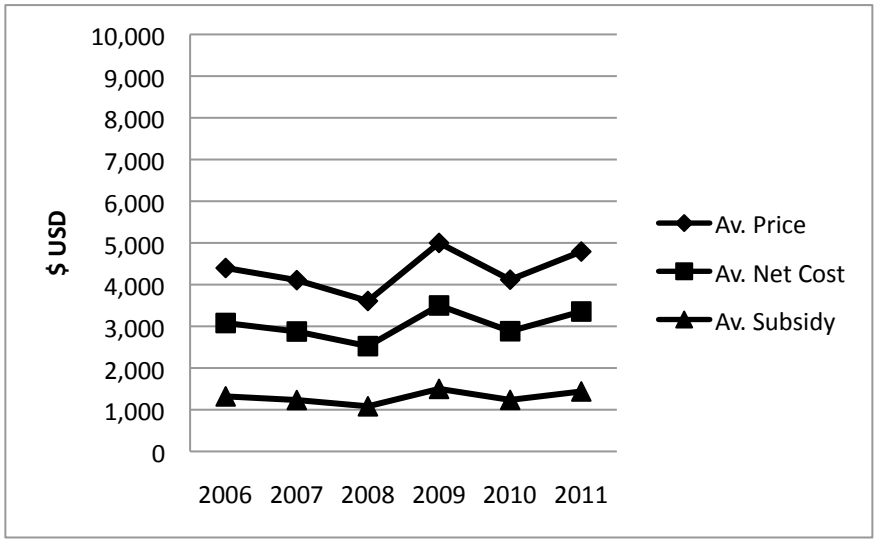

Figure 4.3 Solar thermal investment observations

There was a marked increase in total ST investment and rate of adoptions following 2009, with the number and total value of ST investment doubling in the years following the removal of the

[29] In this way they act as a control for geothermal technologies, the only other technology scaled based on need. It should be noted that the ITC for solar thermal is for residential hot water only, and does not include swimming pools.

ITC. There was no change in financial incentives, meaning the observed effect was due to a change in a non-economic lever.[30]

Solar Thermal	2006	2007	2008	2009	2010	2011
Number	24,357	26,211	61,339	42,380	53,637	57,467
Value ($000)	107,148	107,671	221,267	211,900	220,881	275,426

Table 4.5 Number and total investment in solar thermal

The observed positive effect could have resulted from a change in social or environmental factors, or perhaps from an increase in publicity associated with the Recovery Act of 2009. Whichever non-economic lever induced a change among consumers, installers, and marketers, it had a positive spillover effect for investment in ST.

4.5.3 Ground source heat pumps (GSHP)

Removing the ITC ceiling resulted in some counter-intuitive movements for residential investment behaviour in GSHP. Removing the ITC ceiling increased the financial incentives for homeowners adopting GSHP yet, while the aggregate investment did significantly increase, the number of adoptions declined from 2009 onwards.

Geothermal	2006	2007	2008	2009	2010	2011
Number			58,502	77,238	72,958	70,673
Value ($000)			484,154	1,097,334	920,180	1,215,451

Table 4.6 Number and total investment in GSHP

It has been suggested the decline in installations was due to a decline in single housing starts

[30] The price trend for residential ST is relatively flat, and it is modular in nature offering limited discretion for installers when setting prices.

(Groff 2014). The decline in geothermal installations does not, however, run parallel with the decline. The market for single housing starts declined sharply in 2006, and continued to decline in 2008. Single housing starts begin recovering from 2009 onwards; therefore the number of GSHP installations was falling during a recovery period for single housing starts (US Census Bureau 2015).

The average initial price more than doubled from ~$8,000 in 2008 to ~$17,000 in 2011. The government would have also increased their expenditures, with the value of the ITC increasing from $2K to ~$5K on average per installation. Even with increase in ITC value, the average homeowner cost net of taxes jumped from ~$6,000 to ~$12,000.

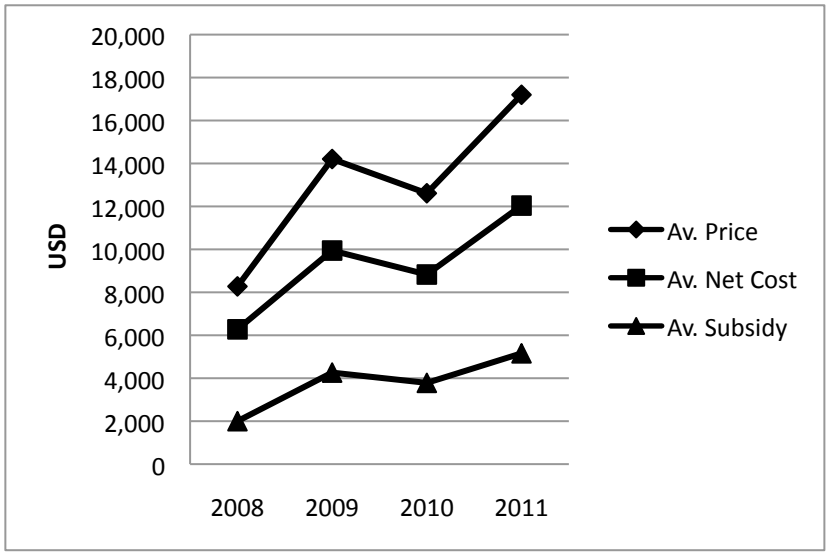

Figure 4.4 GSHP investment observations

GSHP have scale dependent returns, and one should expect rational investors to invest in larger systems more often than smaller (marginal) systems. This is supported by the available data on heat pump shipments showing the majority of systems being located in areas where loads would be higher and systems larger. Namely, in the Southern (cooling) Midwestern (heating) and

Northeastern (heating and cooling) United States (EIA 2008). Similar patterns are reported by the Department of Defense choosing to install GSHP in regions where climactic conditions shorten payback periods (DOD 2007).

If the subsidy were encouraging an increase in marginal installations, the average initial price would have remained flat or fall. The increase in average prices observed during a period of falling demand was likely due to an increase in inframarginal installations, which continued to increase in scale with the higher-powered incentives. [31]

The custom-built nature of GSHP presents a challenge for interpreting GSHP price movements as indicative of larger (inframarginal) or smaller (marginal). A larger system could be indicative inframarginal installations, but it could also indicate local capture by installers. Installers could have extracted a rent on the tax credit given GSHP's custom built characteristics, the discretionary nature in pricing system installation, and overall difficulty in comparing prices among installations.

Reconciling the degree to which system sizes or installations costs were responsible for increasing prices requires micro-data. Absent accessible US data, several conjectures are offered below that might explain the increase in prices, the first two of which can be eliminated.

- There could have been a lack of awareness prior to the introduction of the investment tax credit. If people were unaware of geothermal technologies before the tax credit, the earlier population may not have been indicative of what an average geothermal installation should cost. Data on heat pump shipments from

[31] An increase in condominiums or multi-unit buildings should not affect this. In these situations, the investment tax credit passed down to individual tenants by dividing the initial price equally among future occupants who all claim a share of the tax credit for each household.

the EIA prior to the ITC shows steadily increasing numbers making a lack of awareness seem unlikely (EIA 2012).[32]

- A change in prices could have resulted from an increase in a non-mechanical component, namely, competition for resources in the labour market for drillers. This is unlikely given how the increase in average prices for GSHP were coincident with an abundance of availability in the driller labour market, following the swift drop in the price of crude (Baker Hughes 2009).
- The tax credit may have enabled geothermal installations in more difficult to drill areas, such as homes situated on bedrock or where vertical installations were the only option. These installations may have become affordable following an increase in the value of the tax credit.
- It could be only wealthy homeowners were able to sustain greater levels of investment during the economic crisis, as observed in the average initial investment patterns by income group (see Figure 4.5). Here inframarginal installations would be dominant, as larger homes benefit from the ITC to further improve the return on already profitable systems.

4.6 Investments by income bracket

An interesting population bias arises due to the differences in cost between energy conservation and renewable energy technology. The cost of entry for energy conservation improvements is low with almost any household able to afford some conservation improvements. Renewable investments require someone to have the means afford, and favorable attitude towards, renewable technology. Previous studies on ITC found claimants were wealthier, held higher degrees, and were better informed on the how the tax credit worked (Walsh 1989; Long 1993).

[32] This includes both include geothermal and water source heat pumps.

Figure 4.5 shows the average initial investment for four income groups. There is very little difference among income groups until 2008, when the ITC for energy conservation expired. In 2008, the income groups become clearly stratified with higher income groups claiming greater amounts than lower income groups. The average amount claimed increases steadily by income bracket, with taxpayers earning between $50-100K claiming twice the amount as persons earning between $0-50K. Higher income groups are also able to sustain higher levels of investment compared to lower income groups.

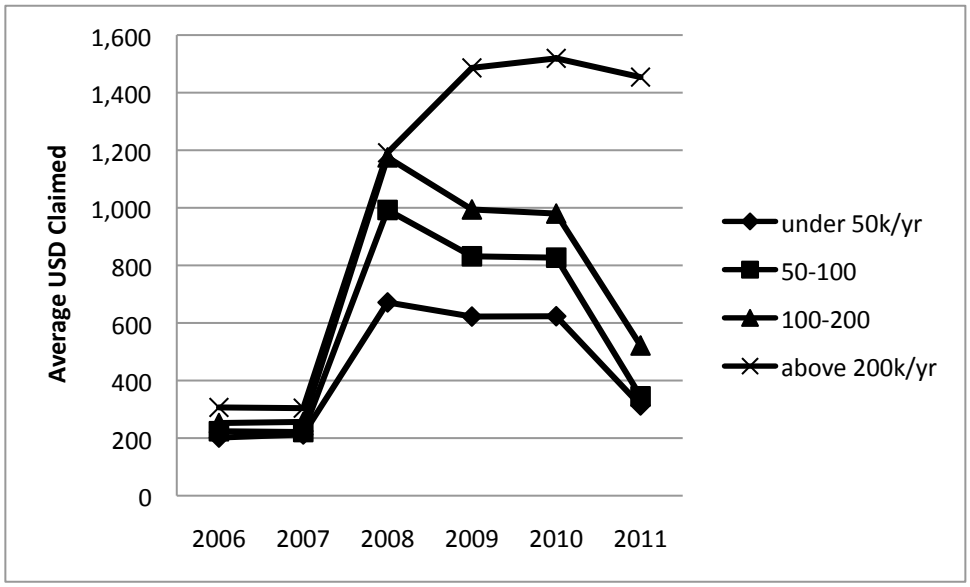

Figure 4.5 Amount claimed on average by individuals in each income group

Table 4.7 shows the number, value, and average amount claimed for different income brackets from 2006-2011. It is tempting to draw inferences on the type of renewable technology adopted by households in each income bracket however, it is difficult to distinguish among renewable technologies based on income groups for two reasons. Renewable technology represents a small fraction of the total claims, making renewable energy claims indistinguishable from the greater majority of energy conservation improvements (see Figure 4.1).

Furthermore, the only year when renewable claims were distinguishable based on income group was 2008, and this year exhibited some anomalous behavior making inferences on specific renewable energy investments for different income groups difficult (described in the previous section under aggregate investment patterns). Closer inspection on the average tax credit claimed by income groups in 2008 reveals very few, if any, of the income groups were claiming the full $2,000 credit. This year contained many small PV, ST, installations and perhaps even GSHP renovations.

Number	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
$0-50k/yr	1,096,610	1,073,880	63,440	1,638,033	1,875,799	975,476
$50-100k/yr	1,930,723	1,922,026	92,835	2,841,261	2,912,926	1,470,304
$100-200k/yr	1,054,189	1,054,235	48,684	1,781,932	1,855,059	941,193
Above $200k	262,665	276,258	20,775	450,400	512,011	255,581
Total	3,247,577	3,252,519	162,294	5,073,593	5,279,996	2,667,078
Value ($000)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
$0-50k/yr	221,332	228,412	42,590	1,019,061	1,168,750	303,728
$50-100k/yr	432,238	424,990	92,134	2,362,646	2,408,341	507,407
$100-200k/yr	266,052	270,179	57,214	1,771,641	1,817,940	491,084
Above $200k	80,529	83,996	24,749	669,333	777,859	371,618
Av Amt ($)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
$0-50k/yr	202	213	671	622	623	311
$50-100k/yr	224	221	992	832	827	345
$100-200k/yr	252	256	1,175	994	980	522
Above $200k	307	304	1,191	1,486	1,519	1,454

Table 4.7 Number, value, and average amount claimed by income bracket

4.7 Estimating the benefits of renewable energy investment

For energy conservation improvements, residential tax credits assist with overcoming the capital-cost barrier. Energy conservation requires high up-front investments to reduce energy expenditures in the long run. The "lower than optimal" level of such investments in the

residential sector has been well studied (Jaffe & Stavins 1994). Economists have described the observation in terms of high implicit personal discount rates. Psychologists and sociologists have described it in terms of the cost of decision-making and social norms (For a review see Wilson & Dowlatabadi 2007).

Similar to the overcoming the capital cost barrier for energy conservation, tax credits also lower the price of technologies producing renewable energy. This may in the long run reduce harmful externalities associated with more carbon-intensive substitutes.[33] Lower prices make renewable technologies comparatively attractive yet lowers the price of energy overall and may encourage further energy consumption (Metcalf 2008; Metcalf 2007).

The adoption of renewable technology has other far-reaching societal benefits. Social benefits such as creating a market for emerging new technologies, increasing local investment in trades and manufacturing, or reducing the price of renewable technologies over time as industry actors learn by doing.[34] There are also a number of other motivations for using tax credits to intervene in energy policy such as overcoming market barriers to energy conservation or reducing negative externalities (Metcalf 2008, p.91; Metcalf 2007, p.3).

Tax credits are also designed to leverage private investment to increase economic output and employment (Aldy 2011). Fiscal stimulus tools like tax credits are designed for this purpose,

---

[33] The environmental benefit of each technology is different. Solar PV displaces electricity that might come from a more carbon intensive source, solar thermal displaces energy for hot water (typically natural gas), and geothermal also displaces natural gas and propane with electricity. If the policy objective is to reduce the carbon intensity of electricity then solar PV can contribute to this objective, whereas the solar thermal and geothermal technologies simply reduce consumption of energy.

[34] Tax credits may also be used in line with other energy policy concerns, such as furthering national security interests by limiting dependence on foreign oil, but this is primarily concerned with transportation and supplanting foreign oil with renewable biofuels. See Metcalf (2009) for a more complete summary on tax policies and low carbon technologies.

and purchasing renewable technologies can have a much greater economic impact than simply the initial purchase price (Aldy 2011). For this reason, ITC are targeted towards investments with higher economic multipliers.

Economic input-output (EIO) models are used to calculate economic multipliers and measure the total economic impact across all sectors of the economy resulting from a purchase. Installing a residential solar panel draws on a whole supply chain spanning multiple economic sectors from construction and manufacturing to transportation and finance. The total combined economic activity between these supporting sectors of the economy is a more comprehensive indicator for evaluating the economic impact associated with adopting a renewable energy technology.

Estimating the EIO of residential investments in renewable energy technology would require detailed information of industry procurement patterns, however, the EIO-LCA 2002 Purchase Price tool developed by Carnegie Mellon can be used to illustrate the critical factors determining the economic benefits (CMU 2013). This approach considers and investment in each renewable technology as a bundle of services. The economic benefits are dependent on the bundle of services associated with each technology, heavily influenced by supply chain procurement decisions.

To consider the economic impact of residential investment in any technology the installed cost is broken down into its various components (i.e., hardware, installation, etc.). The LCA tool is then used to calculate the economic multipliers associated with investments in each sector, taking account of the differences in where the technology is manufactured and see how such investments contribute to economy-wide benefits.

The initial cost of installing GSHP can be broken down into thirds for capital equipment, drilling, and installation (Kantrowitz & Tanguay 2011). This bundle is simulated by assuming equal amounts of services and equipment in drilling, air-conditioning and warm air heating equipment, and residential maintenance and repair (represented by NAICS Industry Codes 213111, 333415, 23611, respectively). Given the supply of goods and services to each of these three sectors, a dollar invested in GSHP yields an overall economic activity of $2 (or an economic multiplier of 2:1).

The price of installing solar PV units is increasingly dominated by soft costs, such as overhead, permitting, financing, sales, and taxes. In 2012, the soft costs accounted for approximately 65% of total costs, 15% of which was associated with installation. The remaining 35% of costs were the module components, or hard costs (Friedman et al. 2013, p.5).

To model the economic impact of purchasing residential solar PV, 50% would be spent on business support services (to represent miscellaneous soft costs), 15% on residential maintenance and repair, and 35% on semiconductor and related device manufacturing (NAICS Industry Codes 56149, 23611, and 334413, respectively). A $1 investment in solar PV yields a total economic benefit of $1.8, slightly less than geothermal but still almost double the initial invested amount.

These economic benefits are entirely dependent on the bundle of services assumed, and the impact of the investment will change if component parts were not manufactured but imported. Consider the hard or module costs of solar PV. They come with an associated economic multiplier of 1.91 ($1 purchased produces $1.91 of economic activity). This assumes that all of the economic activity occurs within the US, including wholesale trade, management, chemical manufacturing, mining, scientific research and development services among others. If the

modules are imported, the only economic benefits from the initial purchase of modules are in the form of wholesale trade, transport, and perhaps an import duty will be realized (taxes are part of the economic benefit). If $1 worth of solar PV modules were purchased, then the economic benefit would only be the $0.267, assuming a 4% import duty.

Returning to the original solar PV example of investing $1 inclusive of installation, support services, and module costs, the economic impact is much lower than if the modules are imported. The new multiplier for this bundle of services is only 1.251, with the majority of economic benefit from module manufacturing lost.

The above example illustrates an important consideration when designing policies to maximize economic multipliers. If the technology relies heavily on imports, the economic benefits to the economy are lessened. These factors should be considered when allocating government expenditures to renewable energy technologies.

4.8 Conclusions

The IRS tax return panel data facilitated a unique opportunity to study residential responses to changing incentives for residential renewable energy. Micro-data is ultimately required to confirm these inferences, but this chapter demonstrated how to use technological characteristics when interpreting panel data for renewable energy technology. To interpret the data available from IRS Form 5695, the renewable technologies were differentiated based on whether they produced renewable thermal energy or electricity, whether they were module or custom built, and their average initial cost.

The marginal installation is smaller for renewable thermal technologies, which exhibit returns to scale and should be more prevalent where systems and loads are larger. The marginal installation for renewable electricity is larger, because the benefit for renewable electricity is not capped and additional electricity can be returned to the grid.

When making inferences on whether a system is (infra)marginal based on prices, the link is likely closer to a modular technology than with one custom built. PV and ST technologies are both modular, and their size closely linked to price. Geothermal is custom built, and a change in prices could be indicative of sizing, site characteristics or installers adjusting the rates they charge.

Whether the removing the ITC ceiling changed the incentive structures faced by homeowners depends on the initial cost of the technology. PV and GSHP were limited by the $2,000 ITC ceiling, and would benefit from the increased deductible. The average initial price of ST installations was low enough the ceiling was never an impediment to claiming the full 30% deduction.

Investment in PV increased along with the number of installations. The average initial price also increased, likely indicating an increase in larger (marginal) installations. The net cost to homeowners remained flat, with homeowners treating PV as a fixed-investment decision.

The average initial price, and therefore size, of ST was unaffected. The total investment and number of adoptions nearly doubled, indicating non-economic levers were influencing consumers and marketers to pursue ST. Further, the windfall of investments for ST, the

renewable thermal energy control, leads one to wonder if the increase in economic incentives would have been necessary for GSHP.

The total investment increased for GSHP, but the number of adoptions declined following 2009. The average initial price reported and net cost to homeowner nearly doubled during this ITC sample period. The increase in average price indicates an increase in inframarginal (larger) systems or an increase in prices charged by installers given their discretion over pricing.

Investments among different income groups were also considered. The greater capital cost of renewable energy led to wealthier households benefitting more from the ITC for renewable energy. The amount claimed on the renewable energy tax credit was greater amongst higher income brackets, and wealthier households were also able too sustain investments during the protracted recessionary period. This is not outside the objectives of the tax credit, which sought to promote investment to assist with the economic recovery, and higher earning income groups contributing more than lower income groups serves this purpose.

The total economic benefit of residential investment in renewable energy depends on the bundle of services associated with its production. Using Carnegie Mellon's EIO-LCA model, the importance of sourcing services and products nationally was shown. When considering the policy objectives for an ITC, policy makers should consider the trade-off of lower prices for imported products against the higher economic multipliers of buying local.

This natural experiment compared residential investment following the removal of the ITC ceiling for PV, ST, and GSHP. In particular, a challenging policy problem for GSHP emerged. Namely, it may be possible to increase investment in geothermal by removing an ITC ceiling,

but doing so will likely lead to an increase in free-ridership amongst already profitable installations.

Chapter 5: Determinants of public sector green investment

This chapter examines the key factors influencing decision-making by the Delta School Board #37 (DSB) in British Columbia, Canada, regarding their space conditioning and water heating needs over the period date to date. The DSB chose to accept a Thermal Energy Services (TES) contract, which would be regulated as a public utility by the British Columbia Utilities Commission (BCUC). The thermal plants, consisting of geothermal and high-efficiency natural gas equipment, are financed, owned and operated by the TES provider, FortisBC. During decision-making proceedings only minor deviations in regulated alternatives to the contract proposed were examined in detail. Yet the novelty of this approach requires closer examination for understanding the costs of such a service to the public sector. Using standard economic criteria I compare the cost of the TES contract to four counterfactuals including: a regulated alternative, two public procurement alternatives, and a 'status quo' scheme on ongoing energy payments. The non-economic factors found to have played a dominant role are: carbon savings, the accounting treatment of capital costs, and a preference for regulatory oversight. The additional cost to the public sector for these non-economic factors over the project lifespan is a premium of 13% ($1.5M) for third party financing via a TES contract. The project also received provincial and federal contributions equal to 21% (~$3M) of its lifecycle cost, or slightly less than half of its capital cost. I conclude with policy recommendations for public institutions prioritizing capital equipment renovations during periods of fiscal constraint while pursuing carbon reductions.

5.1 Motivation

Financially constrained Public Sector Organizations (PSO's) increasingly consider energy services from third parties for renovating buildings and replacing worn capital equipment. This affords access to private sector expertise in energy services and project management. Bundling the design, finance, construction, and operation project phases together also aligns investments incentives to increase quality (Sutherland & Araujo 2010; Iossa & Martimort 2009).[35] Furthermore, there are other intangible benefits such as freeing up capital for other projects and having building improvements sooner rather than later (GAO 2005a).

In the US between 1999-2003, federal agencies undertook over $2.5Billion worth of Energy Performance Contracts (EPC) for capital improvements. Under the intended terms of the EPC, the renovations would be financed entirely from energy savings with no upfront costs (GAO 2005b).[36]

The Government Accountability Office (GAO) conducted an audit of the EPC contracts written for federal agencies to reveal some disheartening patterns. Many agencies expected EPC contracts to be afforded by energy savings, however, it could not be verified by the GAO. The GAO found the limited competition may have led to costlier EPC contracts, furthermore, a lack of expertise in EPC contracting among federal agencies led to unfavorable contract terms and conditions, such as markups and interest rates. The GAO concluded increased scrutiny of

---

[35] There are also gains to be had when bundling renovation projects together so that capital equipment decisions are made in light of conservation measures, such as insulation.

[36] Some agencies contributed capital earmarked for improvements to reduce the amount owed on the EPC to increase the return on investment. Confusion arose among agencies as to whether these projects must then also offer additional financial gains to cover their own capital contributions.

appropriations with no upfront costs is required, as they led to higher costs in the long run (GAO 2005b).

The Government of British Columbia has enacted significant legislation to mitigate climate change and foster a low-carbon economy. In January of 2008, the Greenhouse Gas Reduction Targets Act (GGRTA) came into force. The GGRTA set ambitious targets Greenhouse Gas (GHG) reductions of 33% below 2007 levels by 2030 and 80% below 2007 levels by 2050 (BC L.A. 2007). In May of 2008, British Columbia became the second province in Canada to introduce a revenue neutral carbon tax via the Carbon Tax Act (BC L.A. 2008b).[37] The GGRTA also provides authority for Carbon Neutral Government Regulation (December 2008), which requires all PSOs to reduce, measure, report, and offset all carbon emissions to net zero from 2010 onwards (BC L.A. 2008a).

The carbon neutral mandate applies to all PSOs, including schools, hospitals, and crown corporations. Delta School Board #37 (DSB) of Delta British Columbia embraced their mandate by actively pursuing building improvements and capital equipment renovations. Once provincial grants for renovations slowed, the DSB sought third-party finance and entered into a 20-year contract with FortisBC beginning in 2012. Under this contractual agreement, DSB received extensive upgrades and renovations to their existing mechanical systems. In all, a dozen geothermal systems (11 closed loop, 1 open loop) and seven high-efficiency natural gas (HEGB) systems were installed at no upfront cost as part of an ongoing Thermal Energy Service(s) (TES) (Fortis 2011c, p.1).

---

[37] The carbon tax is revenue neutral, meaning carbon taxes paid are returned by a reduction in taxes elsewhere. The carbon neutral attribute of the legislation does not benefit non-taxable entities, such as school districts.

In exchange, the DSB is billed by the kilowatt-hour of thermal energy delivered in lieu of payments for capital equipment, electricity, and natural gas. The equipment is financed, owned, and operated by the Thermal Energy Service (TES) provider, FortisBC (Fortis 2011c). The TES cost of service (COS) rate was subject to regulatory oversight, in part due to the broad definition of a public utility by the British Columbia Utilities Commission (BCUC, Commission) (BCUC 2012d, p.10). Setting an important precedent in North America, the COS rate was calculated by pooling the relevant costs of the DSB's 19 geographically dispersed buildings.[38]

The DSB district stated their objective was to renovate all 19 buildings, maximizing energy and carbon savings within their budget (DSD 2012, p.4). This renovation assisted the DSB in meeting their environmental objectives, including compliance with the provincially imposed carbon neutral mandate for all Public Sector Organizations (PSO) in British Columbia (BC L.A. 2008a). The renovation was effectively a switch from natural gas to electricity, and this renovation promised to reduce carbon emissions by 70% of status quo at the 19 sites (FortisBC 2011c, p.4).

The TES method of financing offers a compelling prospect for public institutions facing shortfalls in capital contributions from governments. The DSB was subject to difficult financial constraints. The BC Government had rejected prior funding applications for capital equipment, however, through the TES contract the DSB could afford to renovate all 19 buildings at once without committing any of their own capital upfront. The DSB did so without conflicting with any of their debt limitations. The equipment was not recognized upfront on the statement of

[38] Pooling the buildings under a single rate is a form cross-subsidization, not unlike how rural telecommunications were subsidized by urban ratepayers . This is the only project in BC where a project was allowed to cross-subsidize rates among geographically diverse projects using COS rate methodology.

financial position (balance sheet) of the DSB as an asset or liability, but was instead scored annually as an operating lease on their statement of operations (income statement).

How much more was the public sector willing to pay for this new service? The DSB knew the full cost of the TES contract, but the Commission indicated that the range of alternatives presented in the original submission were not as detailed as envisioned in a typical Certificate of Public Convenience and Necessity (CPCN) (BCUC 2012d, p.28). The lack of comparisons explored is at least partially due to the difficulty in designing a contract that would meet the various constraints faced by the DSB. The actual targets and constraints of the DSB are only vaguely described in the proceedings, and in their final submission FortisBC states that the DSB has "specific objectives, specifications and constraints that have to be met to make any project viable" (Fortis 2012b, p.4). As I will illustrate here, the DSB and PSOs can still construct meaningful counterfactuals based on information contained in a standard regulatory filing and evaluate the cost of the contract.

Infrastructure investment and investment behavior is poorly predicted by econometric and traditional net present value calculations. Traditional investment theory predicts that investors will choose the less costly investment, all else held equal. However, investment decision-making is influenced by preferences for lower upfront costs, the availability of capital, risk aversion, preferences for green services, and uncertainty surrounding the volatility of future prices (Fazzari et al. 1987; Dixit 1992).

Here, I use standard economic criteria to compare the TES contract signed to four other scenarios created using publicly available information in the Rate Development Agreement (RDA) filed with the BCUC (Fortis 2011c Appendix D). By assessing the reasonable alternatives that DSB

did not choose, we can measure their revealed preference for three valued criteria: low carbon, least upfront capital, and regulated cost of service rates. I conclude with policy recommendations and best practices to facilitate public procurement decisions balancing pressing climate change commitments with other concerns during periods of rising public indebtedness.

5.2 Background of regulatory proceedings

In British Columbia, it is increasingly common for regulated utilities to operate downstream of the utility meter, offering Thermal Energy Services (TES) for firms, cities, and Public Sector Organizations (PSOs) (BCUC 2012a).

FortisBC is a publicly regulated utility and wholly owned subsidiary of Fortis Inc. FortisBC is a natural monopoly and the largest distributor of natural gas in British Columbia, also offering electricity, and infrastructure services (BCUC 2012d, p.5). In recent years, FortisBC has expanded their offerings upstream and downstream of their traditional regulated distribution utility services. FortisBC entered markets upstream of their gas distribution service by purchasing assets for the production of bio-methane (BCUC 2012a, p.42). FortisBC entered markets downstream of their distribution services by offering Thermal Energy Services (TES), potentially owning capital equipment within the buildings themselves, for heating, cooling, and hot water services (BCUC 2012a, p.63). FortisBC introduced their TES services through FortisBC Energy Inc., which is the sole distributor of natural gas in the lower mainland of British Columbia.

The delivery of thermal energy through a TES contract qualified this project as a public utility in British Columbia. The broad definition of a utility in British Columbia has resulted in the BCUC entertaining applications from real estate developers seeking to develop TES projects for future

developments (BCUC 2012d, p.10). For this reason the DSB project qualifies as a utility as defined by the British Columbia Utilities Act, (BC UCA), even though the BCUC found the market was competitive not warranting regulatory intervention (BCUC 2012d, p.21).

The DSB inquiry began on November 28, 2011 when FortisBC filed a Certificate of Public Convenience and Necessity (CPCN) for approval by the BCUC, requesting permission to build, own, and operate thermal plants for the DSB as part of a regulated utility. Without an approved CPCN, no person or agent can begin construction, extension, or operation of a public utility within British Columbia (UCA 1996 Section 45.1). The CPCN contains information the BCUC needs in order to evaluate the application, including information on the rate and Rate Development Agreement (RDA) (UCA 1996 Section 46.1).

On March 9, 2012, the BCUC announced their decision approving the CPCN on the grounds that FortisBC and the DSB were two sophisticated parties who entered into a mutually beneficial contract, and it was therefore in the public interest (BCUC 2012d, p.116). In short, the DSB was able to renovate their aging equipment while advancing their climate objectives, and FortisBC benefited by gaining valuable experience offering a new service distinct from their traditional natural gas services (BCUC 2012d).

The approval of the CPCN was subject to a number of conditions, such as the requirement for FortisBC to delegate the DSB project from FortisBC Energy Inc. to a separate regulated utility affiliate, namely the newly created Fortis Alternative Energy Service (FAES) (BCUC 2012d, p.96). This delegation allowed for greater structural separation between natural gas and TES utility affiliates and for more transparent observation of the new business. The novel 'pooling' approach to grouping standalone discrete sites under a single postage stamp rate was also

approved, but was not permitted to extend their rate beyond the 19 buildings described in the CPCN (BCUC 2012d, p.117).

The proposed rate and rate design were, however, rejected by the BCUC. The BCUC maintained reservations against using the Cost of Service (COS) rate agreed to in the contract, describing the COS rate as a heavy-handed form of rate regulation transferring most of the risk onto the ratepayer (BCUC 2012d, p.80). The BCUC requested the two parties to consider another rate design that might divide the risk more evenly between the parties, such as a market rate pegged to the price of natural gas. The DSB and FortisBC were asked to return within 30 days having reviewed alternatives to the COS rate, and to compare the Net Present Value (NPV) of the lifecycle cost of the market rate to the COS rate after adjusting for amortization and the deferral account (BCUC 2012d, p.117).[39]

In complying with the BCUC's request, FortisBC and the DSB had their first compliance filing for the revised COS rate rejected, but their third compliance filing was approved (BCUC 2012c; BCUC 2012c; BCUC 2012b; BCUC 2012b). The BCUC maintained serious reservations against allowing COS rate methodology but were not willing to rule out COS if both the DSB and FortisBC desired it.

The DSB project was subject to intense scrutiny and lengthy inquiry due to the project's novelty and number of registered interveners with vested interests.[40] In the end, the CPCN for the

---

[39] The BCUC found that the costs would be greater than indicated once necessary adjustments changes amortization of the DSB deferral account were considered. Furthermore the cost of debt would be changed to reflect a BBB rating, and overhead costs would only be assigned during years when capital costs were incurred.

[40] There was an extensive list of registered interveners for this inquiry, and their arguments will not be summarized here. Neither will I list all of the conditions for the CPCN approval. Intervener arguments and BCUC summary

project was awarded by the BCUC with few material changes. In the aftermath of the inquiry, the record of the regulatory proceedings provide valuable evidence enabling thorough audit of the project so as to provide guidance to future public procurement decisions.

5.3 Case study and counterfactuals

In British Columbia, Public Service Organizations (PSO) have considerable discretion in procuring capital equipment. They can solicit bids for the contract, choose among technological alternatives, or even engage third parties in leasing arrangements for capital equipment (Herman 2013).

TES contracting occupies a grey area between third party finance for capital equipment and an infrastructure service remunerated with utility-like payments. How should the PSO evaluate this relatively novel method of financing? I suggest the simplest method is to compare the cost of the TES contract to a public sector comparator, or what it would cost the DSB to purchase the design-build contract and operate the equipment.

There could be any number of possible futures with different technologies and financing methods employed, but there are at least five scenarios that can be generated on a factually well-grounded basis using only information contained in the Rate Development Agreement (RDA) filed by FortisBC (FortisBC 2011c). The original RDA offers a snapshot of the DSB believed their energy payments were prior to the renovation and subsequent to it. The annual revenue requirements reported in the RDA describe all of the expenses that must be recovered from DSB in a given year, including fuel, electricity, and maintenance.

---

conditions can be found on the BCUC website. A principle-level discussion of economic regulation and the arguments contained in the TES and AES inquiries are contained in the next chapter.

The first scenario I examine is a TES contract in exchange for a regulated Cost of Service (COS) rate. This was the scenario chosen by the DSB, and approved by the BCUC. The second scenario was also proposed during the inquiry, using a market rate indexed to the price of natural gas (FortisBC 2011c). The third scenario presumes government funding for the design-build contract. This is the public procurement comparator for the green technology package offered by FortisBC. The fourth scenario assumes all 19 buildings were renovated for High-Efficiency Natural Gas (HEGB) systems. This is public procurement of business as usual equipment, without the more significant GHG savings available through switching to green technologies. The fifth scenario assumes the DSB's existing payments carry forward into the future without any renovation of the building equipment. The buildings did require renovation in the immediate future, however, for tractability of the comparative modeling exercise, a no-renovation scenario was the primary benchmark used during the regulatory proceedings for carbon and energy savings (Fortis 2011c, p.11).

The five scenarios differ in their financing, technology, and payment assumptions. These are described below, and summarized in Table 5.1. Scenarios 1-2 are regulated TES contracts. Scenarios 3-4 are public procurement alternatives, and scenario 5 looks at the existing energy payments of DSB. The NPVs of cash outflows paid by the DSB under each scenario are then compared.

	Technology*	Capital Cost	Operating Cost**	Grants
Scenario 1	HEGB, GSHP	Terminus	COS rate, CO2	Yes
Scenario 2	HEGB, GSHP	Terminus	Market rate, CO2	Yes
Scenario 3	HEGB, GSHP	Start	Gas, electricity, CO2, O&M	Yes
Scenario 4	HEGB	Start	Gas, electricity, CO2, O&M	No
Scenario 5	GB		Gas, electricity, CO2, O&M	No

*HEGB: High Efficiency Gas Boilers, GSHP: Ground Source Heat Pump, GB: Gas Boilers
**COS: cost of service, CO2: carbon offset, O&M: operations & maintenance expense

Table 5.1 Scenario characteristics and payments made by DSB

5.3.1 Scenario one: TES contract with COS rate design

This scenario describes a regulated TES contract with rates set using a cost of service methodology. This is the scenario chosen by the DSB, and the scenario to which the other counterfactuals are compared when estimating the revealed preference of DSB.

All expenses, as well as the return on investment for FortisBC, are recovered by charging for the thermal energy delivered to the DSB, using cost of service rate setting methodology. The cost of service rate is calculated by totaling the revenue requirements (energy, maintenance, taxes payable, earned return) and dividing it by the thermal energy delivered. The earned return (or regulated rate of return) is equal to the cost of equity and debt multiplied by the rate base. The rate base includes capital costs, assigned overhead, and even the feasibility study for the project design.[41]

The cost of service rate does not cover the cost of carbon emitted, which remains a separate liability for the DSB. This is the only other ongoing cost the DSB is required to pay in this

[41] Year one actually beings with a market rate pegged to the price of natural gas, which is switched to cost of service rate at the requested by the DSB. I assume this switchover occurs in 2013 (as do they), the year when the cost of service rate is lower than the market rate.

scenario. The cost of carbon offsets are estimated based on the fuel forecasts described in the annual revenue requirements.

There remains, however, a contingent liability at contract terminus. In 20 years time, the school district must either sign an extension for ten more years, or buyout the contract at its market value (Fortis 2011c, p.46). I assume buyout, since it presents the lower of the two alternative costs for this scenario, and also scenario 2. If the DSB were unable or unwilling to purchase the equipment the cost of the stranded asset would need to be absorbed by the shareholders of FortisBC.

This project used green technology offering significant carbon reductions, and as such was eligible for grants from the provincial government. The provincial government provided capital for carbon savings via the Public Sector Energy Conservation Agreement (PSECA) (Fortis 2011c, p.23).

The project was also eligible for a federal accelerated depreciations tax credit for investing in green technology. The Class 43.3 Canadian Renewable and Conservation Expense Tax Credit allows eligible taxpayers to deduct 50% of eligible capital costs each year against federal taxes (NRCAN 2013). This reduces taxes payable by the utility, the cost of which would have been recovered from the DSB under the cost of service rate. The federal incentive can only be applied to the first two scenarios. The DSB is a non-taxpaying entity, so does not have any taxable revenues against which to employ this tax credit.

5.3.2 Scenario two: TES contract with market rates

Scenario 2 describes the cash outflows of payments made by the DSB as part of a TES contract, which indexes future rates to the market price of natural gas. The difference between the cost of service (scenario 1) and the market rate (scenario 2) counterfactual reveals the DSB's preference among different rate designs.

For scenario 2, the rate charged per unit of thermal energy is indexed to the price of natural gas over time. Beginning with a negotiated rate of $0.089/kWh, the rate would be adjusted monthly to the Natural Gas Price Index for BC (CANSIM V41692506) (Fortis 2011c, p.47). However, this price index is not forward looking (Statistics Canada 2014).

There are two different forward-looking projections for natural gas prices contained in RDA: the assumptions on future prices assumed for the market rate from Stats Canada, and those used to make projects for the cost of service rate. The market rate assumptions lead to a greater increase in the price of natural gas than the cost of service price assumptions. While this makes the market rate appear more expensive, I use the assumptions on future gas prices from stats Canada for the market rate, consistent with the assumptions used during the inquiry.

All maintenance, tax, and related expenses are contained within this market rate. The DSB must also pay for any associated carbon emissions outside of the thermal energy rate, and for the contingent liability for capital equipment in 20 years time.

The technology and carbon savings delivered by this contract are identical to scenario 1 so I also award the PSECA grant to this scenario. This varies from the assumption of the BCUC inquiry

(discussed in the next section). This technology was also eligible for the federal tax credit, but I assume FortisBC accounted for advantage this when negotiating the starting market rate.

5.3.3 Scenario three: Upfront procurement of green technology

This scenario considers the total cash outflows paid by the DSB, had they purchased the design-build contract proposed by FortisBC and operated the equipment. The difference in cost between the COS TES contract (scenario 1) and the procurement of green technology (scenario 3) indicates how much the DSB was willing to pay for the TES service above the actual cost of technology and related expenditures.

This scenario requires a large one-time payment for the initial cost made in year 1, including the feasibility study for the project. This is financed with a capital grant from the provincial government, with no ongoing interest payments charged to the DSB. This is a departure from convention in calculating the cost of finance, however it does accurately portray the cash payments made by DSB. Ordinarily, a PSO does not borrow for renovations, but waits for annual grants provided by the government for facilities and capital equipment, and the cost of financing is paid by the province through bonds or taxation.

The technology assumptions are identical to the TES contract but the annual payments are different. It is a return to normal billing practices as the DSB is billed directly for the electricity and natural gas inputs they use. These annual payments are lower than assumed under the TES contract as an efficient geothermal system can return three units of energy for every unit consumed.

The ongoing maintenance and carbon expenses are also identical to the TES contract. This assumes the ongoing costs taken in the revenue requirements for the TES contract are reasonable estimates of cost for whomever owns the equipment, calculated to be ~4% of capital expenditures.

Given that the technology employed and carbon savings delivered are identical to the TES contract, I also deduct the PSECA grant from the initial cost. I do not award the DSB any benefits for the federal accelerated depreciation tax credit considering they are a non-taxable entity.

5.3.4 Scenario four: Turnkey natural gas boiler renovation

This scenario considers the cost to the DSB for renovating all 19 schools with HEGB. The difference in cost between of the TES contract (or the procurement of green technology) is the amount the DSB was willing to pay to go green with TES.

Like the upfront procurement of green technology, they are financed with an annual facility grant from the provincial government. This involves initial cash expenditure in year one, but no ongoing interest charges are paid by the DSB.

This is the only counterfactual that changes the technology mix beyond what is described in the CPCN. Each of the 19 buildings originally used natural gas boilers, and this scenario simply upgrades their boilers with HEGB (Fortis 2011c, p.11).

The costs of these renovations are equal to the fixed portion of the design-build contract. The fixed portion of the design building contract covers the turnkey installation and renovation work required in all 19 buildings, inclusive of fixed project management and margin amounts for

equipment (Fortis 2011c, p.31). While this works out to be only an approximate figure (~$100K per school), each of the buildings were already fitted for natural gas systems, so the renovations would likely be less than or equal to the projected amount for more involved renovations for GSHP. Furthermore, the DSB has recently upgraded one of the buildings for a new gas boiler, and only a meter installation was required at one of the sites (Fortis 2011c, p.24).

Future energy prices are calculated based on the revenue requirements described in the CPCN, and carbon offsets are calculated based on energy demand. In this scenario, however, the energy mix remains the same as before the renovation. Natural gas remains the primary fuel, although less gas is used due to efficiency gains. The CPCN assumes the buildings were using 60% efficient systems, I increase efficiency to 90% for predicting energy use with HEGB (Fortis 2011c, p.11)

The ongoing maintenance expenses are calculated using the same percentage (4%) and escalation rates as the original TES contract.

5.3.5 Scenario five: Initial energy payments

This scenario describes that cash outflows paid by the DSB if none of the schools were renovated. As indicated earlier, a renovation was necessary for these antiquated systems. Nevertheless, these payments were the primary benchmark for energy and carbon savings considered by the DSB (Fortis 2011c, p.12).

There are only three ongoing costs to be considered under this scenario: energy, carbon offsets and maintenance expenses. The energy costs are very high due to the poor efficiency of the pre-existing natural gas boilers (~60% efficient). It follows that there is no change in the fuel mix

away from natural gas to electricity, so carbon costs are also high. The operations and maintenance expense is assumed to be the same as described in the TES contract.

5.4 Net present value of discounted cash flows

In this section I calculate the NPV of all cash outflows paid by the DSB associated with the operation of their thermal plants. In estimating the present value of future cash flows, all future payments are discounted at the end of the year by the reported after tax weighted average cost of capital of FortisBC (7.1%) described on the Economic Test Summary (Fortis 2011c, p.68).

There are some eventualities these types of comparisons do not consider. For example, bundling of construction and operation activities may lead the project investor to invest in quality upfront if it means lower maintenance costs during the projects life, all else held equal (Iossa & Martimort 2009). Fears over energy price increases or future budgetary shortfalls may lead preferences for certain contracts ex ante that become more costly ex-post, such as the unanticipated continued decline of natural gas prices. For these reasons, the stylized comparisons used here may differ in practice.

The NPV of cash outflows for the technologies are illustrated in Table 2. The price of electricity and natural gas are derived from the revenue requirements in the Rate Disclosure Agreement (RDA), along with the annual operation and maintenance expenses. The price of carbon emissions is held constant at $25/tCo2e, as set by the Province of British Columbia. Carbon taxes applied to natural gas are not separated as a line item. They are added onto the price of natural gas paid by FortisBC, and passed onto DSB through the rate design.

Increases in the cost of energy and other expenses are based on the RDA as well. The live spreadsheet was filed confidentially with the BCUC, but model outputs are available for the years 2012-2016, 2021, and 2031. Gaps between years are filled using straight-line interpolation, which are either constant in the case of energy demand or gradually escalating at ~2% per year for energy and maintenance expenses. The price of carbon is held constant at $25/tCO2e.

The cost of any interest payments for borrowing (along with all other expenses) is contained within the TES rates charged. However, there is no interest cost for borrowing added to the upfront procurement alternatives. Ordinarily, it is not the DSB who borrows but the province. It is given annual facility grants and an annual operating budget. These assumptions with zero interest payments are in keeping with the actual cash payments made by the DSB.[42]

I depart from the assumptions in the CPCN in two material ways. First, in terms of when the project is fully installed. The project was built out over four years, however, 96% of the capital investment was made in the first two. I assume full build out in year one to simplify comparisons with the other scenarios.

Second, I exclude one cost described under the revenue requirements from scenarios 3-5. FortisBC plans for municipal taxes to be applied to their project each year in the range of $7-15,000 per year. These costs would not be applied to the DSB had they purchased the equipment themselves, as is assumed in scenarios 3-5.

---

[42] However, it is easy to relax this assumption to reflect the view of the provincial government, for example. These case studies are still valid to reflect the view of the provincial government by adding on their cost of borrowing (~4%), or even a higher utility rate (~10%). The province could then evaluate the cost of the contract in terms of its total payments, and what premium they would consider reasonable.

The total NPV of each of the five scenarios is shown in Table 5.2. The NPV of payments towards the capital cost of equipment, energy, carbon, are operating expenses are broken down into their relative category.[43]

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Capital cost	1,044,219	1,044,219	4,572,038	1,774,043	
Carbon	212,674	212,674	212,674	855,664	1,108,653
Thermal rate	12,430,618	12,224,201			
Electricity			2,791,151	1,173,511	1,173,511
Natural gas			1,513,153	6,663,705	8,653,782
O&M			3,001,767	1,160,696	3,001,767
NPV	**13,687,511**	**13,481,094**	**12,090,784**	**11,627,619**	**13,937,714**
Future cash flows discounted at 7.1%, end of term					

Table 5.2 Net present value of of payments made by the DSB

Ranking these scenarios based on full lifecycle costs indicates the following order: HEGB (scenario 4), upfront procurement of green technology (scenario 3), market rate TES (scenario 2), COS rate (scenario 1), followed by no renovation at all (scenario 5).

Ranking the renovated counterfactuals based on the NPV of cash outflows, least initial investment for capital costs, and carbon savings reveals inconsistent orderings. The HEGB renovation (scenario 4) had the lowest NPV of cash outflows, followed by purchasing the green technology (scenario 3), and then the TES contracts (scenarios 1,2). The lowest initial cost were either of the TES contracts (scenarios 1,2), followed by the HEGB renovation (scenario 4), and then upfront procurement of the green technology (scenario 3). Both the TES contract and the

[43] My estimates are higher than the present value of payments described for the cost of service and market-rate examples in the CPCN. The reasons are three fold. Firstly, I include the cost of carbon and the contingent liability. Secondly, I assume full-build out approximately two years early. However, when correcting for these additions my estimates are still higher. Upon closer inspection, the difference is likely due to discounting. My non-discounted annual revenue estimates for FortisBC (cash payments made by DSB) are almost identical, if not slightly lower. The difference, therefore, is likely due to discounting. Comparing the present value of their payments to mine for various years indicates that they are using a discount factor greater than the one reported (7.1%).

upfront procurement of green technology had identical carbon emissions, followed by the HEGB renovation and the no renovation scenario.

Based on these orderings, the DSB did not choose the lowest cost alternative even among the regulated TES contracts. The only way the ordering of these counterfactuals favors the TES contract is if the DSB sought to minimize first costs for capital equipment, sought lowest carbon emissions, preferred the COS rate design, and then considered the NPV of discounted cash outflows.

There are two measurable, non-economic preferences distinguishing these alternatives: lower carbon emissions, and lowest initial payment for the capital cost. I can measure these preferences as the differences between scenario 1 and scenarios 4 and 3, respectively. Lastly, there is a preference for COS over the market rate that can in part be explained by the uneven application of grants and concerns regarding rate volatility.

5.5 Preferences for low carbon technology

The DSB is subject to a carbon neutral mandate imposed by the province, requiring them to offset their carbon emissions. Even so, the DSB desired to go beyond their mandated obligations, and to pursue carbon reductions on a principled 'global citizen' basis (DSD 2012, p.5). The NPV analysis reveals they are willing to pay a greater amount now than the cost of future carbon offset liabilities.

The reported advantage of the TES approach for achieving energy and carbon savings was an economy of scope achieved by pooling buildings together. Somehow, it was suggested pooling buildings together under a single contract would facilitate a more efficient use and combination

of technologies (Fortis 2011c, p.10). At the very least, pooling might reduce the administrative cost of contracting renovations for each of the 19 sites (DSD 2012, p.6).

Despite the DSB's emphasis on reducing energy use and carbon emissions, the Commission was unable to find any measurable targets or guaranteed carbon savings contained in their contract with FortisBC (BCUC 2012d, p.68). When asked by the BCUC if they knew of any clause guaranteeing energy or carbon savings, the DSB responded affirmatively, but did not identify the clause (DSD 2012, p.14). If carbon reductions fail to materialize the DSB would still be responsible for the greater cost of offsetting these emissions to maintain their carbon neutrality (DSD 2012, p.6).

While this project will almost certainly reduce emissions it is unlikely the carbon reductions will materialize in the magnitude predicted, or at least cost. I will demonstrate this by comparing the projected carbon savings following the renovation to the carbon footprint of the DSB, and by comparing the cost of carbon savings in TES contract to the counterfactuals described in the last chapter.

5.5.1 Accounting for carbon

All Public Sector Organizations (PSOs) and local governments in British Columbia have carbon obligations under the Green House Gas Reduction Target Act of 2007 (GGRTA). The GGRTA requires PSOs to pursue actions to reduce their carbon emissions in 2008 and 2009, and to purchase carbon offsets beginning in 2010. Purchasing carbon offsets fulfills the requirement for PSOs to be considered carbon neutral, starting in 2010 (BC L.A. 2008a; 2007).

While the GGRTA does not set specific targets for the DSB, the GGRTA did set a collective target for the province. The target for emissions reductions is 33% below 2007 levels by 2020, and 80% below 2007 levels by 2050 (BC L.A. 2008c).

In evaluating their progress towards the targets set in the GGRTA, there are two publicly available sources by which one can reference the carbon emissions. The intended or advertised potential of the emission reductions described in the CPCN, and the actual emissions as reported by the DSB on an annual basis. Upon closer inspection the two sources cannot hope to be in agreement.

The accelerated reduction potential of the TES contract is shown in Table 5.3. The project indicated it would reduce energy use from 2,913 to 659 tCO2e per year. This carbon reduction methodology differs in two key ways from commonly accepted carbon accounting practices. It does not count the emissions from the natural gas lost due to inefficiencies, which effectively removes the incentive of carbon savings from upgrading the system. Secondly, it assumes the geothermal technology is carbon neutral. Geothermal technology is only carbon neutral if the electricity used has zero carbon emissions and the electricity in BC is considered to be 0.025t/MWh by the Pacific Carbon Trust. Taking these assumptions into consideration, the savings for the project are actually even larger at ~3K tons per year, a boon to the DSBs carbon saving ambitions.

	Reported in CPCN		Adjusted emissions	
	Pre	Post	Pre	Post
Electricity (GJ)	4,684	11,142	4,684	11,142
Gas (GJ)	58,607	13,255	83,721	14,639
Renewable (GJ)		15,164		
Waste (GJ)	25,114	1,384		
Total demand(GJ)	38,177	38,177		
Emissions tCO2e	2,913	659	4,303	1,010
CO2e emission factors: 0.05 t/GJ gas, 0.025t/MWh electricity				

Table 5.3 CO2e accounting for DSB project

The carbon savings described by the TES project can be compared to the publicly available carbon inventories for PSOs in British Columbia, including the DSB. As shown in Table 5.3, the lions' share of carbon emissions for the DSB comes from the operation of buildings. While there is some small variation over time, building operations account for 75-85% of total emissions, followed by fleet vehicles (~10%) and paper stationary (~5%).[44]

Since the GGRTA of 2007, the DSB has been proactive in reducing their GHG emissions including hiring an energy manager, replacing fleet vehicles, installing light control sensor systems, installing solar hot water systems, and replacing worn out heating and cooling equipment. Table 5.4 shows their carbon emissions for the years 2007-2013. Even under the conservative assumptions in Table 5.4, it appears the DSB was well on their way to meeting the province's carbon objectives. They had achieved a ~25% reduction of GHG within the first three years of the policy. By their own estimates, the DSB estimated their emissions were 37%

[44] However, the DSB is exempt from purchasing offsets for school buses.

below 2007 levels in 2010. So far, the largest emission reductions resulted from 15 buildings being renovated for ASHP systems in 2008 and 2009.[45]

		2007	2008	2009	2010	2011	2012	2013
Buildings	Electricity				248	244	233	142
	Gas, Propane				3,049	3,262	2,871	2,520
	Total	*4,715*	*4,715*	*4,715*	3,297	3,506	3,104	2,662
Fleet	Gas, Propane	*360*	*360*	*360*	360	367	378	452
	Biodiesel	*33*	*33*	*33*	33	36	31	13
Office paper		*437*	*437*	*437*	437	167	219	217
Total		5,544	5,544	5,544	4,127	4,077	3,733	3,344
% 2007		**100%**	**100%**	**100%**	**74%**	**74%**	**67%**	**60%**

Grey font refers to assumed values. These are assumed the same as 2010, making them conservative numbers assuming no actual carbon savings materialized in the first two years.

Table 5.4 Actual energy use across 42 building sites

Comparing the carbon savings for the TES project to the level of publicly available building emissions for the DSB overall illustrates how far apart these two futures are. The ~3KtCO2e reduction for renovating 19 buildings described in the CPCN (Table 5.3) is greater than the initial carbon footprint of 34 buildings in 2010 (Table 5.4). If the TES project delivers the anticipated carbon savings then the carbon emissions for the DSB would be negative, as shown in Table 5.5.

	2010	2011	2012	2013
Emissions 34 buildings				
Electricity	248	244	233	142
Gas, propane	3,049	3,262	2,871	2,520
Total	3,297	3,506	3,104	2,662
Projected carbon savings				
19 buildings			3292	3292
Emissions following renovation			-188	-630

Table 5.5 CO2e emissions for buildings only

The implications of these findings are unfortunate for the DSB. Either ambitious carbon savings were overestimated and will not materialize and the DSB will be responsible for greater than

[45] Building related emissions fell 31% between 2009 and 2010.

anticipated carbon costs, or the carbon emissions reported by the DSB, calculated based on energy purchases, have been improperly accounted for to date.[46] These back-of-envelope approximate calculations to test the reasonableness of the carbon savings proposed did not appear during the proceedings.

5.5.2 Willingness to pay for green

FortisBC, various interveners, and the Commission described different principle-based methods for evaluating the cost effectiveness of the TES approach to carbon emission reduction. The Energy Services Association of Canada (ESAC) emphasized the disproportionately large capital cost compared to annual carbon savings achieved (Fortis 2012c, p.2). The Commission was of the view that carbon reductions were maximized when all actions or improvements less than the price of an offset ($25) were taken, and that actions costlier than this amount were purchased with offsets (BCUC 2012d, p.63). However, the Commission did not indicate when, during the renovation of all 19 buildings, this point would be crossed.

FortisBC emphasized the full lifecycle cost of the service as the appropriate reference for whether offsets were cost effective. Further to this point, FortisBC reasoned that since the cost of service TES contract was less costly than the 'status quo' of existing payments, the project proposed was therefore cost effective (FortisBC 2012c, p.2).

Consistent with the principles of carbon reduction employed by FortisBC and the Commission, here I compare the full lifecycle cost of the procurement alternatives to identify the price paid for carbon reductions. The counterfactuals proposed here facilitate a straightforward method for

[46] My contacts at FortisBC have yet to respond to my inquiries into this discrepancy.

generating measurable estimates for the price of carbon offsets generated via the TES contract. The difference in carbon savings between scenarios 1 and 4, divided by the price difference indicates the price paid for carbon offsets generated by the green technology. The HEGB renovation (scenario 4) would emit 3,256tCO2e per year, a full 2,447tCo2e per annum more than either of the green technology renovations emitting 809tCO2e per year (scenarios 1,2,3). Over 20 years, this amounts to almost 50KtCO2 avoided.

Before offsets are considered, the full lifecycle cost the HEGB renovation and the TES contract are ~$10.8M and ~$13.5M respectively. The value of the offsets generated by the green technology over 20 years ($25/tCO2e) are ~$650K. At this carbon price, the DSB can pay a premium of $650K for green technology, and still achieve carbon reductions at or below the price of carbon. The $2.7M premium of the TES contract above the HEGB renovation is an action to reduce carbon emissions at a price of $55/ton, or an 18% premium above the lifecycle cost of the HEGB renovation.

The lifecycle cost of the upfront procurement for green technology (scenario 3), is ~$1.5M less and still generates identical carbon reductions. Adopting this technology under upfront procurement offsets carbon at $23/tCO2e. Thus it would be less costly for the DSB to purchase the green technology instead of offsetting the emissions associated with the natural gas renovation. This can be described, using the BCUC's methodology described above, as a cost effective strategy for reducing carbon.

5.6 Preferences for lowest capital cost payment

From 2008-2014, the DSB employed different technologies and financing methods to renovate 34 buildings. The first 15 buildings were renovated with ASHP in two phases. Phase 1 in 2008

installed 101 ASHP units using the annual facility grant for capital equipment from the provincial government. Government funding was not available for Phase 2 in 2009, but the DSB installed the remaining 74 ASHP units; presumably financing them out of their operating budget (DSD 2008, p.1; DSD 2009, p.1)

In 2010, there remained 19 buildings with antiquated natural gas boilers requiring replacement (DSD 2010, p.4). Renovating most of these buildings for high efficiency natural gas boilers would normally have been the default solution, but the DSB wanted to pursue geothermal technology to maximize carbon reductions. Subsequent proposals for funding of the geothermal option were rejected by provincial ministries and funding agencies (DSD 2012, p.4). Afterwards, the DSB began discussions with Fortis in 2010 to identify third-party finance for replacing the equipment in the remaining 19 buildings. Fortis and the DSB elected to install a combination of high efficiency natural gas and geothermal systems (DSD 2010, p.4).

There are at least two advantages for the DSB when financing the equipment under the TES contract compared to traditional upfront procurement. One applies to the treatment of debt on the statement of financial position (balance sheet), and the other to reducing the risk of making up funding shortfalls for capital equipment via their annual operation budget.

5.6.1 Balance sheet constraints

During the inquiry it was suggested that the ability for TES contracting to overcome balance sheet constraints explained their preferences for regulated alternatives over capital lease or upfront procurement alternatives (DSD 2012, p.9). It was also indicated that the payments might be treated as debt, and as such might be prohibited under the Province of BC's Debt Management Program (DSD 2012, p.17). However, while the DSB is subject to budgetary

constraints, they indicated that there were no legal, financial, or budgetary constraints preventing them from owning the equipment that they were aware of (DSD 2012, p.9). Even so, TES contracting does have compelling advantages above other methods of financing equipment for a PSO.

The advantage of financing capital equipment improvements via a TES contract stems from its nature as an energy service. The TES contract is not written for the purchase of technology to the DSB, but for the delivery of an energy service providing thermal energy through FortisBC owned thermal plants.

Annual payments for utility expenses, like electricity or gas, appear on the statement of operations (income statement) of PSOs. Ordinarily, the capital equipment would also appear on the statement of financial position (balance sheet) of PSOs as both an asset and as a liability. However, the capital equipment used in delivering the energy services is not recognized on the DSB's balance sheet. It is instead recognized as an operating lease. Operating lease payments are recognized annually as an expense on the income statement, with no obligations recorded on the balance sheet for the capital equipment.

This kind of 'off-balance sheet' financing avoids balance sheet constraints often faced by PSOs during periods of fiscal constraint. A balance sheet constraint may arise, for example, when governments reduce discretionary spending on items such as capital equipment to reduce deficits or balance budgets. They might do so by deferring capital grants, rejecting applications for funding, or even placing a temporary cap on new debt.

The treatment of capital equipment on the balance sheet as both an asset and as a liability means new equipment cannot be purchased without also increasing liabilities. Liabilities increase debt, and so debt-caps prohibit the acquisition of new equipment by means of upfront procurement. By financing the renovations without increasing liabilities, TES financing avoids these types of balance sheet constraints.

A debt-cap can also prevent equipment financed by a third party via a capital lease, the primary method of Energy Performance Contracting (EPC) for financing equipment.[47] Capital leases are paid down over time, and ownership is usually transferred at the end of the contract for a nominal fee. However, the full value of the equipment is recognized upfront as an asset and as a liability just as if the equipment had been purchased upfront. This demonstrates a limit on third party finance, which can provide liquidity for public institutions but cannot overcome balance sheet constraints.

5.6.2 Future capital funding shortfalls drawing on operating budget

The second advantage of TES contracting for financing capital equipment is straightforward. The DSB might have presumed they were unlikely to receive annual facility grants for capital equipment in a timely manner or in the amount required. In this event the DSB would need to draw on their already relatively inflexible operating budget, which is responsible for financing all other non-capital related expenses (DSD 2012, p.17).

---

[47] Energy Saving Companies (ESCOs) write energy performance contracts through which they agree to finance energy saving capital equipment and building improvements for businesses and institutions. Typically, the ESCO will guarantee a level of energy savings via an energy saving performance contract. In exchange, the ESCO earns a return on their investment based on difference between the initial utility payments before and after the renovation.

The DSB sought an alternative financing method to renovate their remaining buildings rather than wait to see when annual facility grants would arrive. The TES contract is more expensive in the long run, but protects the DSB from drawing from their operating budget to purchase capital equipment.

Whether for the off-balance sheet treatment or for security against making up future capital contributions out of their operating budget, a public sector comparator provides an easy to understand measurement for an otherwise obscure payment plan. The difference between the TES contract (scenario 1) and the procurement of the green technology (scenario 3), is ~$1.5M. Effectively, they were willing to pay a premium of ~$1.5M (13%) for to minimize their initial capital costs and remove concerns surrounding future capital funding shortfalls. This is a telling indicator of Canadian public sector risk aversion in technology adoption.

5.7 Preferences for the regulated rate of return

The DSB and FortisBC consistently emphasized their preference for regulated COS rate design over the alternative market-rate design throughout the inquiry and compliance filings. The BCUC remained skeptical of this onerous form of regulation but approved the COS rate design following the second compliance filing.

The DSB believed the COS rate had two primary advantages over the market rate: it was less costly, and volatile than the market rate. In the next section I will illustrate how the COS advantage depends almost entirely on the application of provincial incentives, and how its volatility was a result not of the COS methodology but due to the technology selected.

5.7.1 Application of provincial and federal contributions

Figure 5.1 illustrates the NPV of the four counterfactuals inclusive of subsidies and financing costs. The costs above the $0 are those costs paid by the DSB, whereas the costs below are capital contributions by either the provincial and federal government, including financing. The cost of financing is paid by the provincial government in scenarios 3,4 at 4% of the capital cost. The overall economic feasibility of the project and perhaps the choice between regulated rates was dependent on the application of these capital contributions.

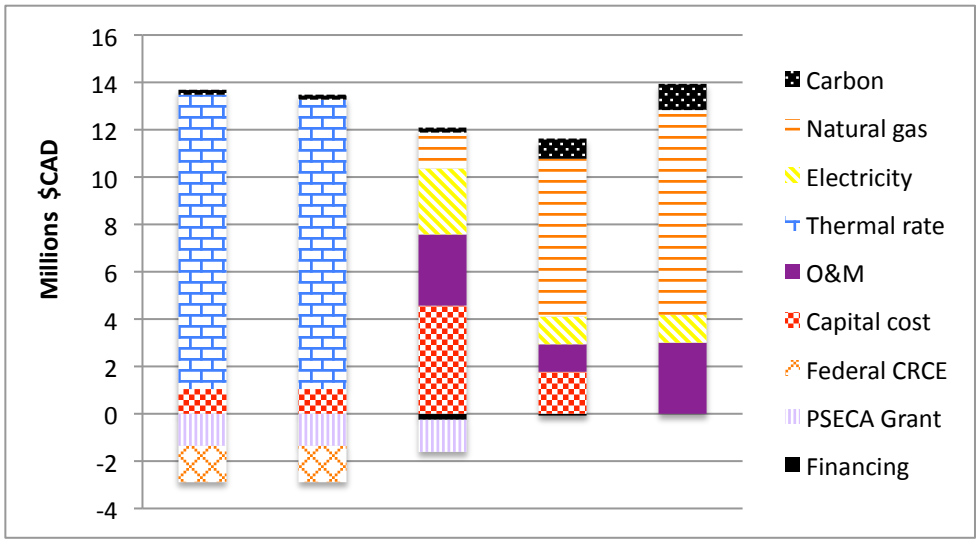

Figure 5.1 Total welfare cost in $CAD for scenarios 1-5 from left to right

The TES contract was eligible for a federal CRCE tax credit. The Class 43.3 Canadian Renewable and Conservation Expense Tax Credit (CRCE) allows eligible taxpayers to deduct 50% of the capital costs each year from taxes payable. An accelerated depreciation tax credit permits firms to deduct this expense from taxes sooner, meaning its value is derived from the time value of money.

Approximately 90% of this credit is extracted within the first five years, worth approximately $1.56M in avoided taxes. The DSB is a non-taxable entity, so it would not have been able to claim this credit without assistance from a third party. Effectively, FortisBC provided indirect tax equity financing of federal funds for the DSB.

It was not the federal but the provincial grant responsible for determining the differences in cost between the regulated COS and market rates. The provincial government provided capital for projects attaining ambitious carbon savings via the Public Sector Energy Conservation Agreement (PSECA). Compared to their initial carbon footprint prior to renovation, the green technology investment saves 3,409tCO2e annually, which adds to ~70K tCO2e over 20 years. The province contributed $1.357M for the GHG savings. At this level of investment, the province was effectively willing to pay $20/tCO2e of future carbon emissions saved by the renovation.

While scenarios 1-3 and their expressed counterfactuals generate identical GHG savings with the same technologies, they pass on the benefit of the subsidy to the DSB differently. Applying the PSECA is straightforward for upfront procurement (scenario 3). The upfront cost of the $6.5M design-building contract is reduced by $1.357M. Without this subsidy the NPV of total cash outflows by the DSD would be ~$13.5M in scenario 3.

The PSECA grant was applied to the COS TES contract (scenario 1) as a Contribution In Aid of Construction (CIAC). The CIAC results in two primary benefits. It reduces the rate base upon which the utility calculates its earned return on the capital base (~8%) throughout the projects life. The result is a rate rider of 1.8cents per kWh for every kWh charged, which reduces operating costs by ~$188K per year. It also reduces the contingent liability at contract terminus

by $1.357M. Without the PSECA grant to provide a rate rider or reduce the capital cost at project terminus, the NPV would be ~$15M, under these assumptions.

The market-rate TES scenario employed the same technologies offering identical carbon savings, yet during the DSB inquiry, the market rate was treated as if it were ineligible for the PSECA grant. Revenue forecasts for the DSB for the market rate (scenario 3) never considered the PSECA grant in the form of a CIAC or as rate rider on future revenues charged. With the PSECA rate rider the market rate is less costly than the COS rate, and without it, more costly.

The application of incentives during the decision-making may also have influenced the decision for choosing between cost of service and market rates. In both the initial and follow-up rate reviews the DSB reiterated their preference for the cost of service rate as depicted by scenario one because it was less costly, and it was assumed they would choose to switch to cost of service from the market rate in the first year it was below the market rate (DSD 2012, p.15). Assuming their preferences among regulated alternatives were based on cost, they might have preferred the market rate (scenario 2) had FortisBC offered a rate rider or similar mechanism incentive. Yet since the PSECA grant was not awarded based on a rate design, but on carbon reductions materialized, the omissions of a rate rider or similar incentive to the market rate may have unduly influenced the DSB towards the COS rate.

In total, a project with a capital cost of $6.5M received approximately $~3M in provincial and federal grants, or 21% of its lifecycle cost. Incentive mechanisms, such as the PSECA rate rider, were developed specifically for the cost of service rate. The DSB should have received this PSECA rate rider for identical carbons savings through another rate structure. The DSB only

stood to benefit from exploring their options for applying both provincial and federal incentives to alternative rate setting and procurement alternatives.

5.7.2 Volatility of the market rate compared to COS

The COS rate was preferred to the market rate because it was deemed less costly, and because it was less volatile. It is perfectly understandable for PSOs with little room for financial maneuvering to prefer contracts with greater price stability and known prices.

In performing a sensitivity analysis FortisBC compared the market and COS rates following changes to the price of gas, price of electricity, corporate tax rate, cost of borrowing, and the Consumer Price Index (CPI) to reflect labour costs among other factors.

The model used for the sensitivity analysis was filed confidentially but the outputs are publicly available. The market rate is more volatile than the COS rate and is very sensitive to the price of natural gas. In contrast, the COS rate is insensitive to the price of gas but sensitive to the CPI rate and electricity prices. Overall, the market rate is expected to be higher following these changes, with a greater variance in price following changes to the price of natural gas.[48] The results of the sensitivity analysis indicate that the COS rate protects the DSB from future increases in the price of natural gas. These results are exactly what one should expect, but can be achieved whether or not the COS rate design is used.

[48] In the sensitivity analysis they did not consider offering rate rider or similar incentive for the market rate.

It is worthwhile to illustrate exactly how the COS rate is calculated. All of the expenses incurred during the year are totaled, including an earned return on capital investment.[49] The expenses are aggregated and divided by the output (MWh), to reveal the anticipated $/MWh rate. In Table 5.6, the COS rate is calculated following a 25% change to the cost of gas, electricity, and operations and maintenance expenses.

	Initial	**Gas∆**	**Electricity∆**	**O&M∆**
	2015	25%	25%	25%
Cost of natural gas	124	**155**	124	124
Cost of electricity	234	234	**293**	234
Operations and maintenance	259	259	259	**324**
Property Taxes	8	8	8	8
Depreciation Expense	216	216	216	216
Amortization Expense	-44	-44	-44	-44
Income Taxes	-140	-140	-140	-140
Earned Return	393	393	393	393
Plus amortization	220	220	220	220
Annual Revenue Requirement	1,270	1,301	1,329	1,335
Annual Energy Demand	10,605	10,605	10,605	10,605
Thermal COS	0.1198	0.1227	0.1253	0.1259
Less rate rider	0.018	0.018	0.018	0.018
COS Rate (C/KWh)	0.1018	0.1047	0.1073	0.1079
% change		2.9%	5.4%	6.0%

Table 5.6 The effect of a 25% rate increase under a COS rate design

If, in 2015 the price of gas increases by 25%, then the new rate would be 10.47 cents/KWh. If instead the price of electricity increases by 25% then the price increases by 5.4% to 10.74cents/kWh, or to 10.79cents/kWh if the cost of O&M were to increase by the same amount. The costs are passed on directly, but the COS rate rises by less when gas prices increase than if electricity prices increase.

[49] The earned return the allowable profit, calculated by multiplying the invested capital cost of the equipment by the allowable return on debt and equity (~7.5-10%).

The DSB project has transitioned from natural gas to electricity, and adopted an energy efficient (but capital intensive) technology that uses less energy, so is less responsive to changes in energy prices. The insulation from changes to the price of gas, or even increases in the price of electricity, arise due to the energy shift and technology adopted. A market rate indexed to a bundle of energy services reflecting the technologies actual energy use is a better benchmark for a market rate.

5.8 Best practices

A CPCN approval and rate review is no substitute for prudent contracting practices. Contracting in regulated markets for TES is still a novel method of procurement, and the best practices described here can assist PSOs entering this arena. Many of the best practices are common to municipal and local governments when contracting for alternative infrastructure services

5.8.1.1 Develop a public sector comparator

When considering an alternative method of service delivery a public sector comparator is the simplest method to calculate the value added of the service provider. As shown here, a public sector comparator is readily constructed using information contained in rate design agreements to debunk otherwise obscure payment plans. Even if public finance appears unlikely in the near term a public sector comparator will assist in calculating price premiums and provides the PSO a reasonable counterfactual to aid in negotiations.

5.8.1.2 Specify outputs when contracting

The DSB contract specified technical and rate design inputs for the building renovations. There were no guarantees regarding energy savings, carbon savings, or quality of service indicators to

be found by the Commission. In fact, the contract was written so that any costs above what was anticipated during the construction phase would simply lead to curtailment of aspects of the project, thereby reducing carbon and energy savings.

PSOs should practice contracting for the desired qualities of the contract using measurable outputs or targets. The DSB can clearly describe their objectives and link payments to targets reached rewarding service providers. Specifying a 19 building renovation subject to maximizing carbon savings and minimizing cost encourages innovation among service providers and encourages them to apply their technical and management expertise. Furthermore, output contracting would have protected the DSB if energy or carbon savings fail to materialize, or would have likely encouraged a reevaluation on whether the carbon savings proposed were attainable.

5.8.1.3 Compare lifecycle costs

Comparing lifecycle costs can lead to economically efficient decision-making. Different interveners emphasized different costs during the DSB inquiry. The DSB prioritized low payments upfront and interveners emphasized the high capital cost of the project. The DSB went so far as to place a hard limit on capital costs FortisBC could incur. For the DSB, the full lifecycle cost is the appropriate measure. This should also have included other relevant costs such as the contingent liability at terminus and anticipated carbon payments.

5.8.1.4 Consider multiple rate alternatives

The counterfactuals used during the inquiry led to the DSB anchoring on the cost of service rate design. The unfeasible no-renovation scenario and the market rate pegged to the price of natural

gas were almost guaranteed to make the COS rate the most desirable alternative. No project is inimitable, and this chapter has shown using existing information regarding the CPCN that multiple comparisons can be constructed.

Moreover, the BCUC offers many different rate designs including performance-contracting rates based on their existing payments. They could have designed alternative market rates pegged to something other than natural gas. For example, a more accurate market rate following the renovation might be a rate pegged to the price of electricity, maintenance costs, and inflation.

5.8.1.5 Share risks throughout duration of contract

The party most able to bear the risks during each phase of the contract should do so during each stage, from design and construction to operation. There is clearly room for more equal risk sharing between the two parties, and the DSB may not have clearly understood the risks they assumed under a COS rate design. If the carbon savings do not materialize as planned during the design phases, then it is the DSB who must pay the higher cost of carbon offsets. The DSB has placed a limit on capital costs during the construction phases, but it is also the DSB who must pay for the greater cost of energy if the geothermal systems are scaled back or equipment malfunctions requiring excessive downtime. The DSB bears the risks of cost overruns or unplanned maintenance during the operational phases by choosing COS rate regulation. The earned return for Fortis BC will not be affected by these events (see Appendix B).

5.9 Policy recommendations

Renovating antiquated, inefficient building energy systems would benefit both the DSB and taxpayers alike. At the heart of this problem is a perceived inability for the DSB to finance their

buildings through the ordinary channels. Rather than continue to operate these deficient systems, or risk having to pay for their replacement out of their own pocket, the DSB chose a TES contract that could finance the renovation of all of their buildings. This resulted in the DSB paying a substantial premium over an own-operate scenario.

The DSB was subject to difficult capital constraints limiting their options. They were unlikely to receive capital grants of sufficient magnitude from the provincial government. If the DSB supplemented these funds with third-party finance from an ESCO, the capital lease would still appear as debt on the balance sheet and could be prohibited under the province's long-term debt management strategies. This resulted in the DSB preferring a service sure not to require capital contributions from themselves or increase debt levels. The DSB should instead choose among identical projects not based on the type of payments made, but their total lifecycle cost.

The goal should be to encourage renovations when the lifecycle cost of borrowing for the equipment is less than the energy savings, or when the energy efficient equipment surpasses a rate of return deemed appropriate rather than non-economic factors, such as accounting treatment. Designing public policy with these objectives in mind helps to protect the interests of frustrated PSOs and indebted public governments alike, and increases the number of choices available.

Chapter 6: The regulation of discrete Thermal Energy Services in British Columbia

FortisBC Energy Utilities (FortisBC, FEI) is the largest distributor of natural gas in British Columbia, serving 950,000 customers in 125 communities. FortisBC is a public utility whose activities are regulated by the British Columbia Utilities Commission (BCUC, Commission). Its regional subsidiaries are the only natural gas distributor in their respective service areas including the lower mainland, Whistler, Fort Nelson and Victoria.[50]

As part of their effort to become an integrated energy service provider, FortisBC has developed a series of new businesses involving alternative energy services including: compressed natural gas, liquid natural gas, biomethane, and Thermal Energy Services (TES).[51] TES includes both district and discrete TES utility services, delivering space conditioning and hot water via energy efficient and renewable technology, including Ground Source Heat Pumps (GSHP). The market interest in TES has been significant, and in 2011 FortisBC reported over 20 projects in the pipeline with a total estimated value of $250M.

TES can be grouped in district TES and discrete TES categories.[52] Discrete TES introduce compelling innovations to the energy service market. Not unlike their district TES cousins,

---

[50] Fortis BC Energy Utilities (FEU) includes three regulated utility affiliates FEI (lower mainland), FEVI (Vancouver Island), and FEW (Whistler). FortisBC was previously known as Terasen Utilities until rebranding in 2011. Fortis Inc. purchased FortisBC in 2005.

[51] FortisBC owns biomethane upgrade facilities upstream of their natural gas meter, and downstream of the utility meter by owning assets for providing liquid and compressed natural gas, and TES services. FortisBC compresses natural gas into compressed natural gas, where it can be distributed to customers through a dispensing facility. Liquid natural gas is sold to fleet vehicles as a transport fuel and its potential for peak electricity production is being explored.

[52] District TES is also known as district energy or district heating. In this chapter I maintain the district TES notation used during the BCUC proceedings.

discrete TES are utilities owned and operated by third parties. However, their ability to serve one or many buildings gives discrete TES a distinctly local characteristic, and they have been dubbed on-site utilities. Furthermore, discrete TES may finance equipment inside of the building as part of its regulated asset base (as shown with the Delta School Board renovations in Chapter 5).

The scalability of technology used in discrete TES, such as GSHP, blur the line between leasing or purchasing mechanical equipment and infrastructure investments undertaken by utility providers. There are no market barriers among discrete TES common to other regulated infrastructures, such as extreme economies of scale. The offering of discrete TES as a regulated service is contentious with respect to whether economic regulation is appropriate to begin with and what form of economic regulation should be used.

These and other issues were addressed by the BCUC during the Alternative Energy Services (AES) and Thermal Energy Service (TES) Inquiries. The AES and TES inquiries spanned from 2011-2014, and concluded with the creation of a scaled regulatory framework for TES in British Columbia.

This chapter is divided into three interrelated parts. I begin by arguing the characteristics of TES offer several advantages over other energy services available by emphasizing the differences between discrete TES, district TES, and Energy Performance Contracting (EPC). I then describe intervener arguments presented during the AES and TES Inquiries focusing on the implications of market structure and the need for regulation and pricing of outputs (rate design). I conclude by summarizing the resultant scaled regulatory framework for TES and offer policy recommendations to improve the efficiency and transparency of TES in British Columbia.

Appendix C contains a brief chronological summary of relevant BCUC orders and decisions to the TES market.

6.1 Competitive advantages of discrete Thermal Energy Services (TES)

Discrete TES provide thermal energy in exchange for ongoing utility payments. Low carbon or renewable technologies are typically used in conjunction with natural gas to supply green thermal energy. In British Columbia, discrete TES are considered public utilities and are subject to regulation upon complaint (BCUC 2014e).

Using a utility model of ownership offers advantages over incumbent methods for providing energy services. In this section I list the factors that led to the emergence of discrete TES. I then discuss some of the competitive advantages discrete TES offers by comparing it to district TES and Energy Performance Contracting (EPC).

6.1.1 The emergence of TES

There are at least five factors leading to the emergence of discrete TES. They are the introduction of environmental regulations, declining natural gas throughput rates of FortisBC, advent of new technologies (Jaccard 2011), a willingness to pay for green services, and an ability to overcome capital constraints by potential adopters.

British Columbia enacted a series of environmental regulations to further their green objectives, which have raised the price of carbon intensive energy sources, altered public perception surrounding fossil fuels, and helped create a market for green energy services (BC Leg Ass. 2008a; 2008b; 2007; 2010).

FortisBC is experiencing declining throughput with declining demand in the residential and industrial sectors, and flat demand in the commercial market. FortisBC has identified two trends affecting throughput of natural gas, a decline in usage amongst existing customers, and a decline in the market share of new construction choosing natural gas as the primary source of thermal energy (FortisBC 2011b).

FortisBC indicated the ongoing development of new renewable technologies as one of the reasons TES was emerging. The technologies and fuels used in TES range from mature technologies, such as GSHP, to newer waste heat recapture and biomass facilities. The offering of these renewable technologies is part of FortisBC's strategy to maintain natural gas as part of the renewable energy mix (FortisBC 2011b).

Consumers are increasingly aware of other attributes surrounding their consumption of energy, and price is considered alongside the carbon intensity of the fuel source (*ibid*, p.17). This market includes carbon offsets, biogas, and renewable electricity. This market based on consumer's willingness to pay more for green energy services has aided the development of TES in British Columbia.

The fifth factor would be the ability for discrete TES to overcome capital shortages faced by potential adopters of renewable technology. As shown in Chapter 5, the appetite for discrete TES is partly fueled by its ability to navigate capital cost constraints faced by public sector organizations and developers.

It is worth mentioning none of the reasons for the emergence of TES is due to high-energy prices or falling costs of renewable energy technologies. FortisBC offers a premium service, and the customer is choosing what may be a

(a) "…higher cost, more complex design in order to better meet[s] their needs and objectives for a renewable, low carbon energy system (ibid, p.137)."

FortisBC does not offer lower operating costs than conventional technologies, a strategy commonly employed by vendors of renewable thermal systems like solar thermal and geoexhange. Further, there is no requirement or guarantee for a level of carbon savings or renewable energy quota met when providing the service.

6.1.2 Strategies to overcome development risks by district TES

District TES provide metered renewable heat in several municipalities and communities in British Columbia (PICS 2012). District TES entails a large capital investment with significant start up risks. When developing district TES, utilities have employed various strategies to protect their investment.

The first is an exclusive right to operate in an area as a regulated public utility. Once a Certificate of Public Convenience (CPCN) is granted, the utility has monopoly rights to operate in an area. The utility is given exclusive domain and the right to earn a reasonable rate of return, improving the risk-reward profile for the investors of the utility. There remain, however, several eventualities that may prevent the utility investor from recovering their capital investment.

If there is a downturn in the real estate market and developers are unable to sell their units, then there are no ratepayers from which the utility can recover their infrastructure investment. The utility may need to adjust their rates upwards, fail to recover their invested capital, or negotiate

loss sharing with the local government. This threat is known as occupancy risk (load risk), which was described as a high-risk factor by all of the district TES operators during the GCOC Phase 2 proceeding (described in Chapter-section 6.3.2).

District TES adopt three primary strategies insulating themselves from occupancy risk, namely, bringing thermal plants online in phases, rate smoothing techniques, and municipal power.

The economics of renewable energy technology may require TES providers to bring renewable thermal plants online in phases. A district TES may wait until full build out before switching to a renewable fuel source, which may not be economic at small scales. Biomass may be the desired thermal energy technology, for example, but natural gas will be used until full-occupancy and build out are reached. Marine Gateway in Victoria (waste wood) and UniverCity in Burnaby (biomass) have adopted this phased strategy (FAES 2012).[53] They will continue to use natural gas until the load is large enough to enable fuel switching.

District TES use levelized rates and deferral accounts to bridge early and late ratepayers. This spreads early costs over the life of the project that would otherwise result in punitive rates charged to early connectors. The utility draws from deferral accounts until revenues are sufficient and the deferral account can be replenished. This acts as a cushion until ratepayers arrive in greater numbers, and utilities must report whether loads are expected to hit forecasts to the BCUC.

---

[53] The price of fuel will be a consideration. The Lonsdale District Energy System in North Vancouver uses disaggregated natural gas heating stations. The thermal plants were intended to use hydrogen, but the fuel source is unlikely to materialize. It is a hot loop and does not supply air conditioning, a tenuous item amongst developers in the area.

Lastly, district TES almost always work in concert with the municipality to set bylaws requiring buildings in the area to connect to the district TES. Without municipal power, it can be difficult to persuade developers to connect given the greater capital costs they must incur to ensure system compatibility. Heating systems compatible with district heating tend to be costlier to install compared to electric baseboard.[54]

Capital costs are of paramount concern for developers. Absent a market where developers are rewarded for investing in the sustainability of the development, increasing first costs reduce the developer's profits. In British Columbia where electricity is perceived as clean and low carbon, it can be difficult to persuade developers to voluntarily bear the extra cost for connecting to a district TES.

6.1.3 Comparative advantage of discrete TES

Similar to district TES, discrete TES pursue a utility model of ownership. While discrete TES use similar rate smoothing techniques of levelized costs and deferral accounts, these are not the primary sources of their advantage compared to district TES. Discrete TES use different technologies and marketing strategies for overcoming capital constraints faced by developers.

Discrete TES use technologies economic at smaller scales (such as geoexchange), and work backwards from heating loads when deploying disaggregated TES plants (FAES 2014b). Over

[54] Established district energy systems can compete for new customers without mandatory connection rights. Occupancy risk is lower when growing than when establishing a rate base. An easy example is Central Heat Ltd. in downtown Vancouver. Initially a joint venture by several downtown buildings looking to save space in their buildings, Central Heat Ltd/Creative Energy, is now growing and markets their services to new customers.

time the disaggregated TES plants from multiple buildings can be connected for load balancing, not because the project economics require it, because doing so is economically advantageous.[55]

Technologies economic at smaller scales include geoexchange, solar thermal, and in-building waste heat recapture. When working together, these technologies usually employ an ambient temperature ground loop to provide both heating and air conditioning. Air conditioning is required in the lower mainland whenever glass covers a high fraction of the exposed surface (in Richmond air conditioning is required by code for noise concerns near the airport). Hot loops employed by district heating systems using natural gas or biomass technology only supply heating. The utility of which is questionable with Vancouver's mild climate, and few biomass district heating systems are actively contributing to electricity production.

Discrete TES use a market pull approach by offering renovations to existing buildings and financing additional capital costs for developers. They do so by not only financing the thermal plant, but they may also finance the in-building distribution equipment.[56] This removes the first cost faced by developers, and assists with the developer attaining an eco-certification label or higher energy-efficiency rating.

A development with large heating loads and access to nearby sources of waste heat, for example, will allow the discrete TES provider to finance more of the marginal projects by the developer – from insulation, to boilers, to distribution piping and ducts. These additional capital costs paid for by the utility are added onto their rate base, from which the rate of return for the utility is

---

[55] Load balancing occurs when a smaller ground loop can serve multiple buildings with diversified loads. This network benefit is described and modeled in Appendix B.

[56] TerraSource is the separate utility arm of GeoTility. They finance the ground loop based on fixed payments, but do not consider pumps or use the utility rate designs. GeoTility is an industry leader for geoexchange in BC, and they install the loops for FortisBC.

calculated. This creates a clear alignment of interests between a utility looking to offer a competitive price for tenants while still increasing capital costs to maximize their own rate of return, while developers are looking for a way to decrease their capital costs to increase their return. This is a compelling approach for overcoming the agency problem between developers and tenants.

Lastly, discrete TES have demonstrated their suitability for renovations. Renovations have known heating loads and build out profiles, making them ideal candidates for discrete TES with little to no occupancy risk.

6.1.4 Advantages of discrete TES over Energy Performance Contracting

Energy Performance Contracts (EPC) are designed to renovate buildings owned by commercial and institutional clients. An EPC company uses its expertise in energy services and technologies to extract a rent on the difference between the initial prices paid for energy and the energy payments following the renovation. The revenues are based on the financial savings of the project, but a level of energy or carbon savings may be guaranteed. The amount invested depends on a variety of factors, such as total cost paid for energy. In lower British Columbia, where the climate is mild and the price of energy low, the ceiling on affordable renovations is lower than in regions with harsher climates or more expensive energy.

During the AES Inquiry, the Energy Services Association of Canada (ESAC) expressed their concerns over the advantages of discrete TES over EPC (Smith 2012). The utility rate designs of discrete TES systems allow them to earn a regulated return in an unregulated market. The discrete TES contract begins with negotiated rate designed to be competitive, but there are no guarantees behind it. Whereas for an EPC the price is set based on previous usage. The return

on investment for an EPC rises and falls with the energy savings, increasing the risk involved in an EPC contract should equipment fail to perform as expected or if capital costs overrun.[57]

Given identical payments from a third party, the utility method of financing equipment can afford a greater capital cost compared to an EPC contract. With an EPC, the capital lease must eventually cover the total cost of the capital equipment and renovations provided. A utility rate design charges the carrying cost of the capital equipment (inclusive of earned return) over a longer time period. The contract duration for a utility is generally longer than an EPC. A utility is intended to contract on an ongoing basis, with an initial term of 20 years, and hopefully with renewals every decade afterwards. This spreads out the costs over a greater period than an EPC, which must recover its capital costs in a shorter period of time. The treatment of costs and the investment duration result in lower capital carrying costs. EPC companies have expressed interest in offering capital intensive technology, such as GSHP, for public sector renovations but indicated the financial incentives for energy efficiency must increase before this can be realized (Smith 2012). In short, if both an EPC and a utility are offered the same stream of payments, the discrete TES model can afford to invest a greater amount in a renovation or provision of capital equipment. [58]

Furthermore, utility services have preferential treatment on the balance sheet of a Public Sector Organization(PSO). PSOs are subject to capital constraints, prohibiting the accumulation of

---

[57] This is not to suggest that EPCs do not immunize themselves from certain risks. An EPC is not responsible for changes outside of their controls, including changes of use to the building and increases in energy costs. It can even insure the financial savings, or bear this liability on the balance sheet if cheaper. The mechanical equipment also comes with a manufacturers warranty if it does not perform as expected.

[58] This does not mean indefinite ownership or EPC financing is less costly than upfront procurement. See Chapter 5 for the Delta School Board Case Study.

debt during periods of fiscal stringency. Capital leases, the go-to financing mechanism of EPC are treated as both an asset and a liability on the balance sheet, can be prohibited by balance sheet constraints. Utility bills are an operating expense appearing on the income statement, so capital equipment financed as a utility bill can avoid a balance sheet constraint.

These advantages were not lost on the interveners, and the BC Sustainable Energy Association and Sierra Club of British Columbia asked the Commission to maintain regulation of single customers as a way to preserve these advantages for overcoming debt limitations imposed on public sector organizations (BCSEA 2013). The Commission rejected considerations for the balance sheet treatment of capital costs, or any advantages it might confer to PSOs as out of scope for the proceedings (BCUC 2013c).

6.1.5 Conclusions

The emergence of discrete TES in BC is driven not by rising energy costs, or falling renewable energy prices, but the willingness to pay for green services. The environmental benefits are based on the technology adopted, and not on any guaranteed energy savings or calculated carbon intensity of the services over its lifetime operation.

Part of the reason discrete TES offers premium services is due to the mild climate and low cost of energy in British Columbia. These conditions can make solar thermal and geothermal technologies costlier over their lifespan than natural gas alternatives. It can also be inferred the technologies used by TES may not be premium services in other regions. A region with higher energy prices or a harsher climate could supply discrete TES with geoexchange technology and operate at a discount to natural gas or electricity.

In emphasizing the competitive advantages of discrete TES, I endeavored to highlight their qualities beyond being mini-district energy systems. Discrete TES follows a market pull strategy by financing construction costs for developers and renovations for institutional clients. Furthermore, discrete TES works backwards from loads using technologies economic at smaller scales than district energy substantially lowering occupancy risk in the case of renovations.

With respect to the market for energy performance contracting, the introduction of utility tools into the renovation market poses a direct threat to EPC companies. At current energy prices, the utility can invest more in capital costs that with an EPC, and with preferable balance sheet treatment (Smith 2012).

6.2 Intervener interests and arguments presented before the Commission

Regulation is inherently political, and the regulator will consider intervener arguments when interpreting and applying their legislative mandate. This allows for different actors to advocate for their vested interests when arguing which benefits (and costs) should be given priority in determining the need and form of regulation. Economic efficiency is also a concern, testing neoclassical theory of regulation against actual industry outputs described by price and quality. Thus, the regulation has real distributive implications for the industry, with the dispersal of benefits and costs (Joskow et al. 1989).

In British Columbia, Thermal Energy Services (TES) are considered public utilities and subject to regulatory oversight by the British Columbia Utilities Commission (BCUC, Commission). The Commission derives its mandate from the Utilities Commission Act (UCA), and is required to provide regulatory oversight to all public utilities in British Columbia. The UCA defines a public utility as:

> "a person, or the person's lessee, trustee, receiver or liquidator, who owns or operates in British Columbia, equipment or facilities for
>
> (a) the production, generation, storage, transmission, sale, delivery or provision of electricity, natural gas, steam or any other agent for the production of light, heat, cold or power to or for the public or a corporation for compensation…(UCA 1996)."

The inclusion of *any other agent* for the production of heat or cold as a public utility requires TES to be subject to regulatory oversight in British Columbia.[59] This permitted FortisBC to file for regulatory oversight from the Commission for TES projects (FortisBC 2011b).

The BCUC indicated a review of FortisBC's new business activities was in order, so regulatory proceedings were initiated when the Energy Services Association of Canada (ESAC) and Corix Utilities (Corix) filed a complaint with the BCUC (See Appendix C).[1] Both ESAC and Corix were concerned FortisBC might use revenues from their regulated natural gas business to subsidize their new activities resulting in an unfair advantage. They claimed unless structural regulation was used to separate the new business activities FortisBC could distort the competitive landscape and hinder the development of the emerging TES market.

The BCUC acts to protect ratepayers entitled to safe and reliable service while also affording utilities a fair return on prudently made investments. The BCUC was faced with two regulatory challenges when interpreting their mandate. To reconcile the interests of the captive natural gas ratepayer with that of the development of TES in general (Jaccard 2011). Secondly, whether and, how, the BCUC ought to regulate the TES service.

---

[59] FortisBC argued the performance nature of the ESCO contract was not relevant; they were still selling thermal energy and should be regulated. FortisBC details the 6 ways TES can be offered, and which ones should be regulated according to their interpretation of the definition of a public utility in British Columbia. See Exhibit B-2 Section 6.4.1.1 on application of the definition of public utilities.

Here I highlight key tensions revealed during the Alternative Energy Services (AES) and Thermal Energy Services (TES) Inquiry, and the arguments found most persuasive by the BCUC in developing the TES regulatory framework.

6.2.1 Role of competition and regulation

Before discussing the purpose of structural separation, it is worthwhile to describe the role of competition and the purpose of economic regulation, given the centrality of whether the entry of FortisBC into the TES market was anti-competitive or an additional competitive presence.

Competition reduces the risk of monopoly rent extraction and promotes innovation within an industry.[60] Competition also increases consumer choice, offers consumer protection, and signals policy makers about the kinds of products and attributes consumers prefer (Viscusi et al. 2005).

It is still possible to have an economically efficient industry without perfectly competitive markets. Under certain conditions a single firm can supply services to a region at least cost, known as monopoly.[61] For practical reasons, some parts of an industry may only support one or very few firms supplying the service. As is often the case with utilities, the sheer size of the investment required to launch services limits the firms able to undertake such an enterprise to all but the largest firms or governments.

---

[60] The textbook scenario for optimal economic performance is a perfectly competitive market where: consumers have perfect information, there are no increasing returns to scale, consumers and producers maximize their benefit using their relative budget constraints and production functions, all agents are price takers, where price equals marginal cost, and externalities are ruled out and markets are at a competitive equilibrium. The resulting market equilibrium is a *Pareto optimal* equilibrium. A market is at *Pareto optimal* equilibrium when the equilibrium cannot increase the welfare of some consumers without making other consumers worse off.

[61] A clearest test for monopoly is subadditivity, or the range over which all outputs can be produced by a single firm at lowest costs is best served by a monopoly. Other tests include extreme economies of scale, significant barriers to entry, decreasing internal costs, or when duplicating assets increases costs for consumer.

Regulators oversee the economic activities of firms in monopoly conditions, often granting utilities exclusive rights to operate within an area. The ratepayers served by a single provider with exclusive rights in an area are captive, so regulators oversee the rates charged by the utility.

In British Columbia, the Utilities Commission Act (UCA) attempts to balance the benefits of competition and monopoly, regulating monopoly when necessary but deferring to markets for consumer protection where competition is sufficient (BCUC 2012a).

The BCUC does not regulate competition, which is the domain of the competition bureau (*ibid*, p.10). The BCUC can indirectly affect competition by controlling the investments of the utility (through CPCN approval), prohibiting a utility from entering a market outside their traditional business subject to certain safeguards, and deferring to competitive market forces by refraining from regulation through the use of exemptions (*ibid*, p.10).

Whenever a monopoly provider offers a new business outside of its traditional activities, the regulator must be vigilant to prevent potential abuses of monopoly power. The risk is the potential for monopoly to shift some of the costs and risks of entering into the new market onto its captive, traditional ratepayers. This is a form of cross-subsidization where the captive ratepayers of the existing business pay for costs unrelated to their usage.[62] This may also distort the unregulated market, if the cross-subsidization results in a price offering low enough to drive potential competitors away. The entry of a monopoly provider to a competitive market can also

[62] Cross-subsidization can also be beneficial, such as when urban ratepayers subsidize the costs of rural services. Without this form of cross-subsidization rural electrification would not have been possible.

be a valuable competitive presence subject to certain safeguards, such as structural regulation.[63] The degree of structural separation required for FortisBC to offer TES was one of the primary outcomes of the AES Inquiry, which I detail in the next section.

6.2.2 Guidelines on structural separation

The BCUC can prohibit or restrict the entry of a regulated business into a new business activity if it finds doing so is necessary to protect ratepayers. The BCUC can do so by requiring greater separation amongst utility businesses. There are five classes of separation offered by the BCUC. Listed in order from complete integration to full separation within a utility: a single class of customer, separate class of customer, separate class of service, affiliate regulated business, and affiliated non-regulated business.

The degree of integration or separation required is related to the market structure, with greater integration permissible in regulated markets and greater separation warranted between regulated and unregulated markets. The degree of integration or separation also determines what resources can be shared: financial, information, employees, sunk costs. The sharing of costs and the potential for cross-subsidization was of paramount concern, considering the advantage FortisBC may have as a natural monopoly offering both natural gas and TES under a single entity as a regulated class of service.

There were three potential degrees of separation applicable to TES:

---

[63] An alternative is behavioral regulation, which requires considerably more effort by the regulatory agency given problems of information asymmetry. The advantage of structural separation is it reduces the need for regulatory oversight.

- TES as a separate class of service
- TES as a regulated utility affiliate
- TES as an unregulated utility affiliate.

When two businesses are offered as different classes of service, accounting rules are used to assign the costs to the class of service responsible for incurring them.[64] Employees can use time sheets to record hours worked on each class of service, and formulaic calculations (observed by the BCUC) can assign certain costs to each class of customer, such as overhead.

Utility affiliates are considered structurally separate, and only share the minimum of resources. Any costs shared between regulated or unregulated affiliates must be disclosed to the regulator, and when purchasing materials or services the utility must pay the higher of their internal or the external market price. The potential for economies of scope is greater amongst classes of service than between utility affiliates, but the threat of cross-subsidization is lower.

The decision to offer TES through structurally separate regulated and unregulated affiliates was reached through the application of the Retail Markets Downstream of the utility Meter (RMDM) guidelines (BCUC 2007). When the BCUC developed the RMDM guidelines to govern the interactions between regulated and unregulated businesses. Figure 6.1 contains the three primary objectives of the RMDM guidelines. These objectives are not ordered, and the BCUC has some discretion concerning the weighting for each objective.

[64] Known as the principle of cost causation.

RMDM Guidelines

- There must be no subsidy of unregulated business activities, whether undertaken by the utility or its NRB, by utility ratepayers.
- The risks associated with participation in the unregulated market must be borne entirely by the unregulated business activity; that is the risks must have no impact on utility ratepayers.
- The most economically efficient allocation of goods and resources for ratepayers should be sought.

Text from Figure 6, Commission Objectives RMDM Guidelines (BCUC 2007. p.23)

Figure 6.1 Objectives of the RMDM Guidelines

FortisBC sought to prevent the adoption of the RMDM guidelines at the outset of the inquiry, arguing the application of guidelines governing the interactions between regulated and unregulated businesses were inapplicable to current circumstances. In their view their activities were properly regulated by definition. The Commission adopted the guidelines stating they could be adapted to the present circumstances of interactions between regulated businesses, a view echoed by Corix and ESAC.

In arguing the merit of offering TES as a separate class of service within the natural gas business, FortisBC indicated the third objective (most economically efficient allocation of resources should be sought) provided justification for offering TES as a separate class of service.[65] Economies of scope resulting from offering both TES and natural gas would lead to FortisBC

[65] Using existing sunk assets for another service, such as service vehicles already is not tantamount to cross-subsidization as long as the cost of using the vehicles is recorded.

being the lowest cost producer, and customers would ultimately benefit from the lower prices. Furthermore, the sharing of costs (such as overhead) between natural gas and TES would also benefit natural gas ratepayers. FortisBC also indicated how accounting rules could correctly assign costs to either natural gas or TES classes of service, and would be adequate to prevent cross-subsidization.[66]

FortisBC was seeking an ability to capture economies of scope, similar to other producers offering multiple utility services through a single entity, such as Corix Utilities. There remains a key distinction between economies of scope realized by offering multiple services through a group like Corix, and economies of scope captured between natural gas and TES by FortisBC. With Corix, any cost overruns on a project are borne by the shareholders. With FortisBC (FEI), any costs not adequately captured by the accounting formula or timesheets should be borne by shareholders, but could also be recovered from natural gas ratepayers. Only FortisBC has a large group of captive ratepayers making cross-subsidization a possibility (BCUC 2012a).

Structural separation completely alleviates the risk of cross-subsidization, and reduces the need for regulatory oversight. Even when accounting rules are in place, there exists information asymmetry between the regulator and the firm, and the tracking and recording of all costs can be difficult. The RMDM guidelines operate on the principle that the preferred method of separation is structural (cf. accounting rules), and onus is on the utility to prove the advantages of greater integration outweigh the potential risks of cross-subsidization.

---

[66] There are two tests for cross-subsidization: the test of stand-alone costs and incremental costs. The stand-alone test states if revenues from a service are greater than the stand-alone costs of that project, it can be said to be subsidy free. The incremental cost test is similar, if Fortis is operating a natural gas business, and TES imposes an additional incremental cost, as long as the revenues from TES are greater than the incremental cost it is subsidy free (See FortisBC 2012a, p.9).

The BCUC did not dispute the economic advantages of offering natural gas and TES as two separate classes of service, but found them inappropriate considering the potential for cross-subsidization between regulated and unregulated businesses. Neither was the BCUC willing to accept at face value economies of scope would have greater benefits than potential costs of cross-subsidization on existing ratepayers or distortion of the competitive market.

The argument of FortisBC begged the question of whether TES was a regulated service. The definition of a public utility must be read with the intention of the act, which implies the BCUC to consider the market conditions and also to apply for exemptions when warranted.

6.2.3 Alternative Energy Services Inquiry

The AES Inquiry sought to provide guidance for future BCUC panels when dealing with applications for new business activities, for utilities entering new lines of business, and clarify the BCUC's view on what activities were outside of the regulatory umbrella (BCUC 2012a).

In arriving at their decision, the BCUC distinguished district from discrete TES. The market for district TES was characterized as competition for the market, with the winning bid offering a regulated service. The BCUC found the market for discrete TES sufficiently competitive, and properly exempt from regulation. FortisBC was not permitted to offer TES as a class of service, but was permitted to offer district and discrete TES projects subject to the following conditions:

- FortisBC could compete for district TES through a structurally separate regulated utility. Any costs shared between utility affiliates must be disclosed, and recorded at the higher of internal or market prices.
- FortisBC could offer discrete TES, but through a structurally separate unregulated utility affiliate. Any and all sharing of costs must be disclosed and recorded at the

higher cost of internal or market prices, but should be limited to upper level executives and emergency response services.

The AES Inquiry concluded by recommending that the UCA be amended to allow the BCUC to exempt markets where there were no natural monopoly characteristics, and tasked the BCUC with developing a scaled regulatory framework for the regulation of TES (BCUC 2012a).[67]

6.2.4 Thermal Energy Services Inquiry and the need for regulation

In developing the scaled regulatory framework for TES, the BCUC saw a grey area separating discrete and district TES, and their need for different regulations. The need for regulation is ultimately determined by market structure, and/or legislative requirement. The BCUC considered a number of factors differentiating the regulatory requirements of discrete from district TES, shown in Figure 6.2.

[67] Several other items required decision including: FortisBC would be permitted to use the Fortis brand name. Customer information would be treated as valuable market information, and only accessed with written permission from the customer. FortisBC's ability to borrow at a lower cost was an advantage, but not harmful to competition.

- On-site description: A stand-alone system, usually sized for a single site with no common facilities beyond that site, and limited use of public rights of way.
- Measure of need: TES results from a contract for an existing building or single building permit, or the unit owners/tenants have selected the TES.
- Measure of technical viability: Uses commercially available equipment
- Measure of cost: the TES utility has a capital cost of $15M or less
- Measure of customer acceptance: Unit owners and ratepayers have accepted or will accept terms of the TES through real-estate purchase disclosure documents, long-term supply contracts, or service agreements, prior to purchasing the unit or initiating the service.

From Table 1 On-site TES with Certain Characteristics (BCUC 2014e p. 6)

Figure 6.2 Characteristics of TES and need for regulatory oversight

The ability for a future ratepayer to choose their TES provider reduces the need for regulatory protection (based on measure of need and customer acceptance) and a regulatory exemption for a TES contracted for single customer was proposed. The single customer exemption was introduced by the AES, maintained for two regulatory drafts, and then removed.

There were two very different descriptions of the single-customer offered in support of the need for regulation. Those seeking exemption from regulation described single customer clients as sophisticated parties willfully entering into a contract capable of contracting for future unforeseen events. Those opposing the exemption in favor of recourse with the regulator described single customers as a vulnerable group of customers most in need of regulatory oversight (BCUC 2013c).

Perhaps the greatest fault line rests on the single customer exemption and its application to the market for renovating institutional or commercial clients, including Municipalities, Universities,

Schools, and Hospitals (MUSH). The MUSH market is a major component of business for companies offering energy performance contracts, such as the group represented by the Energy Services Association of Canada (ESAC). ESAC represents a consortium of eight EPC companies operating in Canada, including groups such as Johnson Controls, Honeywell, and AMERESCO. ESAC received enough votes to intervene collectively as a group during the AES Inquiry, but not for the TES Inquiry.

AMERESCO was the primary EPC intervener with regards to the regulation of discrete TES. Other ESAC members Johnson Controls and Honeywell did not participate, likely due to their ability to play both the discrete and performance contracting sides of the MUSH market. Johnson Controls and Honeywell can offer performance contracts, and they can also sell equipment, assist with installation, or supply controls. AMERESCO does not sell technology services, meaning they were more threatened by the entry of discrete TES into the MUSH market than the other two.[68]

AMERESCO supported the single customer exemption along with the other interveners with different market perspectives, namely the Independent Contractors and Businesses Association (ICBA), the Heating, Refrigerating and Air Conditioning Institute of Canada (HRAI), and the Mechanical Contractors Association of British Columbia (MCABC).[69] These intervening parties

---

[68] Johnson Controls worked with ForisBC on the Delta School Board project for both the feasibility study and controls.

[69] Corix were more concerned with the proceedings involving Stream B utilities, and based on conversations they seem to think there is more than enough work out there without creating a new market vis-à-vis the market for discrete TES. They preferred a regulatory framework granting exemptions wherever competition was found, and regulate only if the resulting situation required, which could reasonably be inferred to lead to a single customer exemption. In contrast, AMERESCO was not actively lobbying for changes to stream B utilities, and did not take issue with certain items such as the Stream B extension test.

saw regulation as a last resort and poor substitute for competition, and recourse with the regulator could lead to a moral hazard if used as a backstop (BCUC 2014g). The ICBA even suggested independent contractors could be required to work with FortisBC in order to win contracts failing the preservation of the single customer exemption (*ibid*, p.14 Appendix A).

FortisBC preferred recourse with the regulator, and this view was echoed by B.C. Sustainable Energy Association (BCSEA) and the Sierra Club British Columbia (SCBC), and British Columbia Pensioners' and Seniors' Organization (BCPSO). For FortisBC, regulation by complaint meant full recourse with the regulator, and the ability to offer discrete TES to single customers, including the MUSH market. They argued a blanket exemption for single customers "takes the regulatory protection of the Act away from the customers who are likely the most in need of it (*ibid*, p.11 Appendix A)."

The BCSEA and SCBC argued maintaining the single customer regulatory exemption might frustrate the implementation of TES in British Columbia. Both supported the BCUC regulation of TES to advance BC's environmental objectives. They argued the utility model maintains certain competitive advantages over performance contracting, and removing the regulatory option would remove a choice from the market (*ibid*, pp.16-17 Appendix A).

The BCPSO argued the TES market was insufficiently competitive, and given the duration of TES contracts having recourse with the regulator in the event of unforeseen events would be preferable, particularly should rates rise significantly over time. Furthermore, they were

unwilling to accept that the presence of a contract as evidence that both parties were equal in bargaining power or equipped to deal with the terms of the contract (*ibid*, p.18 Appendix A).[70]

When the BCUC removed the single customer exemption, granting recourse upon complaint, they did not do so for the reasons put forth by the intervening parties. The BCUC did not agree that regulation in and of itself was a means to achieve environmental objectives, or that regulation provided superior protection than a contract in a competitive market. The BCUC maintained regulation by complaint because it was light-handed and would not impose significant costs on the market, [71] and because the BCUC could be a more efficient arbiter than the courts concerning disputes (BCUC 2013c, p.26).

6.2.5 Conclusions

Wherever the potential for abuse by monopoly power exists, it can be treated through socialization (government ownership) or regulation. In British Columbia, a lack of public funds led to privatization and regulation by the BCUC.

The need to regulate arises from both market characteristics and legislative mandate. The AES Inquiry addressed a novel case governing interactions between two regulated businesses and demonstrated the flexibility of the BCUC in overriding its legislative mandate to further economic principles believed to serve the public interest.

---

[70] BCPSO did not support the strata exemption either, saying that while initial parties signing the contract were privy to its conditions later tenants may not be.

[71] The BCUC would use a micro-TES exemption preventing regulation of smaller contracts, addressing the concerns of the Independent Business and Contractors Association.

The TES Inquiry took off where the AES Inquiry left off, developing a scaled regulatory framework to balance the need for regulation with the benefits of recourse with the regulator. The most contentious item was the single customer exemption, and interveners asking for the preservation or removal of the single customer exemption did so based on the perceived advantages of the resulting service. The BCUC maintained recourse with the regulator by complaint not based on a need to protect end-users, but based on the limited cost of light-handed oversight, and the BCUC's potential efficiency in arbitration should unforeseen circumstances arise.

There were two incidental findings from the TES Inquiry running counter to the initial findings of the AES Inquiry. FortisBC can offer both discrete and district TES within the same regulated utility affiliate (known as FAES). Regulation by complaint is light-handed regulation, but still allows for discrete and district services to be operated within the same affiliate. Secondly, despite the BCUC insisting regulation was not a choice (BCUC 2012a, p.15), but determined by legislative mandate or market conditions, a choice of regulation was preserved in the energy service market. In the upper-end of the renovation market for systems costing more than $500K, a client could chose between a performance contract and regulation by complaint. The determining factor in this case is ownership, with a capital lease leading to eventual ownership and a utility contract leading to indefinite ownership.

Lastly, maintaining recourse with the regulator for single customers allows discrete TES offer renovations for PSOs, altering the competitive landscape for EPC companies.

6.3 Regulatory Framework and Rate Design for Thermal Energy Services

Here I describe the scaled TES regulatory framework for district and discrete TES systems in British Columbia, including which sections of the Utilities Commission Act (UCA) apply. Examples are used to illustrate the critical characteristics of a utility that determine the form of regulation applied, as identified by the BCUC.

I draw attention to the importance of rate design, which affect a firm's investment decisions, alter the financial risk of the utility, and allocate risks among the utility and it's ratepayers (Brennan & Schwartz 1982; Averch & Johnson 1962). The regulatory proceedings led to the creation of a long-term contract similar to a regulated cost of service rates for Stream A utilities. I show how the long-term contract was able to maintain an endogenous rate of return in an unregulated market, and discuss what regulation by complaint entails.

6.3.1 Scaled regulatory framework for TES in British Columbia

There are four Streams of regulation for TES utilities in British Columbia, depending on the project's capital cost and characteristics shown in Table 6.1.

Micro	All TES with a capital cost of less than $500K are considered unregulated.
Strata	Any TES owned or operated by a Strata Corporation for its Strata Members is considered unregulated.
Stream A	Stream A TES utilities are considered public utilities, but will only be regulated upon complaint
Stream B	Full regulatory review for all TES with a capital cost greater than $15M, or any TES not fitting the description of a Stream A utility, or meeting the requirements for a Strata exception.

Table 6.1 Streams of TES regulation in BC

The intensity of regulation increases with the size and complexity of the project. Whether the utility identifies as a Stream B utility is dependent on whether it meets the definitions of Micro,

Strata or stream A TES. The micro and strata exemptions are straightforward, defined by the cost and ownership structure of the project. The micro-TES exemption applies to any system with a capital cost below $500K. A TES system owned and operated by a strata corporation on behalf of its members is exempt from BCUC regulation, no matter what the capital cost. The definition of Stream A utilities is more nuanced, and Table 6.2 groups the characteristics based on whether they pertain to issues of scale or coordination.

Scale	
Total Cost	Capital cost estimate equal to or greater than $500k but less than $15M
System size is known	Designed to meet energy demands of one or more customers/buildings
Coordination/Complexity	
On-site	Serves one or more customers/buildings on a single site, and there are no shared thermal generation or distribution facilities beyond the site.
Limited transmission	No or very limited use of public rights of way or streets
Single permit	Approved for new/existing building under a single municipal permitting process

Source: Table 1, Stream A Characteristics TES Regulatory Guide P. 7

Table 6.2 Characteristics of Stream A TES

The Utilities Commission Act contains explicit exemptions from some parts or all of regulatory oversight, such as public utilities owned by municipal governments,[72] a person engaged in the production or extraction of oil, or a person engaged in the production of a geothermal resource (UCA 1996).[73] Exemptions allow the BCUC to exercise discretion with the application of their regulatory mandate, in particular when considering exemptions to some or all of the sections contained in Part 3 of the UCA titled: The Regulation of Public Utilities.

[72] Examples of municipally owned TES in BC: Lonsdale Energy Corporation in North Vancouver, Southeast False Creek Neighborhood Energy Utility in Vancouver, Cheakamus Crossing in Whistler, and Revelstoke Community Energy Corporation in Revelstoke.

[73] The Geothermal Resource Act defines geothermal resources as hot water or steam with temperatures no less than 80C at the surface level.

It is the application of exemptions that allow for a scaled regulatory framework for TES, with the exemptions shown in Table 6.3. Micro, Strata, and Stream A TES are exempt from all but sections 42, 43,and 44 of Part 3 of the UCA. Stream A utilities could have these exemptions from regulation removed if a complaint leads to an inquiry finding the exemptions unjustified.

UCA Regulations	**TES Project Classification**			
	Micro	***Strata***	***Stream A***	***Stream B***
Section 42: Obey BCUC orders	√	√	√	√
Section 43: Provide information upon request	√	√	√	√
Section 44: Keep records	√	√	√	√
Section 44.1: Long-term planning			√	√
Sections 45-46: Obtain Certificate of Public Convenience and Necessity				√
Sections 59-61: BCUC oversight on rate design			√	√
*Upon complaint, Stream A utilities could be eligible for regulatory oversight including Sections 44.1 and 59-61				

Table 6.3 TES compliance requirements

Micro and Strata TES providers need only comply with the most basic of public utility requirements. Sections 42, 43, and 44 of Part 3 of the UCA require the public utility to obey BCUC orders (42), provide information when requested (43), and to keep records (44) (UCA 1996). They are effectively exempt from regulation, and even in the event of a complaint with not have recourse with the Commission.

Stream A utilities must comply with all of Part 3 of the UCA excluding sections 44.1, 45-46, and 59-61. Section 44.1 requires the utility to engage in long-term resource planning with the Commission. Sections 45-46 require the utility to apply for a Certificate of Public Convenience and Necessity (CPCN). For a CPCN to be granted the Commission must find that the public

utility serves the public interest.[74] Generally, a CPCN is required for a public utility to operate in BC, and also to purchase or create an extension to a public utility. Exemptions from sections 59-61 remove BCUC oversight of the rate design, and this absence of regulatory oversight must be communicated to the end-user.

The points below describe instances where an increase in oversight will be required, overruling considerations of cost and ownership.

- **Stream B TES with a capital cost less than $15M**: Consider two buildings, one or both having a capital cost greater than 500K, but less than $15M. If one building is dependent on the other buildings thermal plant, such that disconnecting would require constructing a new thermal plant, the project has failed the on-site description due to the interdependency of the two projects. This project qualifies as a Stream B utility requiring full regulatory oversight.
- **Stream A TES with a capital cost less than 500K**: The capital cost requirement is decided based on the site, and pooling projects together under a single contract does not affect this. However, a series of projects can be filed all at once for administrative efficiency, such as the case of a School District. If one or a few of the sites have a capital cost greater than $500K, they may all be filed together as a Stream A. This example mirrors the Delta School Board Decision, which would qualify as a stream A under the current regulatory framework even though only two buildings would have renovations exceeding the micro-TES threshold.
- **Stream A TES serving a Strata's members but owned by a third party**: Here the critical distinction is ownership. If the Strata owns or operates the TES, then it is exempt regardless of the capital cost.
- **Any TES awarded a CPCN prior to TES Decision as a Stream A**: This applies to any utility that underwent regulatory review prior to the conclusion of a TES

[74] This requirement need not be onerous. In the case of the Delta School Board Decision, the CPCN was granted as it was what both parties wanted, and each could derive some benefit from the relationship.

Inquiry. This includes TES with capital costs lower than 500K, and regulated utilities now regulated by complaint. They must reapply for their status as either Stream A or Stream B based on the new guidelines.

The clearest indicator for what stream of regulation the TES falls under is capital cost, however, the above issues of dependency, bundling, or ownership overrule cost in determining regulatory oversight.

6.3.2 Stream B TES and regulated rate of return

District TES are usually regulated using a regulated cost of service rate (COS). The COS rate design passes through all costs onto the end-user. The only way the utility earns a return on its investment is by multiplying the rate base by its allowable earned return. The earned return is by multiplying the rate base (eligible costs include: thermal plant, equipment upgrades, distribution equipment, feasibility studies) the fraction of debt and equity components by their respective regulated cost of capital and allowable return on equity.

The BCUC regulates common equity ratio and the rate of return utilities can earn when charging COS rates. The most recent decision on the allowed rate of return was the Generic Cost of Capital (GCOC) on March 25, 2014 (BCUC 2014c). Part of the proceeding was focused on Stream B TES providers, including Corix Utilities, Central Distribution Limited, River District Energy Limited Partnership, and FortisBC Alternative Energy Services Inc. (FAES).

The BCUC assigns a rate of return to indicate a fair return on investment considering the risks involved in offering the service. The most commonly mentioned risks and associated level of risk are described in Figure 6.3.

Business Risks with TES

- Customer load risk/occupancy risk (high): If occupant base is smaller or customers fail to connect to the system as projected following investment in capital assets. This risk is vulnerable to cyclical real estate market fluctuations.
- Development cost risk (high): New technologies with greater risks than benchmark
- Operating cost risk (medium): smaller district energy system has greater risks than larger utilities that can absorb operating cost overruns
- Regulatory risk (medium): evolving regulatory market
- Rate design risk (low): similar to benchmark
- Competition risk (low): If buildings in area are required to connect

Condensed summary of risk ratings reported by Dockside Green, UniverCity in Burnaby, and River District Energy Limited Partnership. GCOC Phase 2 p.132-144

Figure 6.3 Business risks associated with developing Stream B TES

Stream B utility providers were granted a premium above the benchmark return on equity to compensate for the greater risks of TES. The benchmark was FortisBC (FEI lower mainland), with an allowable return on common equity of 8.75. Stream B TES utilities were allowed a 75bps premium above this (9.50%) based on yardstick comparisons with other utilities, and to reflect their small size and business risks. A higher risk premium does not ensure a greater return on investment, it is indicative of greater risks taken in the long run that utilities may require compensation for in order to offer the service.

The BCUC also set a higher common equity ratio limiting the amount of debt. Greater leverage increases returns for the utility, but may pass on greater costs to the end user and confers bargaining power to the utility. Ordinarily, the common equity share is 40-45%, and debt 55-

60% (equity thickness). Stream B TES have their common equity ratio set higher (45% equity 55% debt) to reflect greater risk (BCUC 2014c).[75]

6.3.3 Stream A performance ratio rate design

The BCUC was careful to exclude the extension of any Stream A utilities from the GCOC Phase 2 proceedings. Stream A utilities are not subject to rate overview, and the BCUC will no longer determine their allowed return on equity, capital structures and cost of debt (BCUC 2014c). The BCUC went so far as to try and prohibit the use of COS rate design for stream A utilities, however this was outside of their jurisdiction once they had exempted Stream A utilities from rate design oversight (BCUC 2013c).

Under the TES scaled regulatory framework, Stream A utilities are not required to file a CPCN or undergo rate review, meaning only limited information on the rate design and investments of FortisBC is available. Fortunately, prior to the publication of the TES regulatory framework FortisBC presented the SOLO, Artemesia, and Sovereign developments for BCUC review (FAES 2014a; FAES 2014c; BCUC 2014d). Under the new framework all three would have qualified as Stream A so FortisBC intended these applications as templates. Here I use the SOLO development to observe the rate design of a Stream A utility as offered by FortisBC.

The SOLO development involved the purchase of a thermal plant for $4.4M plus an additional $0.2M in capital development costs (upgrades, repairs, or renovations). The SOLO development contains residential and commercial tenants, and it is expected in the future more condominium

[75] Due to the small size the cost of debt for these utilities were set at the spread between a (riskless) 10yr Canadian bond and a BBB rating. This is a deemed cost of debt, as due to their small size it is unlikely a utility would actually raise bonds on the open market.

towers will be built. These will require additional TES systems that will be reviewed when they are built. The contract was written for 20 years anticipating further renewal every 20 years for the life of the development (BCUC 2014d).

The project was found to be in the public interest, and the CPCN was granted. The contract had to be adjusted to better inform customers about the rates, which were found to be just and reasonable (FAES 2014b).

The contract begins with a negotiated initial rate FortisBC finds competitive (~10.5c/kWh), which then increases at 2% per year (BCUC 2014d). However, this is the forecast rate is not binding. The actual rate is called a performance ratio, but is calculated by dividing all relevant costs by the thermal energy delivered.

The performance ratio duplicates the cost recovery principles of a cost of service rate. The rate charged is the total energy delivered in kWh, divided by the sum of the natural gas, electricity, operation and maintenance expenses, property taxes, depreciation expenses, amortization expenses, income taxes and capital carrying costs. The natural gas and electricity rates are drawn from an annual deferral account, that is adjusted higher or lower using a rate-rider pegged to the actual price of electricity and gas.

Every four years the forecast rates are divided by the actual rates charged, and a high performance ratio would indicate the costs of FortisBC to be lower than anticipated, a low ratio the opposite. FortisBC believes this provides an incentive for them to achieve efficiencies, and while it sets a benchmark target it is unclear whether there is any reduction in profitability for not reaching targets. Rates continue to flow through to customers, who benefit when costs are lower

than anticipated, conversely the consumer pays more if costs rise. The earned return of the utility is independent of these movements.

Cost of service, or a long-term rate agreement for this performance ratio, limits the profitability of the utility provider to their benchmark rate.[76] However, these ceilings on profitability also act as floors, which is why the BCUC has been hesitant to allow their application. There is little incentive for economic efficiency, and the end-user still pays the costs (high or low) plus the capital carrying cost inclusive of the earned return of the utility.

6.3.4 Regulation by complaint

Persons served by a TES subject to complaint-based regulation, or considering contracting for such a service, should be aware of the limited scope of regulatory oversight applicable to any dispute with their provider. The BCUC was not interested in overseeing contracts written between sophisticated parties.

Short of complete exemption from regulatory oversight, regulation by complaint is the lightest form of regulation. There are no CPCN requirements to grant exclusive rights to operate and the rates charged are not subject BCUC review. The BCUC does set minimum requirements with respect to the communication of the rates being charged and terms the long-term contract must contain, including: clearly describing fee schedules, disclose any front or back end fees, payment due upon contract termination and early exit, and how to file a complaint (BCUC 2014e). The

[76] Identical to a COS rate design, the carrying cost of the capital equipment (inclusive of the renovation costs, thermal plants etc.) changes to reflect book value of the asset and the benchmark rate assuming a 45% equity 55% debt mix plus a 75bps risk premium. This 75bps premium (and presumably benchmark rate) are identical to the earned return calculated on the rate base of under cost of service regulation described in the GCOC Phase 2 Proceeding for Stream B utilities.

contract must also state that while this service qualifies as a utility, and must provide safe, reliable service; it has been granted certain exemptions including oversight for any rates charged.

Prior to contacting the BCUC, plaintiffs are directed to attempt to resolve their disputes with the utility provider. Failing this, any one or group of end users can trigger a complaint. The BCUC can launch a full review, in which the plaintiffs and the utility would be directed to file their arguments with supporting evidence. If the BCUC deems it necessary, the utility may be ordered to improve its services, adjust the rates, or have its exemption from regulation removed (among other items) (BCUC 2014e).

The BCUC will not accept complaints on the rate design unless it can be shown the utility has violated the terms of the long-term contract. The BCUC has made this position clear and requires it to be written into the long term contracting, stating that no oversight of the rates was conducted (BCUC 2014e).

If the ratepayers agree to a rate design that later results in higher rates or greater risks than they had anticipated, the BCUC will not consider the propriety of the rates. The BCUC will first act to enforce the terms of the contract between the two parties, meaning it is the contract that will be enforced, and only once the terms of the contract have been violated, the BCUC will consider intervening. If the two parties agree to a rate design that later results in a higher cost of service than intended or an unequal partitioning of risk for the ratepayers, the ratepayers cannot ask the Commission to revise this. The propriety of rate design is outside the scope of regulatory oversight by the Commission.

The BCUC cannot approve any rate not found to be just and reasonable, but the language of the UCA Act can lead to a flattering interpretation of the rate design among prospective ratepayers. The language of the UCA should not automatically be interpreted as a ringing endorsement, but as a necessary requirement for the application to be approved. Just and reasonable does not imply any consideration for the best rate, does not follow any optimization principle identifying the best rate, and never acts as a guarantee for lowest cost.

Ratepayers should further temper their expectations for complaints taken before the BCUC concerning capital costs incurred. The Commission acts to protect ratepayers entitled to safe and reliable service while also affording utilities a fair return on prudently made investments. Under cost of service regulation (simulated by the performance ratio), the utility is entitled to a regulated rate of return on its invested capital. This can include all reasonable costs prudently incurred, such as thermal plants, feasibility studies, improvement or renovation upgrades, and the carrying cost of the asset.

Whether the invested capital is just and reasonable is linked to the notion of prudently incurred costs. A prudency test may simply require that the previous expenditure schedule or CPCN be approved by the Commission. A utility may fail in the execution of delivering their services, but an approved CPCN can be cited as evidence that the initially invested capital was prudent. In other words, the project might not operate correctly and the utility could be held before the Commission for poor execution, but their choice of capital inputs or technologies, and how they actually earn their rate of return is not. FortisBC sought the same standards for their new TES businesses.

> "A cornerstone of just and reasonable rates is the recovery of prudently incurred costs. A prior finding that expenditures are in the public interest (or public interest and necessity) generally means that the decision to undertake the expenditure was prudent, although the execution of the project is still subject to review for prudence. Provided the execution was prudent, the expenditure is a legitimate utility cost of service and is recoverable from customers. This would be true in the case of each of the New Initiatives (FortisBC 2011b)."

In a sense, BCUC proceedings and decisions are similar to legal precedents. Past decision can be cited as evidence for appropriate behavior guiding current and future decisions. The utility may appeal to similar cases and decisions when arguing their activities to be in agreement with the normal activities of a utility subject to the UCA. There is no such prudency test in a competitive market where a firm could seek a reasonable rate of return based on prudently incurred costs, citing prior decisions in support of their claim. Whereas utilities charging regulated cost of service rates are entitled to earn and fair and reasonable return on the invested asset, so long as the investment is found reasonable and prudent (UCA 1996 Section 60(2)).[77]

ESAC took issue during the AES Inquiry with TES services offering regulated services in an otherwise competitive market stating:

> "It appears that the only risk that the FEU [FortisBC] would undertake in owning and operating a thermal asset is the risk of prudency and all other risks would be absorbed by the thermal customer. This is irrespective of the initial tariff agreed to by the customer (or the initial capital and operating cost estimates it was based on) (FortisBC 2012a)."

This is not entirely accurate portrayal of the risks facing a utility, which may fail to earn a return on its investment if occupants do not connect to the system as planned when the capital was invested, or if the utility fails to contain cost overruns (BCUC 2014c). The issue of costs and technology decisions made upfront, however, are unlikely to be revisited once deemed prudent.

---

[77] A utility may fail to earn an adequate return on their investment, if loads fail to materialize as planned, or if they are unable to control cost overruns.

If upon complaint the Commission decides the initial contract signed for the discrete TES qualifies as a CPCN, then the contractually agreed costs are unlikely be revisited.

6.3.5 Conclusions

If regulation can be described as a long-term contract with periodic renegotiation, then this chapter has illustrated how a long-term contract can mirror regulation. The performance ratio maintains the heavy-handed elements from cost of service rate designs in a lightly regulated market, maintaining the flow through of costs to ratepayers, substantially lowering the financial risk of utility investors. The performance ratio makes the rate of return endogenous to the capital invested, creating both a ceiling and floor on the return on investment for the utility. The performance ratio appears as though it can maintain the advantages of regulatory services in an unregulated market.

The BCUC has maintained regulation upon complaint for Stream A utilities, but only accepting to intervene on a limited number of issues. The BCUC will first enforce the terms agreed to in the initial contract. Rate design and prices charged are off the table, unless it can be shown that utility has breached the terms of the long-term contract. If the BCUC revisits the utility-ratepayer arrangements, it will be within the confines of a COS regulatory framework. Decisions concerning investments are settled upfront, and the Commission cannot act as a safety net for poor contracting.

6.4 Policy recommendations

It is early days in the discrete TES market, but I can recommend three policy items that can improve the decision-making of the parties involved. I recommend: a) additional information to

be provided to future ratepayers concerning the rates charged, b) education for ratepayers on the limits of regulation by complaint, and c) suggest altering the rate design in order to encourage higher economic efficiencies.

The long-term contract for Stream A utilities has minimum informational requirements, such as the rate charged, and how it was calculated. The contract terms are likely negotiated prior to the arrival of ratepayers. To protect future ratepayers I suggest the following augmentations to increase the usefulness and value of information contained in rate disclosure agreements.

Supplement the $/kWh rate with projected monthly and annual cost estimates. The same energy forecasts used to calculate the rate can be used for projected monthly and annual costs, based on predicted average use (non-binding estimate of course). Thermal energy is invisible, and guidance as to what the new thermal energy service will cost is beneficial. This makes the cost concrete in real estate disclosure agreements as separate from electricity and other utility bills, and makes it easy to compare with the tenants previous experience with energy bills. Even in mild seasons when little energy is used, ratepayers will be required to pay for the carrying cost (inclusive of the utility's rate of return), overhead, and maintenance cost.

TES providers should include information on either the energy intensity of the building or the carbon content of the energy used. The willingness to pay for TES has priority over previous sales techniques promising lower costs in the long run for technologies, such as GSHP. If tenants are paying a premium for green, they should know what they are paying for, including how often back-up energy sources are relied upon. This will provide transparency for the ratepayers and future tenants.

The minimum contract requirements for Stream A utilities require ratepayers be informed that the BCUC has not reviewed the rate design, and are instructed on the proper procedures for filing a complaint. Future ratepayers should also be instructed on the limits of recourse they can expect from the BCUC in the event they issue the complaint.

The regulator will first enforce the terms of the contract. They will not consider the propriety of the rates charged, unless the utility has breached the terms of the contract. If the regulators could lower the price of utility services there would not be such disparity in energy prices across North America, as we observe due to different fuel and technology choices. Even if the utility were to breach the terms of the contract and rates revisited, the regulator cannot control rate increases per se, simply the method through which rates are calculated based on commonly accepted utility practices.

The terms of arbitration for complaints filed with the regulatory are generally not favorable to ratepayers unless the contract has been breached. Regulatory hearings follow processes and standards of evidence with which the utility is well acquainted. Ratepayers can challenge the utility's execution of the project over time, but it is unlikely they can challenge prudency of the initial capital investment. The earned return of the utility is dependent on the capital investment, and the prudency test is decided once the contract is written. If upon complaint the BCUC treats the agreed to contract as a CPCN, the initial capital costs will likely be found reasonable and prudent. This places the onus on the initial parties signing the contract to consider the technology chosen, and how the utility earns its rate of return.

The performance ratio closely resembles a regulated cost of service rate, where all costs flow through to the end-user. The prices charged are endogenous, and the rate of the return for the

utility fixed. Cost of service rate designs reduce the financial risk of the investor, affect capital and technology inputs, and may also encourage X-inefficiency (Joskow et al. 1989). The BCUC sought to prohibit COS because of the risk transfer, and partly because there were so few incentives for economic efficiency. However, by denying regulatory oversight of rates charged the BCUC cannot intervene as arbiter.

Small amendments to the existing contract to incorporate revenue sharing can reward both end users and utilities. For example, revenue sharing occurs when the utility is rewarded for meeting performance targets by reducing costs. The utility is then allowed to split the financial savings with ratepayers. The opposite is also true, and if the utility were unable beat the benchmark the utility would not redeem all of their earned return. This amendment is found among regulated utilities but could easily be adapted for a discrete TES contract.

There is always some form of regulation, even in 'unregulated' markets. Regulation can be in the form of contract law, competition policy, energy efficiency standards, property law, environmental regulation, and even income tax. The competitive environment will ultimately determine the shape of discrete TES, either through the education of end users learning to demand better terms or by new market entrants offering more attractive energy services.

Chapter 7: Conclusion

In Canada, and in other industrialized nations, space heating and hot water dominate secondary energy use among buildings. The combustion of fossil fuels to provide these services makes them the largest sources of carbon emissions from the built environment (NRCAN 2011a). Public policy designed to promote the adoption of renewable and energy efficient technology is a growing priority.

GSHP provides a technological solution for realizing energy and carbon savings by using less than one-third of the energy used by traditional space heating technologies (DOE 2012). Further, GSHP offers both climate change mitigation and adaptation capabilities by reducing carbon emissions, and maintaining resiliency against heat waves through active air conditioning.

GSHP is technologically mature, and has been commercially available for decades, yet serves only a small fraction of the market for space conditioning in North America. It is even less common among larger buildings, such as hotels, condominiums, and building clusters, where economies of scale ought to make it more compelling for end users.

In exploring the barriers and bridges to adopting GSHP, I asked two key questions:

1. GSHP has been adopted in the residential sector, but can we be more specific about by whom and under what conditions? What has been the impact of the enabling policies?
2. There is a dearth of GSHP at higher scales, despite economies of scale; could there be other barriers and enablers at higher scales?

To answer these questions I compiled and analyzed disparate sources of data at multiple scales. Chapter 2 demonstrated quantitatively the financial benefits of pursuing GSHP at higher scales.

Chapters 3 and 4 answer the first question, using econometric techniques to explore detailed site and panel data at the residential scale. Chapters 5 and 6 answer the second question with evidence submitted during regulatory proceedings to analyze the offering of Thermal Energy Services (TES); one method for financing GSHP among institutional, commercial, and community clients. The appendix contains technical specifics for GSHP, and an engineering-economic model for demonstrating the economics of large, interdependent, GSHP systems.

In Chapter 3, the CGC database was used to analyze the adoption of residential GSHP in Canada. The dataset overlapped with various incentives, permitting an examination of the effect of incentives on the adoption of GSHP. This database is the largest and most detailed repository of GSHP installations in North America, providing descriptions of the homes adopting GSHP.

Comparing the CGC dataset to the general population of detached housing in Canada reveals that homeowners adopting GSHP did so most often when switching away from costly, inconvenient fuel types. Homeowners rarely switched from centralized heating units, such as furnaces, when they had access to natural gas or electricity. Of homeowners adopting GSHP who had previously heated their homes with electricity, most were free riders replacing heat pumps. Homeowners who had relied on electrical plinth space heating (the second most common heating system using electricity) switched to GSHP to also benefit from air conditioning.

Most studies on GSHP lack access to reliable information on prices. The CGC dataset reveals the capital cost of GSHP systems installed in Canada is significantly higher than similar systems in the US. Given Canadian-specific system costs, the lifecycle cost savings argument for GSHP in Canada can be firmly rejected in most circumstance. The low adoption rate is not a

consequence of inadequate information, but a consequence of high capital costs and much lower cost and technically proven conventional alternatives.

The CGC dataset reflects systems installed during a period of generous provincial and federal incentives, up to $10,000 in certain regions. Considerations for the potential of GSHP should be tempered by the inability of incentives to create lasting momentum during or after the period of subsidy, with the rate of adoption peaking two years before the subsidy expired. Further, GSHP is unable to make inroads into the most common fuel types for heating in Canada, except where auxiliary benefits, such as air conditioning, are provided. Hence, one can demonstrate the benefits of incentives for GSHP go to those with the means and desire for premium space conditioning services.

Chapter 4 provided the opportunity to examine whether GSHP responded differently to financial stimulus when compared to other renewable technologies: Solar Photovoltaic (PV), Solar Thermal (ST). Panel data from US tax returns facilitated a unique opportunity to study residential responses to changing incentives. The Investment Tax Credit for renewable energy leveraged private investment to stimulate spending and assist with the development of industry. However, findings from the CGC dataset suggest that it was vulnerable to free ridership by homeowners and rent extraction where suppliers have captive markets.

Where homeowners had a competitive market supplied using standard modular systems, the subsidy led to larger system installations where the excess energy could be sold. Where the system had to be sized to the needs of the homeowner, the subsidy level did not impact the size or cost of the system installed. Where suppliers had to customize their product to the needs of the customer, higher tax credits led to much higher system costs – hence supplier rent collection.

The economic benefits of the ITC depend on the objectives considered, and one objective of the credit was to increase household investments and spur on the economic recovery. Unlike energy conservation investments, renewable energy requires substantial capital investment and is a benefit to those with high incomes. As such, the beneficiaries of the ITC align well with the objectives of the ITC to stimulate spending.

Economy-wide benefits are dependent on the bundle of services used to produce and install the technology. Using the EIO-LCA model from Carnegie Mellon, I calculated the economy-wide benefits assuming products were sourced locally and compared these benefits to a setting where key technology components are imported. The benefits are much higher if goods are manufactured within the US, so procurement decisions should be considered when allocating government expenditures for renewable energy.

By comparing the subsidy programs in the US and Canada, we can design more targeted incentives. In the US, when the ITC ceiling was removed more expensive systems were installed. In Canada, the incentive was capped and systems installed during the period of subsidy were smaller on average, when comparing area, design heat load, and cost. Capped incentives appear to lead to marginal installations for GSHP.

In comparison to the renewable ITC in the US, the financial incentives likely had lower economic multipliers. Canadians rarely manufacture the renewable technologies being promoted via investment credits. Thus, capital subsidies and similar supportive policies only deliver marginal economic stimulus when applied.

Both datasets showed declining numbers prior to incentive terminus, and the Canadian sample provides clues as to why. One hypothesis explaining the limited appetite for GSHP is the limited number of households with characteristics to make GSHP compelling. The CGC dataset showed they tended to be homes converting away from costly fuel types, or towards central heating with air conditioning. A significant fraction were also replacing heat pumps. The incentive leads to homeowners who would likely have made the conversion at some point in the future to do so now. Once this pool of adopters has diminished, GSHP is unable to attract homeowners away from the conventional technologies dominant in the market.

The analysis of the IRS dataset also provided an explanation for why the capital cost of GSHP is higher in Canada. The custom-built nature of GSHP makes comparison of pricing difficult and subject to site conditions. This makes the pricing for GSHP somewhat discretionary, with installers able to charge higher prices depending on what the market will bear. The site-specific and customized aspects of GSHP also make it resistant to downward price movements over time, compared to modular technologies, such as PV, where installers can become more efficient and manufacturing learning curves can drive down costs.

Awareness is often cited as one of the most challenging barriers to the adoption of GSHP. The available data did not support any direct analysis of the role of awareness. However, the incentive programs did raise awareness about the technology. One would expect that this increased awareness would also lead to more investment in GSHP where there was no incentive being offered. In the US and Canada, no such spillover leading to an increase in GSHP adoption was observed. This provides some evidence that awareness is not a key barrier to the adoption of GSHP.

In Chapters 5-6, I moved beyond detached housing to examine GSHP installations at higher scales. The common element was the provision of Thermal Energy Service (TES) by FortisBC in financing, owning, and operating GSHP in conjunction with other technologies. TES provides green, thermal energy to one or more buildings in exchange for utility payments. The market interest in TES has been significant, and in 2011 FortisBC reported over 20 projects in progress with a total estimated value of $250M.

At higher scales, there are two primary methods for a third party to finance GSHP: Energy Performance Contracting (EPC), and TES. Financing GSHP as part of an EPC is rare in Canada, and based on industry interviews, unknown to the author in Western Canada. The mild climate and low energy prices makes earning a sufficient Return-on-Investment (ROI) with GSHP within the duration of a standard EPC contract difficult. In the US, EPC contracts for GSHP are exclusive to regions for very cold and hot climates or where energy prices are high

TES emerged as a means to bridge barriers to the adoption of GSHP at higher scales. The TES method of financing offers several advantages over incumbent EPC providers. The equipment is financed off-balance sheet, avoiding balance sheet restrictions often imposed on public sector organizations (PSO). For developers, financing the thermal plant and inner mechanics reduces capital costs, making it easier for developers to reach their ROI targets when units are sold.

When transitioning from selling systems to energy services, the emphasis on GSHP as an energy savings investment dissipates. At higher scales, TES is sold on its merits as a premium, green technology, offering superior comfort space conditioning services to affluent households. No promises are made that it will ever be less costly than conventional heating system types.

TES is a compelling prospect for institutions and developers alike, but there are pitfalls to this method of contracting. Namely, severe fiscal constraint can lead to institutions accepting contracts that are generous in the near term, but more costly in the long-term. While developers can be easily persuaded to offer green services if doing so lowers their own costs, future tenants are being saddled with undesirable contracts. I addressed these and other key issues by reviewing the regulatory proceedings and contracts filed with the British Columbia Utilities Commission (BCUC).

The Delta School Board (DSB) was the first TES contract written for a PSO in North America, and is regulated by the BCUC as a public utility. My first objective in examining the DSB project was to provide a template for evaluating this novel method of project finance. The DSB effectively contracted out their heating plants to a third party, and the procurement process had much in common with privatization experiments with public infrastructures. Lessons learned from privatization and public-private partnerships for service delivery provide valuable insights for how to advise PSOs considering TES, including the importance: of maintaining a public sector comparator, PSOs agreeing on carbon accounting standards, sharing risks throughout the contracts lifecycle, and specifying outputs when contracting.

I found three non-economic factors to have played a dominant role in the adoption of a TES contract: carbon savings, the accounting treatment of capital costs, and a preference for regulatory oversight. The additional cost to the public sector was a 13% premium ($1.5M) for third party financing via a TES contract even though the project received ~$3M in provincial and federal contributions (slightly less than half of its capital cost).

In Chapter 6, I reviewed the BCUC scaled regulatory framework, which encompassed TES systems serving larger, interconnected loads. In general, as the system grows in size and complexity, so does Commission oversight, although exceptions increase regulatory requirements, such as system interdependency.[78] The framework was scaled to limit the regulatory burden on small utilities. The BCUC maintained light-handed regulation to be in the best interests of certain segments of the TES market.

For Stream A TES, the BCUC set contractual stipulations to protect future ratepayers, including notifying ratepayers the contract had not been subject to BCUC rate review. In addition to the required terms set by the BCUC, I recommended further additions to increase the value of information contained in rate disclosure agreements for Stream A TES including: replace kWh rates with monthly or annual estimates, include the information on the carbon intensity of service, and reiterate how the regulator is not a suitable replacement for due diligence when contracting.

In exploring the barriers and bridges to adopting GSHP the objective of this thesis was to answer two questions:

1. GSHP has been adopted in the residential sector, but can we be more specific about by whom and under what conditions? What has been the impact of the enabling policies?

[78] The capital cost hurdle for regulation was somewhat arbitrary, and subject to future revision. Any system costing greater than $14M is regulated (Stream B), and subject to full BCUC oversight, whereas anything below is only regulated upon complaint (Stream A). The two primary exemptions are the micro and strata exemptions, which are not eligible for any BCUC oversight, even upon complaint. The micro and strata exemptions exclude from regulatory oversight systems with a capital cost below $500k, or any system owned by a building's strata, respectively.

2. There is a dearth of GSHP at higher scales, despite economies of scale; could there be other barriers and enablers at higher scales?

In conclusion, GSHP is a stranded technology. Even when generous incentives are available, it is unable to gain momentum against natural gas and conventional heating systems. In both Canada and the US, the incentives failed to maintain adoption rates throughout the incentive period, let alone afterwards. Once the pool of households most likely to benefit from (or already considering) adopting GSHP dried up installations plummeted. While the design of incentives can be improved, expectations for the long-run potential of GSHP for realizing sizeable gains within the residential heating market in North America should be tempered.

TES arose as a means to finance GSHP at higher-scales, opening the door for economies of scale, scope, and network benefits. TES was able to bridge capital cost barriers between PSO's and developers by lowering first costs, although closer analysis reveals the lifecycle cost of GSHP makes it a premium service and TES is a high cost option unsuited for a financially constrained public sector.

Challenges to cooperation were addressed through the BCUC's scaled regulatory framework increasing oversight with project scale and interdependency. The reliance on heavy-handed regulation, even among negotiated contracts, remains the norm despite the BCUC's hesitation in its application. Whether the low risk-reward characteristics of the COS rate design is essential to the offering of TES is as of yet uncertain, considering the novelty of TES and the limited number of service providers. I endeavored to offer insight on how to compare TES contracts to other methods of public procurement, and to increase transparency of the emerging TES service.

Research at both residential and higher scales is ongoing. At the residential scale, further study is required with respect to the response of installers to incentives and the importance of household characteristics when adopting GSHP.

The CGC dataset indicates which companies were responsible for each installation. There are at least two hypotheses to test. Firstly, does competition lead to lower prices among installers? If prices charged in areas with more companies are lower than in areas with multiple providers, it could be that competition is transforming the industry, but unevenly. A second approach is to test the prices charged by incumbents compared to newer entrants. Do new entrants arrive to benefit from higher prices until incumbents price them out?

Furthermore, factors such as age, income and education are related to the adoption of renewable energy. Information of household characteristics from the Canadian Census can be compared to the fraction of households adopting GSHP from the CGC dataset. Ordering and ranking of these factors through statistical analysis can indicate whether income, real estate prices, fuel type or the share of air conditioning are most important when marketing GSHP.

The market for TES is rapidly evolving, providing compelling service innovations to the energy services market. The utility's meter is typically the stopping point for utilities, but TES crosses this barrier to finance equipment inside the building, lowering first costs of developers and ensuring compatibility the thermal plant and the building's distribution system. The stopping point for TES in providing heating and cooling is somewhat arbitrary considering these energy services already occupy the lion's share of energy use among residential buildings.

TES can be adapted to include lighting and appliance loads for net zero or energy positive buildings by combining the lowest cost portfolio of energy efficiency, renewable energy, electricity, energy storage (battery and thermal), with procurement contracts for renewable energy or carbon offsets. The combination of technologies and services to achieve carbon neutrality can offer lower prices than any one approach. Such an energy service replaces 'either or' strategies for lowering emissions with a bundle of technologies and energy services tailored to local circumstances and resources.

TES is a compelling means for bridging capital cost barriers faced by renewable and energy efficient technologies among developers and municipalities. However, this thesis has shown how fiscal constraints can lead actors accepting unfavorable contract terms. The long-term potential of TES may be dependent on its continued development. Providing information to actors considering TES and exploration into alternative market or pooled rate designs will help advance TES and the means for providing energy services.

Bibliography

Aldy, J.E., 2011. *A Preliminary Review of the American Recovery and Reinvestment Act's Clean Energy Package*, HKS Faculty Research Working Paper Series.

Arkay, K. & Blais, C., 1996. *The District Energy Option in Canada*, Ottawa: Natural Resources Canada.

Arthur, W.B., 1989. Competing Technologies, Increasing Returns, and Lock-In by Historical Events. *The Economic Journal*, 99(394), pp.116–131.

Averch, H. & Johnson, L.L., 1962. Behaviour of the Firm Under Regulatory Constrain. *The American Economic Review*, 52, pp.1052–1069.

B.C. Sustainable Energy AssociationSierra Club of British Columbia, 2013. *BCSEA-SCBC Comments*, William J. Andrews Barrister & Soliciter.

Baker Hughes, 2009. Baker Hughes U.S. Rig Count Baker Hughes, ed. Available at: <http://gis.bakerhughesdirect.com/Reports/StandardReport.aspx> [Accessed 01 September 2014].

Barbose, G. et al., 2013. *Tracking the Sun VI*, Lawrence Berkeley National Laboratory. Available at: <http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf> [Accessed 24 August 2014].

Bayer, P. et al., 2011. Greenhouse Gas Emission Savings of Ground Source Heat Pump Systems in Europe: A Review. *Renewable and Sustainable Energy Reviews*, 16(2), pp.1256–1267.

BCUC, 2012a. *AES Report In the Matter of FortisBC Energy Inc*, Vancouver. Available at: <http://www.bcuc.com/Documents/Decisions/2012/DOC_33023_G-201-12_FEI-AES-Inquiry-Report_WEB.pdf> [Accessed 24 July 2014].

BCUC, 2012b. *Commission Order G-71-12*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2012/DOC_30891_G-71-12_FAES_Delta-School-District-Rates-and-Rate-Design.pdf> [Accessed 18 August 2014].

BCUC, 2012c. *Commission Order G-88-12*, Vancouver. Available at: <http://DOC_31025_G-88-12_FAES_Delta-School-District-Rates-G-71-12-Compliance> [Accessed 18 July 2014].

BCUC, 2013a. *Commission Staff Proposal Draft - Thermal Energy System Regulatory Guide*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2013/DOC_34697_05-09-2013_TES-Regulatory-Framework-Strawman.pdf> [Accessed 12 November 2013].

BCUC, 2012d. *Decision (Commission Order G-31-12)*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2012/DOC_30034_03-09-2012-FEI_DeltaSD-37-Decision-WEB.pdf> [Accessed 5 July 2014].

BCUC, 2014a. *Exhibit A - 7 Proposed Regulatory Framework Thermal Energy Service Utilities*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2014/DOC_41540_A-7-Request-for-Comments.pdf> [Accessed 31 October 2014].

BCUC, 2014b. *Exhibit A-8 Thermal Energy Service Regulatory Framework Guidelines Notice of Edits*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2014/DOC_41606_A-8_Notice-of-Edits-Guidelines.pdf> [Accessed 31 October 2014].

BCUC, 2014c. *Generic Cost of Capital Proceeding (Stage 2)*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2014/DOC_41123_03-25-2014-BCUC-GCOC-Stage-2-Decision-WEB.pdf> [Accessed 31 October 2014].

BCUC, 2014d. *Order C-3-14 FAES SOLO Rates CPCN*, Vancouver. Available at: <http://www.bcuc.com/Documents/Decisions/2014/DOC_40769_02-25-2014_FAES_TES-SOLO-Rates-CPCN_Reasons.pdf> [Accessed 1 November 2014].

BCUC, 2014e. *Order G-127-14 Thermal Energy Systems Regulatory Framework*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2014/DOC_42027_G-127-14_BCUC-TES-Framework-Guidelines.pdf> [Accessed 29 October 2014].

BCUC, 2013b. *Order G-132-13 Draft Thermal Energy Service Utility Sacled Regulatory Framework and Guide*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2013/DOC_35541_A-2_RegulatoryTimetable-HrgNotice_G-132-13.pdf> [Accessed 29 October 2014].

BCUC, 2013c. *Order G-231-13A A Proposed Regulatory Framework Including an Exemption for Certain Thermal Energy Service Utilities*, Available at: <http://www.bcuc.com/Documents/Orders/2013/DOC_39186_G-231-13A_BCUC_TES-AmendedTimetable.pdf [Accessed 29 October 2014].

BCUC, 2014f. *Orders G-119-14, G-120-14, G-121-14*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2014/DOC_42004_A-9_BCUC-G-119-14-G-120-14-G-121-14.pdf> [Accessed 31 October 2014].

BCUC, 2014g. *Reasons for Decision Proposed Regulatory Framework and Guide for Thermal Energy Service Utilities*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2014/DOC_39384_A-5_Amended-Order-G-231-13A.pdf> [Accessed 31 October 2014].

BCUC, 2007. *Retail Markets Downstream of the Utility Meter Guidelines*, Vancouver. Available at: <http://www.bcuc.com/Documents/Guidelines/RMDMGuidelns.pdf> [Accessed 17 November 2014].

Blum, P. et al., 2009. CO2 Savings of Ground Source Heat Pump Systems – A Regional Analysis. *Renewable Energy*, 35(1), pp.122–127.

Bolinger, M., 2014. *An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Energy Tax Incentives*, Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/reports/re.

Bolinger, M., Barbose, G. & Wiser, R., 2008. *Shaking up the Residential PV Market: Implications of Recent Changes to the ITC*, Berkely Lab and the Clean Energy States Alliance. Available at: <http://emp.lbl.gov/sites/all/files/CASE%20STUDY%20res-itc-report.pdf> [Accessed 12 August 2014].

Brennan, M.J. & Schwartz, E.S., 1982. Consistent Regulatory Policy under Uncertainty. *The Bell Journal of Economics*, 12, pp.506–521. Available at: <http://www.jstor.org/stable/3003470> [Accessed 22 November 2014].

Brown, M.A., 2001. Market Failures and Barriers as a Basis for Clean Energy Policies. *Energy Policy*, 29(14), pp.1197–1207. Available at: <http://www.sciencedirect.com/science/article/pii/S0301421501000672> [Accessed 7 April 2013].

Canadian GeoExchange Coalition, 2009. *A Buyers Guide for Residential Ground Source Heat Pump Systems*, Canadian GeoExchange Coalition. Available at: <http://www.geo-exchange.ca/en/UserAttachments/article58_Residential_Geothermal_Buyers_Guide_2009.pdf> [Accessed 22 April 2013].

Canadian GeoExchange Coalition, 2012a. *Canadian Geothermal Heat Pump Industry Technology Roadmap*, Canadian GeoExchange Coalition. Available at < http://www.geo-exchange.ca/en/UserAttachments/article84_Roadmap_FINAL_E.pdf> [Accessed 11 May 2013].

Canadian GeoExchange Coalition, 2015a. CGC database of residential GSHP systems.

Canadian GeoExchange Coalition, 2013. *Ten years of progress and achievement: 2002-2012*, Canadian GeoExchange Coalition. Available at: < http://www.geo-exchange.ca/en/cgc_publications_arc3.php> [Accessed 2 May 2013].

Canadian GeoExchange Coalition, 2012b. *The State of the Canadian Geothermal Heat Pump Industry 2011*, Canadian GeoExchange Coalition. Available at < http://www.geo-exchange.ca/en/UserAttachments/article81_Final%20Stats%20Report%202011%20-%20February%206,%202012_E.pdf> [Accessed 20 October 2012].

Canadian GeoExchange Coalition ed., 2015b. *Vision and Strategies* CGC, Canadian GeoExchange Coalition. Available at: http://www.geo-exchange.ca/en/cgc_visions_strategies_p4.php [Accessed May 20, 2015b].

CANMET Energy, 2005. *Clean Energy Project Analysis* 3rd ed., Varennes: Natural Resources Canada. Available at: <http://www.retscreen.net> [Accessed 16 April 2014].

CANMET Energy, 2002. *Commercial Earth Energy Systems*, Natural Resources Canada. Available at:

https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/files/pubs/M92-251-2002E.pdf [Accessed 16 April 2014].

CANMET Energy Technology Centre - Varennes, 2005. *Ground-Source Heat Pump Project Analysis*, Natural Resources Canada. Available at: <http://www.retscreen.net> [Accessed 19 September 2012]

Carnegie Mellon University Green Design Institute ed., 2013. *Economic Input-Output Life Cycle Assessment (EIO-LCA), US 1997 Industry Benchmark model [Internet]*, Available at: http://www.eiolca.net [Accessed January 1, 2014].

Carpenter, E.H. & Durham, C., 1985. Again, Federal Tax Credits Are Found Effective: A Reply. *The Energy Journal*, Volume 6 (Number 3), pp.127–128.

Carpenter, E.H. & S Theodore Chester, J., 1984. Are Federal Energy Tax Credits Effective? A Western United States Survey. *The Energy Journal*, Volume 5(Number 2), pp.139–149.

Chandler, A.D., 1990. *Scale and Scope: The Dynamics of Industrial Capitalism*, Cambridge, M.: Belknap Press.

Chua, K.J., Chou, S.K. & Yang, W.M., 2010. Advances in Heat Pump Systems: A Review. *Applied Energy*, 87(12), pp.3611–3624.

Compass Resource Management, MK Jaccard and Associates, 2005. *Sustainable Energy Technology and Resource Assessment for Greater Vancouver*, Compass Resource Management.

Curien, N., Jullien, B. & Rey, P., 1998. Pricing Regulation Under Bypass Competition. *RAND Journal of Economics (RAND Journal of Economics)*, 29(2), pp.259–279.

Davies, A., 1996. Innovation in Large Technical Systems:The case of telecommunications. *Industrial and Corporate Change*, 5, pp.1143–1180.

Defense, D.O., 2007. *Ground-source heat pumps at Department of Defense facilities*, Office of the Deputy Under Secretary of Defense.

Department of Energy, 2012. *Solar Water Heating with Low-Cost Plastic Systems*, Federal Energy Mangement Program. Available at: <https://www1.eere.energy.gov/femp/pdfs/lowcost_shw.pdf> [Accessed 21 August 2014].

Dixit, A., 1992. Investment and Hysteresis. *The Journal of Economic Perspectives*, 6, pp.107–132.

Dowlatabadi, H. et al., 2011. *Lifecycle Analysis of GHG Intensity in BC's Energy Sources*, Vancouver: Pacific Institute for Climate Solutions.

DSB, 2008. *Delta Board of Education: 2008 Carbon Neutral Action Report*, Delta. Available at: <http://www.env.gov.bc.ca/cas/reports/cnar/SD37.pdf> [Accessed 10 July 2014].

DSB, 2009. *Delta Board of Education: 2009 Carbon Neutral Action Report*, Delta. Available at: <http://www.env.gov.bc.ca/cas/reports/cnar/SD37_2009.pdf> [Accessed 10 July 2014].

DSB, 2010. *Delta Board of Education: 2010 Carbon Neutral Action Report*, Delta. Available at: <http://www.env.gov.bc.ca/cas/reports/cnar/SD37_2010.pdf> [Accessed 10 July 2014].

DSB, 2012. *Response to British Columbia Utilities Commission Information Request No. 1 (Exhibit C1-2)*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2012/DOC_29668_C1-2_Delta_Resps_BCUC_IR-1.pdf> [Accessed 6 July 2014].

EIA, 2012a. *Table 10.6 Solar Thermal Collector Shipments by Type, Price, and Trade, 1974-2009*, U.S. Energy Information Administration. Available at: <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb1006> [Accessed 21 August 2014].

EIA, 2012b. *Table 10.8 Photovoltaic Cell and Module Shipments by Type, Trade, and Prices, 1982-2010*, U.S. Energy Information Administration. Available at: <http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb1008> [Accessed 21 August 2014].

EIA ed., 2014. *Energy Improvement and Extension Act of 2008: Summary of Provivisions* EIA, EIA. Available at: <http://www.eia.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/eiea.html [Accessed July 17, 2014]> [Accessed 17 July 2014].

FAES, 2014a. *Order C-9-14 Artemisia Development*, Vancouver. Available at: <http://www.bcuc.com/Documents/Decisions/2014/DOC_42012_08-26-2014-C-9-14_FAES-Artemisia_Decision.pdf> [Accessed 16 November 2014].

FAES, 2014b. *Order G-54-14 Phase 2 SOLO District Development*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2014/DOC_41213_G-54-14_FAES_TES-SOLO-Rates-Phase2_Reasons.pdf> [Accessed 16 November 2014].

FAES, 2012. *PCI Marine Gateway Application for a Certicate of Public Convenience and Necessity*, Vancouver: BCUC. Available at: <http://www.bcuc.com/Documents/Proceedings/2012/DOC_30825_B-1_FAES-PCI-Marine-Gateway-TES-CPCN-Application.pdf> [Accessed 22 May 2015].

FAES, 2014c. *Sovereign Decision Order C-10-14*, Vancouver. Available at: <http://www.bcuc.com/Documents/Decisions/2014/DOC_42013_08-26-2014-C-10-14_FAES-Sovereign_Decision.pdf> [Accessed 16 November 2014].

Fazzari, S., Hubbard, R.G. & Petersen, B.C., 1987. Financing Constraints and Corporate Investment. *NBER Working Paper*.

FortisBC, 2011a. *Exhibit B-1 Written Submission of the FortisBC Energy Utilities for Procedural Conference on June 15, 2011*, Vancouver. Available at:

<http://www.bcuc.com/Documents/Proceedings/2011/DOC_27923_B-1_FEU-Procedural-Submissions.pdf> [Accessed 9 October 2014].

FortisBC, 2011b. *Exhibit B-2 Evidence of FortisBC Energy Utilities*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2011/DOC_28443_B-2_FEU-EvidenceFF.pdf> [Accessed 9 October 2014].

FortisBC, 2012a. *Exhibit B-19 Rebuttal Evidence of FortisBC Energy Utilities*, Available at: <http://www.bcuc.com/Documents/Proceedings/2012/DOC_29622_B-19_FEU-Rebuttal-Evidence-Submission.pdf> [Accessed 9 October 2014].

FortisBC, 2012b. *FEI Final Argument Submissions*, Vancouver. Available at: <http://www.bcuc.com/Documents/Arguments/2011/DOC_29753_02-02-2012_FEI_Final-Argument-Submissions.pdf> [Accessed 26 July 2014].

FortisBC, 2012c. *FEI Response to BCUC Supplemental Information Request (Exhibit B-8)*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2012/DOC_29671_B-8_FEI-BCUC-Supplemental-IR-Response.pdf> [Accessed 26 July 2014].

FortisBC, 2011c. *FortisBC Energy Inc. Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of Contracts and Rate for Public Utility Service to Provide Thermal Energy Service to Delta School District Number 37 (Exhibit B-1)*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2011/DOC_29231_B-1_FEI_Delta-School-District-37-TES-CPCN-Application.pdf> [Accessed 22 July 2014].

Frederick, S., Loewenstein, G. & O'Donoghue, T., 2002. Time Discounting and Time Preference: A Critical Review. *Journal of Economic Literature*, 40, pp.351–401.

Friedman, B. et al., 2013. *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey - Second Edition*, Golden: National Renewable Energy Laboratory. Available at: <http://www.nrel.gov/docs/fy14osti/60412.pdf> [Accessed 25 August 2014]

Garrabrant, M., 2013. *Development and Validation of a Gas-Fired Residential Heat Pump Water Heater*, US Department of Energy Publications. Available at: <http://www.osti.gov/scitech/servlets/purl/1060285> [Accessed 6 May 2015].

Gaz Métro ed., 2015. *Gaz Métro: Understanding my bill*, Gaz Métro. Available at: http://www.gazmetro.com/en/residential/customer-centre/billing-and-pricing/understanding-my-bill/ [Accessed April 11, 2015].

Gintis, H., 2000. Beyond Homo Economicus: Evidence From Experimental Economics. *Ecological Economics*, 35(3), pp.311–322.

Goetzler, W. et al., 2009. *Ground-Source Heat Pumps: Overview of Market Status, Barriers to Adoption, and Options for Overcoming Barriers*, Navigant Consulting, Inc.

Gold, R. & Nadel, S., 2011a. *Assessing the Harvest: Implementation of the Energy Efficiency Provisions in the Energy Policy Act of 2005*, Washington: ACEEE. Available at: <http://www.aceee.org/sites/default/files/publications/researchreports/E113.pdf> [Accessed 12 May 2014].

Gold, R. & Nadel, S., 2011b. *Energy Efficiency Tax Incentives, 2005-2011: How Have They Performed*, Washington: ACEEE. Available at: <http://www.aceee.org/files/pdf/white-paper/Tax%20incentive%20white%20paper.pdf> [Accessed 12 May 2014].

Groff, G., 2014. Heat Pumps in North America 2014: Regional Reports. In 11th IEA Heat Pump Conference. Montreal, pp. 1–12.

Hanova, J., 2008. *Environmental and Techno-Economic Analysis of Ground Source Heat Pump Systems*. PhD Thesis University of British Columbia, Vancouver.

Hanova, J. & Dowlatabadi, H., 2007. Strategic GHG Reduction Through the Use of Ground Source Heat Pump Technology. *Environmental Research Letters*, 2(4), p.044001.

Hassett, K.A. & Metcalf, G.E., 1995. Energy Tax Credits and Residential Conservation Investment: Evidence From Panel Data. *Journal of Public Economics*, 57(2), pp.201–217.

Hemmera Engineering, 2007. *Geoexchange Technical Feasibility Study*, Hemmera.

Herman, J., 2013. *Canada's Approach to School Funding*, Centre for American Progress, Available at: <http://cdn.americanprogress.org/wp-content/uploads/2013/05/HermanCanadaReport.pdf> [Accessed 26 July 2014].

Hughes, P.J., 2008. *Geothermal (Ground-Source) Heat Pumps: Market Status, Barriers to Adoption, and Actions to Overcome Barriers*, Oak Ridge National Laboratory, US Department of Energy Publications. Available at: <https://www1.eere.energy.gov/geothermal/pdfs/ornl_ghp_study.pdf> [Accessed 12 August 2014]

Hughes, T.P., 1983. *Networks of power: Electrification in Western society, 1880-1930*, Baltimore & London: John Hopkins University Press.

Huovila, P., Programme, U.N.E. & Branch, S.C.A.R., 2007. *Buildings and Climate Change : Status, Challenges, and Opportunities*, Paris, France: United Nations Environment Programme, Sustainable Consumption and Production Branch.

Huttrer, G.W., 1997. Geothermal Heat Pumps: an Increasingly Successful Technology. *Renewable Energy*, 10(2–3), pp.481–488.

Hydro Québec ed., 2015. *Hydro Québec: Understanding Your Bill*, Hydro Québec. Available at: http://www.hydroquebec.com/residential/understanding-your-bill/rates/residential-rates/rate-d/ [Accessed April 11, 2015].

Internal Revenue Service ed., 2014. *SOI Tax Stats - Individual Income Tax Returns, Line Item*

Estimates, Available at: http://www.irs.gov/uac/SOI-Tax-Stats-Individual-Income-Tax-Returns,-Line-Item-Estimates [Accessed May 21, 2014].

Iossa, E. & Martimort, D., 2009. The Simple Micro-Economics of Public Private Parternships. *Economics and Finance Working Paper Series*, pp.1–57.

Jaccard, M., 2011. *Exhibit C12-5 BCUC Inquiry in FortisBC Eneergy Inc. ("FEI") regarding the Offering of Products and Services in Alternative Energy Solutions ("AES") and Other New Initiatives*, Vancouver. Available at: <http://www.bcuc.com/Documents/Proceedings/2011/DOC_29118_C12-5_CORIX_%20Evidence-Dr-M-Jaccard.pdf> [Accessed 14 November 2013]

Jaffe, A.B. & Stavins, R.N., 1994. The Energy Paradox and the Diffusion of Conservation Technology. *Resource and Energy Economics*, 16(2), pp.91–122.

Jensen, T. & Dowlatabadi, H., 2012. Improving the economics of ground source heat pumps through a community energy utility. In American Council for an Energy-Effecient Economic. Monterey, CA, pp. 1–12.

Joskow, P.L., Rose, N.L.Massachusetts Institute of Technology. Department of Economics, 1989. The Effects of Economic Regulation. In *Handbook of Industrial Organization*. Amsterdam: North-Holland, pp. 1449–1506.

Kantrowitz, T. & Tanguay, D., 2011. GSHP Market Growth in Canada: Future market opportunities, incentive programs, and labour market strategies. In The IEA Heat Pump Conference. Tokyo, pp. 1–12.

Kegel, M., Sunye, R. & Tamasauskas, J., 2012. Life Cycle Cost Comparison and Optimization of Different Heat Pump Systems in the Canadian Climate. In The Canadian Conference on Building Simulation. Halifax, pp. 492–614.

Legislative Assembly of the Province of British Columbia, 2008a. *Carbon Neutral Public Sector*, Available at: <http://www.bclaws.ca/civix/document/id/complete/statreg/07042_01> [Accessed 16 October 1014].

Legislative Assembly of the Province of British Columbia, 2008b. *Carbon Tax Act*, Available at: <http://www.leg.bc.ca/38th4th/3rd_read/gov37-3.htm> [Accessed 16 October 1014].

Legislative Assembly of the Province of British Columbia, 2010. *Clean Energy Act*, Available at: <https://www.leg.bc.ca/39th2nd/1st_read/gov17-1.htm#section32> [Accessed 16 October 1014].

Legislative Assembly of the Province of British Columbia, 2008c. *Greenhouse Gas Reduction (Cap and Trade) Act*, Available at: <http://www.leg.bc.ca/38th4th/3rd_read/gov18-3.htm> [Accessed 16 October 1014].

Legislative Assembly of the Province of British Columbia, 2007. *Greenhouse Gas Reduction Targets Act*, Available at: <http://www.leg.bc.ca/38th3rd/3rd_read/gov44-3.htm> [Accessed

16 October 1014].

Long, J.E., 1993. An Econometric Analysis of Residential Expenditures on Energy Conservation and Renewable Energy Sources. *Energy Economics*, 15(4), pp.232–238.

Lovins, A., 1992. *Energy-efficient buildings: Institutional barriers and opportunities*, E Source, Inc., Boulder, CO (United States).

Lund, H. et al., 2010. The Role of District Heating in Future Renewable Energy Systems. *Energy*, 35(3), pp.1381–1390.

Margolis, R., Friedman, B. & Feldman, D., 2013. *Financing, Overhead, and Profit: An In-Depth Discussion of Costs Associatd with Third-Party Financing of Residential Commercial Photovoltaic Systems*, Denver: National Renewable Energy Laboratory. Available at: <http://www.nrel.gov/docs/fy14osti/60401.pdf> [Accessed 26 August 2014].

Markbek Resource Consultants Ltd., 2007. *BC Hydro 2007 Conservation Potential Review*, BC Hydro.

Metcalf, G., 2009. *Tax Policies for Low-Carbon Technologies*, Cambridge, MA: National Bureau of Economic Research.

Metcalf, G.E., 2007. *Federal Tax Policy Towards Energy*, MIT Joint Program on the Science and Policy of Global Change.

Metcalf, G.E., 2008. Using Tax Expenditures to Achieve Energy Policy Goals. *The American Economic Review*, 98, pp.90–94. Available at: http://www.jstor.org/stable/29730001 [Accessed 12 August 2014].

Mustafa Omer, A., 2008. Ground-Source Heat Pumps Systems and Applications. *Renewable and Sustainable Energy Reviews*, 12(2), pp.344–371.

Natural Resources Canada, 2012a. Secondary Energy Use and GHG Emissions by Energy Source, Residential Sector, Canada. Available at: <http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/list.cfm> [Accessed 29 August 2012].

Natural Resources Canada, 2007. *Survey of household energy use 2007*, Ottawa: Office of Energy Efficiency. Available at: <http://oee.nrcan.gc.ca/Publications/statistics/sheu07/pdf/sheu07.pdf> [Accessed 24 August 2012].

Natural Resources Canada, 2011a. *Survey of Household Energy Use* 2011, Ottawa: Office of Energy Efficiency. Available at: <http://oee.nrcan.gc.ca/publications/statistics/sheu11/sheu2011.pdf> [Accessed 8 April 2015].

Natural Resources Canada, 2012b. Table 2: Secondary Energy Use and GHG Emissions by End-

Use: Ontario, Ottawa: Office of Energy Efficiency. Available at: <http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=22&page=0.> [Accessed 15 April 2015].

Natural Resources Canada, 2012c. Table 2: Secondary Energy Use by GHG Emissions and End Use: Quebec, Ottawa: Office of Energy Efficiency. Available at: <http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=qc&rn=2&page=0.> [Accessed 15 April 2015].

Natural Resources Canada, 2012d. Table 5: Space Cooling Secondary Energy Use and GHG Emissions by Cooling System Type Canada, Ottawa: Office of Energy Efficiency. Available at: <http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=ca&rn=5&page=0> [Accessed 15 April 2015].

Natural Resources Canada, 2012e. Table 7: Space Heatig Secondary Energy Use and GHG Emissions by Energy Source Canada, Ottawa: Office of Energy Efficiency. Available at: <http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=ca&rn=7&page=0> [Accessed 15 April 2015].

Natural Resources Canada, 2012f. Table 22: Single Detached Heating System Stock by Heating System Type Quebec, Ottawa: Office of Energy Efficiency. Available at: <http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=qc&rn=22&page=0> [Accessed May 15, 2015].

Natural Resources Canada, 2012g. Table 28: Single Detached Heating System Stock by Heating System Type Canada, Ottawa: Office of Energy Efficiency.. Available at: <http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=ca&rn=28&page=0> [Accessed 15 May 2015].

Natural Resources Canada, 2009. Total Households by Building Type and Principal Heating Energy Source, Residential Sector. Available at: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/list.cfm.

Natural Resources Canada, 2011b. *Comprehensive Energy Use Database Tables*, NRCAN. Available at: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive/trends_res_ca.cfm [Accessed December 2, 2014b].

Natural Resources Canada ed., 2014. *Grant table for ecoEnergy Retrofit - Homes* NRCAN, NRCAN. Available at: http://www.nrcan.gc.ca/energy/efficiency/housing/home-improvements/5015 [Accessed May 20, 2015].

Natural Resources Canada, 2012h. *Office of Energy Efficiency Comprehensive Energy Use Database Tables Residential Sector British Columbia* NRCAN, NRCAN. Available at: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/tablestrends2/res_bc_39_e_3.cfm?attr=0 [Accessed April 8, 2015h].

Natural Resources Canada, 2013. *Tax Savings for Industry: Class 43.1, 43.2, and CRCE* NRCAN. Available at: http://www.nrcan.gc.ca/energy/efficiency/industry/financial-assistance/5147 [Accessed July 26, 2014].

Newell, R.G., Jaffe, A.B. & Stavins, R.N., 1999. The Induced Innovation Hypothesis and Energy-Saving Technological Change. *The Quarterly Journal of Economics*, 114(3), pp.941–975.

Nightengale, P. et al., 2003. Software, control and the growth of large technical systems. *Industrial and Corporate Change*, 12, pp.477–517.

Ontario Energy Board ed., 2015a. *Ontario Energy Board: Electricity Prices*, Ontario Energy Board. Available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Electricity%20Prices [Accessed April 11, 2015a].

Ontario Energy Board ed., 2015b. *Ontario Energy Board: Enbridge Residential Rates*, Available at: http://www.ontarioenergyboard.ca/oeb/_Documents/QRAM/enbridge_QRAM_20150401.pdf [Accessed April 11, 2015b].

Ozgener, O. & Hepbasli, A., 2007. Modeling and Performance Evaluation of Ground Source (Geothermal) Heat Pump Systems. *Energy and Buildings*, 39(1), pp.66–75.

Pacific Institute for Climate Solutions, 2012. *The Regulation of District Energy Systems* P. Ostergaard, Victoria. Available at:<http://pics.uvic.ca/sites/default/files/uploads/publications/WP_District_Energy_May2012.pdf> [Accessed 19 September 2012].

Petersen, H.C., 1985. Solar Versus Conservation Tax Credits. *The Energy Journal*, 6(3), pp.129–135.

Pitts, R.E. & Wittenbach, J.L., 1981. Tax Credits as a Means of Influencing Consumer Behavior. *Journal of Consumer Research*, 8(3), pp.335–338.

Rawlings, R.H.D. & Sykulski, J.R., 1999. Ground Source Heat Pumps: A Technology Review. *Building Services Engineering Research and Technology*, 20(3), pp.119–129.

Raymond, J. et al., 2015. Direct Utilization of Geothermal Energy from Coast to Coast: a Review of Current Applications and Research in Canada. In World Geothermal Congress 2015. Melbourne, p. 10.

Roe, B. et al., 2000. US Consumers' Willingness to Pay for Green Electricity. *Energy Policy*, 29(11), pp.917–925.

Rogers, E., 2004. A Prospective and Retrospective Look at the Diffusion Model. *Journal of Health Communication*, 9(sup1), pp.13–19.

Sanner, B. et al., 2004. Current Status of Ground Source Heat Pumps and Underground Thermal Energy Storage in Europe. *Selected Papers from the European Geothermal Conference 2003*, 32(4–6), pp.579–588.

SaskEnergy, 2011. Saskatchewan EnerGuide for houses program renewed to Fall 2013 SaskEnergy, ed. Available at: <http://www.saskenergy.com/About_SaskEnergy/News/news_releases/2011/EnerGuide%20Prog%20Mar%2016%2011.pdf> [Accessed 20 May 2015].

Self, S.J., Reddy, B.V. & Rosen, M.A., 2012. Geothermal Heat Pump Systems: Status Review and Comparison with Other Heating Options. *Applied Energy*, 101(0), pp.341–348.

Smith, C., 2012. ESAC Evidence Alternative Energy Services Inquiry. Available at: < http://www.bcuc.com/Documents/Proceedings/2012/DOC_29564_A2-6_Delta%20SD37%20TES_Exhibit%20C1-5%20AES.pdf> [Accessed 2 December 2013].

Staffell, I. et al., 2012. A Review of Domestic Heat Pumps. *Energy Environ. Sci.*, (11), pp.9291–9306.

Statistics Canada ed., 2014. *Data Quality, Concepts and Methodology: Explantory Notes for Tables (Table 9)*, Available at: http://www.statcan.gc.ca/pub/62-001-x/2014006/technote-notetech1-eng.htm [Accessed July 2014].

Stern, N., 2007. *Stern Review: The Economics of Climate Change*, Cambridge.

Sullivan, J., 2011. Ontario Code Tops in Energy Efficiency. *The Star*. Available at: http://www.thestar.com/life/homes/2011/08/19/ontario_code_tops_in_energy_efficiency.html [Accessed 1 May 2015].

Sutherland, D. & Araujo, S., 2010. *Public-Private Partnerships and Investment in Infrastructure*, OECD Publishing.

Terasen Gas Inc., 2011a. *Decision 2010 Long Term Resource Plan Terasen Utilities*, Vancouver. Available at: <http://www.bcuc.com/Documents/Decisions/2011/DOC_26891_TUS-2010-LTRP-WEB.pdf> [Accessed 2 November 2015].

Terasen Gas Inc., 2011b. *Order G-14-11 Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc and Terasen Gas (Whistler) Inc. 2010 Long Term Resource Plan*, Vancouver. Available at: <http://www.bcuc.com/Documents/Orders/2011/DOC_26908_G-14-11_TUS-2010-LTRP-Decision.pdf> [Accessed 2 November 2014].

Thorsteinsson, H.H., 2008. *U.S. Geothermal Distric Heating Barriers and Enablers*. PhD Thesis Massacheusetts Institute of Technology.

U.S. Department of Energy, 2012. Heat Pumps. *energy.gov*. Available at: http://energy.gov/energysaver/articles/tips-heat-pumps [Accessed October 19, 2012].

U.S. Energy Information Administration, 2012. Table 4.1: Goethermal Heat Pump Shipments by

Model Type, 2000-2009 U.S. Energy Information Administration, ed. Available at: <http://www.eia.gov/renewable/annual/geothermal/> [Accessed 22 July 2014].

U.S. Energy Information Administration, 2008. Table 4.7: Goethermal Heat Pump Shipments by Destination, 2008 and 2009 U.S. Energy Information Administration, ed. Available at: <http://www.eia.gov/renewable/annual/geothermal/> [Accessed 1 July 2014].

Utilities Commission Act, 1996. *Utilities Commission Act*, British Columbia Legislative Assembly. Available at: <http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_96473_01#section45> [Accessed 20 July 2014].

United States Census Bureau, 2015. New residential construction: Jan-1959-Dec-2015 United States Census Bureau, ed. Available at: <http://www.census.gov/econ/currentdata/dbsearch?program=RESCONST&startYear=1959&endYear=2015&categories=APERMITS&dataType=TOTAL&geoLevel=US&adjusted=1&notAdjusted=0&errorData=0> [Accessed 21 May 2015].

United States Government Accountability Office, 2005a. *Capital Financing: Partnerships and Energy Savings Performance Contracts Raise Budgeting and Monitoring Concerns*, Washington, D.C.

United States Government Accountability Office, 2005b. *Energy Savings: Performance Contracts Offer Benefits, but Vigilance Is Needed to Protect Government Interests*, Washington, D.C.

VIGeothermal ed., 2013. *Home Improvement Grants*, VIGeothermal. Available at: http://www.vigeothermal.ca/home-improvement-grants/ [Accessed May 20, 2015].

Viscusi, W.K., Harrington, J.E. & Vernon, J.M., 2005. *Economics of Regulation and Antitrust*, MIT Press.

Walsh, M.J., 1989. Energy Tax Credits and Housing Improvement. *Energy Economics*, 11(4), pp.275–284.

Wilson, C. & Dowlatabadi, H., 2007. Models of decision making and residential energy use. *Annual Review of Environmental Resources*, 32, pp.169–203.

Yang, H., Cui, P. & Fang, Z., 2010. Vertical-Borehole Ground-Coupled Heat Pumps: a Review of Models and Systems. *Applied Energy*, 87(1), pp.16–27.

Appendices

Three appendices accompany the main thesis text. Appendix A is a technical overview of Ground Source Heat Pumps (GSHP). Appendix B describes an engineering-economic model used to calculate the lifecycle cost of GSHP. It also contains a sensitivity analysis of costs, with a profitability analysis for a utility. Appendix C is a chronological overview of the orders and decisions relevant to the Thermal Energy Services Inquiry.

Appendix A Review of GSHP components and operation

The earth provides a stable source of geothermal energy year-round, being warmer than the ambient air during winter months and cooler in the summer (Yang et al. 2010). The amplitude of soil temperature variation decreases with the depth, holding nearly constant year round below 8m. Near surface low-grade geothermal energy is abundant, renewable, and readily available throughout North America (RETScreen 2005).

In heating mode, GSHP systems extract energy from the ground or a body of water and transfer it to a heat sink, normally a home. Transferring thermal energy is much more efficient than creating it, enabling GSHP's to produce three or more units of heating energy for every unit consumed (Mustafa Omer 2008). The GSHP system requires three main components to operate: a ground loop, a heat pump, and a distribution system within the building.

The performance of the GSHP system will diminish if any of the three components are improperly installed or if site characteristics are outside of normal design parameters. The complexity of GSHP, and concerns over the reliability of system performance, has led to a checkered reputation for the industry (CGC 2013). The Canadian GeoExchange Coalition has

made great strides with respect to this issue by developing a rigorous network of training, standards, and accreditation. The following sections detail GSHP system operation.

A.1 Heat pump

Heat pumps are a mature technology, available for residential and commercial heating applications for decades (Chua et al. 2010). Shallow geothermal energy is low-grade heat (~10°C in most urban areas of Canada), and must be raised to the heating system temperature. When in heating mode, the heat pump uses electricity to power a vapour compression cycle to upgrade the heat. In cooling mode, heat from inside the building is ejected into the ground (Rawlings & Sykulski 1999).

A simple heat pump operates with an evaporator, condenser, compressor and expansion valve. The evaporator and condenser are essentially heat exchangers; one connected to the homes heat distribution system and the other to the ground loop. A simplified vapour compression cycle in heating mode is described below. See Chua (2010) for a technical description of heat pump operation, including multi-stage cycles.

- Thermal energy from the ground warms a water glycol mixture circulated in the ground loop. The warmed liquid comes into contact with the heat pump's first heat exchanger, known as the evaporator. The fluid in the evaporator is colder than the ground, so heat flows into the evaporator causing the liquid to evaporate.
- The low temperature gas in the evaporator passes through the compressor. The compressor uses electricity to increase the pressure, further increasing its temperature.
- The high temperature, pressurized vapor then enters a second heat exchanger inside the home, known as the condenser. At this point the vapour is hotter than the home's interior, so thermal energy flows into the home's distribution system. This causes the temperature of the refrigerant to drop and for the gas to condense back into a liquid.

- The now liquid refrigerant passes through an expansion valve, returning to the evaporator. As the pressure is released, the temperature continues to drop. The cycle begins again as it comes in contact with the ground loop warmed by the earth.

The heat pump repeats this cycle to provide continuous heating and/or hot water. The cycle operates in reverse for cooling, with the two heat exchangers swapping their roles as condenser and evaporator. In cooling mode, the home's hot water tank can also be used as a heat sink. A desuperheater, an auxiliary heat exchanger connecting the compressor and hot water tank, sheds thermal energy into the hot water tank (Self et al. 2012).

The Coefficient of Performance (COP) describes the energy efficiency of GSHP. The COP is the thermal output of the heat pump divided by the energy used in the system (RETScreen 2005). If a heat pump provides three units of heat for every unit of electricity consumed it has a COP of 3 (or is 300% efficient). The COP for GSHP normally ranges from 3-5 for heating, depending on site characteristics (CGC 2009).

The difference in temperature between the source of energy and the system temperature drives system performance (CGC 2009; Sanner et al. 2004). Staffell et al. (2012, p.9299) estimate a 10°C temperature difference between the source and sink in the system the will reduce performance by 0.6 -1 COP. This explains the higher efficiencies of GSHP in colder climates compared to ASHP, given the greater variation in ambient air temperatures.

A.2 Distribution system

The distribution system transfers thermal energy within the building, either through water-to-air or water-to-water systems (Self et al. 2012). In Canada, the most common distribution system for GSHP is water to air (CGC 2012b).

With a forced air system, an air coil is heated (cooled) by the condenser (evaporator) of the heat pump. The warm (cold) air is then circulated using ducts or vents throughout the home. The advantage of combining GSHP with forced air is the ability to provide year round heating and air conditioning through a centralized unit (Self et al. 2012).

With water to water, or hydronic distribution systems, water is heated by the pump and passed through the building in piping where it connects to radiant heaters or distributed air coils (Self et al. 2012). Radiant heaters can be wall mounted, such as radiators, or they can be hidden beneath the floor. In-floor hydronic heating is a premium system, with a lower water temperature providing invisible and comfortable space heating, but does not offer cooling.

As indicated earlier, the efficiency of heat pumps is highest when the thermal lift is minimized. Heat pumps are better suited to heating systems operating at low temperatures, relying instead on circulating greater volumes of air or passively radiating heat upwards through the floor (Staffell et al. 2012).

Among new buildings, the capital cost of distribution systems can range from 1-6% of total building construction, and 15-25% of GSHP system costs (CGC 2009). Table A.1 shows some of the capital cost components for different distribution systems. Electric baseboard heating is much less expensive than forced air or in-floor hydronic heating. However, the capital cost of GSHP inside the building may be less than a traditional system if the cost of cooling towers may be avoided.

Electric baseboard	Wall-mounted hydronic heat	In-floor hydronic heat
Electric baseboard Programmable thermostat	Wall-mounted radiators Programmable thermostat Project installation is more time consuming and increases cost of labor Project involves more material costs The longer, more expensive project will incur higher cost of capital	In-floor piping Programmable thermostat Project installation is more time consuming and increases cost of labor Project involves more material costs The longer, more expensive project will incur higher cost of capital Increase floor topping depth

Table A.1 In-building capital cost components based on distribution system

In renovation projects, compatibility of GSHP with the previous heating system will affect system performance and cost. Table A.2 lists heating system types, whether renovating for GSHP would be an invasive procedure, and if the technology change would result in air conditioning. Heat pumps can connect directly to central heating systems that use forced-air ventilation or in-floor hydronic heating with minimal adjustment. Renovating a home with electric baseboards would require installing vents or laying pipes beneath the floor to connect to the heat pump, substantially increasing costs. Boilers are also a form of central heating system, but usually connect to radiators, which operate at a much higher system temperature than GSHP. This would also require additional work within the home, and the same is true for wood stoves and electric radiant heating.

Heating System	*Air conditioning*	*Invasive Renovation*
Forced air	Yes	No
Hydronic w/ distributed air coil	Yes	No
In-floor hydronic	No	No
Wall-mounted radiator	No	No
Electric plinth (convection)	No	Yes
Electric baseboard	No	Yes

Table A.2 Renovation requirements based on system type

A.3 Ground loop

The ground loop (earth heat exchanger, ground coupled heat exchanger) is the point of exchange between the thermal energy source and the building. The thermal energy source can be the earth, a pond, underground aquifer or even heat ejected from the mechanical load. The choice depends on the availability of water, space constraints, and soil conditions. Some common types of loops are shown are described below.

- Vertical ground loops are installed using drilling, and can be installed compactly in a small area or even beneath buildings. Vertical GCHE are placed in vertical boreholes at depths of 80-150 meters deep (Staffell et al. 2012). Vertical GCHE are the most expensive system to install, but require less piping and may perform better for thermodynamic reasons, given the constant temperature of the earth at greater depths.
- Horizontal ground loops are installed through excavation, and laid in trenches 4-6m deep over a wider area. Excavation is less costly than drilling, but requires access to a large area and amenable surface conditions. Landscaping, nearby buildings or roads can all frustrate horizontal ground loops. Diagonal loops are a special case of horizontal loops, installed through horizontal drilling without disrupting surface features.
- Closed water or pond loops are sunk or floated into a water source for a water-to-water connection. The pond loop is closed meaning there is no contact between the refrigerant and the water source. This requires no drilling or excavation, making it less costly than

vertical or horizontal loops. Ponds are cooler than the ground in winter, making these systems less efficient.

- Open loops do not use piping to extract geothermal energy, but extract groundwater from a well nearby the building. The water is circulated past the heat pump before being discharged into a second well. This type of well is the simplest, and least costly to install, making it a popular early approach. However, rising concerns about adverse environmental impacts are leading to increasingly restrictive regulations governing their use (CGC 2009).

Among closed loops, the ground loop consists of durable high-density polyethylene piping, which can have a lifespan greater than 50 years. It has traditionally contained a water-glycol mixture to prevent freezing, although environmentally benign fluids are now available (Rawlings & Sykulski 1999). The flow inside the pipe is maintained using a fluid pump, which also uses electricity to operate. Improperly functioning fluid pumps are considered parasitic loads and can reduce overall efficiencies (CANMET Energy 2002). In well-designed systems, flow rates through the geo-exchange field are automatically adjusted to meet the demand on the system.

Soil conditions affect the ability of the ground loop to extract and eject thermal energy, and poor conditions will require a large loop to extract the same amount of energy. Tightly packed conductive soil types, such as clay and rock, are superior to closely packed dry soils, such as sand (Staffell et al. 2012). Water significantly improves soil conductivity, and can improve conductivity from 0.25 WmK to 2.5 WmK. Laying backfill or grouting around the pipe can improve soil contact to increase system performance (Rawlings & Sykulski 1999).

The ground loop is an additional feature that no other HVAC systems need factor in during installation. Boulders, expensive landscaping, availability of water features or drilling conditions determine what type of loop can be installed, or even prevent installation (CGC 2009). Drilling

conditions vary widely, and one study of the lower mainland in British Columbia estimated cost of installing a ground loop to span a range from $600-$2500/kW(CRM 2005).

The ground loop is a kind of battery for the heat pump, and a larger heating load requires a larger ground loop. For example, a 150sq-m home in Vancouver might only require 4kW of peak heating due to the temperate climate. A similar home located in Toronto might require a ground loop sized to meet 6kW to compensate for the hotter and colder temperatures.

Unused capacity is costly, which is why GSHP systems are often designed to meet less than 100% of total demand. The heat pump's auxiliary electric unit is inexpensive to spec at full-demand capacity and is the emergency backup should the heat pump fail (Staffell et al. 2012; CGC 2012b). For an example of a system sized with an auxiliary unit to meet peak demand see appendix B.

A.4 Conclusion

This appendix provides a technical description of GSHP to use as a reference for the remainder of the thesis. After reviewing the main components of GSHP technology, I identified two technical issues that place GSHP at a disadvantage compared to natural gas or electric baseboard systems. Firstly, it is more complex than traditional heating units and, if systems are improperly installed performance will suffer. Secondly, compatibility constraints inside the building (previous heating system among renovations) and outside of the building (soil conditions) can increase costs or inhibit the adoption of GSHP.

Appendix B Engineering-economic model

The engineering-economic model described here is built using inputs from RETScreen® International, engineering-economic studies within the Greater Vancouver Area, and interviews with industry stakeholders. It is designed to model the effects of network economies on the lifecycle costs of GSHP, offering high-level insight accurate within a magnitude of order. For more precise estimates tailored to local circumstances there are more accurate design tools and software tailored to GSHP (see CANMET Energy 2002; CANMET Energy Technology Centre - Varennes 2005).

This model consists of a building description, a technology comparison, and a cost estimate. First, I create a building archetype in the Vancouver area to calculate the power and energy demand requirements for heating, cooling, and hot water. The load factor is estimated using a demand duration curve. I then use this information to design a rudimentary GSHP system with projected operating and capital costs

B.1 Building archetype

The purpose of the building archetype is to calculate peak power requirements and energy demand.[79] Peak power is measured in Watts, and is the maximum amount of work that must be performed to provide space conditioning and hot water. Energy demand is the duration over which the power must be applied, and is measured in kilowatt-hours (kWh).

[79] This is a coarse description treating the entire building as a block load. For more precise estimates, bin-method or hour-by-hour methods are recommended.

Peak power requirements are calculated by multiplying the building area (m2) by the peak heating or cooling requirements, measured in W/m2 (CANMET Energy 2002).[80] The peak power requirements for heating increase (decrease) linearly with size as the design temperature drops (increases). The design temperature is the maximum or minimum temperature reached once every twenty years, or 1% of the time (CANMET Energy 2002). For a residential building, the peak power requirement for heating may range between 30-120W/m2, and 50-200W/m2 for cooling (Arkay & Blais 1996).

The demand for heating and cooling is estimated using monthly heating and cooling degree-days (HDD, CDD), or the number of hours when the temperature drops below or above 18°C. Ranking degree-days in descending hours creates a load duration curve. It calculates the actual number of hours heating is required out of the year. As shown in Figure B.1 Demand duration curve for Vancouver, there are 8,760hrs in a year but Vancouver only requires 2,216hrs of heating.

[80] This W/m^2 figure treats the entire building as a single zone or block load, and does not consider differences between North and South facing sides or differences in building use.

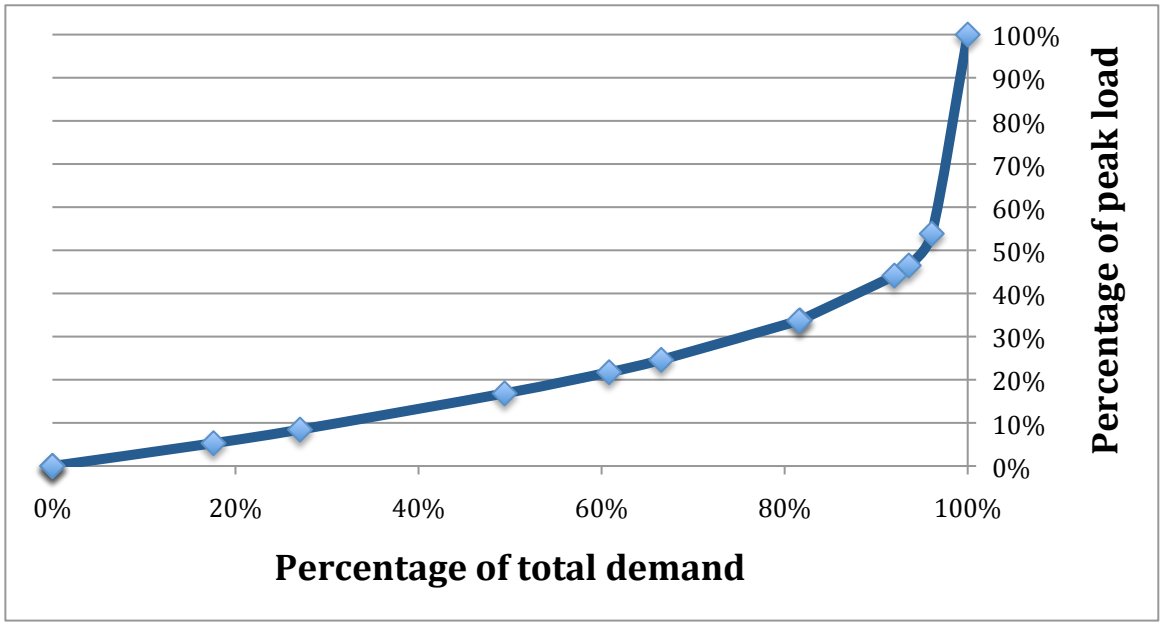

Figure B.1 Demand duration curve for Vancouver

Multiplying the number of peak hours (2,216) by the peak power requirements for heating (37,500) calculates the annual heating demand. Air conditioning loads are calculated in much the same way by multiplying the insulation factor (40W/m2) by the number of full load hours for cooling (1,016).

The peak power requirements for hot water are dependent on the difference between the system temperature and the initial temperature (from the ground) and occupant behavior (number of occupants, hot water for clothes washing). For simplicity hot water demand is assumed to be 30% of demand and added onto the demand duration curves. This fraction is largely consistent year round, but will decline slightly in months when heating demand drops (CANMET Energy 2005). Table B.3 shows the peak power and demand requirements for a 500m2 building in the Vancouver area.

	Heating	Air Conditioning
Peak power (W)	37,5	20
Full load (hours)	2,216	1,016
Demand (kWh)	83,1	20,32

Table B.3 Energy demand for 500m^2 building in Vancouver area

B.2 Technology description

The buildings energy demand and peak power requirements from the last section remain constant, but the amount of energy supplied will vary based on the efficiency of the technology. The technology is described by its fuel type and energy efficiency.

Here I assume a GSHP system sized to meet 70% of peak power requirements is sufficient to meet 90% of demand (Rawlings & Sykulski 1999; Canadian GeoExchange Coalition 2012b). The last 10% of demand is met with a 100% efficient electric auxiliary unit, and the other 90% is met with a 400% efficient GSHP system. I assume this efficiency is constant in heating and cooling mode.

The alternative to GSHP presented here is a combination of electric air conditioning and natural gas heating. The rooftop cooling units are electric, and assumed to be 200% efficient, whereas the electric heating and gas alternatives are assumed to be 100% and 80% efficient, respectively.

The GHG emissions or Carbon Dioxide Equivalents (CO2e) are calculated using an emission factor for each fuel type. These are generally similar for common fossil fuels and vary dramatically by region for electricity. To calculate the carbon emissions associated with the energy used an emission factor 50Kg CO2e/GJ for natural gas and 85 tCO2e/GWh for electricity consumed in British Columbia (Dowlatabadi et al. 2011).

Table B.4 contains the energy requirements and GHG emissions based on four different technology combinations: all electric, natural gas with electric air conditioning, electric space conditioning with natural gas heating for hot water, and GSHP with electric backup.

Units in KWh unless specified	Electric cooling & gas heating	GSHP with electric auxiliary
Heating	83,1	18,698
Auxiliary unit		8,31
Cooling	10,16	5,08
Energy Input	93,26	32,088
Tons CO2e**	16	3
**50kgCO2e/GJ of gas and .085tCO2e/MWh of electricity		

Table B.4 Energy inputs for each technology to produce 100kWh of thermal energy

B.3 Cost estimate

The outputs from the building and technology characteristics are used to create a cost estimate. Capital costs for GSHP are based on the peak power requirements of the building, and operating costs are dependent on the energy efficiency of the technology used.

Capital costs include costs both inside and outside of the building. The out-of building cost is the ground loop heat exchanger, and applies only to GSHP. The ground loop is usually between one to two-thirds of total capital costs for GSHP (Kantrowitz & Tanguay 2011; CGC 2012b). The capital cost of the ground loop is dependent on drilling conditions and the size of the heat load. In these illustrations, the cost for drilling vertical boreholes is assumed to be $1,500/kW under normal drilling conditions and soil conductivity, taken from a survey of the Vancouver area (CRM 2005).

To reduce capital costs the ground loop is not sized to cover 100% of demand. The ground loop is sized using the demand duration curve and here I assume a 26kW is sufficient to meet 70% of

peak power, or 90% of total heating and hot water demand.[81] The cost of installing a ground loop exchanger size for 26kW at $1,500/kW is $52,000.

In-building costs includes the technology for distributing the heat, cooling towers, pumps and furnaces, and will amount to $50,000, or approximately half the total capital cost of the GSHP system. Here I assume in-building costs are identical among technology choices. The capital equipment is financed over a 10-year period, with an initial rate of 5%. This amounts to ten annual payments of $13,109 for GSHP and 6.475$ for the reference system.

Multiplying the energy requirements by the price of energy calculates the annual operating cost. Energy demand held constant throughout the projects lifespan however, the price will escalate 2% per year. The price of electricity is $0.08/KWh for electricity, and $5/GJ for natural gas. The other ongoing charges are for operations and maintenance, calculated to be ~2.5% of capital costs (also escalating 2% per year). Table B.5 Energy payments over 10 years shows the net present value of payments made over 10 years for a 500m2 building located in the greater Vancouver area.

[81] This building is heating dominant and so this capacity is also sufficient to cover all of the summer cooling loads.

	GSHP	Gas & AC
CAPEX PMT	109,723	53,786
Electricity	23,362	7,397
Natural gas	0	17,016
O&M	23,207	11,376
NPV	156,292	89,575
Total Energy	798,582	798,582
$/KWh	0.196	0.1122
t/CO2e	30	21

Table B.5 Energy payments over 10 years

B.4 Sensitivity analysis

A sensitivity analysis is used to determine which parameters have the greatest effect on levelized costs. The inputs for the analysis are generated using an engineering-economic model in the appendix, which consists of a building archetype to calculate demand, a technology description to compare energy requirements, and a cost estimate consisting of capital and operating costs.

Table B.6 shows the starting point for each parameter, and the range over which it is tested. It should be noted that energy prices increase 2% annually, with the sensitivity analysis only manipulating the price during year one.

Parameter	Initial rate	Range tested
Electricity	0.08c/KWh	$.05 to $.15 c/KWH
Gas	$5/GJ	$3/GJ to $10/GJ
O&M	2.5% CAPEX	0 to 5% CAPEX
Interest	5% annual	0-10% per year
Capital cost	102000 CAD	75%-125% of cost
Discounting	5% annual	0-10% per year
Heating	83,100 KWh	75%-125%
Cooling	20,320 KWh	75%-125%

Table B.6 Parameters in sensitivity analysis

The tornado charts shown Figure B.2 and Figure B.3 demonstrate the parameters having the greatest impact are increases in capital costs, interest rates, and energy prices. Increasing heating demand decreases levelized costs by increasing system output. Similar to other engineering-economics studies comparing GSHP to natural gas and electric alternatives, the outlook for GSHP is best where capital costs are low, heating loads are high, and the price of electricity is low compared to other fuel alternatives. Furthermore, the economics of GSHP is largely dependent on heating loads, substantially improving with load size.

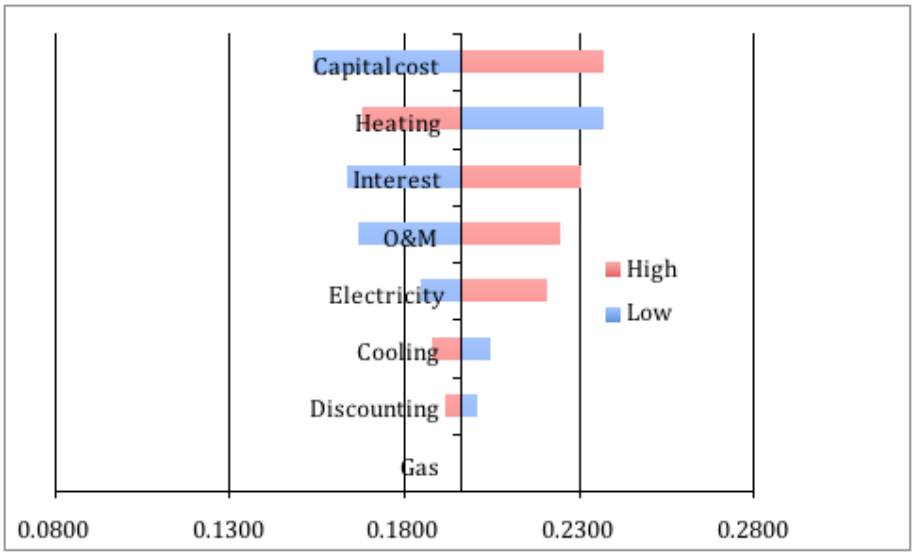

Figure B.2 Change in levelized cost of GSHP

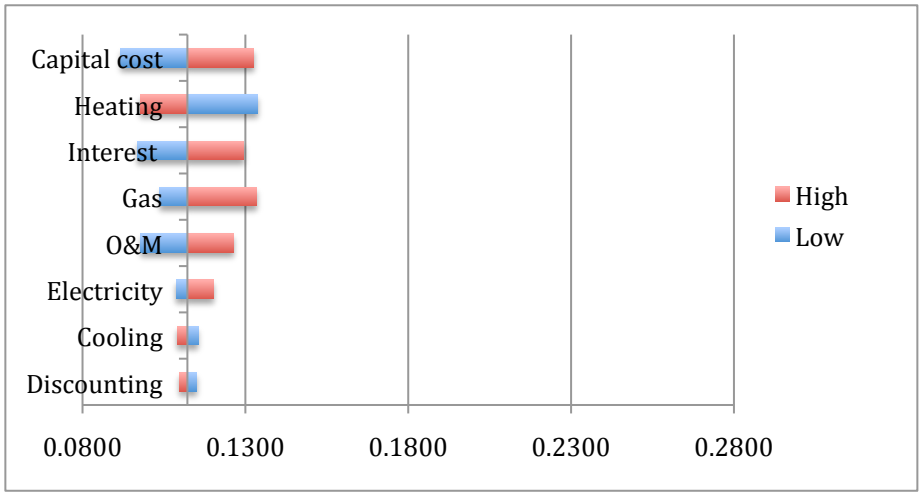

Figure B.3 Change in levelized cost of gas heating and electric cooling

The levelized cost of GSHP is higher than that of the conventional heating system for all single parametric manipulations. For GSHP to be less costly than the conventional system multiple favorable circumstances must align, such as a higher heating load, a lower installation cost, or a higher price of natural gas, for example. The building is located in the Greater Vancouver Area (GVA), which has qualities unfavorable for GSHP, such as a mild climate and low energy prices.

B.5 Divergent loads and networking GSHP with waste heat rejection

To model the economics of collective GSHP, two similar buildings are collocated. Pairing the two systems together as part of a single GSHP system will reduce levelized costs if the loads are divergent or if waste heat can be captured. The network economies are unavailable to the alternative electric and natural gas system, so the levelized cost remains constant.

The economic advantages of divergent loads and waste heat rejection are demonstrated as follows. I assume two buildings, identical to the ones examined in the prior sensitivity analysis, are situated next to one another. For the collective system, I double capital costs and energy demand. The economic benefit of divergent loads assumes the high heating and cooling load

from the previous section (25% increase), while holding capital costs constant. This demonstrates an increase in system utilization without increasing capital costs. The benefits of waste heat rejection are illustrated by enabling a smaller ground loop to offer the same energy services.[82] The demand doubles by combining the two buildings but the capital costs increase by a factor of 1.5x. Lastly I apply both economies at the same time.

	Capital cost ($000)	kWh	$/kWh
Independent	2x	Regular	
Gas & Elec.	204	207	0.1203
GSHP	100	207	0.221
Divergent Loads	2x	High	
GSHP	204	259	0.188
Network benefit	1.5x	Regular	
GSHP	153	207	0.166
Combined	1.5x	High	
GSHP	153	259	0.155

Table B.7 Application of network economies to GSHP

The network economies lower levelized costs significantly, but GSHP remains at a premium to the building heated by natural gas and electricity. Higher assumed heating demand, or alternative energy prices, would be required for GSHP to be cheaper. These economies remain, however, substantial sources of cost savings reducing lifecycle costs by $0.07/kWh.

The application of network economies affect those parameters previously demonstrated to have the greatest impact on levelized costs. Divergent loads increase heating load, and network externalities lower capital costs (and any associated interests payments). Compared to factors such as energy prices and climate, which are difficult or impossible to manipulate, the economies

82 Another advantage might arise if the ground loop was recharged by waste heat. This would reduce thermal lift and improve efficiency. I exclude this economy from the analysis.

arising by pairing interconnected systems can be created wherever divergent loads are collocated.

B.6 Return on investment for a GSHP utility

The engineering-economic model described earlier was primarily concerned with the comparisons of costs. The model I will now examine is concerned with the return on investment over 20 years for an investor in the utility using incentive regulation. Initially, the rate is set at $0.15/kWh with an annual fixed fee of $500.

The utility model is similar to the engineering-economic model increased in scale by a factor of 10, with the following exceptions. Where before there were only costs now there are revenues allowing the utility earn a rate of return on their investment. The rate of return will depend on a variety of parameters subject to sensitivity analysis, along with the rate design. The revenues are for the delivery of thermal energy to the building independent of the fuel consumed in its production. For example, if the building requires 1M kWh of thermal energy but the GSHP system may be able to supply this for 0.4M kWh, then the former will be used to calculate revenues and the latter costs. In calculating revenues the rate design includes a variable ($/kWh) and fixed ($/building unit) component.

There are a few other additional factors that to consider in the sensitivity analysis. A mix of debt and equity finances the capital equipment. Increasing the level of debt without increasing the cost of borrowing should improve the return on investment. The construction and occupancy of the building is now staggered. Taxes are also applied to net cash flows after operating costs and debt servicing. Table B.8 below contains the group of parameters used in the sensitivity analysis.

Costs			
Electricity	$0.08/KWh		.05 to .15
O&M	2.5% CAPEX		.0 to 0.05
Demand	1,000,000KWH		75% to 125%
Capital cost	$1,000,000 in 2015-2016		75% to 125%
Interest		5%	0% to 10%
Debt		60%	50% to 70%
Revenues			
Variable rate	$0.15/KWh		From .12 to .18
Fixed rate	$500/unit		From 250 to 750
Taxes		25%	From 10-40%
Occupancy	50% in 2016 -2017		100% 2015 or 2017-2019
Discounted 5% annually			

Table B.8 Parameters for sensitivity analysis

The tornado charts below show how changes to these parameters affect the rate of return over 20 years. Unlike with the levelized cost tornado charts where bars to the right meant higher costs, here bars to the right are indicators improvement, or a greater return on investment. Figure C.4 shows how changes affect the return on investment.

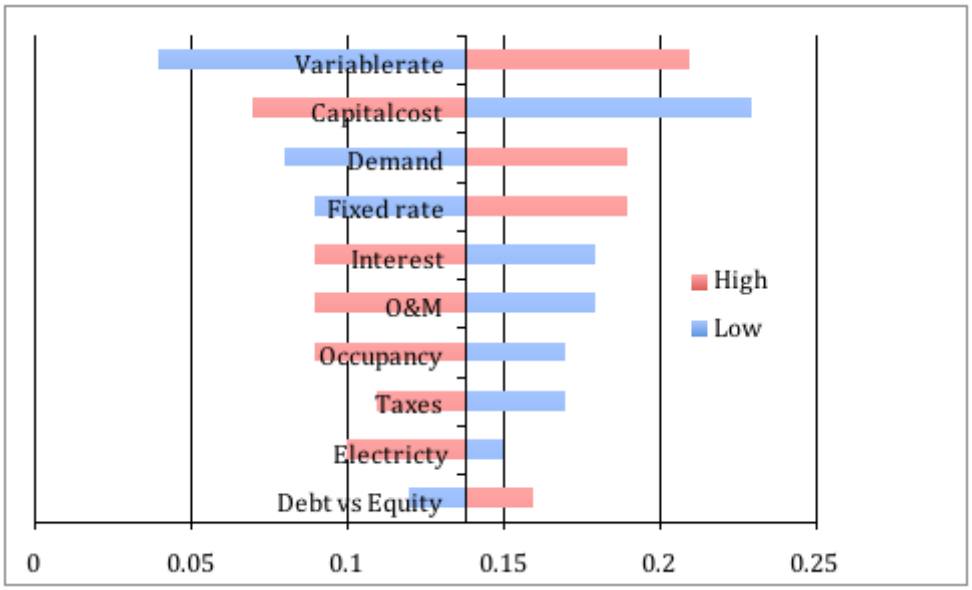

Figure B.4 Return on investment for a GSHP utility

The most critical factor for profitability is the variable rate. A low variable rate could rapidly reduce the profitability to almost zero, along with demand. High capital costs were also detrimental to the profitability of the project along with interest rates. Changes in the tax rate were less important the overall profitability of the project, partly due to the losses incurred early on reduce the tax liability of the utility.[83] Furthermore, changes in the ratio of debt to equity also only had a minor effect compared to the interest rate charged on the debt.[84]

The effect of changes in occupancy was also muted compared to changes in demand over the full life of the project. This was partially due to the fixed-component of the rate design, for so long as the buildings are sold, the fixed-component supplies revenue to the utility. In the next section I illustrate how slight changes to rate design can affect who bears what risks, and what factors affect profitability.

B.7 Rate design

Rate designs can broadly be categorized as rate-of-return or incentive regulation. Rate-of-return regulation is intended to limits the profitability of a firm to zero economic profit, where revenue is equal to cost, often known as Cost of Service (COS) regulation. The base rate is normally set on the original investment cost less depreciation, but can also be the replacement value or the market value. In practice, the debate is usually settled by agreeing upon a reasonable rate of return on the base rate, and then adjustments to the future pricing scheme of the firm follow (Viscusi et al. 2005). COS rate setting is the most common rate design in British Columbia (PICS 2012).

---

[83] This may actually over represent the effect of taxes on profitability. For simplicity, I did not carry forward losses to later years or apply a tax credit based on equipment invested.

[84] The effect would be even greater if I assume the cost of equity was higher than the discount rate of 5% of year.

With incentive regulation, the regulator sets the price, and the firm can increase their profits by reducing costs. This lowers the regulatory burden and occasionally allows a firm to earn above average profits for superior performance. The six most common types of incentive regulations are price caps, rate moratoria, profit sharing schemes, banded rate-of-return regulation, yardstick regulation, and menus. Price caps are typically pegged to an index of commodities or services, and are used to some extent in all OECD countries (Curien et al. 1998). Having a fixed fee attached to the service responsible for covering capital costs, and a variable rate covering energy costs (and perhaps indexed to energy prices) is one way to share risks between tenants and utility owners.

In the last section, the rate charged for thermal energy was an incentive rate containing both a fixed component ($500/unit) and a variable rate component ($0.15KWh). The fixed rate is applied to each unit as long as it has been sold. The variable rate only comes into affect when the units are occupied and energy is used. However, it is not uncommon for condominiums to be purchased as investment properties left uninhabited for extended periods of time. If a significant fraction of the buildings are uninhabited sales may be insufficient to cover the capital cost.[85]

Table B.9 shows the ROI and NPV under four different scenarios. In the first scenario construction is completed within three years and occupied within four. The second case assumes buildings are built within three years, but occupied gradually with one quarter of units occupied each per year from 2017 to 2020. The first two rows maintain the rate of $0.15/kWh and $500/unit each year, and the second two emphasize an increased reliance on either the fixed or variable cost.

[85] Occupancy risk is one of the key risks identified in chapter 6 by providers of thermal utilities.

Occupancy	Fixed/Variable Rate	IRR	NPV
Regular	$0.15/KWh, $500/unit	14%	$359,757
Delayed	$0.15/KWh, $500/unit	11%	$276,505
Delayed	$0.21/KWh, $0/unit	10%	$269,312
Delayed	$0.09/KWh, $1000/unit	12%	$283,699

Table B.9 Internal rate of return by rate design

While the bottom two rows of Table B.9 offered the same rate of return during normal occupancy (14%), the rate with the greater fixed charged offered more protection during periods of low occupancy. The rate relying on variable costs ($0.21/KWh) can only cover the sunk cost of the infrastructure if buildings are occupied as planned. Maintaining a fixed-component in the incentive rate design clearly insulates the utility from occupancy risk.

What if, instead of incentive regulation, rate-of-return or COS regulation were used? With COS the earned return (return on investment) of the utility is calculated by multiplying the regulated rate of return by the invested capital or original investment value less depreciation. COS allows the utility to claim a rate of return based on the capital invested, so only changes to the capital cost or the regulated rate of return affect the net present value of cash flows (resulting in a rectangular tornado chart). All costs flow through to the ratepayer, which is why COS has a reputation for being heavy-handed compared to other rate designs.

The COS rate design cannot, however, insulate the project from occupancy risk. If the units are not sold then there are no tenants from which the investment can be recovered. For this reason occupancy risk remains a high-priority item for utilities no matter the rate design.

B.8 Conclusion

Similar to other engineering-economic studies of residential GSHP, the sensitivity analysis indicated the factors most advantages to GSHP are low capital costs, and high demand. The

network economies of divergent loads and network externalities increase demand and decrease capital costs for significant savings. Unlike other difficult to manipulate parameters, such as energy prices, these economies can be created anywhere.

The immediate conclusion of this appendix is that the economies of GSHP improve as the overall system load increases with scale and diversity of demand. From an engineering-economic perspective, GSHP is most compelling among larger or multi-unit buildings than among detached housing, its primary group of adopters.

The lifecycle cost of GSHP was higher than the reference building heated with natural gas and electricity for all single parameter manipulations. Even where economies of scale or waste heat are available, GSHP may be a premium service in British Columbia.

Under utility ownership, assumptions changes to the variable rate were the primary factor affecting profitability. I used occupancy risk as an example for how rate design can insulate or exacerbate exposure to unexpected outcomes. Even when the utility is able to earn a regulated rate of return, occupancy risk remains a threat to project profitability.

Appendix C BCUC orders and decisions

In 1997, the BCUC developed and published the Retail Markets Downstream of the utility Meter (RMDM) guidelines following FortisBC's entry into competitive retail markets.[86] These guidelines govern the interactions amongst utility affiliates when regulated entities own or compete for projects downstream of the utility meter (BCUC 2007).

In the 2010 Long Term Resource Plan (LTRP), FortisBC announced its intention to offer a number of alternative energy services, implying ownership of assets upstream and downstream of the utility meter. This included compressed natural gas, liquid natural gas, biogas, and Thermal Energy Services (TES) (Terasen Gas Inc. 2011a). These new offerings were described as part of FortisBC's long-term transformation into an integrated energy service provider. The BCUC approved their LTRP, indicating a more thorough review of the new business activities would be required at some point in the future (Terasen Gas Inc. 2011b).

The BCUC came to a decision on a series of applications for TES projects, including the Delta School District and Kelowna District Energy System by FortisBC, and the Marine Gateway and Sun River Decisions by Corix. In the case of TES projects offered by FortisBC, the BCUC instructed that these new assets be transferred to a financially dependent but structurally separate utility affiliate, FortisBC Alternative Energy Services (FAES) (BCUC 2012d).

---

[86] The LTRP was filed by Terasen Gas, and I have kept the FortisBC brand name for simplicity throughout the document to refer the BC monopoly provider of natural gas. They were rebranded FortisBC in 2011, following the sale of Terasen to FortisInc in 2005.

In April and May of 2011, the Energy Services Association of Canada (ESAC) and Corix Utilities Incorporated (Corix), asked the BCUC to exercise their general supervisory powers over FortisBC's offerings in the TES market, issuing separate letters of complaint. The BCUC agreed and issued Order G-95-11 to establish a regulatory timetable of the Alternative Energy Services Inquiry (AES Inquiry) (FortisBC 2011a).

In December of 2012, the BCUC came to a decision on the AES Inquiry and issued Order G-1-12. With respect to FortisBC's TES offerings of district and discrete TES, FortisBC would be permitted to enter the TES market subject to certain conditions. FortisBC was permitted to offer district TES projects through a structurally separate regulated utility. The AES inquiry recommended exemptions from regulation when warranted, and an initial CPCN value was set at $0 until a scaled regulatory framework could be established (BCUC 2012a).[87]

In August of 2013, the BCUC published a proposed regulatory framework for TES (BCUC 2013a). It included proposed regulatory exemptions for Micro, Strata, and single customer TES systems. Interveners were directed to submit recommendations on the exemptions through Order G-143-13, and Order G-143-13A (BCUC 2013b; BCUC 2013c).

Following a review of the intervener arguments the Commission passed Order G-231-13, preserving the micro and strata exemptions, but removing the single customer exemption. All TES with capital costs between the micro-TES threshold and $15M, and not eligible for Micro or Strata exemptions, are Stream A utilities (BCUC 2014g). Interveners were asked to submit their

[87] In the long term resource plan for FEI (lower mainland), FortisBC identifies they no longer pursue TES as decided by the BCUC. These projects are now undertaken by FAES, a regulated utility affiliate.

opinions on appropriate limits of the micro-TES threshold and also a Stream B extensions test determining when a Stream B undergoing an extension should have to apply for a CPCN.

The micro-TES exemption limit was set at $500k. Stream B utilities undergoing extensions were found to require CPCN approval when the renovation might lead to rate shock, or a ~10% increase in rates (BCUC 2014a; BCUC 2014b).

Before the TES Inquiry concluded, FortisBC's structurally separate regulated utility affiliate Fortis Alternative Energy Services (FAES) brought forth the SOLO District Development for BCUC approval in February of 2014, with the intention of practicing a streamlined Stream A regulatory procedure (BCUC 2014d). The BCUC agreed and the SOLO project was approved, however not as a Stream A, which would have been prospective. In the SOLO CPCN, FortisBC describes a performance-based rate setting methodology found to be just and reasonable by the BCUC. The BCUC maintains this decision is unique, and it will not in the future be considering the propriety of rates for Stream A applications (FAES 2014b). FortisBC has three other Stream A applications approved by the BCUC, using the same rate-setting methodology as the SOLO project (FAES 2014a; FAES 2014c).

On March 24, 2014 Phase 2 of the Generic Cost of Capital Proceedings concluded. The BCUC determined a reasonable rate of return for Stream B TES to be 75bps above the benchmark return on equity (FEI's 8.5%). This ruling is inapplicable to Stream A TES, as these projects are not subject to regulatory oversight (BCUC 2014c).

In August 2014, BCUC found their proposed regulatory exemptions for micro and strata TES to be in the public interest, and upon receiving permission from the Lieutenant Governor in Council issued orders G-119-14, G-120-14 and G-121-14 (BCUC 2014f).

The TES Regulatory Guide was published August 28, 2014, maintaining regulatory exemptions for Micro and Strata TES, complaint-based regulation for stream A TES, and full regulatory review for Stream B utilities (BCUC 2014e).

In concluding the proceedings, the BCUC reiterates that while the AES and TES Inquiries were designed to provide stability for the TES market in British Columbia, it reserves the right to revisit capital cost limits as the TES market evolves.