Waste-heat-to-power: A case study of Canadian natural gas compressor stations

by

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The following individuals certify that they have read, and recommend to the Faculty of Graduate and Postdoctoral Studies for acceptance, a thesis/dissertation entitled:

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Abstract

Half of all primary energy input in North America is lost as unused heat. Turning this waste heat into usable energy through waste-heat-to-power (WHP) technologies could help to economically meet climate objectives. Compressor stations on natural gas transmission lines have been identified as a significant potential source of WHP, which would generate electricity with negligible incremental carbon emissions. Installations usually occur as retrofits, and are not dependent on transmission expansion or stock turnover. In Canada, ten such installations were made between 2007 and 2013, but represent a penetration of only 6% of compressor stations. This study conducts an integrated assessment of technical, economic, institutional, regulatory, and policy factors affecting WHP development to examine drivers and barriers, along with appropriate policy levers.

Given the quantified installed gas transmission turbine capacity of 4.6 GW, there is over 1.1 GW of WHP technical potential on Canadian compressor stations. Combined with turbine capacity factors estimated from pipeline throughput and capacity data and costs from past installations, 0.3 GW is estimated to be economically viable. The majority of remaining viable WHP capacity is in Alberta. These are competitive with new natural gas combined cycle plants with a $50 per tonne carbon price. Investment is sensitive to the electricity purchase price, turbine capacity factor, cost of capital, and electrical grid interconnection costs. Generation is expected to be baseload or correlated to seasonal electricity demand fluctuations.

Three primary barriers to implementation were discovered. WHP is not consistently recognized as a clean electricity source in all jurisdictions, including Alberta. Regulations for steam systems

that require continuous on-site monitoring by appropriately certified Power Engineers add significant operating expenses. While gas compressor operation shifted to remote monitoring of automated systems following technological advances in past decades, on-site monitoring thresholds for thermal power generation have not changed since 1975 and should be reassessed to ensure benefits warrant the costs. Lastly, interpretations of cost-of-service regulations have funneled significant benefits back to gas shippers, in addition to transmission companies and WHP developers. This split incentive has reduced the attractiveness of WHP development to decision makers.

Lay summary

When we use fossil fuel combustion to generate mechanical energy – such as in cars or turbines – between 55% and 80% of all the energy in the fuel is lost as heat in the exhaust. Turning this waste heat into usable energy through waste-heat-to-power technologies could help to economically meet climate objectives. Waste heat from compressor stations on natural gas transmission lines have been identified as a significant potential source of waste heat generation, which would generate electricity with negligible incremental carbon emissions. This research estimates there is approximately 0.3 GW of financially viable waste-heat-to-power in Canada, enough to provide electricity to over 350 thousand homes. The majority of the remaining generation capacity is in Alberta, and is cost-competitive with traditional electricity sources under a modest carbon price as already implemented.

Preface

I designed the research methods in this thesis with the helpful feedback of Hadi Dowlatabadi. I assembled the data from government and regulatory sources as primarily described in Chapter 2. I performed the analysis described in Chapters 2 and 3, with the guidance of Hadi Dowlatabadi and feedback from Granger Morgan. I wrote this thesis document, with feedback and suggestions by Hadi Dowlatabadi. This work is currently unpublished, but will be submitted for publication with Dr. Hadi Dowlatabadi as a co-author.

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$Cost_{marginal}$	Marginal cost (or offset value) of carbon per MWh
CP	Carbon price
$EI_{facility}$	Emissions intensity of the generation facility
Q	Volumetric flow
$Q_{capacity}$	Volumetric flow capacity in system or area
Q_{day}	Volumetric flow on given day
P	Compressor power
$P_{turbine,capacity}$	Compressor turbine power installed in system or area
$P_{turbine,day}$	Compressor turbine power required on given day

List of abbreviations

AESO	Alberta Electric System Operator
BC	British Columbia
CAD	Canadian Dollar
CF	Capacity Factor
EGAT	East Gate area of NGTL system
ERSOP	Energy Recovery Standard Offer Program in Ontario
ETri(NE/E)	Eastern Triangle (Northeast/East) areas of TransCanada Mainline
FX	Foreign exchange (rate)
GHG	Greenhouse gas
IESO	Independent Electricity System Operator (Ontario)
IPP	Independent Power Producer
NEB	National Energy Board
NGTL	Nova Gas Transmission Ltd.
NEDA	Northeast Delivery Area of NGTL
NOL	Northern Ontario Line area of TransCanada Mainline
NPV	Net Present Value
OBA	Output Based Allocations (Alberta)
OBPS	Output Based Pricing System (Federal)
ORC	Organic Rankine Cycle
PPA	Power Purchase Agreement
PtEN	Prairies to Emerson/Northern Ontario Line area of TransCanada Mainline
RPS	Renewable Portfolio Standard

USD	US Dollar
USJR	Upstream James River area of NGTL system
WACC	Weighted Average Cost of Capital
WGAT	West Gate area of NGTL system
WHP	Waste-heat-to-power
WHR	Waste heat recovery

Acknowledgements

First of all, to Hadi, for teaching me new ways to think. He has showed me it is possible to be impactful across a wide range of interests, and to not let a fear of what I don't know lead me towards the comfort of niche expertise. He was firmly in my corner when I needed it, and but wasn't afraid to give me a firm kick in the rear when I needed that, too. Thank you for everything.

I'd also like to thank Granger for wittingly allowing himself to fall into the extended interview trap that was this committee work, and for his helpful feedback along the way. Thanks too to Manfred Klein, Jim Cormack, Mike Brennan, Colin Duncan, Jitendra Luthra, and Gerry Goobie for helpful input at early stages of the research. All opinions, recommendations, and errors, of course, are mine.

I'm grateful for financial support from Engineers Canada and TD Meloche Monnex, the National Science Foundation Center of Excellence in Climate and Energy Decision-Making at Carnegie Mellon, and the University of British Columbia over the past two years.

A big shout out to everyone at my intellectual and social home at IRES, especially to Rainer, Emily, Krista, Maddi, Victor, and Zach, for making the past couple years fun as well as stimulating. I also want to thank the rest of the IRES faculty, particularly Milind, Terre, David, Kai and Stephanie, for teaching me all sorts of things I didn't know that I didn't know.

Thank you to my parents for teaching me what I do should have meaning, and their unwavering support along the way. Last but not least, thank you to my partner Gillian, for encouraging me to take the leap to Vancouver and being my best friend and co-adventurer.

Dedication

To my dad, to whom I owe my love of learning.

Chapter 1: Introduction

Currently, up to 50% of primary energy in North America is lost as waste heat (CESAR, 2017; LLNL, 2014). This waste heat, usually leftover energy from combustion processes, is often vented to the atmosphere at very high temperatures. This unused high temperature waste heat presents a significant opportunity to generate electricity without increasing energy inputs. This electricity would be generated with close to zero incremental greenhouse gas (GHG) emissions, and therefore represent a significant opportunity to partially decarbonize the electricity system. Given the scale and urgency of the need to reduce GHG emissions, these waste-heat-to-power (WHP) technologies could present an important decarbonization “wedge” in industrialized countries to complement other near zero-emission electricity systems (Pacala & Socolow, 2004).

The U.S. Department of Energy has funded numerous initiatives aimed to facilitate R&D and investment in the development of numerous waste heat projects (Department of Energy, 2017). This included tools for heat intensive industries to identify opportunities at their own facilities, providing data of the available opportunities to WHP developers, and identification of supportive policies at the federal and state levels. In the U.S., it is estimated there is 8.8 GW of high quality WHP technical potential, equivalent to three-quarters of the U.S. nuclear capacity scheduled to retire by 2025 (EIA, 2018; Elson, Tidball, & Hampson, 2015).

In Canada, by contrast, we are unaware of any studies that attempt to quantify the technical or economic potential of WHP in various sectors. There is one non-academic study for the upstream oil and gas industry (Neill and Gunter, 2007) which identifies appropriate technologies but not overall potential, as well as some project specific information that is identified later in this thesis. Due to the proliferation of heat intensive industries in Canada, including oil and gas, petrochemicals, pulp and paper, cement, and steel, it would be logical to have a potential that is similar to or larger than the U.S. on a per capita basis.

This thesis estimates the technical and economic potential for WHP installations in Canada, using natural gas compressor stations as a case study. Further, it provides an overview of institutional, regulatory, and policy-related factors toward WHP that help or hinder its adoption. Together, this will inform policy makers on the potential size for near zero-emission electricity, and whether the barriers to its further adoption are economic, institutional, regulatory, policy, or some combination of all four.

Despite multiple installations from 2007 to 2013, WHP penetration at compressor stations is low, and when this research was started no new projects had been announced since. The proposed research will focus on the following questions: Why did investment in pipeline waste heat recovery stall in the late 2000s? Given power prices, pipeline load factors, and proximity to electric power lines, what is the economic potential for waste heat generation at compressor stations? To what degree can waste heat generation capacity be depended on at times of peak electricity demand? What institutional and regulatory barriers exist to the development of waste heat generation, and what policy interventions may be used to remove these barriers?

1.1 Natural gas transmission in Canada

Of the 8.8 GW of estimated U.S. WHP capacity, natural gas transmission compressor stations account for 46% of the identified installation sites and 12% of the technical potential (Elson et al., 2015). There may be a larger opportunity in Canada relative to the population, as Canada produces one-quarter of the natural gas but has one-tenth of the population compared to the U.S. (IEA, 2016). In addition, natural gas compressor stations have seen some of the early commercial WHP installations. This indicates that these heat sources may be relatively economically attractive. Also, WHP capacity on each compressor station is smaller than typical of other promising industries for WHP but there are more potential sites. This may facilitate investment decisions at the crucial period early in technological deployment, as less capital investment is required in each investment decision, and learnings from each installation can be more rapidly reintegrated into future installations, resulting in faster cost reductions and quality improvements (Sagar & van der Zwaan, 2006).

Canada is the fourth largest producer of natural gas in the world (NRCan, 2018b). The vast majority of gas is produced in Western Canada, with large volumes transported east to meet the demands of the larger population centres in both Canada and the U.S. The ownership of these systems is also concentrated a handful of firms. Major transmission systems in Canada, organized by their owner, include:

- **TransCanada**
    - **NGTL** – Large system in Alberta and Northeast BC
    - **Foothills** – From Alberta to US border export points in Saskatchewan and BC
    - **Mainline** – From Alberta-Saskatchewan border to eastern markets
    - **Trans Quebec & Maritimes** (50% ownership) – From Ontario-Quebec border to Quebec population centres and US export points

- **Enbridge**
  - **Alliance** (50% ownership) – From Northeast BC to US border in Saskatchewan
  - **Enbridge West** (formerly Spectra Westcoast) – From Northeast BC to Vancouver and US border exports
  - **Maritimes & Northeast Pipeline** – From Maritimes offshore production to US border
  - **Union Gas** – From US border near Sarnia, ON to south of Toronto
- **TransGas** – Gathering and transmission system in Saskatchewan
- **FortisBC** – Distribution and small transmission system in southern BC
- **ATCO Gas –** Distribution and small transmission system in Alberta

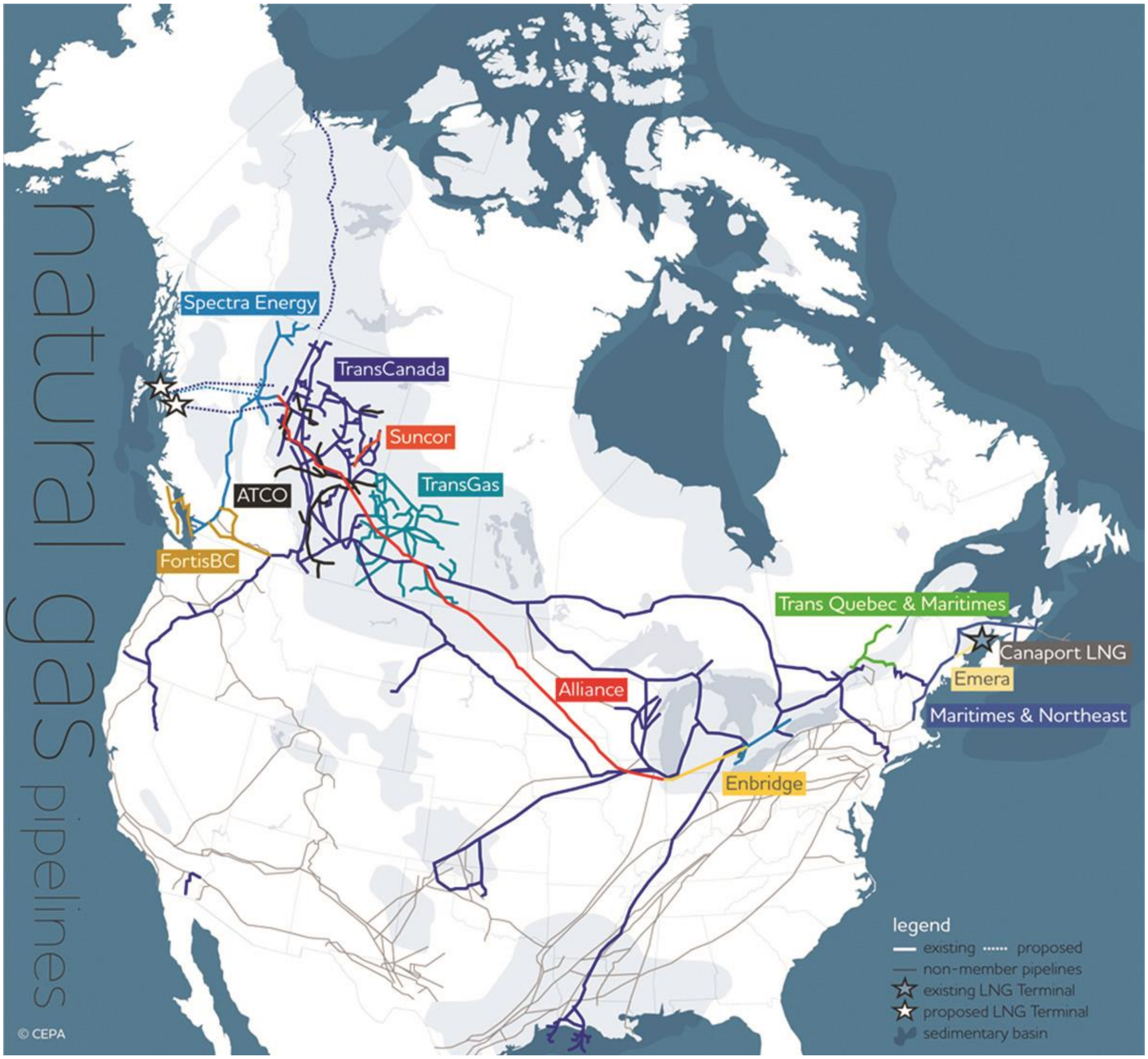

Figure 1: Map of natural gas pipelines in Canada (reproduced from CEPA, n.d.)

1.2 Waste-heat-to-power technology

WHP technology operates using the same thermodynamic cycles and similar equipment to conventional thermal power plants. Natural gas compressor station WHP in particular operates very similarly to the Rankine cycle side of a natural gas combined cycle plant.

Natural gas transmission compressors are required to push natural gas along the transmission line. These compressors are usually driven by gas turbines, which are mechanically linked to the gas compressors. These gas turbines are the same models sold to power generators for similarly sized power plants, except for dedicated electricity generation the gas turbine drives an electrical generator rather than a gas compressor (GE Power, 2017; Siemens, 2018).

These gas turbines are 30 to 40% efficient at turning the natural gas fuel into mechanical energy. The remaining 60 to 70% of the energy in the combusted gas is vented to the atmosphere at temperatures around 500 °C (GE Power, 2017; Siemens, 2018; Solar Turbines, 2018). Whereas it is standard practice for most dedicated power generators (except for gas generators fulfilling specific market niches) to capture this waste heat to drive an additional turbine through a Rankine cycle and increase electrical output, this is not standard practice in natural gas transmission. As shown in Figure 2, WHP installations can partially recover this waste heat to generate useful electricity. Where practical, some WHP installations have further been designed to recover the waste heat from multiple gas turbines to increase the output from a single electric generator (Bohl, 2009).

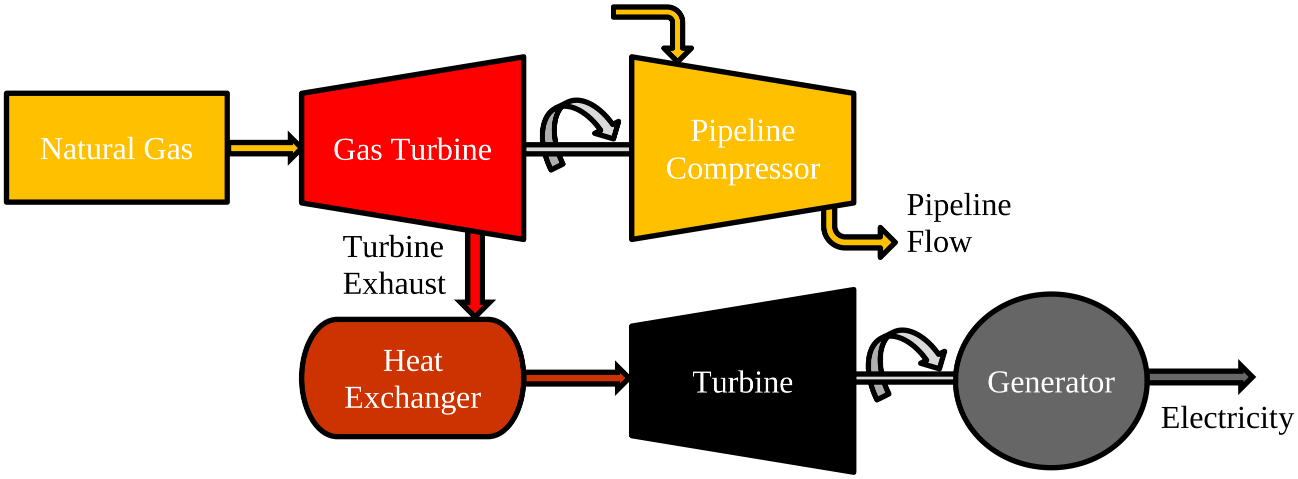

Figure 2: Natural gas compressor station WHP technology. A WHP installation adds the heat exchanger, turbine, and generator to the typical gas turbine and compressor arrangement.

Where steam is used almost exclusively at a combined cycle power plant in the Rankine power generation cycle downstream of the turbine exhaust, organic fluids such as pentane or butane are more common to pipeline compressor installations, often branded as the organic Rankine cycle (ORC). These fluids have lower freezing and evaporation points which facilitate operation in regions with low ambient temperatures and in processes with lower waste heat temperatures (Colonna et al., 2015). In addition, where steam systems require 24/7 onsite supervision by an appropriately certified Power Engineer[1], ORC installations are free from safety regulations founded on risk perceptions in the 19th century and can be remotely operated, significantly reducing operating costs (Bohl, 2009). Technological development is now focused on lowering capital costs and improving the efficiency of the ORC cycle by testing a variety of supercritical fluids and cascading thermodynamic designs (Colonna et al., 2015).

[1] Power Engineers are also referred to as Stationary Engineers, Operating Engineers, or Steam Engineers. I use the term Power Engineer in this thesis as it corresponds to the regulations discussed in Section 3.5.

Based on measured turbine fuel gas increases of 0.5% to 1.5% due to backpressure from the heat exchangers on the exhaust gas (Bohl, 2009), the incremental WHP greenhouse gas emissions intensity is estimated to be 12 to 35 g CO_2 per kWh[2]. To properly compare to other sources of near zero emission electricity, lifecycle emissions intensity is required. The lifecycle analysis of a natural gas combined cycle power plant (Draucker et al., 2010) estimated that the emissions intensity of plant construction, commissioning, and decommissioning is equivalent to 0.5 g CO_2e per kWh. Assuming this value is a reasonable approximation for the construction, commissioning, and decommissioning of a WHP installation, the lifecycle incremental emissions intensity of natural gas pipeline WHP is approximately 13 to 36 g CO_2 per kWh. This makes the incremental lifecycle WHP emissions on par with lifecycle emissions of wind, less than solar photovoltaics, less than 10% the emissions of natural gas combined cycle, and less than 5% the emissions of coal generation (Dolan & Heath, 2012; Hsu et al., 2012; O'Donoughue, Heath, Dolan, & Vorum, 2014; Whitaker, Heath, O'Donoughue, & Vorum, 2012).

1.3 Thesis outline

The remainder of this thesis is split into three chapters, in which I conduct a technoeconomic and regulatory assessment of WHP installations on natural gas transmission lines.

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[2] Using 56 kg of CO_2 per GJ of natural gas, 36.6% simple cycle efficiency (GE Power, 2017), and an ORC system electrical capacity to turbine brake power ratio of 5.5:23 (based on actual installations).

Chapter 2 presents a technoeconomic assessment of WHP installations on natural gas pipeline systems. Using costs from existing installations, an investment model is developed for a single WHP unit, considering a range of input variables. Next, the capacity factors of existing gas compressor stations are estimated from transmission line throughput data, and these capacity factors are used in the investment model to gain an estimate of the economic WHP potential in Canada.

Chapter 3 summarizes existing policy, regulatory, and institutional factors influencing WHP investment generally, as well as on natural gas compressor stations more specifically. This chapter attempts to determine what incentives, disincentives, and constraints exist to new installations. It also contrasts these factors with the incentives and disincentives available to other forms of near zero emission electricity such as wind and solar.

Chapter 4 concludes by attempting to answer the question: to what degree are the barriers to WHP adoption in Canada based on economic, regulatory, institutional, and/or policy factors? Are policy changes justified, and if so, what should these be?

Chapter 2: Technoeconomic assessment of WHP technologies on Canadian gas transmission pipelines

This chapter details the data sources and technoeconomic model development underlying the calculation of the technical and economic WHP capacity. I begin by summarizing the history of WHP installations on transmission systems in Canada. I then detail relevant technical statistics available for the natural gas transmission systems in Canada, along with the data sources available on their gas throughput and gas turbine installations. Using information about current WHP installations, I use the gas turbine installations to estimate the technical potential for WHP installations in Canada. From there, I develop the method and investment model for determining the amount of economically viable WHP installations.

2.1 WHP installation history on gas pipelines

Canada was a world leader in the development of waste heat recovery (WHR) in the 1980s. TransCanada Pipelines first installed a WHR cycle using steam at a compressor station to drive an additional pipeline compressor, using negligible additional fuel gas (Klein, 2018). With existing control technologies, this system proved too slow in responding to gas system operational changes, prompting a shift toward electricity cogeneration (Klein, 2018). TransCanada then installed WHR systems between 1992 and 2000 on five natural gas compressor stations in Northern Ontario using an innovative system that boosted the output of nearby steam power plants using compressor waste heat (Hedman, 2009). Four of the five have now ended operation at the expiry of their original Power Purchase Agreements (PPAs) due to the electric oversupply situation in Ontario (Atlantic Power, n.d.). Their broader dispersion is limited by co-location with nearby steam power plants (Hedman, 2009), water availability and susceptibility to winter freeze-off (Klein, 2018).

The commercialization of organic Rankine cycle (ORC) systems of the capacity required for pipeline compressors in the 80s and 90s, largely driven by the company Ormat, expanded the possibilities for small, distributed WHP installations (Bronicki, 2016). In 1999, TransCanada installed a 6.5 MW Ormat ORC system at the Gold Creek Compressor Station in Alberta. This was followed between 2006 to 2009 by six installations in Canada on the Alliance and Westcoast pipelines and eight installations in the US on the Northern Border and Trailblazer pipelines, all by Ormat and of similar generation capacity (Hedman, 2009).

In 2009, ten new projects were publicly announced as being under development. However, of these only the four US projects were completed while the Canadian projects were cancelled. The only completed Canadian compressor station WHP installations after 2009 were two installations on the Alliance and Foothills pipelines in 2013, and two small installations on TransGas. See Table 1 for a list of all known gas pipeline WHP installations. The existing installations are installed on less than 10% of compressor stations and are heavily concentrated in specific systems with large differences between ownership companies. The reason the four Canadian projects were cancelled is unknown, and the decline in installations since the late 2000s and early 2010s is one of the drivers of this thesis.

Table 1: Canadian WHP installations

Compressor Station	Pipeline System	WHP Capacity (MW)	Developer/ Operator	ORC Equipment Manufacturer	Electricity Contract Type	Installation Year	Source
Gold Creek	NGTL	6.5	Maxim Energy (3rd party)	Ormat	Energy market	1999	(Hedman, 2009)
Calstock	Mainline	19.8*	TransCanada Power	N/A	Long-term PPA	2000	(Atlantic Power, n.d.; Hedman, 2009)
Kerrobert	Alliance	5.5	NRGreen Power LP (Alliance subsidiary)	Ormat	Long-term PPA	2007	(Hedman, 2009)
Loreburn	Alliance	5.5	NRGreen Power LP (Alliance subsidiary)	Ormat	Long-term PPA	2008	(Hedman, 2009)
Estlin	Alliance	5.5	NRGreen Power LP (Alliance subsidiary)	Ormat	Long-term PPA	2008	(Hedman, 2009)
Alameda	Alliance	5.5	NRGreen Power LP (Alliance subsidiary)	Ormat	Long-term PPA	2008	(Hedman, 2009)
150 Milehouse	Enbridge West	5	EnPower (3rd party)	Ormat	Long-term PPA	2008	(BC Hydro, 2006; Hedman, 2009)
Savona	Enbridge West	5	EnPower (3rd party)	Ormat	Long-term PPA	2008	(BC Hydro, 2006; Hedman, 2009)
Rosetown	TransGas	0.9	Found Energy (3rd party)	Turboden	Likely long-term PPA	2011	(SaskEnergy, 2011; Turboden, n.d.)

Compressor Station	Pipeline System	WHP Capacity (MW)	Developer/ Operator	ORC Equipment Manufacturer	Electricity Contract Type	Installation Year	Source
Coleville	TransGas	0.1	Found Energy (3rd party)	IST exhaust heat exchanger StarRotor turboexpander	Likely long-term PPA	2011	(SaskEnergy, 2011)
Crowsnest	Foothills	6.5	Mistral Energy (3rd party)	Atlas Copco	Long-term PPA	2012	(Atlas Copco, 2014; Excelsior Engineering, n.d.; Kensington Capital Partners Limited, 2013)
Windfall	Alliance	14	NRGreen Power LP (Alliance subsidiary)	GE ORegen	Long-term PPA	2013	(Gray, 2012; Tony Straquadine, 2012)
Total	-	79.8	-	-	-	-	

***** The estimated max power attributable to pipeline waste heat. The total power capacity is 35 MW, including power from burning biomass (Atlantic Power, n.d.). The estimated waste heat power is likely an overestimate, derived using the 42.5 MW capacity of the two compressor units with higher capacity factors in 2010 (TransCanada Pipelines, 2011), and the added nominal capacity ratio of moving from a simple to combined cycle turbine for a similarly sized turbine (GE Power, 2017)**.**

At the time this research began, no known plans for further installations were public, however the potential first-of-a-kind WHP commercial installation using supercritical CO_2 as a working fluid was announced (with few details) as this research was concluding (Emissions Reduction Alberta, 2019; TransCanada Pipelines, 2019a). This presents a positive sign that developers are again evaluating these opportunities.

2.2 Technical potential

The technical potential in terms of installed electrical power, or capacity, can be estimated from the installed brake power of the natural gas transmission turbines. These were found from a collection of National Energy Board (NEB) regulatory filings and from the companies' web documents for NGTL, TransCanada Mainline, Enbridge West, Alliance, and Union Gas system, and summarized in Table 2. See Appendix A for a detailed list of system unit capacity and their sources. Installed turbine capacity on the Foothills, Trans Quebec & Maritimes, Maritimes & Northeast, TransGas, and FortisBC systems could not be located. However, with the potential exception of TransGas (for which very little information was found), these systems tend to have smaller flow capacities and/or be smaller in length compared to the systems for which turbine capacities are available, suggesting their installed turbine capacities would also be relatively small compared to the systems for which information is available.

Table 2: Installed gas turbine capacity by system

System	Installed Turbine Capacity (MW)	Stations	Units
NGTL	1174.8	60	96
TransCanada Mainline	2214.8	54	134
Enbridge West	418.5	12	27
Alliance	228.0	7	9
Union Gas	563.8	5	23
Total	***4599.9***	***138***	***289***

Based on the 4.6 GW of known gas turbine capacity installed on natural gas transmission lines and a typical installation ORC generator to gas turbine power ratio of 5.5:23 (Hedman, 2009), the Canadian technical potential of ORC generation is approximately 1.1 GW. This is approximately 10% of the existing Canadian coal capacity of 10 GW to be phased out by 2030 (NRCan, 2018a).

A comparison of the existing WHP installations to the technical potential is shown by system in Table 3. The nine existing installations on systems with known gas turbine capacities represent 6% of the 138 natural gas transmission line compressor stations. There are however significant differences between systems. The Alliance system has half of the installed WHP capacity, but only 5% of the technical potential.

Table 3: Comparison of current WHP installations to technical potential by system

System	Installed Turbine Capacity (MW)	Compressor Stations	WHP Technical Potential (MW)	WHP Installed Capacity (MW)	WHP Installations
NGTL	1174.8	53	280.9	6.5	1
TransCanada Mainline	2214.8	53	529.6	19.8	1
Enbridge West	418.5	12	100.1	10	2
Alliance	228	7	54.5	36	5
Union Gas	563.8	5	134.8	0	0
Foothills	Unknown	Unknown	Unknown	6.5	1
TransGas	Unknown	Unknown	Unknown	1	2
Total	***4599.9***	***130***	***1100.0***	***72.3***	***12***

There are also significant differences by province, as shown in Table 4. Ontario has by far the highest WHP technical potential at 50% more than Alberta, which is followed by Saskatchewan, BC, then Manitoba. While BC, Alberta, Saskatchewan and Ontario all have similar amounts of installed WHP capacity, the proportion versus technical potential is much higher in BC and Saskatchewan than in Alberta and Ontario. The reasons for this are explored in the coming chapters.

Table 4: Comparison of current WHP installations to technical potential by province

Province	Installed Turbine Capacity (MW)	Compressor Stations	WHP Technical Potential (MW)	WHP Installed Capacity (MW)	WHP Installations
BC	418.5	12	100.1	16.5	3
Alberta	1310.8	56	313.5	20.5	2
Saskatchewan	621.2	11	148.5	23	6
Manitoba	295.7	5	70.7	0	0
Ontario	1930.9	44	461.7	19.8	1
Quebec	22.8	2	5.5	0	0
Total	***4599.9***	***130***	***1100.0***	***79.8***	***12***

As Quebec has very little WHP technical potential and significant other options for low-cost and low-emissions electricity, the rest of the analysis will focus on the provinces between BC and Ontario inclusive.

2.3 Waste-heat-to-power costs

Costs for past WHP installations are available from academic and grey literature sources, as detailed in the sub-sections below.

2.3.1 Capital costs

Hedman (2008) estimates the installation cost to be $2,000 to $2,500 USD/kW, including equipment, installation, and grid interconnection. Leslie, Sweetser, Zimron, & Stovall (2009) report an installed cost of $2,500 USD/kW for an installation in North Dakota, though it is not clear whether this includes owner's costs and grid interconnection, and estimate a minimum required electricity purchase price of $50 USD/MWh for future projects. Using a cost of capital between 6% and 10%, and contract terms of 15 to 25 years, they estimate an NPV of $2 million to $12 million and internal rates of return between 5% and 15%, without including clean electricity subsidies. Gray (2012) reports that the latest Canadian WHP installation had a pre-installation estimated capital cost of $4571 CAD/kW, though it is not clear what is included in this value.

The most recent WHP unit installed on a transmission pipeline compressor station was constructed for $22.3 million USD (Ormat Technologies Inc., 2016). Given the net generating capacity of 7.8 MW, the installation cost is $2,859 USD/kW ($3,791 CAD/kW). This compares well to previous estimates considering cost escalation partially mitigated by improvements in technology and project execution. However, according to the green bond issuance document (UAMPS, 2014), the values above are for the engineering, procurement, and construction contract only and do not include other owner's costs such as transmission interconnection, project substation, development and permitting costs, and contingency. A comparison of capital costs from various estimates are shown in Table 5.

Table 5: Summary of capital cost estimates from available sources

	Hedman (2008)	**Leslie et al. (2009)**	**Gray (2012)**	**UAMPS (2014)**
Unit	$USD/kW	$USD/kW	$CAD/kW	$USD/kW
Capital Equipment Cost	2000 to 2500	2500	4571	2859
Grid interconnection and upgrades		*	*	568
Owner's Costs (development, permitting, contingency, etc.)	*	*	*	580
Total (quantifiable)	2000 to 2500	2500	4571	4007
* Unclear if included in above estimates				

As the most recent, most verifiably complete, and most conservative project estimate among available sources, the capital cost provided by UAMPS (2014) will be used for this analysis. Using the difference between the US Producer Price Index for manufacturing between the contract close date (Nov 2014) and the most recent data (Aug 2018), the manufacturing cost is increased by 2.8% (U.S. Bureau of Labor Statistics, n.d.).

2.3.2 Operating costs

Hedman (2008) estimates operation and maintenance costs between $1 and $5 USD/MWh, in addition to $5 USD/MWh for heat payments to pipelines. Leslie et al. (2009) estimate an operation and maintenance cost of approximately $200,000 per year. For comparison purposes, this equates to $4.7 USD/MWh. They do not specify whether or not this includes heat payments. The most recent Canadian installation at Crowsnest Station on the Foothills pipeline specified a 2013 heat, land lease, and backpressure payment of $427,000 CAD (Brennan, 2014). Based on Crowsnest's electricity generation of 64.92 GWh/yr from BC Hydro's Independent Power Producer (IPP) Supply report[3], the estimated heat payment is $6.6 CAD/MWh. Some total operational costs were also obtained for the installations on Alliance and the Enbridge Westcoast system. The Westcoast costs are in line with previous estimates, while the Alliance numbers are on the high side. All operational cost estimates are summarized in Table 6.

For the purposes of investment analysis, an operating cost of $4.7 USD/MWh, converted to $6.1 CAD/MWh, plus a variable heat payment of $6.6 CAD/MWh will be used.

[3] The BC Hydro report specifies a capacity of 10.5 MW and energy production of 64.92 GWh/year, for a capacity factor of 70%. However, based on multiple other reliable sources, the installed capacity is 6.5 MW, for which the capacity factor would need to be 114% to produce 64.92 GWh/year. This is not an unreasonable result however, considering power generated usually exceeds the nameplate rating, as reported by Leslie et al. (2009). However, the BC Hydro source may be less reliable given the discrepancy in capacity.

Table 6: WHP operational cost estimates

<table>
<tr><th></th><th>Hedman (2008)</th><th>Leslie et al. (2009)</th><th>Brennan (2014)</th><th>Alliance (2018)</th><th>Westcoast (2016)</th></tr>
<tr><td>Units</td><td>$USD/MWh</td><td>$USD/MWh</td><td>$CAD/MWh</td><td>$CAD/MWh</td><td>$CAD/MWh</td></tr>
<tr><td>Operation & maintenance</td><td>1 to 5</td><td>4.7</td><td>Not specified</td><td rowspan="2">14.3 to 17.8[1]</td><td rowspan="2">6.2 to 7.7[1]</td></tr>
<tr><td>Heat, land lease, and backpressure payment</td><td>5</td><td>*</td><td>6.6</td></tr>
<tr><td colspan="6">* Unclear if included in above estimate
[1] Calculated using the dollar amounts from the column reference, the installed capacity in Table 3, and a capacity factor from 80% to 100%. The Westcoast dollar amount includes all of the incremental operational costs of the WHP installation and the heat payment refundable to the shippers but not the heat payment kept by Westcoast.</td></tr>
</table>

2.4 Investment analysis

Investment analysis was conducted using the Net Present Value (NPV) method over a 20-year time period, modelled using Analytica decision making software. An influence diagram of the investment model is shown in Appendix D . The investment analysis was conducted for each unit using the costs and capacity factors detailed in the preceding sections, and the base case investment parameters specified in Table 7. The analysis is conducted in constant dollars.

The listed Weighted Average Cost of Capital (WACC), and its components, were chosen as reasonable typical values, however these can vary significantly over time due to larger economic forces (broad changes in bond rates) as well as between sectors and companies. Therefore, the values chosen in the base case are not intended to be a definitive view of the current financial landscape, particularly for one type of development company. Rather, they are simply the starting point for an analysis to determine the most significant policy leverage points to encourage WHP adoption.

Table 7: Base investment cases

Parameter	Market	Incentivized
Electricity price ($CAD/MWh)	50	80
Project debt-to-equity	60:40	70:30
Return on equity	12%	10%
Debt interest rate	7%	6%
Federal income tax rate	15%	15%
Provincial income tax rate	12%	12%
Weighted average cost of capital (WACC)	7.9%	6.1%
Capacity factor	90%	90%
Capital Cost Allowance (CCA) rate[4]	100%	100%
20-year NPV	**-$10,090,000**	**$705,000**

Using the base investment parameters, the 20-year NPV is negative $10.9 million dollars. Therefore, it is not profitable to build a WHP unit given the investment parameters. In the incentivized case, the 20-year NPV is positive. A sensitivity analysis is next conducted to determine what inputs have the most potential to bring WHP into profitability, if they can be reassessed.

2.5 Sensitivity analysis

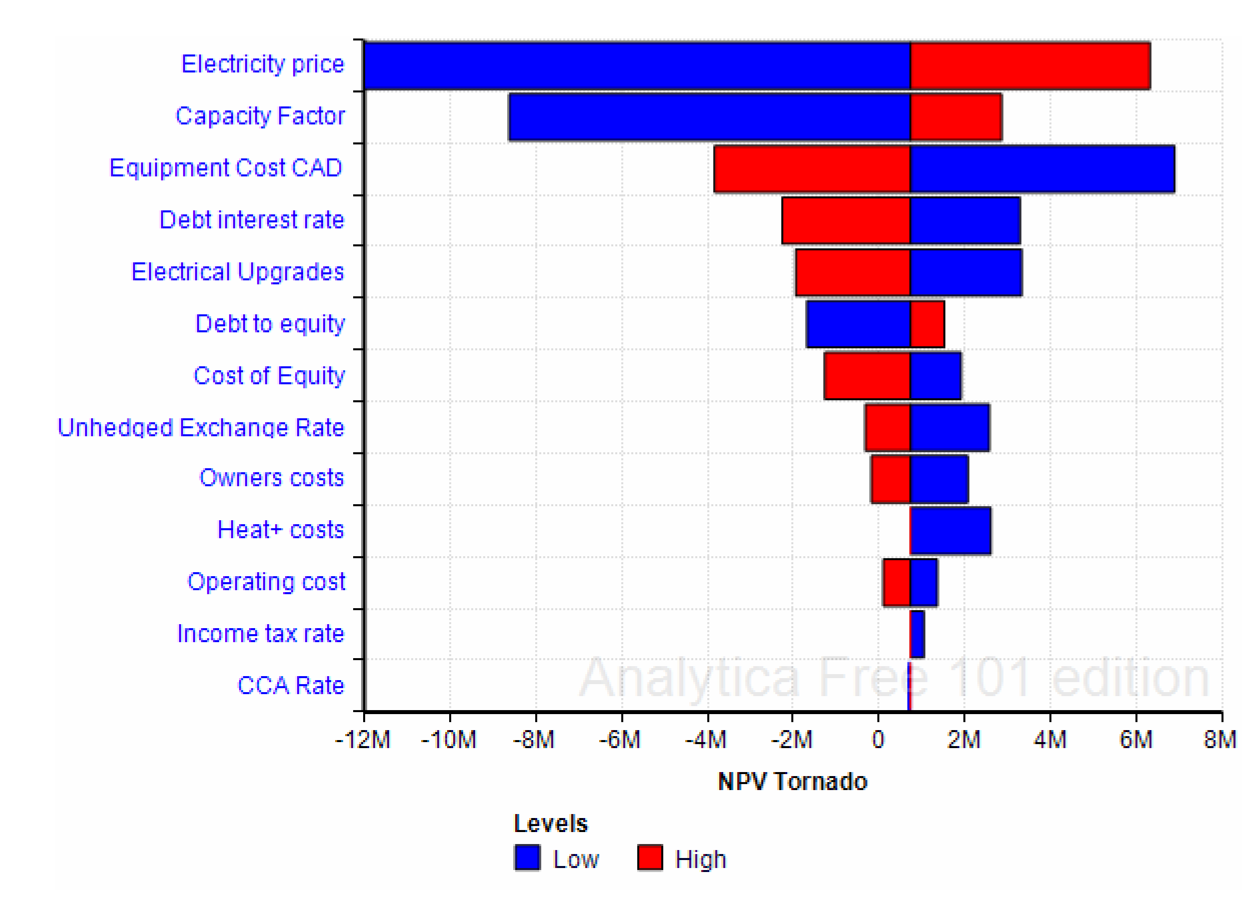
A sensitivity analysis was conducted using ranges of plausible values, considering both project uncertainty and policy initiatives. A tornado diagram and its inputs are shown in Figure 3. Due to

[4] CCA is the tax expense equivalent to depreciation, similar to Modified Accelerated Cost Recovery System (MACRS) in the United States.

thresholds and non-linearities between negative and positive NPV values in the model, only the sensitivity for the Incentivized case is shown.

Electricity purchase price and capacity factor are the key determinants of investment profitability. Results are also more sensitive to changes in capital cost. Inputs to the WACC, particularly in combination, are quite significant. Lowering the WACC, either by increasing the debt to equity ratio, or by lowering the return on equity and/or debt interest rates through investment de-risking, could be a significant policy lever. Variations in electrical interconnection upgrade costs also have a significant impact on the investment but are very context dependent.

As the equipment cost and operating costs are from US sources, these costs were translated to USD using a foreign exchange (FX) rate typical of 2018. A FX range of 0.97 to 1.45 represents most of the 10-year historical range. To determine the sensitivity, variations in FX was constrained to impact only 50% of equipment and operating costs to reflect that much of these expenses are local. Note that the majority of Canadian WHP installations came in the late 2000s and early 2010s when the exchange rate was roughly on par.



Low	Base	High	Units
40	80	100	$/MWh
50	90	100	%
1896	3791	4928	$/kW
3	6	9	%
0	733	1466	$/kW
40:60	70:30	80:20	%
8	10	15	%
0.97	1.29	1.47	$US/CAD
374	748	1000	$/kW
0	6.6	6.6	$/MWh
3	6.4	6.4	$/MWh
15	27	27	$
30	100	100	%

Figure 3: Tornado diagram of NPV sensitivity to input parameters, incentivized case

The Capital Cost Allowance (CCA) was recently increased to 100% for "Clean Energy Investments" (Government of Canada, 2018a). This allows for the capital cost to be written off immediately, provided the business net income is positive. This should create a substantial incentive for capital intensive projects by reducing tax payable in the year of construction. However, the investment model is unable to adequately quantify this incentive as the annual profit from this project alone is smaller than the capital cost of the project, and business income from other sources is not available in the model to be offset.

The Incentivized case requires an electricity purchase price of $80/MWh. Due to the conservativeness of cost assumptions and inability to quantify CCA incentive, this model likely underestimates the investment attractiveness of an individual investment. Electricity prices of $70/MWh or lower could be possible if actual values are lower than the conservative inputs.

2.6 Capacity factor calculation

Pipeline turbine unit capacity factors have significant impact on the financial viability of WHP installations, however these are not generally publicly available. In the U.S. estimates of viable WHP capacity, Elson *et al.* (2015) assume a 100% capacity factor for all compressor stations, leading to an overestimate of viable capacity. Hedman (2008) estimates a capacity factor above 60% is required for financial viability, and determines 40% to 50% of large turbines meet this threshold though the method is unclear.

For this research, I aim to estimate capacity factor using available operating data. Therefore I use gas pipeline system volume throughput and capacity (Government of Canada, 2018b) to estimate unit capacity factors. Data is available for all pipeline systems listed in Table 2 for which installed gas turbine power is known, except for the Union Gas. Union gas is therefore not included in the rest of the analysis.

First, the daily volume throughput is used to estimate the daily average compression power requirement. Next, this is transformed into annual load duration curves, from which the capacity factors of units are calculated.

The relationship between compression power and throughput volume is shown in Equation 1 (Mohitpour, Golshan, & Murray, 2007, p. 165). This equation is typically used for a single compressor station and assumes a static piping system resistance curve.

Equation 1

$$\frac{P_1}{P_2} = \left(\frac{Q_1}{Q_2}\right)^3$$

Where *P* is compressor power, and *Q* is volumetric flow.

Given the total pipeline system (or area) installed power, the nominal system capacity, and the daily throughput, Equation 2 is used to estimate the daily average power requirement. Using this equation for the entire system does not consider changes in the system resistance curve implicit in operating more or less compressors in the system, as well as other changes in pressure and flow, however is used as a first order approximation of required power.

Equation 2

$$P_{turbine,day} = P_{turbine,capacity} * \left(\frac{Q_{day}}{Q_{capacity}}\right)^3$$

Compressor load duration curves are then generated, with horizontal lines corresponding to turbine units. The intersection of the load duration curve and turbine unit lines determines the unit capacity factor. This assumes a consistent dispatch order. An example of this method for the Alliance system is demonstrated in the subsection below.

2.6.1 Alliance system

The Alliance System, shown in Figure 4, was built in 2000 to transport gas mostly from northeast BC and northwest Alberta to the Chicago natural gas market hub. Canadian gas turbine power is 228 MW ISO, with compressor stations approximately 193 km apart, which drives a system capacity of approximately 50 M m^3/day.

Gas turbine and compressor data were collected from regulatory documents (see Appendix A) for the all Alliance Mainline compressor stations, and summarized in Table 8. These include stations between the US border and the Windfall compressor station, located 200 km northwest of Edmonton.

Figure 4: Alliance system map with key points (reproduced from NEB, 2018)

Table 8: Alliance turbine installations

Operational Area	Flow Point	Total Power (MW)	Units Installed	Power Per Unit (MW)
Mainline	Border	228	9	25.3

The throughput at the Canada-U.S. border is used to determine the Mainline throughput, as shown in Figure 5.

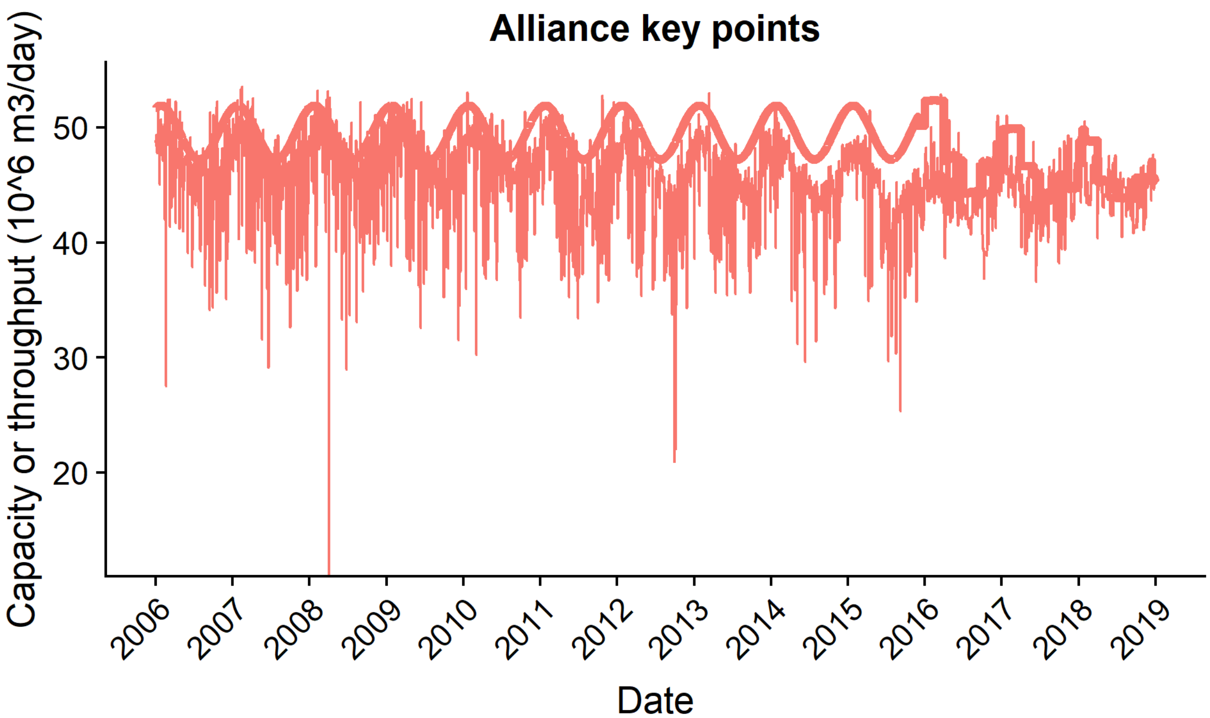


Figure 5: Flow through the Alliance Mainline. Thinner line is throughput, thicker line is capacity.

Analysis of the system was conducted using the method in Section 2.6 using throughput data from 2018, producing the results shown in Figure 6. The blue load duration curve is the daily required power calculated from Equation 2, sorted from highest to lowest power over the year. The horizontal green lines represent each gas turbine on the system and are spaced according to the average unit power for each system or area. The capacity factor for each unit is determined from the intersection of these load duration curves and each green line, with units below the blue line assumed to have a capacity factor of 100%. The capacity factors for Alliance are shown in Table 9.

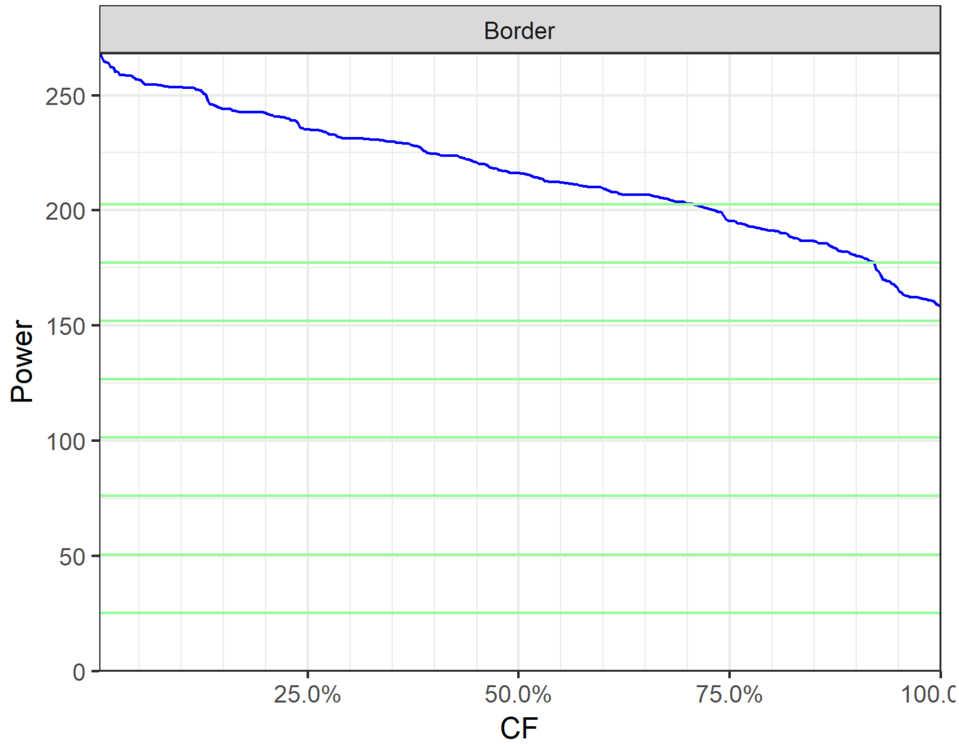


Figure 6: Alliance load duration curve. Capacity factor for each unit measured at intersection between load duration curve and horizontal lines spaced according to the system average unit size.

Table 9: Alliance turbine capacity factors

Unit	T-South
1	1
2	1
3	1
4	1
5	1
6	1
7	1
8	0.92
9	0.71

This method is sensitive to how the transmission line volumetric capacity is defined. As evident from Figure 5, throughput regularly exceeds the defined capacity in 2018, which manifests in

Figure 6 requiring approximately 15% more power than the 228 MW actually installed on the system.

2.6.2 Other systems and capacity factor accuracy evaluation

The capacity factors for the TransCanada Mainline, NGTL, and Enbridge West are estimated in Appendix B and shown in Table 20. This analysis was conducted in R (R Core Team, 2018; Wickham, 2017).

This method estimates the physical relationship between system throughput and required power, but is less accurate than the more complex hydraulic models that are used by the transmission companies themselves. There are two sources of error. The first is in the calculation of daily power. As demonstrated above, the nominal capacity is not a hard limit. The actual maximum throughput varies with ambient temperature and pressures at interconnections up and downstream of the pipeline.

The second source of error is in the assumed distribution of this daily power calculation by individual turbine unit. In actual operations there will be deviations from a strict dispatch order as assumed in these calculations. The system is optimised to meet required pressures at delivery points without exceeding safe pressures anywhere along the pipeline, while minimizing fuel gas use. This involves a balance of operating the most efficient units (often the newest), while maintaining the most efficient operating configuration of an even distribution of operating units along the system. This may change as the number of required units increases or decreases, units are added or removed from service, or pressures at interconnections change due to third party operations. The strict dispatch order assumption for this study then implies a larger variation in unit capacity factor than is likely in reality. Certain units are also located at critical points in the system, for example at junction points between flow paths or at increases in the system design pressure, which often leads to high capacity factors.

As the 2010 unit capacity factor data for the TransCanada Mainline system is publicly available (TransCanada Pipelines, 2011), the accuracy of this method for calculating system capacity factors, and ultimately viable WHP capacity, is evaluated in detail in Appendix C .

For the two large TransCanada Mainline areas with relatively complete information to conduct a mass balance analysis, the sum of the annual turbine energy calculated based on 2010 throughput data is accurate within +/- 23% (see Figure 38). The Alliance and Enbridge West systems are also large systems with relatively complete mass balance information, and this value therefore could be representative of their accuracy as well. The eastern TransCanada Mainline areas were less accurate (-81% to +23%), however these are a smaller proportion of the total technical potential. These areas were defined to consist of single units or without complete mass balance information, characteristics not representative of other systems in the analysis.

The capacity factor distribution from the calculated capacity factors is generally representative of capacity factors in the 2010 data, with a small bias toward high capacity factors on fewer units. This appears to bias the calculation of viable WHP capacity upward. However, a few smaller areas do have a different load profile. See Figure 39 and Figure 40 for more information.

NGTL is unlike the other systems assessed in this thesis as there are a large variety of flow paths throughout the system, and the measurement points provided in the throughput data do not completely describe gas transfer on the system. As such, I do not extrapolate the assessed accuracies from the 2010 TransCanada Mainline data to the NGTL system.

2.7 Electric grid interconnection

The cost to connect the new generator to the existing electrical grid could significantly influence the economics of a given installation. The transmission interconnection cost will vary significantly between installations due to a range of site-specific factors. For any given installation, a connection study would be required from the distribution or transmission utility and would typically be conducted early in the project.

For the purpose of this study, the value report by UAMPS (2014), $568 USD/kW, is used as reported above - 14% of the capital cost. This included $1.6 million USD ($205,000 USD/MW) for the substation and $2.8 million USD for the transmission interconnection. The transmission interconnection of UAMPS consisted of a few hundred meters of new 34.5 kV line and significant upgrades to 4 kilometers of existing overhead distribution line. For comparison, the SaskPower charge for WHP installations is $170,000 CAD/MW and $43,000 CAD/km for interconnections (SaskPower, 2018a). The Crowsnest interconnection study estimated a total cost of $153 CAD/kW, lower than the other estimates (BC Hydro, 2010). This underscores the site-specific differences in interconnection needs and implies the UAMPS values may be conservative in many cases.

For remote compressor stations, the distance to the electrical grid may be too great for a WHP installation to be viable. In these cases, the interconnection cost would be much larger than the value above or the reasonable range of the sensitivity analysis. The remoteness of each evaluated gas system to the electric grid is evaluated in Table 10. I therefore compared maps or shapefiles of the electrical grid to maps of each pipeline system to qualitatively determine the remoteness of each system or area[5].

Table 10: Remoteness of gas pipeline system to the electric grid

System	Area(s)	Remote	Rationale	Electrical grid source
TransCanada Mainline	PtEN	Less	Southern Saskatchewan and Manitoba are largely agricultural areas serviced by existing transmission and distribution networks.	(Manitoba Hydro, n.d.-b; SaskPower, 2018b)
	NOL	More	Significant portions of the pipeline pass through areas of northern Ontario with sparse access to the electrical grid.	(IESO, 2018)
	Eastern Triangle region	Less	This area of southern Ontario is generally close to major population centers and well served by the existing electrical grid.	(IESO, 2018)
NGTL	East Gate	Less	Passes through areas of southern Alberta generally close to population centers and agricultural areas.	(ATCO Electric, 2015;

[5] I was unable to obtain data and maps to combine in a single GIS program. Some of the data can only be seen in dedicated web browsers, but not downloaded, some of it is only available on pdf maps, and some is shown from only a high profile.

	West Gate	Less	Passes through areas of southern Alberta generally close to population centers and agricultural areas.	FortisAlberta, 2019; Government of Alberta, n.d.)
	USJR	More	Some stations in this area are in remote regions without nearby powerline access, particularly stations that are farther north.	
	NEDA	More	Some stations in this area are in remote regions without nearby powerline access, particularly stations on the northern pipeline corridor to the oil sands region. Stations farther east, toward the oil sands region, tend to be closer to powerlines.	
Enbridge West	T-South	Less	The pipeline shares an infrastructure corridor with large transmission lines for the majority of its length.	(BC Hydro, 2018; Government of British Columbia, 2019)
Alliance	Mainline	Less	The mainline passes through areas of Alberta and Saskatchewan that are agricultural or near population centers, with access to the existing electrical grid. Five of the seven stations already have WHP installations (see Table 1).	(ATCO Electric, 2015; FortisAlberta, 2019; Government of Alberta, n.d.; SaskPower, 2018b)
Note: Pipeline locations were observed from the About Pipelines map (CEPA, 2018).				

A greater proportion of stations in the NOL, USJR, and NEDA areas are likely to be remote from the electrical grid, with interconnections costs not well represented by the range in the sensitivity analysis. Of these, the NOL area currently has low calculated capacity factors, and the remoteness is unlikely to significantly overestimate WHP capacity. However, the USJR and NEDA areas in northern Alberta do have high calculated capacity factors, and station remoteness should be considered in the analysis.

2.8 Viable WHP capacity

The estimated unit capacity factors calculated in Section 2.6 and the station remoteness are now incorporated into the investment model to estimate the total viable WHP capacity in Canada.

Based on the calculated capacity factors summarized in Table 20 of Appendix B , the model determines whether each turbine unit meets the investment criteria in the “Incentivized” case of Section 2.4. The model then sums power of these profitable turbine units, the capacity of which are defined at the average turbine capacity for each system. This is then multiplied by the nominal ratio of WHP power to compressor brakepower from past installations, 5.5:23. This estimates the viable WHP capacity per system, based on the selected investment criteria. The results are shown in Figure 7.

This method cannot directly specify which particular units or stations have capacity factors high enough for an economically viable WHP unit. To estimate how the viable WHP capacity is distributed provincially for areas of systems that span across provincial borders, the estimated viable WHP power per system is multiplied by the systems’ proportion of gas turbine power within each province.

The conservativeness of costs assumed in the project level investment analysis would lead to an underestimate, while the capacity factor calculations may lead to an overestimate, and the variation in the interconnection costs may lead to under or overestimates. The degree to which these offset cannot be explicitly assessed with the available data.

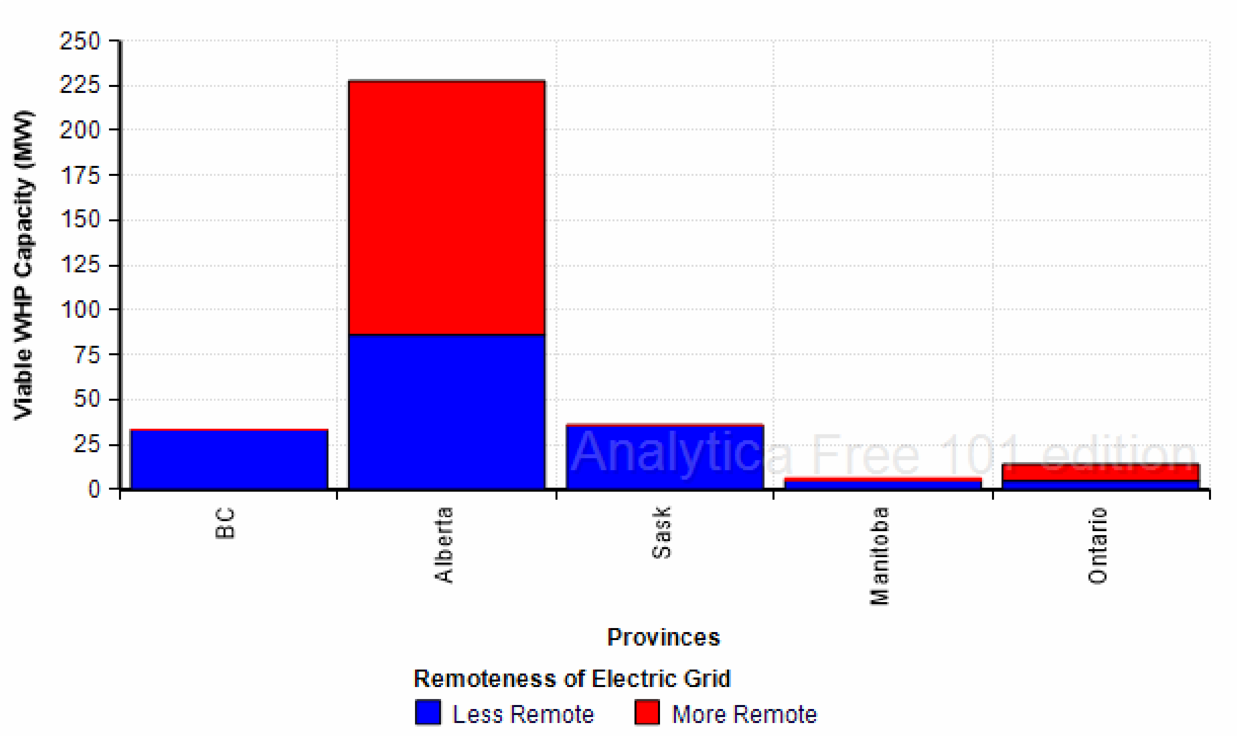


Figure 7: Viable WHP capacity by province for Incentivized case

The viable WHP capacity, including more remote areas, is broken down by province and system in Table 11.

Table 11: Viable WHP by province and system

System	BC	Alberta	Sask	Manitoba	Ontario	*Totals*
Mainline - PtEN	0	0	13.7	5	0	**18.7**
Mainline - NOL	0	0	0	1.1	9.5	**10.7**
Mainline - ETriNE	0	0	0	0	3.5	**3.5**
Mainline - ETriE	0	0	0	0	1.1	**1.1**
Mainline - Iroquois	0	0	0	0	0	**0**
Mainline - Kirkwall	0	0	0	0	0	**0**
NGTL - EGAT	0	38.3	0	0	0	**38.3**
NGTL - NEDA	0	34.4	0	0	0	**34.4**
NGTL - USJR	0	107.1	0	0	0	**107.1**
NGTL - WGAT	0	21.5	0	0	0	**21.5**
Enbridge West - T-South	33.4	0	0	0	0	**33.4**
Alliance Mainline	0	26.1	22.3	0	0	**48.4**
Totals	**33.4**	**227.5**	**35.9**	**6.1**	**14.1**	**317**

2.9 Summary

In this chapter, I have presented the principal data sources for the technoeconomic analysis. I used this to develop a WHP installation economic model. I also estimated the capacity factors for gas turbine units on most of the major transmission lines. I then combined the capacity factor estimates with the WHP installation economic model to estimate the viable WHP capacity, by pipeline system and province. This is now compared to the identified existing transmission system WHP installations in Canada, and the principal opportunities for additional installations are identified.

Alberta has by far the most viable capacity if WHP were incentivized. This is due to both a high technical potential, as well as high capacity factors for the units in the province. Despite this, it has a low actual installed WHP capacity. This is likely in part due to past lack of incentives in Alberta compared to other jurisdictions, as will be discussed in the next chapter.

While Ontario has the largest technical potential, the capacity factors on the pipelines in Ontario have been low due to the changing dynamics of gas supply brought by unconventional gas in the northeast U.S. This results in relatively little viable WHP capacity. Saskatchewan and BC have significant portions of their calculated viable capacity already installed. There is very little viable capacity in Manitoba.

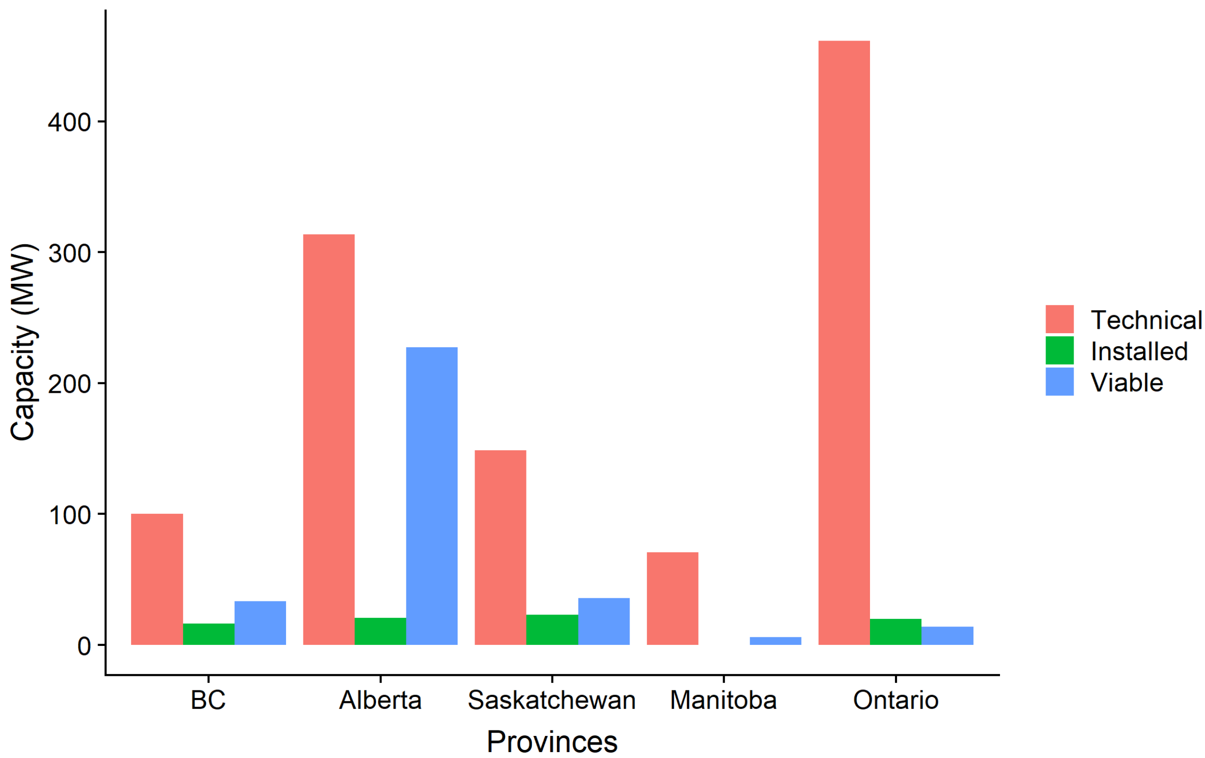


Figure 8: Comparison of technical, installed, and viable WHP capacity by province

These comparisons are summarized in Figure 8. Assuming an annual household electricity consumption of 7200 kWh per year as typical in Alberta, the Canadian viable WHP capacity is sufficient to provide electricity to over 350 thousand homes (Energy Efficiency Alberta, 2018). As indicated in Section 2.4, the viable WHP capacity depends on supportive policy, potentially including market internalization of carbon emission costs. In the next chapter, I assess these policies including their historical differences between provinces.

Chapter 3: Institutional, regulatory, and policy related factors

In this chapter I explore the institutional, regulatory, and policy-related factors to WHP development on natural gas transmission lines. I start by examining policies designed to improve low carbon project economics, looking at clean electricity purchasing programs and the recently implemented carbon price to determine if they provide adequate incentives. I also look at whether eligibility for green bonds will provide significant benefits. Next, I assess the integration of WHP from gas transmission on electric grids, considering whether they will generate electricity when it is needed. Lastly, I look at how regulations indirectly impact project finances, focusing on power engineering supervision requirements and the effect of cost-of-service regulations.

3.1 Clean electricity purchasing programs in Canada

A survey of existing clean electricity purchasing programs in Canada which may impact WHP is summarized here. The focus is on programs that are or could conceivably be targeted toward waste-heat-to-power systems.

3.1.1 British Columbia

Electricity in BC is provided by the integrated public utility BC Hydro. BC Hydro buys electricity from Independent Power Producers (IPPs) through the Standing Offer Program (BC Hydro, 2016). All electricity must be provided by a "Clean or Renewable Resource," of which waste heat is a recognized resource. Projects must generate between 100 kW and 15 MW of electricity, which is inclusive of most of the range applicable to compressor stations in the province. The standing offer provides a fixed price ranging from $102.06 to $111.56 per MWh, for a middle value of $106.81 per MWh. The price within this range varies by installation region and escalates annually with CPI. The initial offer term is 20 to 40 years. The Standing Offer Program was suspended on February 14, 2019, as part of the ongoing broader governmental review of BC electricity planning.

3.1.2 Alberta

Wholesale electricity in Alberta is provided through a wholesale energy-only electricity market, with plans of introducing a capacity market in the coming years to facilitate the province's Renewable Power Standard (RPS) of 30% by 2030, whereby 30% of its electricity must come from renewable sources. Until the capacity market is implemented, reverse auctions for renewable electricity are procuring significant amounts of renewable electricity. However, waste heat is not considered a "renewable energy resource" by law and is therefore ineligible for the RPS or reverse auctions (Renewable Electricity Act, n.d.).

A comparable clean energy purchase price is assessed based on the renewable energy reverse auctions. Round 1 procured 600 MW of wind at a weighted average cost of $37/MWh, round 2 procured 363 MW of wind at a weighted average cost of $38.69/MWh, and round 3 procured 400 MW of wind at a weighted average price of $40.14/MWh (AESO, 2019). In addition, the

Government of Alberta recently procured 94 MW of solar at a weighted average price of $48/MWh (Government of Alberta, 2019).

The wholesale energy market price, for comparison, has averaged $53.26/MWh over the last ten years, with significant fluctuations in the annual average price between $18.28 and $89.95/MWh (AESO, 2018a).

3.1.3 Saskatchewan

Electricity is managed by SaskPower, a vertically integrated public utility, with which all power generators must contract. SaskPower has standing offers for waste heat and flare gas at $70/MWh and for solar, biomass, geothermal, or hydro at $108/MWh (SaskPower, 2018a). The purchase rate escalates at 2% annually. No justification for the difference between rates has been found. Also of note, eligible waste heat projects are limited between 100 kW and 5 MW, which will be a binding limitation for many compressor stations. This constraint would not have been in place when existing installations were completed in Saskatchewan, as they are over 5 MW.

3.1.4 Manitoba

Electricity in Manitoba is managed by the vertically integrated public utility Manitoba Hydro. Manitoba Hydro will pay $39.49/MWh for electricity generated by non-utility generation of 200 kW or less (Manitoba Hydro, n.d.-a). This rate is reviewed annually. For facilities greater than 200 kW, the purchase price must be negotiated with Manitoba Hydro, and “will include, but not be limited to, factors such as environmental premiums, government subsidies and shaping and firming the generator output in a 5 x 16 product (On peak hours Monday through Friday from 6AM to 10 PM, 5 x 16)” (Manitoba Hydro, 2016).

3.1.5 Ontario

The Ontario power market is administered by the Independent Electricity System Operator (IESO). Generation capacity in the province is approximately evenly split between an energy market and fixed long-term contracts (IESO, 2015). Due to capacity oversupply, the average energy market price in 2018 was $22.43/MWh (IESO, 2019). Long-term contracts began with bi-lateral negotiations and competitive bids and have since moved toward standard offer programs. Contract terms range from 5 to 50 years, with an average of 20 years. WHP contract lengths are 20 years, and IESO had 626.3 MW of capacity in the larger Combined Heat and Power (CHP) category as of Q3 2018, including projects currently under development.

The Energy Recovery Standard Offer Program (ERSOP) offers 20-year contracts for eligible programs. The offer price is $90/MWh, escalating at 30% of CPI, though applicants can bid with a purchase price reduction to gain a higher chance of acceptance (IESO, 2011). By contrast, the feed-in-tariff for solar and biogas projects was $179/MWh to $213/MWh in 2016, though this program has since been discontinued (IESO, 2017). Before being discontinued, the last large wind procurement had an average cost of $85.90/MWh (IESO, 2016).

3.1.6 Electricity rate summary

An inter- and intra-provincial comparison of electricity prices and programs reveals significant differences in approaches to WHP and clean electricity purchase programs in general. This is evident in the electricity prices and programs from the preceding subsections summarized in Table 12.

Table 12: Electricity prices in $/MWh.

	BC	AB	SK	MB	ON
Retail rate[1]	77.70	84.25	89.80	51.80	107.30
Wholesale market rate	N/A	53.26 (10 yr avg)	N/A	N/A	22.43 (2018)
WHP purchase price	106.81 (2019)	N/A	70.00 (current)	Negotiated	90.00 (2011-2015)
Wind purchase price	106.81 (2019)	40.14 (2018)	Negotiated	Negotiated	85.90 (2016)
Solar purchase price	Net metering	48.00 (2019)	108.22 (current)	39.49 (current)	179.00 (2016)

Note: See above subsections for sources, except for retail rate.
[1] From Hydro-Québec (2018), for large power customers in major cities. Includes total bill cost except taxes for monthly consumption of 3,060 MWh and power demand of 5 MW levelized to unit costs. Alberta numbers are the average of reported Edmonton and Calgary values, Ontario numbers are the average of reported Toronto and Ottawa values.

Supportive electricity purchasing programs for WHP have been available in BC, Saskatchewan, and Ontario. Perhaps unsurprisingly, this is evident in the location of existing WHP installations. WHP with ORC units have been most prevalent in BC and Saskatchewan as shown in Table 4 relative to the technical potential. Despite a supportive purchasing program, Ontario did not have any WHP installations on gas pipelines during the program period. This may be due to the low pipeline capacity factors in Ontario, the remote location of the pipelines in northern Ontario compared to the electric grid, or other reasons.

Alberta, despite having much larger technical and viable potentials, has only two installations. A large part of this is undoubtedly because the Alberta average wholesale market rate over the last ten years has been too low to justify WHP investment without supportive policies, as shown in Section 2.4. Eligibility of all zero-emission electricity generation technologies in Alberta's reverse auction programs would ensure fair competition for equal emissions benefit.

The fact that purchase prices are fixed in other provinces' programs is a significant additional incentive. In Alberta, developers would be subject to the price fluctuations of the energy market, the annual average price of which has varied between $18.28/MWh and $89.95/MWh over the last ten years (AESO, 2018a). This creates highly variable cash flow, and market low points can be a significant issue for highly leveraged and/or public firms. Consequently, investors subject to electricity price risks, rather than a fixed price, will have a higher WACC. This is because investors will demand a higher expected return on equity, finance the project with relatively more equity than debt, and will pay higher interest rates on debt to compensate for the increased risk (Parkinson, 2011). As shown in Figure 3, changes to one of these three variables can impact the 20-year NPV by $3 to $6 million dollars, and significantly improve project economics. Therefore, fixed electricity pricing could provide significant incentive to developers even without considering higher electricity pricing.

While I made best efforts to ensure comparable inter- and intra-provincial values, due to different market and contracting systems and time discrepancies between sources the following must be considered. While most sources are valid within the last year, the Ontario purchase price values were last valid in 2015/2016. Therefore a comparison between Ontario and other provinces must take into account the incredible price drop of wind and solar over even that relatively short time period (Lazard, 2015, 2018). Despite this difference, it is clear that significantly better prices can be obtained through the reverse auction process used for wind and solar in Alberta than the standing offer programs, particularly as applied in BC and Ontario. While it is possible that annual updates to the standing offer program prices could, in principle, lead to the same cost reductions as through the reverse auction process, this requires government officials to have very good knowledge of the costs facing developers. If the electricity price is set too high, developers get wind fall profits and the cost of electricity for consumers increases unnecessarily, as evidenced in BC (Davidson, 2019). If the price is set too low, no installations will occur. For this reason, for provinces procuring electricity through long-term contracts reverse auctions are recommended over standing offers.

3.2 Carbon pricing

Carbon pricing has recently been broadly introduced across Canada and will also incentivize WHP installations (Government of Canada, 2018c). Unlike the electricity purchase programs described above, technologies are treated according to their GHG emissions alone rather than the eligibility criteria of the purchase program.

In Canada, the minimum carbon price in 2019 is \$20/tonne CO_2, which is legislated to rise to \$50/tonne CO_2 by 2022 (Government of Canada, 2018c). Provinces are free to determine their own equivalent climate policies, so long as the federal government determines that the provinces are meeting the same threshold as the established federal minimum carbon price. Alberta's carbon pricing scheme introduced Output Based Allocations (OBAs), ostensibly directed toward emissions intensive trade exposed industries to give them the same carbon price incentive at the margin, but reducing the overall cost of compliance to prevent capital flight and cross-border emissions leakage (Carbon Competitiveness Incentive Regulation, 2017).

With an OBA, a facility is charged for its emissions using the standard carbon price but is rebated according to the facility output per an industry benchmark. This means industry is subject to an emissions intensity price, rather than a traditional carbon tax, with the emissions intensity price designed to provide the same marginal dollar per tonne of CO_2 incentive in all industries. While the system was primarily developed for emissions intensive trade exposed industries, it was also applied to the electricity market, despite Alberta's electricity market having relatively little trade exposure. This is likely to prevent a large increase of costs to large industries that consume electricity and are trade exposed, and to the public where the price shock would be politically unpalatable. The Alberta benchmark is set using a "good-as-best-gas" concept, at 0.370 tCO_2 per MWh (Carbon Competitiveness Incentive Regulation, 2017). Therefore, facilities with emissions intensities above the benchmark will have extra costs, while facilities with emissions intensities below the benchmark receive offset credits with a nominal value equal to the carbon price.

Equation 3

$$\boldsymbol{Cost_{marginal}} = \left(\boldsymbol{EI_{facility}} - \boldsymbol{0.370}\right)\left(\frac{\boldsymbol{tCO_2}}{\boldsymbol{MWh}}\right) * \boldsymbol{CP}\left(\frac{\boldsymbol{\$}}{\boldsymbol{tCO_2}}\right)$$

where:

$Cost_{marginal}$ is the marginal cost (offset value) of carbon per MWh;

$EI_{facility}$ is the emissions intensity of the generation facility; and

CP is the carbon price.

The federal government adopted the same concept with the proposed Output Based Pricing System (OBPS) regulations, also applied to large industries and electricity. However, instead of a common benchmark for electricity, they provided a separate benchmark for different fuels, as shown in Table 13 (Government of Canada, 2018c).

Table 13: Electricity output-based carbon pricing benchmarks

Fuel source	Alberta OBA (tCO_2/MWh)	Federal OBPS (tCO_2/MWh)
Zero-emissions benchmark	0.370	None
Gaseous fuels (natural gas)		0.370
Solid fuels (coal)		0.800 in 2019, declining annually to 0.370 in 2030

In addition to separate fuel benchmarks, where Alberta has defined WHP generated electricity to be subject to the electricity rate (Government of Alberta, 2018), the proposed federal OBPS does not consider waste heat from a pipeline separately from the natural gas transmission pipeline benchmark of 0.419 tCO_2/MWh (Government of Canada, 2018c). As shown in Table 14, WHP generators on pipelines would receive offset credits with values of approximately $20/MWh (depending on how incremental fuel input would be accounted for), despite wind and solar not being eligible.

Table 14: Marginal cost (-offset value) incentive of electricity by technology per MWh for Canadian carbon pricing regimes

Technology	Emissions intensity (tCO_2/ MWh)	Simple tax	Simple tax	AB OBA	Federal OBPS, pipeline value	Federal OBPS, electricity value
Carbon Price ($/tonne)	-	20	50	50	50	50
Wind and solar	0	0	0	-18.50	0	0
WHP[1]	0	0	0	-18.50	-20.95	0
	0.035	0.70	1.75	-16.75	-19.40	0
Natural gas combined cycle	0.370	7.40	18.50	0	0	0
Coal	0.800	16.00	40.00	21.50	13.30[2]	13.30[2]

[1] WHP values calculated for both zero emissions and incremental emissions.
[2] Average annual price before mandatory coal phase out in 2030. Increases from $0/MWh in 2019 to $21.50/MWh in 2030

Where the Alberta OBA system creates the same gradient of emissions reductions incentive for all fuel and technology types, the federal system has a gradient unique to each fuel type. This will incentivize different generator types to reach the benchmark for their type but creates very little incentive to switch between fuel types despite emissions benefits. The exception under the proposed regulations would, however, be for WHP. While positive for WHP development, the Alberta policy creates a much more coherent policy to efficiently drive emission reductions using all zero-emission options.

Section 2.5 found that viable WHP required electricity purchase prices of \$70 to \$80 per MWh. With a carbon price of \$50, WHP can compete with market prices (before carbon pricing) of \$51.50 to \$61.50/MWh. The Alberta 10-year average price is on the lower end of that range. As this period contains several years of generation oversupply, low natural gas prices, no carbon price, and the investment analysis in Section 2.4 is believed to be conservative, there is good reason to believe that WHP can compete in the Alberta market with only the newly established carbon price of \$50/tCO_2. This is supported by the calculations of Doluweera *et al.* (2018), who estimates that with a \$50/tCO_2 carbon tax a new efficient natural gas combined cycle generator would have a 20-year levelized cost of \$73/MWh.

WHP is also likely to be a cost competitive source of new generation in BC and Saskatchewan. In BC, WHP is already cost-competitive based on the standing offer pricing from the previous section, but as the existing generation options are low emissions carbon pricing gives WHP little advantage. Saskatchewan, however, is still heavily dependent on coal and natural gas. Therefore, carbon pricing would make WHP competitive in that province.

3.3 Is natural gas pipeline WHP "green"?

The importance of a developer's WACC has been emphasized in previous sections. Here, I look at the role of lower debt interest rates more specifically, and implications for the eligibility of WHP projects for green bonds.

Green bonds are an area of climate finance intended to facilitate investment in "green" projects (Shishlov, Morel, & Cochran, 2016). Bond issuers identify "green" projects, which are sold to environmentally minded investors. For investors, they are in a sense an extension of recent trends toward green or sustainable equities, but for the fixed income portion of investment portfolios. Ostensibly, they facilitate green projects by providing debt financing to developers who have a harder time getting financing through traditional lending vehicles. For project developers, this would translate into a lower risk-weighted cost of debt than they could get through traditional lending options. However, there is considerable debate over the eligibility of various projects due to different definitions of "green" (Packer & Ehlers, 2017; Shishlov et al., 2016). This is particularly relevant for WHP, in particular for pipelines but also in other industries, as the source of waste heat is a fossil fuel. For investors whose goal is emissions reductions, I submit that there are two important criteria to determine the eligibility of "green" bonds for "brown" industries. The first is whether or not the lower interest rate drives additional projects, put differently, whether green bond facilitates the project to go forward. The second is whether WHP operations lead the "brown" operations to operate more or persist longer. In such a case, WHP environmental benefits must be weighed against the environmental costs of this increased operation.

As shown in Figure 3, lowering the debt interest rate by 2% increases the project NPV by over $2 million which can manifest in lower required electricity purchase prices. Decreasing the interest rate from 7% to 5%, for example, decreases the purchase price hurdle rate from $80/MWh to $70/MWh.

However, it is not clear that green bonds are actually significantly stimulating new green investments with lower interest rates. Shishlov *et al.* (2016) claim “green bonds have not directly stimulated green investments by lowering the cost of capital.” Further, they note what they call the green bond ‘coherence gap,’ in which they point out that green bonds cannot achieve equal risk-weighted returns to traditional bond markets (as they are marketed to investors) and also give developers lower risk-weighted costs of capital. Therefore, investors must be willing to accept lower returns for ethical environmental reasons, or they must believe that bond ratings agencies are undervaluing the risks associated non-green bonds. Others have found a difference, albeit a small one, in what investors are willing to pay for the same risk-weighted return with estimates of 0.18%, 0.20%, 0.02% (Packer & Ehlers, 2017; Preclaw & Bakshi, 2015; Zerbib, 2016). There is also some evidence this is increasing over time (Preclaw & Bakshi, 2015), and that the difference is larger for lower rated bonds (Packer & Ehlers, 2017; Zerbib, 2016). These same studies also find that the bond returns are equal after they are issued, evidence that initial valuations are the effect of a preference for green bonds rather than risk or market premiums.

A debt interest reduction of 0.20% leads to an increase in NPV of $0.2 million. While likely appreciated by a developer already investing, other policies are required to substantially drive increased WHP development. Therefore, green bond eligibility would provide only a small incentive for WHP development.

3.4 Electrical system integration

Electricity production by WHP is dependent on flow rates in natural gas pipelines, as for electricity to be produced the turbine must be operating to meet gas demands. Like wind and solar, there are system implications associated with the integration of power sources that are not dispatched based on electricity system needs alone, as system operators must ensure sufficient available generating capacity for peak electricity demand periods (Bistline, 2017).

However, both gas and electricity demand in Canada are winter peaking and temperature anti-correlated, suggesting that pipeline WHP-generated electricity could be relied upon to some degree during periods of peak seasonal electricity demand. Furthermore, the flow rates in gas pipelines have a different pattern of predictability to an intermittent source such as wind. Figure 9 shows the monthly load profile for the Alberta electric grid, compared to gas flow, solar radiation, and wind generation. Solar generates almost double the electricity in July as December and wind generation tends to have slightly higher winter generation but varies significantly from month to month. By contrast, increases in winter gas flow tends to match the winter electricity peak loads fairly closely, though in the summer are anti-correlated. Gas pipeline WHP would therefore provide a seasonal complement to solar installations, and also likely provide electricity generation more correlated to load than wind.

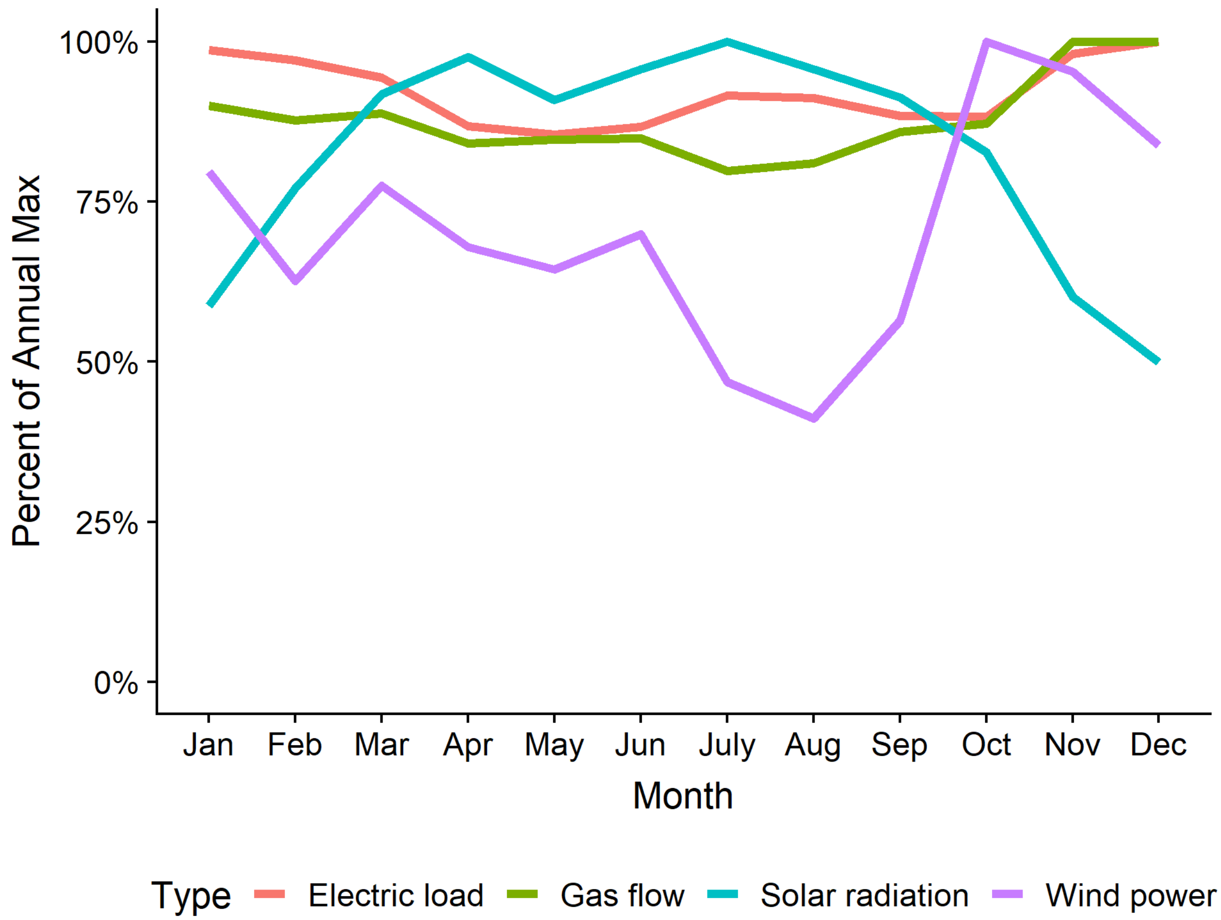


Figure 9: Monthly generation and load profiles. The electrical load and wind power profiles are from Alberta 2017 data (AESO, 2018b). Gas flow is the largest gas export point from Alberta, East Gate on NGTL (Government of Canada, 2018b). Solar radiation is for Calgary with tilt equal to latitude (NRCan, n.d.).

This generation profile will also have positive implications for WHP generation purchase price in energy markets. WHP generators with 100% capacity factors will, by definition, receive the annual weighted average wholesale electricity price shown in Table 12. However, WHP installations with capacity factors in the range of 60-80% could become viable by receiving a premium to this average price. As prices tend to increase with increased electricity load, this premium would arise from generating more electricity during the winter, during times of high gas demand. Pipeline companies should therefore explicitly determine how potential WHP station sites' historical running hours have correlated with provincial electricity prices. Where these installations would be linked to a fixed price PPA, higher power prices might be negotiated where justified.

As wind and solar penetrations increase, this price premium would become more pronounced in the absence of significant electricity storage and/or transmission interconnections to other power markets (Bistline, 2017). If WHP developers can capture these system benefits, the business case for WHP will likely improve as more wind and solar is installed.

3.5 Safety regulations

Power generators operate at high temperatures and pressures, and the careful design and operation of these systems is essential for safety. As such, many safety regulations and standards exist to ensure high standards are met. The American Society of Mechanical Engineers' Boiler & Pressure Vessel Code, adopted by law in most U.S. states and Canadian provinces, is one of the major codes addressing these needs (ASME, n.d.). Demonstrating its importance, it arose directly following a 1905 incident that killed 58 people and injured 117 others, leading to the publication of the first version in 1915. These codes are complemented by jurisdictional regulations stipulating numerous operating requirements, including (in most North American jurisdictions) continuous on-site supervision by an appropriately certified Power Engineer (Bohl, 2009).

Continuous on-site monitoring was cited by numerous sources as a significant barrier to financially viable WHP (Bohl, 2009; Elson et al., 2015; Hedman, 2008; Leslie et al., 2009; Neill and Gunter, 2007). In Alberta and BC, on-site supervision is required whenever the power plant is operating if the boiler is 20 kW or larger, and continuous on-site supervision is required whether or not the plant is operating if the boiler is 250 kW or larger (Bohl, 2009; Power Engineers Regulation, n.d.). As WHP typically occurs on a smaller scale than dedicated power generation facilities this becomes a significant operating expense, as demonstrated below.

This has been a major driver toward the ORC process over the traditional steam process on gas pipelines, as despite most regulations not initially distinguishing between the two, regulators have made exceptions or revisions to allow ORC plants to be remotely supervised (Bohl, 2009; Power Engineers Regulation, n.d.). ORC plants do have some safety advantages over steam plants as they operate at a lower temperature and pressure. They have also employed an intermediate liquid heating loop between the gas turbine exhaust and ORC process that reduces the potential for over pressurization in the turbine exhaust heat exchanger, failures in which could potentially cascade to the gas turbine and its fuel (Bohl, 2009). However, steam equipment is considerably more mature and cheaper than ORC technologies. Steam is also more efficient at the relevant temperatures, leading to greater electricity generation for the given heat source (Bohl, 2009). The ability to use steam without continuous on-site monitoring could therefore lead to more WHP installations through improved project economics.

To estimate the importance of steam system continuous monitoring to WHP installation financials, the model was adjusted to consider both steam and ORC technologies, each with two scenarios. Scenario inputs are shown in Table 15.

Table 15: Summary of steam and ORC scenario inputs

Technology	Capacity (MW)	Power Ratio	Equipment Cost ($USD/kW)	Operating Cost ($USD/MWh)
Steam – remote operation	10.5	10.5/23	1800	4.7
Steam – continuous on-site operation	10.5	10.5/23	1800	10.7
ORC – ideal	7.5	7.5/23	2097	4.7
ORC – nominal	5.5	5.5/23	2859	4.7

Using the sales brochure for a GE LM2500 turbine, a combined cycle plant using steam adds an additional 10.5 MW of electrical generation above the 23 MW of generation from the simple cycle alternative (GE Power, 2017). This is the same turbine used throughout this analysis when designating the nominal 5.5:23 ratio of electrical generation from an ORC set-up to compressor brakepower, and represents an almost doubling of electrical power from the same heat source (Leslie et al., 2009). Part of this improvement is due to the superior thermodynamic properties of steam compared to pentane at the operating temperatures, and part of the improvement is because steam is heated directly from the exhaust heat, rather than an intermediate thermal fluid loop (Bohl, 2009).

In addition, as the 5.5 MW ORC system rating is from an installed system that likely has contractual performance guarantees across a range of operating conditions, this likely designates a more conservative number relative to the steam system sales brochure which may report its electrical rating under ideal conditions. To support this, Leslie *et al.* (2009) report that the nominal 5.5 MW ORC system produces up to 7.5 MW of power under optimal ambient temperatures. A 7.5 MW ORC system was therefore included for comparison purposes, with the per unit capital equipment cost adjusted to reflect the same total capital cost of the 5.5 MW installation.

The additional operating costs from continuous on-site monitoring was estimated to be $500,000 a year. This allows for five Power Engineers at an average employee cost of $100,000 per year, including salary, benefits, and other expenses. This equates to a levelized additional operating cost of $6/MWh. The steam equipment cost is from Elson *et al.* (2015).

Model results in Figure 10 show that the assumed continuous on-site monitoring cost does not definitively make an ORC installation more attractive across the entire range of electricity purchase prices and cost of capital. The higher efficiency, lower capital costs and higher operating costs of steam systems do however make ORC systems more attractive at electricity prices closest to market rates, particularly when the investment is made with more equity and less debt, which is likely to be a more attractive investment arrangement for many companies.

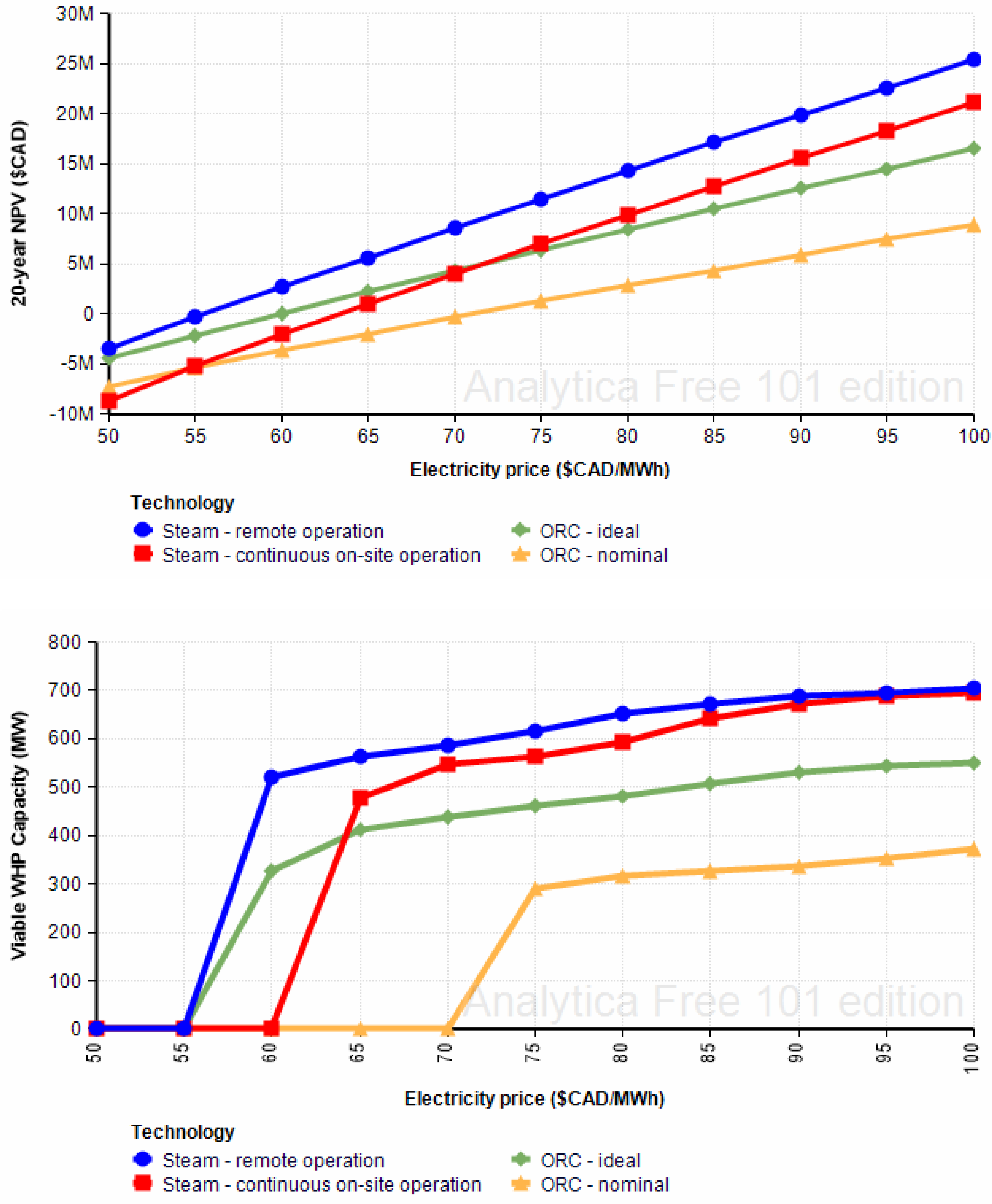


Figure 10: NPV and viable WHP capacity by technology with Incentivized case parameters

By contrast, natural gas compressor stations do not require continuous on-site monitoring. Gas compressor stations regularly operate at similar or higher temperatures and pressures than the potential steam cycles that would be installed at them (GE Power, 2017). With the innovations in control systems technologies, monitoring, and telecommunications over the last several decades, natural gas compressor stations are now largely operated from a centrally located remote location. Consideration for remote operation is evident in the oldest obtainable applicable codes and regulations, the *Onshore Pipeline Regulations* (1999) and *CSA Z662-99 Oil and Gas Pipeline Systems* (1999). These documents explicitly consider the need for telecommunications equipment and remote operation. It is unknown how much earlier than this a shift toward remote monitoring occurred, however from my professional experience I am aware of full time on-site housing built in the 1960s and 1970s for compressor station operators and their families, and am under the impression that automation and remote monitoring system implementation was well under way by 1999.

To determine whether power engineering regulations have changed significantly with the development of control systems technologies, monitoring, and telecommunications advances, I reviewed the developments in the *Alberta Safety Codes Act*'s *Power Engineers Regulation*, and its predecessors, in effect between 1975 and the present day (ABSA, 2018; Engineers' Regulations, n.d.; Power Engineers Regulation, n.d.).

As indicated above, on-site supervision is required during operation by an appropriately certified person if the boiler is 20 kW or larger. For steam systems, this requirement has essentially been unchanged since 1975. The first consideration of improved control system technologies, monitoring, and telecommunications advances are not apparent in the power engineering regulations until 2013, at which point newly defined "instrumentation alternatives" can "ensure the safe operation of pressure equipment without the level of supervision by a Power Engineer or other competent operator that would otherwise be required" (Power Engineers Regulation, n.d.). According to the Alberta Boilers Safety Association, "[r]educed supervision was permitted in recognition that an equal or greater degree of safety is expected and has been made possible as a result of technological changes that have taken place since the original requirements were established decades ago" (ABSA, 2018). While a significant step forward, it is only applicable to ORC and other atypical generation types, and specifically excludes steam plants from reduced supervision eligibility. Steam systems are therefore still subject to the same on-site supervision requirement for boilers 20 kW or larger as present since at least 1975.

Safety regulators should consider whether the reduced on-site supervision allowances should also be extended to lower risk steam systems. This would significantly improve the economics of small thermal generators and facilitate the installation of WHP equipment in a variety of industries. I have not, and do not claim to have, completed the engineering or risk analysis necessary to set revised supervision thresholds, nor to ensure the governance of proper engineering and administrative controls are in place to provide for safe operation. However, I do believe that given the 45-year or longer period since the steam supervision threshold was implemented, major technological changes over that time period, and the identified regulation discrepancies for gas compressor stations at similar temperatures and pressures, that there is a strong argument such analysis would find the current steam supervision regulation could be amended to provide for greater remote supervision with lower operational costs without compromising safety. Due consideration to required engineering and administrative protections is necessary to ensure the proper safeguards are implemented.

3.6 Regulation of WHP on regulated transmission lines

Canadian natural gas transmission companies are considered natural monopolies. As such, they are generally[6] compensated through a cost-of-service rate structure, where the transportation toll paid reflects a fixed rate of return on approved transportation expenditures. The expenditures and rate of return are initially negotiated between shippers and the transmission company, with the negotiated result and any contested matters ultimately approved (or rejected) by the applicable regulator. Since WHP is not useful in the act of flowing gas on the pipeline, it is important to shippers of natural gas that any incremental costs (from WHP construction, maintenance, extra fuel, etc.) associated with WHP are not included in the cost-of-service calculation and that WHP does not impact the reliability of the gas transmission system (Brennan, 2011).

In addition, since transmission companies are directly compensated for their costs, fuel gas to run the turbines is given "in-kind" by the shippers to the pipeline companies to prevent a fuel mark up from the transmission company's rate of return. This has led to disputes over how to distribute profits from waste heat use. The shippers argue they should recover as much of the

[6] Unlike the U.S., Canadian transmission lines operate under cost-of-service regulations. The possible exception is the TransCanada Mainline, which underwent rapidly declining throughputs starting in the late 2000s. Long-term tolls were lowered to below levels required for capital investment recovery, while TransCanada was given discretion on short-term toll pricing, a higher fixed return on equity, and other efficiency incentives to make up for increased risk (NEB, 2013). Whether this continues to constitute a cost-of-service structure is beyond the scope of this thesis.

fuel gas costs as possible, while the transmission companies argue they should keep the profits to provide more incentives to be energy and economically efficient.

3.6.1 Who should profit from greater efficiency?

There is little controversy over whether the waste heat should be able to be used productively, and the regulator affirmed that “[t]he use of such waste heat in value-added initiatives is appropriate and encouraged by the Board” (NEB, 2004). There seems to be three questions at issue:

1. Were the shippers properly compensated for all incremental costs of the waste heat operation?
2. Should the profits beyond incremental cost recovery from waste heat use accumulate to the transmission company or to shippers?
3. If shippers should receive some or all of the above profits, how should the fair market value of the waste heat be determined?

While much of the negotiations between shippers and transmission companies on the profit distribution on waste heat uses is not public, some of the disputes have been detailed in regulatory proceedings as reviewed here.

The first reference to waste heat profit disputes is from a 1981 ruling on the ducting of waste heat to heat a greenhouse (NEB, 2004). The transmission company initially applied to include the costs of the waste heat ducting within the cost-of-service calculation, however the regulator rejected these expenses as outside the scope of the regulated pipeline. As such, the transmission company determined for future waste heat agreements that as the additional costs of waste heat installations cannot be claimed as eligible expenses, then the waste heat profits should not be considered as part of the regulated cost-of-service, either. The waste heat could therefore be sold to third parties so long as any incremental costs of waste heat recovery are not charged to the cost-of-service calculation.

Agreements were then signed in the 1990s for multiple waste heat facilities where natural gas combined cycle power plants were co-located with compressor stations to enhance the power plants' output. These agreements stipulated that the power producer must compensate the transmission company for any incremental costs, including increased fuel gas use, maintenance, land use, operational planning, or other costs as determined reasonable[7] (TransCanada Pipelines, 2004). They would also pay a nominal fee of $100,000 per ~30 MW gas turbine, starting in 1997 and indexed to inflation (TransCanada Pipelines, 2004).

However, between the original agreements and the hearings in the 2000s, the power producer was bought by a non-regulated corporate affiliate of the transmission company, leading to conflict of interest concerns. If the transmission company inadequately recovers all incremental costs from their affiliated power producer they essentially profit twice, by earning more money than deserved from their regulated asset and a larger profit margin from the power producer affiliate. This concern was amplified by the fact that new agreements with their affiliate were

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[7] Interestingly, it also includes a specific clause that the power producer must compensate the transmission company for "all documented reasonable costs incurred [by the transmission company's] participation in any judicial or regulatory proceeding arising out of or in connection with the [WHP] Facility"

signed after the capacity factor on the pipelines started to decrease, though the valuation of the waste heat did not substantially change. These disagreements are evidenced by the excerpts below.

> **Preamble:**
>
> One can argue that the waste heat produced by the five compressor units is a commodity that has value, and that [the power affiliate] is generating profits for its shareholders through the use of the waste heat received from [the transmission company]'s compressors. Following this train of thought, one could argue that [the transmission company]'s shippers should therefore receive compensation for the waste heat transferred to [the power affiliate].
>
> **Request:**
>
> Does [the transmission company] agree with the proposition that the [shippers] should receive compensation from [the power affiliate] for the waste heat transferred to [the power affiliate] because the waste heat produced by the five compressor units of the [transmission line] is a valuable commodity being used by [the power affiliate] to generate profits for its shareholders? If not, why not?
>
> **[Transmission company] Response:**
>
> No. The agreements attached to the response to IGUA 2 provided access to the exhaust gases which are otherwise being vented to atmosphere or "thrown away." Under the agreements there is no guarantee of the availability of the exhaust gases at specific times, if at all, and there is no warranty as to the attributes of the exhaust gas including the

> temperature, water content, pressure or flow uniformity thereof. (TransCanada Pipelines, 2004)

In the view of the shippers, the benefits of the waste heat should accumulate to the shippers, not to the transmission company. In the view of the transmission company, they had no obligation to compensate shippers beyond ensuring that incremental costs were recovered. The shippers also advanced an argument that they should not only receive the waste heat benefits, but that the value of the waste heat is much higher than the valuation in the agreement.

> Where a purchaser's avoided costs substantially exceed a seller's incremental costs of providing a particular product or service, a prudent seller, acting at arm's length from a prudent buyer, will not accept a price substantially below the purchaser's avoided costs. Common sense supports that conclusion. […]
>
> Where there is a wide range between the purchaser's avoided costs and the seller's incremental costs of providing the product or service, the fair market value of the product or service will exceed the seller's incremental costs and, at the very least, tend towards the mid-point of the range. Fair market value in such circumstances substantially exceeds the seller's incremental costs. (Industrial Gas Users Association, 2005)

The difference between the transmission company's incremental cost and the power producer's avoided cost is significant, as the shipper claimed the avoided cost is "40 to 50 times the contract price paid" (Coral Energy Canada Inc. & Cogenerators Alliance, 2005). Similar results were estimated by my own calculations for the heat value of natural gas, summarized in Appendix E .

In the decision, the regulator determined:

> The Board is of the view that [the transmission company] should seek the higher of incremental costs or fair market value in all non-tariff transactions from parties wishing to contract with it. Further, fair market value is whatever a competitive market is willing to pay. The Board sees no evidence that there were other parties interested in waste heat from Mainline compressors at the time the Potter Agreement was signed. The Board also finds no persuasive evidence that at least incremental costs incurred by [the transmission company] are not being recovered through the original waste heat agreements, or that at the time they were signed, the waste heat agreements were unreasonable. (NEB, 2004)

The regulator, therefore, in determining that the transmission company "should seek the higher of incremental costs or fair market value" implicitly determines that the shippers should receive compensation above the incremental costs (where they exist) for use of the waste heat, though they do not determine that fair market value is higher than the incremental costs in this case. Surprisingly, their written decision does not expressly consider why shippers should be compensated for higher heat valuations, and how that influences the incentives for the transmission company to implement waste heat projects. If the rate base is credited with the entirety of the higher waste heat valuation, the transmission company actually loses money, as their claimable expenditures are decreased which reduces the amount of money they receive based on their rate of return. Under this framework, a transmission company trying to maximize their profit actually has a disincentive to pursue WHP agreements. In a sense, the regulator's decision was not favorable for either party. The shipper wanted greater benefits in this specific case, which they did not receive when the regulator did not determine that the market value was higher than the incremental costs. The transmission company (or their parent company) wanted to keep the benefits of WHP agreements, whether or not those accrued through the transmission or power affiliate.

After this decision, no further waste heat installations were installed on this pipeline system, though this would also have been significantly influenced by the decline in capacity factors in the years immediately following this regulatory hearing.

Evidence of more recent WHP compensation arrangements for two other pipeline systems, owned by different companies, indicate that a compromise seems to have been reached. For these systems, shippers are compensated for all incremental costs associated with WHP installations, and payments for the waste heat itself is split 50:50 between the transmission company and the shippers (Brennan, 2011). To avoid conflicts of interest, these installations have also been developed by third party companies owning, constructing and operating the waste heat recovery system, rather than an affiliate of the pipeline company (Hedman, 2009). While this decreases the potential for conflicts of interest, it reduces investment incentives by creating more mouths to feed.

Regulators must therefore ask: what provides the greatest public benefit? On the one hand, maximizing profit return to the transmission cost-of-service calculation has the benefit of reducing the cost of delivered energy to all public and private gas users. But the more WHP profit is returned to shippers, the less incentive there is for WHP investment decision makers, who bear the investment risk. This is further complicated because GHG emission reductions have traditionally not been valued or were undervalued in decision-making.

3.6.2 Developer matters

The previous subsection demonstrates how the regulator's ruling that waste heat should be valued at the higher of the incremental cost or the market value has disincentivized WHP installations. This has occurred by both increasing the cost of the waste heat and leading to third party developers over pipeline affiliate developers, which requires more profit splitting. Third party developers also likely have higher costs of capital. The third parties have tended to be smaller companies with less diversified portfolios and less stable revenue streams than the major pipeline companies.

To estimate the total change in NPV for a WHP installation, I conservatively assess the combined effects on NPV of lowering the heat costs from the \$6.6/MWh to \$1.5/MWh (the estimated inflation-adjusted cost used in the 1990s agreements) and a 1% reduction in the debt interest rate. As shown in Figure 11, the increase in NPV from these two changes is \$2.3 million, enough to offset a \$10/MWh decrease in the electricity purchase price.

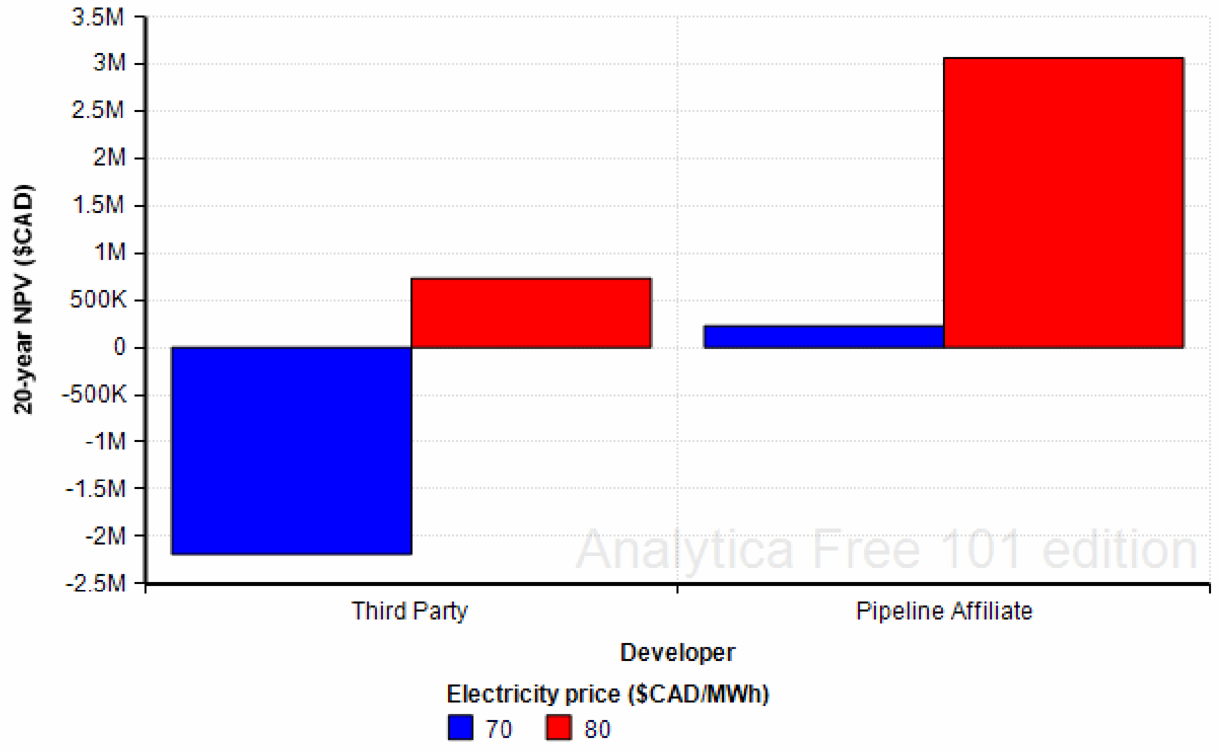

Figure 11: Effect of developer type on installation NPV

As stated in Section 2.5, the model significantly underestimates the benefits from CCA tax write-offs. Better consideration of this benefit would create significant additional benefits to corporations with annual incomes exceeding the capital cost of the WHP installation. This may further benefit the pipeline company or affiliate, but may vary between companies and depends on corporate structure.

The ruling that the transmission company should attempt to recover a higher waste heat valuation, to be shared at least in part with the shippers, has created a disincentive for additional installations.

Chapter 4: Conclusion

In this thesis I have conducted an integrated assessment that attempts to answer two questions:

- To what degree are the barriers to WHP adoption in Canada based on economic, regulatory, institutional, and/or policy factors?
- What policy changes are justified under the circumstances?

In Chapter 2, I calculate that the technical potential for WHP on natural gas transmission lines is approximately 1.1 GW. I also demonstrate that with recent installation costs, an electricity purchase price of $70 to $80/MWh is required for investment in WHP installations on pipeline compressor stations. Capacity factors of at least 80% are required in these cases, and higher electricity prices or other incentives would be required for lower capacity units. Absent the consideration of avoided carbon emissions benefits (as conducted in Chapter 3), the technology is not economically viable at current costs.

Using volumetric throughput data to estimate the capacity factors of the gas turbines along the transmission line systems, I estimate that Alberta has the highest viable WHP capacity, of 228 MW at $80/MWh and 6.1% WACC. Most importantly, Alberta is the only province with a viable capacity significantly higher than the WHP installed capacity, leaving significant opportunity for future investments. Despite having the largest technical potential, Ontario currently has very little economically viable potential due to low capacity factors over the past decade stemming from changing gas supply dynamics. Electricity capacity oversupply in the province substantially compounds the issue. In addition, BC and Saskatchewan are close to saturating their economic WHP potential given existing installations.

The method used to estimate gas turbine capacity factors has relatively large error margins, but achieves a significant improvement over previous publications. As these pipelines are regulated natural monopolies, I argue that such operational data should be made readily available for the benefit of both researchers and industry participants. The estimated capacity factors highlight that the emergence of new gas supply basins, as occurred after the proliferation of horizontally drilled hydraulic fracturing, can substantially impact the capacity factors of pre-existing pipelines. Future climate policy and energy transitions may also lead to changes in the amount and patterns of gas use.

In Chapter 3, I evaluate the institutional, regulatory, and policy related factors influencing WHP installations in Canada. I find that in many provinces, the incentives available for zero-emission WHP electricity generation are unavailable or are not coherent with incentives for other types of zero-emission electricity generation, such as wind, solar, geothermal, and/or hydro.

A carbon pricing mechanism at \$50 per tonne CO_2 substantially equalizes the economics of WHP compared to new natural gas combined cycle generation. Given currently legislated carbon price increases to at least \$50 per tonne CO_2 by 2022, this significantly increases the prospects for WHP in provinces that are still heavily dependent on natural gas, like Alberta and Saskatchewan. However, the proposed federal OBPS regulations for the electricity sector effectively undermine the effect of this carbon price, by setting an output rebate threshold by technology, rather than for all electricity generators as was done in Alberta. It is essential for Alberta to keep their existing threshold system, and it is important that other provinces adopt systems that provide consistent incentives between fuel types as well.

The seasonal correlations of gas and electricity demand suggest gas transmission line WHP can provide electricity at times of peak demand. Considering the seasonal anti-correlation of solar supply and electricity demand, WHP could further complement the generation of solar for a lower total system cost of a low emission electricity grid.

The installed systems on natural gas compressor stations use an organic fluid, such as pentane or butane, to power their electricity thermodynamic cycle. This is in no small part due to current safety regulations that require 24/7 on-site monitoring by an appropriately certified Power Engineer to install cheaper steam powered systems, an expensive proposition for these smaller systems. I calculate that permitting steam generation without continuous on-site monitoring would substantially improve the economics of these small WHP systems, decreasing the required electricity purchase price by $5 to $20/MWh. I also demonstrate that the requirements for on-site continuous monitoring have not significantly changed since 1975, despite the development of remote and/or autonomous monitoring equipment over the last several decades. By contrast, natural gas transmission compressor stations are now remotely and largely autonomously operated, despite previously having multiple permanent on-site operators. This is despite gas compressor stations and comparable power stations operating at similar temperatures and pressures. While this thesis has not considered the engineering and governance requirements for safely permitting remote monitoring of steam systems, I argue that a detailed analysis is likely to conclude that continuous on-site monitoring requirements could be safely loosened in some, though not all, cases. These requirements are therefore considered an interesting avenue of future research and engineering analysis.

WHP installations are capital intensive projects, and as such the developer's cost of capital is a significant determinant of profitability. Lowering the cost of capital could happen in two ways. One is through the provision of fixed rate long-term power purchase agreements. This will lower the electricity price fluctuation risk inherent in energy markets, and would be particularly important in Alberta due to the market structure. This risk reduction would lead directly to reduced return on equity thresholds and debt interest rates. The second primary way to reduce the cost of capital is by facilitating investments by the pipeline transmission companies (or their affiliates) rather than third parties, as transmission companies generally have access to low cost financing. A decision by regulators that the benefits accruing from the waste heat should substantially accrue to the transmission company and developer, as opposed to the shippers, would facilitate this arrangement. Green bonds can also lower a developer's cost of capital, but based on current analyses of green bond interest rates compared to traditional financing options they are unlikely to have a significant impact.

Returning to the first question driving this research: to what degree are the barriers to WHP adoption in Canada based on economic, regulatory, institutional, and/or policy factors? I conclude that it is a mix of all of these factors. The economics of WHP on natural gas transmission lines is currently slightly too expensive to justify investment without supporting policies, such as consideration of avoided emissions. The institutional frameworks of a natural gas transmission company as a regulated natural monopoly currently create disincentives and constraints on WHP development. And existing regulations for continuous on-site monitoring of steam systems potentially make WHP installations more expensive than needed.

Plans for a new WHP project using the next generation of WHP technology was announced toward the end of this research (Emissions Reduction Alberta, 2019; TransCanada Pipelines, 2019b). This provides positive indications both that companies are beginning to again take an interest in this technology, and that new policy changes such carbon pricing are having their desired impact as predicted by this research.

4.1 Policy recommendations

Despite the good news of the newly announced WHP project, there remain multiple policy recommendations that are appropriate given the above analysis.

- **The federal OBPS should be amended to provide a consistent carbon pricing signal to all fuel sources.** Providing different pricing signals to coal than natural gas generators, and no pricing signal to zero-emission technologies, substantially undermines the intent of the carbon price. Alberta's policy provides an effective model, and it is essential that the Alberta policy remains as currently designed.
- **Provinces with integrated utilities rather than energy markets should consider using reverse auctions rather than standing offer programs.** These provinces should continue to recognize the avoided emissions value of WHP alongside renewables like wind, solar, and hydro. Reverse auctions have been demonstrated to procure lower cost

electricity than standing offers, and better react to fast changing generation prices. Further, these auctions should explicitly consider electricity value, along with the price, by assessing the technologies ability to produce power at times of higher demand.

- **The Saskatchewan procurement cap on WHP project size should be raised from 5 MW to 10-15 MW.** The 5 MW cap on SaskPower's standing offer for WHP electricity is a binding constraint which may substantially limit installations options.
- **Gas transmission regulators should clarify that WHP profits should substantially benefit the transmission company and WHP developer, rather than the shippers.** While controversial, this change will greatly increase development incentives for the decision-makers.
- **Safety regulators should assess whether requirements for continuous on-site monitoring of steam systems by a certified power engineer continues to be necessary in all cases.** The capacity threshold over which continuous on-site monitoring is required has not changed since at least 1975. Given significant advances in remote and autonomous monitoring technologies, this requirement should be reassessed to determine if any incremental safety benefits justify the monitoring costs which substantial deter investment.

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Appendices

Appendix A List of compressor units

Table 16: List of transmission compressor units

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	Mainline	Prairies	2 (Burstall)	Saskatchewan	1002C1	Turbine	15.2	1969		(National Energy Board, 2015; TransCanada Pipelines, n.d., 2011, 2012)
TransCanada	Mainline	Prairies	2 (Burstall)	Saskatchewan	1002E1	Turbine	21.6	1973	2015	
TransCanada	Mainline	Prairies	2 (Burstall)	Saskatchewan	1002F1	Turbine	21.6	1981		
TransCanada	Mainline	Prairies	2 (Burstall)	Saskatchewan	1002G1	Turbine	26.1	1992		
TransCanada	Mainline	Prairies	2 (Burstall)	Saskatchewan	1002H1	Turbine	30	1998		
TransCanada	Mainline	Prairies	2 (Burstall)	Saskatchewan	1002J1	Turbine	30	1999		
TransCanada	Mainline	Prairies	5 (Cabri)	Saskatchewan	1005B1	Turbine	10.4	1968		
TransCanada	Mainline	Prairies	5 (Cabri)	Saskatchewan	1005C1	Turbine	10.4	1970		
TransCanada	Mainline	Prairies	5 (Cabri)	Saskatchewan	1005D1	Turbine	20	1981		
TransCanada	Mainline	Prairies	5 (Cabri)	Saskatchewan	1005E1	Turbine	28.3	1997		
TransCanada	Mainline	Prairies	9 (Herbert)	Saskatchewan	1009B1	Turbine	10.4	1967	2015	
TransCanada	Mainline	Prairies	9 (Herbert)	Saskatchewan	1009C1	Turbine	10.4	1969		
TransCanada	Mainline	Prairies	9 (Herbert)	Saskatchewan	1009D1	Turbine	20	1981		
TransCanada	Mainline	Prairies	9 (Herbert)	Saskatchewan	1009E1	Electric	30.6	1997		
TransCanada	Mainline	Prairies	13 (Caron)	Saskatchewan	1013C1	Turbine	10.4	1970		
TransCanada	Mainline	Prairies	13 (Caron)	Saskatchewan	1013D1	Turbine	22.8	1991		
TransCanada	Mainline	Prairies	13 (Caron)	Saskatchewan	1013E1	Turbine	28.3	1997		
TransCanada	Mainline	Prairies	13 (Caron)	Saskatchewan	1013F1	Turbine	30	1998		
TransCanada	Mainline	Prairies	17 (Regina)	Saskatchewan	1017B1	Turbine	10.4	1968		
TransCanada	Mainline	Prairies	17 (Regina)	Saskatchewan	1017C1	Turbine	10.4	1970		
TransCanada	Mainline	Prairies	17 (Regina)	Saskatchewan	1017D1	Turbine	21.6	1981		
TransCanada	Mainline	Prairies	17 (Regina)	Saskatchewan	1017E1	Electric	30.6	1997		
TransCanada	Mainline	Prairies	21 (Grenfell)	Saskatchewan	1021B1	Turbine	10.4	1967		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	Mainline	Prairies	21 (Grenfell)	Saskatchewan	1021C1	Turbine	10.4	1969	2012	
TransCanada	Mainline	Prairies	21 (Grenfell)	Saskatchewan	1021D1	Turbine	26.1	1992		
TransCanada	Mainline	Prairies	21 (Grenfell)	Saskatchewan	1021E1	Turbine	28.3	1997		
TransCanada	Mainline	Prairies	25 (Moosomin)	Saskatchewan	2025B1	Turbine	10.4	1968		
TransCanada	Mainline	Prairies	25 (Moosomin)	Saskatchewan	2025C1	Turbine	10.4	1970		
TransCanada	Mainline	Prairies	25 (Moosomin)	Saskatchewan	2025D1	Turbine	26.1	1992		
TransCanada	Mainline	Prairies	30 (Rapid City)	Manitoba	2030B1	Turbine	10.4	1967		
TransCanada	Mainline	Prairies	30 (Rapid City)	Manitoba	2030C1	Turbine	10.4	1970		
TransCanada	Mainline	Prairies	30 (Rapid City)	Manitoba	2030D1	Turbine	21.6	1981		
TransCanada	Mainline	Prairies	30 (Rapid City)	Manitoba	2030E1	Turbine	28.3	1999		
TransCanada	Mainline	Prairies	34 (Portage La Prairie)	Manitoba	2034B1	Turbine	10.8	1968		
TransCanada	Mainline	Prairies	34 (Portage La Prairie)	Manitoba	2034C1	Turbine	10.4	1970		
TransCanada	Mainline	Prairies	34 (Portage La Prairie)	Manitoba	2034D1	Turbine	26.1	1992		
TransCanada	Mainline	Prairies/ PtEN	41 (Ile des Chenes)	Manitoba	2041B1	Turbine	15.2	1966		
TransCanada	Mainline	Prairies/ PtEN	41 (Ile des Chenes)	Manitoba	2041C1	Turbine	15.2	1967		
TransCanada	Mainline	Prairies/ PtEN	41 (Ile des Chenes)	Manitoba	2041D1	Turbine	11.5	1970		
TransCanada	Mainline	Prairies/ PtEN	41 (Ile des Chenes)	Manitoba	2041E1	Turbine	26.1	1991		
TransCanada	Mainline	Prairies/ PtEN	41 (Ile des Chenes)	Manitoba	2041F1	Electric	30.6	1997		
TransCanada	Mainline	Prairies/ PtEN	41 (Ile des Chenes)	Manitoba	2041G1	Electric	30.6	1997		
TransCanada	Mainline	PtEN	43 (Spruce)	Manitoba	2043A1	Turbine	15.2	1964		
TransCanada	Mainline	PtEN	43 (Spruce)	Manitoba	2043B1	Turbine	10.5	1992		
TransCanada	Mainline	PtEN	43 (Spruce)	Manitoba	2043C1	Turbine	28.3	1998	2011	

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	Mainline	PtEN	45 (Falcon Lake)	Manitoba	2045B1	Turbine	22.8	1990		
TransCanada	Mainline	PtEN	49 (Kenora)	Ontario	2049B1	Turbine	21.6	1982		
TransCanada	Mainline	PtEN	49 (Kenora)	Ontario	2049C1	Turbine	28.3	1998		
TransCanada	Mainline	PtEN	52 (Vermilion Bay)	Ontario	2052A1	Turbine	15.2	1964		
TransCanada	Mainline	PtEN	52 (Vermilion Bay)	Ontario	2052B1	Turbine	10.5	1992	2012	
TransCanada	Mainline	PtEN	52 (Vermilion Bay)	Ontario	2052C1	Electric	30.6	1997		
TransCanada	Mainline	PtEN	55 (Dryden)	Ontario	3055B1	Turbine	14.1	1992	2012	
TransCanada	Mainline	PtEN	55 (Dryden)	Ontario	3055C1	Turbine	28.3	1994		
TransCanada	Mainline	PtEN	58 (Ignace)	Ontario	3058B1	Turbine	21.6	1982		
TransCanada	Mainline	PtEN	58 (Ignace)	Ontario	3058C1	Turbine	30	1999		
TransCanada	Mainline	PtEN	60 (Martin)	Ontario	3060A1	Turbine	15.2	1964	2012	
TransCanada	Mainline	PtEN	60 (Martin)	Ontario	3060B1	Turbine	10.5	1992		
TransCanada	Mainline	PtEN	60 (Martin)	Ontario	3060C1	Turbine	28.3	1997		
TransCanada	Mainline	PtEN	62 (Upsala)	Ontario	3062B1	Turbine	10.5	1995		
TransCanada	Mainline	PtEN	62 (Upsala)	Ontario	3062C1	Turbine	28.3	1995		
TransCanada	Mainline	PtEN	62 (Upsala)	Ontario	3062D1	Turbine	28.3	1998		
TransCanada	Mainline	PtEN	69 (Eaglehead)	Ontario	3069A1	Turbine	20	1982		
TransCanada	Mainline	PtEN	69 (Eaglehead)	Ontario	3069B1	Turbine	22.8	1994		
TransCanada	Mainline	PtEN	75 (Nipigon)	Ontario	3075B1	Turbine	26.1	1990		
TransCanada	Mainline	PtEN	75 (Nipigon)	Ontario	3075C1	Turbine	28.3	1997		
TransCanada	Mainline	PtEN	77 (Jellicoe)	Ontario	3077A1	Turbine	13.6	1964		
TransCanada	Mainline	PtEN	77 (Jellicoe)	Ontario	3077B1	Turbine	10.5	1992		
TransCanada	Mainline	PtEN	77 (Jellicoe)	Ontario	3077C1	Turbine	28.3	1995		
TransCanada	Mainline	PtEN	80 (Geraldton)	Ontario	3080B1	Turbine	20	1982		
TransCanada	Mainline	PtEN	80 (Geraldton)	Ontario	3080C1	Turbine	30	1998		
TransCanada	Mainline	PtEN	84 (Klotz Lake)	Ontario	3084A1	Turbine	15.2	1964		
TransCanada	Mainline	PtEN	84 (Klotz Lake)	Ontario	4086A1	Turbine	10.5	1992	2012	

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	Mainline	PtEN	86 (Hearst)	Ontario	4086B1	Turbine	22.8	1990		
TransCanada	Mainline	PtEN	88 (Calstock)	Ontario	4088A1	Turbine	15.2	1964		
TransCanada	Mainline	PtEN	88 (Calstock)	Ontario	4088B1	Turbine	14.2	1992		
TransCanada	Mainline	PtEN	88 (Calstock)	Ontario	4088C1	Turbine	28.3	1997		
TransCanada	Mainline	PtEN	92 (Mattice)	Ontario	4092B1	Turbine	15.2	1973	2012	
TransCanada	Mainline	PtEN	92 (Mattice)	Ontario	4092C1	Turbine	28.3	1996		
TransCanada	Mainline	PtEN	95 (Kapuskasing)	Ontario	4095B1	Turbine	24.9	1969		
TransCanada	Mainline	PtEN	95 (Kapuskasing)	Ontario	4095C1	Turbine	28.3	1998		
TransCanada	Mainline	PtEN	99 (Smooth Rock Falls)	Ontario	4099B1	Turbine	13.6	1973		
TransCanada	Mainline	PtEN	99 (Smooth Rock Falls)	Ontario	4099C1	Turbine	28.3	1994		
TransCanada	Mainline	PtEN	102 (Tunis)	Ontario	4102A1	Turbine	15.2	1992	2015	
TransCanada	Mainline	PtEN	102 (Tunis)	Ontario	4102B1	Turbine	10.5	1992		
TransCanada	Mainline	PtEN	102 (Tunis)	Ontario	4102C1	Turbine	28.3	1997		
TransCanada	Mainline	PtEN	105 (Ramore)	Ontario	4105D1	Turbine	28.3	1995		
TransCanada	Mainline	PtEN	107 (Tarzwell)	Ontario	4107B1	Turbine	26.1	1990		
TransCanada	Mainline	PtEN	107 (Tarzwell)	Ontario	4107C1	Turbine	30	1998		
TransCanada	Mainline	PtEN	110 (Haileybury)	Ontario	4110B1	Turbine	15.2	1972		
TransCanada	Mainline	PtEN	110 (Haileybury)	Ontario	4110C1	Turbine	28.3	1996		
TransCanada	Mainline	PtEN	112 (Marten River)	Ontario	4112B1	Turbine	26.1	1990		
TransCanada	Mainline	PtEN	112 (Marten River)	Ontario	4112C1	Turbine	30	1999		
TransCanada	Mainline	PtEN/ ETriNE	116 (North Bay)	Ontario	4116C1	Turbine	26.1	1991		
TransCanada	Mainline	PtEN/ ETriNE	116 (North Bay)	Ontario	9006	Turbine	10.5	1995		
TransCanada	Mainline	None	119 (Sundridge)	Ontario	5119B1	Turbine	28.3	1995		
TransCanada	Mainline	None	123 (Bracebridge)	Ontario	5123B1	Turbine	10.6	1973		
TransCanada	Mainline	None	123 (Bracebridge)	Ontario	5123C1	Electric	30.6	1997		
TransCanada	Mainline	None	127 (Barrie)	Ontario	5127B1	Turbine	28.3	1994		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	Mainline	Maple	130 (Maple)	Ontario	5130A1	Recip.	1.1	1959	2015	
TransCanada	Mainline	Maple	130 (Maple)	Ontario	5130A2	Recip.	1.1	1959	2015	
TransCanada	Mainline	Maple	130 (Maple)	Ontario	5130A3	Recip.	1.1	1959	2015	
TransCanada	Mainline	Maple	130 (Maple)	Ontario	5130A4	Recip.	2.5	1967	2015	
TransCanada	Mainline	Maple	130 (Maple)	Ontario	9004	Turbine	6.3	1992		
TransCanada	Mainline	Maple	130 (Maple)	Ontario	5130B1	Turbine	11.2	2013		
TransCanada	Mainline	Maple	130 (Maple)	Ontario	5130B2	Turbine	11.2	2013		
TransCanada	Mainline	Maple	130 (Maple)	Ontario	5130B3	Turbine	11.9	2016		
TransCanada	Mainline	None	134 (Bowmanville)	Ontario	5134A1	Electric	2.2	1965		
TransCanada	Mainline	None	134 (Bowmanville)	Ontario	5134A2	Electric	2.2	1968		
TransCanada	Mainline	None	134 (Bowmanville)	Ontario	5134B3	Electric	7	2007		
TransCanada	Mainline	None	136 (Cobourg)	Ontario	5136A1	Electric	2.2	1963		
TransCanada	Mainline	None	136 (Cobourg)	Ontario	5136A2	Electric	2.2	1963		
TransCanada	Mainline	None	136 (Cobourg)	Ontario	5136B1	Electric	2.2	1968		
TransCanada	Mainline	None	139 (Belleville)	Ontario	5139A1	Electric	2.2	1965		
TransCanada	Mainline	None	139 (Belleville)	Ontario	5139A2	Electric	2.2	1968		
TransCanada	Mainline	None	142 (Kingston)	Ontario	51042A1	Electric	2.2	1964		
TransCanada	Mainline	None	142 (Kingston)	Ontario	51042A2	Electric	2.2	1964		
TransCanada	Mainline	None	142 (Kingston)	Ontario	5142B1	Electric	2.2	1972		
TransCanada	Mainline	None	144 (Brockville)	Ontario	5144A1	Electric	1.1	1967		
TransCanada	Mainline	None	144 (Brockville)	Ontario	5144A2	Electric	1.1	1967		
TransCanada	Mainline	None	144 (Brockville)	Ontario	5144B1	Electric	2.2	1968		
TransCanada	Mainline	ETriE	147 (Cornwall)	Ontario	5147B1	Turbine	4.1	1989		
TransCanada	Mainline	ETriE	147 (Cornwall)	Ontario	5147B2	Turbine	4.1	1989		
TransCanada	Mainline	ETriE	147 (Cornwall)	Ontario	5147C1	Turbine	4.3	1993		
TransCanada	Mainline	ETriE	148 (Les Cedres)	Quebec	5148A1	Turbine	3.2	1984		
TransCanada	Mainline	ETriE	148 (Les Cedres)	Quebec	5148B1	Turbine	3.2	1984		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	Mainline	ETriE	148 (Les Cedres)	Quebec	5148C1	Turbine	6.6	1998		
TransCanada	Mainline	ETriE	148 (Les Cedres)	Quebec	5148D1	Turbine	6.6	1998		
TransCanada	Mainline	None	209 (Ancaster)	Ontario	5209A1	Turbine	3	1970	2015	
TransCanada	Mainline	None	209 (Ancaster)	Ontario	5209A2	Turbine	3	1981	2015	
TransCanada	Mainline	None	209 (Ancaster)	Ontario	5209B1	Turbine	3.2	1988	2015	
TransCanada	Mainline	None	211 (Lincoln)	Ontario	5211B1	Turbine	11.2	1993		
TransCanada	Mainline	None	211 (Lincoln)	Ontario	5211C1	Turbine	11.2	1997		
TransCanada	Mainline	None	802 (Candiac)	Quebec	5802B1	Recip.	1.6	1988		
TransCanada	Mainline	None	802 (Candiac)	Quebec	5802B2	Recip.	1.6	1988		
TransCanada	Mainline	ETriNE	1206 (Deux Riviers)	Ontario	41206A1	Turbine	14.2	1992		
TransCanada	Mainline	ETriNE	1206 (Deux Riviers)	Ontario	41206B1	Turbine	14.1	1992		
TransCanada	Mainline	ETriNE	1211 (Pembroke)	Ontario	41211A1	Turbine	14.1	1990		
TransCanada	Mainline	ETriNE	1211 (Pembroke)	Ontario	41211B1	Turbine	14.1	1992		
TransCanada	Mainline	ETriNE	1217 (Stittsville)	Ontario	41217A1	Turbine	14.1	1990		
TransCanada	Mainline	ETriNE	1217 (Stittsville)	Ontario	41217B1	Turbine	14.2	1992		
TransCanada	Mainline	Kirkwall	1301 (Kirkwall)	Ontario	501301B1	Turbine	6.3	1993		
TransCanada	Mainline	Kirkwall	1301 (Kirkwall)	Ontario	51301C1	Turbine	6.3	1993		
TransCanada	Mainline	Kirkwall	1301 (Kirkwall)	Ontario	51301A1	Turbine	10.7	1994		
TransCanada	Mainline	Kirkwall	1301 (Kirkwall)	Ontario	51301A2	Turbine	11.2	1998		
TransCanada	Mainline	Kirkwall	1301 (Kirkwall)	Ontario	9005	Turbine	6.3	1996		
TransCanada	Mainline	Iroquois	1401 (Iroquois)	Ontario	51401A1	Turbine	14.2	1992		
TransCanada	Mainline	Iroquois	1401 (Iroquois)	Ontario	51401B1	Turbine	14.2	1992		
TransCanada	Mainline	Iroquois	1401 (Iroquois)	Ontario	51401C1	Turbine	14.2	1995		
TransCanada	Mainline	Douglas-town	1703 (Douglastown)	Ontario	51703A1	Turbine	10.7	1994		
TransCanada	Mainline	Douglas-town	1703 (Douglastown)	Ontario	51703B1	Turbine	10.7	1994		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	Mainline	Douglas-town	1703 (Douglastown)	Ontario	51703C1	Turbine	11.2	2008		
TransCanada	NGTL	ATCO	VERMILLION	Alberta	1	Turbine	1	2014		(TransCanada Pipelines, n.d., 2008, 2018a, 2018b)
TransCanada	NGTL	ATCO	VERMILLION	Alberta	2	Turbine	1	2014		
TransCanada	NGTL	EGAT	BEISEKER	Alberta	1	Turbine	10.4	≤2008		
TransCanada	NGTL	EGAT	BEISEKER	Alberta	2	Turbine	10.4	≤2008		
TransCanada	NGTL	EGAT	HUSSAR	Alberta	B8	Turbine	14	≤2008		
TransCanada	NGTL	EGAT	HUSSAR	Alberta	A6	Turbine	14	≤2008		
TransCanada	NGTL	EGAT	HUSSAR	Alberta	A7	Turbine	14	≤2008		
TransCanada	NGTL	EGAT	MEDICINE HAT	Alberta		Turbine	3.5	2017		
TransCanada	NGTL	EGAT	PRINCESS	Alberta	B6	Turbine	23.5	≤2008		
TransCanada	NGTL	EGAT	PRINCESS	Alberta	A1	Turbine	2.7	≤2008	2013	
TransCanada	NGTL	EGAT	PRINCESS	Alberta	A2	Turbine	2.7	≤2008	2013	
TransCanada	NGTL	EGAT	PRINCESS	Alberta	A3	Turbine	2.7	≤2008	2013	
TransCanada	NGTL	EGAT	PRINCESS	Alberta	A4	Turbine	4.5	≤2008	2013	
TransCanada	NGTL	EGAT	PRINCESS	Alberta	A5	Turbine	4.5	≤2008	2013	
TransCanada	NGTL	EGAT	RED DEER RIVER	Alberta	1	Turbine	25.1	≤2008		
TransCanada	NGTL	EGAT	RED DEER RIVER	Alberta	2	Turbine	25.1	≤2008		
TransCanada	NGTL	EGAT	SCHRADER CREEK	Alberta	1	Turbine	14	≤2008		
TransCanada	NGTL	EGAT	SCHRADER CREEK	Alberta	2	Turbine	25.1	≤2008		
TransCanada	NGTL	EGAT	SCHRADER CREEK	Alberta	3	Turbine	14	≤2008		
TransCanada	NGTL	NEDA	BEHAN	Alberta	Mobile 9	Turbine	3.5	≤2008		
TransCanada	NGTL	NEDA	BENS LAKE	Alberta	A3	Turbine	1	≤2008	2013	
TransCanada	NGTL	NEDA	BENS LAKE	Alberta	A7	Turbine	1	≤2008	2013	
TransCanada	NGTL	NEDA	BENS LAKE	Alberta	B4	Turbine	3.3	≤2008		
TransCanada	NGTL	NEDA	BENS LAKE	Alberta	C5	Turbine	3.3	≤2008		
TransCanada	NGTL	NEDA	BENS LAKE	Alberta	D6	Turbine	4.8	≤2008		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	NGTL	NEDA	BENS LAKE	Alberta	A1	Turbine	1	≤2008	2013	
TransCanada	NGTL	NEDA	BENS LAKE	Alberta	A2	Turbine	1	≤2008	2013	
TransCanada	NGTL	NEDA	DENNING	Alberta		Turbine	3.5	2014		
TransCanada	NGTL	NEDA	DUSTY LAKE	Alberta	2	Turbine	14	≤2008		
TransCanada	NGTL	NEDA	DUSTY LAKE	Alberta	3	Turbine	15	≤2008		
TransCanada	NGTL	NEDA	FARRELL LAKE	Alberta	1	Turbine	14	≤2008		
TransCanada	NGTL	NEDA	FARRELL LAKE	Alberta	2	Turbine	15	≤2008		
TransCanada	NGTL	NEDA	FIELD LAKE	Alberta	1	Turbine	3.3	≤2008		
TransCanada	NGTL	NEDA	FIELD LAKE	Alberta	2	Turbine	3.3	≤2008		
TransCanada	NGTL	NEDA	GADSBY	Alberta	1	Turbine	14	≤2008		
TransCanada	NGTL	NEDA	GADSBY	Alberta	2	Turbine	15	≤2008		
TransCanada	NGTL	NEDA	GADSBY	Alberta	3	Turbine	4.8	≤2008		
TransCanada	NGTL	NEDA	GOODFISH	Alberta		Turbine	30	2017		
TransCanada	NGTL	NEDA	HANMORE LAKE	Alberta	1	Turbine	0.5	≤2008	2013	
TransCanada	NGTL	NEDA	HANMORE LAKE	Alberta	2	Turbine	0.5	≤2008	2013	
TransCanada	NGTL	NEDA	HANMORE LAKE	Alberta	B3	Turbine	3.5	≤2008		
TransCanada	NGTL	NEDA	HANMORE LAKE	Alberta	C4	Turbine	3.5	≤2008		
TransCanada	NGTL	NEDA	LEISMER	Alberta		Turbine	1	2016		
TransCanada	NGTL	NEDA	LEISMER EAST	Alberta		Turbine	15	2016		
TransCanada	NGTL	NEDA	MOODY CREEK	Alberta		Turbine	15	2013		
TransCanada	NGTL	NEDA	OAKLAND	Alberta	1	Turbine	14	≤2008		
TransCanada	NGTL	NEDA	OTTER LAKE	Alberta		Turbine	30	2017		
TransCanada	NGTL	NEDA	PAUL LAKE	Alberta	Mobile 5	Turbine	3.5	≤2008		
TransCanada	NGTL	NEDA	PAUL LAKE	Alberta	1	Turbine	3.2	≤2008		
TransCanada	NGTL	NEDA	PAUL LAKE	Alberta	B2	Turbine	20	≤2008		
TransCanada	NGTL	NEDA	SLAVE LAKE	Alberta	4	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	SLAVE LAKE	Alberta	1	Turbine	1	≤2008	2014	

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	NGTL	NEDA	SLAVE LAKE	Alberta	2	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	SLAVE LAKE	Alberta	3	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	SMOKY LAKE	Alberta	D7	Turbine	15	≤2008		
TransCanada	NGTL	NEDA	SMOKY LAKE	Alberta	A3	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	SMOKY LAKE	Alberta	A1	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	SMOKY LAKE	Alberta	A2	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	SNIPE HILLS	Alberta		Turbine	3.5	2015		
TransCanada	NGTL	NEDA	TORRINGTON	Alberta	Mobile 8	Turbine	6.5	≤2008		
TransCanada	NGTL	NEDA	WAINWRIGHT	Alberta	B2	Turbine	2.1	≤2008	2017	
TransCanada	NGTL	NEDA	WAINWRIGHT	Alberta	C3	Turbine	1.2	≤2008		
TransCanada	NGTL	NEDA	WAINWRIGHT	Alberta	C4	Turbine	2.7	≤2008		
TransCanada	NGTL	NEDA	WANDERING RIVER	Alberta	1	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	WANDERING RIVER	Alberta	2	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	WANDERING RIVER	Alberta	3	Turbine	1	≤2008		
TransCanada	NGTL	NEDA	WOODENHOUSE	Alberta		Turbine	10.7	≤2008		
TransCanada	NGTL	NEDA	WOODENHOUSE	Alberta	B2	Turbine	20	≤2008		
TransCanada	NGTL	None	CARDINAL LAKE	Alberta	3	Turbine	0.8	≤2008	2014	
TransCanada	NGTL	None	CARDINAL LAKE	Alberta	1	Turbine	0.8	≤2008	2014	
TransCanada	NGTL	None	CARDINAL LAKE	Alberta	2	Turbine	1.2	≤2008	2014	
TransCanada	NGTL	None	CAVENDISH	Alberta	1	Turbine	1.3	≤2008	2014	
TransCanada	NGTL	None	CAVENDISH	Alberta	2	Turbine	3.9	≤2008	2014	
TransCanada	NGTL	None	CLARKSON VALLEY	Alberta	1	Turbine	15	≤2008	2014	
TransCanada	NGTL	None	DIDSBURY	Alberta	4 Test Facility	Turbine	1	≤2008	2014	
TransCanada	NGTL	None	DIDSBURY	Alberta	5	Turbine	0.7	≤2008	2014	
TransCanada	NGTL	None	DIDSBURY	Alberta	6	Turbine	0.7	≤2008	2014	
TransCanada	NGTL	None	PELICAN LAKE	Alberta	2	Turbine	3.3	≤2008	2014	

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	NGTL	None	THUNDER CREEK	Alberta		Turbine	2.9	≤2008	2015	
TransCanada	NGTL	None	VALLEYVIEW	Alberta		Turbine	2.9	≤2008	2014	
TransCanada	NGTL	Unknown	BEAVER CREEK	Alberta	1	Turbine	1	≤2008	2013	
TransCanada	NGTL	Unknown	BEAVER CREEK	Alberta	2	Turbine	1	≤2008	2013	
TransCanada	NGTL	Unknown	BEAVER CREEK	Alberta	3	Turbine	1	≤2008	2013	
TransCanada	NGTL	Unknown	BEAVER CREEK	Alberta	4	Turbine	1	≤2008		
TransCanada	NGTL	Unknown	BEAVER CREEK	Alberta	5	Turbine	1	≤2008		
TransCanada	NGTL	USJR	ALCES RIVER	Alberta	1	Turbine	3.3	≤2008	2013	
TransCanada	NGTL	USJR	ALCES RIVER	Alberta	2	Turbine	11.2	≤2008		
TransCanada	NGTL	USJR	ALCES RIVER	Alberta		Turbine	15	2017		
TransCanada	NGTL	USJR	BERLAND RIVER	Alberta	1	Turbine	25.1	≤2008		
TransCanada	NGTL	USJR	BERLAND RIVER	Alberta		Turbine	28	2012		
TransCanada	NGTL	USJR	CLEARWATER	Alberta	1	Turbine	22.8	≤2008		
TransCanada	NGTL	USJR	CLEARWATER	Alberta	2	Turbine	22.8	≤2008		
TransCanada	NGTL	USJR	DRYDEN CREEK	Alberta	Mobile 6	Turbine	3.5	≤2008		
TransCanada	NGTL	USJR	FOX CREEK	Alberta	1	Turbine	10.4	≤2008		
TransCanada	NGTL	USJR	GOLD CREEK	Alberta	B1	Turbine	9.4	≤2008		
TransCanada	NGTL	USJR	GOLD CREEK	Alberta	B2	Turbine	25.1	≤2008		
TransCanada	NGTL	USJR	GOLD CREEK	Alberta		Turbine	28	2010		
TransCanada	NGTL	USJR	HIDDEN LAKE	Alberta		Turbine	9.4	≤2008		
TransCanada	NGTL	USJR	HIDDEN LAKE NORTH	Alberta		Turbine	15	2013		
TransCanada	NGTL	USJR	KNIGHT	Alberta	3	Turbine	14	≤2008		
TransCanada	NGTL	USJR	KNIGHT	Alberta	4	Turbine	14	≤2008		
TransCanada	NGTL	USJR	LATORNEL	Alberta	1	Turbine	28.3	≤2008		
TransCanada	NGTL	USJR	LODGEPOLE	Alberta	3	Turbine	2.9	≤2008		
TransCanada	NGTL	USJR	LODGEPOLE	Alberta		Turbine	5	2017		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
TransCanada	NGTL	USJR	MEIKLE RIVER	Alberta	2 a.k.a. Station2	Turbine	3.5	≤2008		
TransCanada	NGTL	USJR	MEIKLE RIVER	Alberta	C3	Turbine	15	2006		
TransCanada	NGTL	USJR	MEIKLE RIVER	Alberta	C4	Turbine	15	2006		
TransCanada	NGTL	USJR	MEIKLE RIVER	Alberta	D	Turbine	33	2017		
TransCanada	NGTL	USJR	MEIKLE RIVER	Alberta	1	Turbine	3.3	≤2008		
TransCanada	NGTL	USJR	MEIKLE RIVER	Alberta	Mobile4	Turbine	3.5	≤2008		
TransCanada	NGTL	USJR	NORDEGG	Alberta	3	Turbine	33	≤2008		
TransCanada	NGTL	USJR	PIPESTONE CREEK	Alberta		Turbine	28.3	≤2008		
TransCanada	NGTL	USJR	SADDLE HILLS	Alberta	1	Turbine	3.3	≤2008		
TransCanada	NGTL	USJR	SADDLE HILLS	Alberta	2	Turbine	6.3	≤2008		
TransCanada	NGTL	USJR	SADDLE HILLS	Alberta	3	Turbine	7.1	≤2008		
TransCanada	NGTL	USJR	SWARTZ CREEK	Alberta	1	Turbine	28.3	≤2008		
TransCanada	NGTL	USJR	VETCHLAND	Alberta	1	Turbine	25.1	≤2008		
TransCanada	NGTL	USJR	VETCHLAND	Alberta	2	Turbine	25.1	≤2008		
TransCanada	NGTL	USJR	WOLF LAKE	Alberta	2	Turbine	25.1	≤2008		
TransCanada	NGTL	WGAT	BURTON CREEK	Alberta	1	Turbine	15	≤2008		
TransCanada	NGTL	WGAT	BURTON CREEK	Alberta	2	Turbine	15	≤2008		
TransCanada	NGTL	WGAT	DRYWOOD	Alberta		Turbine	3.5	≤2008		
TransCanada	NGTL	WGAT	TURNER VALLEY	Alberta	1	Turbine	25.1	≤2008		
TransCanada	NGTL	WGAT	TURNER VALLEY	Alberta	2	Turbine	25.1	≤2008		
TransCanada	NGTL	WGAT	WINCHELL LAKE	Alberta	1	Turbine	25.1	≤2008		
Enbridge	West	T-South	2 (Willow Flats)	BC	1	Turbine	9.3	1976		(Westcoast Energy, 2005, 2007, 2015a, 2015b, 2018)
Enbridge	West	T-South	2 (Willow Flats)	BC	2	Turbine	9.3	1976		
Enbridge	West	T-South	2 (Willow Flats)	BC	4	Turbine	14.9	1989		
Enbridge	West	T-South	2B (Azouzetta Lake)	BC	10	Turbine	18.5	2006		
Enbridge	West	T-South	2B (Azouzetta Lake)	BC	1	Turbine	12	1982		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
Enbridge	West	T-South	3 (McLeod Lake)	BC	5	Turbine	17.7	1974		
Enbridge	West	T-South	3 (McLeod Lake)	BC	6	Turbine	14.2	1992		
Enbridge	West	T-South	4A (Summit Lake)	BC	1	Turbine	11.9	1981		
Enbridge	West	T-South	4A (Summit Lake)	BC	3	Turbine	23.3	1995		
Enbridge	West	T-South	4B (Hixon)	BC	1	Turbine	12	1981		
Enbridge	West	T-South	4B (Hixon)	BC	2	Turbine	8.3	1966		
Enbridge	West	T-South	4B (Hixon)	BC	3	Turbine	23.3	1994		
Enbridge	West	T-South	5 (Australian)	BC	7	Turbine	23.3	1995		
Enbridge	West	T-South	6A (150 Mile House)	BC	1	Turbine	12	1980		
Enbridge	West	T-South	6A (150 Mile House)	BC	2	Turbine	8.3	1966		
Enbridge	West	T-South	6A (150 Mile House)	BC	10	Turbine	18.5	2003		
Enbridge	West	T-South	6B (93 Mile House)	BC	1	Turbine	11.9	1981		
Enbridge	West	T-South	6B (93 Mile House)	BC	2	Turbine	11.9	1997		
Enbridge	West	T-South	6B (93 Mile House)	BC	10	Turbine	31	2018		
Enbridge	West	T-South	7 (Savona)	BC	10	Turbine	18.5	2003		
Enbridge	West	T-South	7 (Savona)	BC	20	Turbine	18.5	2003		
Enbridge	West	T-South	8A (Kingsdale)	BC	1	Turbine	11.9	1981		
Enbridge	West	T-South	8A (Kingsdale)	BC	2	Turbine	11.9	1998		
Enbridge	West	T-South	8A (Kingsdale)	BC	10	Turbine	31	2018		
Enbridge	West	T-South	8B (Othello)	BC	10	Turbine	18.5	2003		
Enbridge	West	T-South	9 (Rosedale)	BC	1	Turbine	8.3	1966		
Enbridge	West	T-South	9 (Rosedale)	BC	2	Turbine	8.3	1968		
Enbridge	Alliance	Border	3 (Windfall)	Alberta	1	Turbine	30	2000		(National Energy Board, 1998)
Enbridge	Alliance	Border	3 (Windfall)	Alberta	2	Turbine	30	2000		
Enbridge	Alliance	Border	3 (Windfall)	Alberta	3	Turbine	30	2000		
Enbridge	Alliance	Border	5 (Morinville)	Alberta	1	Turbine	23	2000		
Enbridge	Alliance	Border	7 (Irma)	Alberta	1	Turbine	23	2000		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
Enbridge	Alliance	Border	9 (Kerrobert)	Saskatchewan	1	Turbine	23	2000		
Enbridge	Alliance	Border	11 (Loreburn)	Saskatchewan	1	Turbine	23	2000		
Enbridge	Alliance	Border	13 (Estlin)	Saskatchewan	1	Turbine	23	2000		
Enbridge	Alliance	Border	15 (Alameda)	Saskatchewan	1	Turbine	23	2000		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	B	Turbine	19.9	1978		(Spectra Energy, 2016; Union Gas, 2015)
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	C	Turbine	22.6	1982		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	D	Turbine	24.9	1989		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	E	Turbine	26.1	1990		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	F-1	Turbine	7.7	2006		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	F-2	Turbine	7.7	2006		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	G	Turbine	26.1	1993		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	I	Turbine	32.9	2008		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	J	Turbine	7.7	2011		
Enbridge	Union	Dawn-Parkway	Dawn	Ontario	H	Turbine	33.2	2017		
Enbridge	Union	Dawn-Parkway	Lobo	Ontario	A1	Turbine	15.3	1970		
Enbridge	Union	Dawn-Parkway	Lobo	Ontario	A2	Turbine	15.3	1972		
Enbridge	Union	Dawn-Parkway	Lobo	Ontario	B	Turbine	26.1	1990		

Company	System	Area	Station	Province	Unit #	Model Type	Unit Power (MW)	Installation Year	Decomm-issioning Year	Source
Enbridge	Union	Dawn-Parkway	Lobo	Ontario	C	Turbine	33.2	2016		
Enbridge	Union	Dawn-Parkway	Lobo	Ontario	D	Turbine	33.2	2017		
Enbridge	Union	Dawn-Parkway	Bright	Ontario	A1	Turbine	29.5	2008		
Enbridge	Union	Dawn-Parkway	Bright	Ontario	A2	Turbine	29.5	2008		
Enbridge	Union	Dawn-Parkway	Bright	Ontario	B	Turbine	26.1	2008		
Enbridge	Union	Dawn-Parkway	Bright	Ontario	C	Turbine	33.2	2018		
Enbridge	Union	Dawn-Parkway	Parkway East	Ontario	A	Turbine	14.9	1989		
Enbridge	Union	Dawn-Parkway	Parkway East	Ontario	B	Turbine	31.7	2007		
Enbridge	Union	Dawn-Parkway	Parkway West	Ontario	C	Turbine	33.6	2015		
Enbridge	Union	Dawn-Parkway	Parkway West	Ontario	D	Turbine	33.6	2015		

Appendix B Pipeline system throughput and area selection

This appendix shows the capacity factor analysis for the TransCanada Mainline, NGTL, and Enbridge West gas transmission systems. Analysis for the Alliance system is included in the main text. The summary section at the end of the appendix contains the capacity factor results by system and unit.

B.1 TransCanada Mainline system

The TransCanada Mainline has historically been the largest system delivering gas from the Western Canada Sedimentary Basin to eastern markets. Specifically, it delivers natural gas from the border of Alberta and Saskatchewan to the U.S. border in Manitoba, to Ontario and Quebec, and to Eastern U.S. border export points. With the rise of shale gas production from the Marcellus and Utica basins in the Northeast U.S. beginning in the late 2000s, some of the Eastern U.S. export connections have been reversed into major sources of gas imports for Ontario and Quebec, significantly lowering throughput and capacity factors west of the "Eastern Triangle." This was recently partially mitigated by a significantly lower but long-term toll implemented in 2017/2018.

The Mainline has 54 compressor stations, with 134 compressor units, of which 110 are gas turbines (TransCanada Pipelines, 2011). The system has 2215 MW of gas turbine installed power, almost double the capacity of the next largest pipeline system in Canada. An overview map is shown in Figure 12, and station location maps can be found in Appendix C

Figure 12: Map of TransCanada Mainline with labeled flow measurement points (reproduced from NEB, 2018).

The Mainline system has been subdivided into smaller flow areas to calculate the unit capacity factors, based on the location of flow point measurements.

- **Prairie to Emerson/Northern Ontario Line (PtEN):** The units between the Prairie flow measurement point and the junction where the flow splits between the Emerson I & II and Northern Ontario Line. Includes Station 2 (Burstall) to Station 41 (Ile des Chenes).

- **Northern Ontario Line (NOL):** The units between the Northern Ontario Line measurement point and the Eastern Triangle – NOL Receipts measurement point. Includes Station 41 (Ile des Chenes) to Station 116 (North Bay).
- **Eastern Triangle Region:** The units east and south of Eastern Triangle-NOL Receipts. In contrast to the preceding two areas, the flow measurement points for this area are located on the outside of an area with multiple flow paths, and assumptions are required to determine flow along each path. The analyzed flow paths or locations are listed below, with required assumptions outlined in more detail below in the Eastern Triangle report section.
    - **Eastern Triangle North-East (ETriNE):** The units between Eastern Triangle-NOL Receipts and the eastern tip of the Triangle, Station 116 (North Bay), Station 1206 (Deux Riviers), Station 1211 (Pembroke), and Station 1217 (Stittsville).
    - **Eastern Triangle East (ETriE):** The units east of the eastern tip of the Triangle, Station 147 (Cornwall) and Station 148 (Les Cedres).
    - **Iroquois:** The station at the Iroquois import/export point.
    - **Douglastown:** The station near the Chippawa import/export point.
    - **Kirkwall:** The station at the Kirkwall import/export point.
    - **Maple:** The station at the southern tip of the triangle.

Area characteristics are summarized in Table 17.

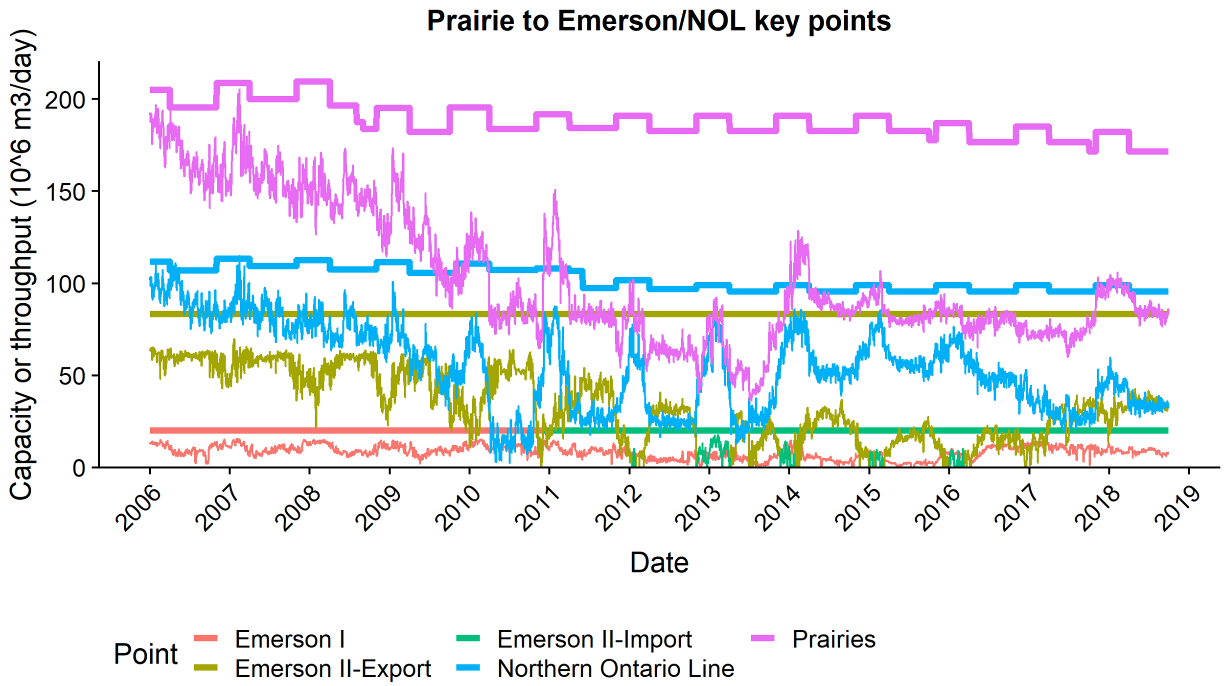
Table 17: TransCanada Mainline turbine installations by area

Operational Area	Flow Point	Total Power (MW)	Units Installed	Power Per Unit (MW)
PtEN	See sections below	683.5	35	19.5
NOL		993.8	44.5	22.3
ETriNE		94.0	6.5	14.5
ETriE		32.1	7	4.6
Iroquois		42.6	3	14.2
Kirkwall		40.8	5	8.2
Maple		40.6	4	10.2
Unassigned		287.4	29	NA

Prairie to Emerson/Northern Ontario Line

The Prairie to Emerson/Northern Ontario Line (PtEN) area includes the units between the Prairie flow measurement point and the junction where the flow splits between the Emerson I & II and Northern Ontario Line. Includes Station 2 (Burstall) to Station 41 (Ile des Chenes), inclusive, except half of the area border station 41 (Ile des Chenes) is assigned to PtEN and half is assigned to NOL. The installed turbine brakepower capacity in PtEN is 683.5 MW. Throughput and capacity are shown in Figure 13. For the area, the following throughput aggregations were made:

- **Receipts:** Prairie measurement point.
- **Deliveries:** The sum of Northern Ontario Line, Emerson I, and Emerson II-Export, less Emerson II-Import.
- **PowerCalc:** The average of Receipts and Deliveries.
- **Consumption:** Receipts less Deliveries. Includes gas consumed in Saskatchewan and Manitoba, turbine fuel gas, and fugitive emissions, and ranges from 5 to 15% of Prairie point throughput.



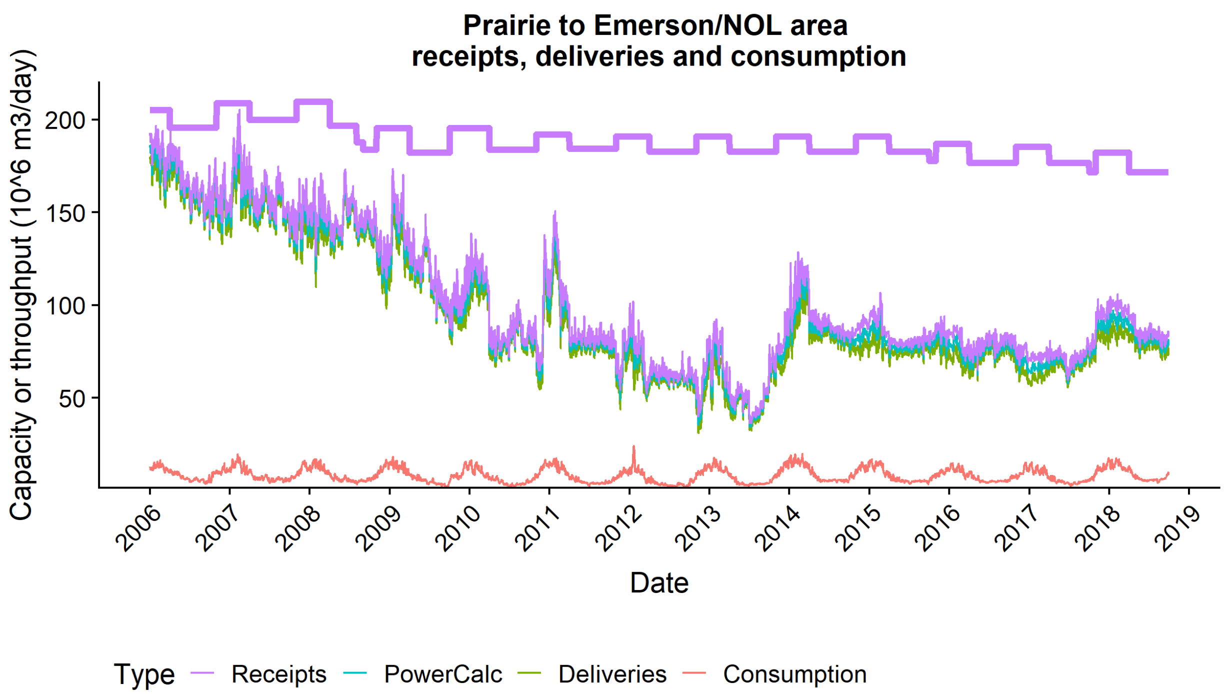


Figure 13: Flow in the PtEN area. The top figure shows data for each flow measurement point. The bottom figure includes aggregated flow data. The top thick line is capacity, thin lines are throughput.

Northern Ontario Line (NOL)

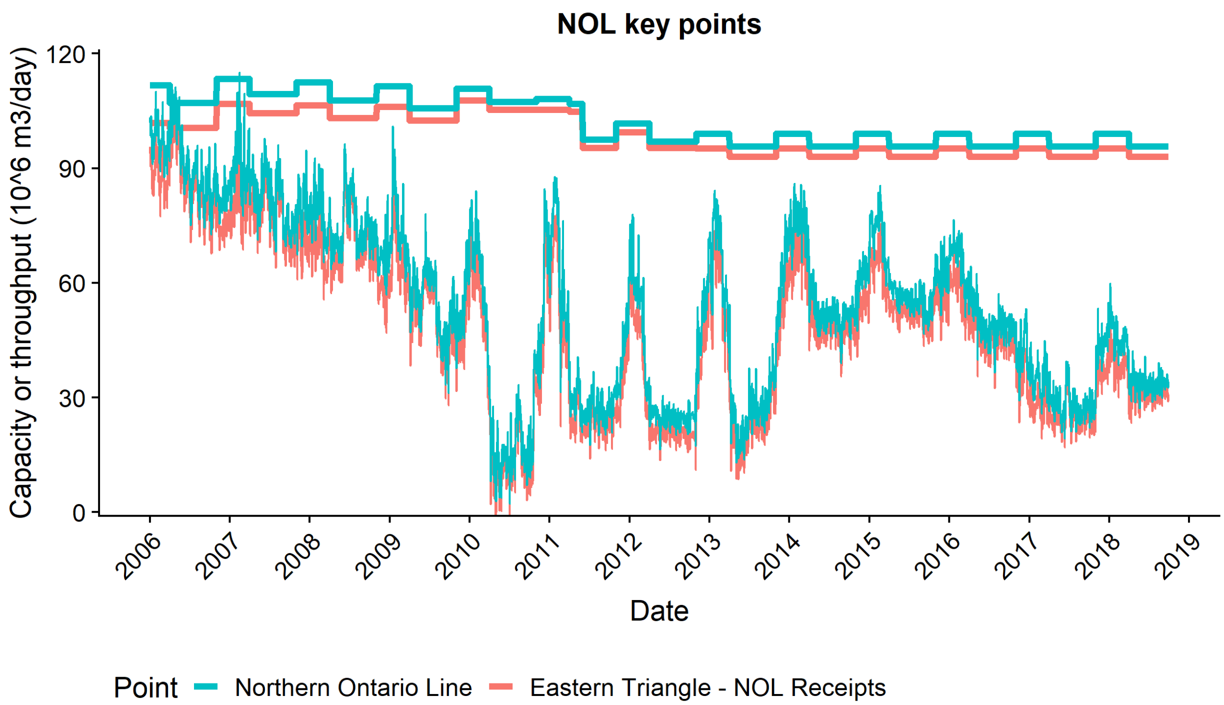
The NOL area includes units between the Northern Ontario Line measurement point and the Eastern Triangle – NOL Receipts measurement point. Includes stations between Station 41 (Ile des Chenes) and Station 116 (North Bay), plus half of the border stations Station 41 (Ile des Chenes) and Station 116 (North Bay).

Throughput and capacity are shown in Figure 14. For the area, the following aggregations were made:

- **Receipts:** Northern Ontario Line measurement point.
- **Deliveries:** Eastern Triangle – NOL Receipts measurement point.
- **PowerCalc:** The average of Receipts and Deliveries.
- **Consumption:** Receipts less Deliveries. Includes gas consumed in Manitoba and Northern Ontario, turbine fuel gas, and fugitive emissions.

Eastern Triangle Region

The Eastern Triangle Region includes units east and south of Eastern Triangle-NOL Receipts. In contrast to the preceding two areas, the flow measurement points for this area are located on the outside of an area with multiple flow paths, and assumptions are required to determine flow along each flow path as there is insufficient information to complete a mass balance analysis. To start however, receipts and deliveries to the entire region are aggregated and examined in Figure 15.



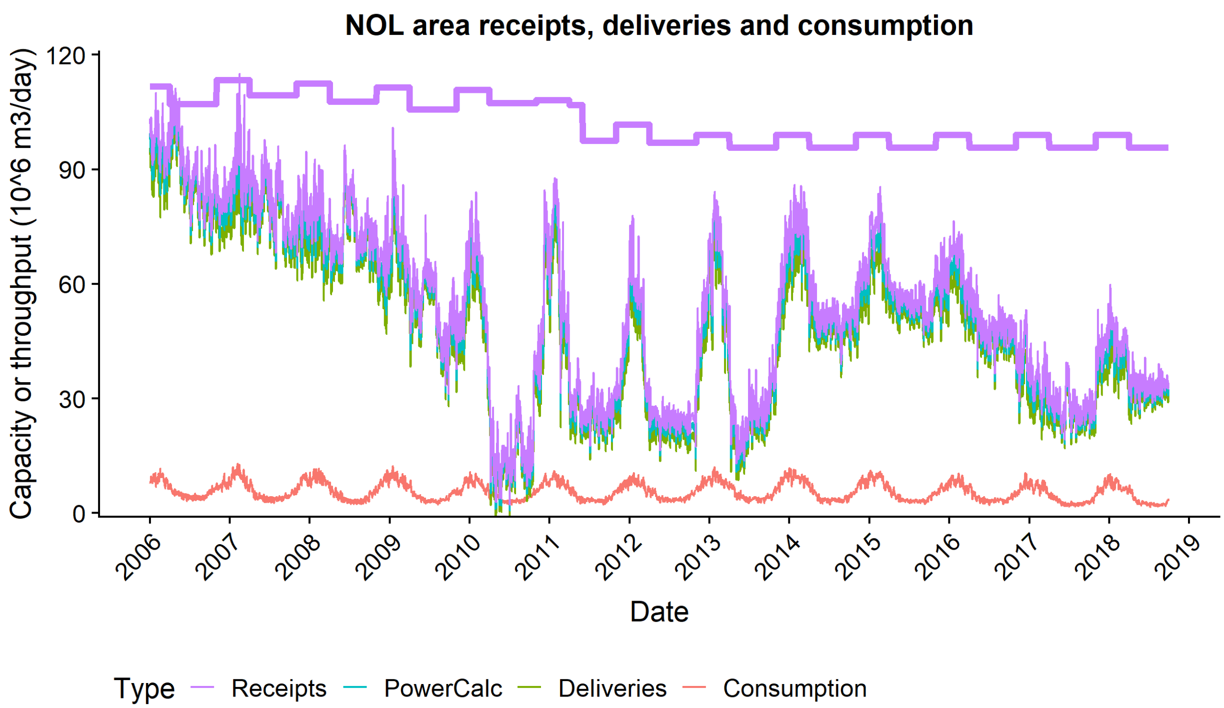


Figure 14: Flow in the NOL area. The top figure shows data for each flow measurement point. The bottom figure includes aggregated flow data. The top thick line is capacity, thin lines are throughput.

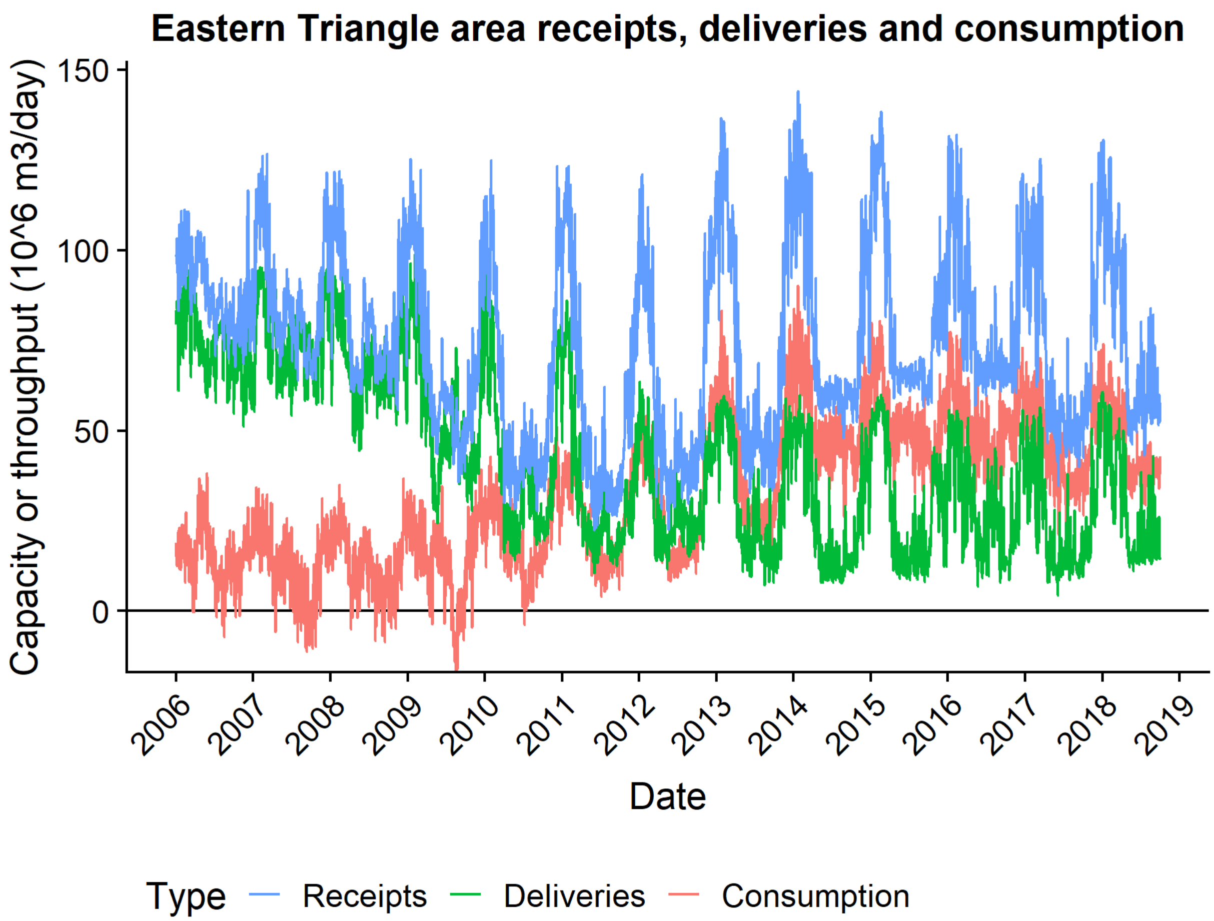


Figure 15: Eastern Triangle area receipts, deliveries, and consumption.

Note that during some time periods, consumption within the Eastern Triangle appears to be negative, i.e. deliveries are exceeding receipts. As there is no underground gas storage within the area analyzed, this is likely the impact of a significant receipt point near the Kirkwall Compressor Station (SW of the Parkway receipt station) not being available in the data. While it is conceivable that another cause could be storage of natural gas within the pipeline system itself using higher static pressures (linepack), it is unlikely this is a significant driver due to the length of time over which deliveries exceed receipts. In addition, consumption seems to increase significantly between ~2010 and 2013, whereas other sources for historical Ontario gas consumption don't indicate a significant increase (Government of Ontario, 2016). I suspect that between 2010 and 2013 receipts at Kirkwall decreased, as receipts rose at Parkway, Niagara, and Chippawa. This theory gets some support by looking at total average Ontario gas consumption from other sources, which is approximately 59 million m^3/day (National Energy Board, 2019). Since this region encompasses a very high proportion of the Ontario population, the consumption numbers after 2013 seem to align better with this source than pre-2010 and during the 2010 to 2013 transition period.

To estimate required compressor station energy along individual flow paths in the region, I show the Eastern Triangle region in Figure 16 with 2010 capacity factor data (TransCanada Pipelines, 2011). Since the compressor utilization on the west side of the Eastern Triangle is almost zero, the flow in this segment to assumed to be zero. This is in contrast to compressor utilizations on the north-east and south-east side of the triangle, which are more significant. While it is possible (or likely) the west side is free flowing some gas either north or south, the amounts are likely low and an assumption is required to make a tractable mass balance problem. For an assessment of the accuracy of this assumption, see Appendix C .

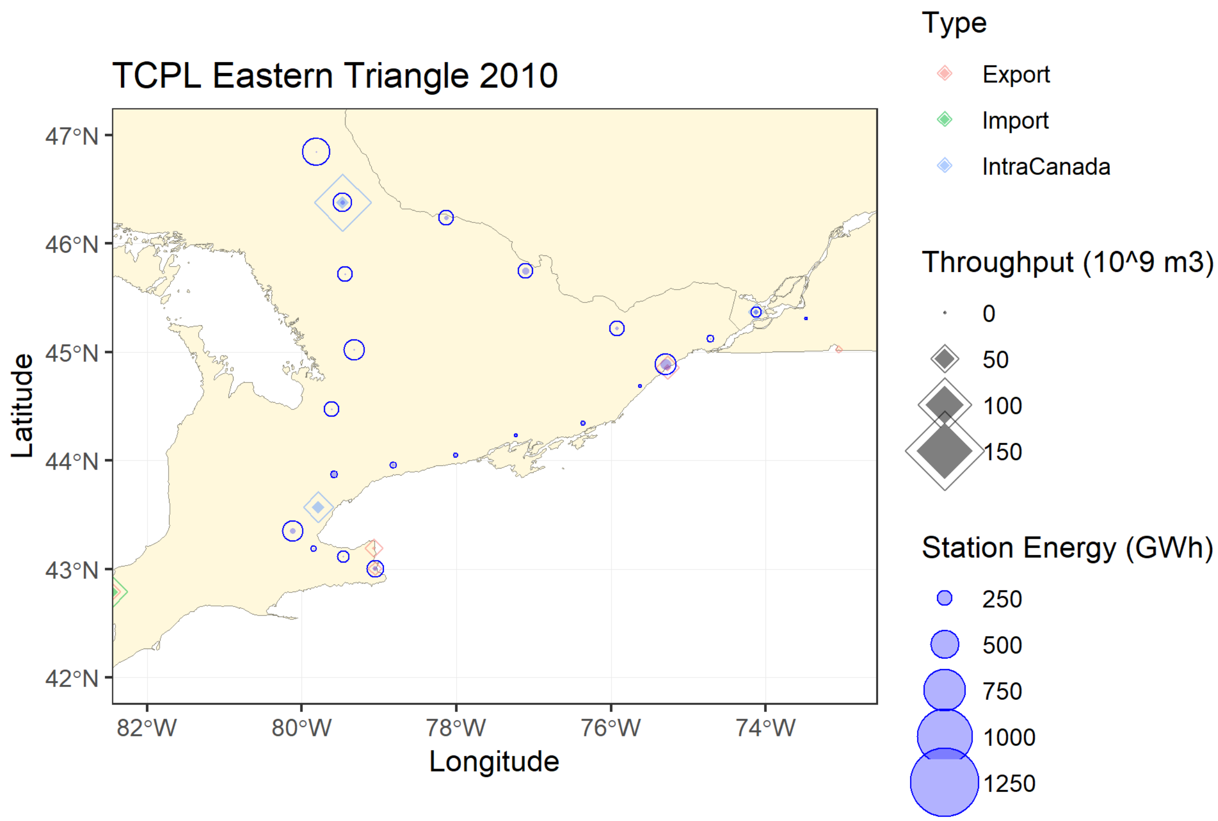


Figure 16: Eastern Triangle station energy map. The unfilled shapes are the potential flow and station energy at full capacity. The filled circles are the actual flow and station brakepower energy summed over 2010.

Analysis of the area can be further simplified by examining the types of units and direction of flow in 2017 to eliminate other stations from eligibility for WHP installation. The south-east side of the triangle is composed entirely of electric drive compressor units, and therefore no waste heat is available (see Appendix A). Flow in the area south of the Eastern Triangle has also been reversed since 2010, as Douglastown and Chippawa have become net importers. The compressor stations on these lines are therefore not currently running as they are not capable of flowing in the reversed direction. The rest of the units can be divided into two areas (ETriNE and ETriE) and three single stations (Iroquois, Kirkwall, and Maple) where flow can be approximated.

Eastern Triangle North-East

The Eastern Triangle North-East (ETriNE) area includes the units between Eastern Triangle-NOL Receipts and the eastern tip of the Triangle, Station 116 (North Bay), Station 1206 (Deux Riviers), Station 1211 (Pembroke), and Station 1217 (Stittsville). As the flow on the west side of the triangle is assumed to be zero, the flow in ETriNE is the same as the flow measurement at Eastern Triangle – NOL Receipts, shown in Figure 17.

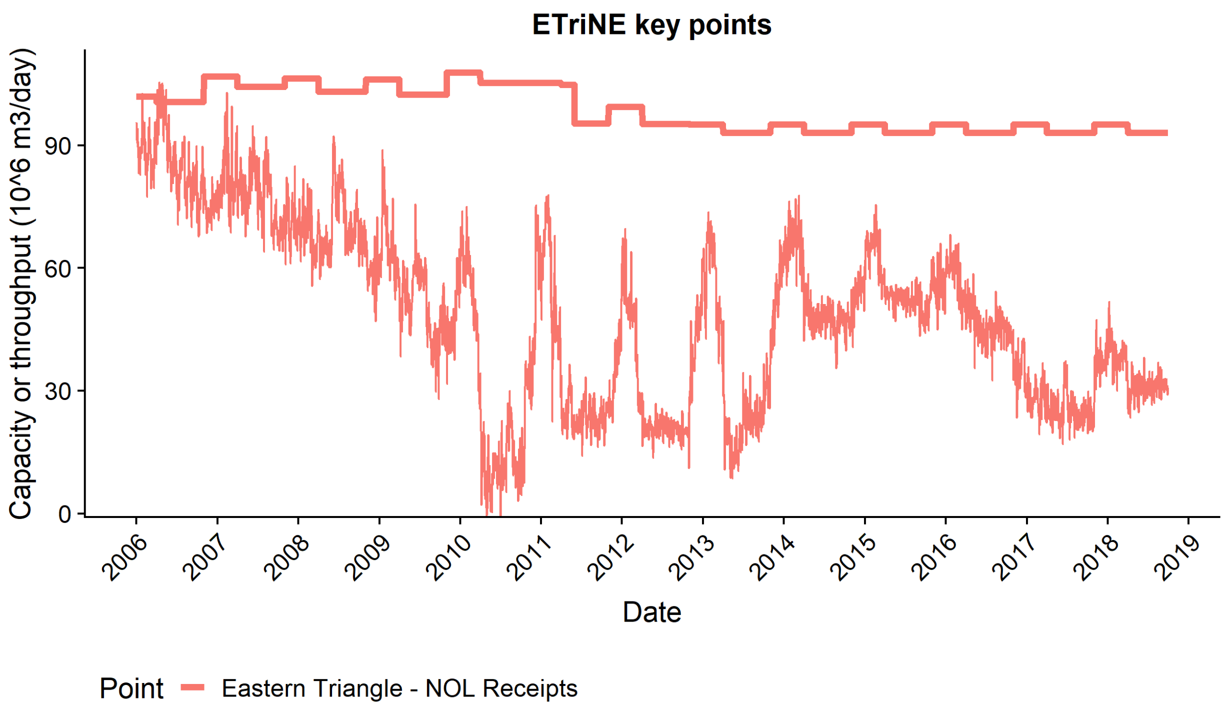


Figure 17: Flow in the ETriNE area. The thin line is daily throughput, the thick line is capacity.

Eastern Triangle East

The Eastern Triangle East (ETriE) includes the units east of the eastern tip of the Triangle, Station 147 (Cornwall) and Station 148 (Les Cedres). The flow in this area is the sum of the Saint Lazare and Other US Northeast flow measurement points, shown in Figure 18.

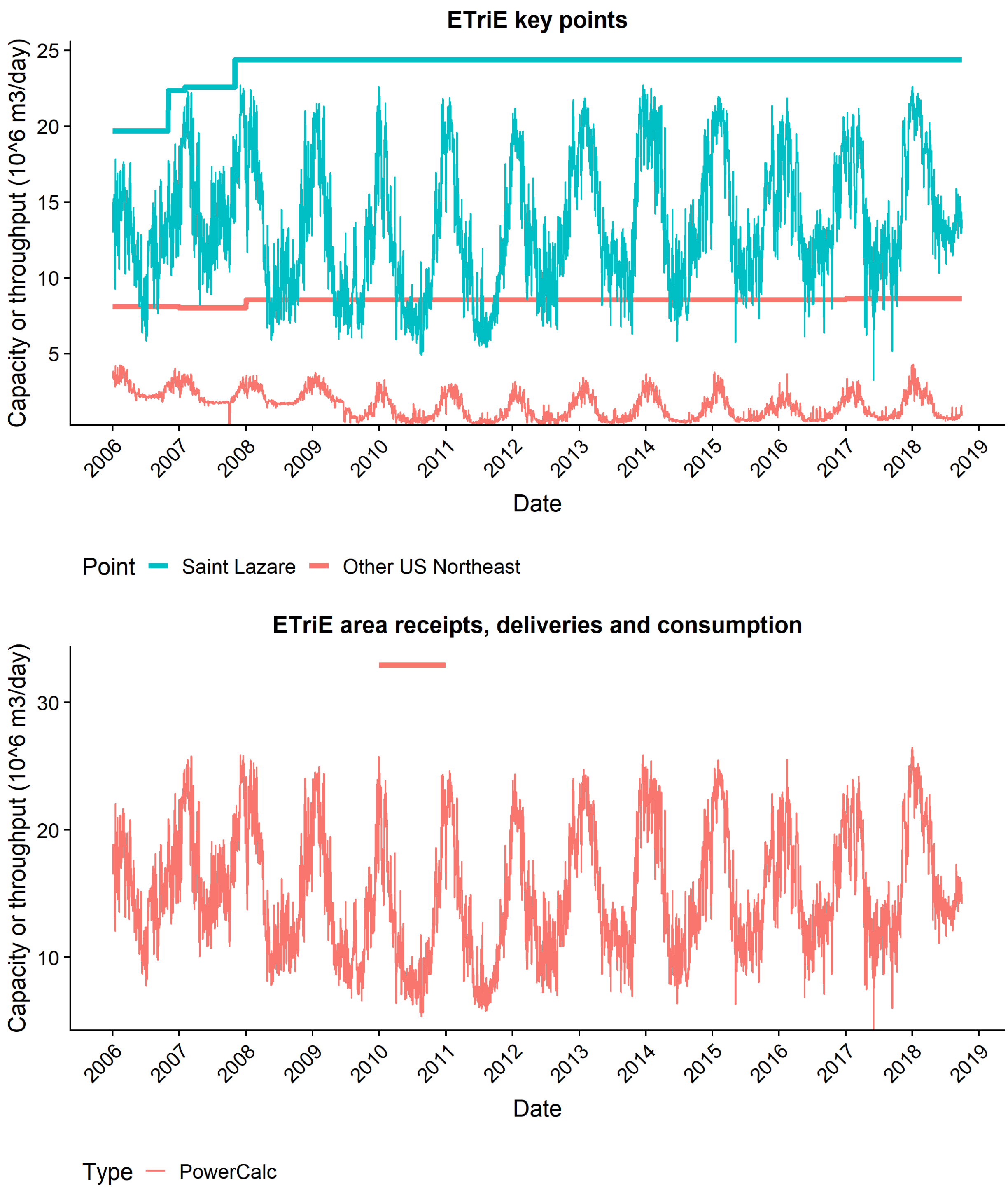


Figure 18: Flow in the ETriE area. For the top graph, the thin line is daily throughput, the thicker line is capacity.

Iroquois

The Iroquois station is located at a significant export point to the US, and the flow is measured directly at the station, as shown in Figure 19.

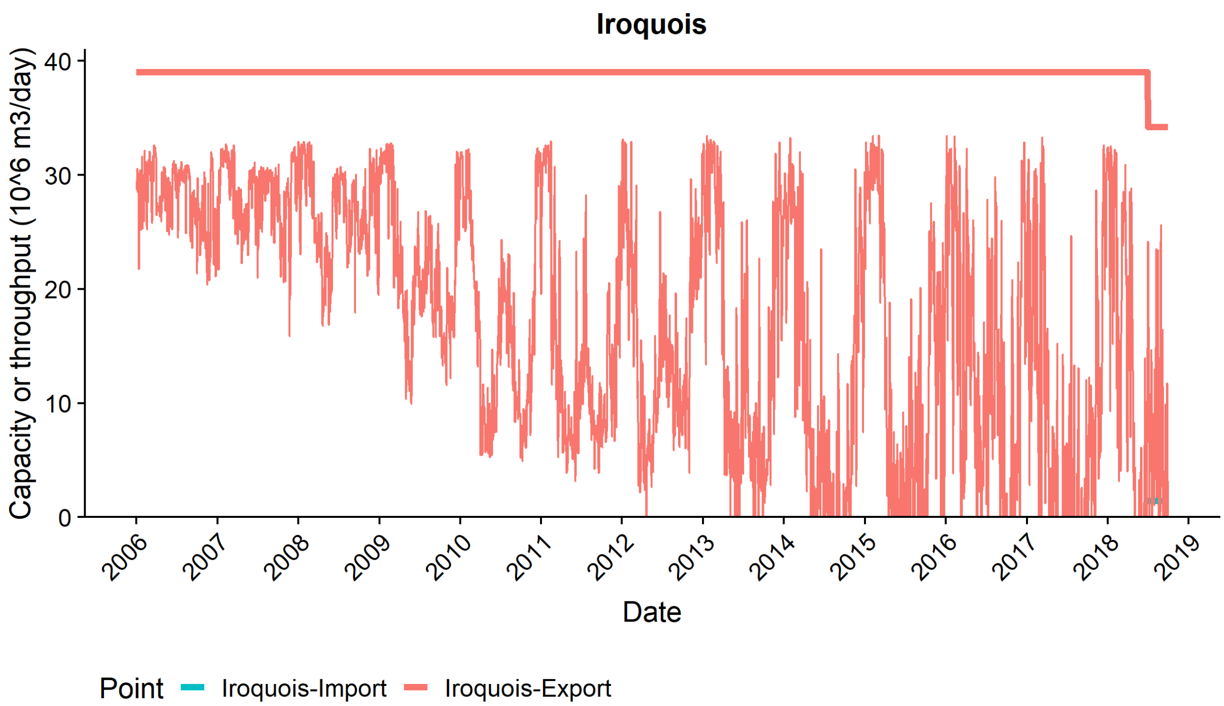


Figure 19: Flow at Iroquois. The thin line is daily throughput, the thick line is capacity.

Kirkwall

The Kirkwall station is a significant receipt point to the Mainline system, but flow data is not provided in the dataset. The flow data at the Parkway receipt point is therefore used, as shown in Figure 20. The Parkway and Kirkwall receipt points are from the same connecting pipeline system (Union Gas) and have similar drivers but would not be identical. For an evaluation of the accuracy of this method, see Appendix C .

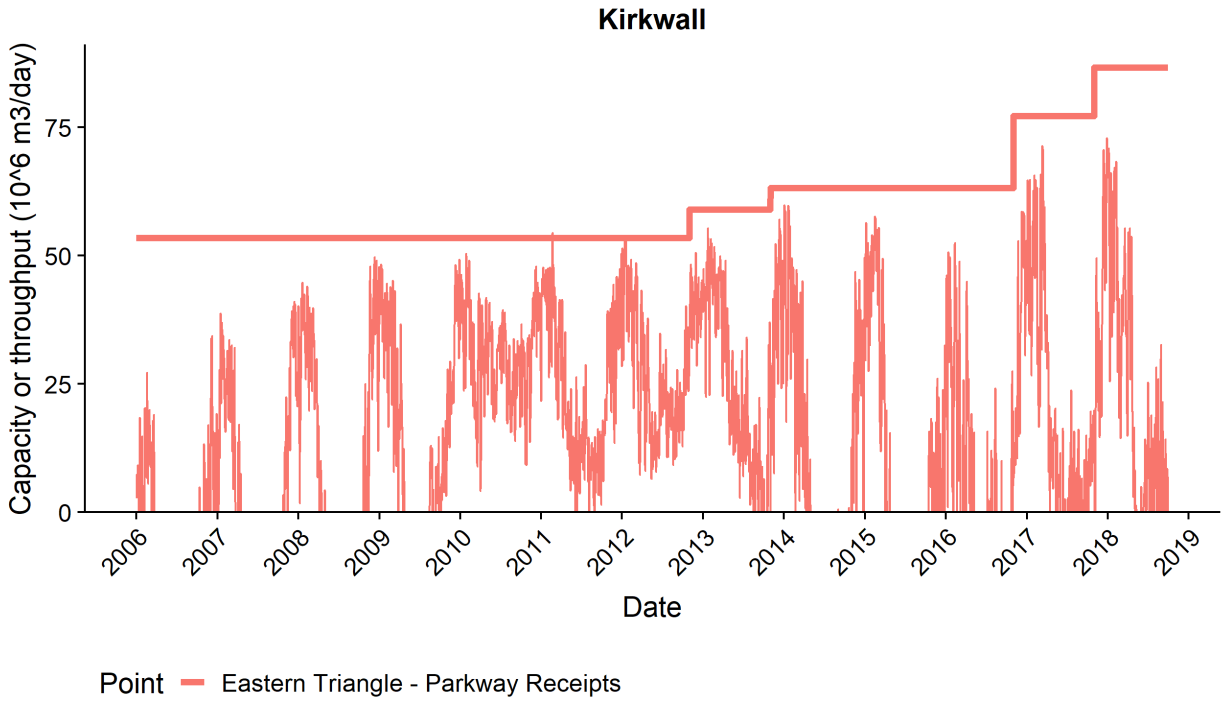


Figure 20: Flow used for Kirkwall station. The thin line is daily throughput, the thick line is capacity.

Maple

The Maple station is at the junction point at the southern tip of the triangle. The flow at the station is estimated to be the difference between imports at Eastern Triangle – Parkway Receipts, Chippawa and Niagara, and exports at Chippawa and Niagara, as shown in Figure 21.

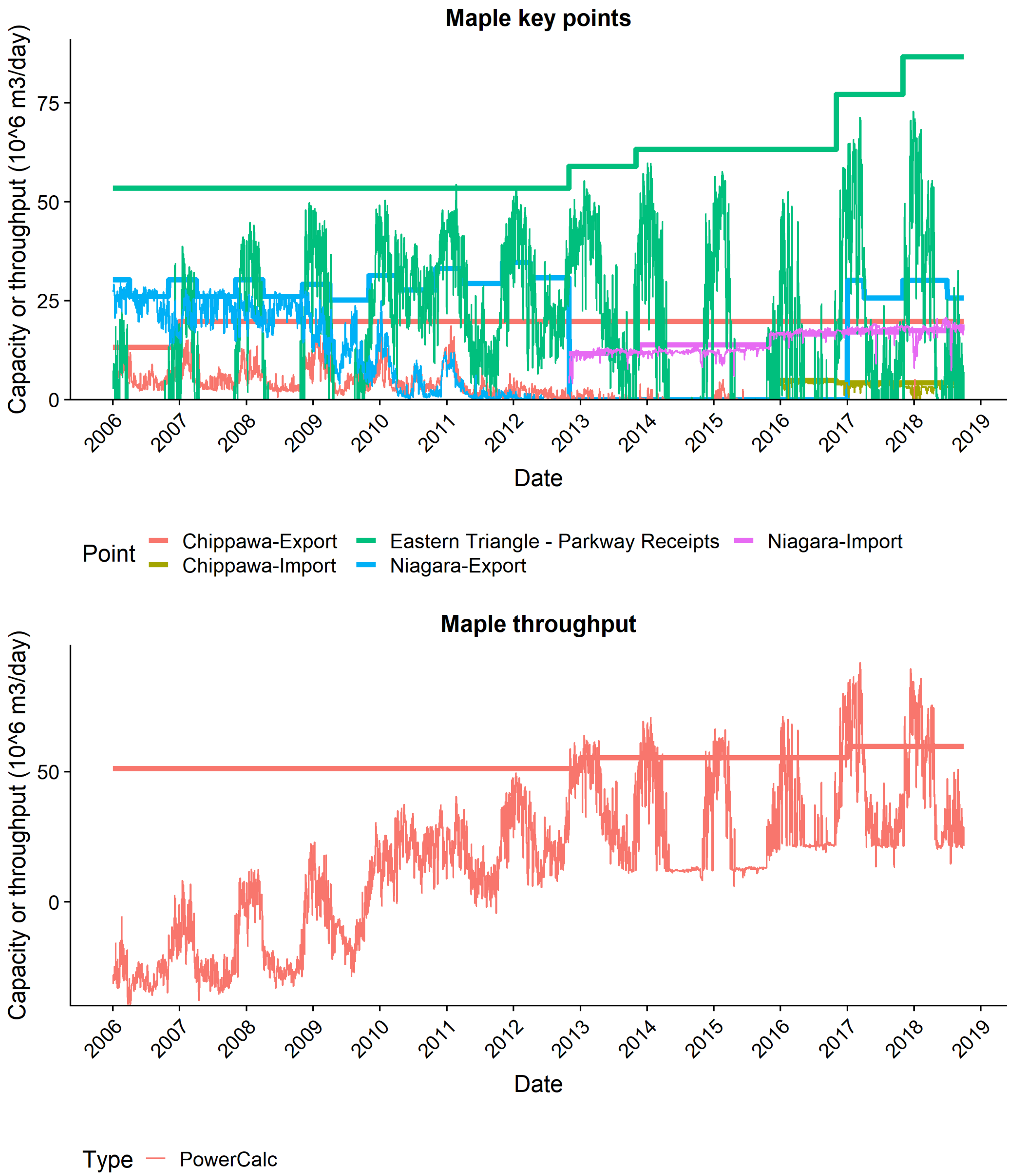


Figure 21: Flow at Maple.

Imports at Niagara and Chippawa begin in late 2012 and 2016, respectively. Winter peak receipts also increase at Parkway. These numbers do not include a significant receipt point at Kirkwall.

Based on the analysis described above, it is believed that receipts at Kirkwall declined as receipts at Chippawa, Niagara, and Parkway increased.

The values in Figure 21 also do not account for deliveries to distribution companies between the receipt points and Maple. It is evident from the figure that this is significant, as calculated throughput significantly exceeds capacity. The calculated load duration curve for 2018 is non-sensical as it displays power requirement above the actual installed power for approximately a third of the year. This station is therefore omitted from the analysis, and potential WHP capacity at the station is not counted. Qualitatively, this station may actually be a strong candidate for WHP installations. As it sits at the southern junction of the triangle, it is key to directing gas flow. This is evidenced by the ongoing construction of new compressor capacity at this station, with three new turbine units installed since 2013, and one unit under construction (National Energy Board, 2015, 2017). These are the only new turbine installations on the Mainline in this time period.

Load duration curves

Load duration curves for the six areas or stations are shown in Figure 22. Capacity factors are listed in Table 20.

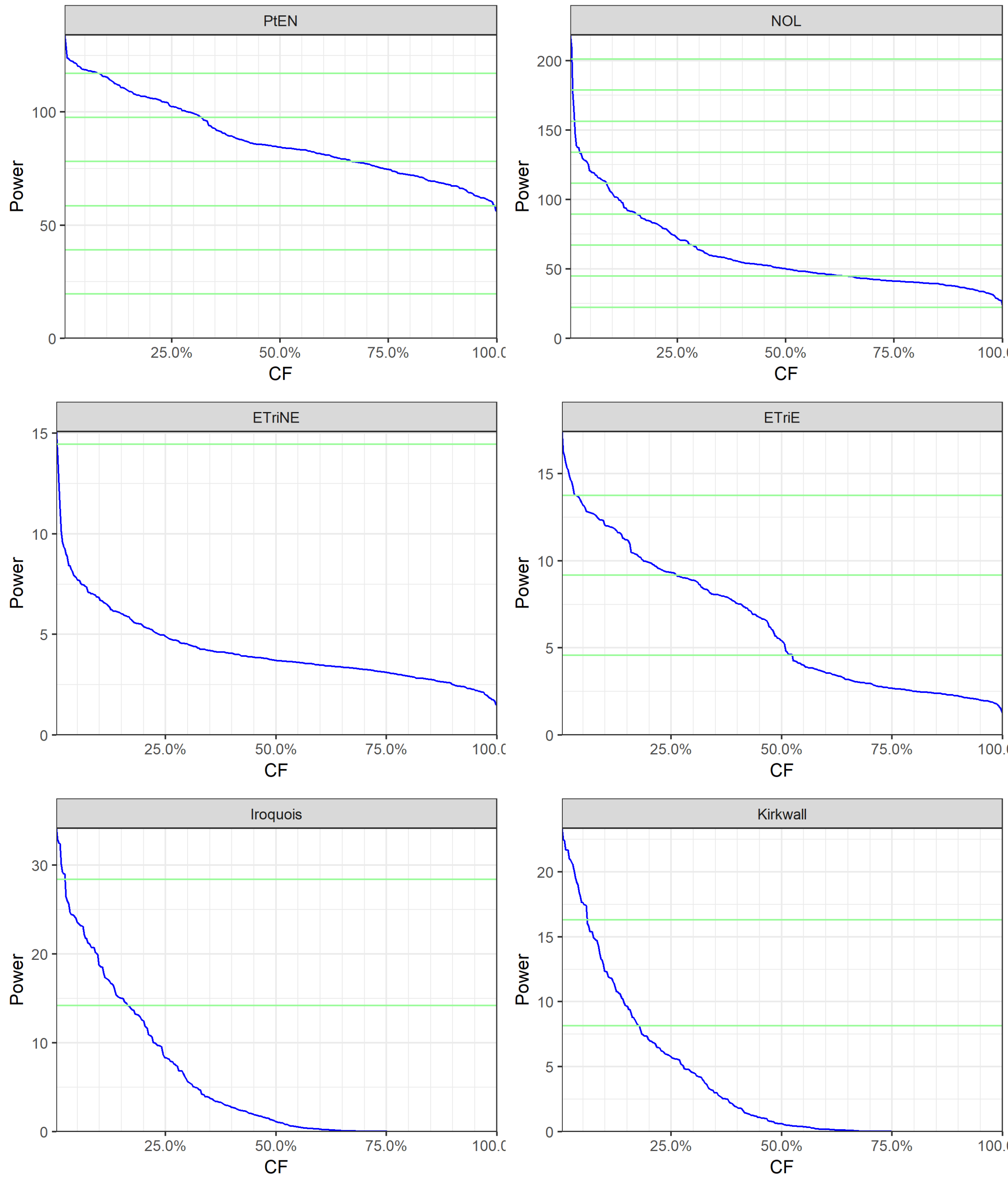


Figure 22: TransCanada Mainline area 2018 load durations curves

B.2 NGTL system

The NGTL system, shown in Figure 23, is the largest transmission system on the Western Canada Sedimentary Basin, and operates in Alberta and Northeast BC. It has over 1100 receipt and 300 delivery points (NEB, 2018). The system continues to expand as gas production in the Montney formation and gas consumption in the oil sands delivery area increase. The key points in the throughput data (Government of Canada, 2018b) generally correspond to the NGTL operational areas (TransCanada Pipelines, 2018b).

- **East Gate (EGAT):** Delivery point to the TransCanada Mainline and Foothills (Saskatchewan) pipelines in southeastern Alberta.
- **West Gate (WGAT):** Delivery point to the Foothills (BC) pipeline in southwestern Alberta.
- **Upstream of James River (USJR):** Measures gas flow along the mainline of northeastern NGTL, including gas produced in the Montney and Horn River formations.
- **North and East Delivery Area (NEDA):** Gas flow to deliveries in northeastern Alberta, including to the oil sands.

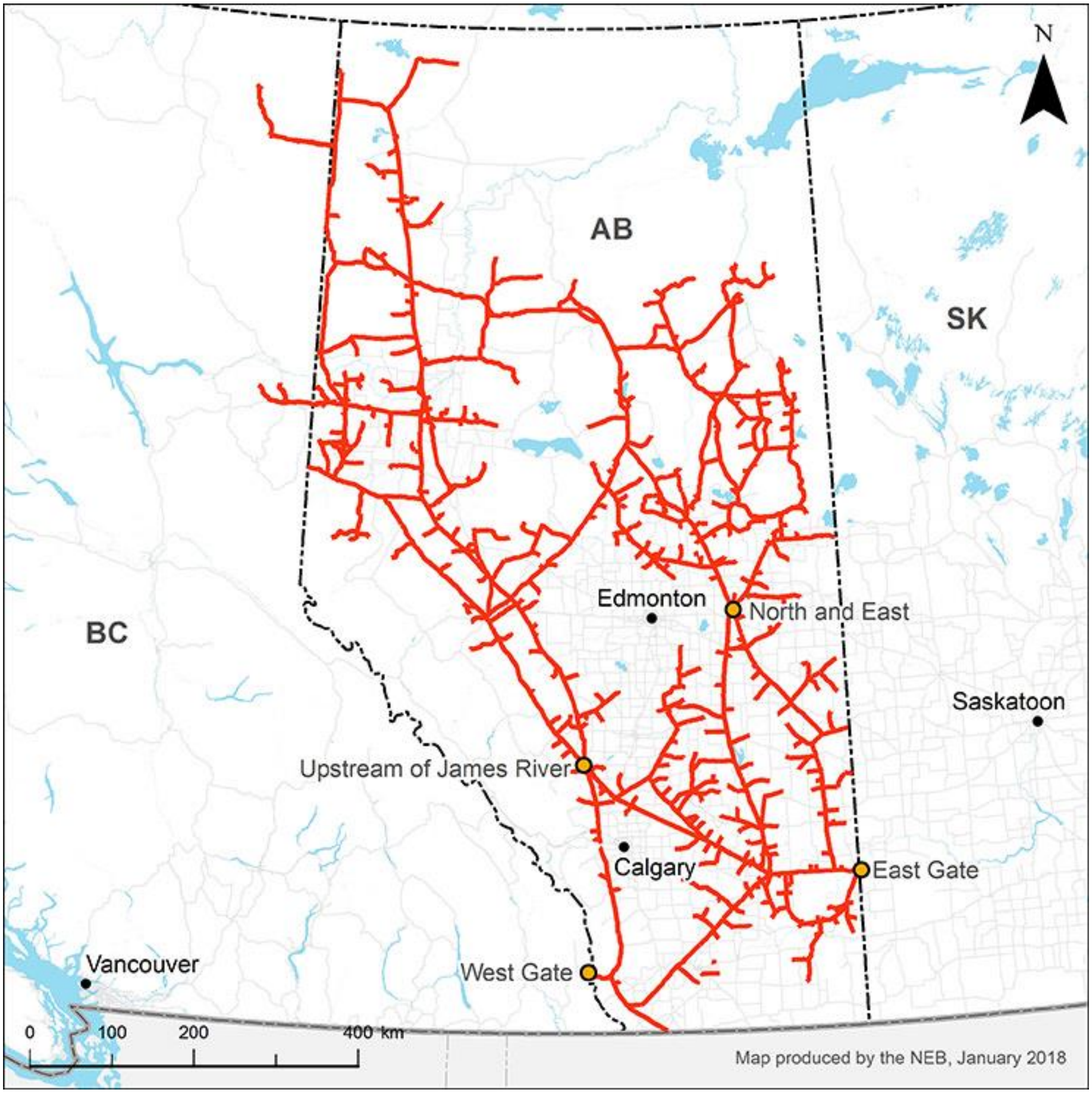


Figure 23: NGTL system map with key points (reproduced from NEB, 2018)

Gas turbine and compressor data was collected from regulatory and system planning documents (TransCanada Pipelines, 2008, 2018a), and aggregated by area using system maps (TransCanada Pipelines, 2018b), as shown in Table 18. Throughput and capacity data are shown in Figure 24.

Table 18: NGTL turbine installations by area

Operational Area	Flow Point	Total Power (MW)	Units Installed	Power Per Unit (MW)
EGAT	East Gate	193.1	12	16
NEDA	North and East	326.2	32	8
USJR	Upstream of James River	548.1	34	16
WGAT	West Gate	108.8	6	18

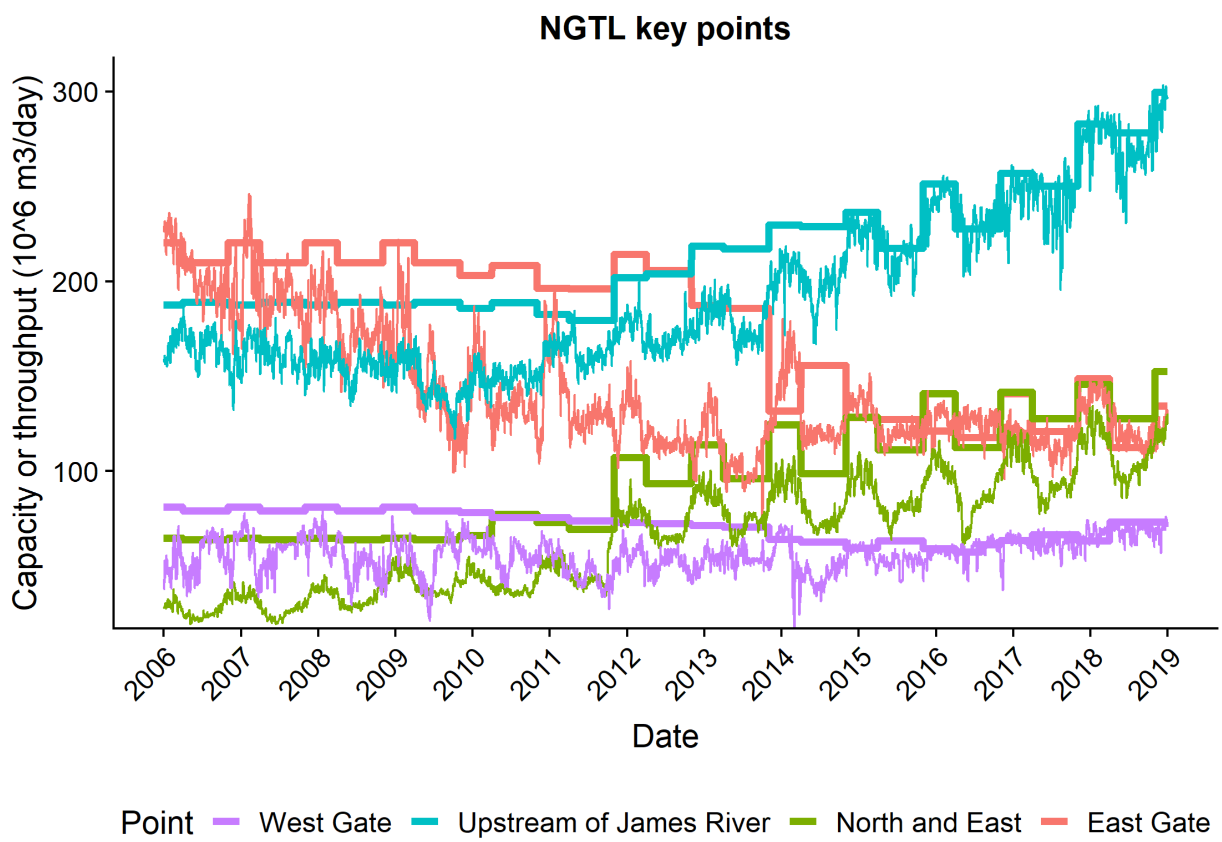


Figure 24: Flow in NGTL. The thin line is daily throughput, the thick line is capacity.

Analysis of the system was conducted using the method in Section 2.6, producing the load duration curves shown in Figure 25.

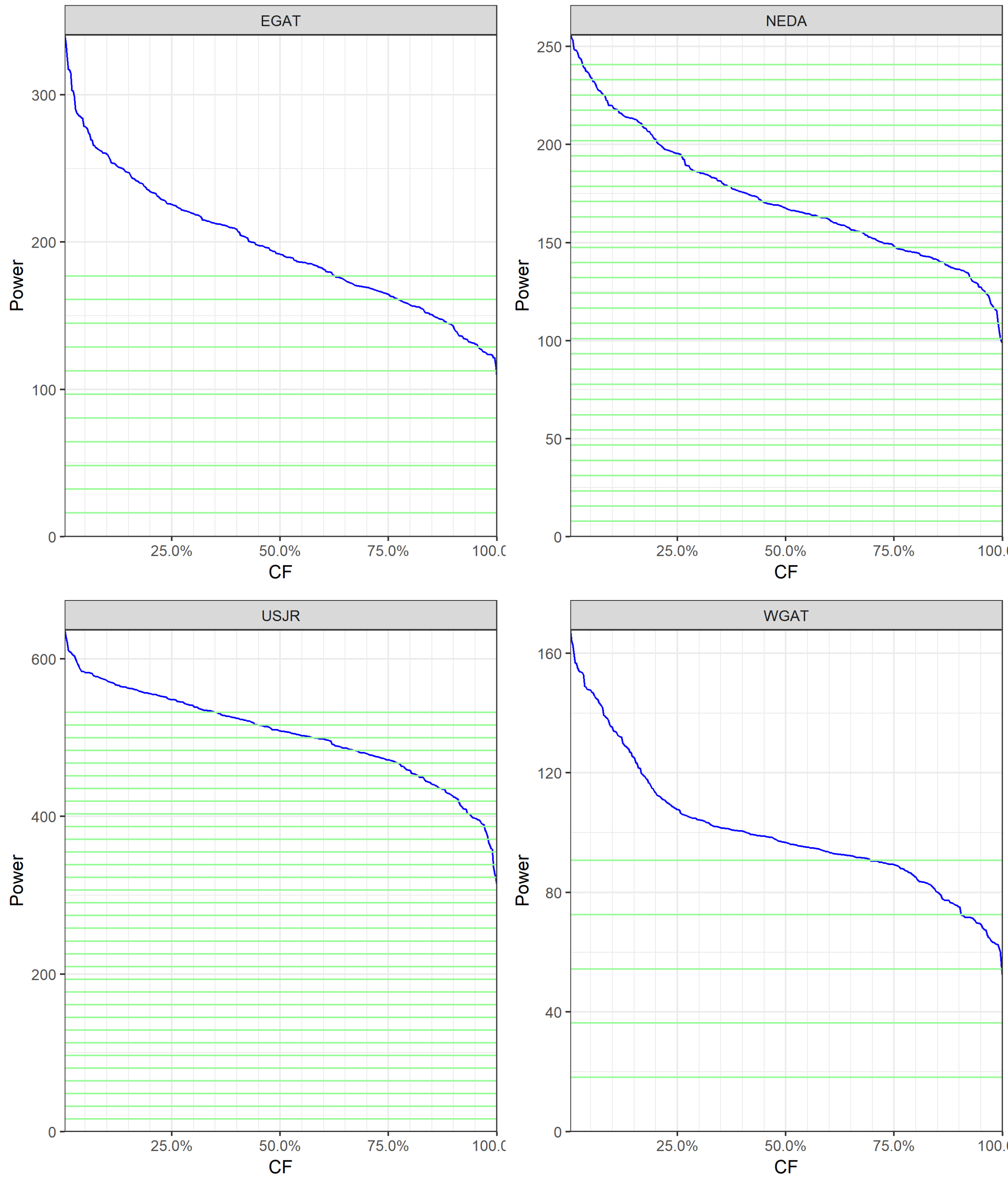


Figure 25: NGTL area 2018 load duration curves

Capacity factors are listed in Table 20. As the system operates more closely to an interconnected web than a single path delivery line, the given key points in the throughput do not however give a complete picture of the throughput relevant to each individual compressor station. Notwithstanding this, for the purpose of estimating the potential economic opportunity for WHP aggregated by province, the applied method nonetheless provides the best estimate of a key economic variable (capacity factor) given available data and reasonable effort.

B.3 Enbridge West system

The Enbridge West System, shown in Figure 26, is the primary transmission system in BC. The system brings gas from the Montney formations and interconnections with NGTL to the Lower Mainland area around Vancouver, export points to the US Pacific Northwest, and other delivery points along the way (NEB, 2018).

Gas turbine and compressor data was collected from regulatory documents (see Appendix A) for the area known as T-South, stretching from delivery points close to the US border up to the junction of the gathering systems in Northern BC, and summarized in Table 19.

Table 19: Enbridge West turbine installations

Operational Area	Flow Point	Total Power (MW)	Units Installed	Power Per Unit (MW)
T-South	Fortis BC Lower Mainland, Huntingdon Export, Kingsvale	418.5	27	15.5

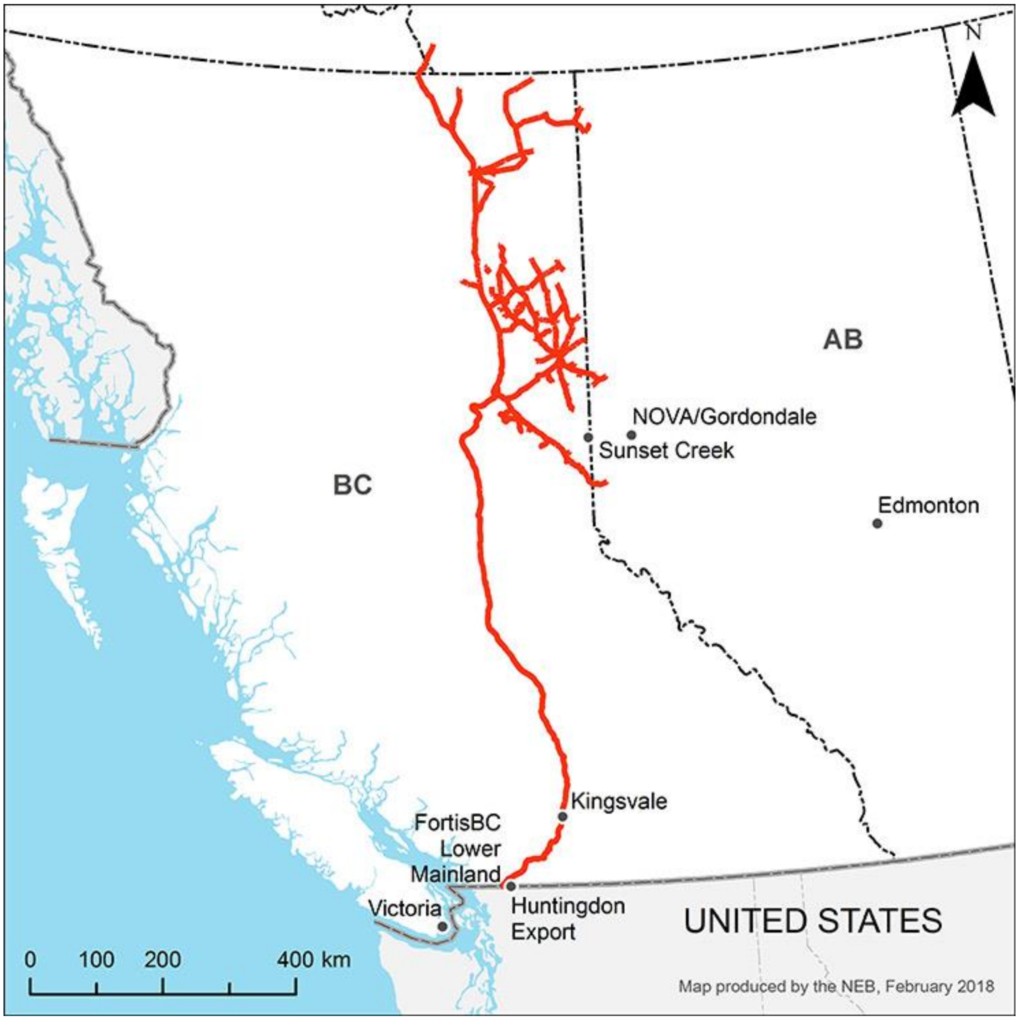


Figure 26: Enbridge West system map with key points (reproduced from NEB, 2018)

The combined flows at FortisBC Lower Mainland and Huntingdon export, adjusted for receipts or deliveries at Kingsvale (up to 10% of total flow), are used to determine the flow in T-South, as shown in Figure 27.

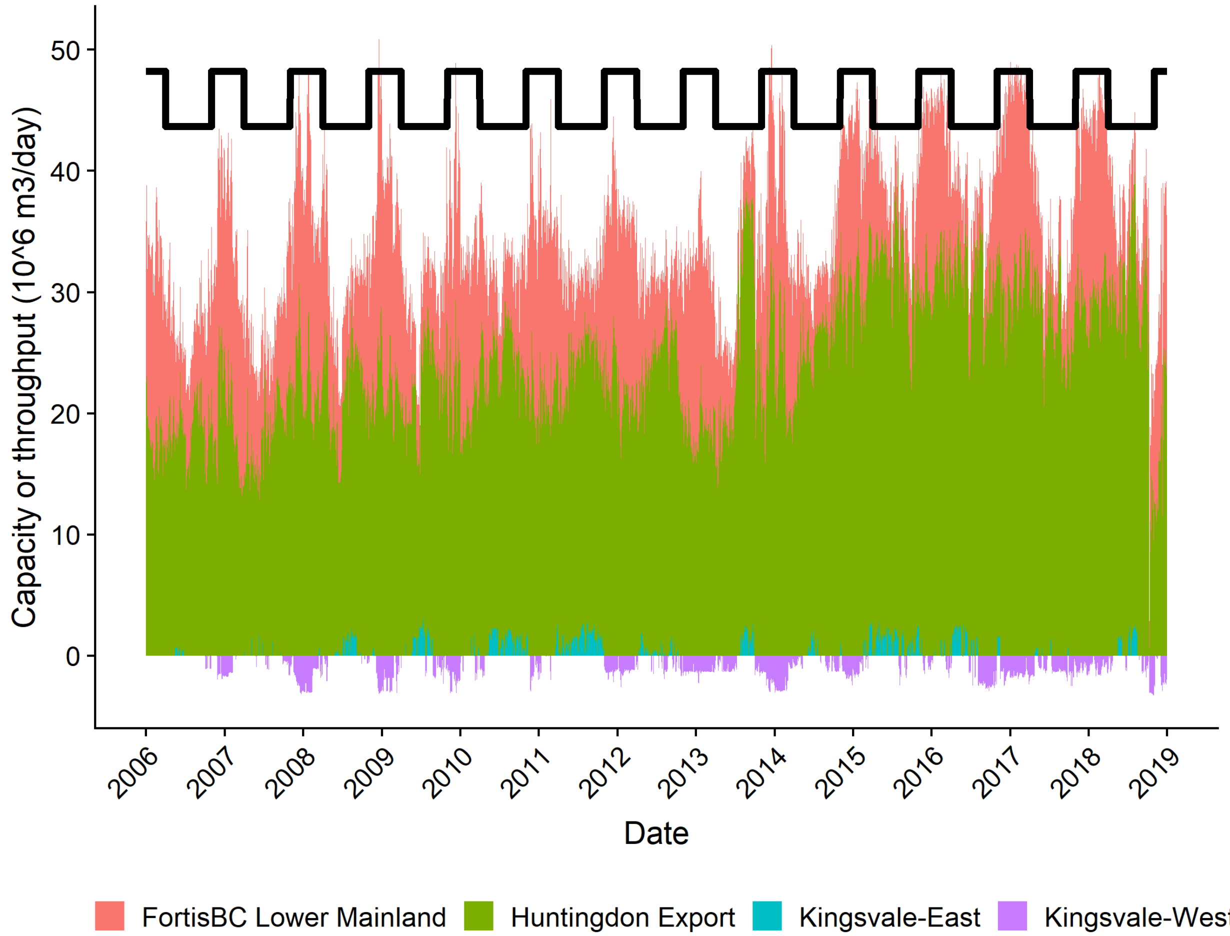


Figure 27: Flow in the Enbridge West T-South area. Colored areas are the stacked throughput, the black line is capacity.

Analysis of the system was conducted using the method in Section 2.6, producing the results in Figure 28. The data for 2017, rather than more recent 2018 data, is used as 2018 experienced significant atypical disruptions.

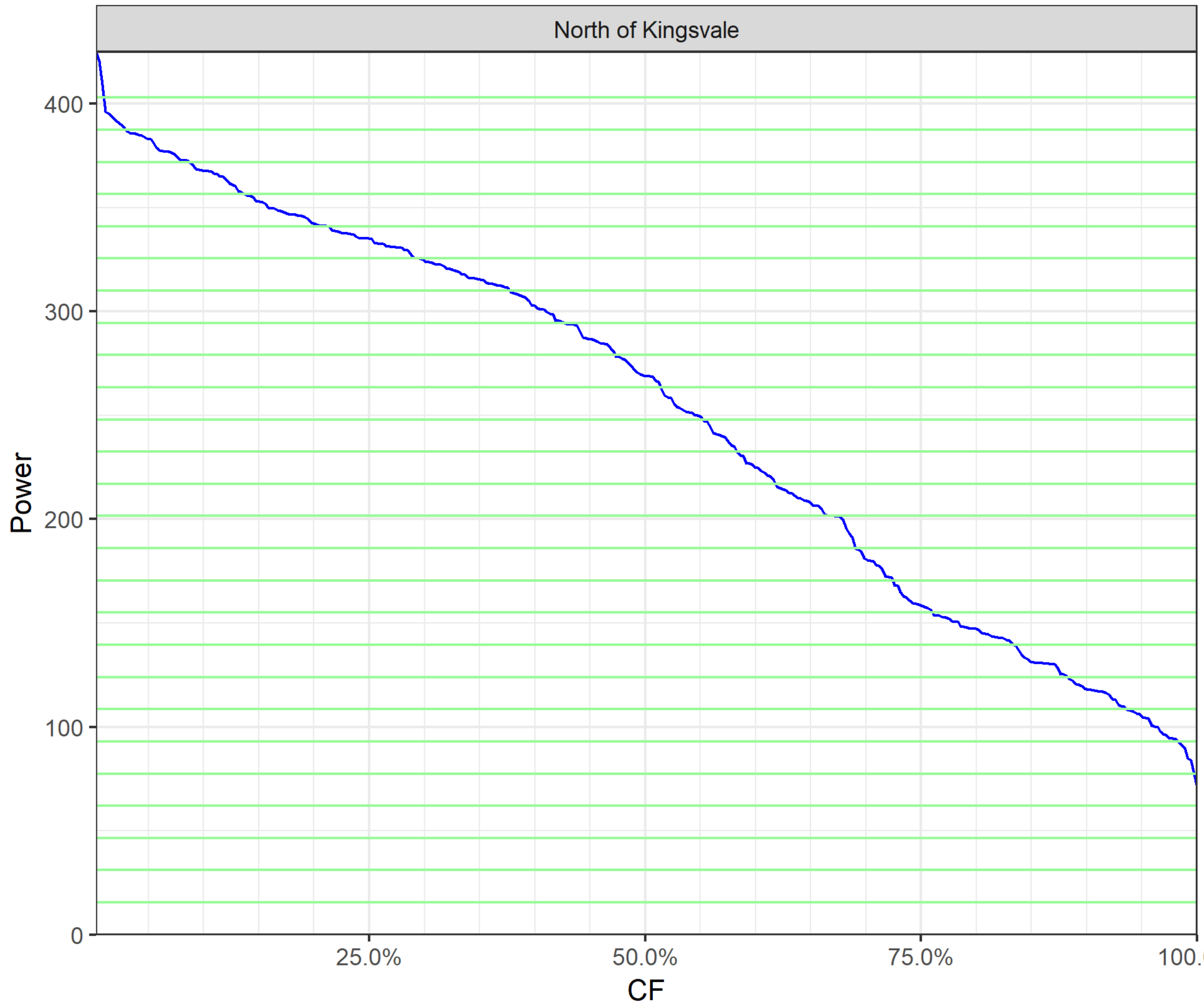


Figure 28: Enbridge West T-South 2017 load duration curve

Capacity factors are listed in Table 20.

B.4 Summary

The inputs and results of the above sections are summarized in Table 20 and Table 21.

Table 20: Summary of system and area capacity factors

System	NGTL				Enbridge West	Alliance	Mainline							
Area	EGAT	NEDA	USJR	WGAT	T-South	Mainline	PtEN	NOL	ETriNE	ETriE	Iroquois	Kirkwall	Maple	Unassigned
Total Power	193.1	326.2	548.1	108.8	418.5	228	683.5	993.8	94	32.1	42.6	40.8	40.6	287.4
Units Installed	12	32	34	6	27	9	35	44.5	6.5	7	3	5	4	29
Power per Unit (MW)	16	8	16	18	15.5	25.3	19.5	22.3	14.5	4.6	14.2	8.2	10.2	NA
Capacity Factor, per unit number)														
1	1	1	1	1	1	1	1	1	1	1	0.63	0.62	N/A	N/A
2	1	1	1	1	1	1	1	1	0	0.52	0.17	0.18		
3	1	1	1	1	1	1	1	0.65	0	0.27	0.02	0.06		
4	1	1	1	1	1	1	0.99	0.28	0	0.02		0		
5	1	1	1	0.90	1	1	0.67	0.16	0	0		0		
6	1	1	1	0.71	1	1	0.33	0.08	0	0				
7	1	1	1		0.98	1	0.08	0.02		0				
8	0.99	1	1		0.94	0.92	0	0.01						
9	0.96	1	1		0.88	0.71	0	0.01						
10	0.89	1	1		0.84		0	0.01						
11	0.77	1	1		0.76		0	0						
12	0.62	1	1		0.72		0	0						
13		1	1		0.69		0	0						
14		0.99	1		0.67		0	0						
15		0.99	1		0.62		0	0						
16		0.98	1		0.58		0	0						
17		0.96	1		0.55		0	0						
18		0.92	1		0.52		0	0						
19		0.86	1		0.48		0	0						

System	NGTL				Enbridge West	Alliance	Mainline							
20		0.75	1		0.42		0	0						
21		0.68	0.99		0.37		0	0						
22		0.58	0.99		0.3		0	0						
23		0.45	0.99		0.21		0	0						
24		0.37	0.98		0.14		0	0						
25		0.29	0.97		0.08		0	0						
26		0.26	0.94		0.02		0	0						
27		0.20	0.91		0.01		0	0						
28		0.17	0.87				0	0						
29		0.11	0.82				0	0						
30		0.08	0.77				0	0						
31		0.05	0.67				0	0						
32		0.03	0.58				0	0						
33			0.45				0	0						
34			0.35				0	0						
35							0	0						
36								0						
37								0						
38								0						
39								0						
40								0						
41								0						
42								0						
43								0						
44								0						

Table 21: Portion of installed system power by province

Systems	Provinces					
	BC	Alberta	Saskatchewan	Manitoba	Ontario	Total
Mainline - PtEN	0	0	0.732	0.268	0	1
Mainline - NOL	0	0	0	0.105	0.895	1
Mainline - ETriNE	0	0	0	0	1	1
Mainline - ETriE	0	0	0	0	1	1
Mainline - Iroquois	0	0	0	0	1	1
Mainline - Kirkwall	0	0	0	0	1	1
NGTL - EGAT	0	1	0	0	0	1
NGTL - NEDA	0	1	0	0	0	1
NGTL - USJR	0	1	0	0	0	1
NGTL - WGAT	0	1	0	0	0	1
Enbridge West - T-South	1	0	0	0	0	1
Alliance Mainline	0	0.54	0.46	0	0	1

Appendix C Capacity factor calculation evaluation – TransCanada Mainline

C.1 Purpose

Capacity factors for the pipeline compressor units are one of the most significant variables affecting the viable WHP capacity. Generally, pipeline compressor unit capacity factor data is not publicly available. Therefore, the unit capacity factors have been estimated based on daily pipeline volumetric throughput and capacity data, which is available for all analyzed systems (Government of Canada, 2018b). While the method described in Section 2.6 relies on physical relationships between system power and throughput, it is a simple model that is not expected to be as accurate as a significantly more complex hydraulic model.

The accuracy of this method for calculating system capacity factors is therefore evaluated here. I use the unit capacity factor data for the TransCanada Mainline system in 2010, which is the only known publicly available capacity factor dataset (TransCanada Pipelines, 2011). When evaluating this information, it must be considered that this data is only available because the TransCanada Mainline was becoming economically unviable due to large throughput decreases. The listed capacity factors should not be seen as indicative of other systems.

This appendix is intended to be read in conjunction with Section 2.6 and Appendix B Section B.1.

C.2 2010 capacity factor characteristics

Some exploratory visualizations of 2010 Mainline capacity factors are shown in this section.

Actual brakepower energy was calculated by multiplying the nameplate turbine brakepower and the 2010 turbine operating hours, and do not consider the effects of ambient temperature, site elevation, and partial loading. This analysis includes the units active in 2010, including 17 compressor units that have been decommissioned and excluding new units installed since 2010 (see Appendix A).

Figure 29 through Figure 32 show exploratory analysis of 2010 utilization data broken down variably by station, unit, power, energy, and/or installation year.

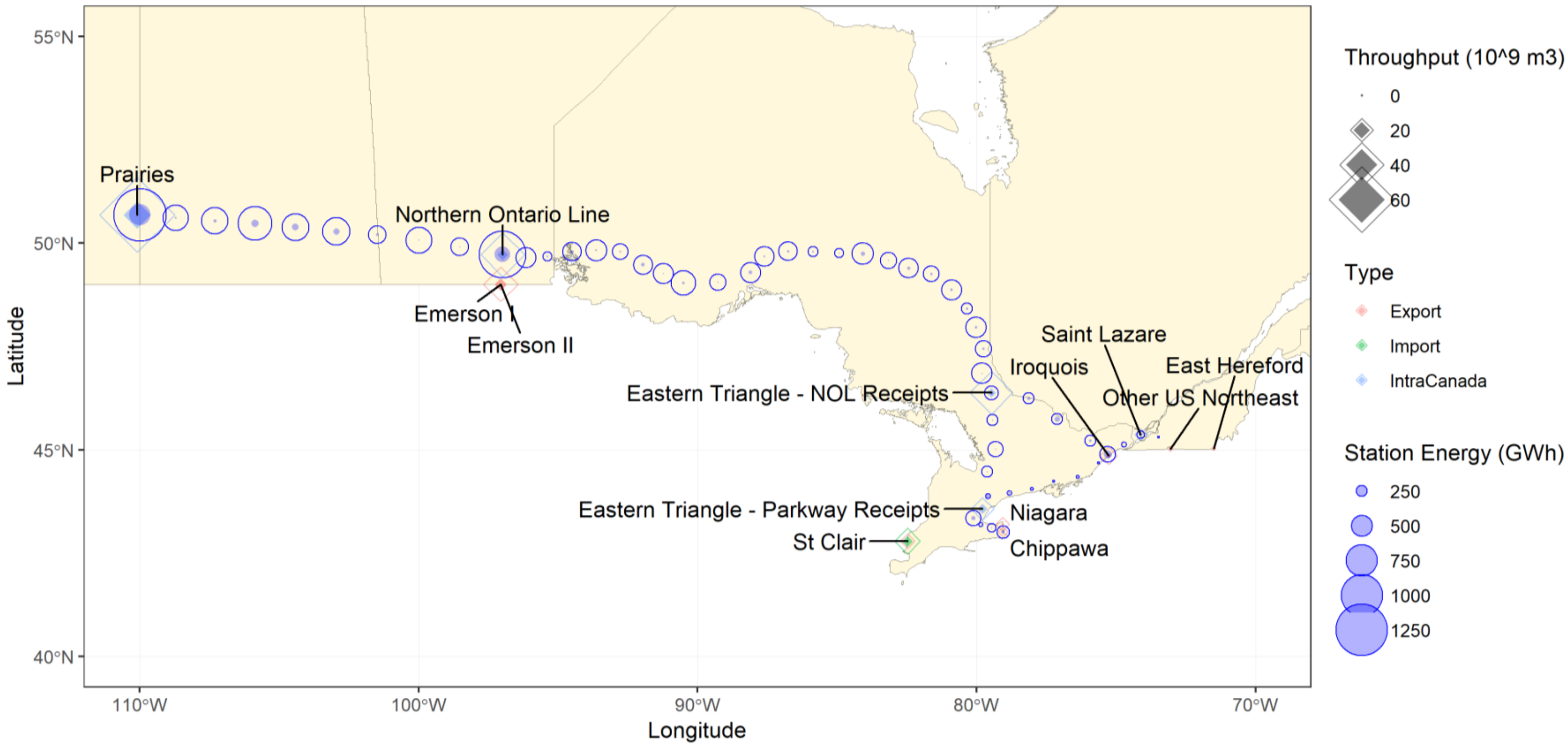


Figure 29: TransCanada Mainline 2010 overview. Circles indicate compressor stations, with all units at each station combined together. Diamonds indicate flow measurement points. The unfilled shapes are the potential flow and station energy at full capacity. The filled shapes are the actual flow and station brakepower energy summed over 2010.

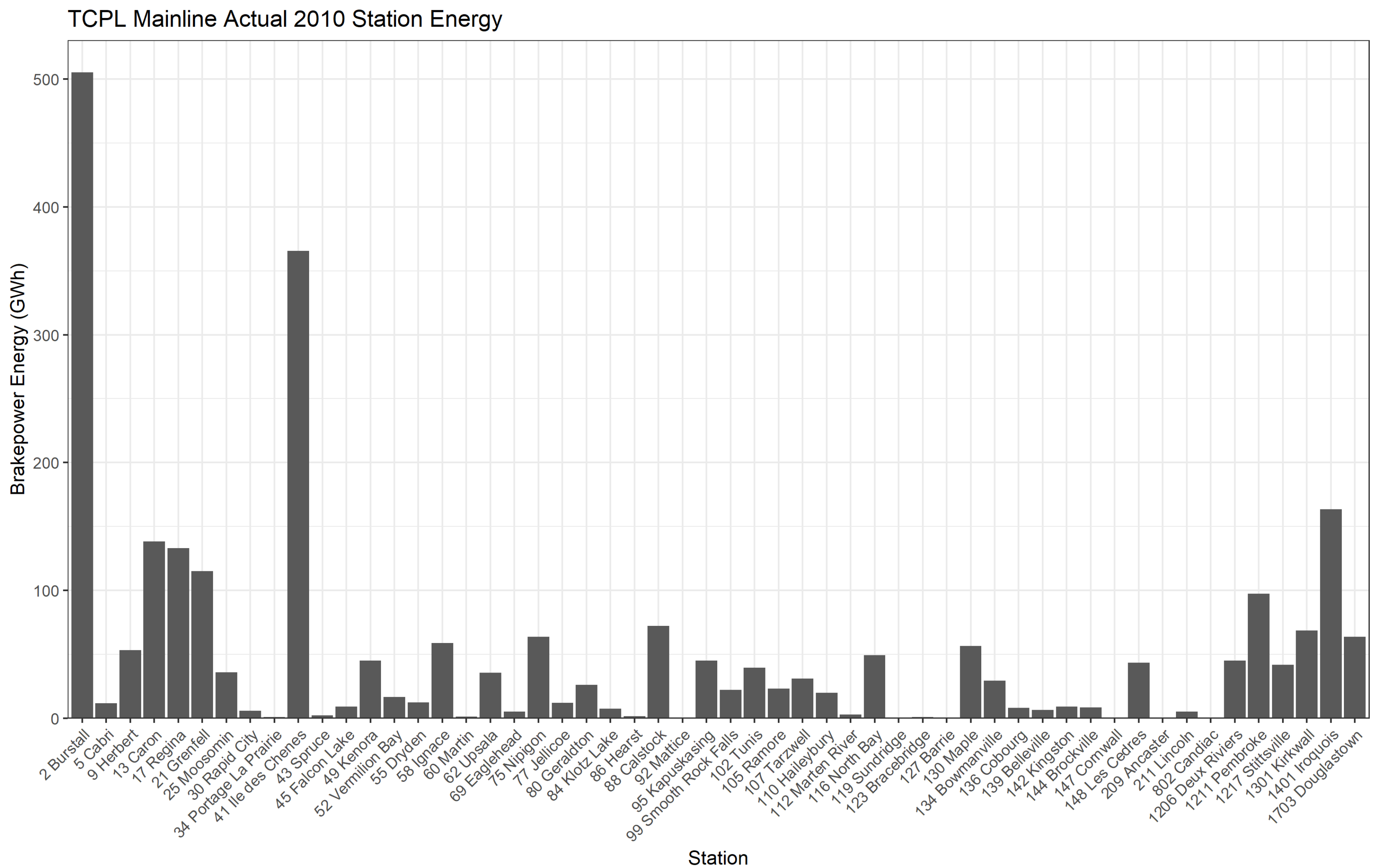


Figure 30: TransCanada Mainline 2010 brakepower energy by station.

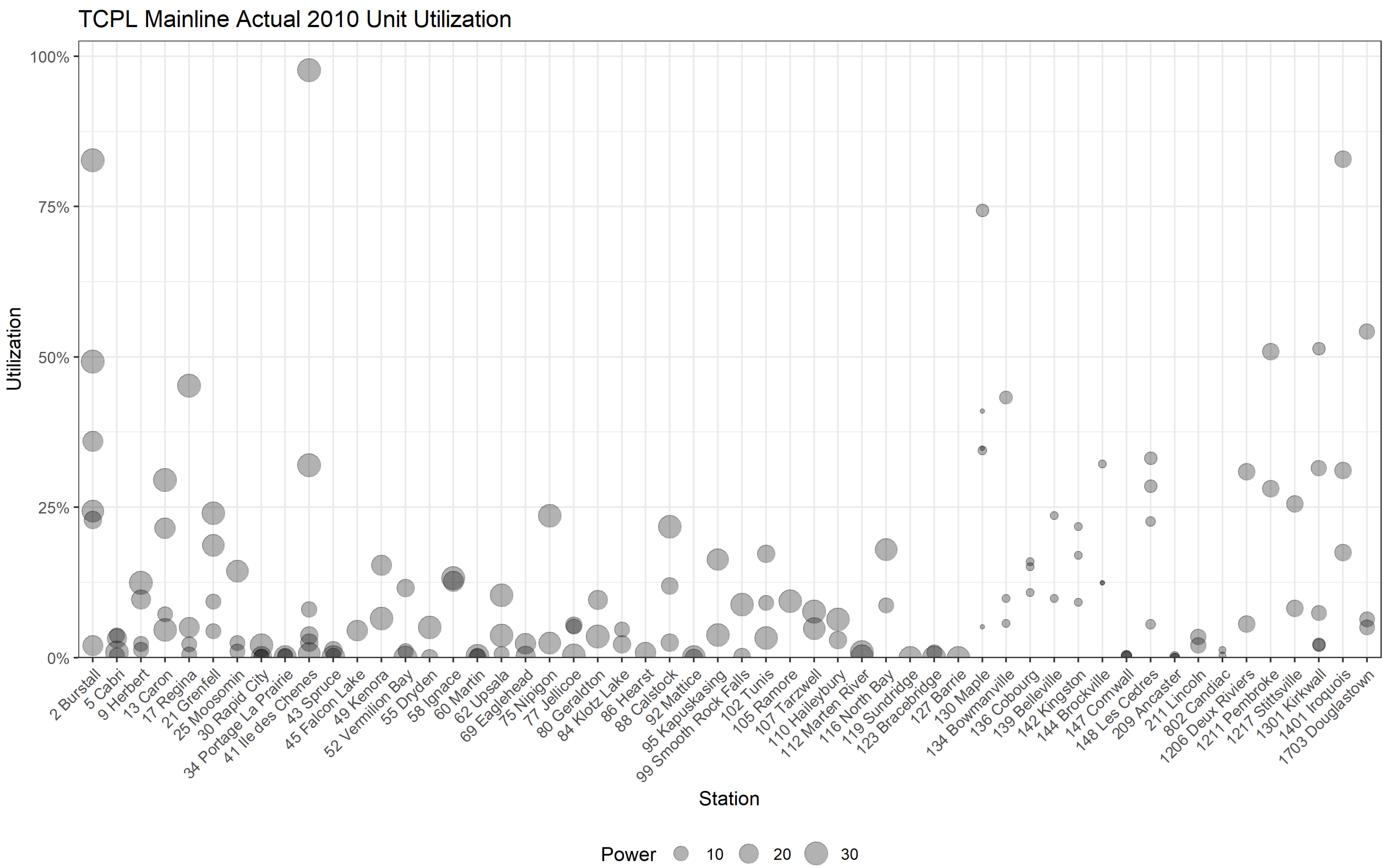


Figure 31: TransCanada Mainline 2010 utilization per unit, by station.

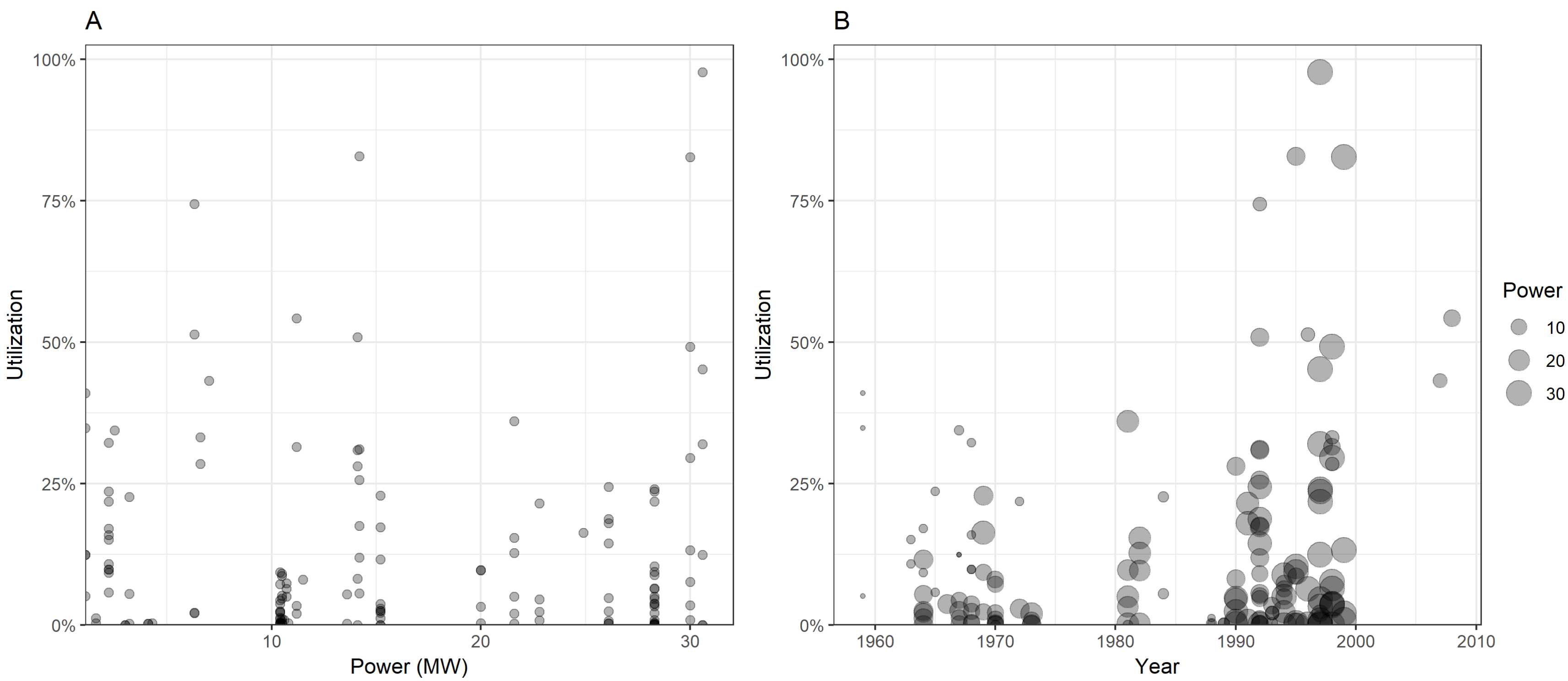


Figure 32: Compressor unit utilization by unit capacity (A) and installation year (B). Installation year is an indicator of higher utilization factors, but low utilization units are prevalent across the range of unit sizes and installation years.

Prairie to Emerson/Northern Ontario Line

The stations with the highest brake energy are at the flow measurement points, which are also at the junctions between different flow paths, as shown in Figure 33. Using the method described in Section 2.6, a load duration curve is shown in Figure 34.

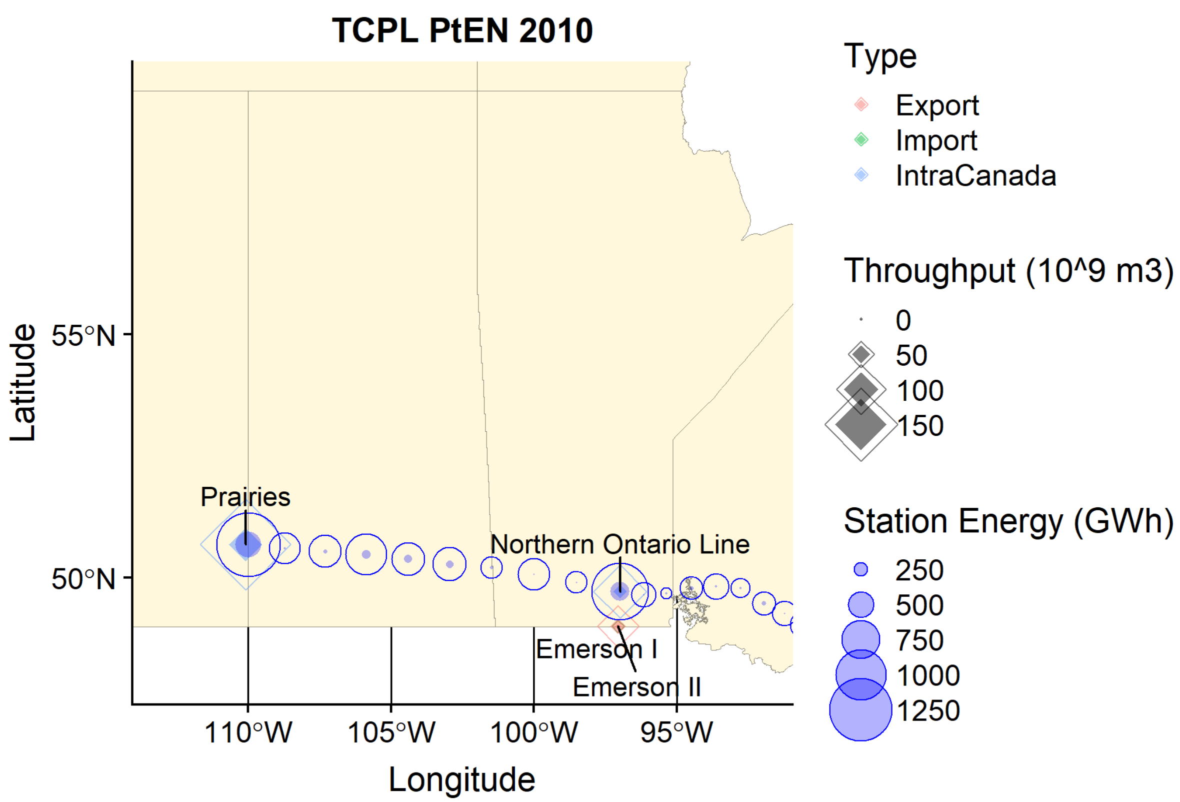


Figure 33: TCPL Prairies to Emerson - Northern Ontario Line. The unfilled shapes are the potential flow and station energy at full capacity. The filled circles are the actual flow and station brakepower energy summed over 2010.

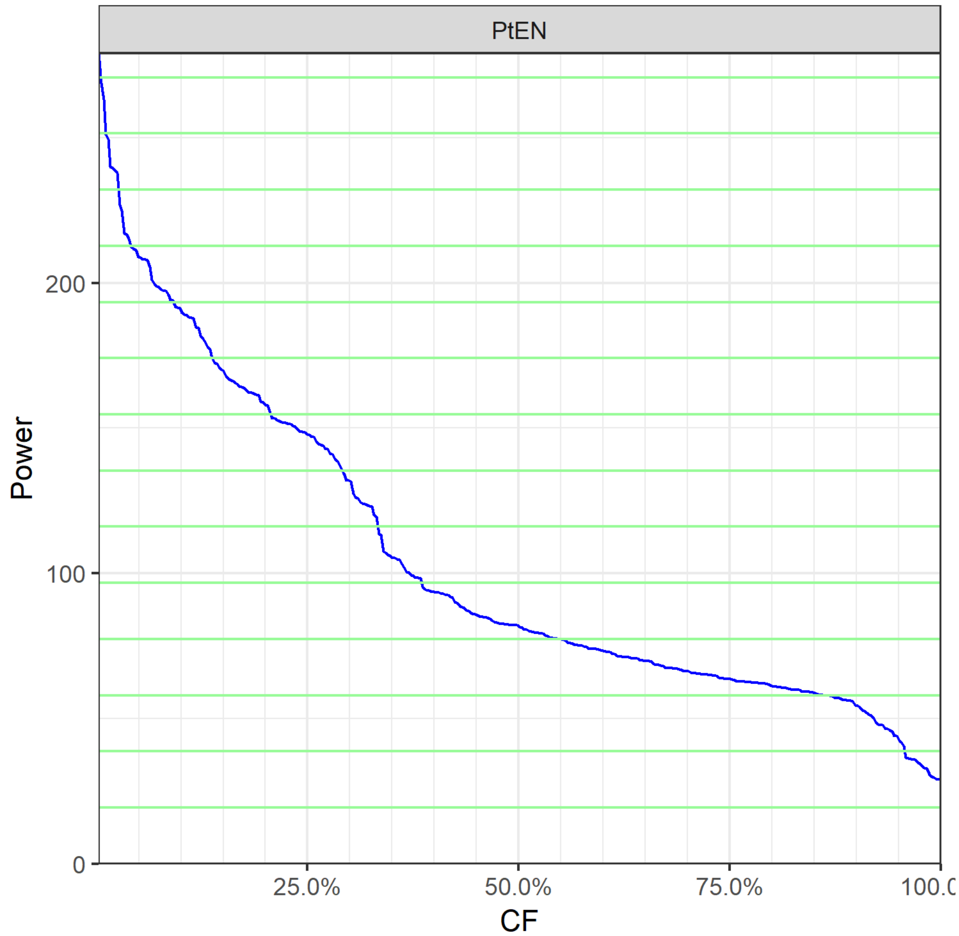


Figure 34: Calculated power requirement for the PtEN area. The blue line represents the estimated mechanical brakepower requirement for 2010, organized as a load duration curve. The horizontal green lines are multiples of the average power per unit installed in the area. From this graph, unit capacity factors are determined.

Northern Ontario Line

A more detailed view of the NOL area is shown in Figure 35. The stations operated the most are at the flow measurement points, which are also at the junctions between different flow paths. Installed turbine brakepower capacity between the NOL to Eastern Triangle – NOL Receipts key points is 1081 MW. A load duration curve is shown in Figure 36.

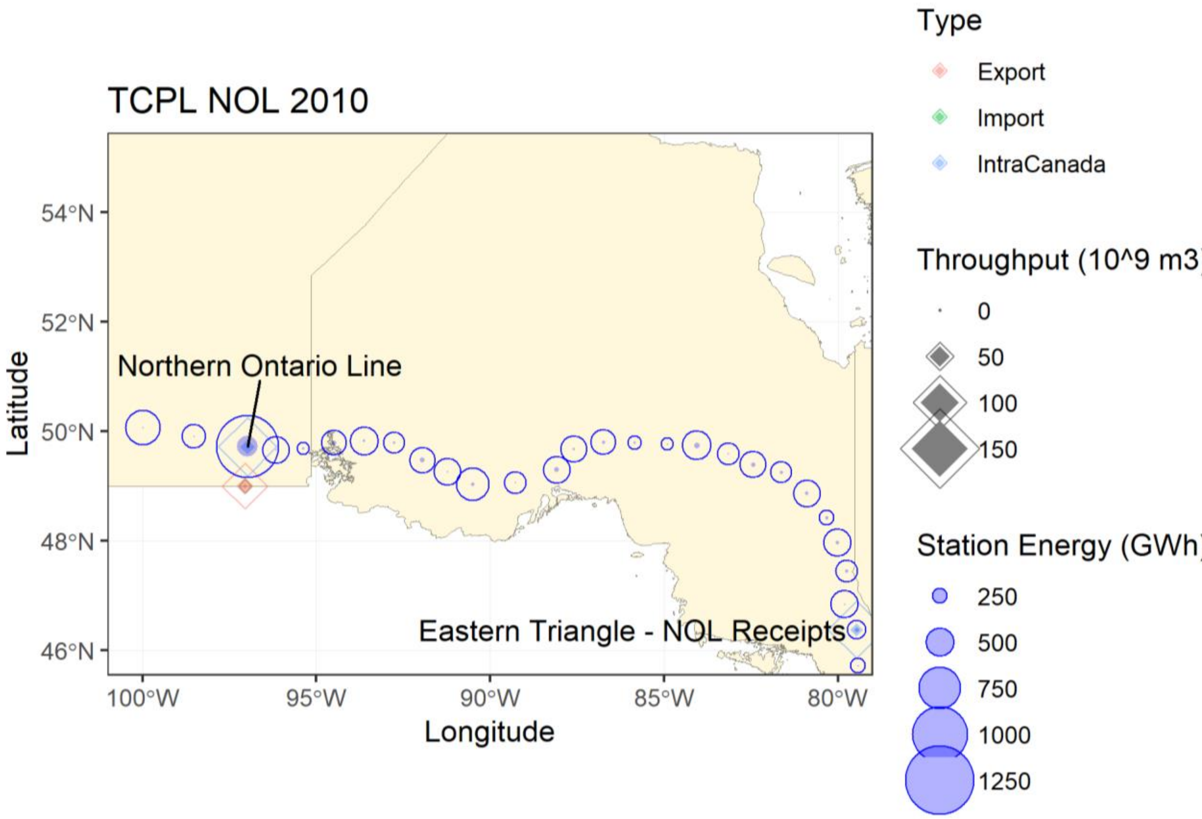


Figure 35: Northern Ontario Line. The unfilled shapes are the potential flow and station energy at full capacity. The filled circles are the actual flow and station brakepower energy summed over 2010.

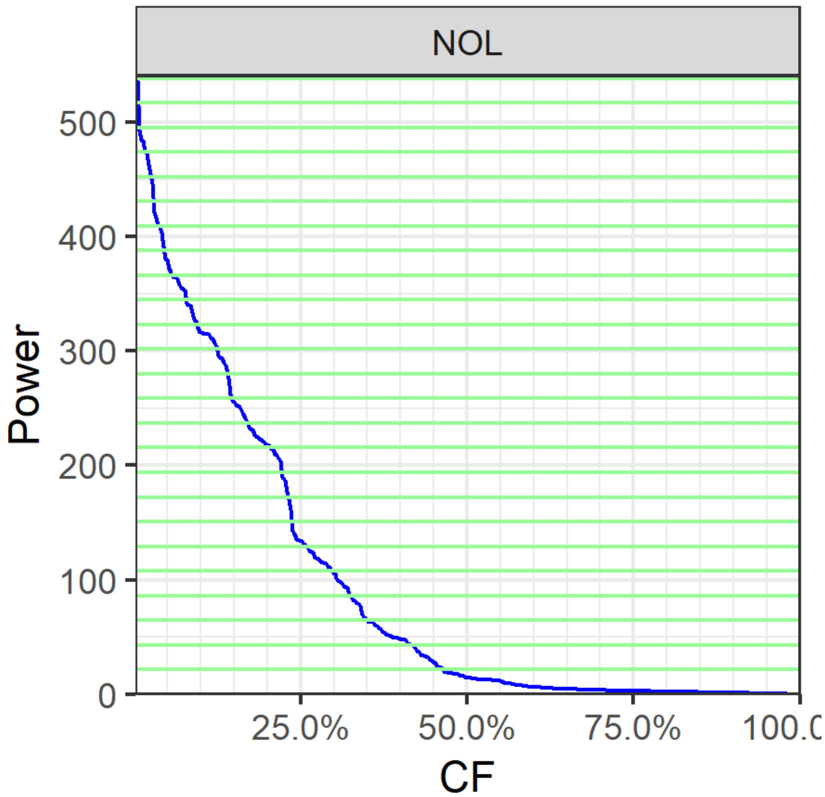


Figure 36: Calculated power requirement for the NOL area. The blue line represents the estimated mechanical brakepower requirement for 2010, organized as a load duration curve. The horizontal green lines are multiples of the average power per unit installed in the area. From this graph, unit capacity factors are determined.

Eastern Triangle

For a detailed map of the Eastern Triangle with 2010 load data, refer to Figure 16. Load duration curves are shown in Figure 37.

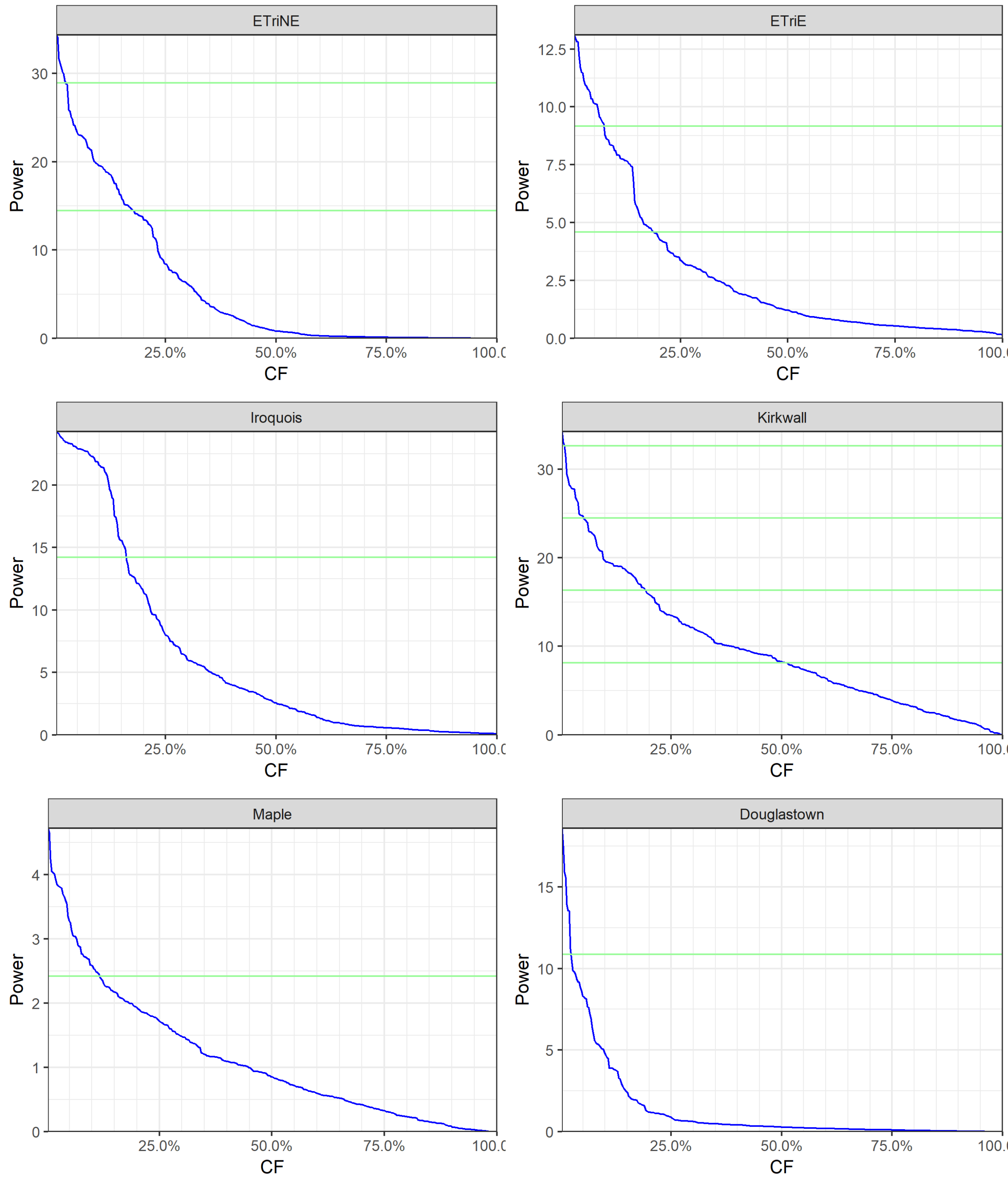


Figure 37: Eastern Triangle 2010 estimated capacity factors

C.3 Results

Estimated capacity factor results for all areas are shown in Table 22.

Table 22: TransCanada Mainline 2010 estimated capacity factors

Unit	PtEN	NOL	ETriNE	ETriE	Iroquois	Douglastown	Kirkwall	Maple
1	1	0.95	0.93	1	1	0.96	1	0.97
2	1	0.46	0.18	0.18	0.16	0.02	0.51	0.12
3	0.95	0.42	0.02	0.07	0	0	0.18	0
4	0.87	0.35	0	0	0	0	0.05	0
5	0.55	0.33	0	0	0	0	0.01	0
6	0.38	0.3	0	0	0	0	0	0
7	0.33	0.26	0	0	0	0	0	0
8	0.29	0.24	0	0	0	0	0	0
9	0.20	0.23	0	0	0	0	0	0
10	0.13	0.22	0	0	0	0	0	0
11	0.08	0.21	0	0	0	0	0	0
12	0.04	0.17	0	0	0	0	0	0
13	0.03	0.15	0	0	0	0	0	0
14	0.01	0.14	0	0	0	0	0	0
15	0.01	0.12	0	0	0	0	0	0
16	0	0.09	0	0	0	0	0	0
17	0	0.08	0	0	0	0	0	0
18	0	0.06	0	0	0	0	0	0
19	0	0.04	0	0	0	0	0	0
20	0	0.04	0	0	0	0	0	0
21	0	0.03	0	0	0	0	0	0
22	0	0.03	0	0	0	0	0	0
23	0	0.02	0	0	0	0	0	0
24	0	0.01	0	0	0	0	0	0
25	0	0.01	0	0	0	0	0	0

Results between estimated and actual 2010 turbine capacity factors are compared in three ways. The first is to compare the total brake energy estimated to the actual brake energy produced in 2010 (Figure 38). The second is to analyze the capacity factor distribution between units (Figure 39). The third is to compare how these differences in capacity factors affect the actual objectives, namely the investment NPV calculation and the economic WHP capacity calculation (Figure 40).

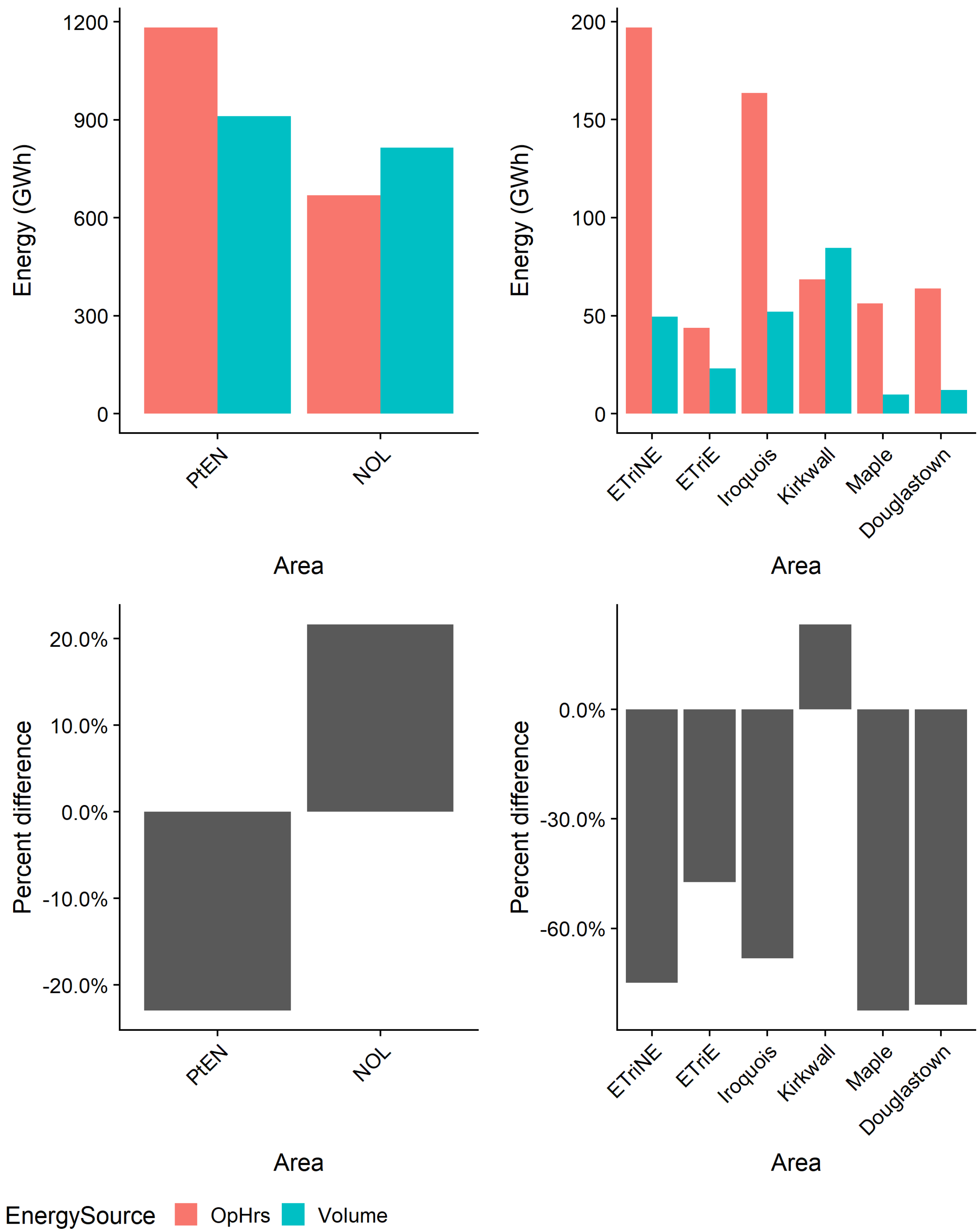


Figure 38: Comparison of actual (OpHrs) and estimated (Volume) 2010 brake energy by area

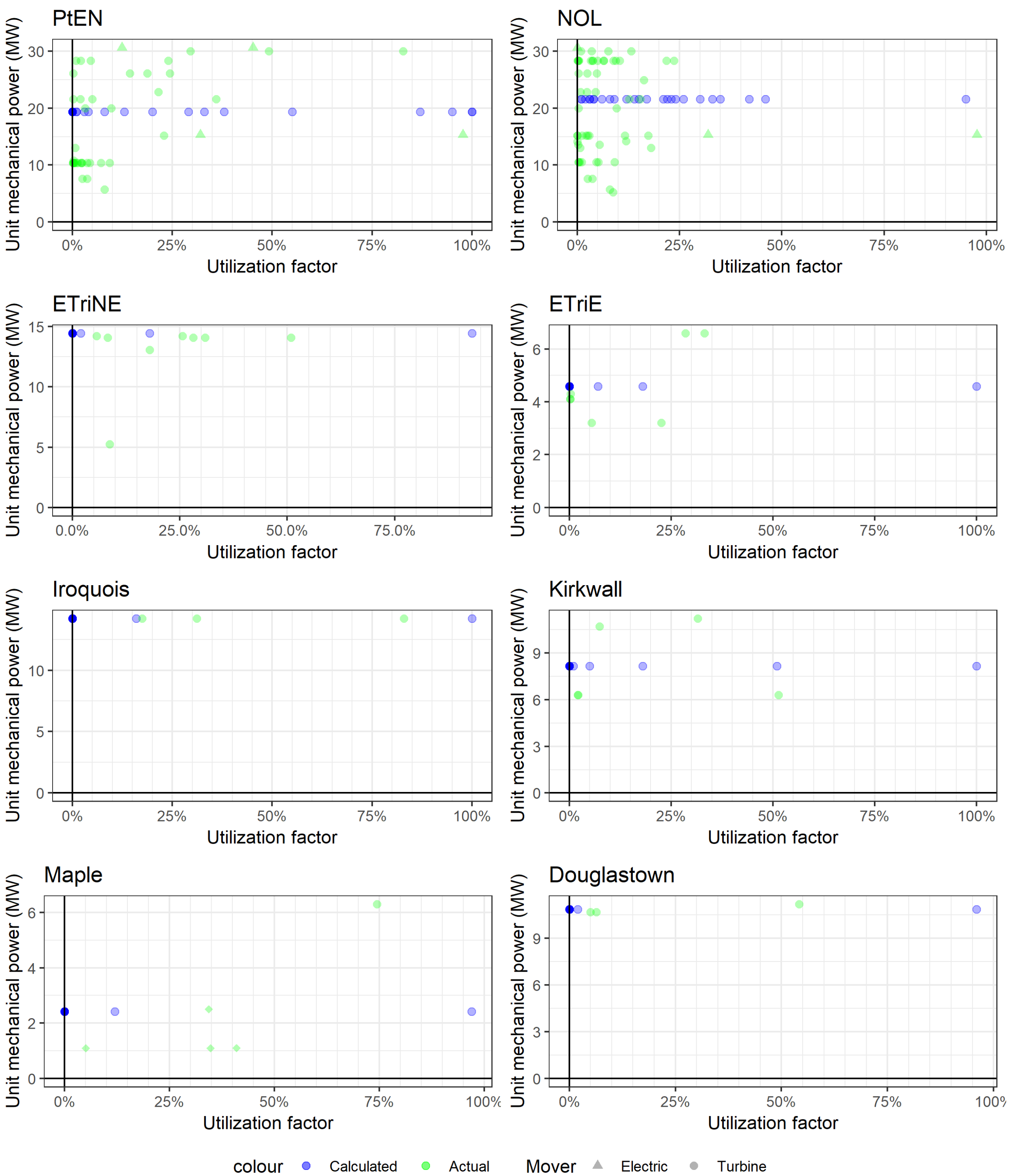


Figure 39: Comparison of actual and estimated 2010 unit capacity factors by area

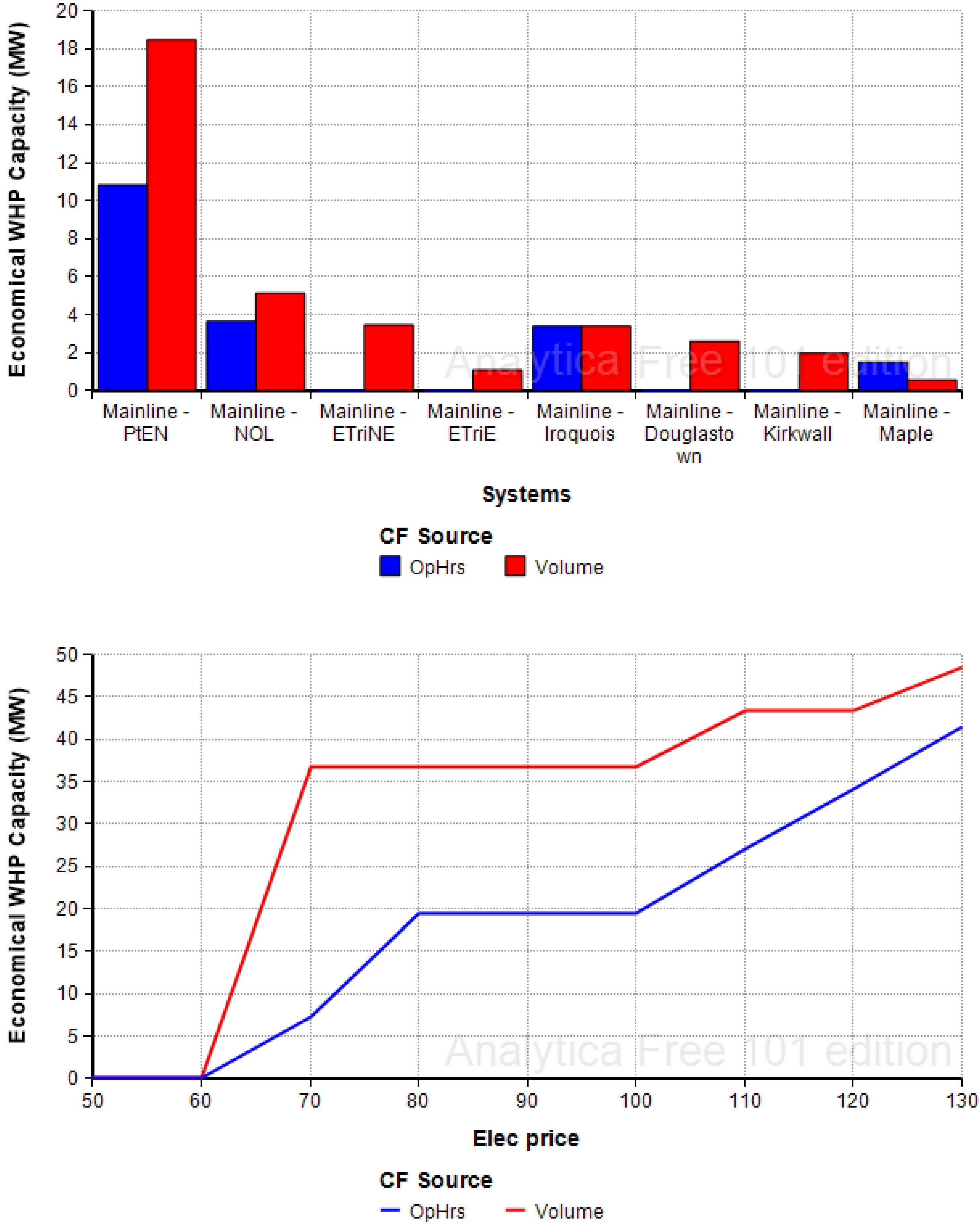


Figure 40: Comparison of economical WHP capacity by data source, area, and electricity purchase price

Note, Douglastown, Iroquois, NOL, and PtEN had flow measurement points directly adjacent, or surrounding, the area/unit in question. By comparison, EtriE, EtriNE, Kirkwall, and Maple all required mass balance equations with assumptions to produce these results, introducing additional sources of error.

It appears that the accuracy is better for larger areas compared to individual units, and the assumptions in the mass balance equations introduce significant additional errors. The higher accuracies of PtEN and NOL may therefore be most indicative of accuracies for Enbridge West and Alliance. However, this is based on limited observations and it's unclear if these inferences would hold if more comparisons were possible. The Mainline system is also operating significantly below its design capacity. The operating strategy may differ from the operating strategy of systems closer to their design capacity, which should be considered when determining the applicability of extrapolating this comparison to other systems. Further reflections on method accuracy are included in Section 2.6.2 of the main text.

Appendix D Investment model influence diagrams

Influence diagrams for the Analytica investment model shown in Figure 41 to Figure 43.

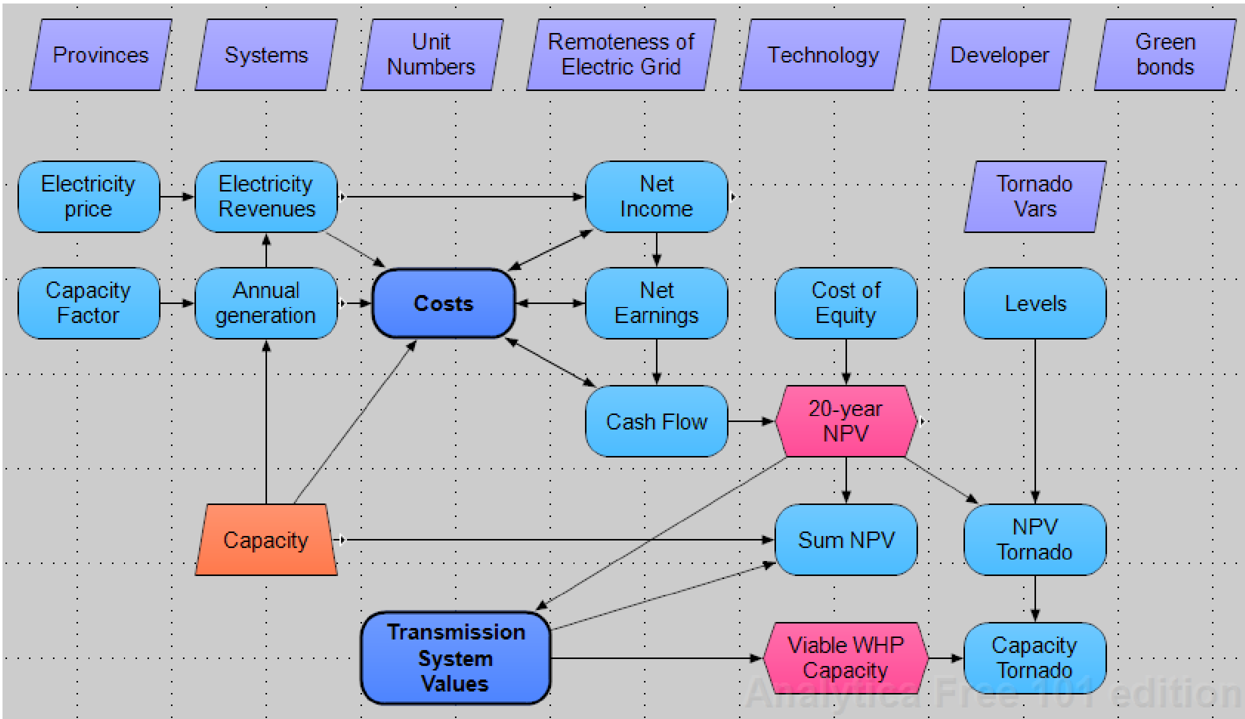


Figure 41: WHP investment model diagram

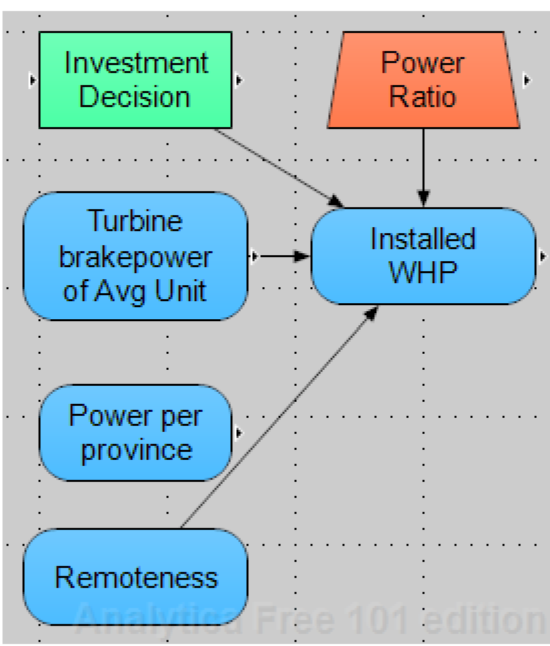


Figure 42: WHP investment model diagram – transmission system values

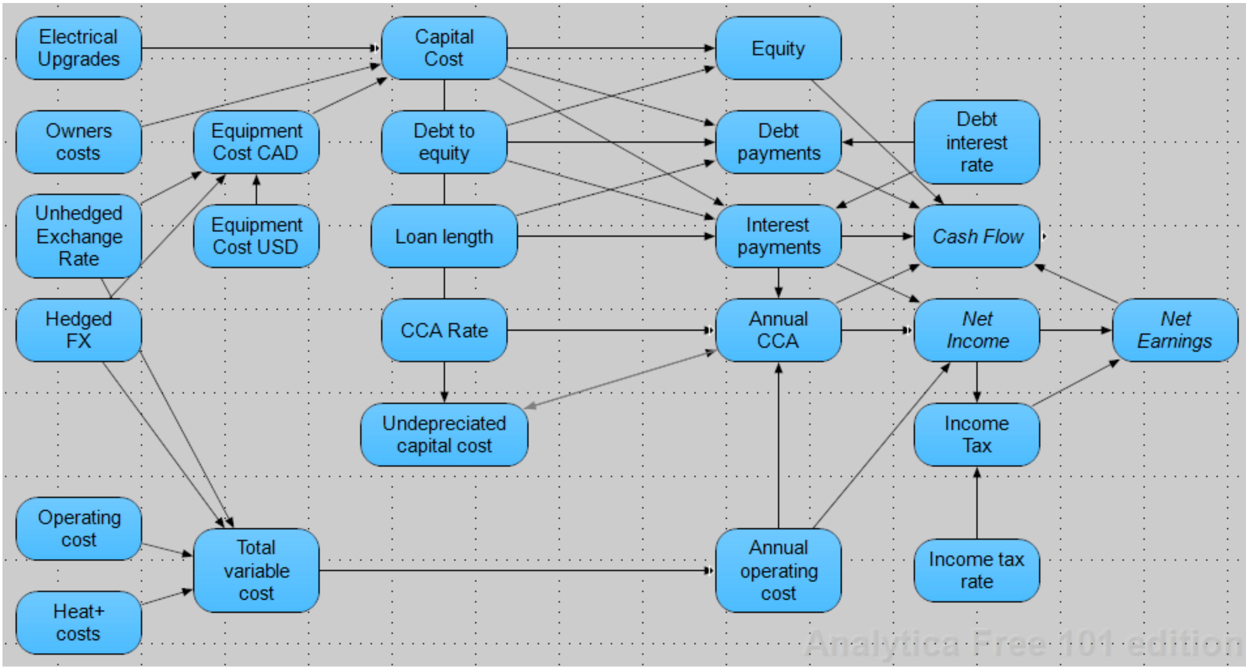


Figure 43: WHP investment model diagram - costs

Appendix E Heat payments

Table 23: Summary of heat payment valuations

Station	Power (MW)	Ref. Year	Assumed efficiency[2]	Capacity factor	Exhaust energy (MW)	Annual equivalent energy demand (GJ)	Natural gas price in ref. year ($/GJ)	Avoided cost ($)	Total Annual Contract Heat value	Contract value per GJ	Avoided cost/ Contracted value
Enhanced combined cycle stations											
Potter Station 102	28.3	1997	0.35	0.8	52.6	1,326,862	3.5	4,644,016	100,000	0.075	46.4
Nipigon	28.3	1997	0.35	0.8	52.6	1,326,862	3.5	4,644,016	113,350	0.085	41.0
North Bay	26.1	1997	0.35	0.8	48.5	1,223,714	3.5	4,282,997	102,100	0.083	41.9
Calstock Unit B	14.2	1997	0.35	0.8	26.4	665,775	3.5	2,330,213	50,000	0.075	46.6
Calstock Unit C	28.3	1997	0.35	0.8	52.6	1,326,862	3.5	4,644,016	100,000	0.075	46.4
Kapuskasing	28.3	1997	0.35	0.8	52.6	1,326,862	3.5	4,644,016	102,100	0.077	45.5
ORC WHP Stations											
Crowsnest	6.5	2013	0.2	0.8	32.5	820,498	3.0	2,461,493	400,000	0.488	6.2

[1] Gas turbine brake power for Enhanced combined cycle stations, electric power for ORC WHP installations
[2] Gas turbine efficiency for Enhanced combined cycle stations, waste heat cycle efficiency for ORC WHP installations

The earlier contractual waste valuation of approximately \$0.08/GJ is adjusted for inflation from 1997 to 2013 to a value of \$0.108/GJ. The actually Crowsnest waste heat valuation is estimated as 4.5 times this earlier inflation adjusted valuation. The waste heat value used in the analysis, \$6.6/MWh, would instead be \$1.5/MWh if it had increased at the rate of inflation. It would be even lower if tied to the inflation-adjusted cost of natural gas, which has fallen significantly over this time period.