Greening the Saskatchewan Grid

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Abstract

Saskatchewan is home to one of the most greenhouse gas (GHG) emissions intensive electricity sectors in Canada. To contribute to global efforts to mitigate climate change, and comply with Canadian coal-fired electricity regulations, the province must transform its electricity sector in the coming decades. This dissertation asks, what is the cost of reducing Saskatchewan's electricity sector GHG emissions by 80% or more by 2050, using a mix of renewable electricity generating technologies? A renewable focused *Greening the Saskatchewan Grid* scenario is compared with a business-as-usual scenario and alternative pathways for reducing GHG emissions. Scenarios are selected using a linear programming model called the Saskatchewan Investment Model (SIM). The resulting scenarios are then tested using the 'Will-It-Run-Electricity' Model (WIRE) to understand whether a given electricity generation mix can adequately meet hourly electricity demand. Scenarios are compared using indicators such as electricity cost, GHG emissions, land impact, water impact, and radioactive waste, and sustainability criteria such as path dependence. It is found that a *Greening the Grid* scenario can reduce electricity sector GHG emissions to near zero levels by 2040. There is an added financial cost for taking this leadership path, but the cost of the *Greening the Grid* scenario becomes comparable to competing scenarios when an escalating carbon price is assumed.

This dissertation also presents the results of a deliberative modelling exercise. Three workshops were held in Saskatchewan that brought together diverse participants interested in the future of the Saskatchewan electricity system. The goal of the workshops was to understand whether deliberation, supported by an interactive version of SIM, could encourage shared understanding of the barriers to and opportunities for expanding renewable energy in Saskatchewan. Workshop participants did not shift their positions to a great extent, except to find consensus that there are political and policy barriers to renewable energy expansion.

This research contributes to the energy transitions literature by providing a case study of the costs and barriers faced when pursuing a renewable energy focused electricity system. It also contributes to the field of deliberative ecological economics and provides an example of an ecological economics approach to energy policy modelling.

For my family

Acknowledgements

I would like to thank my supervisor Peter Victor for his wise counsel, encouragement, and kindness. The might of your intellect is matched with a warmth and good humour that has made my PhD journey, while challenging, at least happily so. Thank-you to my supervisory committee Ken Belcher, Ellie Perkins, and Mark Winfield for all of the work you put into this project, including countless hours reviewing research proposals and drafts of this document. It felt as if we were all rowing the boat together. Thank-you to Jennifer Fix for all your help workshop preparing, note transcribing, map making, and document stitching. Your support has made an impossible task possible and saved my sanity at all the right moments. A tremendous thank-you to everyone who participated in this research project, whether it was sitting down for an interview, attending a workshop, supplying data, or contributing in all three ways. This research is like the parable of stone soup; the contributions of research participants have made it much richer. Thanks especially to SaskPower for your openness and willingness to share information, and to Dr. Mark Bigland-Pritchard for the crucial hourly wind and solar data for Saskatchewan. Any errors and omissions are of course still the responsibility of the chef of this stone soup, myself. Lastly, I would like to acknowledge financial support from the Social Sciences and Humanities Research Council (SSHRC), and administrative support from York University's Faculty of Environmental Studies.

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Chapter 1 – Introduction

Introduction

In the spring of 2009 the Government of Saskatchewan released a report by the government-funded Uranium Development Partnership (UDP, 2009). The report set out an ambitious expansion strategy for the Saskatchewan uranium mining industry, and proposed that Saskatchewan construct "up to approximately 3000 MW of nuclear capacity…to meet Saskatchewan's power needs and capture export opportunities" (UDP, 2009: 55). Two months later former Deputy Premier Dan Perrins travelled around the province seeking input from the people of Saskatchewan on the UDP proposals. Thousands of citizens attended meetings expressing their opposition to the plan (Perrins, 2009). One of the strongest sentiments was that Saskatchewan had yet to explore other low-carbon electricity pathways. Why, they asked, pursue dangerous nuclear power when the province could instead pursue energy conservation and renewable energy from wind, solar, biomass, and hydroelectricity?

I was working as a journalist that spring. When a friend called to ask if I would cover the UDP consultation I agreed. The consultation would be the first province-wide discussion of the uranium industry in a generation, and the first province-wide discussion of nuclear power in the history of Saskatchewan. Scraping by with borrowed film equipment, and sleeping on the couches of family, friends and acquaintances to conserve our limited budget, we followed the Perrins consultation around the province. From the first meeting in Yorkton, opposition to nuclear power was clear and strong. We arrived in Yorkton to witness a local woman demand that Mr. Perrins allow her to present an alternative perspective to the UDP. Perrins consented and so this concerned citizen stood at the front of the room and warned of the dangers of nuclear power. She spoke of the long-lived nuclear waste, the higher incidence of cancer in children who lived near nuclear power plants in Germany, and the readily available renewable energy alternatives that could provide Saskatchewan with the power it needed. This meeting was not unique. At each stop on the trip we heard eloquent and well-researched arguments against nuclear power and for renewable energy. A common question was: why does the Government of

Saskatchewan not undertake a study of the potential for renewable energy in the province?

The question lingered in my mind for months. Where would this study come from? Who would investigate the potential for renewable energy in Saskatchewan? With my background in economics and public policy I eventually thought to myself, why not me? Thus began a six-year journey to understand how to *Green the Saskatchewan Grid* using renewable energy. This dissertation presents the results of my inquiry.

Related Literature

Others have investigated the potential for renewable energy in Saskatchewan. Mark Bigland-Pritchard and Peter Prebble published a series of papers outlining a vision for a renewable electricity future and policies to achieve this vision (Prebble, 2011; Bigland-Pritchard, 2011; Bigland-Pritchard & Prebble, 2010; Bigland-Pritchard, 2010a & 2010b; Bigland-Pritchard, 2015a). Bob Halliday (2013) provided a roadmap for how SaskPower could reduce GHG emissions in the province by shifting to renewable energy. These studies stopped short, however, of comprehensively modelling the likely electricity rate, employment, and environmental impacts of transitioning towards a sustainable electricity system in the province. This dissertation builds on their work.

There have been economic modelling studies of the cost of reducing greenhouse gas (GHG) emission in Saskatchewan's electricity sector. Kwaczek *et al.* (1996) used a MARKAL (MARKet ALlocation) linear programming model to evaluate the cost of stabilizing Saskatchewan's GHG emissions at 1990 levels by 2000 or by 2010. They concluded that emission reductions in the electricity sector would be less expensive than reductions in sectors like oil refining (Kwaczek *et al*., 1996). To achieve GHG emissions reductions the model recommended that Saskatchewan build additional hydroelectric capacity, wind capacity, and nuclear capacity in that order of preference (Kwaczek *et al*., 1996). Lin *et al*. (2005) and Lin *et al*. (2010) also used a MARKAL linear programming approach to study the cost of Saskatchewan GHG emission reductions that would comply with the Kyoto protocol. They concluded,

> When Canada ratified the Kyoto protocol, the least-cost solution for Saskatchewan in the absence of nuclear power, would be to phase out coal-fired power generation plants and to replace them with lower emission options, such as gas-fired, hydro, and wind-power technologies. (Lin *et al*., 2010: 1601)

Lin *et al*. (2010) reported that nuclear power would achieve emissions reductions at a lower price, if it were socially acceptable. They did not report the cost assumptions used in their model.

While Kwaczek *et al*. (1996), Lin *et al*. (2005) and Lin *et al*. (2010) focused on short- and medium-term GHG reductions in Saskatchewan to comply with a Kyoto-type emission reduction target, they did not analyze the costs or opportunities to achieve more ambitious long-term GHG reduction targets. These studies were also conducted on the eve of large shifts in renewable energy costs. Solar costs have fallen substantially in recent years, as has the cost of electricity storage (Barbose and Darghouth, 2015; CitiGroup, 2015). Wind costs increased from 2000-2008, but have since fallen by 20-40% (U.S. DoE, 2015). As the cost of generating and storing renewable energy falls, the appeal of renewable energy for Saskatchewan increases. In this dissertation I explore the potential for renewable energy to contribute to electricity sector GHG emission reductions of 80% or greater by 2050. I compare the renewable energy pathway to other scenarios for lowering GHG emissions in the Saskatchewan electricity sector.

Reports evaluating the potential for renewable energy have been conducted for Alberta (Bell and Weis, 2009; Glave and Thibault, 2014) and Ontario (Weis and Partington, 2011; Weis *et al*., 2013). This dissertation provides a comparable report for Saskatchewan. This research will also contribute to the energy transitions literature. Jacobson and Delucchi (2011) and Delucchi and Jacobson (2011) outlined the potential for renewable energy to provide all global energy needs by 2050. The research I have conducted is a detailed look at how renewable energy could provide a substantial proportion of electricity within a specific jurisdiction: Saskatchewan. This case study approach offers insights into the sorts of real-world barriers that must be overcome if we are to achieve an energy transition to renewables.

Several other studies of the Saskatchewan electricity system have been carried out in recent years. White and Noble (2012) conducted a strategic environmental assessment to rank pathways for reducing GHG emissions in the Saskatchewan electricity system. They found that a renewable energy pathway was preferred by a group of expert participants, and a nuclear focused pathway was ranked second. Richards *et al*. (2012) interviewed eighteen individuals active in wind energy policy in Saskatchewan. They asked participants whether the pace of wind expansion was fast enough, and also asked about "barriers to expansion, and potential opportunities" (Richards *et al*., 2012: 3). Richards *et al*. (2012) found that participants were divided in their assessments,

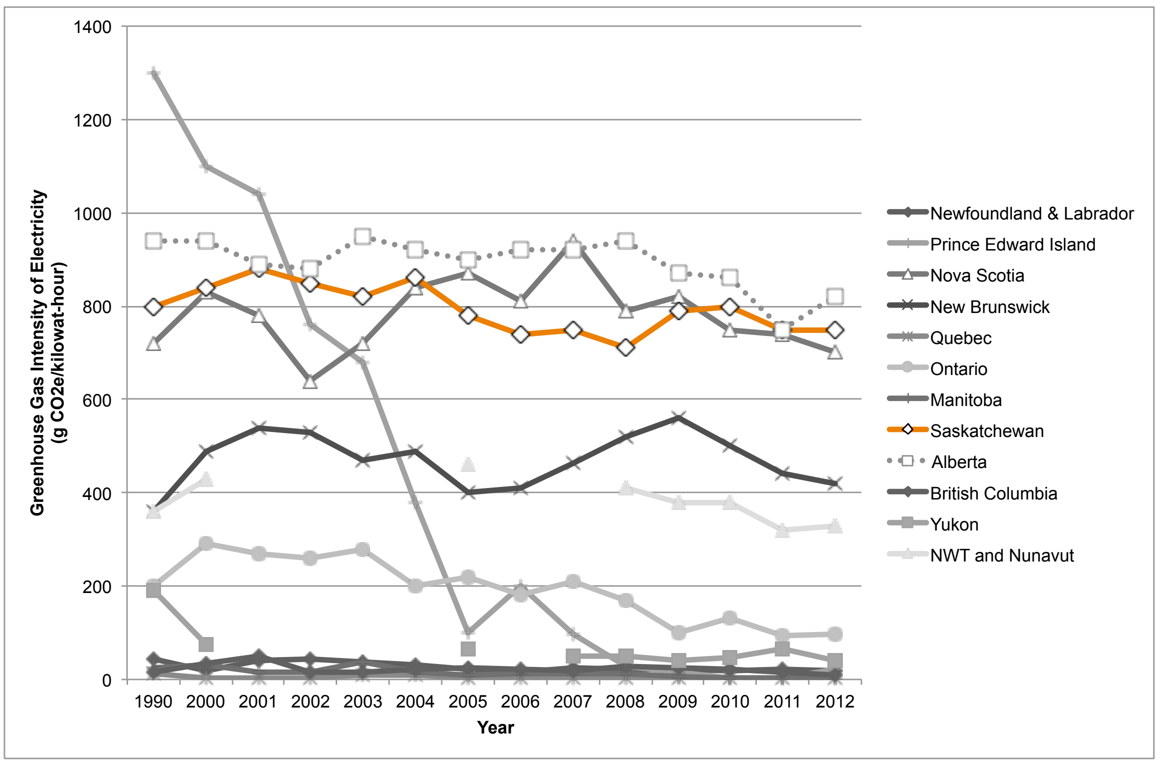
> Participants could be divided into two major groups with opposing viewpoints: those who felt that the current rate of wind energy development was appropriate tended to identify technology as a major barrier; those suggesting that current rate of expansion was insufficient agreed that political barriers were amongst the most significant barriers. (Richards *et al.*, 2012: 4)

In my research I extended the work of Richards *et al.* (2012) by bringing Saskatchewan electricity policy stakeholders together to discuss opportunities and barriers to renewables in a deliberative workshop setting. I used these workshops to determine whether a shared understanding could emerge between stakeholders with diverse positions, beliefs and values.

Other studies of the Saskatchewan electricity sector include Richards *et al*. (2013) who used Saskatchewan wind power as a case study for understanding barriers to effective public policy communication. Linsay Martens (2015) analyzed Saskatchewan as a case study of how First Nations could become involved in a renewable energy transition. I hope that this dissertation can contribute to the growing literature on the cost and potential for renewable energy in Saskatchewan.

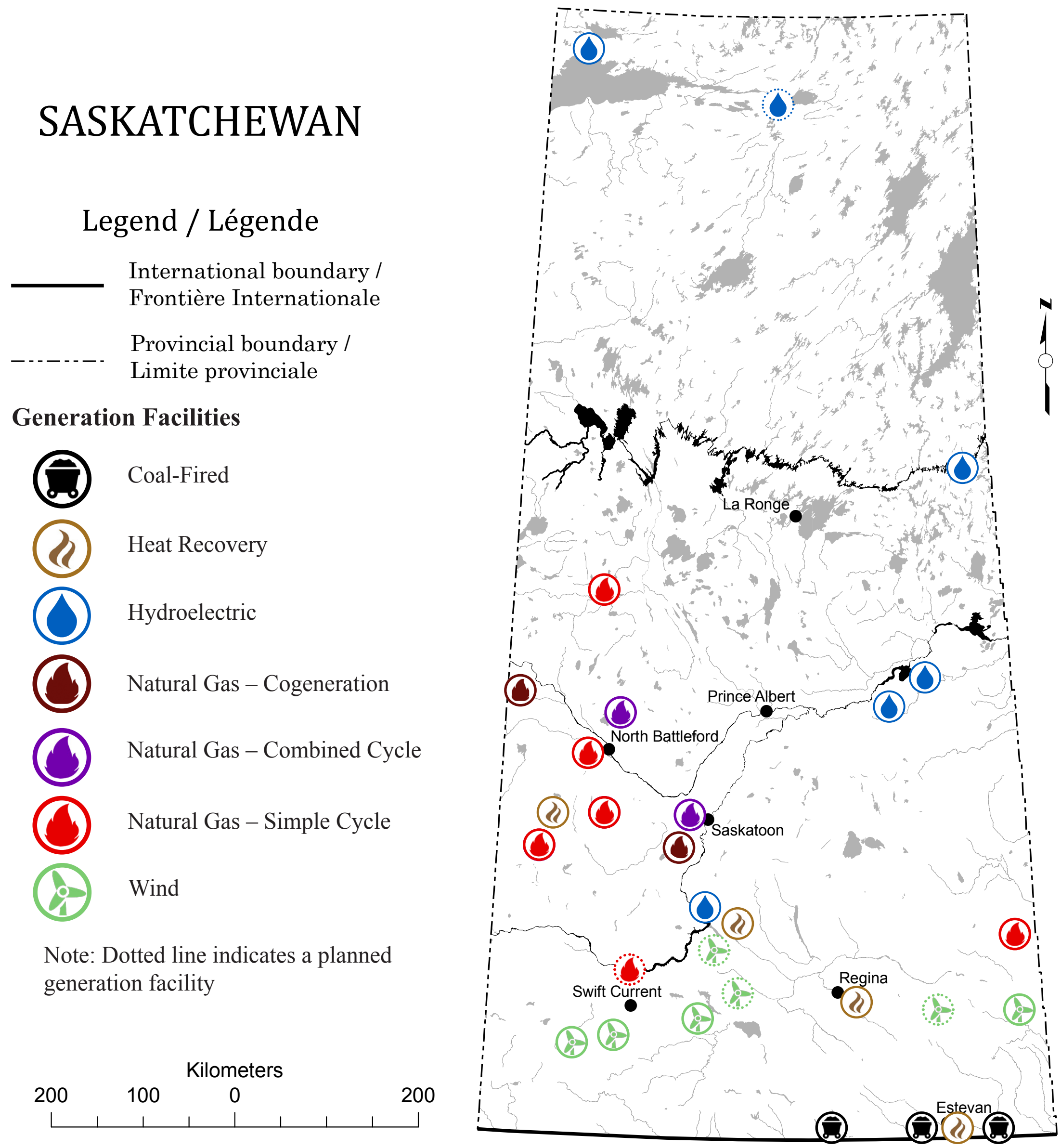
Saskatchewan Context

Saskatchewan is home to one of the most GHG emission intensive electricity systems in Canada (Figure 1-1). Across the globe, and in each sector, annual flows of GHG emissions must be lowered to near zero levels in order to stop atmospheric concentrations of GHGs from rising and mitigate the risk of catastrophic climate change (IPCC, 2014). As one of the worst performers in this regard, Saskatchewan is in need of an electricity system transformation.



(Data source: Environment Canada, 2012; Environment Canada, 2014)

Figure 1-1 Greenhouse Gas Intensity of Saskatchewan Electricity



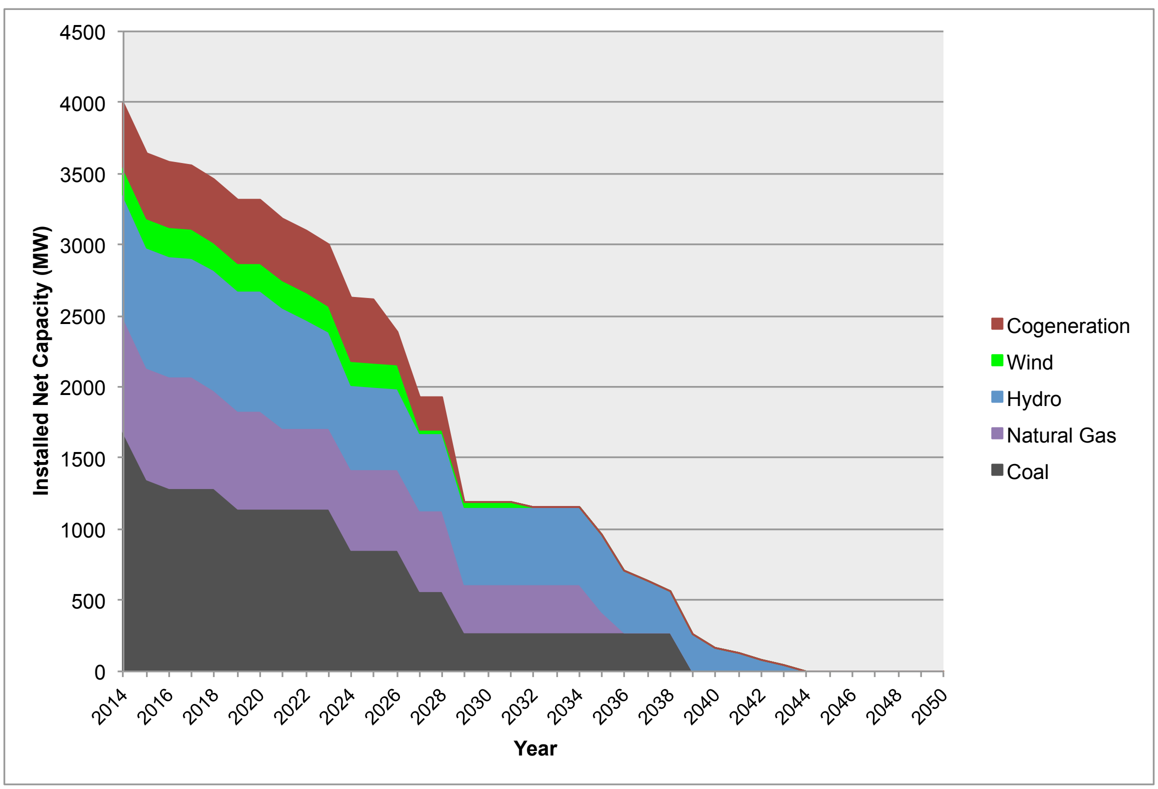
(Source: Fix and Korteling, 2015a)

Figure 1-2 Saskatchewan Electricity System

Historically, electricity in Saskatchewan has been produced predominantly by coal. The provincial crown utility SaskPower owns the coal generation stations in the southeast part of the province (black icons in Figure 1-2), hydroelectric generation sources in the central, northeast, and northern parts of the province (blue icons in Figure 1-2), natural gas facilities in the western part of the province (red and purple icons in Figure 1-2), and wind installations in the southwest (green icons in Figure 1-2).

SaskPower also purchases electricity from independent (*i.e.* private) power producers, including wind farms, natural gas plants (*e.g.* the Cory natural gas cogeneration facility operated by Potash Corporation of Saskatchewan, the dark maroon flame southwest of Saskatoon Figure 1-2), and heat recovery power-production installations owned and operated by the pipeline industry (light brown icons in Figure 1-2).

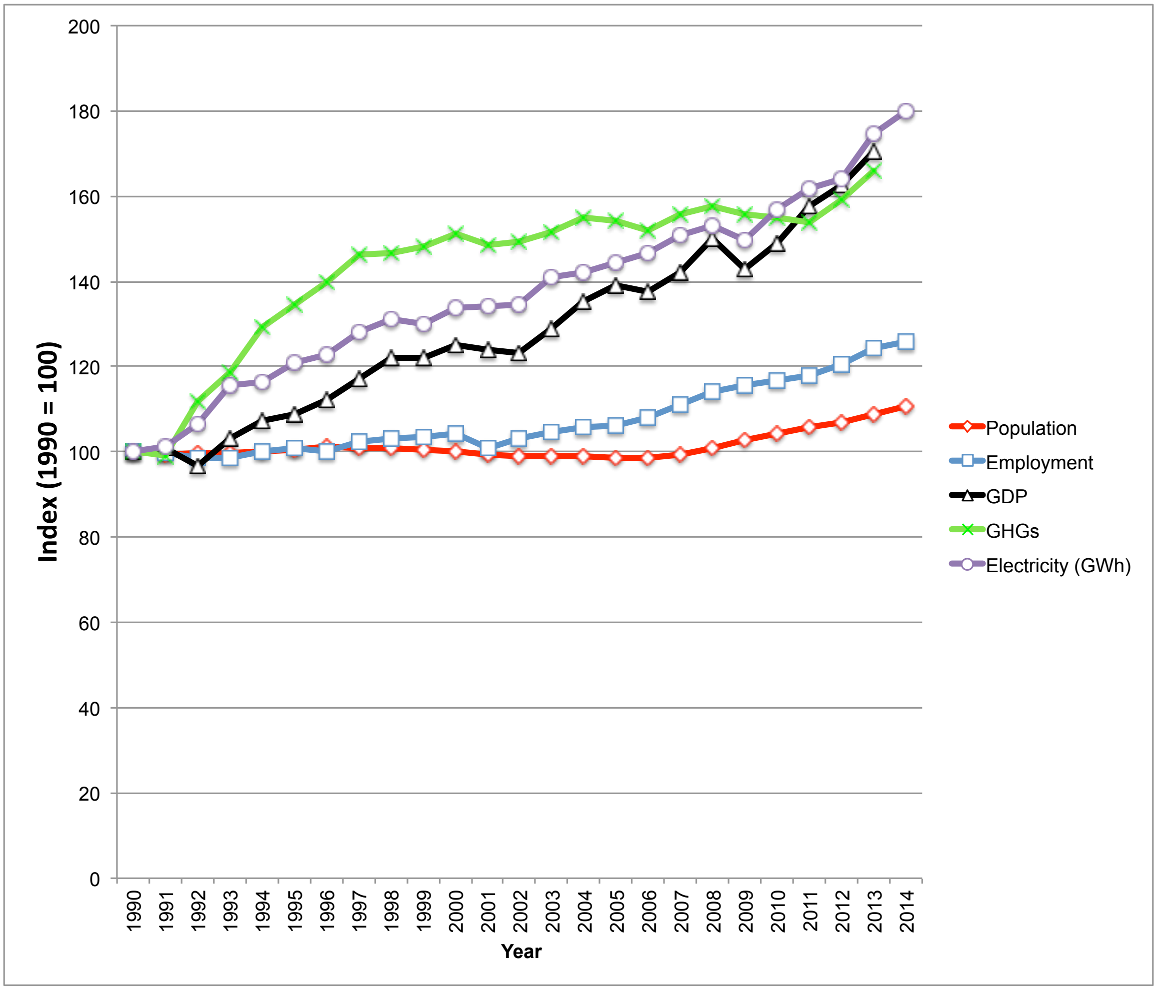
In the coming decades Saskatchewan has an opportunity to transform its electricity generation mix substantially as aging generation stations reach the end of their useful lives (SaskPower, 2011). Figure 1-3 displays Saskatchewan's electricity generation capacity minus the retirements that will lead capacity to decrease in the coming years.



(Data source: SaskPower, 2011)

Figure 1-3 Electricity Capacity in Saskatchewan Minus Scheduled Retirements

Saskatchewan must also meet the electricity needs of a growing population and a growing economy (Figure 1-4). The province is experiencing sustained population growth for the first time in decades. The governing Saskatchewan Party has a vision to encourage this growth and achieve a population of 1.2 million people in the province by 2020 (Government of Saskatchewan, 2013). GDP and employment growth has been strong in the province, encouraged by high commodity prices for exports like potash. Strongly correlated to GDP growth is growth in electricity demand in the province.



(Data sources: Population as of 1st quarter from Statistics Canada CANSIM Table 051-0005; Employment from Statistics Canada CANSIM Table 282-0002; Gross Domestic Product (GDP) measured in chained $2007 dollars using the expenditure approach from Statistics Canada CANSIM Table 384-0038; Provincial greenhouse gas emissions (GHGs) from Environment Canada, 2015; Electricity from SaskPower annual reports 1990-2015; author's calculations to normalize the data relative to 1990 levels)

Figure 1-4 Growth Trends in Saskatchewan

As SaskPower works to supply growing demand, while coping with aging infrastructure, it can be assured that Saskatchewan's future electricity mix will not look like the past. The Government of Canada has introduced regulations that specify that Saskatchewan must either retire its coal-fired electricity plants or retrofit them with carbon capture and storage (CCS) technology to ensure they achieve a GHG intensity of no more than 420 grams CO_2 per kilowatt-hour (kWh) (CEPA, 2012). To comply with the regulations all but one coal-fired power plant must be retired or retrofitted by 2029, creating an opportunity for a large-scale shift away from conventional coal.

The Government of Saskatchewan has, however, made it a priority to find ways to "keep coal in play" (Wall quoted in Zinchuk, 2014). Premier Brad Wall supports coal because it provides jobs in the Estevan and Coronach areas and because Saskatchewan has a supply of coal that could last another two to three hundred years and this provides a degree of "energy independence" (Wall quoted in Zinchuk, 2014).

To "keep coal in play" SaskPower has tested the viability of CCS technology at the Boundary Dam III station. This first-of-a-kind plant captures 90% of carbon dioxide (CO_2) before it leaves the smokestack. The CO_2 is then sold to an oil company called Cenovus for use in enhanced oil recovery. While CCS may prolong the life of Saskatchewan's coal-fired plants and coal industry, it has been criticized as a more expensive and less sustainable way of reducing emissions than renewables, especially wind (Glennie, 2015; Banks & Bigland-Pritchard, 2015).

Saskatchewan has a strong wind resource and one of the best solar resources in Canada (see Chapter 4). The electricity system is poised for a great transition. Despite its small population Saskatchewan has shown a willingness to be a laboratory for sustainable electricity policies. With a concerted effort Saskatchewan could become the first jurisdiction to meet its energy needs by a combination of wind, water and solar power (Jacobson and Delucchi, 2011 and Delucchi and Jacobson, 2011). In this dissertation I explore the potential to *Green the Saskatchewan Grid*.

Research Questions

I am guided by a central research question,

What is the cost of Greening the Saskatchewan Grid by lowering greenhouse gas (GHG) emissions by 80% or more by 2050 with a renewable energy focused electricity pathway?

To allow comparison I also work to understand the costs of a business-as-usual electricity scenario that keeps with SaskPower's current supply plan, and other competing scenarios for lowering GHG emissions. The central research question can be broken into several smaller questions. I address each in the chapters to follow. The relevant chapters are included in brackets after each question:

- **Research Question #1 –** What energy-environment-economy models are commonly used to develop electricity scenarios and can I improve upon them? (Chapter 2)
- **Research Question #2 –** What historical events have shaped the present electricity system in Saskatchewan? (Chapter 3)
- **Research Question #3** – What is the potential for renewable electricity generation in Saskatchewan? (Chapter 4)
- **Research Question #4** – How much do competing electricity generation technologies cost in Saskatchewan? (Chapter 5)
- **Research Question #5** – How will electricity demand in Saskatchewan change between 2015 and 2050? (Chapter 6)
- **Research Question #6** – What electricity generation and storage scenarios will meet Saskatchewan's annual energy needs out to 2050 while minimizing electricity costs and meeting greenhouse gas emissions reduction targets? (Chapter 7)
- **Research Question #7** – Once a scenario is developed that meets projected annual demand and achieves the desired objectives, how can I ensure that it can also meet projected hourly demand? (Chapter 7)

On research question #7, in this dissertation I pay particular attention to scenarios that feature renewable energy. In doing so, I am aware of the critique, oft heard in Saskatchewan, that renewable energy is variable and so cannot provide a reliable supply of electricity.[1] With that critique in mind, I have worked to model the hourly operation of each electricity scenario. This is a means of testing whether a given system can adequately balance the variability of renewable energy. While this is not an engineering study, I am interested in understanding the cost of balancing variable renewable electricity generation using technologies like demand side management, electricity storage, and hydroelectric power with reservoir storage. The operations modelling I have conducted is a means of testing whether the level of electricity storage and generation capacity included in each scenario is adequate. I discuss this modelling effort in greater detail in Chapter 2, Chapter 7 and Appendix 7B.

- **Research Question #8** – What are the projected electricity costs (Chapter 7) and electricity rates (Chapter 8) in each electricity scenario?
- **Research Question #9** – What are the projected greenhouse gas emissions implications of each scenario? (Chapter 7 and Chapter 8)
- **Research Question #10** – How does each scenario compare in regards to other indicators that can be used in a sustainability assessment? (Chapter 8)

Perhaps my most ambitious research objective was to generate a shared understanding amongst diverse stakeholders of the opportunities to expand renewable energy in Saskatchewan and the barriers that prevent expansion. In particular I hoped to build a shared understanding between SaskPower and environmental groups who have called for

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[1] In a recent news article, Mike Monea of SaskPower stated his views on this subject, "You need a lot of base power to support your renewables. You can't really have 100 per cent renewables. If you do, you're not going to have power all the time. That's what people have difficulty understanding. Every time we have to replace a plant, we can't just put up wind turbines. It doesn't work. It's too simplistic. It doesn't work that way. Last Sunday we hit a peak (of power consumption) at 6 p.m., suppertime. We had one megawatt coming from our wind turbines. There was no wind blowing. What did we use? We used coal-fired plants for the baseload, so nobody had disruption in their power." (Zinchuk, 2015)

a renewable energy future. To accomplish this research objective I convened three workshops with diverse stakeholders to discuss the future of the Saskatchewan electricity system with an emphasis on the potential for renewable energy to power the province. I ask the following question of these workshops,

- **Research Question #11** – Can a deliberative energy policy-modelling workshop generate shared understanding amongst diverse participants on the potential for renewable electricity to contribute to Saskatchewan's electricity future? (Chapter 9)

By answering these research questions I hope to offer sound policy advice to SaskPower and the Saskatchewan provincial government as to the relative merit of a pathway to *Green the Saskatchewan Grid*. I also hope to inform broader efforts to assess the sustainability of competing electricity scenarios in the province. Lastly, I hope to empower citizen activists who asked for a detailed study into the potential for renewable energy during the Perrins' consultations of 2009 (Perrins, 2009). This dissertation provides that study.

I now turn to the methods I have used to answer these questions.

Chapter 2 – Towards an Ecological Economics Approach to Energy Policy Analysis

Introduction

In this dissertation I work to develop an ecological economics approach to energy policy analysis. Ecological economics is a methodologically diverse "trans-discipline" (Norgaard, 1989; Norgaard, 2007). Ecological economists are called to integrate information from across the social and natural sciences, as well as the humanities (Norgaard, 2007). This requires proficiency with conventional methods of economic analysis, as well as openness to other ways of knowing. I use a diverse set of methods, including participatory modelling, historical document analysis, linear programming, and deliberative energy policy modelling to answer the research questions I outlined in Chapter 1.

Participatory Modelling

To understand how to make my research useful to SaskPower, citizen activists, and environmental non-governmental organizations I carried out a process of participatory modelling. Participatory modelling is a form of interactive social research (Talwar *et al.* 2011) and embraces the ideal of sustainability as a process of democratic decision-making (Robinson, 2004). Participatory modelling shares similarities to mediated modelling (van den Belt, 2004) in that it relies on engagement to make a model meaningful and useful to participants.

I carried out the process of participatory modelling in four stages (Figure 2-1). A fifth stage of 'sharing the results' will follow the completion of my PhD program. The stages proceeded as follows:

Stage 1 – Framing the Research

Engagement began in the early stages of the research process. I interviewed citizen activists, environmental non-governmental organization representatives, technical experts, and SaskPower staff and asked:

- What information gaps exist?
- What research questions should I strive to answer?
- What information would be useful for you to know?

What I heard from citizen activists and environmental non-government organizations (ENGOs) was that they were looking for a detailed cost analysis of a renewable energy future for Saskatchewan. Citizens and ENGO representatives were also interested in understanding the employment impacts of a renewable energy scenario relative to a business-as-usual scenario.

What I heard from SaskPower staff was that they were open to sharing their expertise with me as I explored a renewable energy scenario. They also expressed concern over the variability of renewable energy. This concern led me to ask, will a renewable focused electricity system be capable of reliably supplying electricity to meet hourly electricity demand?

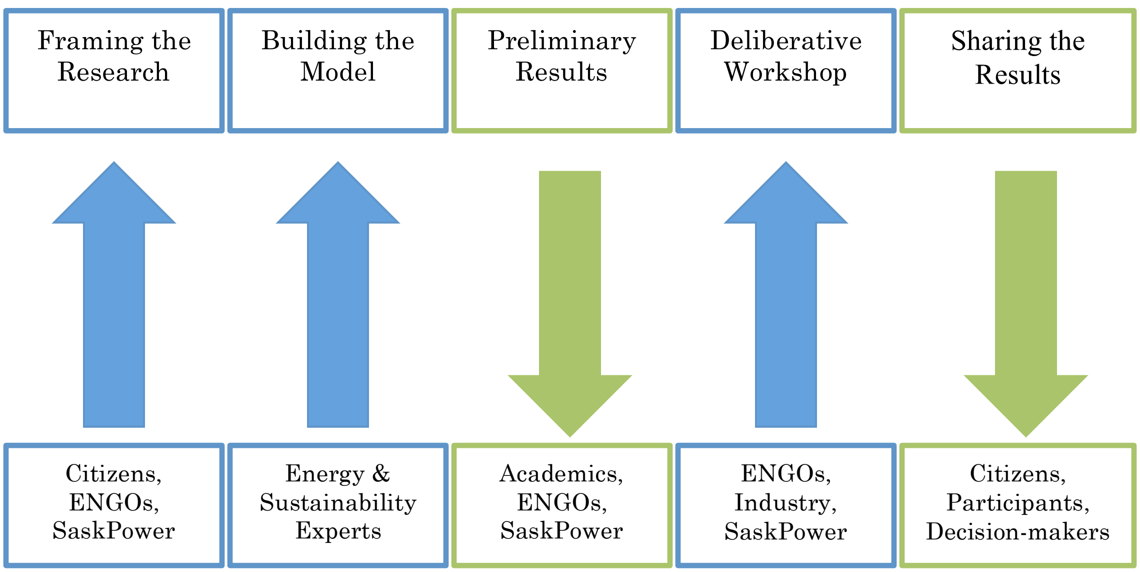
Stage 2 – Building the Model

I conducted interviews with energy and sustainability experts to understand the technical nuances of modelling the Saskatchewan electricity sector. These experts included representatives from:

- SaskPower;
- Saskatoon Light and Power;
- Saskatchewan Eco-Network;
- Saskatchewan Environmental Society;
- Green Energy Project Saskatchewan;
- Summerhill Group;
- Saskatchewan Industrial Energy Consumers Association (SIECA);
- Saskatchewan Ministry of Economy;
- Saskatchewan Research Council;
- First Nations Power Authority;

- ICF Marbek;
- Saskatchewan Community Wind;
- Northland Power; and
- Manitoba Hydro.

The goal of this stage was to make the model technically rigorous and as "true to life" as possible (Robinson, 2006). Insights from these interviews were incorporated into the Saskatchewan Investment Model (SIM) and the Will It Run Electricity Model (WIRE model) developed for this project.



(Adapted from Talwar *et al.*, 2011: 382)

Figure 2-1 Participatory Modelling Plan

Stage 3 – Preliminary Results

I developed an initial version of the SIM model and shared my initial results in a number of ways:

- I presented at the *Canadian Resource and Environmental Economics (CREE)* conference in Saskatoon, SK October 2, 2014;

- I presented at the *Ontario Network for Sustainable Energy Policy* conference in Waring House, Prince Edward County, ON April 28, 2015;
- I wrote a summary report outlining the initial results and shared the report with a select group of participants I had interviewed. These participants were selected based on their technical knowledge and level of interest in the project;
- I conducted follow-up interviews with a range of participants I had interviewed to discuss my initial results.

Through this process I received useful feedback that helped me to improve the model. This feedback included the following suggestions:

- Add Manitoba Hydro to the model;
- Add small, modular nuclear reactors as an investment option;
- Improve assumptions about the cost and potential of hydroelectric power in the province;
- Use a multiplier to capture the cost premium paid to build thermal generation (coal and natural gas fired facilities) in Saskatchewan. This cost premium is due to factors such as a shortage of skilled labour in the province, which increases project costs due to delays and higher payments to labour;
- Outline the employment impacts of the scenarios I created;
- Evaluate the impact of the federal government's coal-fired regulations;
- Evaluate an ambitious greenhouse gas (GHG) emissions reduction scenario that would include a coal phase-out by 2030.

Participants I spoke to also provided improved data for use in the modelling, including:

- The cost and potential of hydroelectric power in the province;
- Ramp rates for electricity generation technologies in Saskatchewan;
- Additional cost data for electricity generation technologies.

I incorporated this feedback into an improved version of SIM that included: updated cost information; the addition of Manitoba Hydro and small, modular nuclear reactors as generation technologies; and indicators such as jobs and water use. I used the enhanced

SIM model to evaluate the impact of the coal-fired regulations and an ambitious *Greening the Grid* scenario (see Chapter 7).

Stage 4 – Deliberative Workshop

After improving the model using feedback from Stage 3, I ran three half-day workshops of between six and eleven people to help generate scenarios for a sustainable electricity system in Saskatchewan. Working from the mediated modelling philosophy I brought together participants from a variety of interests and backgrounds to test whether a deliberative modelling workshop could build consensus around the potential for renewable energy to contribute to Saskatchewan's electricity future (van den Belt, 2004). These workshops were also a second chance for feedback on the model assumptions. The outcomes of these workshops are outlined in detail in Chapter 9.

Stage 5 – Sharing the Results

After completion of the dissertation I plan to share the final results of this research project with the participants who have provided input into the study. I then plan to translate the dissertation into a format that can be easily communicated to decision-makers and the broader Saskatchewan public. In this stage I hope to contribute to a broader discussion of Saskatchewan's electricity future. I also plan to continue offering deliberative workshops and include a broader spectrum of participants.

Over the course of the participatory planning process I interviewed thirty-one individuals. Twenty-one individuals participated in the deliberative modelling workshops, nine of whom were also interviewed for the project. In total, forty-three individuals have contributed their time and insights to this project. The process of involving stakeholders in the modelling process has helped to ensure the relevance and accuracy of the modelling work. I have heard from participants that they look forward to the final results. It is my hope that the results of this analysis can contribute to a productive discussion of Saskatchewan's electricity future and the role of renewables in lowering Saskatchewan greenhouse gas emissions.

History

The trans-disciplinary nature of ecological economics admits the value of case study and qualitative research methods. We can learn from history. Political economist Harold Innes taught us much about the Canadian economy by exploring the history of the fur trade in this country (Innes, 1930). I studied the history of the Saskatchewan electricity system through an analysis of SaskPower annual reports dating back to 1949, reports from the Saskatchewan Power Commission dating from 1929-1949, books such as White (1976) and Rediger (2004), and other assorted books and papers documenting the history of electricity in the province.

An understanding of the historical roots of a problem can offer insights where context-free economic analysis cannot. By studying the history of the Saskatchewan electricity system I was able to understand why the crown utility focused their GHG reduction efforts on expensive carbon capture and storage technology when an analysis of economic costs would suggest pathways that could achieve the same GHG emission reductions at a lower financial cost. Chapter 3 presents this historical analysis.

Energy-Environment-Economy Modelling

To evaluate the costs and greenhouse gas emissions of various scenarios for meeting Saskatchewan's electricity needs I built a suite of energy-environment economy models, which includes the Saskatchewan Investment Model (SIM) and the Will It Run Electricity (WIRE) model.

Economic models are a way of "disciplining our thinking" (Victor, 2015). They challenge the modeller to understand the system well enough to describe it through numerical representation. Models also help us to see relationships and outcomes that we might not otherwise anticipate. Four energy-environment-economy models are frequently used to analyze energy policy in Canada: Energy 2020, TIMES-Canada, CanESS, and CIMS. I describe each in turn before outlining my own modelling approach.

Energy 2020 and TIM

Energy 2020 is a simulation model owned by the US private consulting firm Systematic Solutions Inc. The model was created in 1981 to analyze regional energy and environmental policy in the United States. It is now capable of analyzing regional energy policy in fifty states, and each province and territory in Canada. (Amlin & Backus, 2014)

In Canada, the Energy 2020 model has been used by the National Energy Board (NEB) to create their *Canada's Energy Futures* reports (NEB, 2011; NEB, 2014a). In those reports Energy 2020 is paired with the macroeconomic model TIM, which was created by the private consulting firm Informetrica. TIM is "a detailed, dynamic econometric model of the Canadian economy that provides the macroeconomic drivers for the modeling framework" (NEB, 2014b). Macroeconomic forecasts in TIM are informed by projections made by the private banks and government agencies such as the Federal Department of Finance and the Bank of Canada (NEB, 2014b).

ENERGY 2020 and TIM communicate through changes in energy production, prices, energy intensities, investments in energy industries, and various macroeconomic parameters. The models run sequentially and iteratively over each year in the projection period. For each year, energy supply and demand outcomes from ENERGY 2020 are read and processed by TIM. TIM incorporates the energy information into a new macroeconomic projection for the year. The new macroeconomic data is then returned to ENERGY 2020 to create a new energy projection for the next iteration. More specifically, ENERGY 2020 provides TIM with changes in energy production, investments, energy intensity, and prices. TIM provides changes in gross domestic product (GDP), gross output, housing, inflation, the Canada-U.S. exchange rate, floor space, and population. (NEB, 2014b: 3-4)

The macroeconomic capabilities of the Energy 2020-TIM combination have made the NEB projections the preferred macroeconomic forecast of Canadian energy policy modelers. For example, the TIMES-Canada model uses the economic and demographic forecasts from the NEB *Canada's Energy Futures* reports – developed using the

Energy2020-TIM combination – as an exogenous input (Vaillancourt et al., 2013). Energy 2020 is also used for in-house policy analysis by Environment Canada and NRCAN (Miller, 2014).

Energy 2020 is a capital stock turnover model. It models stocks of energy-using, energy-converting, and energy-producing technologies in physical terms. The capital stock of existing technologies ages and at the end of its useful life must be retired or retrofitted. When demand for energy-related technologies exceeds supply, this demand must be met with investment in new technologies. (Miller, 2014; NEB, 2014a)

Human behaviour in the model is represented by a multinomial logit (MNL) equation. The multinomial logit equation indicates the probability that a consumer will choose a specific technology represented in Energy 2020. Attributes like cost affect the probability that a technology will be selected, but other attributes are relevant as well. For example, consumers do not simply choose a stove with the lowest operating cost, "some people choose gas stoves because they prefer to cook with them, not because of price differentials" (SSI, 2014: 21). The multinomial logit equations are estimated using a discrete choice econometric approach. (SSI, 2014; Miller, 2014)

The electricity module of Energy 2020 includes detailed information on existing electricity generating units in Canada, including their capacity factors and scheduled retirement dates (NEB, 2014b). Electricity demand is divided into two seasons (summer and winter), and six time slices (peak, near peak, high intermediate, low intermediate, high base load, and low base load) for a total of twelve representative time slices. A linear programming approach is used to solve for the least cost method of meeting electricity demand in each representative time slice. (Miller, 2014)

TIMES-Canada – GERAD

TIMES-Canada is a dynamic linear programming model developed by the Quebec-based

GERAD research institute.[2] TIMES stands for "The Integrated MARKAL-EFOM System" (Bahn *et al*., 2013). TIMES was developed as an extension and replacement of the MARKAL, or MARKet ALlocation, linear programming model previously used by GERAD. (Vaillancourt *et al*., 2013)

TIMES-Canada has been used to create an energy outlook for Canada to 2050 (Vaillancourt *et al*., 2013). It is one of two models being used in the Trottier Energy Futures Project, which is a joint project between the David Suzuki Foundation and the Canadian Academy of Engineering (Hoffman & McInnis, 2014).[3] TIMES-Canada has also been used to analyze scenarios for electric vehicle penetration in Canada (Bahn *et al*., 2013). Applications of the new model will continue; the GERAD website indicates that TIMES-Canada is now being applied to the study of pipeline expansion and future scenarios for the oil industry.

TIMES-Canada is a bottom-up model with rich technological detail. Its database "includes more than 5,000 specific technologies and 400 commodities in each province and territory" (Vaillancourt *et al*., 2013: 4). The electricity segment of TIMES-Canada explicitly models 3500 existing electricity plants in Canada.

TIMES-Canada runs from 2007 to 2050 in time steps of 1-2 years in the initial periods, and five year time-steps in later periods. The model is divided into twelve "time-slices" for each time-step representing combinations of daily electricity demand fluctuation (day, night, peak); and seasonal demand variations (winter, spring, summer, fall). (Vaillancourt *et al*., 2013)

Like Energy 2020, the TIMES-Canada model is driven by demand for energy services. As Vaillancourt *et al*. (2013) write, "The TIMES-Canada model is driven by a set of 67

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[2] More information on the GERAD (Group for Research in Decision Analysis) can be found at: https://www.gerad.ca/en.
[3] More information on the Trottier Energy Futures Project can be found at: http://www.trottierenergyfutures.ca.

end-use demands for energy services in five sectors: agriculture (AGR), commercial (COM), industrial (IND), residential (RSD) and transportation (TRA)" (p. 4).

Future energy service demands result from exogenous projections of economic and demographic trends that are sourced from the National Energy Board's (2011) *Canada's Energy Future* outlook up to 2035 and extended to 2050 using a "regressive approach" (Vaillancourt *et al*., 2013: 7). As discussed above, the National Energy Board (NEB) projections are created using the Energy 2020 and TIM energy policy modeling approach.

TIMES is also a capital stock turnover model. Stocks of technologies related to final energy demand, secondary energy carriers, and primary energy supply are tracked in TIMES-Canada. When existing technologies reach the end of their useful lives, or demands for energy services grow, new technologies compete to provide the required end-use demand service, energy conversion service, and to supply primary energy.

For example, in Bahn *et al*., (2013) an array of conventional, hybrid, and electric vehicles is available in the model to meet demand for personal road transportation. These automobile technologies compete, "based on lifecycle costs, which are calculated using capital, operation and maintenance and fuel costs" (Bahn *et al*., 2013: 596). Through an optimization routine, TIMES-Canada selects the lowest cost means of meeting the required demand over the time horizon.

TIMES-Canada selects low-cost technologies through the process of maximizing "net total surplus", which is the "sum of producers' and consumers' surpluses" (Vaillancourt *et al*., 2013: 3). Producer surplus is maximized by "minimizing the net total cost of the energy system", which includes investment costs, operation and maintenance costs, and fuel costs (Vaillancourt *et al*., 2013: 3). Consumer surplus is maximized by minimizing "welfare losses due to endogenous demand reductions" (Vaillancourt *et al*., 2013: 3). This means that there is a penalty in the model for scenarios and technology choices that raise the price of energy and reduce consumption of energy services. The objective function combines the cost of the energy system to producers and the welfare losses to consumers into one equation to be minimized.

The quantity of energy services demanded in TIMES-Canada is sensitive to price. Elasticities define this price response. Generally, demand is exogenous in the "business-as-usual" (BAU) run of the model, and becomes endogenous when scenarios are run to test the impact of various policies (Vaillancourt *et al*., 2013). This price-driven demand response provides macroeconomic feedback in the model.

TIMES-Canada is subject to the standard critiques of linear programming. Linear programming models such as TIMES-Canada exhibit "penny-switching", wherein the optimization routine will favour one technology over another even if costs differ by mere pennies (Jaccard *et al*., 2003). Market share constraints can be introduced to ensure that individual technologies do not capture an entire market. However, these constraints introduce a degree of arbitrariness into the model.

As a bottom-up model TIMES-Canada may fail to capture "intangible costs" such as the sentiment that a new technology is risky because it is untried. Lacking these costs, TIMES-Canada may be too optimistic about the costs of climate mitigation policies. (Jaccard, 2002; Rivers & Jaccard, 2005)

To include consumer surplus in the objective function, TIMES-Canada models human behaviour and preferences using a social welfare function. From an ecological economics perspective the use of a social welfare function is problematic. This form of modelling uses 'RARE' individuals to represent human behaviour. A RARE individual is a homogenous *R*epresentative *A*gent acting with *R*ational *E*xpectations to maximize utility by maximizing consumption (King, 2015). This caricature of human behaviour is sometimes referred to as 'homo economicus.' While the representative agent makes consumption decisions mathematically tractable in an optimization model, it is a departure from the complex reality of human behaviour in the following ways:

- People are diverse and not well served by being treated as "homogenous globules of desire" (Erickson quoting Thorstein Veblen, 2013);
- Preferences are not well-defined across all goods in a market, instead rationality is bounded (Kahneman, 2003); this means that rather than optimizing their consumption decisions, people make decisions that "satisfice" (sufficiently satisfy given the available information) (Simon, 1956);
- People are not solely self-interested and rapaciously working to maximize their consumption of market goods, instead we are characterized by a mix of self-regarding and other-regarding behaviour (Gintis, 2000).

Some scholars have called for 'homo economicus' to evolve into something more akin to 'homo sapiens' (Thaler, 2000). Others have argued that in a democracy it is better to ask people what they want, and let them deliberate and debate in a public forum, rather than to simply assume their desires and fold the assumptions into an economic model (Norgaard, 2007). In the case of lowering greenhouse gas emissions in the electricity sector, we could ask if people are willing to pay more for electricity in order to stabilize the climate. Discussion of such trade-offs is inherently political and is influenced by the values and identities of those engaged in the deliberation (Kahan *et al*., 2007). An interactive approach to energy policy modelling, such as that applied in the *CanESS* model, can be used to discuss those trade-offs and avoid the RARE assumption.

CanESS Model

The CanESS (Canadian Energy Systems Simulator) model was developed by Robert Hoffman and Bert McInnis of 'Whatif? Technologies'. The CanESS model is being used in the Trottier Energy Futures Project for Canada along with the TIMES-Canada model (Hoffman & McInnis, 2014). CanESS was used by the Pembina Institute to study the future of electricity supply in Ontario (Weis & Partington, 2011). It has been used to explore scenarios for alternative vehicles in Canada (Steenhof & McInnis, 2008). It has also been used to create the Australian Stocks and Flow Framework (Turner *et al*., 2011). The Canadian Energy Systems Analysis Research (CESAR) group – led by David

Layzell at the University of Calgary – is working to further develop CanESS for research purposes.[4]

The prime objective of CanESS is to allow for the simulation of *plausible* scenarios for Canada's energy future. Plausible scenarios are those that respect fundamental physical laws such as the conservation of energy and materials. CanESS models stocks and flows using a physical accounting framework. This means that rather than focusing on the economic value of human artifacts like cars and buildings, these are counted in physical terms (number of cars, number of buildings, megawatts of electricity generation capacity). Energy and material stocks and flows are also tracked in physical terms (*e.g.* tonnes of coal). Physical stocks and flows must "obey the thermodynamic constraints of conservation of mass and energy" (Turner *et al*., 2011: 1140).

CanESS avoids making *any* assumptions about human behaviour. The approach was selected intentionally to remove "ideological bias…since the core represents largely irrefutable accounting relationships reflecting mass balance" (Turner *et al*., 2011: 1147). According to Hoffman and McInnis (2014), many energy policy models are built with the embedded ideologies contained in economic theory. Hoffman (2012) is critical of the RARE model of human behaviour arguing, "human behaviour is too diverse and complex to be represented as an aggregate consumer agent" (p. 79).

Without behavioural assumptions CanESS cannot be used for least-cost optimization; the model is not "closed" in the way that a linear programming model is closed. Instead it is a descriptive model, "Open to the influence of different sets of values, *i.e.* not normative or prescriptive, but more descriptive" (Turner *et al*., 2011: 1137).

Similar to a flight simulator, Hoffman and McInnis have designed CanESS to be highly interactive. When a simulation is run, users are made aware of "tensions" in the model. These tensions are instances when the model runs into "physically unfeasible or problematic outcomes" (Turner *et al*., 2011: 1138). These tensions "must be resolved by

[4] More information on CESAR can be found at: http://www.cesarnet.ca.

people interacting with the (model), similar to the flight simulator concept" (Turner *et al*., 2011: 1138).

Through the process of resolving tensions CanESS becomes a learning tool. Like a telescope, it is designed as an extension of the human nervous system. CanESS is meant to help users better understand the long-term, systemic consequences of energy policy choices. As such, Hoffman and McInnis (2014) borrow a concept from de Rosnay (1979) and refer to CanESS as a kind of "macroscope." (Hoffman & McInnis, 2014)

CanESS is designed to be used without reference to prices. For this reason it has been critiqued by economists (Turner *et al*., 2011). However, Hoffman and McInnis (2014) argue that price is a human-created institution and institutions can be changed. For Hoffman and McInnis (2014) energy policy decision-making should begin with an exploration of physically plausible scenarios for the future. Then decision-makers can select a desirable scenario for the future. Only at the last stage, do decision-makers decide on the policies and institutions required to support the desirable scenario. With this approach energy policy models should never conclude that we "can't afford" a physically plausible scenario; if a scenario is physically plausible Hoffman & McInnis (2014) argue that we should be able to design institutions, prices, and policies to support it. From an energy policy modelling perspective this leaves something to be desired. CanESS lacks a clear decision-rule for sorting between scenarios. The world of physically plausible scenarios is wide and economic models are often tasked with recommending a favoured scenario. We can ask, is it enough for a decision-maker to know a scenario is physically plausible? Or will they expect more from a model and a modeller?

The results of CanESS simulations can be combined with financial cost information. The modeling work conducted by the Pembina institute for Ontario's electricity sector identified "two plausible scenarios of Ontario's electricity future" and reported on the electricity price impacts of each (Weis & Partington, 2011: IV). The work of finding a recommended cost-effective and plausible scenario occurs through iteration as the modeller interacts with the CanESS model.

The CanESS scenarios for Ontario included rich detail on electricity demand: “hourly load shape pattern is built up from a detailed end-use representation of electricity use across all sectors of the economy”, and operational detail around dispatch rules for supplying electricity (Weis & Partington, 2011: 10). The operational and investment costs required to achieve each scenario were tracked and translated into electricity prices over time for the two scenarios. The scenarios may not have been optimal, but were physically plausible and robust.

CIMS-GEEM

The CIMS model was developed at Simon Fraser University (SFU) by Mark Jaccard, John Nyboer, Chris Bataille, Nic Rivers and other students and faculty associated with SFU’s Energy and Materials Research Group (EMRG). The model was built on code that originated from the ISTUM model (built in the United States in the 1980s) and was enhanced and extended at SFU throughout the past two decades (EMRG, 2014; Bataille, 1998).

CIMS has been used for consulting projects across Canada and the United States, including analysis conducted for the National Round Table on the Environment and Economy (e.g. NRTEE, 2009). CIMS is currently used as a consulting model by the firm Navius and has been enhanced in recent years with the addition of a macroeconomic, computable general equilibrium (CGE) sister model called GEEM.

CIMS is a “technology choice simulation model” (EMRG, 2014) that “simulates the evolution of capital stocks over time” (Jaccard, 2009: 317). The model is billed as a hybrid incorporating the technological detail of bottom-up modelling approaches (*e.g.* linear programming) and the behavioural realism of top-down modeling (*e.g.* CGE modeling) (Rivers & Jaccard, 2005; Jaccard, 2009).

On technological detail, CIMS contains “over 1000 technologies competing for market share at hundreds of nodes throughout the economy” (Jaccard, 2009: 321). Data on the technologies used by industry in Canada is enhanced by the close connection between

EMRG and the Canadian Industrial Energy End-Use Data and Analysis Centre (CIEEDAC). John Nyboer, one of the architects of CIMS, heads up CIEEDAC.

Behavioural realism is represented in CIMS by a market share equation. Technologies achieve market-share not based on cost alone, but also based on consumer preferences for characteristics of the technology. These consumer preferences are represented by discount rates and 'intangible costs' estimated from market data. For example, taking the bus to work might be the least cost option for a commuter, but a preference for driving may lead that person to take their car. The value of this preference must be worth at least the difference between the cost of transit and the cost of driving. These cost differentials are estimated from real world market data. (Rivers and Jaccard, 2005; Jaccard, 2009)

Like the Energy 2020 and TIMES-Canada models, CIMS is driven by exogenous demand for energy-services. This demand is linked to economic and demographic forecasts. CIMS has a macro-economic module containing elasticities that allow for demand to shift when policies are introduced in the model. The integration of CIMS and the GEEM computable general equilibrium (CGE) model now allows for further macroeconomic feedback. GEEM is subject to the same critiques of 'RARE' modelling mentioned above. (Rivers & Jaccard, 2005; Jaccard, 2009)

Model Comparison

The energy policy models reviewed above share the following common features:

- *Capital Stock Turnover* - Physical stocks of energy-using artifacts age, and must be retired or repaired;
- *Energy Service Demand* – Demand for energy services such as lighting, heating, and industrial processes drive the models. Technologies and energy sources compete to supply these services.

The models differ in the following areas:

- *Simulation or Optimization* – TIMES-Canada is an optimization model and Energy 2020 uses linear programming optimization for its electricity module, but is otherwise a simulation model. CIMS and CanESS are simulation models;
- *Human Behaviour* – TIMES-Canada assumes cost-minimizing and welfare maximizing behaviour, as does the GEEM CGE addition to CIMS. Energy 2020 and CIMS are built to allocate market share using logistic, probabilistic equations estimated empirically. CanESS relies on user interaction rather than embedded assumptions about human behaviour;
- *Participatory modeling* – Energy2020-TIM, TIMES-Canada, and CIMS-GEEM are all expert models; that is they are designed and operated by modelling experts with limited input from stakeholders. CanESS models are built through a participatory process and user interactivity is an important feature;
- *Technological detail* – Models differ in the level of technological detail they contain. While all of the models contain basic features of electricity generation technologies such as capacity factors and fuel efficiencies, they differ in their representation of the operation of an electricity system. TIMES-Canada represents the operation of an electricity system using representative “time slices”. The CanESS model for Ontario contains detailed hourly electricity demand and supply information.

Towards An Ecological Economics Energy Modelling Approach

I have created a suite of energy-environment-economy models tailored to address my specific research questions. When creating these models I worked to take the useful elements from the models described above and improve upon their weaknesses. I describe each model in turn.

The Saskatchewan Investment Model (SIM) is a linear-programming optimization model. It is built to minimize the cost of meeting Saskatchewan electricity demand over the course of 2015-2050. Investment decisions are made in five-year time-steps beginning in 2020. SIM is built with rich technological detail to describe the costs and operating characteristics of the Saskatchewan electricity system, including the fuel use and greenhouse gas emissions associated with each technology. It is a capital stock turnover model in which generating units age and must be replaced or, in some instances, retrofitted. Electricity demand is exogenous in the model and is calibrated to SaskPower's (2015) load forecast (see Chapter 6 for a detailed description of the electricity forecast used). This means that the model does not include macroeconomic feedback; energy demand does not respond to changes in price. SIM does, however, include demand side management (DSM) as a supply option. If the costs of generating electricity increase above those projected in the base case, then, in SIM, the utility puts more effort into DSM to lower electricity demand. This behavior by the utility is a proxy for price-induced reductions in electricity demand though it may not capture the full amount. Otherwise SIM excludes a representation of demand-side human behaviour. Instead, it represents the electricity system from the perspective of a rational system planner responding to inelastic demand. In Saskatchewan the crown utility SaskPower has a monopoly on electricity supply and a mandate to provide affordable electricity (*i.e.* SaskPower does not seek out monopoly rents). This makes the electricity system amenable to the assumption of a rational system planner; although in practice there are significant socio-technical biases that influence SaskPower's decision-making (see Chapter 3 and Chapter 9). I do not address the issue of inelastic demand within SIM, but instead discuss some of the implications of rising electricity prices in Chapter 8. I use SIM to answer the research question, what electricity generation scenarios can lower greenhouse gas emissions in Saskatchewan while minimizing financial cost? SIM is described in detail in Technical Appendix 7A.

The Will-It-Run Electricity model (WIRE model) is an hourly operations model of the Saskatchewan electricity system. The WIRE model includes real-world electricity demand data, wind power production data, solar production data, and hydroelectric seasonal capacity factors to provide a realistic picture of the variability of both electricity demand and renewable energy production. Electricity storage capacity is modelled as a means of smoothing the variability of renewable electricity production. Demand side management is modelled through the option of 'peak shifting' demand three hours into the future. Dispatchable electricity generation technologies (including electricity storage) are called to meet electricity demand, but are constrained by ramp rates; this means that it takes time for technologies to increase or decrease their output. The WIRE model is a linear programming model that runs in the GAMS (General Algebraic Modelling Software) modelling environment. A detailed description of WIRE is included in Appendix 7B.

WIRE is designed to be used iteratively with SIM. Least-cost investment pathways selected by SIM are trialled in WIRE to answer the questions, is this scenario capable of reliably supplying electricity to meet hourly electricity demand? In instances where the scenarios will *not* run I adjust the parameters in SIM and seek out another least-cost scenario. WIRE approaches the technological realism of the CanESS model, but is accompanied by SIM, which provides a useful decision rule for selecting scenarios.

On the matter of a decision rule, both SIM and the WIRE model can be critiqued for taking an optimization approach. As Ruth (2016) points out,

> In places where environmental standards are low, resource extraction and environmental pollution may cause harms that remain unaccounted for in economic decision-making. The prices of goods and services in conditions of social and environmental exploitation are then not worth much with respect to their ability to guide economic decisions towards optimal outcomes (Røpke 1999). More likely, they will entrench unsustainable practices.
> (Ruth, 2016: 6-7)

We can ask, what good is an optimized scenario if the costs are ridden by market failures? Or in other words, what good is a first-best scenario in a second-best world? The costs contained in the SIM model are financial alone; they are the direct financial costs required to build and operate the electricity system. In scenarios that contain a carbon price, this should be understood as a policy to reduce GHG emissions, not an estimate of the social cost of carbon. SIM does not put a monetary value on the damage done by greenhouse gas (GHG) emissions, nor does it put a monetary value on the negative health impacts from particulates or radiation, or the birds and bats killed by wind turbines and uranium tailings ponds. Methods for valuing such impacts in monetary terms are widely applied, but can aggregate and hide impacts, rather than bring them to attention. Valuations of health impacts in particular often contain questionable ethical propositions such as the belief that a monetary value of 'a statistical life' adequately captures the public's concern about changes in the risk of premature death. This is an ethical leap that many citizens would abhor. Rather than creating one number with which to evaluate a scenario, I identify multiple impacts for each scenario including: employment impacts, cumulative GHG emissions, cumulative radioactive waste produced, cumulative carbon dioxide stored through carbon capture and storage (CCS), land area impacted by wind and solar installations, and water required (Chapter 8). These indicators do not provide a comprehensive sustainability assessment of the scenarios. Other indicators that might be of interest include the health benefits of reducing particular matter and mercury emissions from coal plants, and lifecycle impacts such as the indirect GHG emissions released to manufacture generation technologies, or land impacts from hydroelectric facilities, uranium mines, and natural gas extraction. The indicators I include do provide insights into a number of sustainability criteria. It is my hope that they can inform a broader discussion of Saskatchewan's electricity future in which citizens and decision-makers use multiple attributes to evaluate scenarios and consider trade-offs. I do not attach weights to any one of the indicators I measure, but instead make the information available to be discussed and deliberated in a democratic fashion, which takes me to the third model: iSIM.

Scenario construction by a modelling expert may result in a report that can be published in an academic journal, or a news release that makes a brief headline in an evening news story. The most productive use of a model, however, may be as "a tool for beginning a *dialogue*" (Jackson and Victor, 2013). iSIM, the interactive scenario-builder version of SIM, is identical in function to SIM, but is designed to be used in a deliberative modelling workshop.

Deliberative modelling workshops are a way to stimulate deliberative exchange amongst participants with different values, beliefs, and positions (Norgaard, 2007; Zografos and Howarth, 2010). I used the iSIM model to structure a discussion on Saskatchewan's electricity future with representatives of electric utilities, private consultants working in the field of energy conservation, private power producers, and environmental non-governmental organizations. The iSIM model, like SIM, is built in Excel, a software program with which many are familiar. By lowering the technical barriers to interacting with the model I hoped to make it "fun to use" (Carmichael *et al*., 2004).

The iSIM model allows users to specify an electricity generation mix they would like to see in 2050. The user can also set policy inputs such as a carbon price in each time-step, and can adjust assumptions related to cost, electricity demand, renewable energy potential, and the proportion of electricity that can be provided by wind. Once the inputs have been set, the user (or the modelling expert) runs 'Solver' and iSIM identifies a least-cost investment pathway to achieve the desired generation mix, given the assumed costs and constraints. The iSIM model provides data on electricity generation and greenhouse gas emissions in easy to interpret area charts (identical to those found in Chapter 7). It also summarizes both price and non-financial impacts in radar diagrams to allow scenarios to be quickly and easily compared. In a deliberative modelling workshop small groups of diverse participants can use iSIM to create scenarios and revise assumptions as they explore Saskatchewan's electricity future.

The goal of a deliberative workshop is to build a shared understanding that can foster a shared commitment to action (van den Belt, 2004). In a deliberative modelling exercise the role of the ecological economist is to create a space for dialogue and to integrate the contributions offered by diverse participants. This, I would argue, is a more democratic method of approaching economic analysis than a model that merely assumes RARE behaviour (Norgaard, 2007; King, 2015). Although power inequities do pose a barrier for open conversation (Zografos and Howarth, 2010), I set out to discover if antagonism could be suspended to make room for understanding, and conflict could be replaced with curiousity. To do this I used the iSIM model to focus discussion in three four-hour deliberative modelling workshops in Saskatchewan. The results of those workshops are presented in Chapter 9.

Limits of My Approach

The modelling approach I have taken is an attempt to move towards an ecological economics approach to energy policy modelling. Like any modelling exercise it faces limitations. For one, the model does not include estimates of the impacts of the scenarios beyond Saskatchewan. In fact, it does not model the rest of the world at all, except for the inclusion of hydroelectric purchases from Manitoba. This is not all to the bad since the Saskatchewan electricity system is quite isolated from the rest of the world, possessing only limited interconnections to Alberta, North Dakota and Manitoba.

The more consequential limitations result from my choice of a linear programming approach, which can be critiqued for the following reasons:

1. *Lack of Uncertainty* - The model is dynamic in that decisions made in one time-step influence decisions made in the next time-step. Capital is long-lived and once it is built it lasts for its expected lifetime. However, the model does not capture uncertainty. The rational system planner implied by an optimization approach can accurately see the entire horizon of electricity demand, fuel costs, and capital costs from 2015-2050 when making investment decisions. I work to deal with this by including a sensitivity analysis of important variables like the price of natural gas and the rate of cost improvement for electricity generation technologies. Others have approached this problem by using stochastic programming techniques (*e.g.* Bistline, 2014).
2. *Continuous Capital Investment* – In SIM investments in capital are continuous, not lumpy. Integer programming techniques could have introduced lumpiness into SIM. This would mean that power plants would have to be built at certain discrete sizes (*e.g.* 300 MW). To some extent the five-year time step introduces a degree of capital lumpiness, but more could be done.

3. *Linear Relationships* – The relationships in the model are linear, with a few exceptions; demand side management potential and hydroelectric potential are both modelled as step-wise functions where costs increase as further investment is made.

I defend my choice of strictly linear programming as a compromise made while working to ensure iSIM is both "fun to use" and "true to life" (Carmichael *et al*., 2004). The WIRE model helped to enhance the rigour of the SIM scenario results, but more technical wizardry could have been applied. Whether that would have resulted in richer discussion at the deliberative modelling workshops is unclear.

Modeling Process

In Chapters 4 to 9 I describe the process of creating and applying the energy-environment-economy models I have created. The chapters roughly capture the process of creating an energy policy model that Bataille (1998) outlines so well. Paraphrasing Bataille's (1998: 10) description, the modeling process is typically carried out in the following fashion:

1. *Forecast demand for energy services* –these forecasts are typically based on exogenous economic and demographic drivers (Chapter 6);
2. *Determine available technologies and costs* – work to understand the technologies that can provide the required energy services and their related costs (Chapter 4 and Chapter 5);
3. *Capital stock* – understand the age and expected service life of the existing capital stock (Chapter 1 and Chapter 5);
4. *Technology selection* – decide on a method of selecting technologies to provide energy services. This could involve optimization, simulation using probabilistic market share equations, or user-specified technology investment paths (my choice of an optimization approach is described herein Chapter 2);
5. *Use the model* – use the model to forecast an energy outlook, simulate a technology path, or test the likely effectiveness of an energy policy (optimized

scenarios are presented in Chapter 7, impacts are described in Chapter 8, and the deliberative modelling results are outlined in Chapter 9).

In practice, the modelling process did not work as neatly and linearly as this outline suggests. For example, in my research I developed several models using different modelling approaches. I created a version of the SIMS investment model in the GAMS (General Algebraic Modelling Software) environment. This model allowed greater computational power, but did not provide an interactive user interface. I also developed a system dynamics investment model of the Saskatchewan electricity system. After asking colleagues to evaluate this model I was advised to improve the user interface to allow participants to select a generation mix they desired in 2050, rather than having them decide on investments in each time-step. As I worked to make this change, I found that the excel-based model version of SIM I had created could provide that user interface quite neatly. This is all to say that it took iteration between Step 4 and Step 5 in order to arrive at the excel-based investment model (SIM) I have used in this dissertation.

Before discussing how to model the Saskatchewan electricity system, it is useful to understand the origins of system. The history of Saskatchewan's electricity system is described in Chapter 3 to provide the context for the modelling work and stakeholder deliberations outlined in later chapters.

Chapter 3 - A History of Saskatchewan's Electricity System

Introduction

In this chapter I describe the historical context that gave rise to Saskatchewan's present-day electricity grid. A largely rural, agricultural province in the early 20th Century, power production in Saskatchewan began in a decentralized fashion. Proposals were soon made to centralize power production in low-cost locations, particularly in the southeast lignite coalfields around Estevan. The Saskatchewan River system also held the promise of hydroelectricity.

From 1929-1949 it was the job of the Saskatchewan Power Commission to integrate the decentralized production facilities and electricity grids into a centralized, integrated grid. In 1949 the Crown Corporation SaskPower was created to complete this integration. A major undertaking in the 1950s was the electrification of rural Saskatchewan, one of SaskPower's greatest achievements.

By the mid-1960s SaskPower had created a centralized, integrated electricity grid, powered by low-cost lignite coal and hydroelectricity. In recent decades challenges to this publicly owned, centralized system and the coal-hydro nexus of electricity generation have put pressure on the SaskPower system to change.

In the 1970s and 1980s environmental concerns slowed or blocked hydroelectric projects and dams for coal-fired plants' cooling reservoirs. Concerns over acid rain and climate change have demanded that SaskPower look beyond conventional coal. In recent decades, natural gas has become an important fuel for electricity generation, wind power projects have proven successful, and smaller biomass and heat recovery projects add diversity to the generation mix. SaskPower and the government have also flirted with nuclear power, most recently in 2009 with the Saskatchewan Party's Uranium Development Partnership. Well-organized public opposition has so far kept nuclear power out of the province, but talk has turned to "small, modular reactors" in the north.

Public ownership of the SaskPower Crown has also come under pressure. Changes in the ideology of Saskatchewan's ruling parties have at times threatened SaskPower with the spectre of privatization. Cogeneration and independent power producers now make up 20% of the electricity grid and have opened the door to a slow privatization of the corporation.

This is the story of power in Saskatchewan.

Early Beginnings

Electricity came to Saskatchewan in 1890 when private operators installed the first "electrical systems in Regina, Moose Jaw and Prince Albert" (White, 1976: 3). These early systems provided power for lighting the streets of the small prairie towns. Many operated their facilities on a "moonlight basis" only when the moon was not expected to shine (White, 1976: 3).

In the early 1900s, municipalities across Saskatchewan began to build and operate their own electrical utilities. Regina, Moose Jaw, and Prince Albert were early into the business, each city taking over the operations of the original private developers. By the outbreak of World War I twenty communities owned and operated electric light utilities. The Great War slowed the number of light utilities being created, but still seven more electricity generation plants were built during the War. In the decade that followed, "slightly over a dozen additional municipalities had established or otherwise acquired their own electrical systems" (White, 1976: 8).

By the late 1920s the municipal electric utilities were profitable enterprises. Municipalities used the revenue from electric utility operations to finance their operations and keep property taxes low (White, 1976). Municipal electrical systems were also diverse. The cities of Moose Jaw, Regina, and Saskatoon operated efficient facilities and charged an average of 1.65 *¢CDN* per kilowatt-hour for electricity (SPRC, 1928). Electricity generated in small communities was often much more expensive. In 1926, in the communities of Readlyn and Briercrest, the cost of electricity was "forty-five and thirty-five cents" per kilowatt-hour respectively (White, 1976: 14).

As early as 1911, electricity boosters such as Frederick Haultain, Leader of the Opposition in the Saskatchewan legislature, began to call for a centralized electric power system that would utilize the lignite coalfields in southwest Saskatchewan and tap into the hydroelectric potential in the province. Electricity rates throughout the province would be reduced and cheap electricity would help the province diversify its economy, which was highly dependent on agriculture, into areas such as manufacturing. (White, 1976)

The idea of a centralized power system received intermittent attention for the next fifteen years. It was not until 1925 that Liberal Premier Dunning announced that Saskatchewan would establish a provincial power policy. (White, 1976)

On January 7, 1927 the Provincial government, now led by Liberal James Gardiner, appointed the Saskatchewan Power Resources Commission (SPRC) to "report upon the economic practicability of generating power at central power plants and water power sites throughout the province" (SPRC, 1928: 3). The committee reported back in 1928 (SPRC, 1928). In their report, the SPRC took stock of the electricity situation extant in the province,

> the total capacity of the power plants in the province is 43,757 K.W. and…there are 712 miles of distribution pole lines. The total energy generated in these plants during the year 1926 was 69,553,844 K.W. hours sold to 44,471 customers.[5] (SPRC, 1928: 3)

[5] To build this system $9,058,076 had been spent (SPRC, 1928). In 2015 $CDN this equates to $123,465,514. This means the average cost of constructing the 43,757 kilowatt system, including the cost of the transmission lines, was $2822 per kilowatt in 2015 $CDN. (SPRC, 1928; Author's calculations using All-Items CPI for Canada in Statistics Canada, CANSIM table 326-0020).

Of the electricity generated, 80% of electricity was supplied by city owned power plants in Regina, Saskatoon, and Moose Jaw. The commission spoke positively of the ability of the three cities to provide cost-effective power. The cost of generating electricity in each city in 1926 is outlined in Table 3-1 and is listed in both 1926 Canadian cents (¢CDN) and 2015 ¢CDN adjusted for inflation using the Canadian all-items Consumer Price Index (CPI) (Statistics Canada, 2015). (SPRC, 1928)

Cost of Generation in 1926 (cents per kilowatt-hour)		
	1926 ¢CDN	*2015 ¢CDN*
Regina	0.81	11.08
Moose Jaw	1.04	14.16
Saskatoon	1.07	14.54

Table 3-1 Cost of Electricity Generation in 1926
(Source: SPRC, 1928; CANSIM 326-0020; author's calculations)

The commission recommended that the best path forward for the Saskatchewan electricity system was to allow the city utilities to expand their operations and begin branching out to nearby towns and villages. Power plants in medium-sized centres such as Swift Current, Estevan, Unity, Yorkton, and Weyburn were to be encouraged and would provide power for regions removed from Saskatchewan's three cities.

The commission believed that this organic approach to power development would save money in the short term, and in the long term – as electricity load grew, transmission networks branched out, and old equipment came up for renewal – would open the door for a centralized generation system. (SPRC, 1928)

The commission also concluded that a southwest coal plant would only make sense if it could provide power for Regina, located 217 kilometers away. Since a plant to serve Regina's electrical load was already built and working efficiently the commission concluded, "there is no economy to be derived from the establishment of a large plant on the coal field at a point so far distant from the centre of the load" (SPRC, 1928:9). Any savings that could be generated by accessing cheap lignite coal in the southwest would be overwhelmed by the cost of building a transmission system, and the sunk fixed costs of the existing city power plants. The southwest coal-fired plant would have to wait until electricity demand had grown substantially. (SPRC, 1928)

The commission reached a similar conclusion in regards to hydroelectricity, finding that a central hydroelectric plant on the Saskatchewan River system would not make economic sense until the 1940s when summer load had grown substantial enough to justify the supply. (SPRC, 1928)

But, it was predicted, demand for electricity would grow, and fast. Electricity demand had increased at a rate of over 10% per year from 1907-1928 in Regina and 1913-1928 in Saskatoon (SPRC, 1928: 10). The commission predicted these rapid growth rates would continue into the future.

To prepare for an eventual centralized generation system, the SPRC (1928) recommended that a central agency oversee the rational growth of the electrical system. A central coordinating agency would avoid duplication of expenses on transmission lines and could optimize investments in new generation equipment. (SPRC, 1928)

> The tendency in the development of the individual stations is to plan primarily for the needs of each community without reference to any wider scheme throughout the province, and have suggested, that as time goes on, there will be a duplication of equipment which will be costly, unless there is a general plan of organization, either of the efforts of the large city installations under a pooling arrangement, or by the consolidation of these plants into one general scheme. (SPRC, 1928: 34)

To create this centralized entity the committee recommended that the provincial government purchase and operate the municipal plants. Provincial ownership was preferred to municipal ownership because the province could borrow at lower rates of interest and coordinate the entire provincial system. Public ownership was preferred to private ownership because it would save money; “the element of private gain which necessarily must be provided to private ownership need not be figured in a publicly owned system” (SPRC, 1928: 15). (SPRC, 1928)

After two months of considering the SPRC (1928) report the Gardiner government accepted the recommendation for public ownership. Negotiations with municipal power authorities began and Saskatoon agreed to sell their generating assets and purchase power in bulk from the new public entity. This willingness on the part of Saskatchewan’s second biggest city to join a provincial scheme encouraged Premier Gardiner to draft the Power Commissions Act. In January 1929 the Act became law and with it the Saskatchewan Power Commission (SPC) was born. (White, 1976)

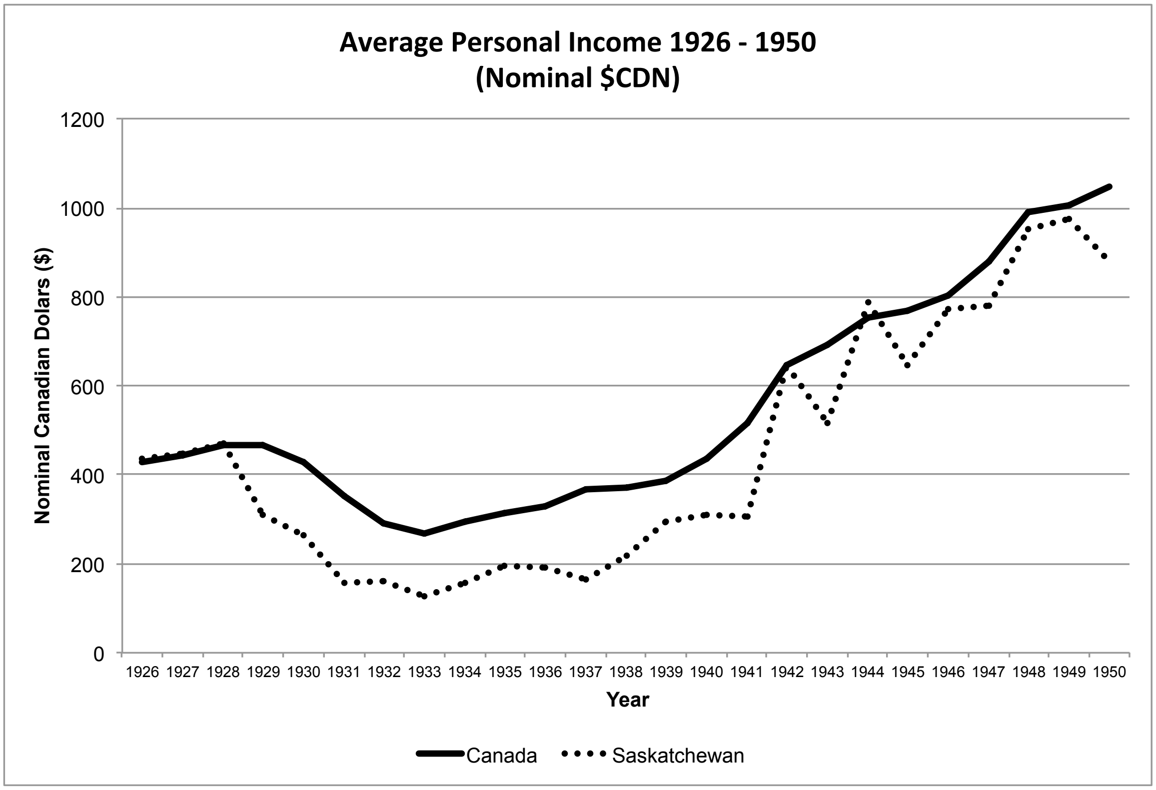
Saskatchewan Power Commission 1929-1949

The Saskatchewan Power Commission (SPC) operated from 1929-1949 and laid the groundwork for the existing electricity grid and the SaskPower Corporation. Its first commissioner was Louis Thornton who had chaired the Saskatchewan Power Resources Commission (SPRC). (White, 1976)

The SPC was tasked with purchasing municipal utilities and expanding the provincial electrical system. In 1930, after SPC had taken control of Saskatoon’s generation facilities, the ownership of the Saskatchewan electricity grid was distributed as follows: Saskatchewan Power Commission 26.3 Megawatts (MW), municipally owned 37 MW, and privately owned 29.2 MW for a total system capacity of 92.6 MW (SPC, 1930).

The Great Depression

Almost immediately after the SPC had been created the Great Depression interrupted SPC’s expansion plans. The Depression hit Saskatchewan particularly hard. Where personal income fell 43% between 1928 and 1933 on average in Canada, average incomes in Saskatchewan fell by 73% (see Figure 3-1 below). Unemployment rose to the point where “almost one in four adult male workers in the Queen City (Regina) had lost his job” (Waiser, 2005: 285).



(Source: Statistics Canada, 2015 CANSIM Table 380-0050)

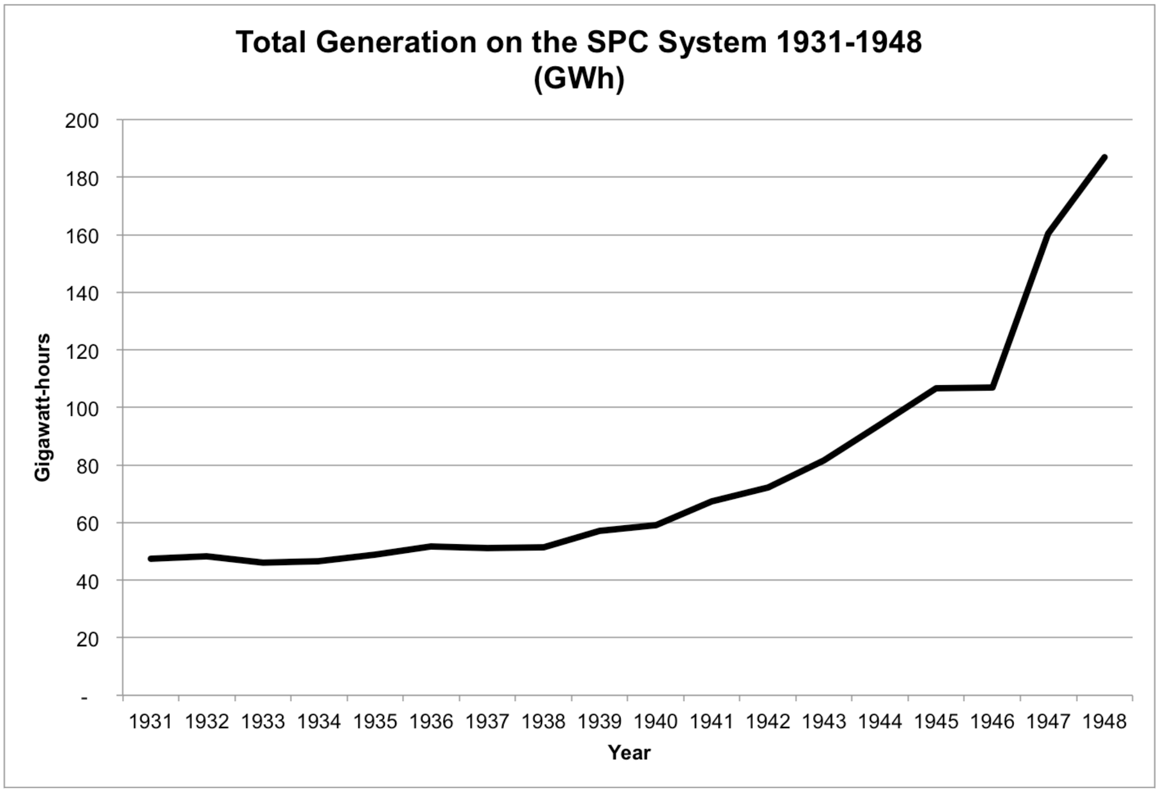
Figure 3-1 Average Personal Incomes Canada and Saskatchewan 1926-1950

The Depression exposed the vulnerability of the rural, agricultural province to the boom and bust cycles of international commodity markets. Low international demand for agricultural products led to low commodity prices, especially for wheat, Saskatchewan's most important crop. For many, the Depression reaffirmed the need to diversify the provincial economy away from a reliance on agriculture. (Waiser, 2005)

Compounding the misery, a long-lasting drought destroyed agricultural output in 1931, 1933, 1934, and 1937. Topsoil blew freely from the land creating giant dust storms that would block out the sun and coat homes inside and out with a layer of dust. The period is popularly referred to as the "dust bowl" of the "dirty thirties" and it casts a dark shadow over the memories of those who lived through it. (Waiser, 2005)

In the depths of the Depression there was no income to spare for luxuries like electric lighting. From 1931 to 1935 electricity production in facilities owned by the

Saskatchewan Power Commission hovered around 45 Gigawatt-hours per year (See Figure 3-2).



(Source: SPC Annual Reports, 1929-1948)

Figure 3-2 Total Electricity Generation on the Saskatchewan Power Commission System 1931-1948

Annual reports from this era outline the situation,

> The general economic depression which obtained throughout the year was felt in a marked degree in this province and brought about the need for curtailment in any expenditures beyond absolute necessities. Accordingly, no new undertakings or extensions of the Commission's system were embarked upon except the minimum that was required to maintain adequate service. (SPC, 1932: 3)

> The general economic depression which obtained throughout the year 1932 has continued during 1933, and, as a result, the demand upon the Commission's generating plants and transmission line systems has shown no increase over the preceding year, but is, in fact, very slightly less.
> (SPC, 1933: 4)

In this desperate time SPC operated at a loss. Impoverished citizens had a difficult time paying their bills and SPC employees would accept produce as payment, paying the SPC the value of the produce, “These were the days when a month’s light account would purchase a dressed hog or a quarter of beef, often with vegetables thrown in!” (SaskPower, 1953: 17)

Wartime Scarcity

Power demand began to grow again in step with incomes in the latter half of the 1930s. For the Saskatchewan Power Commission increasing demand meant increasing revenues and indicated “a betterment in local conditions in the towns served” (SPC, 1936: 3). Improving economic conditions in the late 1930s meant that existing infrastructure could be used at its full capacity. As SPC chairperson Louis Thornton wrote in his 1939 annual report “Encouraging load increases indicate that more stable economic conditions have been evident in all districts and bring the total energy demands to proportions which were contemplated when the systems were built” (SPC, 1939: 4). SPC owned generation capacity reached 30 MW in 1939 and production increased to 55 Gigawatt-hours in that year.

Were it not for the intervening conditions of war, the early 1940s might have been a time of capacity expansion for the Saskatchewan electricity system; demand continued to grow and investments were badly needed, especially in Saskatoon. Instead wartime restrictions were placed on the production of non-essential manufactured goods. As Louis Thornton wrote in the 1941 SPC annual report,

> It has been evident for some time that additional generation capacity was urgently required at the Saskatoon plant, and an order for a 15,000 KW turbo-generator was placed with an English manufacturer in May. Shortly afterward the British Government issued a suspension order on the construction of this unit, and, up to the present, efforts made to have the suspension order lifted and the work put in hand have been of no avail. (SPC, 1941: 3)

This state of rationing continued throughout the war years as materials and labour power were directed to war-related production rather than domestic goods and services.

Integrating the System

In 1944, the socialist Co-operative Commonwealth Federation (CCF), led by the charismatic T.C. (Tommy) Douglas, swept into power in Saskatchewan. The CCF favoured public ownership of industry, and electricity was no exception. Joe Phelps was appointed Minister responsible for the Saskatchewan Power Commission and soon laid out a plan to purchase the remaining private and municipal electric utilities companies in the province and "integrate" the electric system (SPC, 1945). A farmer himself, Phelps was eager to see the electricity system extend to farms and rural communities. With an integrated system under public control it would be possible to finance rural electrification in the province. (White, 1976)

The CCF appointed H.F. Berry to replace Louis Thornton as the commissioner of the Saskatchewan Power Commission. Berry was a strategic choice as, until his appointment, he had been the General Manager of the privately owned National Light and Power Company in Moose Jaw. As such, he could understand the motivations and interests of the private power producers. (White, 1976)

It is clear that the CCF government wanted Berry to take a more aggressive approach to fulfilling the mandate of the SPC. The *Saskatchewan Reconstruction Council* had issued a report in 1944 criticizing the Commission for its "cautious" approach (p. 148). The SPC had prevented private companies from expanding electricity service in the province, while also refusing to expand service itself. The province had seen its share of hardship in the Depression and World War II and so the SPC's slow progress was not without reason, but, in the post-war era, progress was expected.

Under instruction from the provincial government Berry began to consolidate the provincial electricity system. Dominion Electric was first on the list of companies to be purchased. Dominion generated electricity using lignite coal near Estevan in southwest Saskatchewan. The purchase would provide SPC with an anchor for the consolidated system. As the new commissioner for the SPC explained,

> The Dominion Electric…Plant at Estevan purchases fuel for one-third the cost on a B.T.U. basis of cost for fuel at any other location in…Saskatchewan. The Province, in endeavouring to build up a base power supply in the Estevan area, will be securing the cheapest source of power in the Province and, in addition, will be furnishing employment to its own citizens and using a natural resource of the Province.
> (H.F. Berry to Minister Joe Phelps in White, 1976: 140)

Cheap and abundant coal in the southwest of Saskatchewan would be used to generate electricity that would be transmitted throughout the province and would support the CCF government's plans to electrify rural Saskatchewan and promote industrial development. Coal was also a "natural resource of the Province" and would generate mining jobs in the Estevan area. Similar arguments in favour of coal reappear in Saskatchewan to this day.

Throughout the late 1940s SPC purchased electricity generation facilities small and large. In 1945 SPC purchased the Prairie Power Company and folded their operations into SPC (SPC, 1945). In 1947 SPC purchased Canadian Utilities Limited (SPC, 1947).

As wartime shortages of materials eased, the SPC built transmission lines to connect the localized electricity distribution networks (White, 1976). Inefficient diesel plants were closed and expansions were made at centralized generation facilities such as Saskatoon's coal-fired steam plant. These efforts were directed at creating an “integrated electric power network” (SPC, 1945: 6).

Integration lowered generation costs and allowed SPC to progressively reduce electricity rates. In 1945 the maximum rate for electricity sold by the SPC was fifteen cents per kilowatt-hour (SPC, 1947). Rates were lowered May 1 1945, June 1 1946, July 1 1947, and June 1 1948 (SPC, 1947; SPC, 1948),

> The rate reduction on June 1st, 1948, enabled the Commission to secure complete uniformity of rate schedules for similar towns throughout the Province. Street lighting schedules were standardized and rates to rural customers were reduced along with other rates so that the maximum for any electrical energy sold by the Commission was lowered to eight cents per kilowatt-hour. (SPC, 1948: 12)

The rate reductions were aimed at “building load” and they had their desired effect. Electricity demand began to grow rapidly (See Figure 3-2 above). The Commission also found itself with a sizable accumulated surplus (See Table 3-2), which would provide investment capital in the decade to come.

Still, the SPC had not succeeded in creating an integrated system. A report written by consultant David Cass-Beggs in 1947 was critical of the SPC. Cass-Beggs argued the SPC had been operating “simply as one of the power companies operating in the province and serving what loads it could conveniently serve” (Cass-Beggs in White, 1976: 151). SPC had no success in obtaining the municipal plant at Regina and the privately owned National Light and Power in Moose Jaw. It had also not made any major progress towards rural electrification. (White, 1976)

This critique was particularly poignant to the CCF government, amongst whose most ardent supporters were Saskatchewan farmers. If the SPC could not electrify rural Saskatchewan it was not doing its job.

Year	Loss	Surplus	Accumulated Deficit	Accumulated Surplus
1929	$ 180		$ 180	
1930	$ 946		$ 1,126	
1931	$ 35,880		$ 37,006	
1932	$ 50,979		$ 87,985	
1933	$ 77,497		$ 165,483	
1934	$ 77,135		$ 242,618	
1935	$ 46,981		$ 289,599	
1936	$ 24,151		$ 313,749	
1937	$ 12,617		$ 326,366	
1938	$ 570		$ 326,936	
1939		$ 7,500	$ 319,437	
1940		$ 3,387	$ 316,050	
1941		$ 12,945	$ 303,105	
1942		$ 16,747	$ 286,358	
1943		$ 22,463	$ 263,895	
1944		$ 32,477	$ 231,418	
1945		$ 156,835	$ 74,583	
1946		$ 414,283		$ 339,700
1947		$ 632,775		$ 972,475
1948		$ 427,743		$ 1,400,281

(Source: SPC, 1946; SPC, 1947; SPC, 1948)

Table 3-2 Saskatchewan Power Commission Financial Conditions

Berry returned to his position as head of the Moose Jaw utility in 1948, a position he held until 1960 when the Moose Jaw utility was finally purchased. The CCF government made major changes to the Saskatchewan Power Commission. (White, 1976)

Birth of the Saskatchewan Power Corporation

In 1949 the CCF government reorganized the Saskatchewan Power Commission, separating its regulatory duties and its generation and distribution duties. The newly created Saskatchewan Power Corporation (SaskPower) would be responsible for generation and distribution in the province while the Saskatchewan Power Commission (SPC) would maintain its regulatory oversight role.[6] (White, 1976)

[6] SaskPower was one of many crown corporations created during this period. The CCF also created the Saskatchewan Government Insurance (SGI) agency, the Saskatchewan Government Telephones company (SaskTel), and the Saskatchewan Transportation

SaskPower, the Corporation, "inherited 35 power plants and 4,190 miles of transmission line" from the Saskatchewan Power Commission (SaskPower, 1969: 25). The task of the Corporation was to finish the integration that the Commission had begun. This meant purchasing distribution and generation facilities still held by municipal and private operators in Regina, Moose Jaw, Weyburn, Swift Current, North Battleford, and Yorkton. It meant connecting the province with high-voltage distribution lines to allow electricity to be generated at low-cost sites and distributed through the province. It also meant extending electrical service to rural Saskatchewan.

Rural Electrification

The CCF government, re-elected in 1948 with the continued support of Saskatchewan farmers, put a high priority on rural electrification. Joe Phelps, former Minister in charge of SPC, lost his seat in the 1948 election but stayed on with the SPC board and helped to develop the *Rural Electrification Act*, which was signed into law in 1949. This Act committed SaskPower to build distribution lines to areas where farmers had agreed to organize and contribute towards the costs. (White, 1976; SaskPower, 1955)

Rural electrification would be an expensive undertaking. There were 125,612 census farms in Saskatchewan in 1946, and that number fell to 112,018 in 1951 (Ministry of Agriculture, 2012). These farms were spread throughout the southern part of the province and the population density of rural areas was low, "The 70,000 farms to be supplied were scattered in an area of about 130,000 square miles" (SaskPower, 1969: 25). Thousands of kilometers of distribution lines would have to be built to electrify rural Saskatchewan.

SaskPower began the process of rural electrification by focusing on the rural areas that were most economical to serve: those along or near existing lines. In 1949, electricity was connected to 1,142 farms. The next year over 2,000 farms were connected bringing the total farm and rural customer count to 4,500 (SaskPower, 1950: 5), and in 1951 over

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Company (STC), which provides bus service in the province. All of these crowns remain in public ownership today. (Rediger, 2004)

3,000 more farms received service. The pace was quickening, but much work remained. (White, 1976; SaskPower, 1950)

In 1952 The CCF won their third term in office. Tommy Douglas campaigned on a promise to electrify 40,000 farms and bring electricity to all towns. Charles Smith, rural electrification superintendent for SaskPower, offered his frank concerns about the magnitude of this challenge,

> This will make a grand total of 56,000 new customers in the next four years! 75% of the total number of customers presently served by the Saskatchewan Power Corporation (counting the cities of Prince Albert, Yorkton and North Battleford)! Building in four years *many more miles of line than* were built in all the preceding twenty-five years! Providing, as well, extra generating equipment and main trunk lines to supply these new customers and handle normal load growth of existing customers! In others words planning, I will venture to say, a relatively more ambitious program than has ever been carried out on this continent, or perhaps in the entire world! A program calling for detailed planning and a ruthless determination to carry it out! (Charles Smith quoted in White, 1976: 273)

Ruthless determination appears to have been present in the leadership and employees of SaskPower. SaskPower ramped up rural electrification through the 1950s; over 4,000 farms were connected in 1952 (SaskPower, 1952), 7,500 farms were connected in 1955 (SaskPower, 1955), and 7,800 were connected in the peak year of 1956 (SaskPower, 1969).

Electricity transformed life on the farm, alleviating much of the labour that had characterized rural life, especially for women (Champ, 2001). Water was pumped, not hauled to the farmhouse; water heaters replaced the work of boiling water for baths (Champ, 2001). For those who could afford appliances, electricity soon meant cooking on an electric range rather than chopping wood to fuel the stove; and washing machines replaced hours of scrubbing clothes on a washboard (Champ, 2001). At least one awestruck prairie woman (my great-grandmother) was found gazing at her washing machine as it worked to clean the family linens, watching it as we would a television, still in disbelief at the labour-saving device.

Rural electrification was a great success and by 1960 the program "was essentially completed, having brought electricity to about 67,000 farms and to all the villages and hamlets in the populated half of the province" (SaskPower, 1969: 25). The feat stands as an impressive demonstration of how the *im*possible can become possible when motivated by determined political will and institutional buy-in. It is an example to remember as SaskPower begins the challenge of electrifying Saskatchewan with sustainable, low emissions electricity.

Rural electrification was also a great success for the CCF government. CCF leader Tommy Douglas, the father of Medicare and the first socialist elected to office in North America, is believed to have said the rural electrification of Saskatchewan was his greatest achievement (Calvert, 2005). With the goodwill it created for Douglas, rural electrification may have helped make Medicare possible.

Power for Industry

Farms were not the only new electricity customers in the province in the 1950s. SaskPower also worked to provide electricity and natural gas sales to Saskatchewan's growing industrial sector.[7] As SaskPower's (1957) Annual Report states,

> Reaching into more and more of her resource-filled stockrooms – oil, natural gas, uranium, potash – Saskatchewan has learned that power and natural gas are the keys to enable these stocks to be taken from storage, processed, and moved to market. (SaskPower, 1957: 15)

[7] "During 1951, the Saskatchewan Power Corporation was designated as the provincial authority to handle the distribution of natural gas" (SaskPower, 1951: 3). It retained this responsibility until 1989 when the SaskEnergy Crown Corporation was created to distribute natural gas (SaskPower, 1989).

The oil industry in the province was encouraged to power their pump jacks with electricity. A salt plant at Unity used substantial electricity and natural gas, both supplied by SaskPower. Various manufacturing facilities drew from the grid including "a major cement plant, a clay products plant, and two light aggregate plants at Regina; a fibreboard plant at Saskatoon; and a clothing plant at Moose Jaw" (SaskPower, 1957: 15).

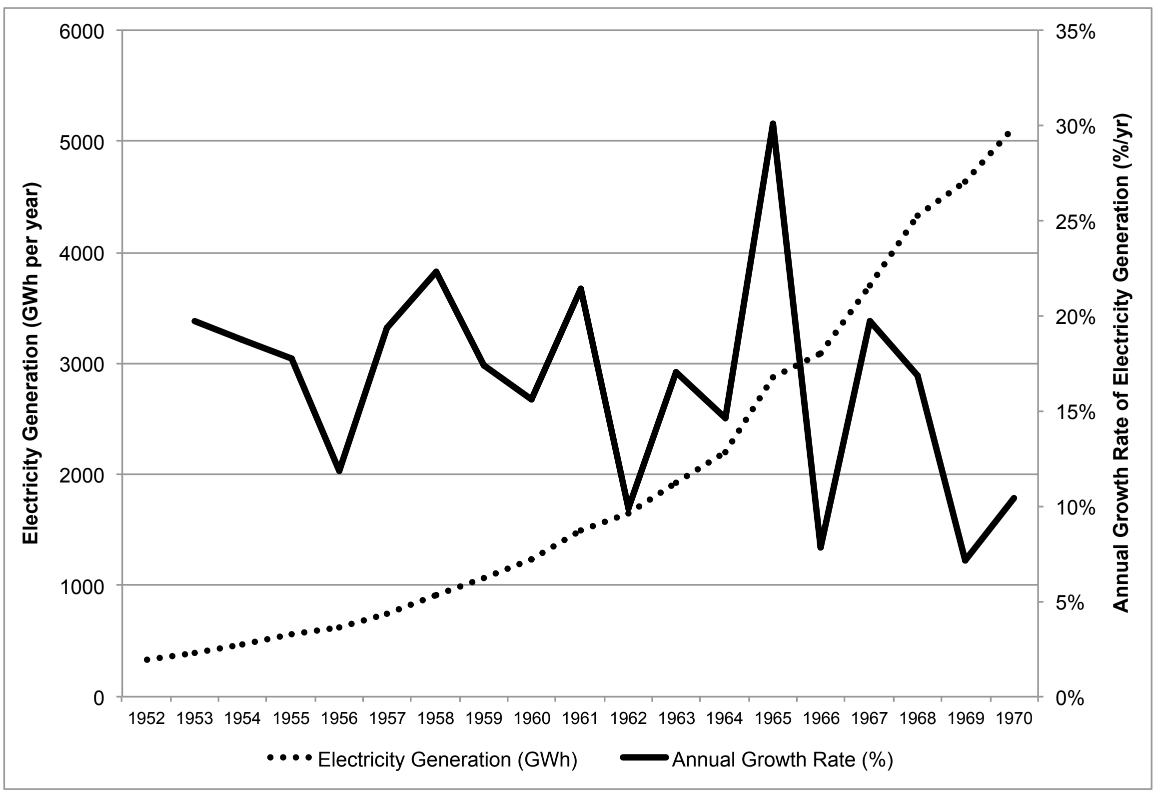
The potash industry was in its infant stages in the 1950s, but in 1954 SaskPower signed a five-year agreement with Potash Corporation of America assuring, "if the mining operations proved successful" the Potash Corporation could count on purchasing "60 million kilowatt-hours" per year from SaskPower by 1958 (Rediger, 2004: 59). The mining proved more difficult than anticipated, and it was not until 1962 that Saskatchewan had its first potash mine (Burton, 2014). The potash industry remains one of SaskPower's largest customers using electricity for "powering mining machines, hoisting, conveying, ventilation, lighting, dewatering, mill operations, tailings management and office/administration facilities" (CIPEC, 2003: 12). The potash industry drives growth in electricity demand in the present day (Interview 5).[8]

Beyond the economic development imperative, increased electricity sales to industrial customers helped to "build load" allowing generation equipment to run during the night when demand from residential and farms was low (SaskPower, 1952: 10). This in turn made better use of SaskPower's generation equipment and helped to further lower electricity rates. (SaskPower, 1952)

[8] It is not clear what rates were charged to each industry, but it was clear that deals were often cut. As the 1952 SaskPower *Annual Report* revealed, "In co-operation with the Industrial Development Office, special industrial rates were devised to attract industry to Saskatchewan (SaskPower, 1952: 10)."

Expanding Generation (1955-1965)

Electricity demand grew exponentially during the 1950s and 1960s, doubling nearly every four years (See Figure 3-3).[9] The pace of growth required an ambitious construction schedule. Coal-fired steam plants at Saskatoon (A.L. Cole Station) and Estevan were expanded in 1955-56 and a new gas plant was installed in Swift Current in 1955. Most significantly, in the fall of 1955 announcements were made that "two new $40,000,000 power plants" would be built at Estevan and Saskatoon (SaskPower, 1955: 19). The Saskatoon plant was the Queen Elizabeth and was commissioned by the Queen herself in July 1959 (Rediger, 2004). The new Estevan plant was called Boundary Dam. By 1960 Boundary Dam Unit 1 provided 132 MW of lignite coal generation capacity to the Saskatchewan grid.



(Source: SaskPower Annual Reports 1953 to 1970)

Figure 3-3 SaskPower Electricity Generation 1952-1970

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[9] Note that the anomalous growth rates of 30.1% in 1965 and 7.1% in 1966 correspond to the Regina municipal plant becoming part of the SaskPower system in 1965.

SaskPower also made plans to build Saskatchewan's first hydroelectric plant. Hydroelectricity had been long studied in the province. In 1927 the Saskatchewan Power Resources Commission hired consulting engineers Sullivan, Kipp and Chase to study hydroelectric potential in Saskatchewan. The consultants concluded that a hydroelectric plant on the Saskatchewan River would not be economical until 1945 when load had grown substantially (SPRC, 1928; White 1976).

In 1930, after being approached by a proposal from a private developer, the Saskatchewan Power Commission hired H.G. Acres and Company to study hydroelectric potential at Fort a la Corne, located just downstream of the junction of the North and South Saskatchewan Rivers (White, 1976). Acres and Company were optimistic about the site and believed a hydroelectric project there to be "physically and economically feasible, and more particularly as a public enterprise" (Acres and Company, 1931: 1). They estimated that the dam at Fort a la Corne along with transmission to Saskatchewan's largest cities "Regina, Moose Jaw, Saskatoon, and Prince Albert" could be built at a cost of $19,000,000 (White, 1976: 116).

The Depression put the Fort a la Corne proposal on indefinite hiatus. However, H.G. Acres was asked to update their analysis after World War II. They produced an updated report in 1946 and recommended the Fort a la Corne project be delayed until electricity demand had grown; a conclusion similar to that reached by Sullivan, Kipp and Chase in 1928. (White 1976)

With electricity demand growing rapidly in the 1950s SaskPower again looked to hydroelectricity. The decision was made to build a hydroelectric plant on the Saskatchewan River near Nipawin at an estimated cost of $46,250,000 or $230 per kilowatt (in 1959 $CDN dollars) (SaskPower, 1959a). A second hydroelectric station would be brought into service at Gardiner Dam once that joint federal-provincial project was complete.[10]

[10] The Gardiner Dam was a $182 million joint federal-provincial project to control streamflow on the South Saskatchewan River and provide irrigation water to farmers.

Construction of the E.B. Campbell hydroelectric station began in 1960.[11] The project was producing electricity by 1963, operated at 201 MW in 1964, and was fully commissioned at 280 MW in 1966. At present it remains in service.

Completing the Integration

The Boundary Dam plant was the fulfillment of the long-sought dream to use cheap and abundant lignite coal to power the province. With high-voltage transmission lines this cheap power could be distributed throughout the province and was used as a bargaining chip to negotiate with the remaining utilities operating outside the SaskPower system. (White, 1976)

The City of Weyburn agreed to sell its utility in 1957 for "$2,000,000 in annual installments over a twenty-year period" (White, 1976: 239). When asked how SaskPower could justify the purchase price General Manager David Cass-Beggs replied that he was relying "on the availability of cheap Estevan power" (Cass-Beggs quoted in White, 1976: 239). Though Boundary Dam was not yet online, Cass-Beggs had calculated that the low cost lignite-fuelled power would allow SaskPower to make up the expense through electricity sales back to Weyburn.

The 64-meter tall Dam created a created a 225-kilometer long reservoir of water that is now called Lake Diefenbaker. At the time of construction it was estimated that approximately 500,000 acres of cropland could be irrigated, increasing the value of output from $7 million to $50 million. As a secondary benefit the dam would also allow for hydroelectric generation; the 187 MW Coteau Creek generating station. The dam was not without impact, however, and valued First Nations cultural artifacts were destroyed, both by the flooding, and intentionally by government officials in order to prevent a hold-up of construction. (CBC, 2015b; Water Security Agency, 2015; Herriot, 2000)

[11] The power plant was originally called 'Squaw Rapids'. In 1987, John Dorion, a native educator, wrote to SaskPower asking them to change the name due to its racist connotations. The head of SaskPower, George Hill, responded by mailing a survey to customers in the same envelope as their power bills asking whether they supported or opposed the name change. Only 1% of SaskPower customers responded, and three-quarters opposed the name change. Hill stood fast. Dorion expressed his disbelief, "It's obvious it's a racist sign? A survey shouldn't be needed" (Windspeaker, 1987). SaskPower eventually relented and in 1988 the station was re-named to honour former SaskPower President E.B. Campbell.

A comparison of costs between local generation and SaskPower rates eventually convinced the holdout Regina City Council to agree to sell their electric utility to SaskPower. Regina City Council had remained committed to municipal ownership of the Regina power plant despite an explosion in 1960 and frequent blackouts in the early 1960s. They had come to enjoy the revenue earned from selling power, as it was a much less visible source of funds than property taxes. It was not until 1965 that Regina's Council faced the realization that rebuilding and retaining their aging power plant would cost much more than obtaining "cheap Estevan power" from SaskPower. Pressure from groups such as the Chamber of Commerce likely helped. The Chamber lobbied for the sale of the Regina power plant, arguing that SaskPower could supply businesses with electricity at lower rates. (White, 1976)

The sale of the Regina Power Plant and distribution system in 1965 was the final puzzle piece in creating a truly integrated electricity system in the province. Large coal-fired and hydroelectric plants provided cheap power and SaskPower distributed the power throughout the province with a network of high-voltage transmission lines. This publicly owned system, and the logic of centralized power production, remains in place today. This 50-year reign has not been without its challenges.

The Dawning of Environmental Concern

The E.B. Campbell Dam was SaskPower's first hydroelectric project.[12] More were to follow. For SaskPower E.B. Campbell was "the first step in a thirty-year plan to harness electricity from the Saskatchewan River and other northern rivers to meet an increasing provincial energy demand" (Waldram, 1993: 58). In 1960, General Manager David Cass-Beggs sketched out a plan for a system of cascading hydroelectric dams along the South Saskatchewan River (Figure 3-4). Other dams in the remote north would power northern mining communities.

E.B. Campbell (shown as Squaw Rapids in Figure 3-4) was not without impact. Upstream from the dam valuable farmland was flooded. Farmers were offered compensation of "2.5 times the assessed value of expropriated land" and further compensation was given for buildings that had been on the land (Waldram, 1993: 62).

Downstream, the story was different. Cumberland House, a largely Métis community located downstream from the dam, and the nearby Cumberland House Indian Band, struggled with the problems created by the dam for years without compensation. On construction the residents had been assured that the dam would smooth out streamflow on the river; lowering expected streamflow during summer melt, and increasing streamflow in winter, when flows were typically low. (Waldram, 1993)

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[12] The first hydroelectric project was built in Saskatchewan between 1929-1931 and is called Island Falls. This hydro dam is located near the border town of Flin Flon, Manitoba and was built by the Hudson Bay Mining and Smelting Corporation to power their copper and zinc mining operations. SaskPower purchased Island Falls in 1981 and the station, now upgraded to 111 MW of capacity, remains in operation today. (Olsen, 1955; SaskPower, 1981; SaskPower, 2014)

Saskatchewan is also home to a partially completed hydroelectric station at Lacolle Falls near Prince Albert. Construction of the $1.2 million dam began in 1912, but a recession, and a lack of access to capital, forced Prince Albert to stop construction in 1913. The City of Prince Albert only finished paying for the expensive and incomplete project in 1965 and the half-completed dam stands as an example of the vulnerability faced by large capital projects. A recent architectural thesis reimagined the incomplete dam as a spa, but as of now it sits in dis-use (Hurd, 2007). (Waiser, 2005)

Problematically SaskPower did not plan to operate the dam in this manner. E.B. Campbell, Assistant Chief Engineer of SaskPower, whose name would eventually adorn the dam, stated internally, “The Squaw Rapids project will be operating as a peaking plant, at least during heavy load season, and this will result in extremely large daily fluctuations in discharge” (Campbell quoted in Waldram, 1993: 63).

The results were decidedly negative for Cumberland House. Residents in the area relied on fishing, trapping, and tourism for their livelihoods. In a letter to the Provincial government in 1964, the President of the Cumberland House Fisherman’s Cooperative described the impact,

> From the time the Squaw Rapids dam has been operational, we have noted the following:
>
> Fish have been caught in deeper holes in rivers and lakes, when the water flow is suddenly reduced. Fishing operations carried on elsewhere have had to be abandoned. If the situation is reversed, the fish drown on sudden high levels. We suffer heavy losses both ways.
>
> Sudden high water destroys nests of waterfowl during nesting seasons. Income usually derived from this source of guiding and hunting by natives is lowered.
>
> At this time of writing, the species of wildlife suffering most from the consequences are big game. Their young are being caught in lowlands and drowned in the rise of water. The latter effects on fur bearing animals will also be greatly felt. The unsteady flow is definitely hampering with conservation.
>
> We trust that our plea will reach sympathetic ears. We are a people depending on these sources for a living. We ask for more consideration from the management of the dam and your support before our plight is increased. (Waldram, 1993: 68)

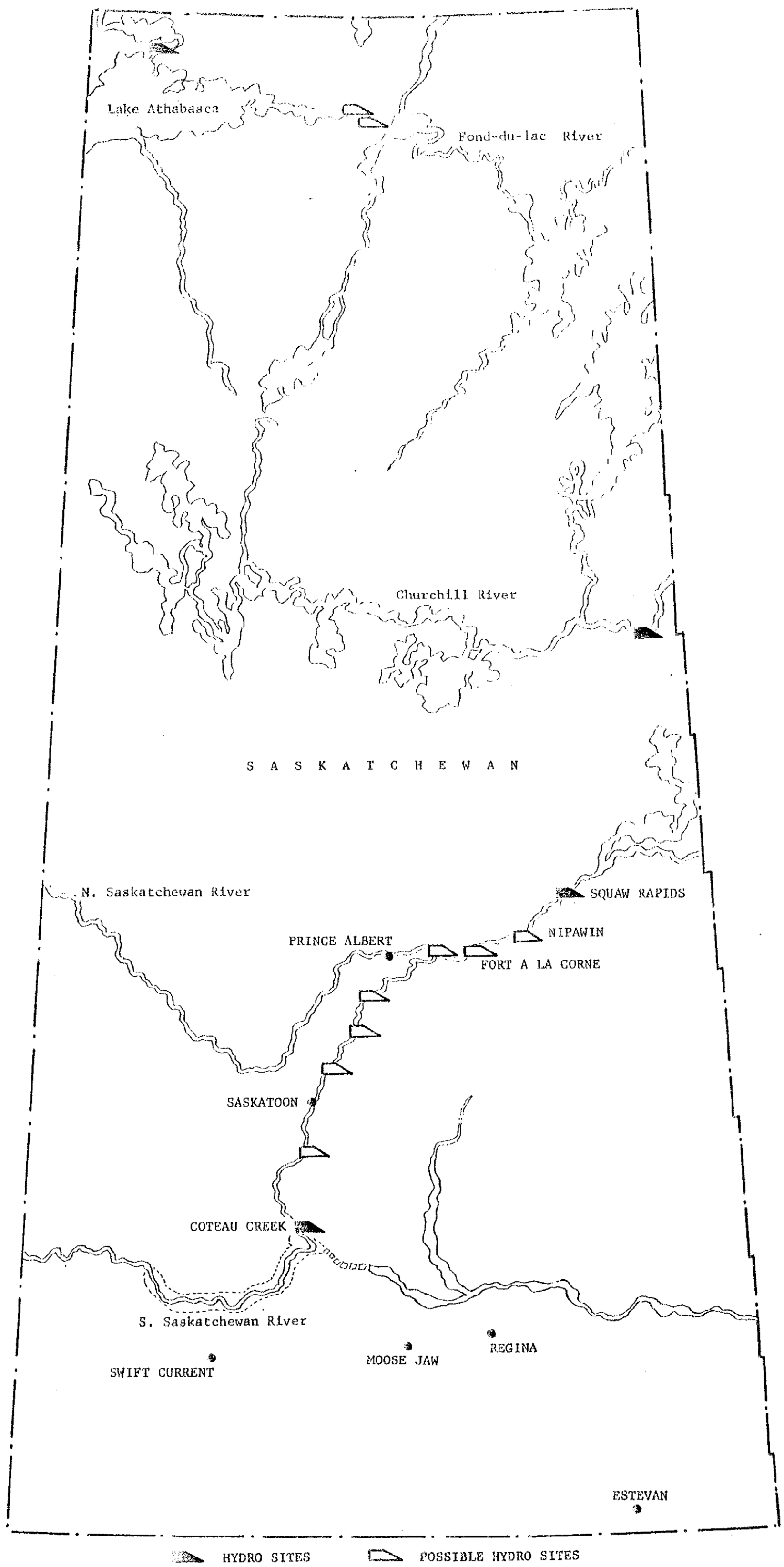


Figure 3-4 Cass-Beggs' Hydro Plan for Saskatchewan (Cass-Beggs, 1960: i)

The pleas of the community did not reach sympathetic ears. E.B. Campbell, in the same SaskPower internal memo quoted above wrote,

> I don't think that we can be expected to limit operations at the Squaw Rapids site to protect beaver and muskrats…Any restriction on (dam operation) in the interests of wildlife will, no doubt, result in economic losses to the hydro project that will greatly exceed the value of any fur bearing animals. (Waldram, 1993: 63)

Though SaskPower believed its hydro-power had a higher market value than the fur-bearing animals downstream, the corporation did not compensate fishers or trappers for the external costs imposed by the dam. The only downstream entity to receive compensation from SaskPower was an outfitting company called *Les Voyageurs*, who were paid $1500 in 1963 because the dam had reduced fall streamflow and shortened their outfitting season. In exchange, *Les Voyageurs* agreed they would not file a lawsuit against SaskPower. (Waldram, 1993)

Rather than offering compensation, SaskPower and the Saskatchewan government reacted to the letter from the President of the Fisherman's Co-operative by studying the downstream impacts of the dam. Mitigation was deemed too expensive. The community continued to press the government for compensation. More studies were commissioned. After years of delay the community grew frustrated by the government's "more study – no action" approach and launched a legal challenge for compensation (Waldram, 1993: 74). The government in turn offered to continue negotiations. In good faith the community put the lawsuit on hold. A mediator was appointed in 1986, but progress was slow. In 1987, to press home their demands, hundreds of community members even began constructing their own dam to "raise the level of Cumberland Lake" and improve downstream conditions (Waldram, 1987: 78). Waldram writes, "Ironically, the Saskatchewan government's Department of the Environment expressed concern that not only was the dam illegal, but also that it could cause environmental damage" (1987: 79).

In 1989, over twenty-five years after the dam was constructed, a compensation package was awarded to the community worth an estimated $25 million dollars. (McLennan, 2008)

During the struggle with SaskPower, other dams were proposed. A dam at Nipawin was proposed in the mid 1970s and was built upstream from E.B. Campbell in the 1980s. A dam was also proposed for the Churchill River at Wintego Rapids. The proposition was contentious. The Churchill River was a prized destination for recreational canoeing and fishing, and is home to a rich aquatic ecosystem. The government organized the Churchill River Board of Inquiry to seek public input on the Wintego dam proposal. The residents of Cumberland House made sure to let the commission, and those living downstream from the dam, know what to expect; a damaged ecosystem and a Corporation unwilling to compensate for the damage. The final report of the Churchill River Board of Inquiry was released in 1978 and summarized public opposition to the Wintego project. The dam was scrapped. (Waldram, 1994; SaskPower, 1991a; Rediger, 2004)

SaskPower's plans to expand coal-fired generation were also generating local environmental concern. In 1975 SaskPower expressed interest in building another coal-fired plant near Coronach. Farmers in the area were concerned that local coal-mining would damage valuable farmland. Many had been to Estevan and had seen firsthand the "moonscape" that had been created by surface mining coal (Rousseau, 2014). Coronach area farmers formed a surface rights group and lobbied to have the mining companies store the topsoil when they removed it, and replace the 'overburden' and topsoil when they were finished. This practice would ensure that agriculture could continue in the area after the coal had been mined. (Rousseau, 2014)

The remediation practices have been a success. Around the Poplar River plant hay fields now cover what used to be coalmines. For residents of Coronach the environmental remediation, won through the advocacy of local farmers, is a source of pride (Rousseau, 2014). SaskPower learned a valuable lesson in the importance of obtaining social license for their projects.

Still, concern over local environmental impacts of planned power projects continued to plague SaskPower into the 1980s. North of Coronach, a planned coal-fired plant near was "blocked in 1981 when the Rural Municipality Gravelbourg designated four heritage sites in the area" (Rediger, 2004: 123). To supply their coal-fired power plant with cooling water SaskPower had planned to dam the Wood River and create a reservoir. If the dam were built, three of the newly designated heritage sites would be flooded. SaskPower disputed the size of the heritage sites and wanted to see them reduced. A third-party investigation was carried out, which concluded, "Staggering quantities of heritage resource information exists in the proposed Cooper reservoir. Reservoir construction and inundation will probably completely destroy the information potential of all heritage resources occurring in or near the impact zone" (LeaderPost article quoted in Rediger, 2004: 123). The reservoir and the power plant did not proceed.

The most notorious power siting conflict in Saskatchewan occurred when SaskPower made plans to supply cooling water for the proposed Shand coal-fired power plant near Estevan. Two dams were planned: the Rafferty and the Alameda. These dams would offer cooling water for Shand, and would control streamflow on the Moose Mountain creek and the Souris River. Project proponents argued the flow control would protect the city of Minot in North Dakota from flooding. (Jowett, 2012)

When two farmers, Ed and Harold Tetzlaff found out the Alameda dam would flood their land they took action to stop it. With other affected landowners the two brothers started an organization called SCRAP 'Stop Construction on Rafferty-Alameda Projects'. The farmers were joined by the Saskatchewan Wildlife Federation, an organization that grew concerned that the projects would destroy valuable wetlands. (Jowett, 2012)

Trouble arose when the Federal Minister of the Environment, Tom McMillan issued an approval of the Rafferty-Alameda project without the project having gone through an environmental assessment. One of McMillan's senior aides resigned over the decision. Her name was Elizabeth May.[13] (Jowett, 2012; Harrison, 1996)

May caused an uproar when she went public with the reason for her resignation. May alleged that the decision to approve Rafferty-Alameda without an environmental review was the result of a political deal cut between the Federal Government and the Government of Saskatchewan. Critics of the decision believed it went against the Federal government's own Environmental Assessment and Review Process (EARP) Guidelines, published in 1985 (Environment Canada, 1985). The Canadian Wildlife Federation took the federal government to court demanding an environmental assessment be completed. (Jowett, 2012; Harrison, 1996)

Rafferty-Alameda was a landmark case in environmental law. The federal court decided for the plaintiff and against the Federal government. They ruled that the EARP Guidelines were binding and that the Federal government had an obligation to conduct an environmental assessment on the project. (Harrison, 1996)

The courts did not, however, approve an injunction to halt construction of the project. Construction continued, the dams were completed in 1991, and Ed and Harold Tetzlaff lost their farmland. The brothers had, however, won a victory for environmental groups in Canada,

> Although only thirty-five proposals were referred for public reviews by the federal government in the fifteen-year period from 1974 to 1989, there were twenty-four reviews in less than two years after the *Rafferty-Alameda* decision. (Harrison, 1996: 134)

SaskPower worked to respond to the rise of environmental concern. In 1972 SaskPower CEO warned presciently of the challenges to come,

[13] May now leads the federal Green Party.

> The development of energy resources to meet the anticipated growth in demand for power and gas services in the face of rising costs and increased public concern on environmental matters is the most important challenge facing the Corporation in the future. While on one hand the Corporation is committed to the development of energy resources to meet the growing demands of its customers, it also stands committed to the orderly and economic development of these resources, and to minimizing the undesirable environmental impact of such activities. (R.R. Keith in SaskPower 1972: 3)

In 1980, SaskPower conducted an internal reorganization that created several new business units in "energy supply planning, environmental protection, energy conservation and public participation" (Rediger, 2004: 121). The CEO at the time, Robert Muncor, described the need to balance costs, environmental, and social concerns,

> The very major challenge is to provide the (power) needs of the province in a reasonable way, reasonable meaning at as low a cost as possible, in as an environmentally and socially sound way as those objectives can be balanced together. (Muncor quoted in Rediger, 2004: 123).

In 1989 George Hill, then CEO of SaskPower wrote of the corporation's progress and aspirations,

> In 1989, SaskPower formalized a comprehensive Environmental Policy Statement, which confirms that environmental responsibility has always been a priority. It provides a framework in which we can protect the environment while continuing to meet the province's electrical needs. We intend to make SaskPower the most environmentally responsible power utility in Canada. (George D. Hill in SaskPower, 1989: 6)

By the early 1990s it was clear that a sea change had occurred in public perception of power production. The public had realized that electricity generation, of any type, has an environmental and social impact.

> What was once thought of as an environmentally benign source of energy has been linked to ozone depletion, acid rain, the greenhouse effect and other negative environmental concerns such as flooding, water diversion and radioactive contamination. (SEEORP, 1991: 3)

In 1992, the coal-fired Shand Power station was commissioned. The Rafferty-Alameda dams that provided reliable cooling water for the plant had flooded valued farmland and wetlands, but SaskPower claimed that Shand would be an environmentally sustainable power plant. Shand's cooling water would heat a greenhouse where native tree saplings would be grown, and these would be distributed around the province. As a further benefit the trees would act as carbon sinks. Shand was also equipped with a limestone scrubber system to minimize sulphur dioxide emissions and lessen the plant's contribution to acid rain. (SaskPower, 1993)

In 1993, Shand, the power plant, whose cooling reservoirs had been built without environmental assessment and set a ground-breaking precedent in environmental law, was honoured "with the prestigious Power Plant Award" for its sulphur dioxide control systems and "zero discharge water management system" (SaskPower, 1993: 6). Without a hint of irony SaskPower called Shand "Canada's most environmentally friendly coal-fired station" (SaskPower, 1993: 6).

Beyond the Public Power Coal-Hydro Nexus

As outlined above, Saskatchewan's publicly owned power system was built to transmit electricity from southeastern coalfields and hydroelectric plants along the Saskatchewan

River system.[14] These centralized plants replaced more expensive distributed diesel turbines, and public ownership allowed SaskPower to charge lower prices for electricity than private utilities.

The logic and the design of the system did not change in a quarter of a century. In 1992, coal made up 71% of electricity generation, hydroelectricity provided just over 20% of electricity, natural gas provided 4.5%, with imports of hydroelectricity from Manitoba providing the remaining power (SaskPower, 1992).

The system also remained in public ownership. In 1991 the Saskatchewan Electrical Energy Options Panel (SEEOP) observed, "all the electrical energy supplied to the grid connected Saskatchewan system comes from generating facilities owned and operated by SaskPower or from neighbouring utilities" (SEEOP, 1991: 18). SaskPower had survived under public ownership despite two previous periods when the ruling political parties prioritized privatization and free enterprise.

The first wave of privatization in Saskatchewan came during the period of 1964-1971 under Liberal Premier Ross Thatcher. Thatcher was a former member of the CCF, but in the 1964 election he campaigned as Liberal leader on a platform emphasizing lower taxes and less government control of business. Thatcher and the Liberals won the election, unseating the CCF and ending their 20-year reign. (Rediger, 2004)

During the election campaign Thatcher spoke of his desire to sell off struggling crown companies. Crowns would be sold unless they met one of three criteria, providing "an essential service which private firms are unable to supply at a comparable cost to the public", providing "useful employment which otherwise would not be available" or offering "a particularly satisfactory return on invested public funds" (Thatcher quoted in

[14] At least the southern portion of the system. The northern system is predominantly hydroelectric and diesel and was built in a piecemeal fashion to coincide with mining developments and isolated settlements.

Rediger, 2004: 76).[15] SaskPower was a profitable crown in most years and provided dividends to the provincial government, meeting the third criteria. With the memory of the cross-subsidized rural electrification campaign fresh in the minds of Saskatchewan residents, SaskPower also likely passed the first test and provided a service that a private operator would not have supplied. This meant that, despite the ideology of the Thatcher Liberals, SaskPower was safe from privatization during their time in power.[16] (Rediger, 2004)

Thatcher's Liberals lost to the New Democratic Party (NDP) – a reinvented CCF – led by Allan Blakeney in the 1971 election. Thatcher died three months later (Rediger, 2004). Blakeney brought a renewed commitment to public ownership, and expanded Saskatchewan's portfolio of Crown corporations. Of particular note, Blakeney formed the Potash Corporation of Saskatchewan (PCS) as a vehicle to purchase (or expropriate if need be) potash ventures in the province (Burton, 2014).

A second wave of privatization occurred during 1982 – 1991 under Premier Grant Devine and the Progressive Conservative (P.C.) government. The P.C.'s welcomed "public participation" in the economic life of Saskatchewan. The Orwellian phrase referred to Saskatchewan citizens holding stocks in privately owned Saskatchewan corporations. (Rediger, 2004)

The Potash Corporation of Saskatchewan, newly formed in 1975, was sold off by the P.C.s in 1989-1990 (Burton, 2014). It is now one of the world's largest potash mining and

[15] Thatcher's tenure was marked by poor labour relations at SaskPower. In 1966 workers on the natural gas side of the company went on strike to demand an 8% pay increase. The Liberals brought the strike to an end by passing essential services legislation in the form of the *Essential Services Emergency Act*. The Act allowed government to declare a state of emergency and implement compulsory arbitration when a strike threatened "life, health or property" (Rediger, 2004: 87). A strike by natural gas workers was deemed to fit that criterion. A strike by the electrical workers was narrowly averted at the bargaining table in 1969 (Rediger, 2004).

[16] Of note, Ross Thatcher's son Colin became an MLA like his father. Colin Thatcher resigned his post as Minister of Energy and Mines in 1984 when he was convicted of killing his wife JoAnn Wilson.

integrated fertilizer companies, and earned over $7 Billion in revenue in 2014 (NASDAQ, 2015; Burton, 2014). The Saskatchewan Mining and Development Corporation (SMDC), a provincial crown formed to mine uranium in northern Saskatchewan, was combined with Eldorado (a federal uranium mining crown) in 1988. Shares were opened for "public participation" in 1991. CAMECO is now the largest uranium mining company in the world.

The P.C.s planned to privatize the natural gas distribution functions of SaskPower. Taking a step down this path, SaskPower was split in two in 1989: SaskEnergy would handle natural gas sales and distribution; SaskPower would continue to control electricity supply in the province (SaskPower, 1989). When the split was finalized George Hill, head of SaskPower, remarked,

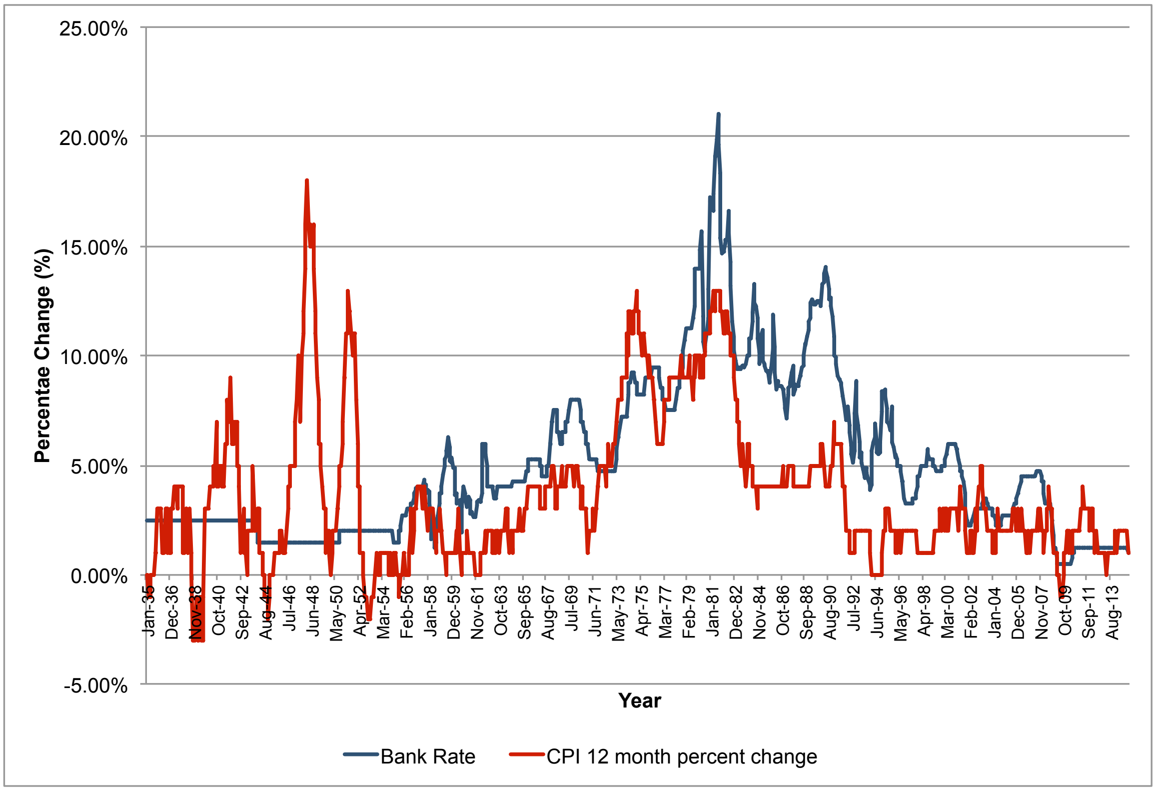
> (SaskEnergy) is the only gas distribution company that is now owned by government. Every other gas distribution company (in Canada) is investor-owned…I firmly believe that every person in Saskatchewan should have an opportunity to participate.
> (George Hill quoted in Rediger, 2004: 152).

In April 1989 the P.C.s announced plans to privatize the newly created SaskEnergy. The profits would be used to pay down SaskPower's debt, which had grown to $2 billion by 1988 (Rediger, 2004; SaskPower, 1988). The debt was in part due to high financing charges. Interest rates had spiked in the early 1980s and remained at historically high levels throughout the decade increasing the cost of capital for SaskPower (See Figure 3-5).[17]

When plans to sell SaskEnergy were announced, the NDP staged a 17-day walk out from the legislature. It was not until the P.C. government promised a commission to study the impacts of privatizing SaskEnergy that the NDP returned. The commission reported in

[17] In 1986 SaskPower's revenue was $507 million (1987 CDN dollars) and financing charges were $214 million, a full 40% of revenue. (SaskPower, 1993)

November of that year, and recommended in favour of privatization. Due to public opposition, however, the P.C.s opted not to sell SaskEnergy. The NDP had won the battle of public opinion. (Rediger, 2004)



(Source: Statistics Canada CANSIM 176-0043 & 326-0020; author's calculations)

Figure 3-5 Bank Rate and 12-Month Canada All-Item CPI Percent Change

The NDP returned to power under Premier Roy Romanow in 1991. But it was a very different NDP than the party that had expanded crown ownership in the Blakeney era. The free market ideology held by the P.C.s in the 1980s had become the neo-liberal governing consensus for parties of all stripes, including Romanow's NDP. At the federal level, free trade agreements were negotiated and signed. Industries that had been previously protected from competition were "deregulated" or "liberalized". The provincial NDP rode the wave of deregulation, making no plans to expand the role of the Crowns, and instead eyeing the possible sale of crown assets. Romanow also implemented hard-nosed budget cuts to balance the provincial budget. These spending cuts are still lauded for their severe austerity (Drummond, 2015).

In this era of deregulation and neo-liberalism SaskPower's CEO Jack Messer, newly appointed by the NDP when they returned to power, believed it was important that SaskPower adapt to the realities of a deregulated electricity market. Messer believed that SaskPower should prepare for competition,

> The business landscape in which SaskPower operates is undergoing dramatic change. Deregulation of the electric industry in the United States has opened the doors to competition, setting the stage for similar circumstances in Canada. The American example is showing us the impact of a shifting market for electrical energy, transforming a once-stable, secure business environment into one facing the uncertainties of open competition for power generation, transmission and distribution. Within this new competitive environment, price and service become the keys to sustaining existing business and attracting new customers. (Jack Messer in SaskPower, 1994: 4)

Preparing for competition meant drafting policy that would allow other power generators access to the Saskatchewan grid (SEEOP, 1991). Messer worked to prepare SaskPower for this competition, but was fired from his position in 1997 before the job was complete.[18]

Messer was succeeded by John Wright, a former Deputy Minister of Finance for the provincial government. Under Wright's leadership the Saskatchewan grid began to move away from the publicly owned coal-hydro nexus. Wright was willing to explore private-public partnerships in the form of "cogeneration." He also explored ways to move away

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[18] Messer's firing was related to the sale of a SaskPower venture called Channel Lake Petroleum Ltd. Channel Lake was created in 1993 as a SaskPower subsidiary. Its role was to purchase natural gas for SaskPower. The venture fared poorly and by 1997 had lost $8 million. SaskPower negotiated the sale of Channel Lake to Alberta based Direct Energy Marketing Ltd for $20.8 million. When it came time to sign the contract, however, the SaskPower team didn't notice that the fine print that subtracted $5.2 million from the price they thought there were getting. Signed contract in hand the purchasing party bought Channel Lake at a steep discount. Messer was fired for the error. The general manager of Channel Lake, who had negotiated the sale, was also fired and went on to work for Direct Energy. (Rediger, 2004)

from SaskPower's reliance on coal. The Kyoto protocol had raised the possibility of greenhouse gas emissions regulation. Despite regulatory uncertainty from the federal government, SaskPower began creating annual climate change "action plans" to take "a proactive approach to reducing and mitigating greenhouse gases" (SaskPower, 2001: 10). Natural gas power generation was an appealing option for SaskPower since it emitted greenhouse gas emissions roughly one-third that of coal per unit of electricity generated. (Wright, 2014)

The first cogeneration project was a natural gas combined cycle unit at Lloydminster. Owned by TransAlta cogeneration, the facility supplies steam to Husky's Lloydminster heavy oil upgrader and sells electricity to SaskPower on a long-term purchase agreement. The Meridian project was commissioned in 2000. (SaskPower, 2001; Wright, 2014)

The next cogeneration was created through a private-public partnership agreement with ATCO, a private utility based in Alberta. ATCO and SaskPower partnered to build a cogeneration plant at the Cory potash mine owned by the Potash Corporation of Saskatchewan (the former crown now operating as a private company). The 228 MW combined cycle natural gas facility provides steam for potash mining process operations and electricity for the Saskatchewan grid. The Cory cogeneration plant was commissioned in 2003. (SaskPower, 2001-2003; Wright, 2014)

The move to cogeneration was not full-blown privatization, but was a shift from SaskPower's former policy of exclusively building, owning and operating generation facilities. The phrase "co-generation" referred both to the technology being employed and generation owned in partnership with another private entity. The move to open new generation projects up to public tender won approval from groups such as the libertarian minded Frontier Centre for Public Policy (1999) who celebrated the Meridian cogeneration project as a successful step in the right direction, "It's taken a couple of generations, but marketplace realities are displacing the old ideas of state control and ownership." Under John Wright and the Romanow NDP, the public power system had begun to open to private ownership. The introduction of natural gas also reflected a shift away from the coal-hydro nexus that had powered the province for the previous forty years.

The Arrival of Wind Power

Wright's desire to lower GHGs and diversify the SaskPower electricity system led him to approve the first utility-scale wind turbine project in Saskatchewan. The SunBridge Wind Power Project was a privately owned joint venture between Suncor Energy Inc. and Enbridge Inc., familiar names in the oil and gas industry. The 11 MW project was built in 2002 in southwest Saskatchewan (SaskPower, 2001: 8). SaskPower built its own 5.9 MW facility in the same region, beginning full operation the following year. (SaskPower, 2001; SaskPower, 2002; SaskPower, 2003; Wright, 2014)

Wind had been under consideration in different forms for many years. There is a reference to farmer-owned "wind machines" in the Saskatchewan Reconstruction Council report of 1944. At that time, wind turbines, partnered with batteries, offered the possibility of supplying power to farmers located far from the existing grid. Several farmers did install these systems to power yard lights and water pumps. (Saskatchewan Reconstruction Council, 1944)

In 1974 SaskPower tested an "experimental model of a small wind turbine developed by the National Research Council" to see how it would fare under "Saskatchewan conditions" (SaskPower, 1974: 10).

SaskPower also explored building a commercial-scale wind project in the 1990s, but the project was rejected by Jack Messer who stated,

> In the final analysis, it was decided the cost premium associated with proceeding with the project could not be justified. In today's rapidly changing business environment, it is critical to SaskPower's customers that efficiencies are achieved wherever possible.
> (Jack Messer in Government of Saskatchewan press release, 1995)

The wind projects in the early 2000s were small and exploratory, but offered substantial returns. Southwest Saskatchewan is home to a rich wind resource and the turbines regularly achieve capacity factors of 40% (Interview 2). Their success, and pressure from environmentally minded members of the provincial NDP such as Peter Prebble, led SaskPower to build a larger project in 2005; the 150 MW Centennial wind power facility. (Wright, 2014)

At present SaskPower continues to expand wind power, albeit in a slow and cautious manner. The preferred approach is to issue a call for proposals for wind power projects and allow private wind developers to respond. This puts developers in the position of identifying wind resources, securing land lease agreements, and seeking community support. SaskPower then agrees to purchase power from one or more of the applicants. Two recent wind projects; at Chaplin and Moosomin respectively were approved in this manner. (Confidential interviews, 2015)

The potential for wind substantially outstrips the installed capacity. SaskPower recently issued a call for proposals seeking 200 MW of new wind capacity. The market returned 4000 MW of interest (Confidential interviews, 2015). Despite this rich resource, wind made up only 2.7% of electricity generated in Saskatchewan in 2014 (SaskPower, 2014).

Advocates of wind energy have been increasingly vocal in asking SaskPower to speed up investment in wind power. Saskatchewan Community Wind, set-up by James Glennie, has been working to build support for a community-owned wind project in the Saskatoon area. The Green Energy Project of Saskatchewan (GEPS) has outlined pathways to increase wind and solar in the province (Bigland-Prichard & Prebble, 2010; Bigland-Prichard 2010; Bigland-Prichard 2010a; Bigland-Prichard 2011). These advocates call for SaskPower to move from 2.7% wind to 25% wind power on the grid in short order.

Problematically SaskPower values wind only as a means of reducing their natural gas expenses. Wind's electricity output is variable, and SaskPower must back-up wind capacity with fast-ramping natural gas single-cycle or combined-cycle turbines. The value of power generated by wind power is thus discounted and is valued at the cost of avoided natural gas consumption – about 3.5-4 cents/kilowatt-hour – rather than the wholesale electricity rate. (Interview 6)

Even as a means of reducing natural gas consumption wind is likely to be more important in the future. We live in an era of low natural gas prices, but this was not always so. The oil crisis of 1979 led to spikes in the price of oil and natural gas. Natural gas prices were also high in the early 2000s. Soon after expanding natural gas capacity with the Lloydminster Meridian cogeneration project SaskPower found itself stung by rising natural gas prices (SaskPower, 2001). A drought in 2001 led to lower than usual hydroelectric production and further worsened the crisis (SaskPower, 2001). As John Wright says of the period, "we were getting hammered by natural gas prices, just creamed!" (Wright, 2014). The volatile price of natural gas remains a challenge for SaskPower's planning at present.

Wind may be the preferred source of power generation by civil society actors such as the Green Energy Project of Saskatchewan (GEPS), but not all Saskatchewan citizens are thrilled with the technology. Residents of the Rural Municipality (R.M.) of South Qu'Appelle, located 20 kilometres east of Regina, said no to a proposed 50 MW 50-turbine wind project in March 2014. Renewable Energy Systems Canada (RES) had hoped to install a wind monitoring station in the R.M. After significant public outcry, the R.M. passed a motion outlining that wind monitoring stations and wind farms would not be allowed (Shepherd, 2014). This despite the fact that the region allows high-impact uses such as intensive-livestock operations.

The renewables are not getting any political support from the governing Saskatchewan Party. Instead Premier Brad Wall has retained a dogged fascination with nuclear power. Recent statements on CBC indicate that the Premier hopes for federal government support for replacing coal-fired generation with nuclear power (CBC, 2015a).

The Nuclear Dream

The Saskatchewan Party was elected in 2007, ending the sixteen-year tenure of the NDP under Roy Romanow and, after 2001, Lorne Calvert. One of Saskatchewan Premier Brad Wall's first actions was to set up the Uranium Development Partnership (UDP) to study the future of uranium in Saskatchewan. The UDP was an industry-stacked panel of twelve that included the CEOs of uranium mining companies CAMECO (Jerry Grandey) and AREVA Canada (Armand Lefèrrere), and the CEO of nuclear power producer Bruce Power (Duncan Hawthorne). The board also included an environmental representative, the infamous Patrick Moore, who has made a living advertising his former ties to Greenpeace while advocating for industries such as nuclear power and chemical pesticides. (UDP, 2009)

It came as no surprise that the UDP recommended: the expansion of the uranium mining industry in Saskatchewan; the building of a nuclear power plant; construction of a research reactor to create medical isotopes; and storage of nuclear waste in the province (UDP, 2009).

To their credit the Government of Saskatchewan took these recommendations to the people of Saskatchewan. Long-time civil servant Dan Perrins was asked to visit communities across the province to get citizen feedback on the recommendations. Hundreds of citizens attended the public meetings and nearly all of them opposed the proposed expansions of the uranium industry (Perrins, 2009).[19]

Opposition to a nuclear power plant was particularly strong in the Lloydminster area. In 2008, Bruce Power, eager to capitalize on the provincial government's support for nuclear power, conducted a feasibility study into building a 1000 Megawatt (MW) reactor in Saskatchewan (Bruce Power, 2008). They selected Lloydminster as a candidate site for

[19] In statistical terms, 84% of submissions (oral or written) that touched upon nuclear power opposed nuclear power; on the issue of nuclear waste storage in the province 86% of submissions that addressed that issue were opposed.

the plant. Straddling the Alberta-Saskatchewan border, Lloydminster would allow the possibility of electricity exports to the Alberta grid (Bruce Power, 2008).

In early 2009, *before* the UDP consultations had occurred, Bruce Power began approaching ranchers in the Lloydminster area to secure a location for a nuclear power plant. One ranching family had just celebrated the centennial anniversary of their family operation, only to find out that Bruce Power was planning to purchase land next door. Concerned about the impact to their land and their children's health, the ranchers organized a group called 'Save Our Saskatchewan' or S.O.S. for short. S.O.S. and other groups in the province attended the public meetings, wrote letters to their MLAs, and sent a message to Premier Wall that nuclear power was not wanted in Lloydminster, or anywhere in the province.

The Government of Saskatchewan responded to public opposition by stating that they had received a "yellow light" for moving ahead on the UDP recommendations (White, 2009). This yellow light soon turned green for uranium mining expansions, nuclear waste storage proposals, and a nuclear-uranium research centre at the University of Saskatchewan. The green light also appears to be back on for nuclear power. Premier Brad Wall has recently indicated his support for building small-modular nuclear reactors in the province (CBC, 2015a).

While the Saskatchewan Party government has been a public advocate of nuclear power in the province, SaskPower has looked at the possibility for several decades. As early as 1955 SaskPower was sending staff for "training in atomic energy plant design" (SaskPower, 1955: 27). SaskPower also drew a link between uranium mining in Saskatchewan's north and the future of nuclear power in the province,

> In Saskatchewan's north, electrical power assists mining companies in the Beaverlodge area to recover another vital source of power – uranium – which will some day soon, in its turn, be added to the fuels used to generate still more electrical power. (SaskPower 1957: 15)

In 1973, SaskPower CEO R.R. Keith wrote, “Nuclear energy is expected to play a significant role in the Provincial energy supply in the long term as it will probably be competitive before Saskatchewan’s coal resources are fully developed” (SaskPower, 1973: 2). There was the sentiment at that time that nuclear power would become “too cheap to meter” and was the electricity generating option of the future.

Under R.R. Keith’s leadership SaskPower took a close look at nuclear power in the early 1970s. In preparation for a possible investment SaskPower commissioned a series of reports: a review of nuclear technology in 1972, a *Feasibility Study for a Nuclear Power Program* in 1973, and an analysis of potential sites for a nuclear power plant in 1975 (SaskPower, 1972a; SaskPower, 1973a; SaskPower, 1975a). A chief concern in the 1975 report was the availability of cooling water on the arid prairies. Possible nuclear power sites were centered on reliable water supplies like the South Saskatchewan River, Last Mountain Lake, and Lake Diefenbaker; the lake that had been created with the construction of the Gardiner Dam in the 1960s (SaskPower, 1975a).

The 1970s, however, turned out to be a bad time to invest in a nuclear mega-project, not only for Saskatchewan, but for utilities across North America. During this “difficult period” costs were spiraling upwards for electrical utilities (Ford, 1997). Inflation rates were high, which increased the cost of building nuclear plants. High interest rates made borrowing to finance capital construction more expensive (see Figure 3-5 above). New plants also took longer to build, and the delay between construction and production increased costs. (Ford, 1997)

Utilities that signed on for large capital projects like nuclear power plants were forced to increase electricity rates, but this had the effect of curbing the growth of electricity demand and reducing revenues. Fears abounded that utilities had entered a “death spiral” (see Figure 3-6) of increasing costs and decreasing demand that could bankrupt the industry. (Ford, 1997)

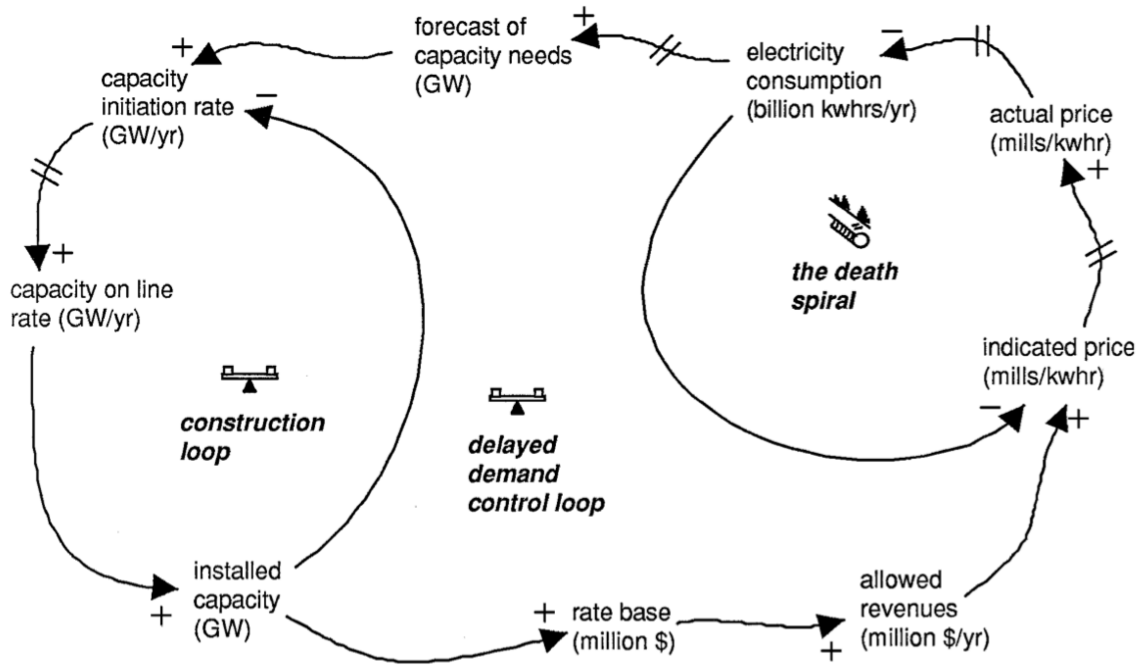

Figure 3-6 The Utility Death Spiral (Ford, 1997: 69)

SaskPower faced similar problems during the difficult period. The 1974 annual report outlined the dual difficulties of increasing costs and long lead times for new capital projects,

> While revenues from sales of electricity and natural gas were higher in 1974 than in the previous year, net income declined as a result of accelerated inflationary increases in direct costs of materials, supplies, wages and debt charges. Increased prices paid for natural gas supplies…contributed significantly to the overall trend of increased costs experienced during the year…The financial outlook for 1975 and for the years ahead can only be viewed with concern if inflationary trends continue.
>
> Public concern regarding the environmental impact of new plant construction, as well as lengthening of delivery times for new equipment have made it necessary to advance the lead time for planning and design for new facilities from approximately four to six years. (R.R. Keith in SaskPower, 1974: 2)

Rather than risk an investment in nuclear SaskPower opted instead to continue to do what it knew best. The coal-fired Poplar River facility was approved in 1974 with scheduled completion in 1979 (SaskPower, 1975).

SaskPower continued to revisit the "nuclear option" in the decades to come. A 1981 study mentioned nuclear fusion as a technology likely to reach technical viability by 1990 and commercial viability by 2000 (SaskPower, 1981a). But fusion has stubbornly remained a horizon-technology; always on the horizon, never reaching technical viability.

The 1991 Saskatchewan Electrical Energy Options Review Panel (SEEORP, 1991) included nuclear fission as an option for Saskatchewan's electricity future and recommended "a broad and thorough public review of nuclear power generation in Saskatchewan including short- and long-term nuclear waste disposal" (p. 3).

In that same year, a report prepared for AECL outlined the benefits of nuclear power in the province (AECL, 1991). Nuclear power would provide electricity that was cleaner than coal, didn't require flooding like hydroelectric dams, and was reliable. The AECL (1991) report is notable because it tied nuclear power to the uranium mining industry, outlining the "synergies" that could be developed in Saskatchewan. Similar logic would appear in the 2009 UDP report, leading some to ask whether the UDP had simply republished the old AECL report 18 years later.

AECL (1991) also promised that nuclear power could provide an economic development stimulus in Saskatchewan,

> As a prototype project, the Saskatchewan Candu-3 reactor could demonstrate the benefits and advantages of its technology as the basis for a new, Saskatchewan-based export-oriented industry. For instance, the demonstrated success of the project in Saskatchewan would help to sell the technology in other areas of the world with similar electrical energy needs.
> (AECL, 1991: 27)

What was good for AECL, it appeared, was good for Saskatchewan.

Two years after the AECL (1991) and SEEORP (1991) reports SaskPower obtained a report written by two east-coast economists commenting on the lessons Saskatchewan could learn from New Brunswick's Point Lepreau I project (Locke & Townley, 1993). The Point Lepreau I power plant was of interest to Saskatchewan since New Brunswick had a similarly sized grid. It was also an example of the risks of building a nuclear power plant. Locke and Townley (1993) describe the project,

> The construction of the first of two planned 630-megawatt CANDU reactors began in 1974 and was brought into commercial operation 105 months later, three years behind schedule. As well, the cost of constructing this reactor was between two to three times higher than the original estimates.[20]
> (Locke and Townley, 1993: 3)

Cost over-runs on the project were attributed to "'cost plus' and 'cost reimbursable' contracts" that allowed suppliers to bill more than original estimates (Locke and Townley, 1993: 27). Locke and Townley (1993) warned SaskPower to steer clear of these sorts of contracts.

Locke and Townley (1993) also cautioned that locals in New Brunswick were disappointed that the construction of the plant didn't lead to as many new jobs as promised. Instead, more senior power union members were hired from outside the community. Locke & Townley concluded, "The major lesson for Saskatchewan is, therefore, to learn from Lepreau I's mistakes" (1993: 27).

Despite their warnings, Locke & Townley (1993) also spoke of the potential "moderating" influence of nuclear power on electricity prices in New Brunswick. This potential upside kept the nuclear conversation open in Saskatchewan. SaskPower explored the feasibility of nuclear in the following year with a report from the Energy

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[20] The second planned reactor, Lepreau II, was never built.

Research Group (ERG, 1994). The ERG report provided detailed cost estimates for a CANDU-3 450-megawatt reactor. The cost estimates were based on AECL supplied data, but were scaled (generally up) after comparison to real-world, measured performance at plants like Point Lepreau in New Brunswick. On a levelized basis the AECL data suggested electricity costs of 2.8-2.9 cents/kilowatt-hour (1994 $CDN) while the revised figures were 2.8-3.7 cents/kilowatt-hour (author's calculations; ERG, 1994).[21]

The Energy Research Group (ERG) report also estimated the amount of used fuel the plant would create, the likely radiation-linked health impacts of operating the plant, and the potential damage the would result from a catastrophic event. A quick release nuclear accident was predicted to cause 92 health "effects" and $1 billion in property damage (1994 $CDN). The Energy Research Group explained, "The primary reason why the consequences of a catastrophic accident are relatively small is the low population density that would surround a CANDU 3 in Saskatchewan" (1994: 32). In contrast, a similar event would cause 1700 health effects in a densely populated region like New York (ERG, 1994). This would likely be small comfort to those living near a Saskatchewan nuclear accident site.

SaskPower continued to keep an eye on nuclear power during John Wright's 1999-2004 tenure as SaskPower CEO.[22] At that time a nuclear investment was found wanting. John Wright commented on the continued interest in nuclear in a recent interview,

> I get a kick out of the nuclear debate, because we'd done a fair amount of look-see while I was there. I'm not averse to a nuke, if you can show me the

[21] In today's currency the ERG cost estimates would range from 4.1 – 5.3 cents/kwh (author's calculation using Canada all-items CPI).
[22] Nuclear also remained on the table during Pat Youzwa's 2004-2008 tenure as SaskPower CEO. During this time SaskPower conducted another "preliminary siting assessment" for a nuclear reactor (SaskPower, 2007a) and drafted an internal document outlining "would it would take" to make a nuclear reactor feasible in Saskatchewan (SaskPower, 2007b). In the siting document Lake Diefenbaker, the source of 40% of Saskatchewan's drinking water, was selected as the most desirable site due to proximity to load and availability of cooling water (SaskPower, 2007a).

economics of it work in an all-in basis, considering carbon at $20, $40, $100 (a tonne). Mathematically it just didn't work; economically it didn't work. There was no business case for it. The government changes and 'oh sure there's a business case'. An awful lot of money has been spent pursuing what I call 'the nuclear dream', 'Oh it's right around the corner'. And now they're talking the smaller units. It's not there, the structure, the nature, the size of demand or generating capacity here, you just can't economically do a nuke. So frankly I just wish they'd stop it and put their money into other forms of generation that I think down the road will pay off bigger.[23]
(John Wright, 2014)

As Wright alludes to, besides the challenge of high costs, SaskPower faces technical barriers to building a nuclear reactor in Saskatchewan. In a 2006 presentation SaskPower outlined that a nuclear reactor would pose significant problems for the Saskatchewan grid (SaskPower, 2006a). At that time the only "economical" units on offer were 1000 MW reactors, but SaskPower's grid was designed so that the largest generating assets have a capacity of about 300 MW. A large, 1000 MW reactor would cause several problems for SaskPower. (SaskPower, 2006a)

First, a 1000 MW reactor would be sized bigger than any single load center and would require new transmission lines for distribution around the province. (SaskPower, 2006a)

Second, a 1000 MW reactor would require SaskPower to build larger interconnections with Manitoba and North Dakota to ensure adequate reserve margins. SaskPower is "synchronously" connected to these jurisdictions and the entire eastern grid. When a unit is forced to shut down in Saskatchewan, the power is instantly backed up through the interconnections. With the introduction of a 1000 MW unit SaskPower would require a "300% plus increase in interconnection capability" and would "likely require new 500 kV

[23] During his tenure as CEO Wright focused on diversifying SaskPower's generation fleet with investments in cogeneration, combined cycle natural gas generation, and the SaskPower's first wind turbines.

transmission for interconnection reinforcement" (SaskPower, 2006a: 6). The bill for this was estimated to be about $700 million (2006 $CDN) (SaskPower, 2006a: 6).

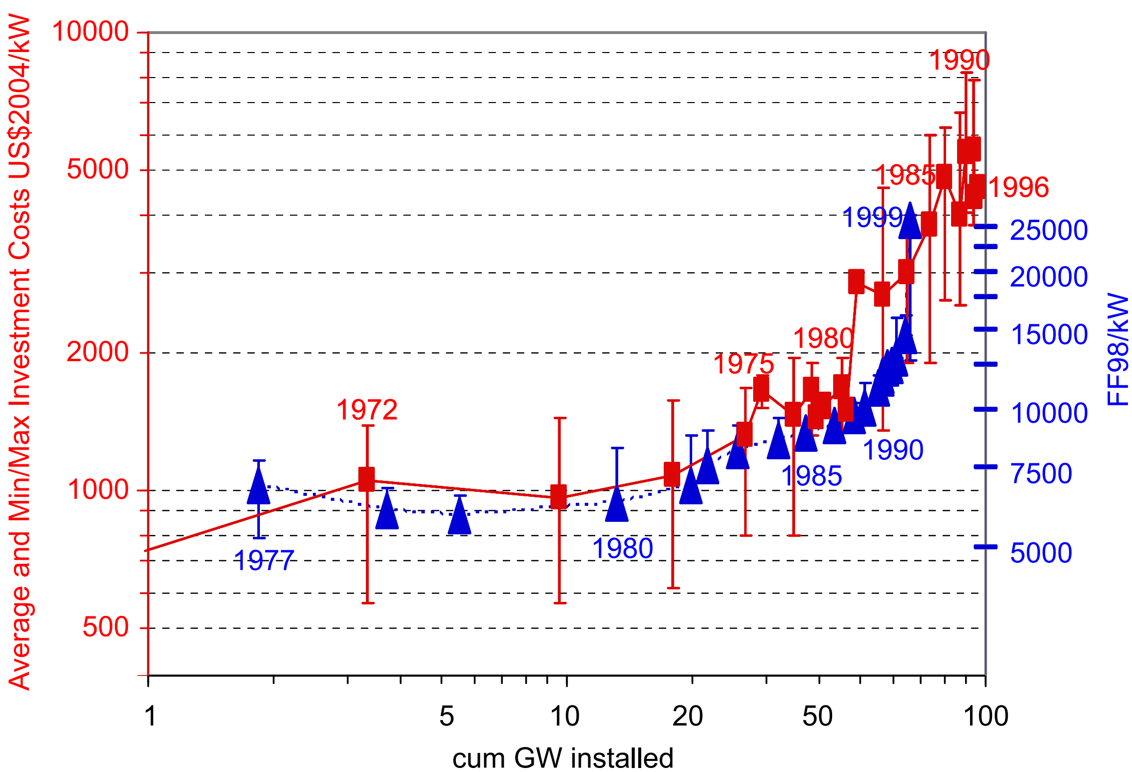
SaskPower (2006a) concluded that a reactor would only make sense in Saskatchewan if it were built primarily or even exclusively to export power. This was the same conclusion reached in a confidential internal report written in 2007; the Saskatchewan electricity system could not host a large (750 MW plus) reactor on its own. Even a medium reactor (361-750 MW) would require substantial export to Alberta. Only a small reactor (10-360 MW) could be integrated into the existing Saskatchewan grid. (SaskPower, 2007b)

The UDP report of 2009 targeted the construction of large reactors, but with an expected partnership to sell electricity to Alberta. The report suggested that up to 3000 MW of nuclear could be built close to the Alberta border so that 2000 MW of power could be exported to the Alberta grid (UDP, 2009). Problematically, Alberta's electricity system runs on a different phase than Saskatchewan and Manitoba. The power would have to be converted from AC to DC and back to AC on the Alberta side, or kept completely separate from the Saskatchewan grid (Interview 8). It is also unclear what price nuclear power from Saskatchewan would fetch in Alberta's de-regulated electricity market. As a must-run generation source a Saskatchewan nuclear plant would have to bid low to sell into the Alberta market. The economic return of this scenario was not made clear in the UDP report.

The UDP report also encouraged Saskatchewan to "'follow Ontario's lead' in selecting a reactor vendor and contractor for the new build project" to avoid "first-of-a-kind" risks trying out an untested technology (UDP, 2009: 68). Ontario was widely expected to invest in new "third generation" nuclear plants and in 2009 issued a call for proposals requesting bids. Recognizing the substantial cost over-runs that had plagued the nuclear industry in the past Ontario required that bids include all of the costs; there would be no 'cost-plus' arrangements in this round of construction. Ontario received only one bid compliant with their guidelines; a $26 billion dollar bid from AECL to build two 1200

MW reactors. The price shocked Energy Minister George Smitherman into suspending the tender process, stating the price-tag was “billions” too high. (Hamilton, 2009)

Still, Saskatchewan’s nuclear dream did not die. Premier Wall understands the technical constraints to building a large nuclear reactor in Saskatchewan and so now focuses his attention on “small, modular reactors.” This puts Saskatchewan in the position of building “first-of-a-kind” units, which entails considerable risk of cost over-runs. This is especially true when the industry appears to demonstrate a negative “learning-by-doing” curve; costs have only increased as more nuclear capacity has been installed in the United States and France (see Figure 3-7).



(Source: Grubler, 2010: 5186)

Figure 3-7 Negative Learning-By-Doing in US and French Nuclear Power

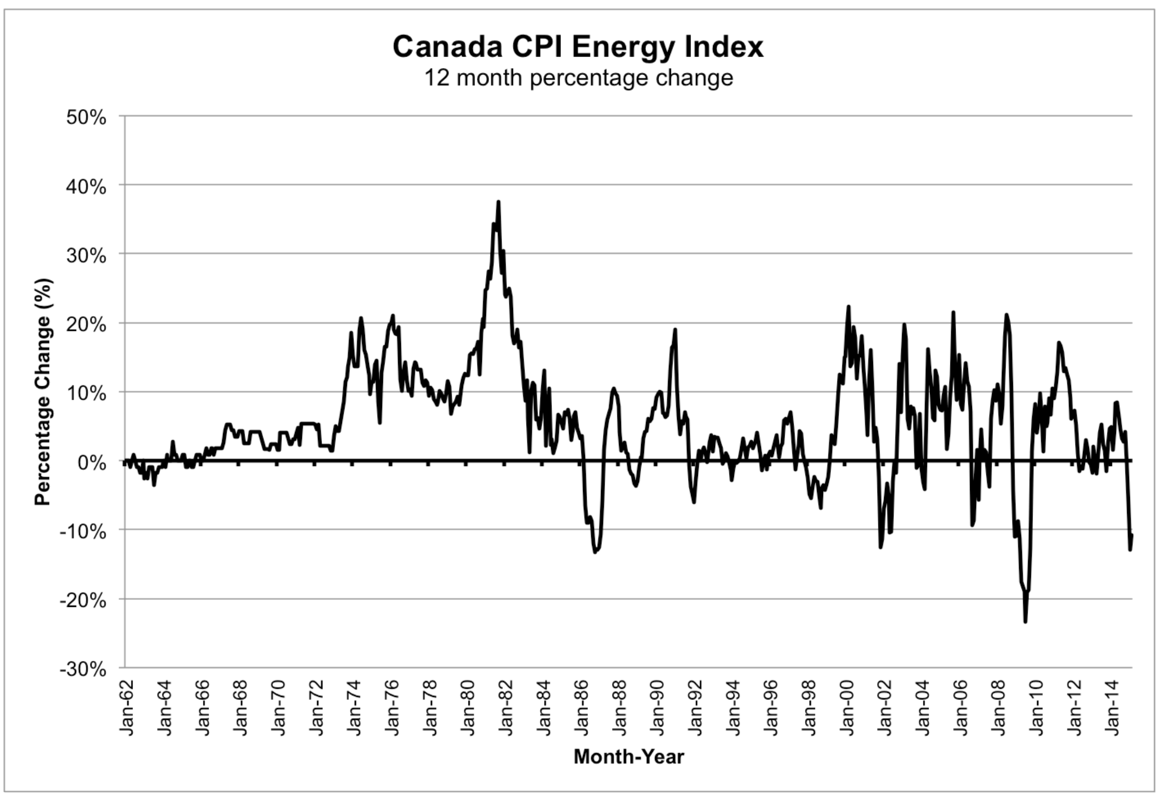
Premier Wall also understands the high price tag involved in building nuclear reactors and so, like Ontario, has put out his hands for funding support from the federal government (CBC, 2015a). After having sold AECL’s CANDU reactor sales division to

SNC-Lavalin in 2011 it is unclear whether a federal government of any stripe will want to subsidize Ontario or Saskatchewan's power bills (Hamilton, 2009; McCarthy, 2011).

And higher power bills might be just what are needed to encourage a culture of energy conservation.

A Conservation Mindset

Rather than the dawn of the nuclear age, the 1970s brought a newfound interest in energy conservation. Oil prices spiked with the OPEC oil embargo in 1973 and high oil prices increased natural gas prices, which were linked to the price of oil (Ford, 1997). Figure 3-8 shows the Canadian CPI Energy Index in terms of 12-month percentage change. Throughout the 1970s, energy prices increased by an average of nearly 10% per year.



(Source: Statistics Canada CANSIM Table: 326-0020; author's calculations)

Figure 3-8 Canada CPI Energy Index 12 month percentage change

Energy price increases in the 1970s translated into inflation across the board (See Figure 3-5) and utilities experienced the “difficult period” of increasing costs and construction delays mentioned above (Ford, 1997).

Meanwhile, people like Amory Lovins argued that a “soft path” of energy conservation and decentralized renewable energy offered a more desirable future than the “hard path” of demand growth and big, centralized generation projects like nuclear plants (Lovins, 1976). Utilities began to rethink their business models.

Prior to this period, the goal in Saskatchewan had been to promote electricity demand, not constrain it. In 1928, the SPRC advocated “an active sales campaign” to increase the use of “domestic electric utensils” (*i.e.* household appliances) and expand demand for electricity (SPRC, 1928: 113).

The story was much the same in at the newly founded SaskPower Corporation in 1950,

> The success of the electric utility depends on the full use of the service by the customer. Much more promotion on electrical use, including greater purchases of electrical equipment and appliances for our customers, is required if electrical consumptions in this Province are to compare with those of other provinces. Studies, commenced during the year, on load growths and customer usage are continuing in an attempt to make electrical service more attractive to customers. (SaskPower, 1950: 4)

SaskPower designed travelling roadshows to promote the “the advantage of electrical living” (SaskPower, 1951: 7) and appointed a female spokesperson they called ‘Penny Powers’ to share the good news about the advantages of electricity (see Figure 3-9).

(Source: SaskPower Flikr, 2014)

Figure 3-9 ‘Penny Powers’ Promoting An Electric Oven-Range Appliance[24]

Industrial electric use was also promoted. For example, the oil industry was encouraged to build electric-powered pumpjacks (SaskPower, 1952). Industrial demand would help to “build load”, especially during off-peak hours, and this would make greater use of the province’s generation capacity.

The first glimmer of a conservation mindset came in SaskPower’s 1968 annual report. In that year, SaskPower introduced a demand response “peak shaving” program with industrial clients, which “resulted in more efficient utilization of plant and equipment” (E.B. Campbell in SaskPower, 1968: p. 4).

[24] This is a photo of Lillian McConnell, the first ‘Penny Powers’. As SaskPower’s (2014a) Flikr account describes, “When the Corporation created the Home Economist Division, its first and most iconic Penny was Lillian McConnell. Lillian travelled to fairs, exhibitions, community centres and schools to demonstrate electrical appliances to rural women. As the Penny Power program grew in popularity, the Saskatchewan Power Corporation employed as many as four ‘Pennies’ at home time.” Image available on-line at: https://www.flickr.com/photos/saskpower/14321348268/in/album-72157644953809889/. Last accessed May 13, 2015.

The 1970s saw this conservation mindset expand. As the 1974 Annual Report described,

> The Corporation has stepped up its public information program emphasizing the wise and efficient use of energy. Through advertisements in newspapers and on radio and television, customers are being encouraged to reduce cost and conserve energy resources by using energy wisely. (SaskPower, 1974: 2)

Penny Power had been transformed into Penny-Pincher.

In 1979 SaskPower formalized its promotion of energy conservation by establishing “an Energy Conservation Division to encourage wise and efficient use of energy in the home, farm, business and industry” (SaskPower, 1979: 13). A series of conservation programs followed in years to come (See Table 3-3).

These energy conservation and demand-side management programs have undoubtedly helped to reduce electricity demand in Saskatchewan. Problematically these programs are not well integrated with supply planning; instead of being under the management of the Supply Planning Department, DSM programs are run out of the Customer Services branch of SaskPower. Their appeal as a marketing exercise is likely as or more important than the savings they generate.

This separation of supply planning and Demand Side Management (DSM) precludes electricity conservation from reaching its full potential. The current target for DSM at SaskPower is to save or shift enough demand to prevent 100 MW of capacity construction by 2018. The technical potential for DSM savings in Saskatchewan may be closer to 400-450 MW, while 300 MW is considered an achievable, albeit more aggressive, target (Interview 12).

SaskPower Energy Conservation Programs		
Program	**Era**	**Program Details**
Industrial Demand Response	1968 - onwards	• Industrial customers paid to shift electricity demand away from peak times
Conservation education	1970s	• Information pamphlets distributed to homes and businesses; e.g. home insulation guide • Farm management courses to encourage wise electricity use on farms • Presence at exhibitions
PowerWise	1980s-early 1990s	• Encourage peak-shifting • Grants for solar- or wind-water pumps on farms • Farm lighting program to encourage efficient lighting • Energy audits for homes and businesses
PowerSmart	Early 1990s	• Participate in national program • Encourage ground source heat pumps
Destination Conservation	2000s-present	• Partner with the Saskatchewan Environmental Society to deliver conservation education
Green Initiatives Fund	2007-2008	• Partner with the Ministry of Environment to provide rebates for energy efficient housing
EnerGreen/EnerAction Go Green	2008-present	• Bulk buying program offering discounted lighting to commercial customers • Municipal ice rink program; funding to reduce power and natural gas costs • Energy Performance Contracting with Honeywell • Demand Response Program for industrial customers • LED Christmas light promotion • Block-heater timer giveaways • Refrigerator recycling; pick up old inefficient units for free

(Source: SaskPower Annual Reports 1950-2014)

Table 3-3 SaskPower Energy Conservation Programs

It is expected that the 100 MW of avoided capacity, or “negawatts”, will be achieved at a cost of $.03/kwh, which is substantially less than the cost of new generation. Still, SaskPower continues to emphasize capacity expansion, and is far from embracing Lovins’ (1976) “soft path” energy strategy.

A confounding factor for DSM is the state of Saskatchewan's electricity grid. For DSM to reach its full potential smart grid technology is key. With a smart grid appliances can be set to respond to the relative availability (or price) of electricity; for example, air conditioners can be cycled on and off throughout the grid to flatten peak demand on hot summer days. This would allow SaskPower to shave peak electricity demand and delay capacity expansions.

Saskatchewan started on the path to a smart grid in 2010 (see Figure 3-10). Between the fall of 2013 and the summer of 2014 108,000 smart meters were installed in the province. Concerns arose in late June 2014 when several smart meters "failed catastrophically" by either melting or burning (CIC, 2014: 2). By the end of July the count of failed smart meters was up to eight. The provincial cabinet responded by ordering all of the installed smart meters removed (CIC, 2014). The removal of Saskatchewan's smart meters was nearly complete by February 2015 at a cost of $15 million (CKOM, 2015).

Political columnist Murray Mandryk compared the smart meter "fiasco" to the Channel Lake scandal (see footnote 14). In a prescient column on September 10, 2014 Mandryk noted that "heads rolled" at SaskPower after Channel Lake. The Crown Investment Corporation (CIC), the umbrella organization in charge of Saskatchewan's Crowns, published its review of the smart meters affair on October 27, 2014 and found that "customer safety was not given enough of a priority" (CIC, 2014a). SaskPower CEO Robert Watson resigned that day (Clancy, 2014). A smart grid for Saskatchewan will now have to wait until the memory of smoking meters fades into history.

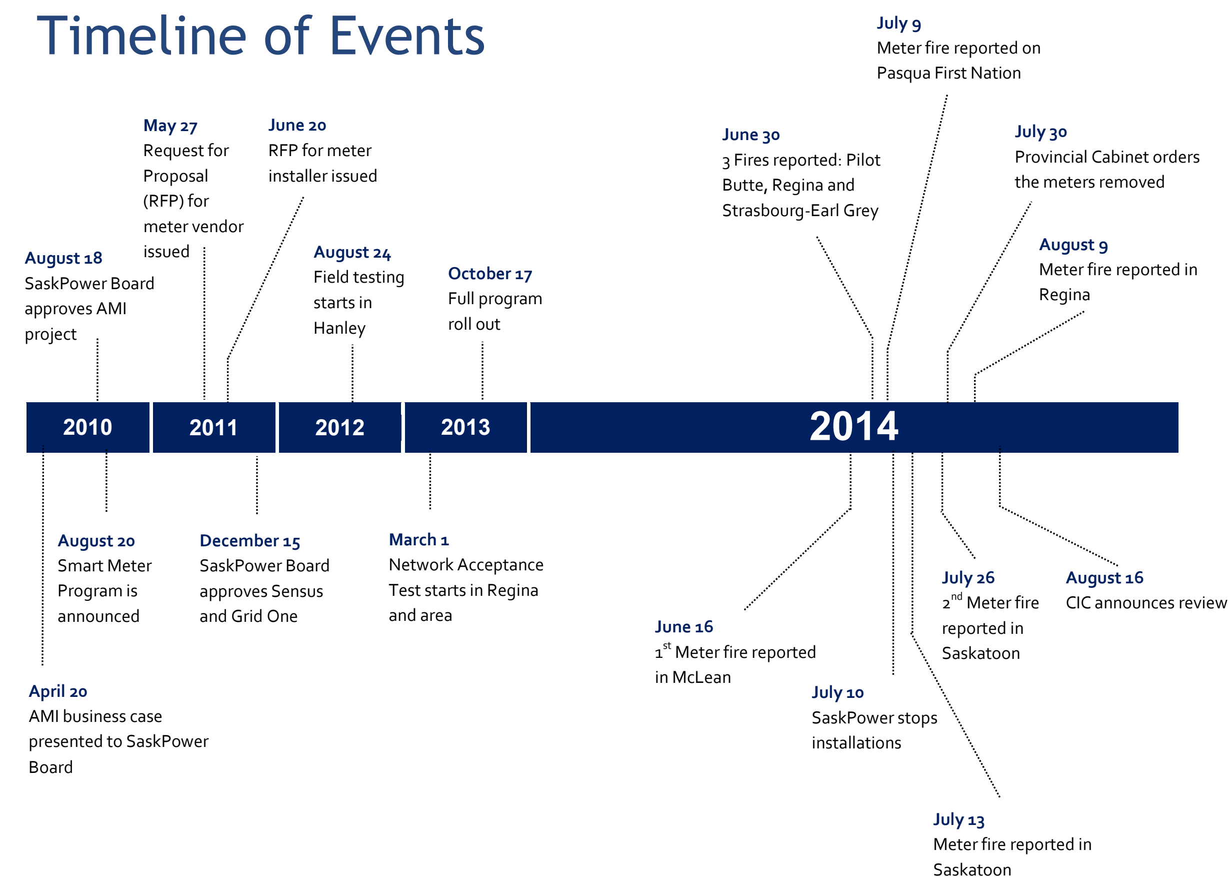


Figure 3-10 Smart Grid Chronology

(Source: CIC, 2014: 3)

The Past As Present

At 12:46 A.M. on Sunday September 14th 2014 carbon dioxide (CO_2) at the Boundary Dam III coal plant began to be captured and successfully prevented from reaching the atmosphere (Pipeline News, 2014). Originally built in 1970, SaskPower's Boundary Dam III (BD3) unit was retrofitted with CCS technology to extend its life and allow it to meet federal greenhouse gas emissions standards.[25] For SaskPower, September 14th, 2014 was a significant milestone,

[25] Boundary Dam Unit III was retrofit with a capacity of 160 MW. Because of the electricity needed to capture the CO_2, the amount of power the plant can deliver to the grid has been reduced to 120 MW. (SaskPower, 2015)

> In 2014, we took a giant leap forward by delivering the world's first commercial-scale post-combustion carbon capture and storage (CCS) facility at coal-fired Boundary Dam Power Station. We will capture 90% of the carbon dioxide created by a generating unit that is capable of providing enough power to supply 100,000 homes. Emissions will be reduced by about 1,000,000 tonnes each year, prolonging the life of an economical, stable and secure local fuel source.
> (SaskPower, 2014: 1)

The final price tag for the CCS project is $1.467 billion, which works out to $12,225/kilowatt; a price even higher than the nuclear plants rejected by Ontario in 2009 (Zinchuk, 2015; Hamilton, 2009). Easing the burden for Saskatchewan, the federal government contributed $240 million to the project (Mandryk, 2014a).

Further revenue will be generated by selling captured CO_2 to the oil company Cenovus for use in enhanced oil recovery (EOR). This source of revenue has set off alarms. For every tonne of CO_2 captured and injected into an oil well "about 2.7 tonnes of carbon dioxide are eventually emitted from combustion of the oil recovered" (Banks and Bigland-Pritchard, 2015: 17 citing figures from Wong *et al*, 2013). Some of the CO_2 injected into the oil wells will also return to the surface when the oil is extracted (Banks & Bigland-Pritchard, 2015).

Political columnist Murray Mandryk (2014a) has argued "the real winner" of the CCS project is "Calgary-based Cenovus" since the company will make millions in added revenue by injecting CO_2 into its aging oil fields. Banks & Bigland-Pritchard (2015) come to a similar conclusion, "The predominant reason for the CCS to go ahead appears to be to recover more oil from south east Saskatchewan and reward the oil producing companies" (p. 20).

The history of the CCS concept in Saskatchewan suggests there is some truth to these claims. As early as 1994 SaskPower discussed "Investigating the practicality of capture carbon dioxide from our coal-fired power stations for use in enhanced oil recovery" (SaskPower, 1994: 16). The idea is mentioned again in 1995's Annual Report where SaskPower stated it was "Studying the potential for capture carbon dioxide from power plants for use in enhanced oil recovery" (SaskPower, 1995: 19). Enhanced oil recovery appears to have been part of the rationale for CCS from the beginning.

For Premier Brad Wall, the link to Enhanced Oil Recovery (EOR) is a strength of the CCS project, "Legislators around the world view CO_2 basically as a pollutant. We're getting paid for it in Saskatchewan because of this clean coal project. That's a positive thing" (Brad Wall in Pipeline News, 2014: A14).

The Premier sees CCS as providing a triple benefit by extending oil production in aging oil wells – which in turn increases provincial royalties – saving jobs in the Estevan coal plants, and indicating Saskatchewan's commitment to greenhouse gas emissions reduction. On this last point, Wall believes that Boundary Dam III will help convince the United States government that the oil-producing provinces of Canada are environmental stewards. This in turn can help convince the U.S. to approve the Keystone XL pipeline:

> I've been saying, when we're down in the United States on Keystone, even, we should reference projects like this. This particular (U.S.) administration, they want some environmental elbow room from the different environmental NGOs that hate, that don't like Keystone. They need some environmental elbow room to quote-unquote "deal with the Canadians." That pipeline is definitely a deal with Canadians.
>
> We're able to go down, and have been going down, saying, "Look at the project, because in your coal states it might have an application. But also look at it as validation that we're serious about the environment, and tell those worried about Canada in general, they ought not to. In Canada, this is the largest per-capita project related to CO2 mitigation." I think it helps on that front as well. (Brad Wall quoted in Pipeline News, 2014: A15)

There are other ways for Saskatchewan to improve its image in the United States that don't involve carbon capture and storage. Banks & Bigland-Pritchard (2015) use calculations by James Glennie to show that an investment in wind could generate the equivalent amount of electricity for $300 million less than the Boundary Dam project. Mike Monea, project manager of the Boundary Dam CCS project, responded to this critique by pointing to the variability of electricity generated by wind,

> Last Sunday we hit a peak (of power consumption) at 6 p.m., suppertime. We had one megawatt coming from our wind turbines. There was no wind blowing. What did we use? We used coal-fired plants for the baseload, so nobody had disruption in their power.
> (Mike Monea quoted in Zinchuk, 2015)

As Monea implies, SaskPower does not plan to rely on variable renewables like wind to replace coal-fired generation because they cannot act as reliable baseload power. This is a perspective that resonates with the Financial Editor of the Regina LeaderPost. After the release of the critique of CCS by Banks & Bigland-Pritchard (2015), Bruce Johnstone wrote,

> Another day, another report from an alternative energy-public policy group slamming the $1.47-billion carbon capture and storage (CCS) project at SaskPower's Boundary Dam power station at Estevan.
>
> But is it realistic to assume the world, which currently relies on coal for more than 40 per cent of its electricity generation, can easily turn to natural gas or renewables for its baseload power? With huge developing countries, like China and India, still dependent on coal-fired generation, what is the responsible alternative?

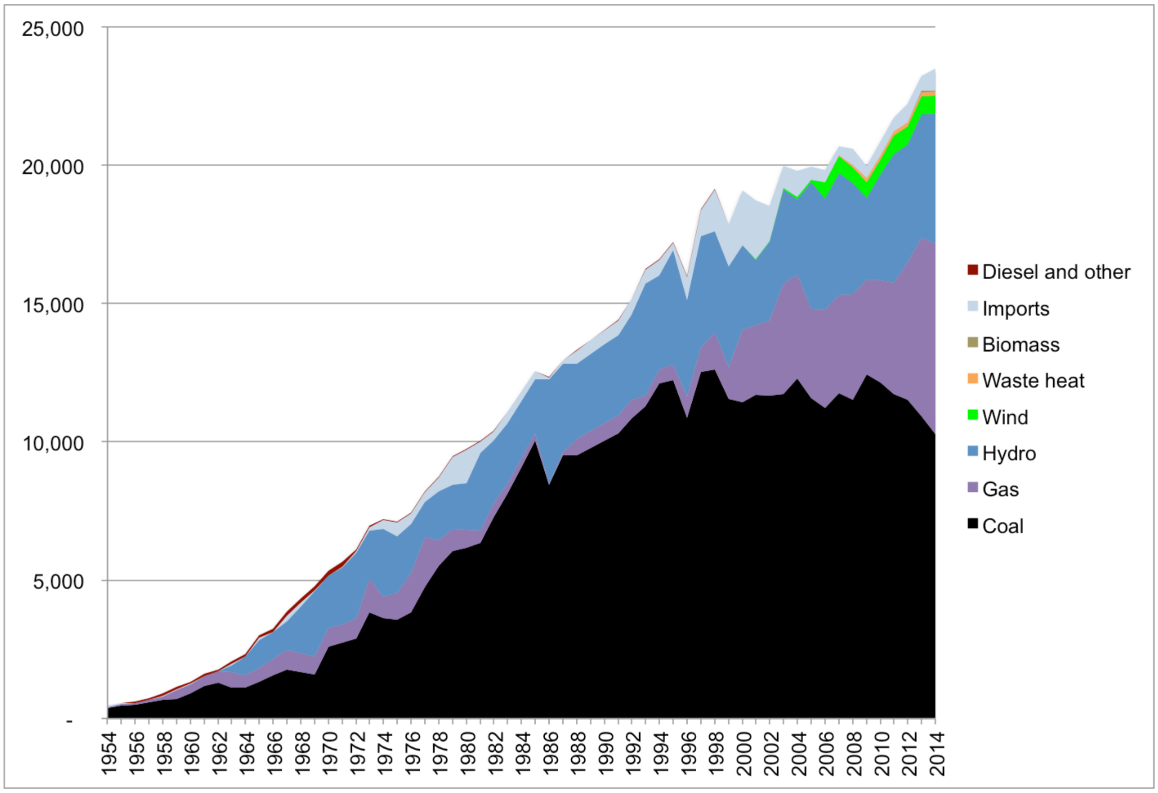
> I submit that CCS or clean coal is one solution. It may not be a silver bullet, but it does provide us some “breathing room,’’ while we reduce our dependence on fossil fuels.
>
> Wind energy is also a solution; so are solar, biomass and other renewables. SaskPower is at 25 per cent renewable energy today and hopes to generate 10 per cent of its capacity from wind by 2020. But SaskPower needs baseload power, like coal and natural gas-fired generation, to keep the lights on.
>
> By definition, intermittent energy sources, like wind, can’t provide baseload power, and it proponents are deluding themselves and the public if they think it can.
> (Johnstone, 2015a)

Interestingly, Johnstone (2015a) points to the viability of natural gas for baseload generation. With the exception of Boundary Dam III, SaskPower appears to prefer that route.

The Natural Gas – Wind Nexus?

Coal has been king in Saskatchewan for over fifty years. The grid was built to move electrons generated by the “cheap lignite coal” found near Estevan and Coronach to load centres like Regina. In interviews with SaskPower employees past and present there was a sentiment that SaskPower possesses a “coal culture”. Generations of SaskPower employees have spent their careers working within the coal-based system. It is little surprise that SaskPower is exploring CCS as a way to keep coal alive in Saskatchewan.

In the past fifteen years, however, a shift has been taking place. Figure 3-11 provides a look at Saskatchewan’s electricity generation by type from 1954-2015. This figure shows that natural gas-fired generation has quietly been growing and electricity generated by coal plants has stagnated and begun to decline.



(Source: SaskPower Annual Reports, 1951-2014)

Figure 3-11 SaskPower Electricity Generation by Generation Type

The expansion of natural gas generation began in the early 2000s with cogeneration projects like the 228 MW Cory Potash facility and the 210 MW Lloydminster Meridian plant mentioned above. More recent natural gas projects include the 260 MW combined cycle North Battleford Power Centre (2013), the 86 MW simple-cycle Spy Hill plant (2011), and the 138 MW simple-cycle Yellowhead plant (2010). The Queen Elizabeth Power Station in Saskatoon is also being expanded and retrofit to make it a combined cycle natural gas plant. The retrofit should be complete by 2016. (SaskPower Annual Reports, 2000-2014)

The move to natural gas generation has helped SaskPower lower the greenhouse gas emissions (GHG) intensity of its electricity output from highs of around 800 tonnes CO_2e/Gigawatt-hour (GWH) to 660 tonnes CO_2e/GWh in 2014 (See Table 3-4). These natural gas plants will also be compliant with the federal government's electricity sector

GHG regulations, which require all new power plants to be 'as clean as gas' and emit only 420 tonnes CO2e/GWh (CEPA, 2012).

	1990	2000	2005	2007	2008	2009	2010	2011	2014
Generation Intensity (tonnes CO_2e/GWh)	798	858	780	750	709	793	800	745	660

(Sources: Environment Canada, 2013; SaskPower, 2014)

Table 3-4 Saskatchewan Electricity GHG Intensity

The move is also changing the business model of SaskPower. Of the six natural gas fired facilities built since 2000, three are privately owned (Meridian, Spy Hill, and North Battleford), and one (Cory) involves a significant private partnership. Brad Wall has kept his promise not to sell off Saskatchewan's Crown Corporations, but Saskatchewan citizens may one day wake up to realize that SaskPower has become only a system operator and electricity distributor, not a power generator.[26]

The increase in natural gas-fired generation offers an effective back-up for variable wind power. New natural gas-fired plants can ramp quickly to fill in supply when the winds die down (Interview 2). And, as mentioned above, SaskPower values wind for its ability to reduce the use of natural gas fuel.

The SaskPower system was home to 198 MW of utility-scale wind capacity in 2014. This is slated to double by 2018 with the installation of a 23 MW wind farm at Morse and a 177 MW wind farm at Chaplin (SaskPower, 2014). At that time wind will comprise just under 10% of system capacity.

Will the trend towards natural gas combined cycle generation paired with wind power continue in Saskatchewan? Is the coal-hydro nexus being replaced with a natural gas – wind nexus?

[26] Under pressure from public sector unions and the NDP Brad Wall committed to not sell Saskatchewan's Crown Corporations in his 2007 election campaign. The promise helped remove fear that Wall's government would be a repeat of the Devine era.

Lessons From the Past Informing the Future

By understanding the lessons of history we might better understand the future of the Saskatchewan electricity system. Figure 3-12 summarizes some of the major events in Saskatchewan's electricity history. The following lessons can be learned from this history:

- **Rural electrification** (1950s): Tommy Douglas called rural electrification his greatest achievement. This feat shows that massive change to the electricity system is possible when strong political will is combined with institutional skill and effort.
- **E.B. Campbell and Cumberland House** (1965-1989): SaskPower's first hydroelectric dam was built without adequate consideration of the downstream impacts on residents of Cumberland House. Power projects in the modern era must seek consent through consultation, or risk lengthy court battles and opposition.
- **Boundary Dam III & Retrofit to CCS** (1970-present): Coal has formed the backbone of Saskatchewan's electricity system for over 60 years. This has created a deeply ingrained coal culture at SaskPower, path dependency in electricity distribution networks, and a constituency of power workers and coal miners in the Estevan and Coronach regions. Carbon capture and storage (CCS) is appealing because it allows Saskatchewan's coal-fired power industry to continue, and provides an ancillary benefit to the oil and gas industry. Campaigns to retire coal will face opposition from these interests.
- **Inflation and Energy Crisis** (1973-1982): Periods of rising prices make capital investment costly. Large projects with time delays worsen the situation. Energy conservation emerged as a useful solution to utilities' woes in the 1970s. Energy conservation may find a more receptive audience in periods when cost pressures are increasing.
- **Deregulation and Private Partnerships** (1990s-present): Saskatchewan's electricity system was under centralized public control for much of its history. Since the year 2000 public-private-partnerships and independent power

producers have become an important part of Saskatchewan's electricity system. The SaskPower business model of keeping electricity rates low through average cost pricing remains, but at some point SaskPower may find itself to be little more than an electricity distribution company. This may have implications for the nature of the grid; private interests are unlikely to pursue expensive generation technologies such as small, modular nuclear reactors or carbon capture and storage (CCS). To date independent power producers have been building cogeneration facilities, natural gas plants, and wind farms.

- **GHG Regulation** (2012-present): The federal government's coal-fired electricity regulations have placed an expiry date on Saskatchewan's coal plants. They must either be shuttered or retrofit with CCS at the end of their life expectancy. SaskPower will be forced to make decisions on expanding the CCS project to include Boundary Dam IV and V within the next few years. If SaskPower decides to retrofit those plants to CCS they will then have until 2025 to make the transition. If they decide not to retrofit the plants they must be shuttered by 2019 (CEPA, 2012). Yet, the high cost of Boundary Dam III makes continued investments in CCS politically risky. Will SaskPower allow coal to wither in Saskatchewan?

With these lessons from history in mind this dissertation explores scenarios for the future of Saskatchewan's electricity system. The history of the system has been filled with intrigue, rolling heads, and Canadian firsts. Where will the future lead?

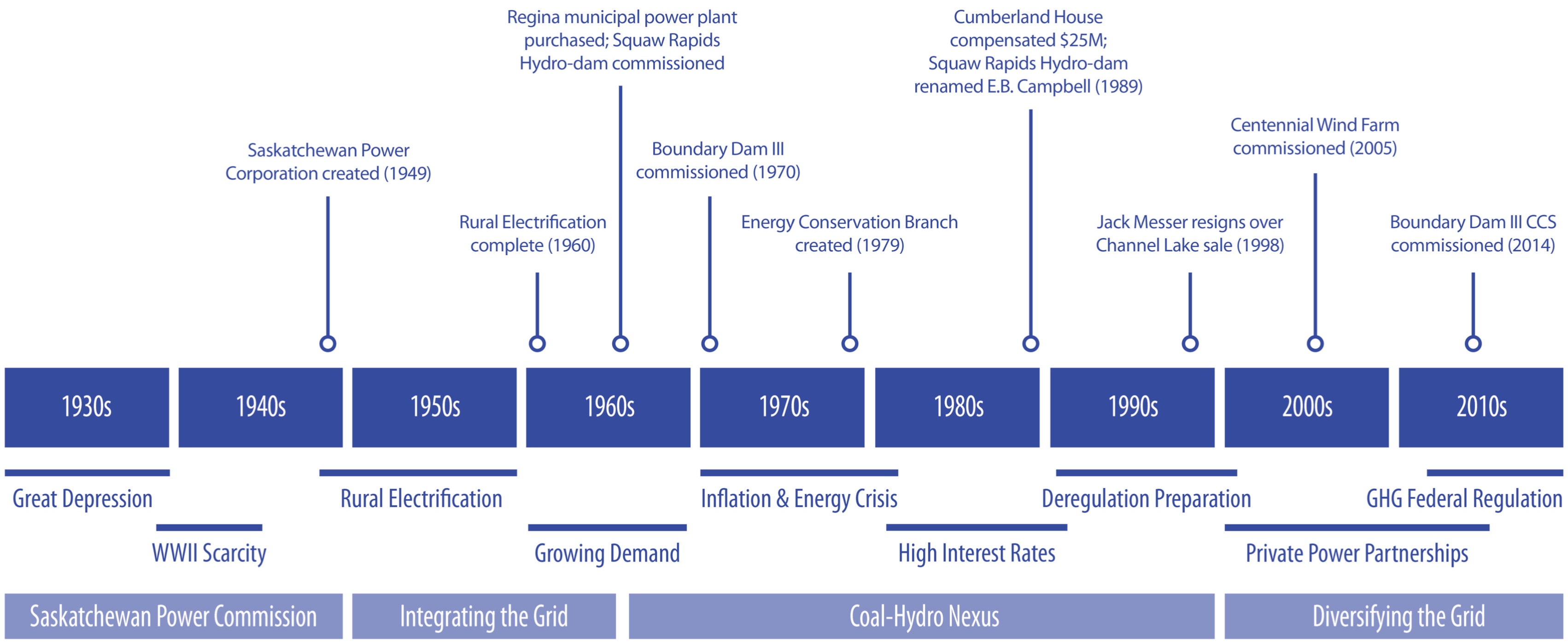


Figure 3-12 History of the Saskatchewan Electricity System

Chapter 4 – Renewable Options for A Low-Carbon Future

Renewable Energy Potential in Saskatchewan

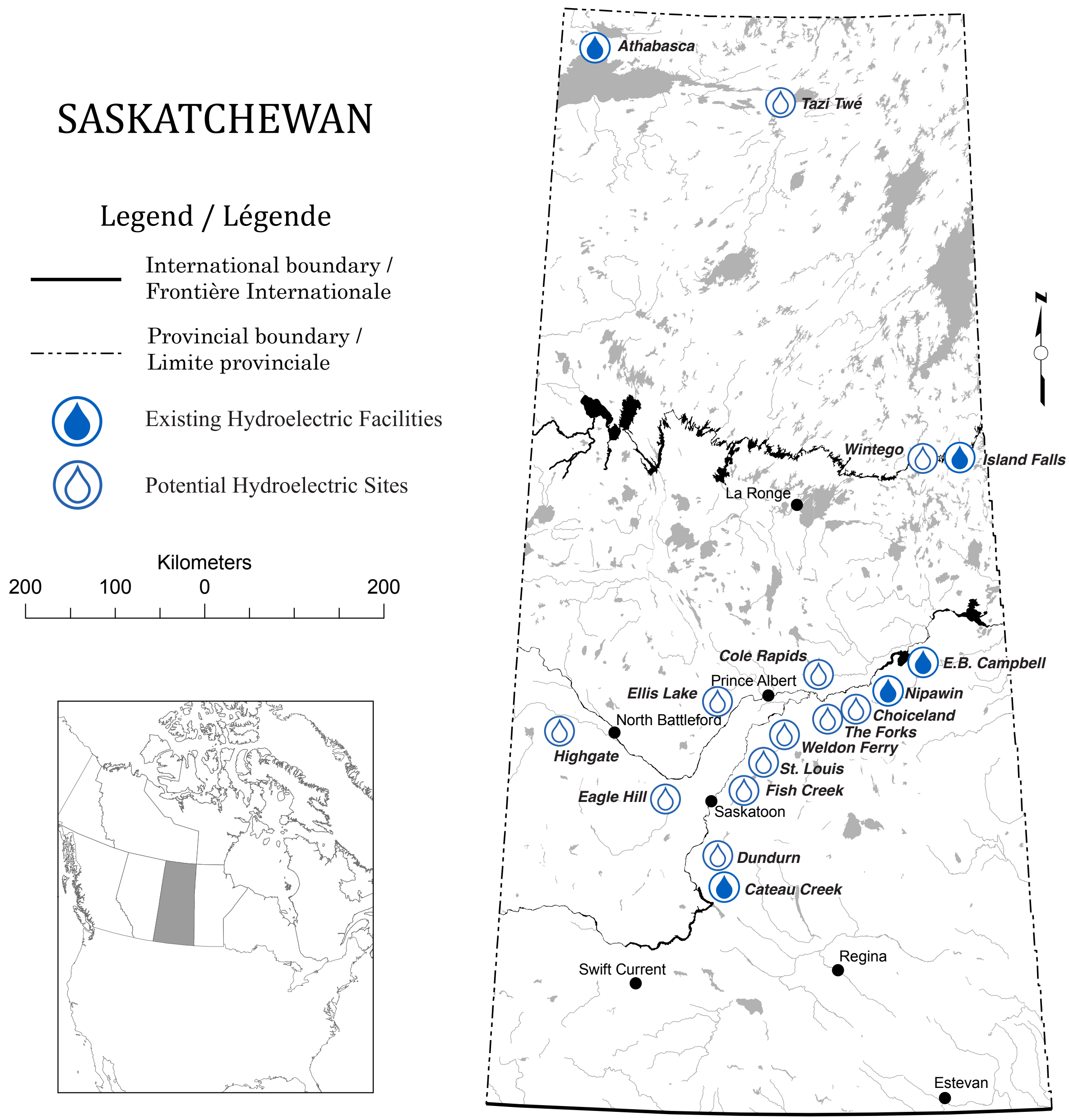
In this chapter I explore the constraints shaping a renewable-energy focused pathway for Saskatchewan's electricity future. Renewable energy options in Saskatchewan include: hydroelectric dams, wind turbines, solar photovoltaics, biomass plants, geothermal plants, solar thermal plants, and hydroelectricity imported from Manitoba. I explore the potential for each resource in turn.

Hydroelectric Potential

Saskatchewan contains three important watersheds with hydroelectric potential: the Saskatchewan River watershed, including the North Saskatchewan and South Saskatchewan watersheds upstream; the Churchill River watershed; and the Lower Mackenzie watershed in the far north. Saskatchewan is currently home to seven hydroelectric facilities totaling 864 Megawatts (MW) of capacity. Table 4-1 describes each facility and in Figure 4-1 existing hydroelectric facilities are indicated with the solid blue water drop.

Hydroelectric Facility	**Capacity**	**Watershed**
Athabasca - Wellington	5 MW	Lower Mackenzie
Athabasca - Waterloo	8 MW	Lower Mackenize
Athabasca - Charlot River	10 MW	Lower Mackenzie
Island Falls	111 MW	Churchill River
Nipawin	255 MW	Saskatchewan River
E.B. Campbell	289 MW	Saskatchewan River
Coteau Creek	186 MW	Saskatchewan River

Table 4-1 Saskatchewan Hydroelectric Facilities (Year = 2015)



(Source: Fix and Korteling, 2015b)

Figure 4-1 Saskatchewan Hydroelectric Facilities Built and Proposed

By all accounts, the existing 864 MW of hydroelectric capacity will continue in operation indefinitely; expenses associated with repowering the hydroelectric facilities are 10-20% the cost of building a new hydroelectric facility, transmission lines are in place, and hydroelectric power does not release greenhouse gas emissions (GHGs) through the combustion of fossil fuels.[27]

The potential for expanding hydroelectric power has been explored several times throughout Saskatchewan's history. As outlined in Chapter 3 (See Figure 3-4), David Cass-Beggs (1960) sketched out a plan for a series of hydroelectric dams along the South Saskatchewan and Saskatchewan Rivers. At that time, SaskPower was preparing to build the E.B. Campbell facility (then called Squaw Rapids). The Coteau Creek (1969) and Nipawin (1986) facilities were later completed in accordance with Cass-Beggs' hydroelectric plan.

Future hydroelectric potential in Saskatchewan varies by watershed. In the Saskatchewan River watershed there is potential for dams at the Forks and Choiceland (See Figure 4-1). A dam at the Forks could contain "five 84 MW units" equaling 420 MW total output, while a dam at Choiceland could host "four 75 MW units", creating 300 MW of output (McClement and Campbell, 1977: 51). There is also potential to install two additional 84 MW units at Nipawin to increase capacity at that station from 255 MW to over 420 MW (McClement and Campbell, 1977). In total this represents a potential to double the current hydroelectric capacity in the province on the Saskatchewan River alone.

There is also potential to expand hydroelectric potential on the Churchill River. As outlined in Chapter 3, SaskPower proposed to build a 300 MW hydroelectric dam at the Wintego site on the Churchill River in 1973. This proposal was met with stiff opposition from Saskatchewan First Nations and was rejected by the Churchill River Board of

[27] There are, however, GHG emissions associated with flooding land to create a hydroelectricity facility. Barros *et al*. (2011) estimated that the sum total of annual emissions from the world's hydroelectric reservoirs is approximately 58 Megatonnes (Mt) as carbon dioxide (CO2) and 3 Mt as methane (CH4) from the reservoir surface. Adding the action of turbines and river outflow increases this estimate roughly twofold. Lakes and streams generally, unless they are eutrophic, release CO2 and CH4. Releases of GHGs from hydroelectric reservoirs are greatest in tropical regions and lower in temperate and boreal forest regions. (Barros *et al*., 2011)

Inquiry (CRBI, 1978; Waldram, 1993). This lack of "social license" poses a barrier for future hydroelectric development on the Churchill.

SaskPower is having better success obtaining social license for the Tasi Twé hydroelectric project in the far north of Saskatchewan, near Black Lake. Formerly called the Elizabeth Falls project, the Tasi Twé project is a partnership between SaskPower and the local Black Lake First Nation (Golder and Associates, 2012). If successful the Tasi Twé project will result in the creation of a 42-50 MW hydroelectric facility on the Black Lake River in the Lower Mackenzie watershed. Other small hydroelectric projects could be built in the watershed to provide a total of 323 MW of additional capacity. These northern dams are, however, quite expensive to build. The most affordable are likely in the range of $11,000-15,000/kilowatt capital cost, while the most expensive may cost as much as $30,000/kw to build (Interview 17).

Watershed	Existing	Potential Additions	Total
Saskatchewan River	730 MW	1000 MW	1730 MW
Churchill River	111 MW	480 MW	591 MW
Lower Mackenzie	23 MW	300 MW	323 MW
Total	864 MW	1780 MW	**2644 MW**

Table 4-2 Potential Hydroelectric Capacity

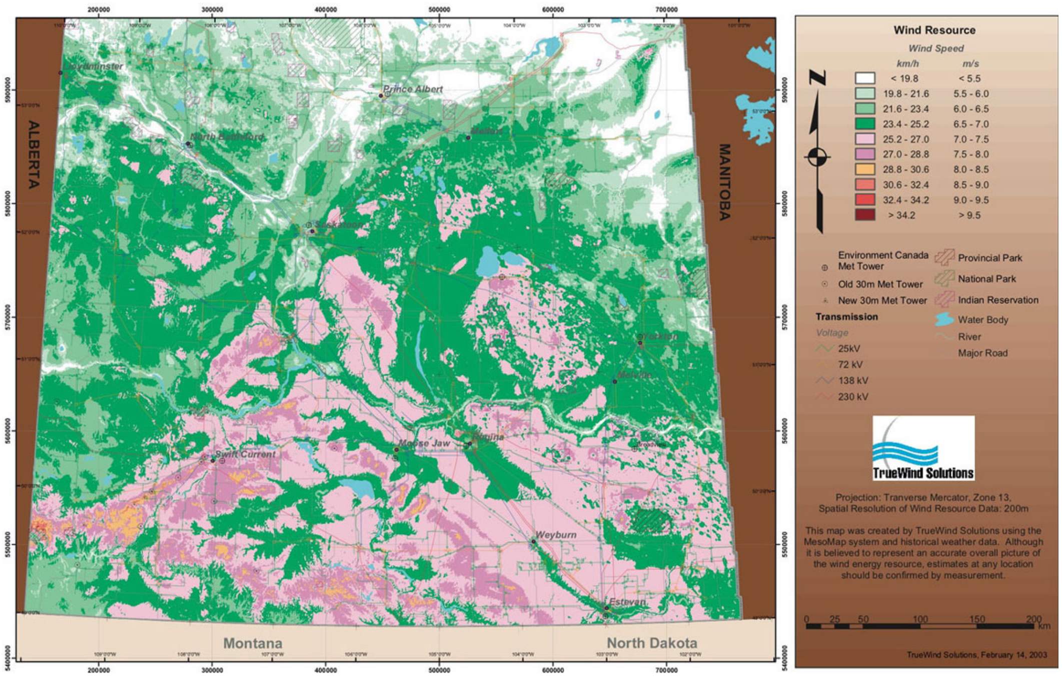
In total, there is potential to add up to 1780 MW of additional hydroelectric capacity in Saskatchewan, which would bring the provincial total to 2644 MW.

Wind Power

Residents of Saskatchewan know very well the strength and frequency of prairie winds. Though the bane of winter existence in the province, these winds provide an opportunity for near zero-carbon electricity generation.[28] Figure 4-2 provides a look at the wind

[28] Note that while wind turbines do not emit greenhouse gas emissions (GHGs) directly in their operation, emissions are generated in the process of manufacturing, installing,

resource in southern Saskatchewan. Regions in dark pink and orange are home to the highest average wind speeds.



(Source: PARC, 2015)

Figure 4-2 Southern Saskatchewan Average Wind Speeds

High average wind speeds in southern Saskatchewan provide a high-quality wind power resource. Capacity factors in the province average 36-40% in the best locations.[29] There are five large wind farms currently operating in Saskatchewan and several more in development. Table 4-3 summarizes the state of operating and proposed wind projects in the province.

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servicing, and dismantling turbines. I estimate the level of embodied GHGs for each generation technology in Chapter 9.

[29] The capacity is a measure of the amount of electricity generated by a facility relative to the maximum amount it could generate. It is calculated by dividing the amount of electricity generated in a given period of time by the maximum amount of electricity the installation could have been expected to generate over that period (see Appendix 5A Equation 5A.4).

Project	Operational Status	No. of Turbines	Average Turbine Size	Turbine Mnfct.	Total Capacity MW	Nearest Town/City	Owner
Cypress Wind	Since 2002	16	0.66	Vestas	10.6	Gull Lake	SaskPower
Sunbridge	Since 2002	17	0.66	Vestas	11.2	Gull Lake	Suncor & Enbridge
Centennial	Since 2006	83	1.8	Vestas	149.4	Swift Current	SaskPower
Red Lily	Since 2011	16	1.65	Vestas	26.4	Moosomin	Concorde Pacific
Cowessess	Since 2013	1	0.8	Enercon	0.8	Regina	Cowessess First Nation
Morse	Since 2015	10	2.3	Siemens	23.0	Morse	Algonquin Power
Chaplin	Development	77	2.3	Siemens	177.1	Chaplin	Algonquin Power
Western Lily	Development	?	?		20.0	Grenfell	Gaia Power Inc.
Riverhurst	Development	5	2		10.0	Riverhurst	Capstone
Total Operational		**143**			**221.4**		
Total Operational, Under Construction & Developed					**428.5**		
Unallocated	Additional Operational by 2020				100.0		
Unallocated	Additional Operational by 2030				600.0		

(Source: Reproduced with permission from SaskWind, 2015)

Table 4-3 Wind Power Projects in Saskatchewan

SaskPower has committed to having wind power contribute 10% of provincial electricity generation capacity by 2020 (Mohr, 2015).[30] By 2019 217 MW of additional wind capacity will be installed, including a 177 MW wind farm near Chaplin and a 20 MW wind farm at Riverhurst – both located in the vicinity of Moose Jaw, and a 20 MW project at Grenfell, which is located 126 km east of Regina. An additional 100 MW of wind power will be developed to meet the 2020 target (Mohr, 2015; SaskWind, 2015).

SaskPower has also made the commitment that by 2030 wind will compose 20% of total electricity generating capacity or approximately 1000-1100 MW (Mohr, 2015). Meeting the 2030 target will require another 500-600 MW of wind power in the decade between 2020-2030 (SaskWind, 2015). This represents a change in plans for SaskPower. Former CEO Robert Watson stated in 2013 that wind would "not in our lifetime" compose more than 8% capacity in the province (StarPhoenix quoted by SaskWind, 2015). SaskPower's new CEO Mike Marsh appears to be more favourable towards the technology.

In a regional context SaskPower's goals appear eminently achievable. Neighbouring North Dakota had 1886 MW of wind capacity installed at the end of 2014, which provided 17.6% of total electricity generated in that state (U.S. DoE, 2015). South Dakota

[30] Due to the lower capacity factor for wind it will supply about 6% of electricity (measured in GWh) when it comprises 10% of capacity (measured in MW).

had 803 MW installed at the end of 2014, which on a smaller grid produced over 25% of total electricity generated in that state (U.S. DoE, 2015). At 20% capacity, SaskPower could expect to produce about 12% of their total electricity from wind (SaskWind, 2015).

The potential for wind power is even higher than the 1100 MW Saskatchewan can expect by 2030. When SaskPower issued their 2011 Request for Proposals for 200 MW of wind power they received project submissions totaling 4000 MW (Interview 4). The total wind resource is estimated to be even greater than this and exceeds any anticipated levels of electricity demand (Interview 3).

Meaningful limits to the wind power resource are largely social, not physical. As outlined in Chapter 3, the R.M. of South Qu'Appelle rejected a wind monitoring station in 2014 due to concerns from local residents that a wind farm would impose negative health impacts and decreased property values. As one of the residents of the R.M. of South Qu'Appelle stated, "There are well documented cases of health problems with these things – constant noise, people can't sleep, people can't have their windows open" (Whittaker quoted in Kaul, 2014). A proposed wind turbine at the Saskatoon landfill faced opposition for the same reasons (Raine, 2011). Ontario has seen a similar pushback against wind projects. Opposition to wind farms by individuals in Ontario is significantly associated with perceived negative impacts to human health (Baxter *et al*., 2013). Anti-wind groups have been successful at creating concerns about these health impacts, despite a lack of scientific evidence that these impacts exist.[31] Critics of wind in Ontario have also raised the spectre of decreased property values near wind developments. The evidence does not support this concern. Vyn and McCullough (2014) conducted a hedonic analysis of the impacts on property values of living near a wind turbine in Melancthon Township Ontario. Their findings "suggest that these turbines have not impacted the value of surrounding properties" (Vyn and McCullough, 2014: 388).

[31] Health Canada has investigated the health impacts of living near wind turbines. Their preliminary results suggest no relation between living near a wind turbine and negative health impacts such as illness, chronic disease, stress, or sleep disturbance. They did however, find evidence that exposure to wind turbine noise is associated with annoyance. (Health Canada, 2014)

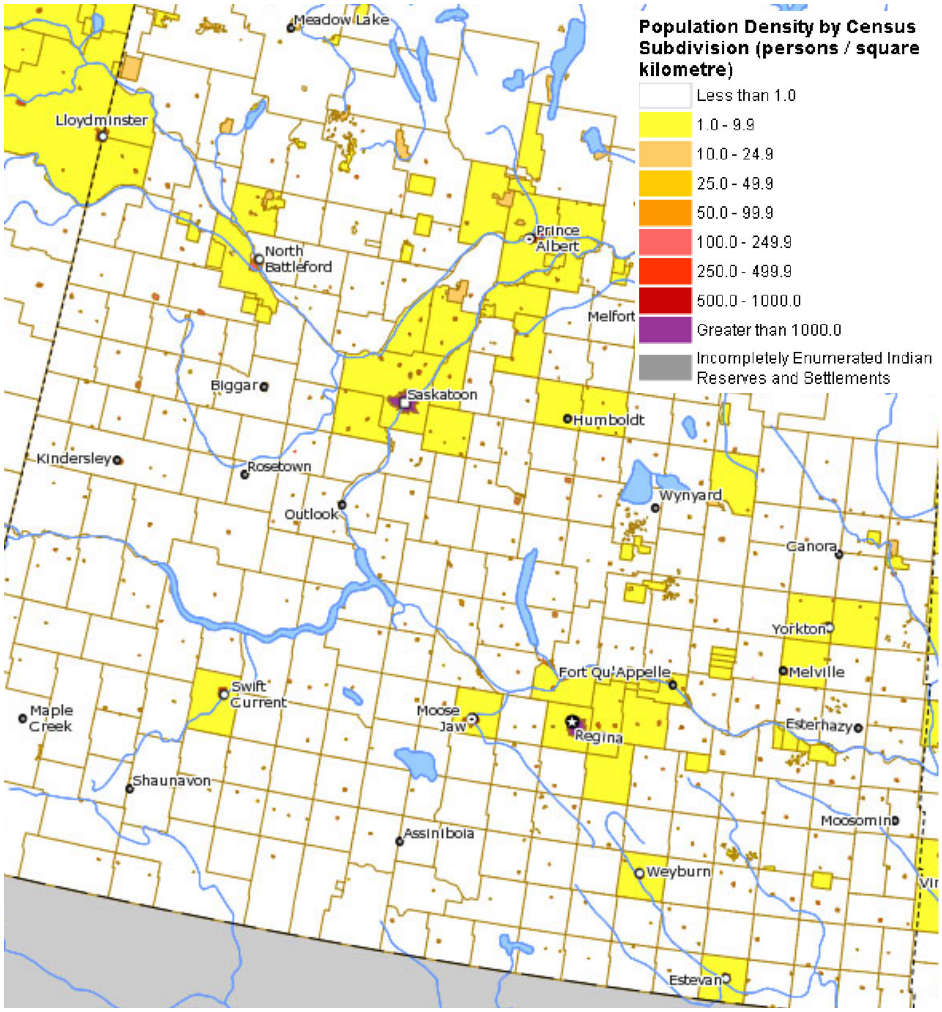
Concerns about impacts on health and property values may mask a deeper concern about lost community control over decision-making (Christidis and Law, 2012). The Ontario *Green Energy and Economy Act* removed the ability of municipalities to say no to wind projects. That loss of citizen control encourages resentment and opposition. It can also increase risk perception; Slovic (1987) has shown that a feeling that a risk is out of one's control increases feelings of dread and heightens risk perceptions. Though inconvenient in the short term, Saskatchewan would do well to maintain the ability of rural municipalities to say no to wind turbines. By placing this control in the hands of local citizens, trust in wind turbine technology can be enhanced in the long-run.

Public resistance to wind energy development in Saskatchewan will likely be less than experienced in Ontario due to the areas with strong wind resources being sparsely populated relative to Ontario. The population density in most areas of southern Saskatchewan is less than 1 person per square kilometer (km^2) (Figure 4-3). The population density of southern Ontario is between 10-50 persons per km^2 (NRCAN, 2014).[32] This makes it easier to locate wind turbines away from farmhouses and small towns.

Concerns remain, however, about impacts of wind energy development on wildlife. For example, the proposed Chaplin wind facility will be located near a bird sanctuary. Respected naturalist and author Trevor Herriot was quoted in the LeaderPost asking,

> "Why put them there? Why not go to a place where there is not an internationally significant, globally important nesting and migrating area for shorebirds? Yes, we've got to deal with climate change and our carbon footprint, but we can't do it at the expense of wildlife."
> (Herriot in Lypny, 2015)

[32] Ontario requires wind turbines to be setback a minimum of 550 meters from the nearest "noise receptor" (Ontario, 2013: 74).



(Source: NRCAN, 2014)

Figure 4-3 Population Density in Southern Saskatchewan

Research has shown that wind turbines kill birds, and even more often, kill bats. Bat kills typically occur at low wind rotor speeds and increase during the autumn southbound migration period, especially when the moon is shining bright (Baerwald and Barclay, 2011). Seasonal changes to the management of wind turbine operation can decrease bat kills (Baerwald *et al.,* 2009)[33] as can locating turbines outside of bird and bat migratory routes. Nonetheless, some level of bird and bat kills is inescapable with existing

[33] Baerwald *et al*. (2009) found that bat kills could be reduced at an Alberta wind farm by increasing the wind speed at which a wind turbine rotor becomes active. A higher wind speed "cut-in" point means that the turbine rotor and blades will be motionless at low wind speeds. No electricity will be produced at these times.

technology and management practices. This has led one renewable energy proponent to declare, "Wind isn't the future. It kills birds. The future is solar."[34] (Interview 31)

Solar Photovoltaics

Saskatchewan has the best solar resource in Canada (See Figure 4-4); Regina Saskatchewan is Canada's sunniest provincial capital, and Estevan, in the southeast corner of the province, is the sunniest city in Canada (NRCAN, 2015a).

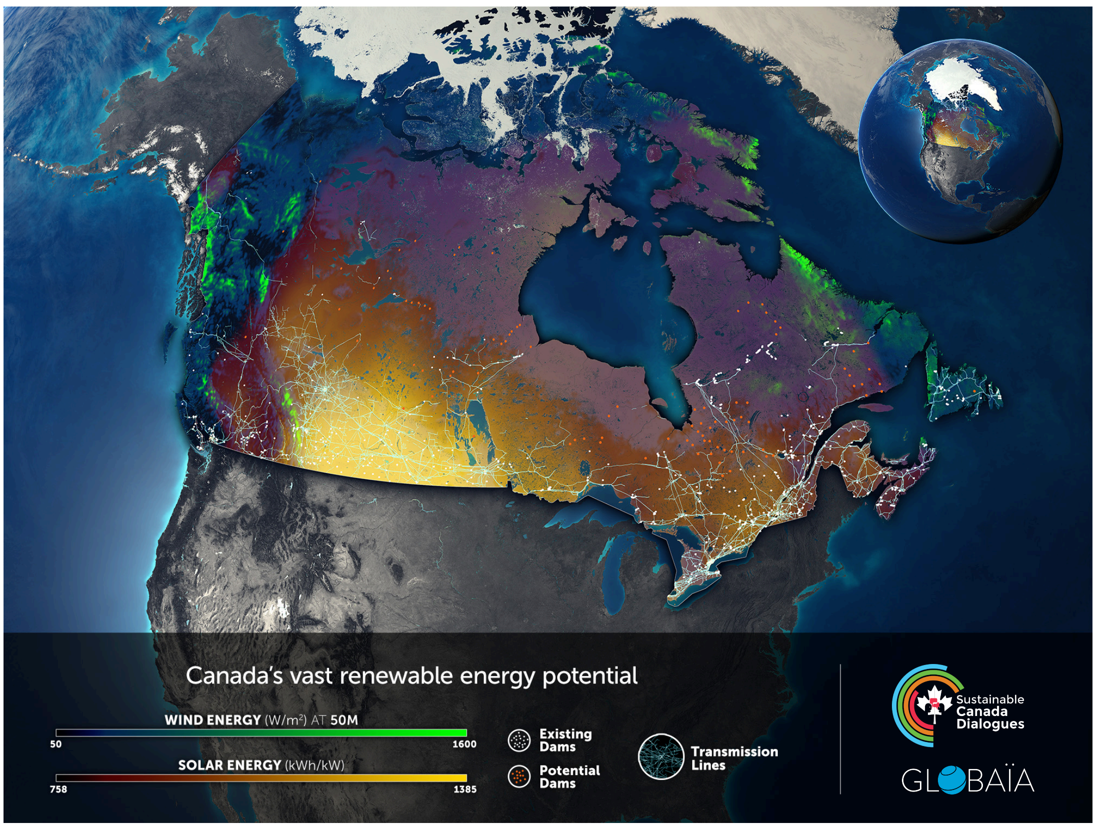


Figure 4-4 Canada's Renewable Energy Potential (SCD, 2015b)

Not only is the solar resource the best in Canada, it is also one of the best in the world (see Table 4-4). Regina has solar photovoltaic potential greater than Sydney, Australia and much greater than German cities like Berlin. The solar resource in Estevan, which

[34] It is worth noting that 95% of human-related bird deaths in Canada result from "predation by feral and pet cats, and collisions with road vehicles, houses, and transmission lines" (Calvert *et al*., 2013: 6).

achieves 1379 kwh/kw in a typical year, is nearly as high as the solar potential in Mexico City (1425 kwh/kw). (NRCAN, 2015a). The greatest solar resource in Saskatchewan is located in the southern half of the province, which happens to coincide with the majority of the province's population and electricity demand. Estevan also happens to be the centre of Saskatchewan's coal-fired power industry meaning that high-voltage transmission lines connect the region to Regina and other load centres.

City	**Yearly PV potential (kWh/kW)**
Cairo, Egypt	1635
Capetown, South Africa	1538
New Delhi, India	1523
Los Angeles, U.S.A	1485
Mexico City, Mexico	1425
Regina, Saskatchewan	**1361**
Sydney, Australia	1343
Rome, Italy	1283
Rio de Janeiro, Brazil	1253
Ottawa, Canada	1198
Beijing, China	1148
Washington, D.C., U.S.A.	1133
Paris, France	938
St. John's, Newfoundland/Labrador	933
Tokyo, Japan	885
Berlin, Germany	**848**
Moscow, Russia	803
London, England	728

(Source: NRCAN, 2015a)

Table 4-4 Solar Photovoltaic in Cities Around the World

Despite the cold winters, the solar resource in Saskatchewan is present throughout the course of the year (see Figure 4-5). Residents of the province will attest that, though the winters are cold, the sun is often shining. The cold temperatures offer an additional boost to solar potential in the province; the photovoltaic process is more efficient in colder temperatures (Masters, 2004). As one participant remarked, the best place for solar is a "cold desert" (Interview 28); Saskatchewan is just that. Saskatchewan's northern location does, however, mean that the days are shorter in the winter months and the solar potential drops accordingly (Figure 4-5).

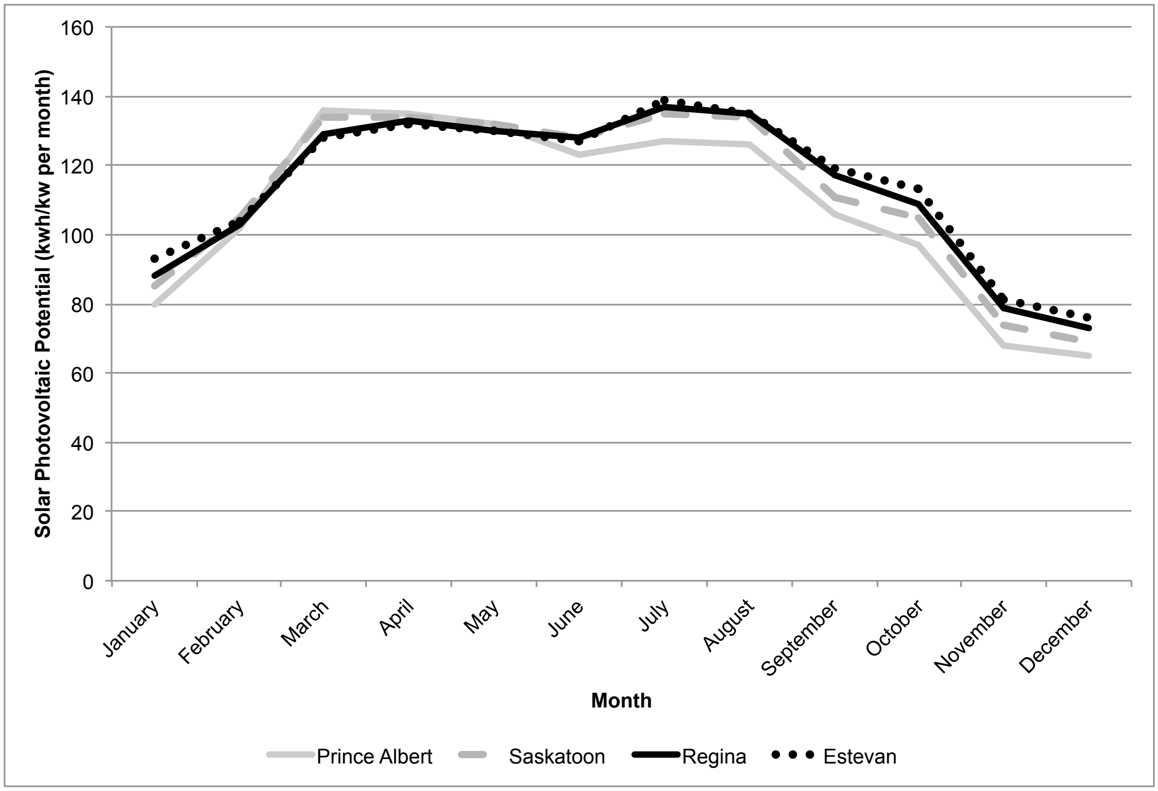


Figure 4-5 Saskatchewan Solar Potential by Month in Four Select Cities

SaskPower does not currently own any utility-scale solar photovoltaic (PV) facilities. Private homeowners and businesses have installed smaller residential and commercial rooftop solar systems in the province, in part supported by the Ministry of Environment's *Go Green* fund. A comprehensive inventory of those projects is not currently available.

Biomass Potential

The majority of biomass potential in Saskatchewan lies along the boreal forest fringe. The feedstock along the forest fringe consists of waste fibre leftover from pulp and paper mills and sawmill operations. The Meadow Lake First Nation is currently developing a biomass project using fuel from the latter. The project will be located beside the NorSask sawmill in Meadow Lake and will offer roughly 36 MW of power (Interview 12). In total, it is estimated that 120 MW of biomass potential exists along the forest fringe (McKenzie quoted in Bigland-Pritchard and Prebble, 2010).

Although burning the biomass does release carbon dioxide (CO2), these emissions are treated as carbon neutral. This assumes that the trees will regrow where they have been cut and uptake an equivalent amount of CO_2 during their regrowth. As long as the forest is continuously regrown the net addition of CO_2 to the atmosphere will be zero.

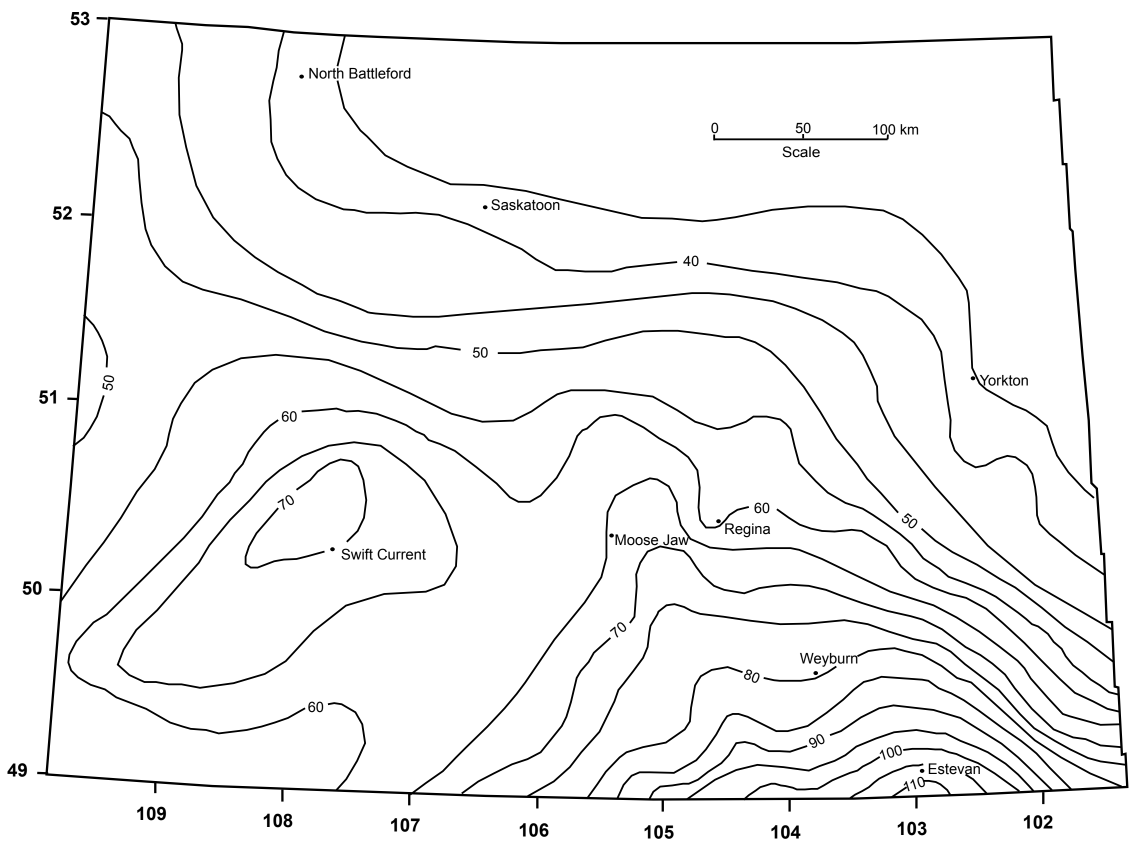
Another biomass resource lies in the garbage dumps of the province. At a landfill, organic matter rots in an anaerobic state and creates methane gas. The leaching of this landfill methane gas is a measurable contributor to climate change. In 2013, 32 kilotonnes (kt) of methane (805 kt of carbon dioxide equivalent (CO_2e)) was released due to solid waste disposal on land in Saskatchewan; (Environment Canada, 2015a). Rather than letting it leach to the atmosphere, the City of Saskatoon is using this landfill gas to generate power. Tubes drilled into the landfill extract the methane, which is then burned to generate electricity onsite. The Saskatoon plant has an electricity generating capacity of 3.2 MW (CBC, 2012; City of Saskatoon, 2015). Proposals are now being made to install solar photovoltaic panels at the landfill to supplement the electricity generated using landfill gas (Interview 20).

Other smaller biomass projects can use crop residues from agriculture, manure from intensive livestock operations, and landfill methane. It is assumed these smaller projects could provide up to 30 MW of biomass power for a total of 150 MW of biomass potential in the province.

Geothermal Potential

Deep geothermal heat has great potential for space heating and industrial processes in Saskatchewan, but limited potential for direct electricity generation. Geothermal energy for space heating was explored at the University of Regina (UofR) in the late 1970s. In 1978 a geothermal test hole was drilled at the UofR campus to a depth of 2226 meters. Brought to the surface from this depth, the water has a temperature of 58-59°C. This hot water was sufficient to meet a 2 MW heating load for a proposed sports complex. The project was discontinued when plans for the sports complex fell through and oil prices collapsed. The drill-hole remains, as does the potential to drill a second hole to complete the loop and use geothermal heat at the University of Regina. (Vigrass *et al*., 2007)

Figure 4-6 shows the approximate temperatures at the bottom of the sedimentary layer in Southern Saskatchewan, presented using isotherms at 5°C intervals.



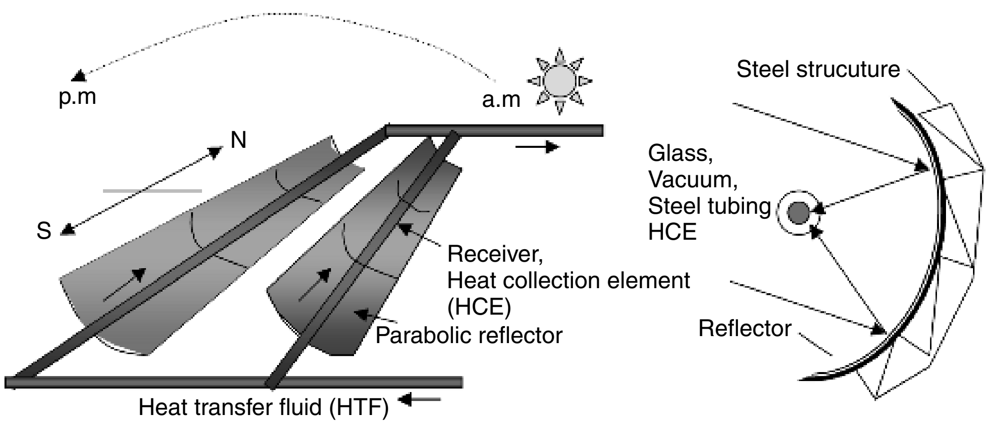
(Source: Vigrass *et al*., 2007: 19)

Figure 4-6 Approximate Temperature at the Base of the Sedimentary Section

The sedimentary layer is deepest in the southeast corner of the province near Estevan. This depth leads to higher temperatures, but even at 110°C this deep geothermal heat is not high enough to efficiently generate electricity. It does have the potential to offset natural gas use for space heating and process heating, but those uses are beyond the scope of this dissertation and geothermal is not included in the analysis.

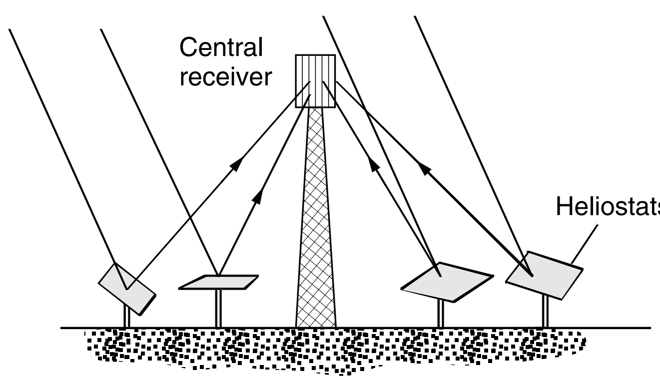
Solar Thermal

Solar thermal electricity is generated by concentrating solar radiation to create useful heat. Heat is concentrated either using parabolic mirrors aimed at a central receiver (Figure 4-7) or with mirrors that reflect solar energy to a central tower (Figure 4-8) (Masters, 2004). This solar heat can be used in a "conventional steam turbine/generator" or a Stirling engine to generate electricity (Masters, 2004: 186).



(Source: Masters, 2004: 186)

Figure 4-7 Solar Thermal Using Parabolic Mirrors



(Source: Masters, 2004: 189)

Figure 4-8 Solar Thermal Using Heliostat Mirrors and a Central Tower

Solar thermal systems can be built with storage in order to generate electricity during the peak hours of 5 p.m. – 7 p.m. Storage becomes important when dealing with the variability of renewable energy (see discussion below). In a typical design, molten salt is heated to 565°C and this heat can be used when desired to operate a steam turbine (Masters, 2004).[35]

Southern Saskatchewan is one of the few places in Canada that receives enough sunshine for solar thermal electricity to be generated. The total potential for solar thermal electricity in Canada is estimated to be 26,190 TWh/yr on lands with slope less than 4%. The Saskatchewan share of solar thermal potential is 13,575 TWh/yr; just over half of the total. To put this in perspective total electricity generation in Saskatchewan in 2014 was 23.4 TWh (SaskPower, 2015). (Djebbar *et al.*, 2014). However, for this total potential to be achieved a good portion of southern Saskatchewan would be covered with solar thermal reflective mirrors. The feasible potential is quite a bit smaller and is limited by ability to access land, much of which is currently used for cereal production or pastureland. The land requirements of the different technologies for solar thermal electricity are as follows; "parabolic troughs about 5 acres/MW, and power towers about 8 acres/MW" (Masters, 2004: 191). On a typical section of land, measuring 1 mile by 1 mile or 640 acres, it would be possible to install 128 MW of parabolic trough solar thermal or 80 MW using solar power towers.

Imported Hydroelectricity

A final renewable resource available to meet Saskatchewan electricity demand is hydroelectricity imported from Manitoba, the province immediately to the east of Saskatchewan. Manitoba's electricity system is nearly 100% hydro-powered.[36] The utility, Manitoba Hydro, exports about 30% of the electricity they generate. The Manitoba Hydro strategy has been to build hydro dams in the north of the province, connect them with transmission lines through Winnipeg, in the southeast part of the province, and export surplus power south to the United States. The sale of power to the

[35] Storing heat to generate electricity is one of several methods of energy storage. I discuss storage further in Chapter 8.

[36] In the fiscal year 2014-2015 Manitoba Hydro reported generated 35,000 Gigawatt-hours (GWh) using hydraulic generation out of a total of 35,044 GWh total generation (Manitoba Hydro, 2015a).

United States helps to pay for the hydro dam capital investment. As electricity demand grows in load centres like Winnipeg, electricity generation can be switched from export to local consumption. (Interview 8)

Manitoba Hydro has signed an agreement to supply SaskPower with 25 MW of power during the period of 2013-2020 for $100 million or $4 million/MW (Manitoba Hydro, 2015b). Manitoba Hydro will also supply SaskPower with 100 MW of power from 2020-2040 (Johnstone, 2015b). This will require the construction of an 80-kilometer 230-kilovolt line connecting the provinces at a cost of $50 million (Johnstone, 2015b). The two crown corporations have signed a memorandum of understanding that SaskPower may negotiate to purchase up to 500 MW of power after 2020 (Manitoba Hydro, 2015b).

The Manitoba and Saskatchewan electricity grids are connected at five locations and will soon be connected at a sixth location. One important link consists of a connection to Manitoba from Saskatchewan's Island Falls hydroelectric generating station and a connection from Manitoba up to the northern segment of the Saskatchewan electricity grid. SaskPower uses this connection to "wheel" power through Manitoba and up to the northern portion of the Saskatchewan grid, which is otherwise unconnected from the southern grid (Manitoba Hydro, 2013). The existing connections between Saskatchewan and Manitoba allow up to 150 MW of power to be exported from Manitoba (Manitoba Hydro, 2013).[37] The new transmission line will increase the potential for exports to facilitate the 100 MW purchase for 2020-2040. Further interconnection upgrades may be necessary to facilitate a 500 MW power purchase.

An upgrade of this magnitude has precedent. As of 2013 Manitoba Hydro had interconnections with the U.S. market that allowed 1950 MW of power to be exported (Manitoba Hydro, 2013). Export agreements are in place with U.S. utilities such as Xcel, Great River Energy of Minnesota, Minnesota Power, Wisconsin Public Service. Of note,

[37] Note that this is above and beyond reserve capacity provided by the Saskatchewan-Manitoba interconnections. Saskatchewan maintains interconnections with North Dakota and Manitoba that provide up to 300 MW of power in reserve in case SaskPower loses a generating unit.

Xcel energy has nearly 6000 MW of wind power on their system. An export agreement to purchase between 375 and 500 MW of hydropower from Manitoba helps to back-up Xcel's variable wind power resource. (Xcel, 2015; Manitoba Hydro, 2015b)

Summary of Potential

Saskatchewan has a strong wind resource and the best solar resource in Canada. Additions of solar and wind capacity are limited by competing land uses, but the available resources exceed Saskatchewan's electricity needs by a large margin. The province has 864 MW of hydroelectric capacity and the potential to develop an additional 1780 MW. Saskatchewan also has an opportunity to access significant hydroelectric imports from neighbouring Manitoba. There is the potential for at least 150 MW of biomass capacity to be built in the province, which would include biomass plants near pulp and paper mills and sawmills, as well as landfill gas plants. Geothermal heat offers the potential to substitute for space heating, but does not appear to offer significant electricity generation potential. While the resource appears more than adequate for Saskatchewan's electricity needs, variability is a concern. I now turn to a discussion of renewable energy variability in Saskatchewan.

Renewable Energy Variability

Renewable energy derived from wind and solar is fundamentally different from fossil fuel derived energy. To use the language of system dynamics, wind and solar energy is flow-limited, while fossil fuels are stock-limited. A flow-limited resource is one that is limited by the flow of energy over time. A flow of blowing wind powers wind turbines. A flow of solar insolation powers solar photovoltaics and solar thermal plants. Wind and sunlight cannot be stored and saved for later; they must be used when available or else they are wasted. They also cannot be used to generate power when they are not available; wind turbines will not turn when the wind is not blowing and solar panels will not generate electricity without light. (Daly and Farley, 2010)

Fossil fuels are stock-limited, but flow unlimited. The stock of coal in Saskatchewan's coal seams can be mined and burned in a power plant at a rate that lies within SaskPower's control (at the Poplar River station 12,000 tonnes of coal are strip-mined and burned per day). These stocks of fossil fuels were built up over millennia; they are the accumulation of the solar flow that collected in biomass and under heat and pressure was transformed into fossil fuels. If we were to keep burning coal this stock would eventually run out, or else become prohibitively expensive to extract. A stock of coal can be saved for later. It can also be used up quickly if we so desire.

Hydropower and biomass exhibit elements of both flow-limited and stock-limited resources. Hydropower is dependent on streamflow, which can vary year to year. In this way it is flow-limited. The streamflow recharges hydro reservoirs, which can hold a stock of water and release it on demand.

Biomass is fuelled by a flow of biomass growth and, if it is to be used sustainably, is limited by the rate at which trees or crops grow. Biomass and biomass fuel can, however, be accumulated in stocks. Forests can expand, and the stocks of biomass stored at sawmills (*e.g.* along Saskatchewan's forest fringe) can offer rich stores of biomass for generating electricity.

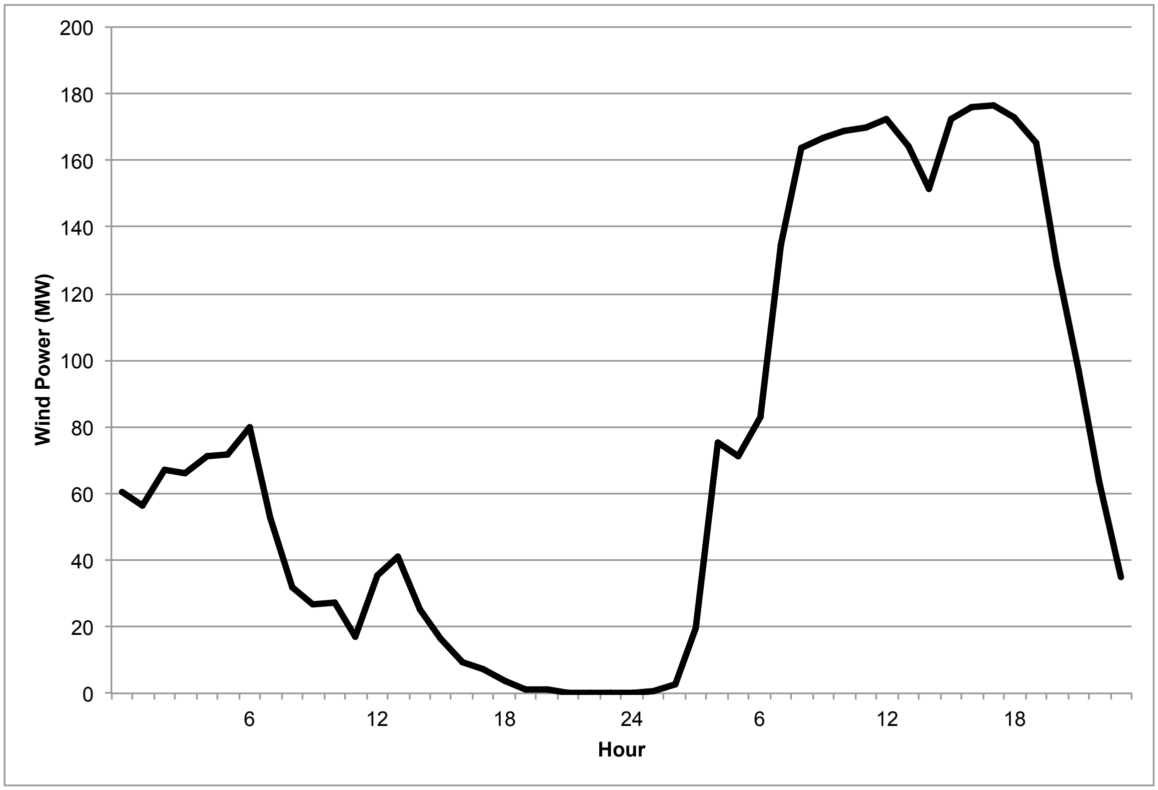
Because renewables are flow-limited they are variable. They cannot be made available on demand. This variability introduces challenges for electricity system operators. Wind and solar cannot be turned on when load is required. Electricity operators must use other tools to respond to this variability. For example, natural gas peaking plants are used to generate power on short notice such as when there is a gap in renewable energy production. Hydroelectric reservoirs can be used to store potential power and release it when needed. Electricity can also be stored using technologies such as compressed air stored under pressure in underground caverns; pumped hydro that moves water upstream or vertically upwards in a mineshaft; fly-wheels; and lithium-ion batteries.

Below I outline the variability of electricity demand and renewables such as wind, solar, and the stream flows that recharge hydroelectric reservoirs.

Wind Power Variability

Wind power varies with wind speed. Turbines do not begin to generate electricity until winds reach a critical "cut-in" speed; for example Vestas V80 turbines begin to turn once winds reach a speed of 4 meters/second (m/s) (Baerwald *et al*., 2009; Vestas, 2015). Below the cut-in speed the output of a wind turbine is nil. Turbines also cut-out at high wind speeds to prevent mechanical damage. For the Vestas V80 turbine, the rotors disengage and stop turning when wind speeds reach 25 m/s (Vestas, 2015).

In 2013, SaskPower had 198 MW of wind power on their system. The average power output of the wind turbines was 72.7 MW, creating a capacity factor of 36.7% over the course of the year. The power output of the wind turbines could swing significantly from hour to hour. The largest swings were a ramp up of 119.1 MW from 20:00 to 21:00 on January 18th and a ramp down of 118 MW between the hours of 9:00 and 10:00 on January 18^{th}, 2013. This large swing would have required other power generation facilities to ramp down from 20:00 to 21:00 and ramp up between 9:00 and 10:00 in order to balance the changes in wind power production. Figure 4-9 shows the 24-hour period with the highest wind power variance in 2013. Wind power ramped up from zero to near full capacity and then back down again over the course of January 29^{th}.



(Source: Bigland-Pritchard, 2015b; author's calculations)

Figure 4-9 Hourly Wind Power Variability (January 28, 2013 – January 29, 2013)

To some extent the variability of wind can be diminished by distributing turbines over a wide geographic area. Table 4-5 shows the correlation between hourly potential wind power output across five sites that stretch from west to east in southern Saskatchewan. The lowest correlation is between Maple Creek and Broadview; communities located approximately 500 km apart.

Saskatchewan's first wind farms were concentrated in the southwest of the province near Maple Creek and Swift Current where average wind speeds are highest. Recent additions at Moosomin and a planned project at Grenfell will add geographical diversity to Saskatchewan's wind power. This diversity will help to reduce the variability of wind power in the province.

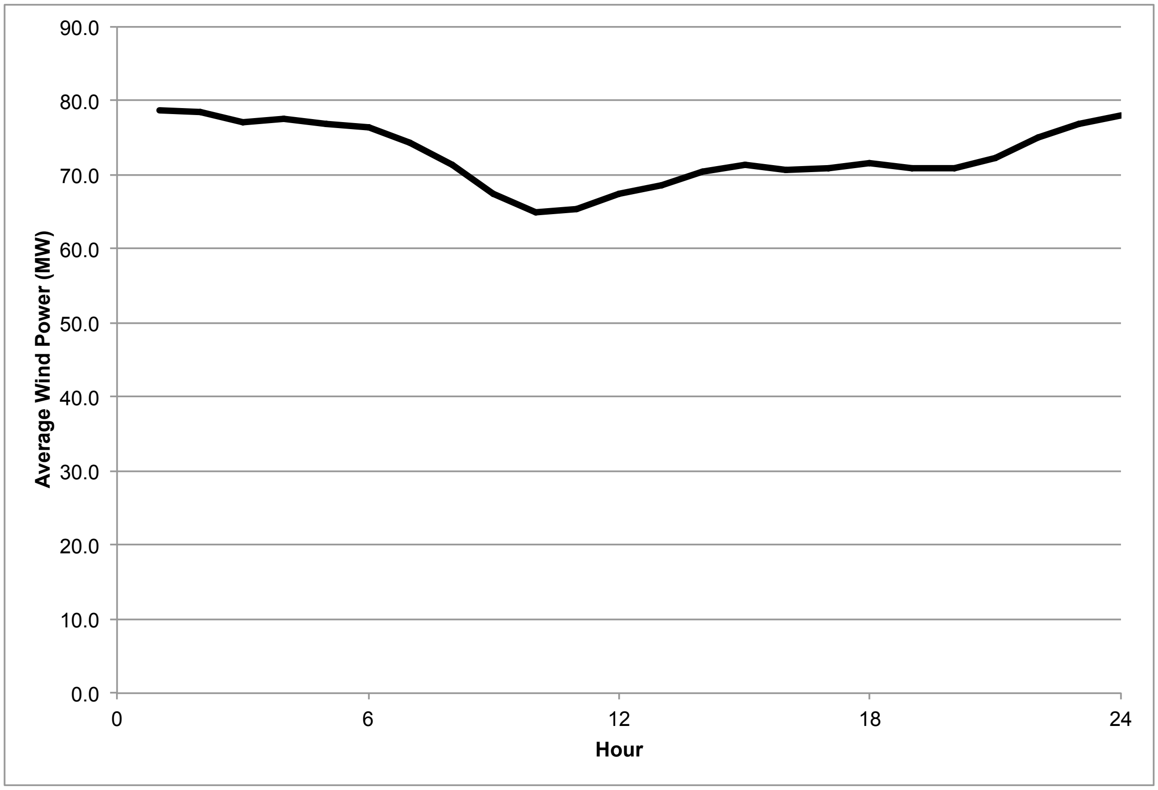
	Maple Creek	Eastend	Swift Current	Indian Head	Broadview
Maple Creek	1.00	0.48	0.54	0.24	0.19
Eastend		1.00	0.50	0.32	0.29
Swift Current			1.00	0.41	0.33
Indian Head				1.00	0.69
Broadview					1.00

(Source: Bigland-Pritchard, 2015b[38]; author's calculations)

Table 4-5 Correlation of Hourly Wind Power Potential Across Saskatchewan (January 1, 2013 to December 31, 2013)

There is also variability over the course of the day. Figure 4-10 presents the 2013 wind generation data in terms of hourly average power production. On average wind power is highest during the night and calms in the midday. This makes it poorly correlated with electricity demand, which generally increases during the day, peaking in the early evening hours. In 2013, the correlation between electricity demand and wind power production was only .158. The wind is, however, complementary to another variable renewable power source: solar energy, to which I now turn.

[38] Bigland-Pritchard (2015) calculated potential wind power at various sites in Saskatchewan using historic data from Environment Canada (2014).



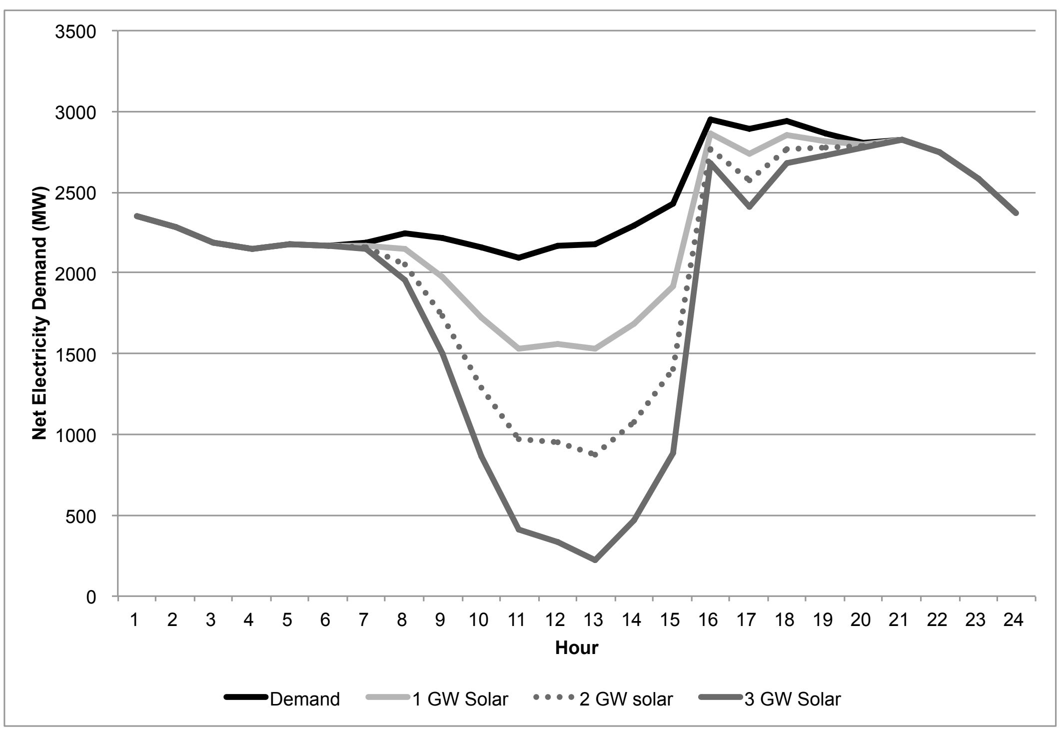
(Source: Mark Bigland-Pritchard, 2014; author's calculations)

Figure 4-10 Average Wind Power Output by Hour in 2013

Solar Variability

Solar energy is generated in direct proportion to the amount of sunlight received, which means electricity begins flowing in the morning, peaks around noon, and tapers off later in the day. Cloud cover reduces solar power output and introduces a degree of unpredictability into the generation of solar energy. In Saskatchewan, electricity demand typically peaks in the late afternoon and early evening when the lights and computers in office buildings have yet to be shut off and people return from their jobs to begin cooking, watching television and doing other households activities. This means that peak generation for solar energy does not correspond with peak electricity demand. This creates a challenge for integrating solar into the electricity system. Just as solar electricity output is winding down, demand is ramping up. This means that other generation sources or stored electricity must be quickly ramped up and brought on-line, or demand must be shifted towards times of abundant electricity.

California is a leading jurisdiction in renewable energy and is working to address the integration of variable renewable energy on the grid. The state has a goal of 33% of electricity to be generated by renewables by 2020. California's Independent System Operators (ISO), the organization that buys and sells power in the state and is in charge of making sure supply equals demand on a constant basis, has worked to understand what this aggressive renewable energy target means for the stability of their electricity system. The California ISO created a now famous "duck chart" to highlight the impact of high rates of solar penetration. The "duck chart" subtracts the power generated by variable renewable electricity sources such as wind and solar from demand to create a measure they call "net load". Figure 4-11 reproduces the California "duck chart" using Saskatchewan electricity demand data and Saskatchewan solar power potential data.[39] As can be seen, net demand resembles the outline of a duck when high levels of renewables are present on the grid.



(Source: Mark Bigland-Pritchard, 2015b; author's calculations)

Figure 4-11 Saskatchewan "Duck Chart" Showing Net Load With Solar-PV

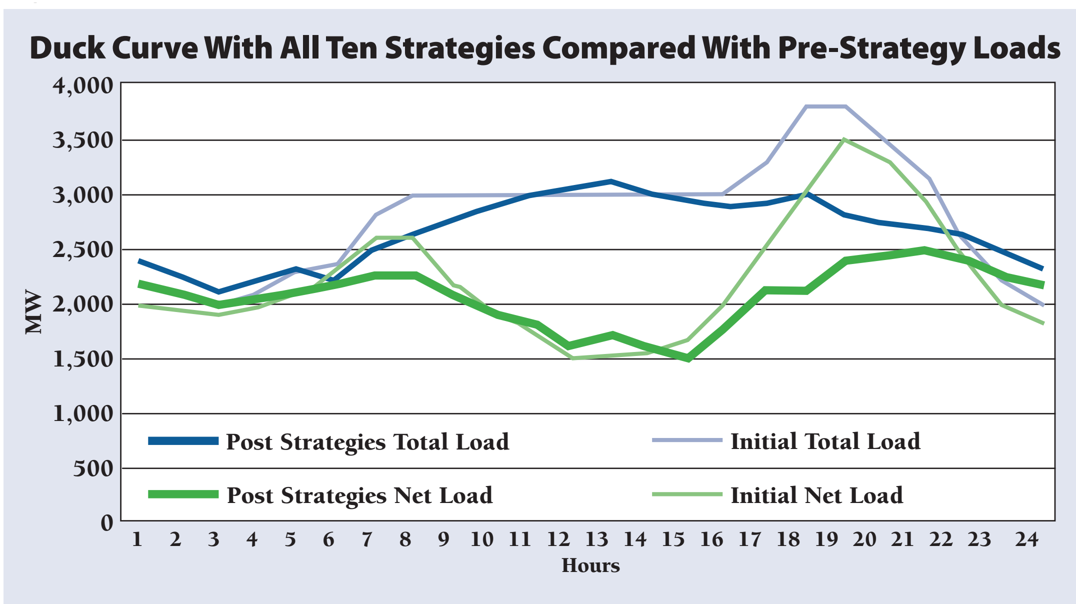
[39] Note the solar data is based on August 28th, 2003 solar insolation data for Estevan, SK and demand data is for August 28th, 2013.

If Saskatchewan were to invest heavily in solar photovoltaics (solar-PV) plans would have to be made to ensure smooth integration into the system. On the afternoon depicted in Figure 4-11, the ramp-up of a significant source of non-solar electricity would be required. For example, in the scenario with 3 GW of installed solar power, net demand (demand minus solar output) increases by 1900 MW between 1:00 and 4:00 p.m. This means that 1900 MW of capacity must be brought online during that period. Although this is an extreme example – this day was selected because it had the largest ramp-up requirement of all possible days in the dataset – the electricity system must be able to respond to even the most extreme cases in order to reliably supply Saskatchewan's electricity needs.

Proponents of solar point out that the electricity system is built to follow the variability of electricity demand; response to variability is already built into the electricity system (Lazar, 2014). Lazar (2014) notes that "ducks vary their shape depending on different circumstances…utility load shapes can do the same" (Lazar, 2014: 2). He outlines ten strategies that can minimize the difference between demand and net load and "teach the duck to fly" (Lazar, 2014):

1. *Target energy efficiency to periods when net load ramps most quickly*; this could mean encouraging LED lighting to reduce residential lighting demand in the evening;
2. *Orient solar panels to the west* to generate more power in the late afternoon, which may be worthwhile even if total power output declines;
3. *Build some solar thermal with storage* to shift the availability of solar power towards the peak demand hours of late afternoon and early evening;
4. *Allow grid operator to manage electric water heating loads*: electric water heaters can be superheated during times of plentiful electricity generation and blended with cool water when needed in the supper hours;
5. *Build air conditioners with thermal storage*; this is less important in Saskatchewan, but would include storing cold by creating ice during the middle of the night;

6. *Retire inflexible generating units that cannot ramp quickly*: coal and nuclear power plants do not ramp quickly and have a harder time following net load than natural gas-fired generating plants;
7. *Introduce time-of-day electricity pricing for the peak hours*: variable pricing can encourage the marketplace to find ways to shift electricity demand away from peaks;
8. *Introduce electrical storage in strategic locations*: storage can be filled when electricity is abundant and emptied during times of ramping;
9. *Implement aggressive demand-response programs* beyond those identified above;
10. *Exchange power on a regional basis to "take advantage of diversity in loads and resources*" (Lazar, 2014: 19).



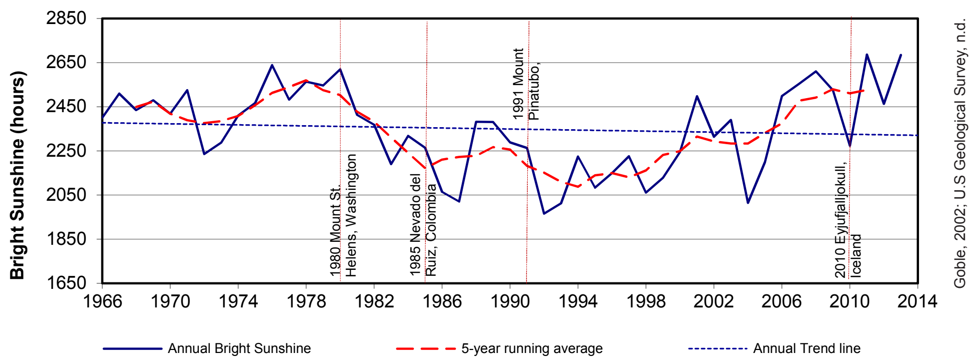
(Source: Lazar, 2014: 20)

Figure 4-12 Teaching the Duck to Fly

Figure 4-12 shows the extent to which the ten strategies listed above can shift both supply and demand and ease the ramping requirements created by variable renewable electricity. After the strategies are implemented there is less variability; notice that the 'Post Strategies Net Load' line demonstrates much less variability than the 'Initial Net Load' line.

It would be possible to pursue many of Lazar's (2014) strategies in Saskatchewan. Already the Saskatchewan Research Centre (SRC) and Cowessess First Nation have partnered on a wind turbine with electricity storage project. This project has shown the potential for a lithium-ion battery to smooth the generation of wind power. Experiments conducted at the site have shown that the combined 800-kilowatt (kw) wind turbine and 400 kW lithium-ion battery can produce a steady stream of power at 250 kW for three days straight (Jansen, 2014). SaskPower has a peak saving program with large industrial customers, but could do more to encourage demand-side management in the province. The rollout of smart meters would help in this regard. Lazar's (2014) tenth recommendation to "Exchange power on a regional basis" could be achieved by enhancing grid interconnections with Manitoba. Manitoba's hydroelectricity could then offer balancing services for Saskatchewan wind and solar. I further address the issue of meeting load with variable renewable electricity in Chapter 7.

Solar energy can also vary from year to year. Figure 4-13 shows the variability of annual bright sunshine hours at a Saskatoon monitoring station from 1966 to 2014. Interestingly, drops in bright sunshine often follow significant volcanic events (as shown on the graph). Plans to integrate solar into the electricity system would also have to consider these longer-term variations in solar power potential.



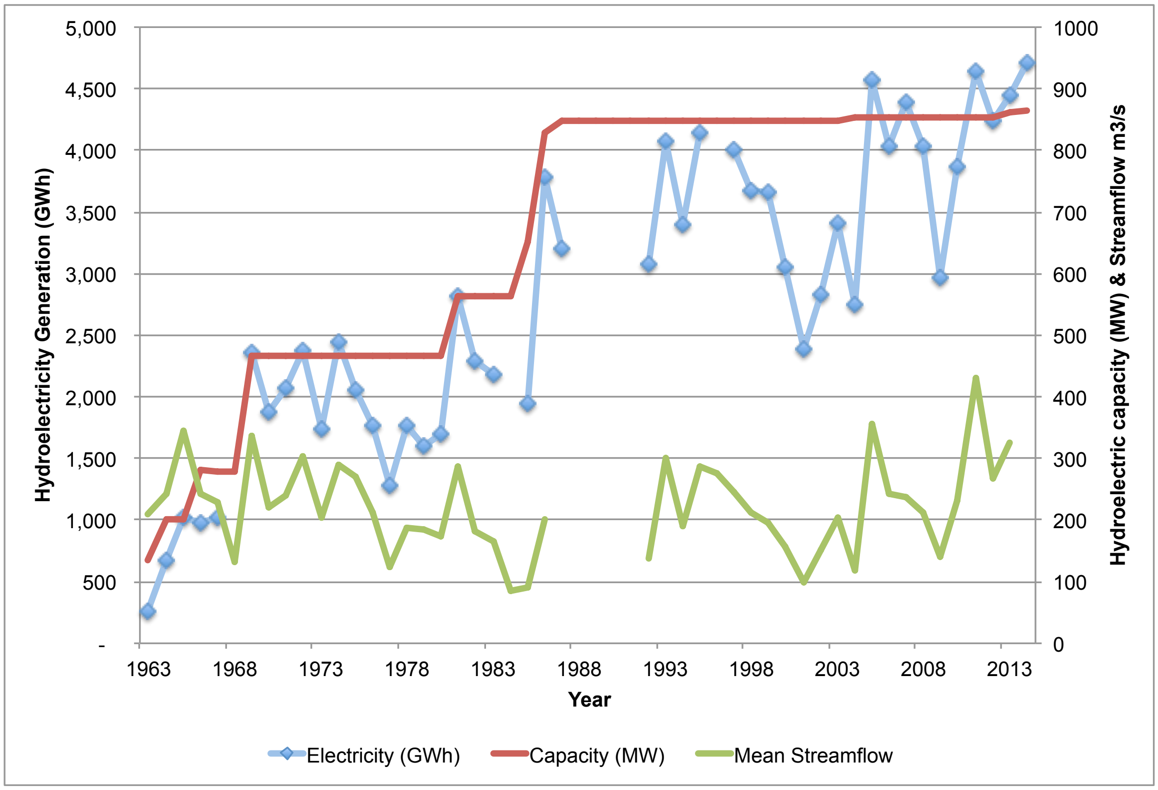
(Source: Beaulieu and Wittrock, 2014: 30)

Figure 4-13 Annual Bright Sunshine Hours in Saskatoon[40]

[40] Note that the y-axis does not begin at zero and so the fluctuations may appear exaggerated. Bright sunshine hours in Saskatchewan from 1966 to 2014 have ranged from a low of around 2000 to a high of nearly 2700.

Hydroelectric Power

Hydroelectric generation is dependent on streamflow and streamflow varies both seasonally and from year to year. Year to year variation is shown in Figure 4-14, which compares Saskatchewan's installed hydroelectric generation with hydroelectric capacity and mean streamflow on the South Saskatchewan River from 1963 to 2014. Years like 2001 and 2009 are notable for the low amount of hydroelectricity generated. They also correspond to years with low streamflow. Contributing to the low streamflow, 2009 was the driest spring in Saskatchewan for 51 years (Environment Canada, 2010).



(Source: SaskPower Annual Reports, 1963-2014; Environment Canada, 2015b[41])

Figure 4-14 Hydroelectricity Capacity and Generation in Saskatchewan

[41] Streamflow data is for the station on the South Saskatchewan River at Saskatoon, downstream from Coteau Creek and upstream from Nipawin and E.B. Campbell (streamflow station 05HG001, Environment Canada, 2015b). Note that hydroelectric generation data was missing from some of SaskPower's annual reports, and that mean streamflow data for select years was missing from the Environment Canada data.

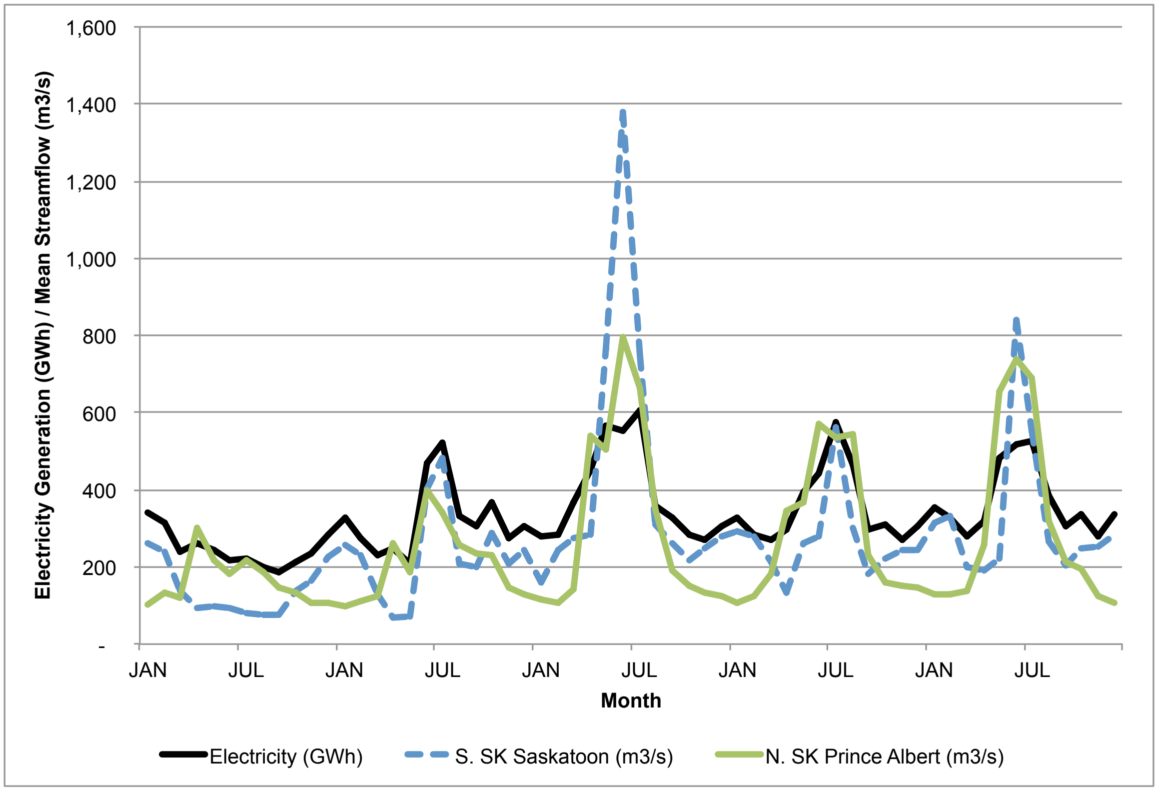
When hydroelectricity is a large part of an electricity system, planners must be aware of the potential for drought. The Saskatchewan River system, home to 84% of current hydroelectric capacity in the province, depends on snowmelt and rainfall runoff from the Rocky Mountains (Sauchyn *et al*., 2011). The long-run historic record shows that "mega-droughts" of up to 30 years have occurred in the Saskatchewan system; one in the early 1700s and another in the mid 1100s (Sauchyn *et al*., 2011). The Saskatchewan River system is fed by snowmelt from the Rocky Mountains. If climate change lowers snowfall in the Rockies then Saskatchewan's hydroelectric potential will suffer. However, even without impacts from anthropogenic climate change, long-lasting drought is a possibility on the prairies and could reduce hydroelectric output in the future.[42]

Streamflow in Saskatchewan is highly seasonal, peaking in June due to the accumulated effects of spring runoff. Hydroelectric production closely follows this seasonal pattern, although hydroelectric reservoirs such as Diefenbaker Lake and Tobin Lake allow streamflow to be stored for release later in time and can smooth hydroelectric production to a certain extent. (See Figure 4-15).

Figure 4-15 shows hydroelectricity generation in Saskatchewan from 2009-2013 (solid black line) along with streamflow on both the South Saskatchewan River, measured at Saskatoon (dashed blue line), and the North Saskatchewan River, measured at Prince Albert (solid light green line).[43] The station at Saskatoon is downstream from Coteau Creek and upstream from Nipawin and E.B. Campbell. Flows at the Saskatoon station are influenced by decisions made regarding hydroelectric production at Coteau Creek. The Saskatoon station shows summer peak flows, but also increased flows in the winter months. This coincides with the highest electricity demand in Saskatchewan; it is a winter-peaking province. The North Saskatchewan River at Prince Albert, which has no

[42] System planners in Manitoba have accounted for the variability of river systems in that province by building more hydroelectric capacity than is needed for provincial use and making conservative estimates of reliable streamflow. Yet even these conservative estimates do not account for the potential of multi-decadal mega-drought.
[43] The Prince Albert station is streamflow station 05GG001 (Environment Canada, 2015b).

in-stream controls on flow, shows the natural seasonal variability of streamflow, which peaks in June and is lowest in the winter months. The Coteau Creek station at Gardiner Dam on Lake Diefenbaker is able to store water to be used in the peak demand season. This is a useful means of matching hydroelectric production to demand.



(Source: SaskPower, 2014; Environment Canada, 2015b)

Figure 4-15 Saskatchewan Hydroelectricity Generation and Streamflow in the South Saskatchewan (S.SK) and North Saskatchewan (N.SK) Rivers (2009-2013)

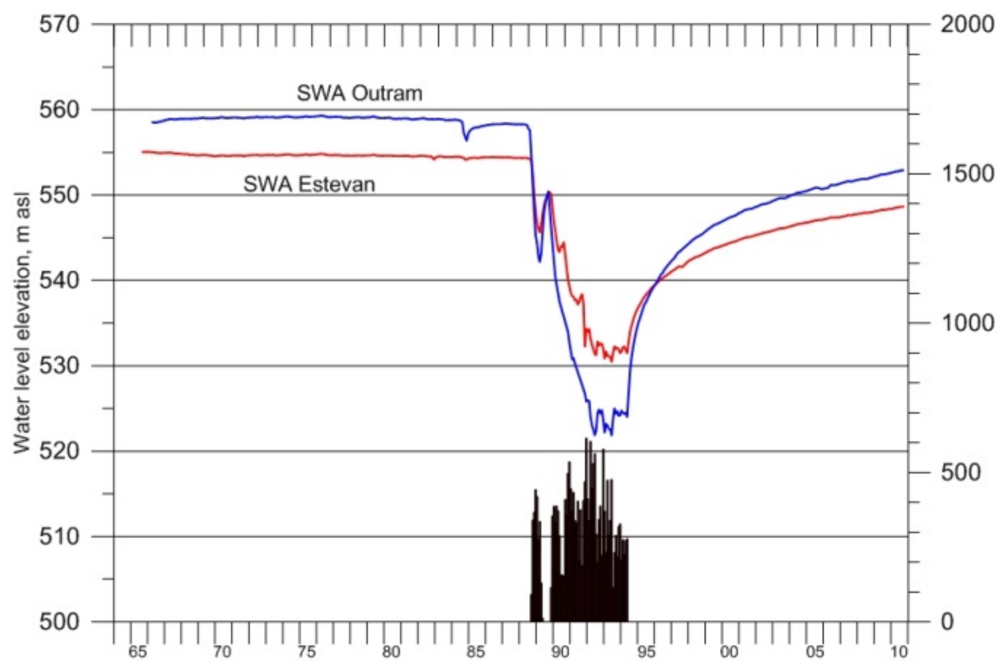
Streamflow and Coal-fired Generation

It is worth noting that streamflow is also crucial to topping up the cooling water reservoirs for Saskatchewan's coal plants. As Halliday (2013) explains,

> SaskPower's coal fired power stations in the Souris River basin near Estevan and the Poplar River basin near Coronach are dependent on prairie streams for their cooling water while the hydroelectric stations on the Saskatchewan River system depend on flows from rivers originating in the

Rocky Mountains. (Even if climate change is not considered, streamflow of prairie streams is much less dependable that that of mountain streams.) (p. 15)

During the late 1980s and early 1990s low streamflow led to a shortage of water at the Boundary Dam Reservoir, which is used to cool the Boundary Dam coal-fired power plant. To make up for the shortfall, groundwater was pumped from two underground aquifers. Figure 4-16 shows water withdrawals from the aquifer in black bars at the bottom. The impact of these withdrawals can be seen by the drop in the level of the Outram (blue line) and Estevan (red line) reservoirs. (Halliday, 2013)



(Source: Maathuis and van der Kamp, 2011)

Figure 4-16 Drawdown of Underground Aquifers for Boundary Dam Cooling

On the prairies moisture is never a certainty. The dustbowl of the 1930s still lingers in the collective memory. If the province's future electricity system is to be resilient it must be resilient against drought. During the dry period of the late 1980s and early 1990s groundwater met the needs for cooling Boundary Dam, but groundwater was depleted. The aquifers at Boundary Dam still had not fully recovered 15 years after the last water withdrawal from the reservoirs. This means that even thermal generating stations like coal-fired plants (and nuclear plants) are dependent on variable streamflow and limited stocks of groundwater. This variation may not have an impact on a seasonal timespan, but could become an issue if Saskatchewan were to experience a multi-decadal megadrought.

Summary

In this chapter I have identified the potential for renewable energy in Saskatchewan. The province is blessed with: high average wind speeds suitable for wind power; the best solar resource in Canada; hydroelectric potential on the Saskatchewan River and Churchill River systems; proximity to Manitoba Hydro's hydropower resources; and potential for a limited amount of biomass along the northern forest fringe. Table 4-6 summarizes Saskatchewan's physical renewable potential and the socio-economic factors that may limit this potential.

Energy Source	Physical Potential (GW)	Limiting Factors	Land Intensity (ha/MWac)	Variability
Wind	>4.00 GW	Siting conflicts	42.3	Hourly
Solar PV	Up to 5300.00 GW	Competing for agl land	3.2	Daily, seasonally
Solar Thermal	4000 - 8000.00 GW	Competing for agl land	2.0-4.0	Daily, seasonally
Hydroelectricity	2.64 GW	Social license	-	Seasonally, annually
Biomass	.15 GW	Available fuelstock	-	
Manitoba Hydro	2.00 GW	Grid interconnection	-	Seasonally, annually

Land Intensity Sources: NREL, 2009 (wind); NREL, 2013 (solar); Masters (2004)

Table 4-6 Saskatchewan's Renewable Energy Potential

Note that Table 4-6 does not consider the economic potential of these electricity generation sources. In the next chapter I evaluate the cost of the various renewable energy technologies and how they compare to alternatives like coal, natural gas, and nuclear power.

Chapter 5 – Levelized Cost of Electricity Generation

Electricity Generation Technologies

SaskPower is making decisions on how to meet Saskatchewan electricity demand by considering a range of generation technologies. In this chapter I explore the cost of building new capacity and generating electricity in Saskatchewan using the following technologies:

- Biomass;
- Conventional coal-fired generation;
- Coal-fired generation with carbon-capture and storage (CCS);
- Hydroelectric new-build;
- Hydroelectric repower (retrofit);
- Natural gas combined cycle;
- Natural gas combined cycle with CCS;
- Natural gas simple cycle (peaking plants);
- Small, modular nuclear reactors;
- Solar photovoltaic (utility-scale);
- Solar thermal (utility-scale);
- Wind turbines.

I am also interested in the cost of adding electricity storage to the Saskatchewan grid. Storage can be a useful way of addressing the variability of renewable energy output and, depending on the circumstances, should be included in the cost of renewables. Several technologies exist that could provide electricity storage in Saskatchewan including: lithium-ion batteries, compressed air storage, and pumped hydro storage. Compressed air storage may be particularly well-suited for Saskatchewan. It requires an underground cavern to store the compressed air. This cavern could be a former natural gas storage cavern or a solution-mined salt dome (Ford, 2015). Saskatchewan is home to both of these resources. I explore the question of storage further in Chapter 7.

There are several costs associated with installing and operating the electricity generation technologies listed above. These include the capital cost of building the technology, the cost of operating and maintaining the technology, fuel costs for coal, natural gas, biomass, and nuclear technologies, as well as technology-specific costs such as water usage charges for hydroelectricity, land leases for wind turbines, and nuclear waste storage costs for nuclear power plants. There are also financing costs associated with borrowing funds to purchase the technologies. In this chapter I outline the assumptions I have made with respect to each of these costs. These cost assumptions are used as inputs to the Saskatchewan Investment Model (SIM) and the interactive Saskatchewan Investment Model (iSIM) and play a key role in determining the least-cost scenarios selected by the SIM and iSIM optimization models.

Levelized Cost of Electricity

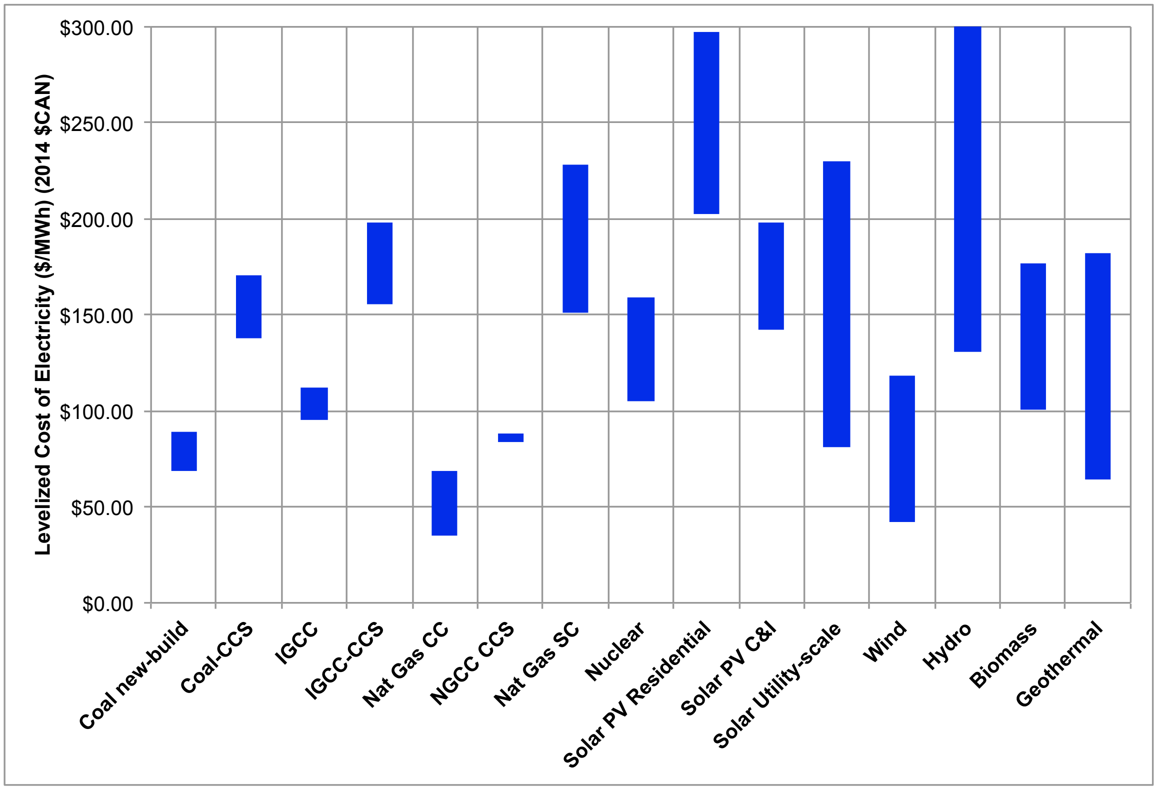
When comparing the costs of electricity generation technologies it is necessary to consider the operating characteristics of each technology. Electricity generation technologies differ with regards to capacity factors, expected life span, and fuel efficiency.[44] These differences in operating characteristics mean that technologies generate different quantities of electricity with the same installed capacity. For example, a 100 MW solar installation that operates at a 14-20% capacity factor will generate less electricity annually than a 100 MW coal-fired plant operating at 75-85% capacity factor. The Levelized Cost of Electricity (LCOE) takes these differences into consideration. LCOE is a measure of the average cost of electricity generation for a given technology

[44] EPRI (2013) explains capacity factor in the following way, “The maximum number of megawatt-hours that a plant could produce in one year would occur if the plant operated at full load 24 hours a day for 365 days a year. In reality, a plant will be shut down at times during the year, either for maintenance or because the electricity is not needed and it would be uneconomical to operate the plant” (EPRI, 2013: 24/1-7). The capacity factor of coal-fired and nuclear plants that are run fairly continuously throughout the year may be as high as 85-90%. Variable renewable electricity technologies like wind turbines do not operate in a continuous manner; electricity generation depends on the presence of wind. The capacity factor for Saskatchewan’s wind turbines in 2014 was 36.5% (SaskPower, 2015; author’s calculations). The life span of various electricity generation technologies also differs: wind turbines have a lifespan of about 20 years; hydroelectric facilities are relatively long-lived at 40 years or longer. For more information on fuel efficiency please see the technical appendix at the end of this chapter.

over its lifetime. It is expressed in either dollars per megawatt-hour ($/MWh) or cents per kilowatt-hour (cents/kWh) and it is the standard measure for comparing the costs of electricity generation technologies.[45]

Several recent studies have used the LCOE measure. Citigroup's Global Perspectives & Solutions (Citi GPS, 2015) published a report entitled *Energy Darwinism II* that used LCOE to compare the cost of climate action to the cost of climate inaction. Because LCOE includes fuel costs Citi GPS (2015) was able to demonstrate that renewables, despite their high capital costs, are rapidly becoming cost competitive with fossil fuel generation. Because of this Citi GPS (2015) found that climate action would actually save money relative to a path of climate inaction. Coad (2015) used LCOE numbers as the basis of a Conference Board study that included a focused look at the Saskatchewan electricity sector. Coad (2015) calculated the portfolio of electricity generation technologies that would minimize investor risk in the province. Lazard (2014) published the eighth edition of their levelized cost comparison in Fall 2014. It is widely cited in the electricity literature. The Global CCS Institute (2015) used LCOE to compare low-carbon technologies to the cost of CCS. They found that renewable technologies like wind, geothermal, and hydroelectricity, when available, provide lower cost GHG reductions than CCS. Figure 5-1 presents the range of LCOE values that result from the various cost assumptions presented in the literature. All figures have been converted to 2014 Canadian dollars (2014 $CAN) using the all-items consumer price index (Statistics Canada, 2015 CANSIM Table 326-0020) and average annual US-CAN exchange rates (Bank of Canada, 2015).

[45] As a long-term average LCOE does have the drawback of not considering the market value of electricity. Market prices can vary throughout the course of the day. Some technologies, like solar-PV may coincide with high demand and high demand in certain seasons. Others, like wind, may provide power during times when prices are low. LCOE misses these aspects of the value of electricity. Studies such as Dewees (2012) take into consideration the cost of electricity displaced by variable renewables.



(Sources: EIA, 2015; Lazard, 2014, EPRI, 2013; author's calculations)

Figure 5-1 Levelized Cost of Electricity from Electricity Cost Literature

Judging by the literature, natural gas combined cycle (NGCC) plants are the lowest cost generation option, followed by wind turbines in favourable locations, geothermal in favourable locations, and conventional coal-fired electricity plants.[46]

The LCOE numbers taken from the literature offer a rough guide to the cost of competing generation technologies, but the cost and availability of technologies differs in Saskatchewan relative to other jurisdictions. I use the LCOE methodology and Saskatchewan specific data to compare the cost of electricity generation technologies in the province. The methodology I have used to calculate LCOE is presented in Appendix 5A. The considerations I have made in undertaking this analysis are outlined in the sections below.

[46] Note that these LCOE numbers assume constant fuel prices as presented in EIA (2015), Lazard (2014), and EPRI (2013).

Saskatchewan Capital Costs

I gathered capital costs from published figures of projects built in Saskatchewan. When Saskatchewan project costs are not available I use cost input assumptions found in publications such as EIA (2015), Lazard (2014), and EPRI (2013). I find a range of capital costs for various energy generation technologies (Figure 5-2). The blue diamonds in Figure 5-2 indicate capital costs in dollars per kilowatt ($/kw) for SaskPower projects, or in the case of nuclear, for the most recent quote on nuclear power obtained in Canada. In the context of the present research the following findings are of particular interest. First, the cost of coal with carbon capture and storage (CCS) is significantly higher than estimates from the literature. Saskatchewan's Boundary Dam III CCS project is the first utility-scale CCS project in the world. The project was originally budgeted to cost $1.24 billion, but costs have increased to $1.46 billion (CAN) (IEAGHG, 2015). Costs were higher than expected due to factors such as a shortage of skilled workers in the province, which increased wages paid to labour, and challenges with retrofitting a brownfield power plant site (IEAGHG, 2015).

A second insight that should be highlighted is that there is a premium paid for thermal construction in Saskatchewan. Capital costs for natural gas combined cycle plants built in Saskatchewan, including the North Battleford Generating Station and the retrofit to the Queen Elizabeth II power plant in Saskatoon, are approximately 2.6 times higher than EIA (2015). Costs for simple cycle natural gas plants are on average 1.8 times higher than EIA (2015). To account for this premium I apply a cost multiplier of 2.0 to EIA (2015) estimates of natural gas combined cycle with CCS costs. This may be an optimistic multiplier for an un-tested technology like natural gas with CCS.

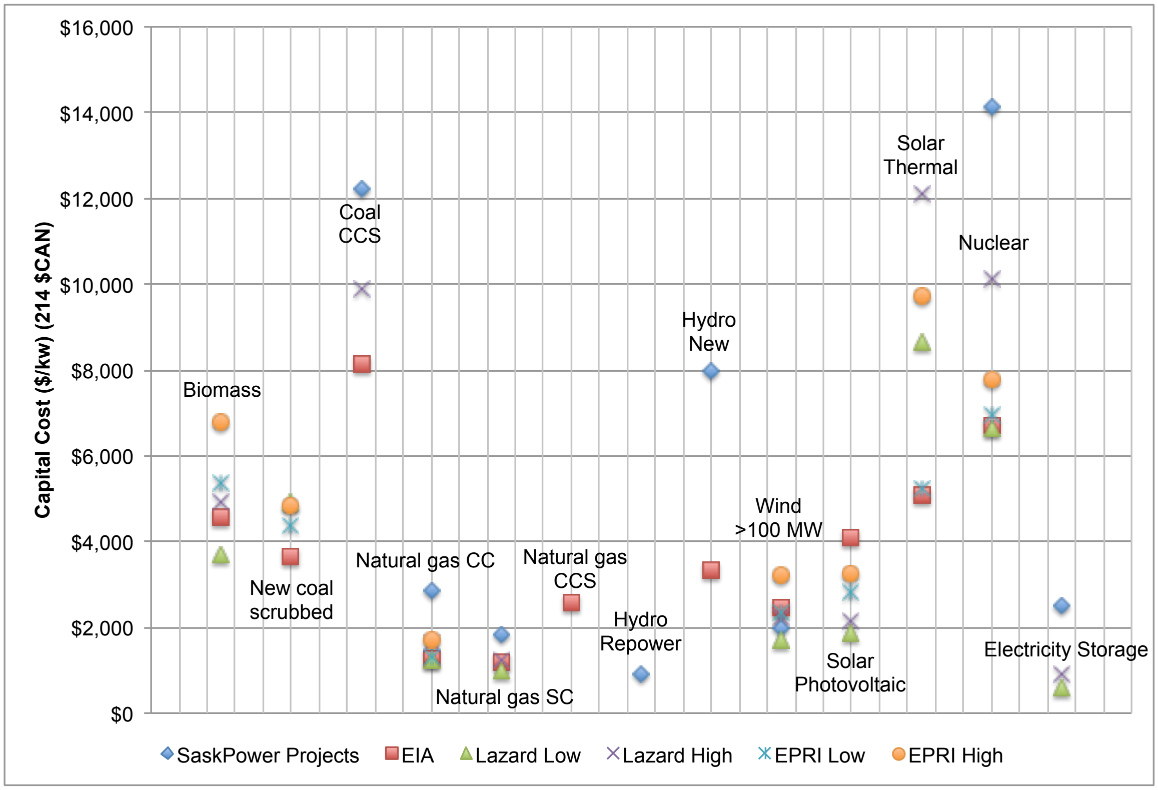


Figure 5-2 Capital Costs of Electricity Generation Technologies

A third finding is that new hydroelectric projects in Saskatchewan cost significantly more than estimates from the EIA (2015). The Tasi Twe project in northern Saskatchewan is anticipated to cost $8000/kw. This is 2.4 times higher than the EIA (2015) estimates for hydroelectricity. Hydroelectric costs may be lower for projects on the Saskatchewan River system and the Churchill River. I model the costs of hydroelectricity as increasing in a step-wise fashion. Based on discussion with SaskPower I estimate that the lowest cost projects will cost $6000/kw and the highest cost projects will cost upwards of $15,000/kw (Interview 26).

Lastly, I find that estimates found in the literature for the cost of conventional nuclear range widely from a high of over $10,000/kw to a low of $6650/kw (Lazard, 2014). Even these high estimates may be too optimistic. As mentioned in Chapter 3, in 2009 the Ontario Power Authority received a $26 billion dollar bid from AECL to build two 1200 MW CANDU reactors (Hamilton, 2009). This is a capital cost of $11,800/kw (2014 $CAN). While there are some who argue the OPA quote was too high, it is noteworthy because of the nature of the quote; OPA would not allow cost over-runs, AECL would receive only the price quoted in their proposal. The nuclear industry in Canada has experienced notorious cost over-runs and delays. The Point Lepreau nuclear facility in New Brunswick was three years behind schedule and cost "between two to three times more than the original cost estimate" (Locke and Townley, 1993: 10). Contractors building the Point Lepreau plant received "cost plus" and "cost reimbursable" contracts; if the project went over-budget contractors would still be paid (Locke and Townley, 1993). Because the OPA would not allow "cost plus" contracts the quote should be seen as closer to reality than more optimistic nuclear cost estimates.

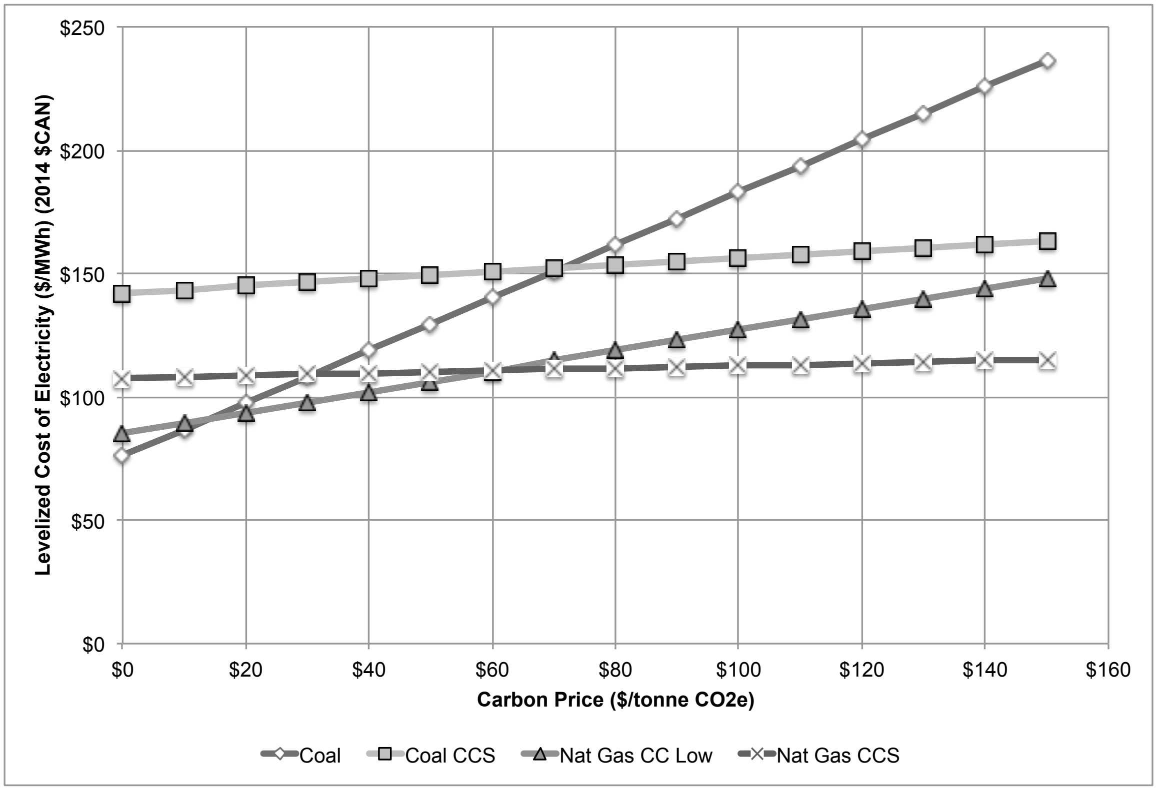
It is important to recognize that the OPA capital cost estimate was for CANDU nuclear reactors, which are typically sized 750-1200 MW, and which are a mature technology. Saskatchewan's grid is ill-suited for such large power plants (see Chapter 3). Instead, small, modular nuclear reactors (SMRs) are being considered for the province. SMRs are a new technology and as such, there are substantial "first-of-a-kind" risks in constructing them. There is reference to the costs of small-modular nuclear reactors (SMRs) in a report by the Australian government (BREE, 2012). First-of-a-kind SMRs are estimated to cost 1.88 times more than larger light-water reactors, while nth-of-a-kind SMRs (those built after many other units have been constructed) are estimated to cost 1.38 times more (BREE, 2012). The capital cost of SMRs ($/kw) are higher than larger reactors because of the loss of economies of scale (Cooper, 2014). Gains from modular construction are not likely enough to make up for the loss of economies of scale. Cooper (2014) estimates that SMR capital costs may be 5-30% more expensive than large reactors. SMRs will also use more fuel and produce more waste per MWh. One potential advantage of modular reactor technology is that SMRs may reduce construction time from 69 to 38 months (Cooper, 2014).

I estimate that the construction of a first-of-a-kind SMR would cost over $14,000/kw in Saskatchewan, or about 18.6% more than the 2009 OPA reactor cost estimate from AECL. If many of these units are installed around the world I estimate that the nth-of-a-kind cost could be reduced to $10,350/kw.

Sensitivity to Carbon Pricing

The LCOE of a fossil-fuel technology will be affected by the imposition of carbon pricing. I find that technologies that use coal and natural gas as fuels are quite sensitive to carbon pricing. In Saskatchewan, coal fired power plants emit roughly 1080 tonnes CO_2e/MWh. When equipped with carbon capture and storage (CCS) technology, 90% of these emissions can be captured. However, there is a substantial parasitic load involved in capturing CO_2. At the Boundary Dam III CCS facility a 160 Megawatt (MW) generation unit is rated at 120 MW available power. The other 40 MW are required to run the CCS processes. This means the emissions intensity of coal-fired generation with CCS is not 10% of the intensity of coal-fired generation without CCS but is actually 143 tonnes CO_2e/MWh, which is 13.2% of the existing GHG intensity.

Natural gas combined cycle facilities in Saskatchewan have an emissions intensity of approximately 420 tonnes CO_2e/MWh. If natural gas combined cycle plants are equipped with a CCS system then 90% of their emissions can be captured and stored. There is again parasitic power demand to run the CCS process. I estimate that natural gas with CCS will lead to a 20% penalty in fuel efficiency. With this parasitic load considered, natural gas with CCS can reduce emissions intensity to approximately 50 tonnes CO_2e/MWh.



(Source: author's calculations)

Figure 5-3 Sensitivity of Fossil Fuel LCOE to Carbon Pricing[47]

Figure 5-3 shows the sensitivity of the LCOE of fossil fuel electricity generation to carbon pricing (holding other cost and performance assumptions constant). At a carbon price of roughly \$70/tonne CO_2e, new-build coal-fired generation becomes more expensive per megawatt-hour than Saskatchewan's Boundary Dam III CCS plant. At a carbon price of \$15/tonne CO_2e conventional coal becomes more expensive than natural gas combined cycle electricity generation. With a carbon price of \$60 and higher, natural gas with CCS becomes the least expensive fossil-fuel based electricity generation option.

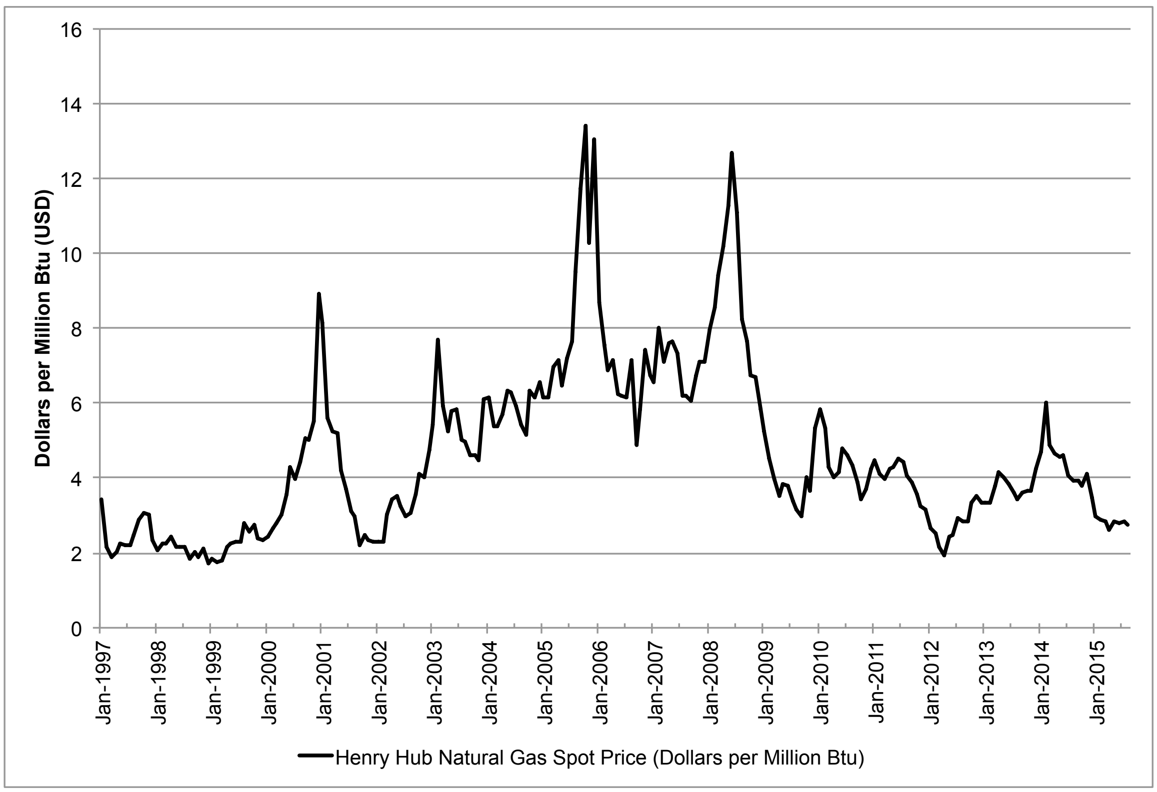
In making decisions about the future of Saskatchewan's electricity system it is sensible to consider the possibility of federal or provincial carbon pricing. British Columbia has instituted a carbon price that now sits at \$30/tonne CO2e and is applied to fuels used in the electricity sector like natural gas and, theoretically, coal although B.C. does not use coal for electricity generation (B.C. Government, 2014). If a carbon price were enacted in

[47] Costs and fuel efficiency rates in this diagram are based on the initial model values selected for use in the baseline scenarios.

Saskatchewan natural gas with CCS would be roughly cost-equivalent to new-build coal-fired generation.

Fuel Cost Escalation and LCOE

Along with carbon price risks there are also fuel price risks that can influence the levelized cost of electricity (LCOE).[48] Natural gas is an especially volatile commodity. In the past decade, natural gas delivered at The Henry Hub has varied in price from highs of \$13.42 USD/Million BTU in October 2005 and \$12.69 USD/MMBTU to a low of \$1.95/MMBTU in April of 2012 (See Figure 5-4).[49] The Henry Hub price for August 2015 remained low at \$2.77 USD/MMBTU.



(Source: EIA, 2015)

Figure 5-4 Natural Gas Price at Louisiana's Henry Hub

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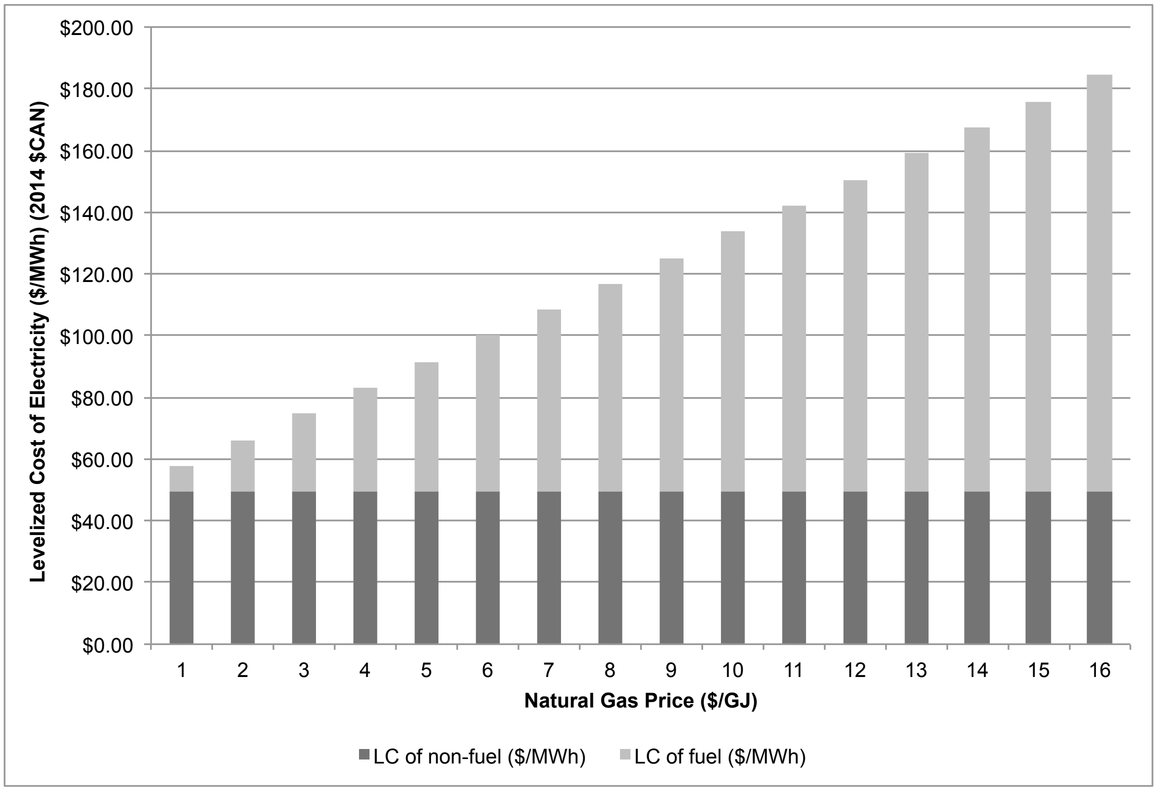
[48] Appendix 5A outlines the method I use to calculate fuel use for fossil fuel technologies.

[49] Henry Hub is a natural gas distribution hub in Louisiana. Natural gas prices at the Henry Hub are regularly used as a benchmark for natural gas pricing.

SaskPower has felt the pinch of high natural gas prices in the past. As noted in Chapter 3, during the natural gas price spike of 2000-2001, SaskPower was "getting hammered by natural gas prices, just creamed!" (Wright, 2014). For every $1 per gigajoule increase in the price of natural gas the LCOE of natural gas combined cycle power increases by about $8.50/MWh (Figure 5-5).



(Author's calculations)

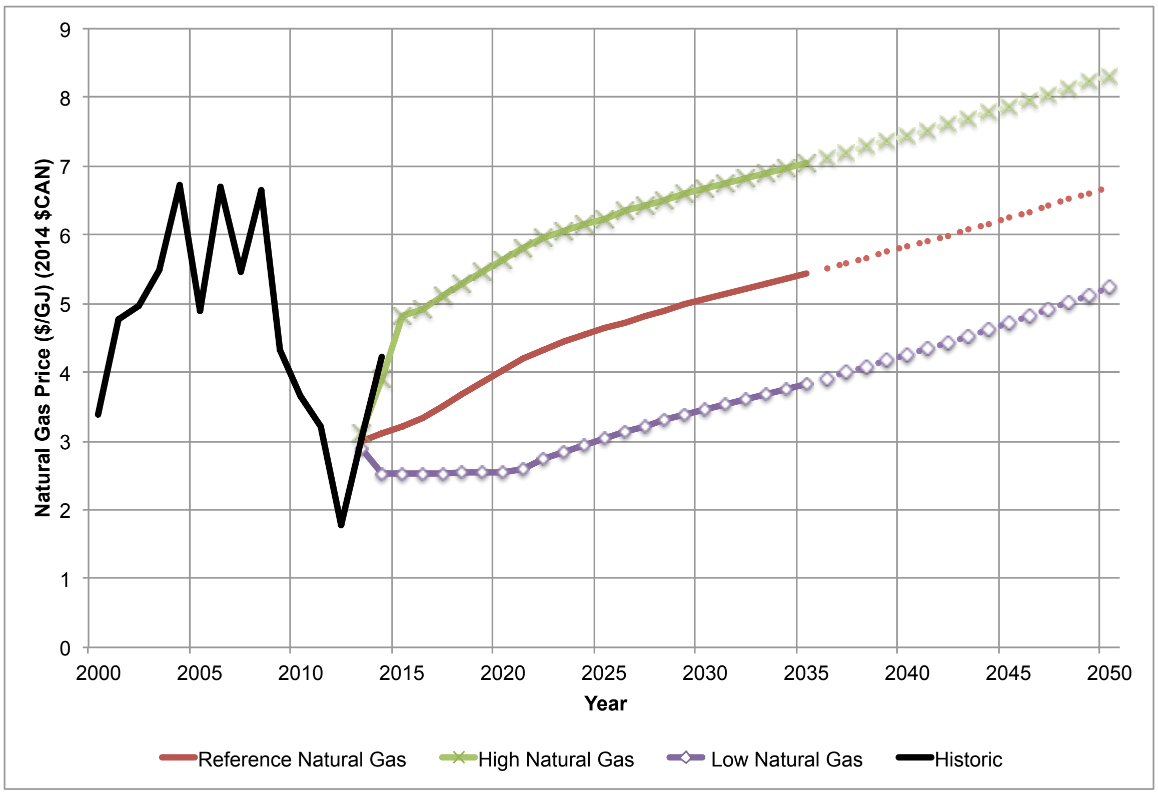
Figure 5-5 Sensitivity of Natural Gas Combined Cycle LCOE to Natural Gas Prices

The future of natural gas prices is uncertain. Advances in hydraulic fracturing technology (or 'fracking') have unlocked natural gas deposits that were previously thought inaccessible. This has increased natural gas supplies and put downward pressure on prices, though for how long is unclear. Fracking has not been without problems and controversy. Fracturing rock beneath the earth can cause earthquakes (Rubinstein and Mahani, 2015).[50] In 2014 fracking "triggered a 4.4-magnitude earthquake in northeastern

[50] Hydraulic fracking is not causing all of the induced earthquakes in North America; wastewater injection from oilfields, and injection for enhanced oil recovery also created

B.C." (CBC, 2015c). Fracking also requires the injection of a cocktail of chemicals, the composition of which is patent-protected. There are concerns that these chemicals will enter groundwater reservoirs and cause water quality problems. These concerns led Québec, Nova Scotia, New Brunswick, and New York to pass laws banning fracking (Leslie, 2015). Fracking bans have the effect of reducing potential natural gas supply, putting upward pressure on natural gas prices.

Canada's National Energy Board (NEB, 2014a) has created three natural gas price forecasts for 2013-2035. These forecasts are specifically for natural gas prices paid by industry in Saskatchewan (Figure 5-6). The historic time series displays average annual natural gas prices and so hides temporary spikes of the kind shown in Figure 5-4.



(Sources: NEB, 2014a; Statistics Canada, 2015 CANSIM Table 129-0003; author's calculations 2035 - 2050)

Figure 5-6 Saskatchewan Industrial Natural Gas Price Forecast

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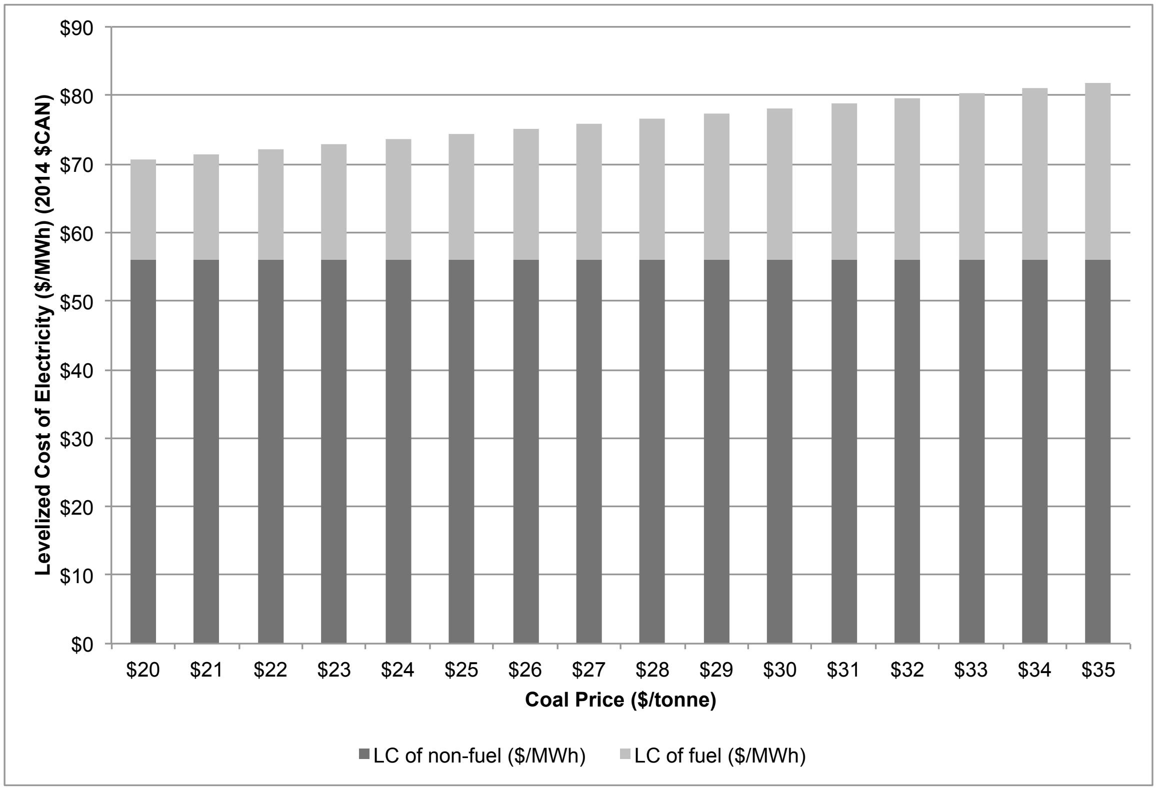
induced earthquakes. Induced earthquakes due to hydraulic fracking are, however, most common in Western Canada. (Rubinstein and Mahani, 2015)

The natural gas price forecasts provide a range of potential values that are within the realm of historic variability. Each forecast tracks upwards over time. I extend the NEB (2013) forecasts to 2050 by increasing prices at the compounding annual growth rate calculated for each series from 2030-2035. For the optimization model (see chapter 7) I use the NEB (2013) reference scenario and then conduct a sensitivity analysis using the high and low price forecasts as the bounds of the 90% confidence interval.

Coal prices will impact the LCOE of coal-fired electricity in Saskatchewan. Saskatchewan's coal-fired plants were built in the lignite fields of south and south-east Saskatchewan. Coal is purchased on long-term agreements from local suppliers in Saskatchewan such as Westmoreland Coal. In the first quarter of 2015 Westmoreland reported revenues of $103.2 million and sales of 5.5 million tonnes of coal, which implies a coal price of $18.77 USD/tonne (Westmoreland Coal, 2015a). Saskatchewan accounts for a large share of Westmoreland's coal sales so I assume that SaskPower pays the average price of Westmoreland's Canadian coal, or approximately $23/tonne (2014 $CAN). Figure 5-7 reports the impact of coal prices ranging from $20/tonne to $35/tonne on the LCOE of conventional new-build coal in Saskatchewan. The fuel cost for coal composes 21% of the total LCOE when coal is $20/tonne and increases to 31% of the LCOE when coal is at $35/tonne.



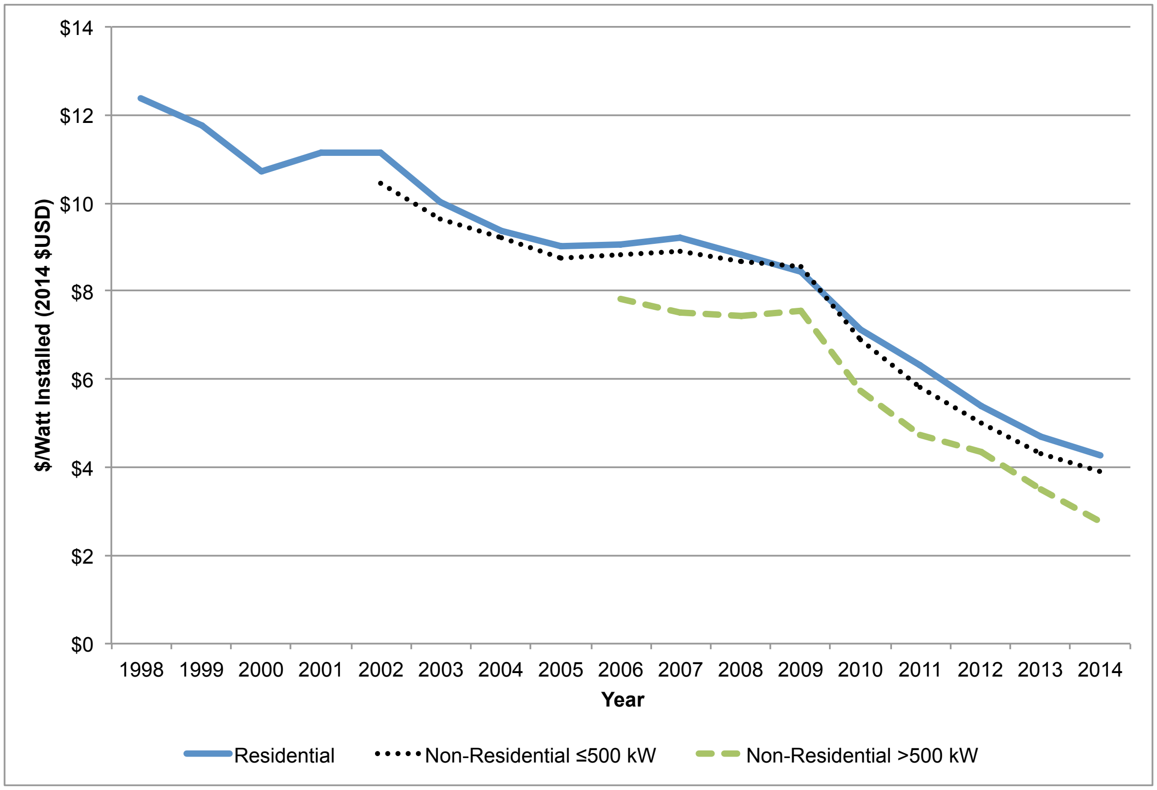
(Sources: Westmoreland, 2015a; author's calculations)

Figure 5-7 Sensitivity of Coal LCOE to Coal Prices

The availability of "cheap, lignite coal" in Saskatchewan has made fuel a small portion of the LCOE, especially relative to natural gas fuelled plants. Coal prices are expected to escalate in Saskatchewan over time. Coal contracts with local suppliers come with built-in escalation factors. Based on historical coal prices in Saskatchewan I estimate that real coal prices will escalate at 1.25%/year from 2015-2050 (Sherritt, 2003; Sherritt, 2012).

Technological Progress and LCOE

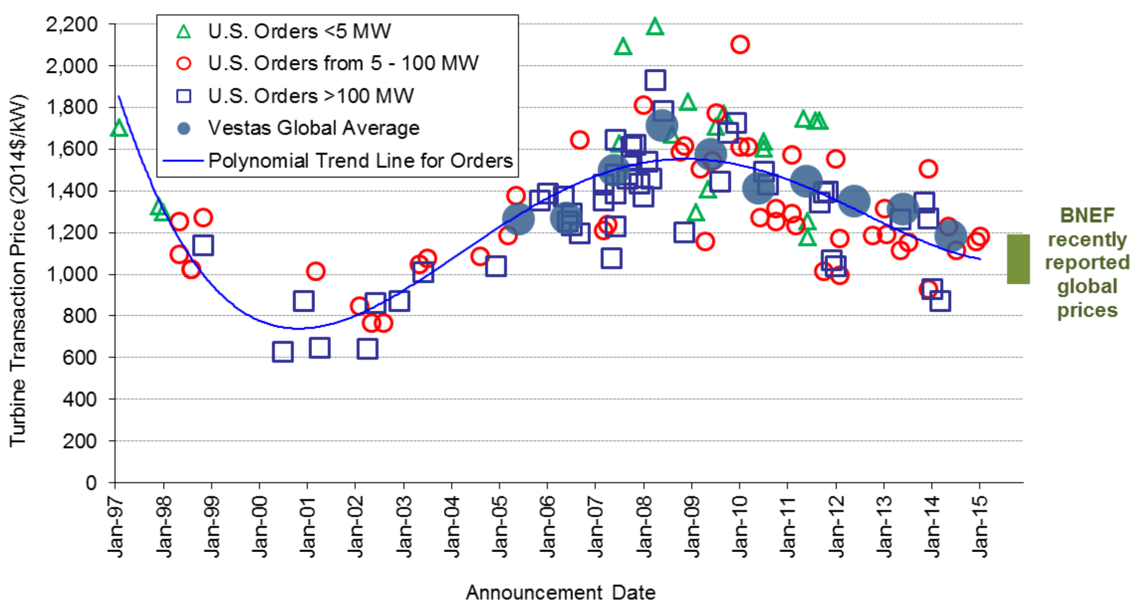
The costs associated with electricity generation technologies are not static over time. Increased regulatory constraints can increase costs. Technological progress can decrease costs. Solar costs have fallen steadily in the United States, especially in the period from 2010-2014. Figure 5-8 show changes to the installed capital costs of solar since 1998. These substantial and rapid cost improvements have greatly improved the economics of solar power.



(Data source: LBNL, 2015)

Figure 5-8 Falling Installed Cost of Solar Photovoltaics

Wind turbine costs have also not been static. In the past two decades real wind turbine costs have fallen, risen, and then fallen again (See Figure 5-9). In recent years innovations such as taller turbines with larger rotor diameters have increased the power rating of turbines and decreased the cost per megawatt installed. These cost improvements have made wind power one of the lowest cost means of generating electricity in places with good wind resources.



(Source: U.S. DoE, 2015: 47)

Figure 5-9 Wind Power Transaction Prices in the United States (1997-2015)

The rate at which costs change is called the "learning rate". Learning can be modeled as an exogenous force acting upon costs, or as an endogenous outcome of "learning-by-doing" (Löschel, 2002). From a "learning-by-doing" perspective, costs change as experience is built up installing a technology. For example, Citi GPS (2015) comments on learning rates that have occurred with a doubling of installed capacity,

> Solar in particular was exhibiting learning rates in excess of 20% (i.e. the cost of a panel would fall by >20% for every doubling of installed capacity), wind at 7.4%, gas was evolving via the shale revolution in the US, while nuclear was becoming more expensive, and liquefied natural gas (LNG) had also increased in cost... (Citi GPS, 2015: 46)

Endogenous learning-by-doing models are useful when analyzing changes to costs in large economies like the United States whose market size is large enough to generate learning-by-doing effects. At just under 5000 Megawatts (MW), the province of Saskatchewan has a relatively small electricity system. Saskatchewan purchases of electricity generation technology are too small to induce noticeable learning-by-doing effects. For this reason I treat learning as something that happens outside of Saskatchewan and I treat learning rates in Saskatchewan as exogenous cost improvements per year. Citi GPS (2015) translates learning rates for wind and solar into the following annual averages, “For solar PV modules the year on year reduction would amount to 2% whilst for onshore wind this number is 1%” (p. 47).

Coad (2015) uses a simple exogenous learning rate equation to model changes to technology costs over time,

$$Eq. 5.1\ \ Cost_t = Cost_0 * exp^{-\gamma t}$$

Where,
γ = learning rate
t = time.

I also use Equation 5.1 to represent learning. This type of equation can be used to calculate or apply average annual learning rates.

I calculate learning rates for each technology using data from EIA (2014). This report presents levelized cost of capital, variable O&M, and fixed O&M costs for 2019 and 2040. I use Equation 5.1 to estimate the learning rate implied by the cost changes in EIA (2014). These learning rates are summarized in Table 5.1. EIA (2014) is optimistic that capital costs for nuclear will fall by 1.54%/yr. Estimates for the annual capital cost improvement of solar are 1.25%, a figure lower than the current rate of cost improvement.

	Capital Cost	Fixed O&M	Variable O&M
Biomass	1.16%	0.09%	-0.06%
Coal	0.94%	-0.06%	-0.10%
Coal CCS	0.54%	0.47%	-0.43%
Hydro	0.37%	-0.55%	-0.37%
Nat Gas CC	1.15%	-1.25%	0.00%
Nat Gas CCS	1.50%	-1.27%	-0.10%
Nat Gas SC	0.92%	-1.17%	-0.15%
Nuclear	1.54%	-0.30%	-0.07%
Solar PV	1.25%	1.00%	-0.57%
Storage	1.50%		
Wind	0.87%	1.00%	-0.06%

(Source: EIA, 2014; author's calculations)

Table 5-1 EIA Learning Rates from 2019-2040

The learning rates in Table 5-1 offer a starting point for forecasting cost improvements, but they are not the final word on technological progress. As mentioned above, Citi GPS (2015) has found that solar photovoltaic costs have been declining at a rate closer to 2%/yr than 1.25%/yr. Wind has been declining at a rate closer to 1%/yr (CitiGPS, 2015). The EIA (2014) numbers also imply a high learning rate for nuclear that is not supported by historical experience. Recent audits of the French nuclear program have revealed cost increases rather than cost reductions; a negative learning rate (Grubler, 2010). Boccard (2014) used French audit data to estimate growth in real costs of 2.1%/yr for French nuclear technology. CitiGPS (2015) also writes that little is expected in the way of cost improvements for nuclear technology since it is a mature technology. The cost of SMRs may, however, decline if they are put into production at a large scale. The promise of SMRs is also that they will lower construction timelines. This will impact the cost of financing for a nuclear project. For the numbers summarized below in Figure 5-10, reducing the duration of construction from 69 months to 36 months would lower the LCOE by nearly $13/MWh.

Future learning rates are a source of uncertainty and a candidate for sensitivity analysis. Figure 5-10 shows the impact of a range of learning rates on the LCOE of nuclear power from SMRs. The low cost line in Figure 5-10 presents the LCOE cost improvements that would result from the EIA (2015) learning rate of 1.5%. The high cost line presents the impact of negative learning at -1.5%. Cost increases in France's nuclear program were driven by safety concerns (Cooper, 2014). Safeguards against nuclear accident have made nuclear designs more complex and this has increased costs. Cooper (2014) argues that this is an inherent property of nuclear power systems, which rely on a "catastrophically dangerous resource that is vulnerable to human frailties and the vicissitudes of Mother Nature" (Cooper, 2014: 174). On the other hand, wind and solar electricity generation technologies are considered relatively benign. Their components are amenable to mass production, which can create economies of scale in the manufacturing process. These attributes have likely contributed to the rapid decline of solar photovoltaic costs but it remains unclear how long they will continue and at what rate. I consider a range of learning rates in the sensitivity analysis of scenario costs in Chapter 8.

Financing Costs

There are costs associated with obtaining the necessary funds for capital projects. In their latest Annual Report, SaskPower notes that it "raises most of its capital through internal operating activities and through borrowings obtained from the Government of Saskatchewan Ministry of Finance" (SaskPower, 2015: 67). In 2014 SaskPower had \$4250 million in recourse debt obtained as advances from the Government of Saskatchewan's General Revenue Fund (GRF).[51] The province currently sits in a relatively strong financial position and as such is able to access low cost debt financing. In both 2013 and 2014 the Government of Saskatchewan had a credit rating of AA on long-term debt obligations (SaskPower, 2015: 67). In the low-interest environment of 2014, SaskPower was able to obtain long-term financing of \$675 million at effective interest rates that varied from 3.43% to 3.95% (SaskPower, 2015: 70).[52] As a Crown Corporation, SaskPower is wholly owned by the Government of Saskatchewan through

[51] Note that the term for most of SaskPower's debt is approximately 30 years from the date of issue.

[52] SaskPower also accessed \$100 million in financing at a floating interest rate and borrowed "\$86 million in short-term advances" from "the Government of Saskatchewan's General Revenue Fund" with "interest rates ranging from .997% to 1% and maturity within 2015 (SaskPower, 2015: 70).

the Crown Investment Corporation (CIC). CIC issues equity advances to SaskPower. As of December 31st, 2014 SaskPower had $660 million in equity advances from CIC. SaskPower has a long-term target for return on equity of 8.5% (SaskPower, 2015: 39). However, due to the need for substantial investment in the Saskatchewan electricity system the Government of Saskatchewan has opted not to take dividends from SaskPower for the foreseeable future. It seems appropriate therefore to model the cost of capital as consisting entirely of debt financing at 4%/yr interest, a rate slightly higher than the current low interest rates charged for long-term debt and which anticipates the possibility of a rate increase.[53]

Private power producers do not have access to the favourable financing terms that SaskPower receives, and instead have higher return on equity targets for their shareholders. This means that private power projects will face higher financing charges. This has implications for the comparative costs of public versus private construction. In the SIM model I make the simplifying assumption that all new capital is constructed by SaskPower.

Financing costs also include interest that accumulates on capital during the construction period. Technologies with long construction periods such as nuclear and coal-fired plants will accumulate more interest. I add interest incurred during the construction period to the capital cost and amortize the whole amount over the expected lifetime of the technology. Details on my methodology can be found in Appendix 5A.

Other Costs

There are other technology-specific costs that can be considered in a calculation of LCOE:

[53] SaskPower had a debt-equity ratio of 73.5% as of December 31, 2014, meaning that debt financing currently accounts for 73.5% of total financing. This is a change from December 31st, 2013 when the debt-equity ratio was 69.8%. This number is forecast to continue to creep upwards; by 2017 the debt ratio (%) target is 77.3%. This reflects the period of intensive investment currently occurring at SaskPower. (SaskPower, 2015)

- In Saskatchewan, hydroelectric facilities pay water royalties at a rate of \$5.10/MWh electricity generated (Interview 24). I assume this cost is included in the variable operations and maintenance cost of hydroelectricity, which I have set at \$7.20/MWh;
- All facilities will also incur decommissioning charges at the end of their life. Nuclear power plants require especially large decommissioning costs due to the hazard of radioactivity. Boccard (2014) estimates that decommissioning of French nuclear reactors will cost 25% of the original investment cost. Due to a lack of data I have not included decommissioning costs, which would appear to favour, in relative terms, nuclear power;
- Nuclear power plants must also pay for the long-term storage of spent nuclear fuel. EPRI (2013) adds \$1/MWh to the variable operations and maintenance (O&M) costs of nuclear power plants to represent the amount that would be paid to a nuclear waste management organization. Canada's Nuclear Waste Management Organization makes the same estimate for the cost of long-term waste disposal (NWMO, 2015). I have used a variable O&M cost for nuclear on par with EPRI (2013).;
- Fossil fuel plants emit pollutants beside CO_2. Coal plants in particular emit sulphur dioxide (SO_2), particulates, and mercury. DSS (2005) quantified the health impacts resulting from these pollutants in Ontario and found the health costs of an electricity futures scenario that maintained the Ontario electricity generation mix at the status quo proportions that existed in 2005 – which included a substantial amount of coal-fired generation – to be three times higher than the financial cost. I have not included health costs in the LCOE figures below, which means that the fossil-fuel costs are conservative estimates.
- The use of carbon dioxide (CO_2) for enhanced oil recovery (EOR) will produce oil that has a 10.8% higher GHG intensity than an average barrel of conventional oil, but 11.5% lower GHG intensity than oil extracted from the oil sands. The EOR operation will also lead to CO_2 emissions on-site. This leads to "a net on-site storage of .696 TCO2e per 1 TCO2e brought to the site" (Wong *et al*., 2013: 8). I

do not consider the GHG implications of EOR in this analysis. (Wong *et al.*, 2013)

Other Benefits

Part of the motivation for the Boundary Dam III carbon capture and storage (CCS) project was to provide a source of CO2 for enhanced oil recovery (EOR) (IEAGHG, 2015). SaskPower sells CO2 to the oil company Cenovus for around $22.50/tonne CO2 (Glennie, 2015). This represents a potential revenue stream for the Boundary Dam project.[54] In Figure 5-10 I include two measures of LCOE for Boundary Dam with (SaskPower Low) and without (SaskPower High) the revenue from sales of CO_2. SaskPower is also able to sell sulphuric acid from the Boundary Dam project. The revenue from these sales is limited (Glennie, 2015) and I have excluded it from the LCOE calculations.

Cost Assumptions

I gathered electricity cost information from published estimates of Saskatchewan built projects and the energy cost literature (EIA, 2015; Lazard, 2014; EPRI, 2013). I adjusted all costs to Canadian 2014 constant dollars using U.S. exchange rate data from the Bank of Canada (Bank of Canada, 2015) and the Canadian All-items Consumer Price Index (Statistics Canada, 2015 CANSIM Table 326-0020).

The initial LCOE calculations for coal and natural gas fired plants (shown below in Figure 5-10) assume constant fuel prices equivalent to current rates ($4.22/GJ for natural gas and $23.18/tonne for lignite coal). They are thus conservative estimates as fuel prices

[54] This potential source of revenue can also be a financial liability. SaskPower has signed a contract with Cenovus to deliver a certain quantity of CO_2 for enhanced oil recovery. If SaskPower cannot deliver the CO_2 and meet its contractual obligations it must pay a penalty to Cenovus. This occurred in 2014 and 2015 when – due to technical problems at the new plant – Boundary Dam III has operated at less than full capacity. This has meant that SaskPower has only been apply to supply half of the 800 kilotonnes of CO_2 is was supposed to provide Cenovus in 2015. By October 2015 SaskPower had paid $12 million in penalties to Cenovus and was on track to face another $5-6 million in penalties by the end of 2015. (Leo, 2015)

will likely rise. I allow fuel prices to rise in the scenarios I consider in Chapter 7. I assume the NEB (2013) reference price forecast for natural gas (see Figure 5-6), and coal price escalation at 1.25% per year.

Levelized Cost of Electricity

Table 5-2 summarizes the values I use to calculate the LCOE of each technology. I also use these as starting values in the scenario optimization analysis summarized in Chapter 7. Figure 5-10 presents the LCOE numbers that result from these assumptions and compares the LCOE numbers to those based on the literature.

For reference I have included the costs of integrated gasification combined cycle (IGCC) coal-fired technologies, but I have not included those in the simulation model used in Chapter 7. Instead, I have included only one coal-fired generation with CCS technology option that matches the cost profile of the Boundary Dam III project. Also note that solar thermal electricity ranges in LCOE from \$386/MWh to \$772/MWh. For visual clarity (to avoid skewing the y-axis) I have not included solar thermal in Figure 5-10. Lastly, the model value shown for hydroelectricity is based on a capital cost of \$6000/kw. Hydroelectricity costs in the simulation model increase in a step-wise fashion to the 'SaskPower high' LCOE as low-cost hydroelectric capacity is developed in the province.

	Co	Vo	Fo	Life	Capacity Factor	FuelEff	Heat Rate (Btu/kwh)	GHG Intensity (kt/MWh)	LCOE ($/MWh)
Biomass	5,000	12.0	115.0	20	0.85	24%	14,500	-	$96
New coal scrubbed	4,500	5.6	70.0	30	0.85	34%	10,000	1.07	$76
Coal with CCS (Boundary Dam)	13,336	10.5	95.0	30	0.85	26%	13,333	1.43	$171
Natural gas combined cycle	2,878	3.5	14.5	25	0.54	43%	8,000	0.42	$85
Natural gas simple cycle	1,810	12.0	15.5	25	0.4	28%	12,000	0.63	$106
Natural gas CCS	5,200	8.5	40.0	25	0.7	36%	9,600	0.50	$118
Hydro Repower	900	7.2	19.0	40	0.56	33%	-	-	$21
Hydro South	6,000	7.2	19.0	40	0.56	33%	-	-	$79
Hydro North	8,000	7.2	19.0	40	0.56	33%	-	-	$102
Wind	2,006	-	47.0	20	0.365	37%	-	-	$60
Solar - PV (Utility-scale)	3,000	-	26.0	20	0.16	33%	-	-	$173
Solar - Thermal	8,000	-	99.0	20	0.16	33%	-	-	$483
Small Modular Nuclear Reactor	14,119	1.7	154.3	25	0.85	33%	10,450	-	$176
Electricity Storage	1,500	-	30.5	20	0.21	33%	-	-	-

(Source: author's calculations; EIA, 2015; Lazard, 2014; EPRI, 2013)

Table 5-2 Cost Assumptions for Saskatchewan Electricity Technologies

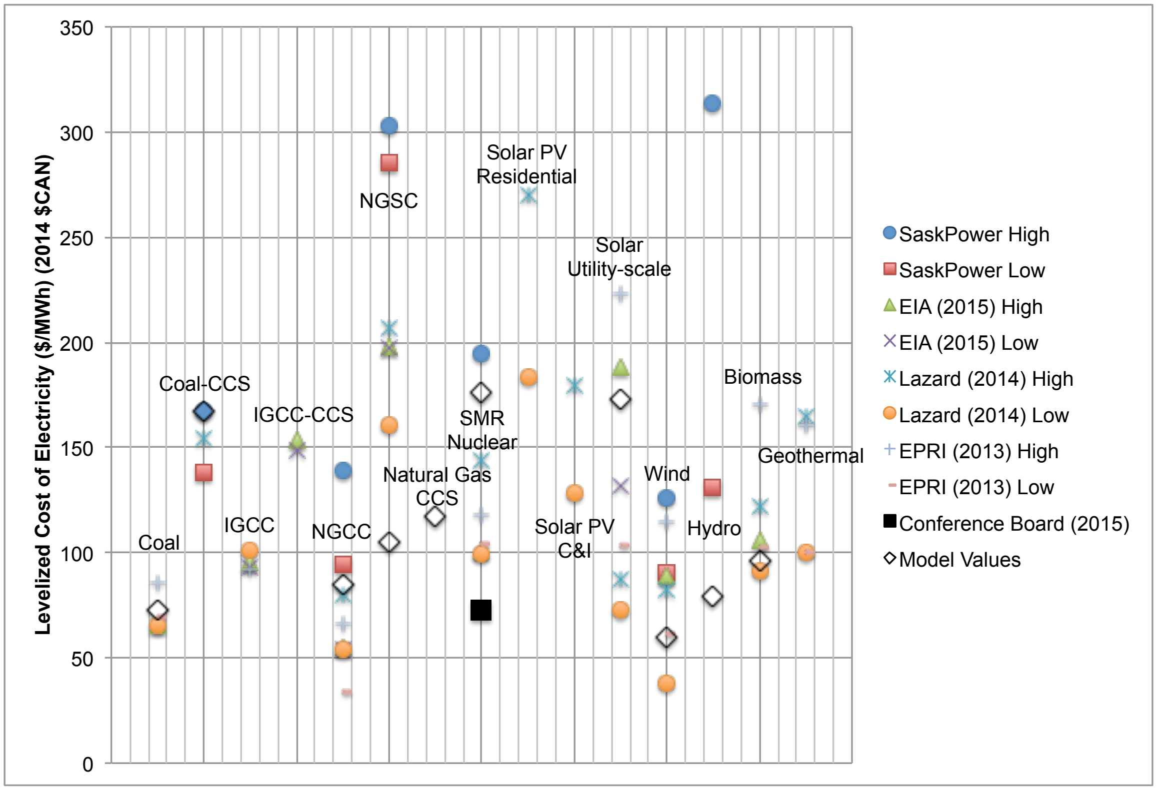


Figure 5-10 Levelized Cost of Electricity by Reference Source

Summary

In this chapter I explored the costs of constructing and operating new electricity generation facilities in Saskatchewan. Based on these calculations wind power is estimated to be the lowest cost electricity generation technology in the province (Figure 5-10). There is a significant opportunity to expand wind power in the province. However, wind expansion will have to consider the issues of variability identified in Chapter 4, which will lead to additional costs that are not yet included in the LCOE numbers above. The costs of the storage and back-up necessary to integrate wind onto the electricity system are included in Chapters 7 and 8. My estimates also indicate that the best hydroelectric locations are also highly cost-effective. As these low-cost sites are developed the cost of hydroelectricity will increase.

Natural-gas fired generation with CCS is a low-carbon fossil-fuel technology that is less expensive than coal-fired generation with CCS. All of the natural-gas fired generation technologies are, however, vulnerable to natural gas fuel price increases.

Other low-carbon technologies such as coal-fired generation with CCS and nuclear power are estimated to be considerably more expensive than the current wholesale price of power, which lies between $50/MWh and $70/MWh for large electricity customers (SaskPower, 2015). Utility-scale solar power is notably on par with coal-fired generation with CCS and small, modular nuclear reactors. Solar costs are also falling rapidly suggesting that solar will likely soon be less expensive than either of these technologies. Solar, like wind, does require a system designed for variability. The costs of integrating solar are included in the scenarios outlined in Chapters 7 and 8, but are excluded from the LCOE numbers in Figure 5-10.

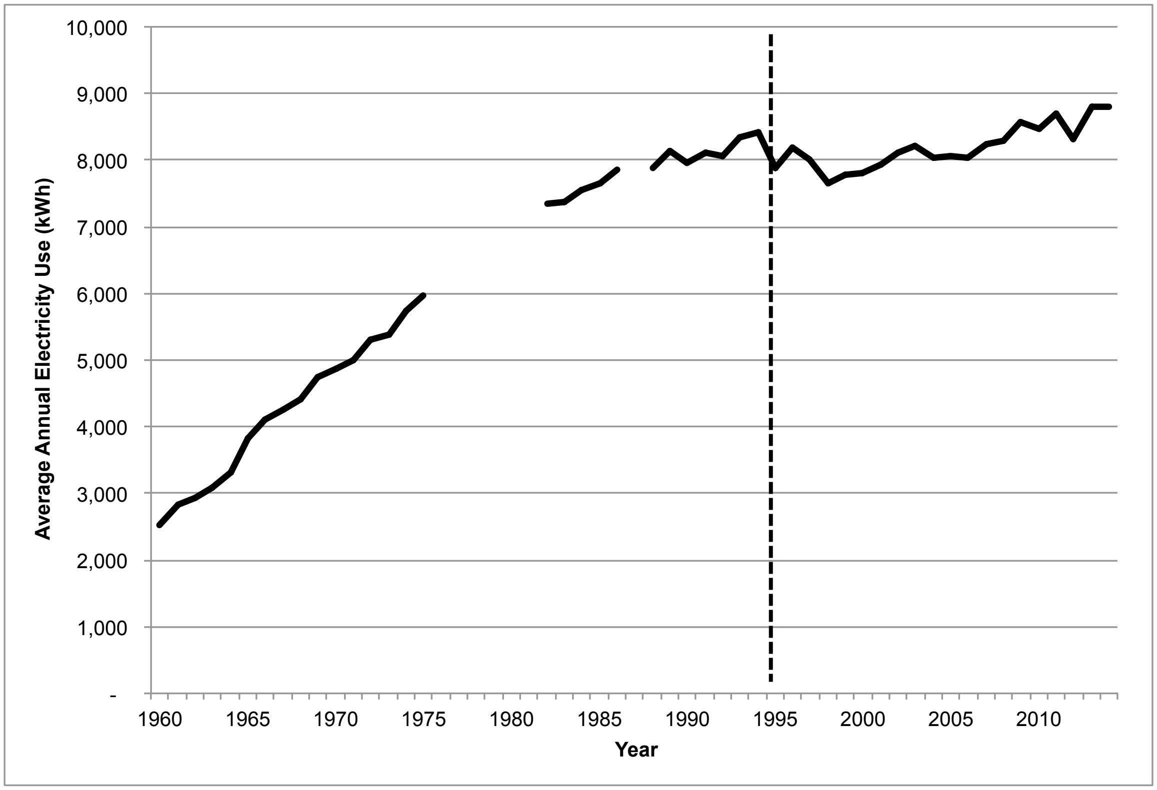
Chapter 6 – Electricity Demand Forecast and Energy Conservation Potential

Introduction

With data on the potential for renewable energy (Chapter 4) and the cost of competing electricity generation technologies (Chapter 5) I am almost ready to analyze scenarios for Saskatchewan's electricity future. First, however, it is important to understand how electricity demand will change over time. In this chapter I develop a forecast for Saskatchewan electricity demand. I also outline the potential for energy conservation, and the cost of implementing energy conservation measures. This information will be used in Chapter 7 to select scenarios for meeting Saskatchewan's electricity needs out to 2050.

Electricity Demand Forecast

Saskatchewan's electricity system has grown nearly continuously since the 1950s (see Figure 3-11). This growth has been fuelled by the expansion of industry, as well as the increased electrification of modern life. Figure 6-1 shows the average electricity used by a SaskPower residential customer from 1960 to 2014. Note that the apparent drop in the mid 1990s is largely due to an accounting change (indicated by the dotted vertical line) rather than an increase in energy efficiency. Also note that the breaks in the solid black line are due to missing data; not all of SaskPower's annual reports provided data on residential electricity use.

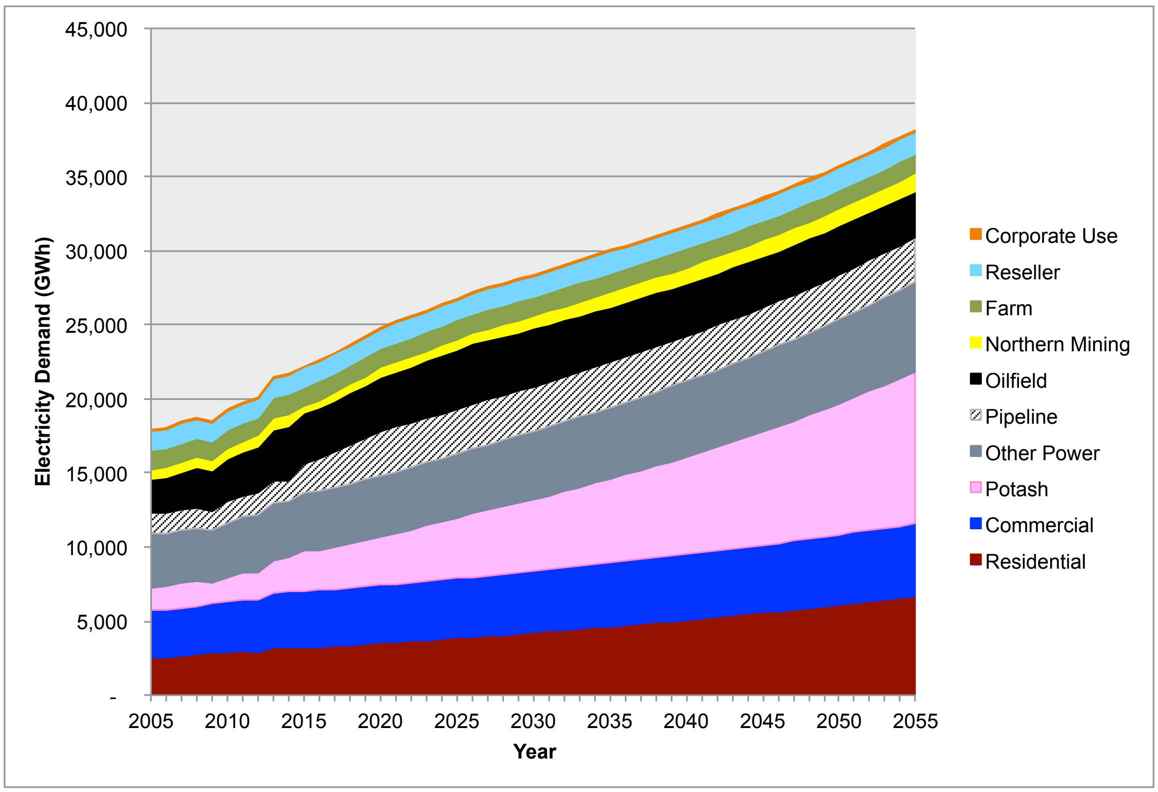


(Source: SaskPower, 1960-2014)

Figure 6-1 Average Annual Electricity Use by a Residential Customer

Saskatchewan's population hovered around one million people for most of the 20th century. Still, residential electricity demand increased as customers outfitted their homes with electric refrigerators, washing machines, dryers, dishwashers, televisions, and microwaves. Average electricity demand continues to grow in the Saskatchewan residential sector, as new electricity-consuming gadgets like computers, laptops, smart phones, and big-screen televisions are all plugged into the power system.

The fastest growing segment of electricity demand in Saskatchewan is, however, industrial. Saskatchewan's potash industry is investing $12 billion to expand operations in the province over the course of the next five years (Government of Saskatchewan, 2015). Pipelines, including the Keystone pipeline, are carrying more oil to U.S. markets. Northern mines are increasing production and this has necessitated the construction of the $380 million, 300-kilometer I1K transmission line from Island Falls to the Key Lake uranium mill (SaskPower, 2015). Electricity demand is also forecast to increase in the oilfields for the next decade, even though some forecasts show Saskatchewan oil production volumes declining (*e.g.* NEB, 2014a). Oilfield electricity use will continue to increase due to the increased energy intensity of oil production; more electricity is required to extract the oil as high-quality reserves are exhausted (Interview 5). Electricity demand grew quickly in the province during the past decade. A forecast of provincial electricity demand, based on the assumption that the past trends continue, suggests a significant increase in demand over the next 40 years (Figure 6-2).[55]



(SaskPower, 2015b; author's calculations)

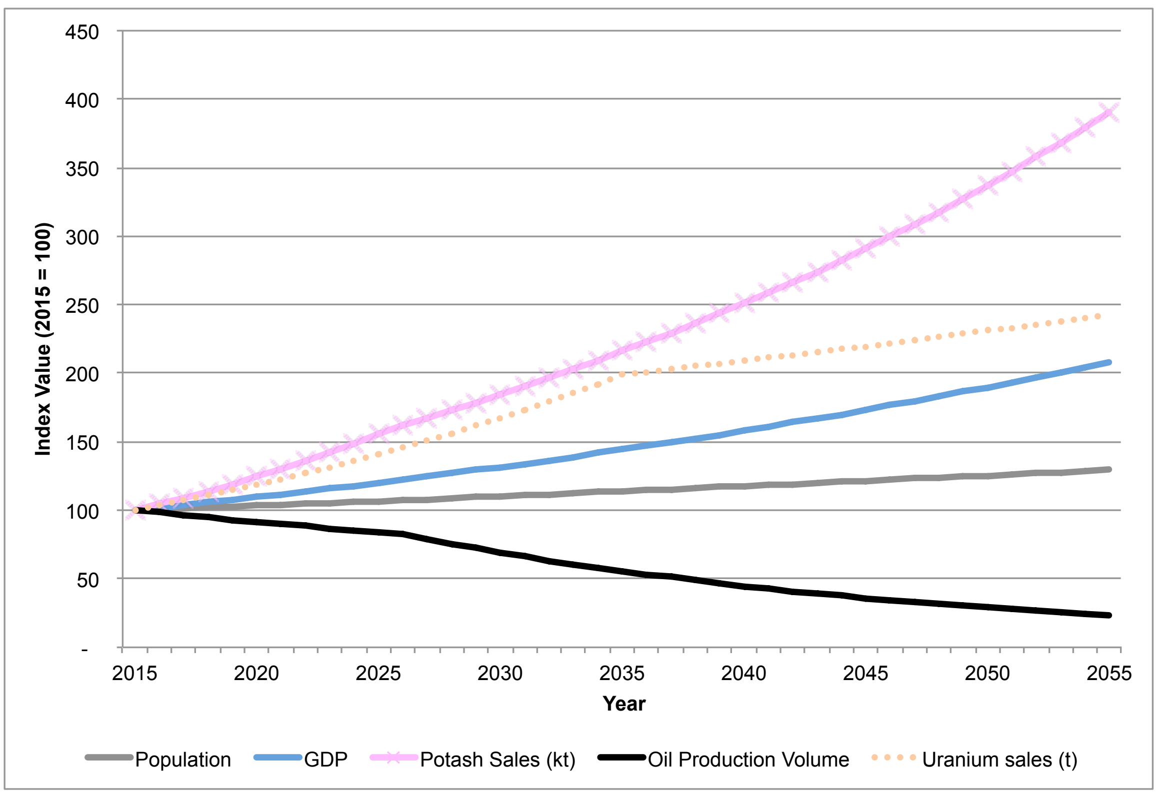
Figure 6-2 Saskatchewan Electricity Demand Forecast (2015-2055)

This forecast assumes growth of four important drivers of Saskatchewan electricity demand: population, gross domestic product (GDP), potash mining, and uranium extraction. It assumes that Saskatchewan oil production peaks in 2015 and electricity

[55] SaskPower produces 10-year, 20-year and 40-year electricity demand forecasts. The 40-year forecast is available only internally. Wherever possible I have worked to calibrate my forecast with SaskPower's forecasts, especially SaskPower (2015b).

demand from the oil sector peaks a decade later in 2026 when declining production begins to outpace the increased electricity intensity of production.

Figure 6-3 presents the forecast indexed values of these five drivers of electricity demand: population, GDP, and potash, uranium and oil production. I assume that population will grow at a constant rate of .6%/year from 2015-2055, reaching a population of 1.46 million people by 2055. GDP, measured in constant dollars, is assumed to grow at a rate of 1.85%/year. Potash production, measured in physical sales volume (kilotonnes) grows at an annual rate of 4.5%/yr from 2015-2026; 3.25% from 2027-2035; and 3% from 2036-2050. Uranium production (measured in tonnes sales volume) grows by 3.5%/year until 2035 and afterwards grows by 1.0%/year.



(Source: author's calculations)

Figure 6-3 Drivers of Electricity Demand

It is important to consider not only the scale of activity in Saskatchewan, but also the electricity intensity of activity. Figure 6-1 showed that per capita electricity use is increasing in the residential sector. Meanwhile, Saskatchewan's commercial and institutional sector has been improving energy efficiency.

Table 6-1 summarizes the assumptions I have made about electricity intensity. A positive number in the 'Intensity Change (%/yr)' column indicates that more electricity is being used per unit in each year. A negative number in that column means that electricity intensity is decreasing; the sector is becoming more energy efficient. These intensities are calibrated using historic data from Statistics Canada (2003-2011), SaskPower (2015b), the *Saskatchewan Economic Review* (SBS, 1997-2015), and the *Comprehensive Energy Use Database* (NRCAN, 2015b).

Sector	Unit	Initial Intensity (GWh/unit)	Intensity Change (%/yr)
Residential	1000 People	2.85	1.20%
Commercial	$1000 GDP (2007 CDN)	63.00	-1.20%
Potash	Kilotonnes sales volume	0.26	0.00%
Oilfields	1000 m3 per day production volume	40.00	3.50%
Northern mining	Tonnes sales volume	50.00	0.00%
Other power	$1000 GDP (2007 CDN)	65.00	-0.75%

Table 6-1 Electricity Intensity Assumptions

Table 6-1 also summarizes my projections on how the drivers will interact with electricity demand from 2015-2050. For example, I assume residential electricity demand will be influenced by the size of the population; initially, for every 1000 people added to Saskatchewan's population, electricity demand increases by 2.85 GWh. Commercial electricity demand is a function of GDP, as is electricity demand by 'power class' customers outside of the potash, pipeline, and northern mining sectors. Potash electricity demand increases with potash production, measured in proxy by sales volume.[56] Northern mining is handled in a fashion similar to potash mining. While not shown, pipeline electricity demand is assumed to grow by 8.5% from 2015-2020 and then to hold at a constant level between 2020-2055. This assumes that increased pipeline capacity will be

[56] Note that sales volumes may differ from production volumes due to the accumulation or drawing down of inventories.

built (*e.g.* the proposed Energy East pipeline) and a continued high volume of oil exports from Alberta after 2020.

The remaining categories of electricity demand are forecast as follows:

- **Farm** electricity demand is constant at 1300 GWh per year; this category of electricity demand has been falling slowly in recent years as small family farms have been purchased and amalgamated into large corporate farms. This has meant fewer people living on farms in rural Saskatchewan;
- **Reseller** electricity demand refers to the electricity sold to Saskatoon Light & Power and Swift Current Light & Power. These companies manage electricity distribution in their respective cities. However, Saskatoon Light & Power sells only to customers within the 1958 city boundaries of Saskatoon; customers outside of this area are served by SaskPower. Electricity demand from these resellers has grown slowly in recent years. I assume that electricity demand grows at half the rate of population growth. This means that reseller electricity demand grows from 1300 GWh in 2015 to 1480 GWh in 2055;
- **Corporate Use** refers to electricity used within SaskPower's operations. This is a relatively small portion of electricity demand. Based on historic data I assume that corporate use equals .4% of the total electricity demand from the other categories;
- **Line Loss** refers to electricity lost through the transmission and distribution of electricity. Based on the historic relationship between electricity demand and line loss I assume that line loss is equal to 7.5% of total electricity demand (including corporate use).

This forecast is by no means certain. The United States government recently said no to the Keystone XL pipeline project and similar opposition in Canada could prevent the Energy East pipeline from being built. Strong climate policy could encourage fuel switching away from fossil fuels and lower demand for Alberta oil. In the potash sector, demand has been cooling in 2015 and PotashCorp has announced a round of lay-offs and temporary shutdowns at three Saskatchewan plants (CBC, 2015d). Lower oil and potash demand would result in a lower electricity demand forecast. Conversely, the forecast would be higher with stronger growth in commodity sales. Higher penetrations of electric vehicles would also increase electricity demand. The forecast used in this dissertation provides one possible demand scenario, and one possible set of drivers that would achieve the scenario. Other demand scenarios are possible.

Electricity Conservation Potential

SaskPower produces two electricity demand forecasts: one that considers opportunities to conserve electricity through 'demand side-management' (DSM), and another that excludes the potential for energy conservation. ICF-Marbek (2011) defines DSM as follows,

> "DSM measures can include energy efficiency (use more efficiently), energy conservation (use less), demand management (use less during peak periods), fuel switching (use a different fuel to provide the energy service) and customer-side generation (displace load off of grid)." [57] (p. 5)

The forecast presented in Figure 6-1 is calibrated to SaskPower's (2015b) DSM-adjusted forecast. This forecast is informed by the efforts of SaskPower's Customer Services Branch, which designs and implements SaskPower's energy conservation programming (Interview 14). This conservation programming is in turn informed by ICF-Marbek's (2011) *Conservation Potential Review* for Saskatchewan. In 2010-2011 SaskPower commissioned ICF-Marbek to conduct a review of conservation potential in Saskatchewan. The results of this review are presented in Tables 6-2 and 6-3.[58] Table 6-2 indicates the potential for peak demand savings (expressed in megawatts). Table 6-3 indicates the potential to reduce total electricity demand in Saskatchewan (in gigawatt-hours/year).

[57] Note that demand management does not necessarily mean using less electricity, but instead involves shifting demand away from periods of high or "peak" demand.
[58] The Residential (Resl) sector includes residential homes and farm households. The commercial sector (Comml) includes commercial and institutional customers. The industrial sector (Indl) includes large power users such as mines and oilfield customers. (ICF-Marbek, 2011)

	Reference Total (MW)	Peak Demand Savings (MW/yr)							
		Upper Potential				Lower Potential			
		Resl	Comml	Indl	Total	Resl	Comml	Indl	Total
2015	3,473	25	32	50	107	12	29	32	73
2020	3,627	56	65	215	336	37	56	64	157
2025	3,772	66	91	269	426	42	73	104	219
2030	3,862	67	118	266	451	42	92	149	283

(Source: ICF-Marbek, 2011)

Table 6-2 Peak Demand Savings Potential

	Reference Total (GWh/yr)	Electricity Savings (GWh/yr)							
		Upper Potential				Lower Potential			
		Resl	Comml	Indl	Total	Resl	Comml	Indl	Total
2015	23,210	206	203	535	944	95	182	354	631
2020	24,452	454	423	2,091	2,968	297	360	702	1,359
2025	25,622	527	601	2,713	3,841	339	483	1,129	1,951
2030	26,324	545	793	2,879	4,217	338	615	1,591	2,544

(Source: ICF-Marbek, 2011)

Table 6-3 Electricity Conservation Potential

The Upper and Lower Potential numbers in Tables 6-2 and 6-3 show the achievable DSM savings in Saskatchewan. To calculate this achievable potential ICF-Marbek (2011) first calculated total economic potential. ICF-Marbek (2011) define economic potential as DSM measures that can achieve electricity savings at or better than a rate of $.15/kwh, the marginal cost of new electricity production (ICF-Marbek, 2011). This places an upper bound on the economic potential for DSM, but this bound is not static. As technologies develop and costs are reduced, the frontier of economic potential expands. LED lights are a case in point; five years ago they were prohibitively expensive, but economies of scale in production, and technological innovation, have led to rapid cost improvements (McKinsey, 2012).[59] Economic potential can also expand if the marginal price of electricity rises above the $.15/kWh threshold identified by ICF-Marbek (2011).

[59] McKinsey (2012) reports that LED prices were declining by 14-24% per year in the 2010-2012 period. They forecast that by 2016-2020 LEDs will gain the highest market share of any lighting technology (McKinsey, 2012).

Achievable potential is lower than economic potential because not all economically beneficial DSM measures will be carried out by customers. There are significant barriers that can prevent energy conservation:

> "New technologies present greater risks, as do the longer paybacks associated with investments such as energy efficiency. Some low-cost…technologies are not perfect substitutes in the eyes of the businesses or consumers expected to adopt them." (Jaccard, 2009: 312)

On this last point, electricity users may have a preference for non energy-related features of a less efficient technology (I personally enjoy the warm glow of an incandescent lightbulb while reading a book on a cold winter's day).

The upper and lower "achievable potential" numbers presented in Tables 6-2 and 6-3 account for barriers to adoption. These numbers were developed by ICF-Marbek (2011) in consultation with SaskPower staff. The difference between upper and lower potential relates to incentives; the upper potential numbers can be achieved if SaskPower supplies customers with more generous financial incentives for conservation.

ICF-Marbek (2011) study in hand, SaskPower's Customer Services Branch set a target of shaving 100 MW off of peak demand by 2018 (Interview 16). This target lies in between ICF-Marbek's (2011) upper and lower achievable potential for 2015 (see Table 6-2 above).

SaskPower (2015) reports that DSM programs have achieved 90 MW in peak demand savings since 2008. In 2014, savings were 13 MW, which exceeded SaskPower's target of 9 MW for that year (SaskPower, 2015). The Customer Services Branch is on track to meet their target of 100 MW peak demand savings by 2018 (Interview 16).

Interestingly, the mix of DSM savings achieved by SaskPower differs from the relative potential identified by ICF-Marbek (2011). ICF-Marbek (2011) forecast that total peak load in 2015 would be composed of residential demand of 485 MW, commercial demand of 542 MW, and 2446 MW of industrial demand for a total of 3473 MW. The industrial sector is the largest of the three sectors and holds the greatest potential for peak demand savings (Table 6-2) and electricity savings (Table 6-3). However, SaskPower (2015) estimates that only "10-15% of DSM-related energy savings can be expected from the industrial market" (p. 50). SaskPower (2015) anticipates further DSM savings of "50-60% from the commercial market" and "30-35% from the residential market" (p. 50). Figure 6-4 compares the ICF-Marbek (2011) potential to the SaskPower (2015) DSM estimates.

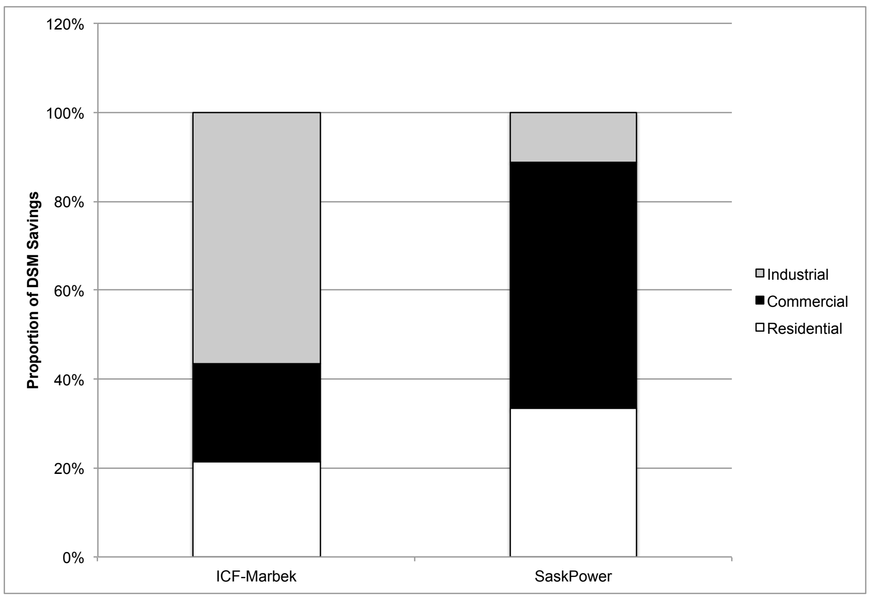
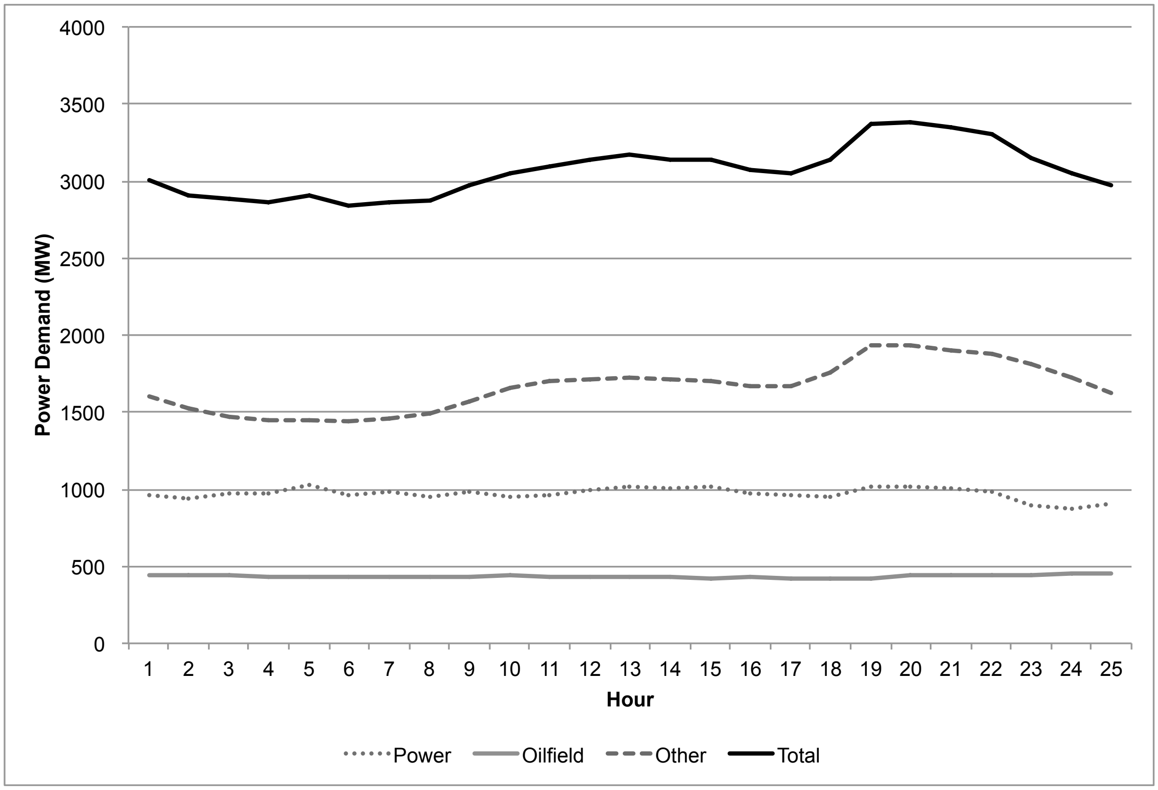


Figure 6-4 Estimated Sectoral Contributions to DSM

The focus on commercial and residential DSM may be partly due to the shape of electricity demand for each sector. Figure 6-5 shows demand for electricity on December 22nd 2013 broken out by power customers, oilfield customers, and a large category for 'other' customers, which includes commercial and residential customers, farms, and resellers. Electricity demand from power and oilfield customers, some of the biggest industrial consumers of electricity in Saskatchewan, is relatively flat. Industrial processes run fairly constantly and so do not demonstrate the fluctuations seen in the residential and commercial sectors.



(Source: SaskPower via Bigland-Pritchard, 2015b)

Figure 6-5 Power Demand on December 22nd, 2013

To reduce peak demand for power in the residential sector, SaskPower has sponsored programs such as providing free timers for block heaters and providing discounts for LED Christmas lights.[60] Typically, peak power demand occurs on a cold evening in December when furnaces are running on high, cars are plugged in, and Christmas lights are switched on (ICF-Marbek, 2011; SaskPower, 1990-2015). Reducing demand at this peak time directly offsets the need for additional generation capacity.[61]

There may be other reasons for the emphasis on commercial and residential customers. Not all industrial customers are enthusiastic about DSM initiatives. DSM may require

[60] Often these programs are carried out by third-party energy conservation consultants such as the Summerhill Group.
[61] ICF-Marbek (2011) reports on the potential savings block heater timers can provide on a winter weekday peak, "block heaters use only 2% of annual electricity, but account for 10% of the residential contribution to the system peak demand. Use of a block heater timer was estimated to reduce the system peak demand from block heaters by at least 90%." (p. 20)

changes in operating practices that increase other costs. For example, large, inefficient fans are used to blow air in potash mines. These fans use a lot of power and more efficient fans are available. However, equipment in a potash mine must be cleaned frequently to deal with corrosion; the salts in the mines quickly accumulate on equipment. The large fans are easily cleaned and this saves labour time relative to more efficient, but smaller and harder to clean, fans. (Interview 21)

Electricity is also a relatively small portion of production costs in Saskatchewan's potash mines; from 2003-2011 expenditures on electricity were about one-fifth the level of expenditures on labour (Statistics Canada, 2003-2011). The electricity cost savings promised by DSM may not be large enough to allocate scarce labour time to achieving them.

Increasing electricity prices may change this thinking. SaskPower customers will often complain when rates increase, and this becomes an ideal time to talk about DSM opportunities (Interview 36). SaskPower is working to create a "culture of conservation" within Saskatchewan that will encourage business and industry to react to price increases with increased efficiency rather than anger (Interview 36).

I now turn my attention to the costs of electricity conservation in Saskatchewan.

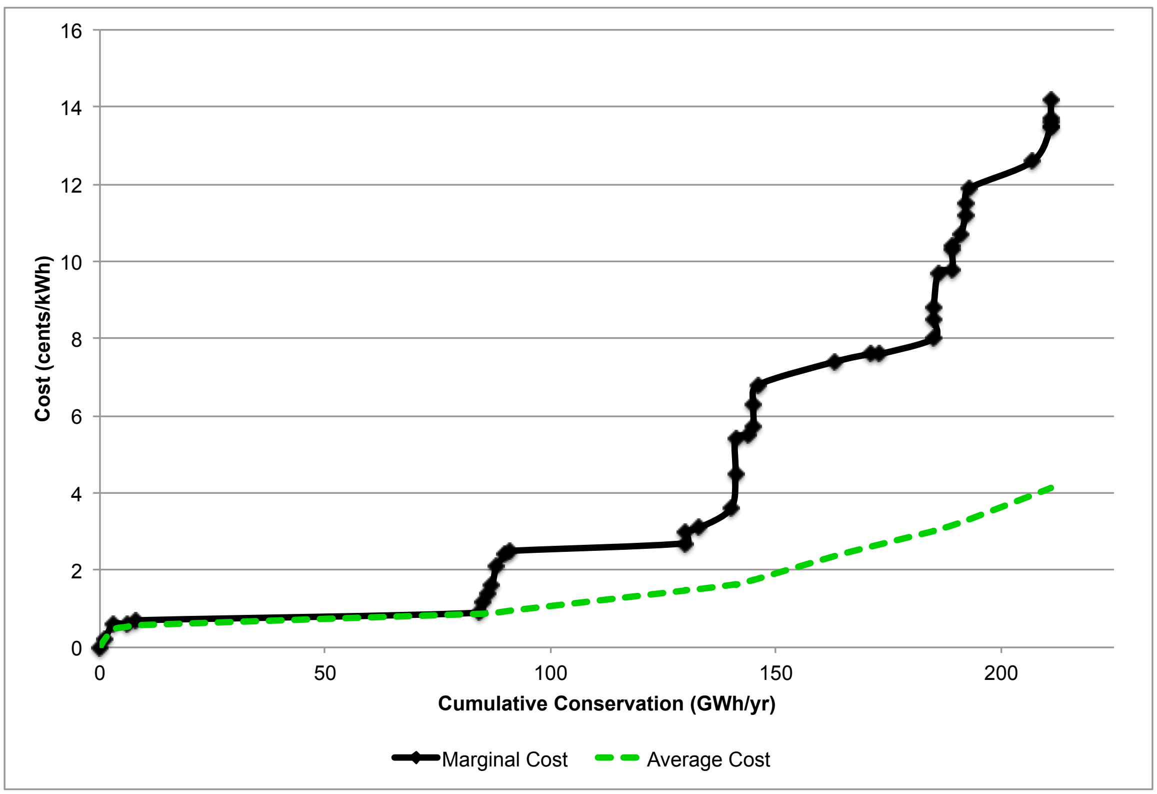
The Cost of Electricity Conservation

The cost of electricity conservation measures can be expressed by the Cost of Conserved Energy (CCE). Marbek (2007) defines CCE,

> "CCE is calculated as the annualized incremental cost (including operating and maintenance) of the measure divided by the annual kilowatt-hour savings achieved, excluding any administrative or program costs to achieve full use of the measure." (p. 5)

$$Eq.6.1\ \ CCE\ (\$/kWh) = \frac{Annualized\ Incremental\ Cost\ (\$)}{Annual\ kWh\ savings\ achieved\ (kWh)}$$

This measure can be used to compare energy conservation to the cost of generating electricity (expressed in Chapter 5 using LCOE). Figure 6-6 shows the cost of conservation in the Saskatchewan residential sector in 2015 as reported by ICF-Marbek (2011). CCE is indicated by the black 'marginal cost' line. Conservation is inexpensive at low levels of cumulative energy conservation. Costs then increase as "low-hanging fruit" (*i.e.* low-cost conservation options) are "picked" (*i.e.* implemented). Once CCE reaches $.15/kwh further conservation measures are beyond the realm of economic potential as defined by ICF-Marbek (2011).



(Source: ICF-Marbek, 2011)

Figure 6-6 Residential DSM Program Costs (Year=2015)

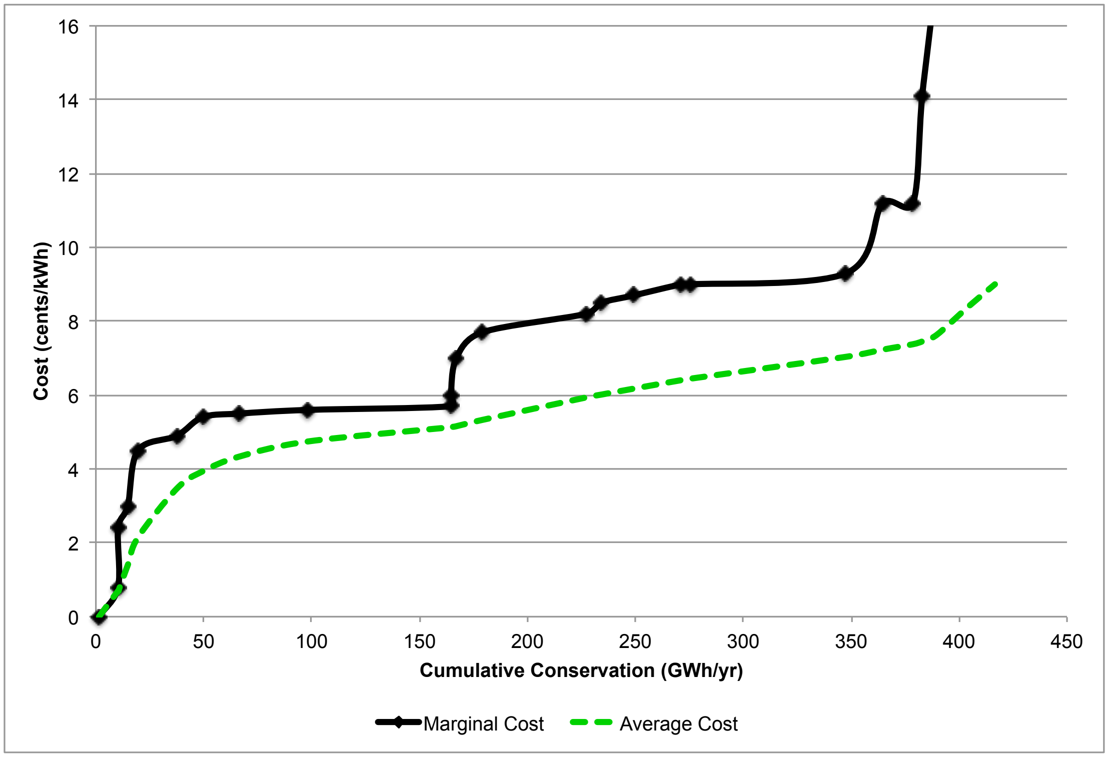
Figure 6-6 shows both the marginal cost of additional conservation efforts (black solid line) and the average cost of cumulative efforts (green dotted line). The cost of conserving electricity (CCE) in the residential sector can be lower than many of

SaskPower's electricity generation options. Until cumulative electricity savings of about 140 GWh/yr are achieved, the marginal cost of conservation is $.03/kwh or less. This cost is lower than all of the electricity generation options outlined in Chapter 5. Conserved electricity is also clean; it avoids greenhouse gas emissions (GHGs).[62]

SaskPower targets a portfolio of conservation measures that achieve an *average* cost of $.03/kwh or less (Interview 8). Average cost is lower than marginal cost because the presence of low-cost actions in the portfolio balances out the presence of higher cost actions. The dotted green average cost line in Figure 6-6 shows how average cost increases with conservation effort. In the residential sector in 2015 it is possible to achieve a portfolio of actions amounting to about 175 GWh/yr in savings before reaching an average cost of $.03/kwh.

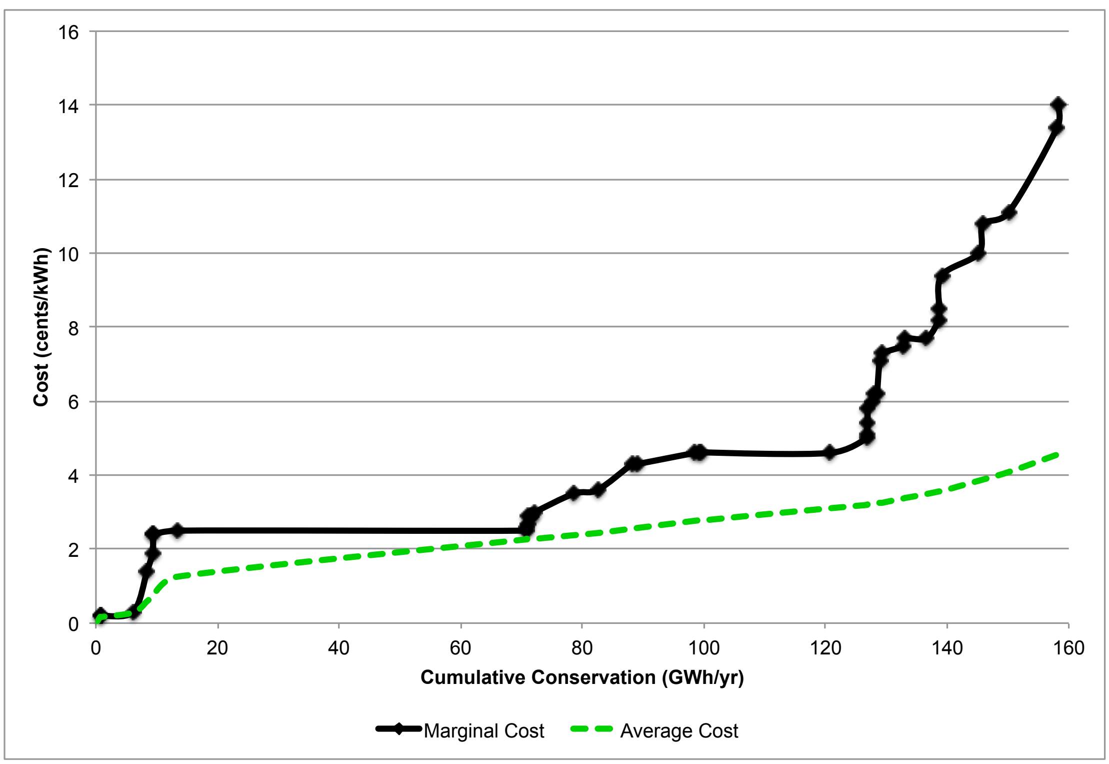
Figures 6-7 presents the cost of electricity conservation for the commercial sector in 2015. If all the conservation measures that belong to the upper achievable potential category, which total 206 GWh/yr in 2015, were implemented in the commercial sector, the average cost of conservation would still be below $.06/kWh. These average costs do increase in the commercial sector over time (see Table 6-5 below). This is to be expected as "low-hanging fruit" are "picked". Average costs also increase as the frontier of achievable potential expands outwards in future years.

[62] At least direct GHGs; energy-saving technologies will contain embodied GHGs.



(Source: ICF-Marbek, 2011)

Figure 6-7 Commercial DSM Program Costs (Year=2015)



(Source: ICF-Marbek, 2011)

Figure 6-8 Industrial DSM Program Costs (Year=2015)

Industrial electricity conservation is more expensive than conservation in the commercial and residential sectors. Figure 6-8 shows that the marginal cost of industrial energy conservation rises above $.05/kWh by the time 50 GWh/yr of savings are achieved. Marginal cost begins to exceed $.10/kWh after reaching 350 GWh/yr of cumulative savings, and the average cost reaches $.09/kWh when cumulative savings reach the ICF-Marbek (2011) cut-off point. These higher costs may explain the emphasis SaskPower places on residential and commercial conservation over industrial conservation.

It is worth noting that large industrial power users pay between $.05 and $.07 per kilowatt-hour for their electricity (SaskPower, 2015d). The largest users receive power directly from transmission lines, operate their own transformers, and pay the lowest rates. This means that most of the conservation measures in Figure 6-8 will be more expensive than simply purchasing more power from the grid. There is little economic incentive for industrial power users to find ways to conserve.

Modelling Energy Conservation

To summarize, the DSM-adjusted forecast presented in Figure 6-1 is premised on SaskPower achieving some of the energy conservation opportunities identified by the ICF-Marbek (2011) report. However, the DSM-adjusted forecast does not assume that all of the achievable gains will be realized; there is still room for further conservation, especially in the industrial sector.

Having identified the cost of conservation in Saskatchewan using ICF-Marbek (2011), I include energy conservation as a substitute for building new generation capacity in my optimization model. I model the potential for electricity conservation beyond the DSM-adjusted forecast by making the following assumptions:

1. I assume that the SaskPower DSM-adjusted forecast is premised on achieving the "lower achievable potential" levels of conservation in the residential and commercial sectors;
2. I assume that the remaining conservation potential in the residential and commercial sectors from 2015-2030 equals the increment between the lower

achievable potential and the upper achievable potential identified by ICF-Marbek (2011);

3. After 2030 I assume that residential conservation potential in each 5-year time step equals 3% of the electricity forecast total for the residential sector. Included in the residential sector total are the residential sector plus farm electricity demand plus half of reseller demand;
4. After 2030 I assume that commercial conservation potential in each 5-year time step equals 3.5% of the electricity forecast total for the commercial sector. Included in the commercial sector total are the commercial sector plus half the reseller demand plus one quarter of 'other power user' demand. I include 25% of the 'other power user' because the category includes large institutions such as the University of Regina and the University of Saskatchewan;
5. I assume that the DSM-adjusted forecast (SaskPower, 2015b) includes industrial conservation only for measures with a marginal cost less than $.05/kWh. From 2015-2030 I subtract the cumulative savings that cost less than $.05/kWh from the upper achievable potential to determine the remaining conservation potential in the industrial sector;
6. After 2030 I assume that industrial conservation potential in each 5-year time step equals 16% of the electricity forecast total for the industrial sector. This large number indicates the high degree of potential ICF-Marbek (2011) identified in the industrial sector. I assume the industrial sector is composed of the oilfields, the potash mining, northern mining and pipeline sectors, and three quarters of the 'other power user' sector.

For each sector I represent the cost of electricity conservation as the average cost of the portfolio of conservation measures that reach the upper achievable potential identified by ICF-Marbek (2011). In the scenarios outlined in Chapter 7, each GWh of conservation potential must be purchased at this average cost. The average cost ($/kWh) increases for the residential and commercial sectors until the year 2030 and then remains constant afterwards. In the industrial sector, average cost ($/kWh) starts at the high level of 8.5 cents per kilowatt-hour and remains there through to the year 2055.

Tables 6-4, 6-5, and 6-6 present the conservation potential and conservation costs that I use in my model of the Saskatchewan electricity system.

Residential	Residential Forecast (GWh/yr)	Conservation Potential Upper Achievable (GWh/yr)	Lower Achievable (GWh/yr)	Model Bound (GWh/yr)	Average Cost ($/kWh)
2015	5,171	203	182	21	0.040
2020	5,492	423	360	63	0.050
2025	5,843	601	483	118	0.055
2030	6,227	793	615	178	0.060
2035	6,647			199	0.060
2040	7,107			213	0.060
2045	7,611			228	0.060
2050	8,162			245	0.060
2055	8,765			263	0.060

(Source: ICF-Marbek, 2011; author's calculations)

Table 6-4 Model Values Assumed for the Residential Sector

Commercial and Institutional	Comml and Instl Forecast (GWh/yr)	Conservation Potential Upper Achievable (GWh/yr)	Lower Achievable (GWh/yr)	Model Bound (GWh/yr)	Average Cost ($/kWh)
2015	5,405	206	95	111	0.050
2020	5,590	454	297	157	0.060
2025	5,782	527	339	188	0.065
2030	5,981	545	338	207	0.070
2035	6,188			217	0.070
2040	6,402			224	0.070
2045	6,625			232	0.070
2050	6,857			240	0.070
2055	7,097			248	0.070

(Source: ICF-Marbek, 2011; author's calculations)

Table 6-5 Model Values Assumed for the Commercial Sector

Industrial	Industrial Forecast (GWh/yr)	Conservation Potential Upper Achievable (GWh/yr)	Conservation Potential Lower Achievable (GWh/yr)	Conservation Potential Model Bound (GWh/yr)	Average Cost ($/kWh)
2015	11,555	535	354	498	0.085
2020	13,657	2,091	702	2,010	0.085
2025	15,068	2,713	1,129	2,591	0.085
2030	16,069	2,879	1,591	2,647	0.085
2035	17,082			2,733	0.085
2040	18,073			2,892	0.085
2045	19,229			3,077	0.085
2050	20,573			3,292	0.085
2055	22,134			3,541	0.085

(Source: ICF-Marbek, 2011; author's calculations)

Table 6-6 Model Values Assumed for the Industrial Sector

Converting Electricity Savings to Peak Demand Savings

When modelling energy conservation I am also interested in peak demand reductions. I convert energy saved (measured in Gigawatt-hours) into peak demand using the following equation,

$$Eq. 6.3 \ \ Peak\ Load\ Savings\ (MW) = \left(\frac{Annual\ Savings\ (GWh/yr)}{(8760 * CF)}\right) * \ 1000$$

The conversion factors were selected to calibrate to the ICF-Marbek (2011) relationship between GWh saved and peak demand savings. I use the following conversion factors (CF):

- Residential: 92.5%
- Commercial: 75%
- Industrial 62%.

These conversion factors can be understood as the capacity factor of a theoretical electricity generated facility sized equal to the peak load savings (MW) that would generate the amount of electricity savings in a year ($Annual\ Savings\ (GWh/yr)$. After solving for these conversion factors, I then divide the industrial peak load savings in half to account for the relatively flat nature of industrial electricity demand and to match the ICF-Marbek data.

Caveat on Energy Conservation Modelling

There is evidence that utilities over-report the effectiveness of their DSM programs, especially if they do not sufficiently account for free-riders and the rebound effect (Rivers and Jaccard, 2011). Free-riders are those who would have taken an action without an incentive from SaskPower. For example, a free-rider of the block-heater timer program may have purchased a block-heater timer on their own if SaskPower hadn't provided them with a free one. The rebound effect refers to an increase in energy use that occurs after an energy efficiency measure is taken. Sorrell *et al*. (2008) describe three kinds of rebound effects:

1. *Direct rebound effect* – efficiency reduces the "effective price" of energy services making them more desirable to customers. For example, more efficient LED lighting decreases the cost of lighting. But because lighting has become less expensive, people may string up three times the number of decorative lights during the holiday season;
2. *Indirect rebound effect* - financial savings from conserving energy in one realm (*e.g.* more efficient lighting) may be funneled into purchasing energy services in another area (*e.g.* buying a hot-tub);[63]
3. *Economy-wide rebound effects* – "A fall in the real price of energy services may reduce the price of intermediate and final goods throughout the economy, leading to a series of price and quantity adjustments, with energy-intensive goods and sectors likely to gain at the expense of less energy-intensive ones." (Sorrel *et al*., 2008: 637)

[63] The rebound effect can also occur as savings in one realm (*e.g.* saving electricity by replacing an incandescent lightbulb with an LED bulb) requires increased energy use in another realm (*e.g.* increased natural gas or electric heating requirements in winter to make up for the heat that was once thrown from the incandescent bulbs).

The combined impact of free-riders and the rebound effect can negate DSM efforts by utilities. Using econometric analysis, Rivers and Jaccard (2011) found that DSM spending did not have a statistically significant impact on electricity use in Canada in the period of 1990-2005. They conclude that energy efficiency gains may be occurring, but they are driven by technological change, stock turnover, and government regulation, rather than DSM spending by utilities (Rivers and Jaccard, 2011).

The Rivers and Jaccard (2011) study highlights that DSM spending on information and incentives has its limits. DSM spending is not, however, the only way to encourage conservation. A fulsome list of approaches to energy conservation would include the following:

1. Moral suasion – provide information to customers on ways to lower energy;
2. Incentives – provide customers with energy efficient products (*e.g.* block heater timer giveaway), or provide rebates for energy efficient products;
3. Regulation – introduce energy efficiency standards on things like housing, appliances, and lighting;
4. Price-based policy – increase the cost of fossil-fuel generated electricity through a policy like a carbon price or increase the price of electricity at times of high demand using time-of-use pricing.[64]

Governments and utilities often prefer the first two policies. Providing information is a friendly way to encourage conservation. Incentives reward people for doing the right thing. Politically there is little to be lost from rewarding good behaviour, which makes an information and incentives approach attractive. Problematically, effectiveness is diminished by free-riders and the rebound effect.

[64] These policies may also be combined. For example, a smart meter system can be used in combination with a peak pricing system. The smart meter provides information to electricity users to indicate when their use is occurring during a period of peak demand, and therefore can encourage customers to react better to price incentives. (Koksal, Rowlands and Parker, 2015).

Workshop participants stressed the importance of energy efficiency regulations to encourage conservation (Workshop 1). Standards can drive improvements, but are not under the legislative control of SaskPower. Instead, the task falls to SaskPower's owner, the Government of Saskatchewan. Critics of regulations complain about the economic costs they impose. Studies such as ICF-Marbek (2011) help to outline the technologies for which standards can be introduced at a socially acceptable economic cost.

Higher prices mitigate the rebound effect by providing a consistent incentive to conserve electricity and improve energy efficiency. There are also no free-riders; everyone pays more for electricity. These strengths make higher prices an economically efficient approach to promoting conservation.

Higher prices can be introduced by putting a price on carbon. A well-designed carbon pricing system will then redistribute the carbon pricing revenue back to citizens, either as a direct payment or through tax reductions. These methods of redistributing carbon revenues may also lead to a rebound effect as income increase. The higher prices do, however, provide a consistent signal that can shift consumption behaviour towards less energy-intensive purchases.

With these caveats in mind, the relatively conservative approach I have taken to modelling energy conservation potential and cost appears justified. In Chapter 7 I outline scenarios to reduce greenhouse gas emissions in the electricity sector. As will be seen, DSM has an important role to play in some of these low-carbon electricity futures.

Chapter 7 – Scenarios for Greening the Saskatchewan Grid

Introduction

In this chapter I explore the electricity rate impacts of scenarios to lower greenhouse gas emissions (GHGs) in the Saskatchewan electricity sector. Scenarios are selected using a linear programming model I call the *Saskatchewan Investment Model* (SIM). This model operates in five-year time-steps from 2015-2050. The purpose of this model is to understand the least-cost pathways to meeting environmental objectives in the electricity sector. Inputs to this model include Saskatchewan's renewable energy potential identified in Chapter 4, the cost of electricity generation technologies in Saskatchewan outlined in Chapter 5, the forecast of electricity demand outlined in Chapter 6, and the cost and potential for energy conservation outlined in Chapter 6. Outputs for each time-step in this model include average electricity prices, capital investments (in Megawatts), and GHGs. Technical documentation for this model can be found in Appendix 7A.

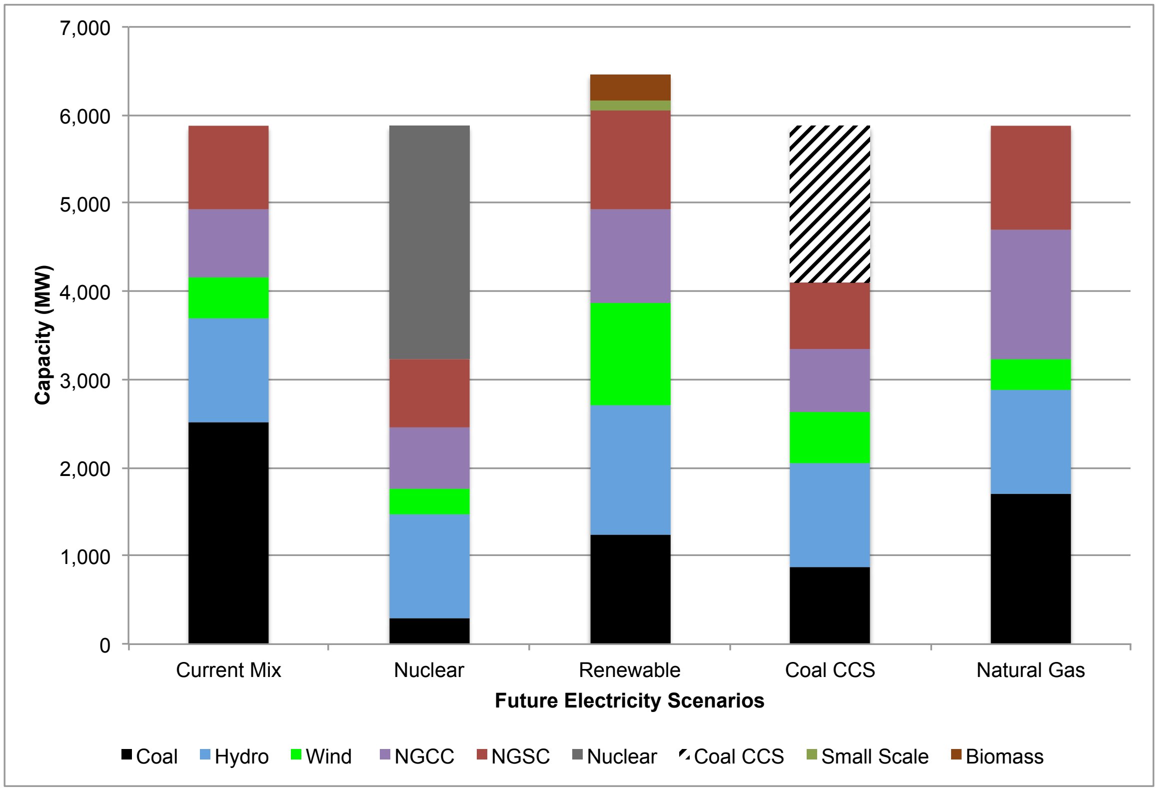
I analyze the 2050 electricity mix for each scenario using a non-linear programming model called WIRE – the *Will It Run Electricity Model*. This model optimizes hourly electricity production for four representative months: March, June, September and December. The purpose of this model is to check whether a given investment scenario will sufficiently meet electricity demand. Its main task is to test whether scenarios with a high penetration of variable renewable electricity can adequately meet demand in the face of hourly and seasonal variations in demand and renewable electricity output. The model also identifies the extent to which electricity storage and demand side management can play a role in ensuring demand is met. The technical documentation for this model can be found in Appendix 7B.

Related Literature

Researchers at the *Center for Studies in Energy and Environment* at the University of Regina, led by engineering Professor Gordon Huang, constructed a MARKAL-based linear programming optimization model for Saskatchewan to analyze least-cost pathways to lower GHG emissions in the province (Lin *et al*., 2010; Lin *et al*., 2005). This model analyzes energy use and energy production across the entire economy, including electricity generation, natural gas processing/production, oil refinery/upgrading, and oil extraction. The model was used to evaluate the cost of reducing Saskatchewan's GHGs to 6% below 1990 levels by the period of 2008 to 2012; that is, the model tested how the province might have met a Kyoto equivalent target within its borders (Lin *et al*., 2010). In the electricity sector the study found that GHGs could be reduced by replacing coal-fired power plants with wind turbines, hydroelectric facilities, and natural gas plants (Lin *et al*., 2010). The modelling group also reported that the costs of GHG reductions would be lower if nuclear power plants could be built in the province (Lin *et al*., 2010; Lin *et al*., 2005).

The researchers using the MARKAL-based model did not explore the potential for a high penetration of renewable energy. They assumed that hydropower was limited to 330 MW of additional capacity, a number much lower than that provided by SaskPower and outlined in Chapter 4 (Lin *et al*., 2005). The research was also conducted at a time when it was still fair to say, "wind power is available at considerably higher cost than electricity from conventional fossil fuel sources" (Lin *et al*., 2005: 153). As shown in Chapter 5, wind is now one of the lowest cost means of generating electricity in Saskatchewan. Cost reductions in solar power and electricity storage have also changed the discussion of renewable electricity futures. The analysis in this chapter provides an updated view of renewable energy potential and cost in Saskatchewan.

In her PhD dissertation, Dr. Lisa White applied strategic environmental assessment to a case study of the Saskatchewan electricity system (White and Noble, 2012; White, 2013). Dr. White consulted with six Saskatchewan experts to identify five scenarios for Saskatchewan's electricity future. These scenarios are presented in Figure 7-1.



(Data source: White, 2014; White and Noble, 2012; author's presentation)

Figure 7-1 Future Electricity Scenarios for Saskatchewan in 2040

The renewable scenario includes a greater focus on wind and hydro electricity. In this scenario wind comprises 18.2% of total capacity and hydro comprises 22.7%. The renewable scenario also includes biomass (4.5% of capacity) and small-scale renewables (1.8% of capacity). Conventional coal remains a greater proportion of capacity than it does in the carbon capture and storage (CCS) scenario and the nuclear scenario. Total capacity in the renewable scenario is higher than the other scenarios because White and Noble (2012) assume that additional simple cycle natural gas turbines are required to provide backup for the variability of wind electricity. The scenarios were not, however, analyzed using an hourly operations model such as WIRE and the renewable scenario did not include the potential for energy storage technology or demand side management. (White, 2013; White and Noble, 2012)

Although economic analysis of future electricity scenarios was not central to her work, Dr. White did provide estimates of the cost of various electricity scenarios. These estimates were based on an estimate of the capital cost to build the facilities and an estimate of the cost per kilowatt-hour to generate electricity. The costs are, however, a simple weighted average of levelized cost estimates: they do not account for technological progress and fuel price escalation; they do not address uncertainty; and they are a static snapshot of expected prices in 2040, rather than a dynamic electricity price pathway. Electricity prices and greenhouse gas emissions (GHGs) for the five scenarios presented in White and Noble (2012) are summarized in Table 7-1. Despite the higher financial cost for the renewable energy scenario, participants in the strategic environmental assessment process indicated that this scenario was the preferred pathway for the future of electricity in the province (White and Noble, 2012).

	Current Mix	Nuclear	Renewable	Coal CCS	Natural Gas
GHG emissions (million tonnes CO2e/GWh)	19.6	7.3	11.5	8.0	15.7
Cost of electricity ($/kWh)	0.11	0.12	0.14	0.13	0.10

(Source: White and Noble, 2012)

Table 7-1 White and Noble (2012) Scenario Outcomes in 2040

In this chapter I present scenarios that are optimized to achieve environmental objectives at the least financial cost to SaskPower. I also address the dynamics of improving technology and increasing fuel prices, include a sensitivity analysis to address the uncertainty inherent in estimates of future scenario costs, and use the WIRE model to test whether the models can provide electricity on an hourly basis. I begin this analysis by outlining SaskPower's short- to medium-term electricity supply plan. This supply plan informs my baseline business-as-usual scenario.

SaskPower's Supply Plan

The baseline scenario in my analysis is designed to align with SaskPower's stated investment priorities. Knowledge of SaskPower's supply plan out to 2030 is based on interviews, SaskPower presentations, and news reports.

The most important constraint faced by SaskPower is the Canadian federal government's coal-fired electricity regulation (CEPA, 2012). This regulation sets a maximum allowable greenhouse-gas emission (GHG) intensity of 420 tonnes carbon dioxide (CO_2) per Gigawatt-hour (GWh) for coal-fired power plants. Existing Saskatchewan coal plants must be either retired at the end of their useful life, or retrofitted with carbon capture and storage (CCS) in order to comply with the regulation. Table 7-2 shows the retirement or conversion schedule for Saskatchewan's coal-fired electricity plants. If a commitment is made to retrofit a given plant then it is allowed to operate as a conventional coal plant for an additional five years before it must be equipped with CCS. The Boundary Dam III carbon capture and storage (CCS) project was commissioned in 2014 and complies with the federal regulation.

Coal-fired Units	Capacity (MW)	Comissioned	Retirement If Not Converted to CCS	Conversion Deadline If Converted to CCS
Boundary Dam I	62	1959	Retired	
Boundary Dam II	62	1959	Retired	
Boundary Dam III	139/120	1970/2014	Converted	
Boundary Dam IV	139	1970	2019	2025
Boundary Dam V	139	1973	2019	2025
Boundary Dam VI	273	1978	2028	2033
Shand	279	1992	2042	
Poplar River I	291	1981	2030	
Poplar River II	281	1983	2030	

(Source: Interviews, 2014; CEPA, 2012)

Table 7-2 Saskatchewan Coal-fired Generation Regulatory Impact

As shown in Table 7-2, decisions must be made in the near future regarding Boundary Dam units IV and V. Significant retirements are also scheduled in the period of 2028-2030 when Boundary Dam VI and both units at Poplar River must be either retired or a commitment made to convert them to CCS. Shand, which was commissioned in 1992, is able to operate out to 2042, representing its fifty-year expected life.

Environment Canada produced a *Regulatory Impact Analysis Statement* that accompanied the coal-fired regulation (CEPA, 2012). This statement provides a cost-benefit analysis of the impact of the regulation. Environment Canada modeled the impact using their in-house E3MC energy-environment-economy model. In Saskatchewan they estimated the coal-fired regulation would increase electricity generation costs by $1,174 million dollars (present value 2010 $CDN) over the period of 2015 to 2035, and would increase average electricity prices by 2.50 cents per kilowatt-hour (kWh) by 2035 (CEPA, 2012: 2064). This is a greater price increase than that faced by Alberta (2.12 cents/kWh) and Nova Scotia (1.40 cents/kWh). Part of the reason for the higher price impact is the choice of how to comply with the regulation, "Saskatchewan officials indicated that the provincial utility intends to implement CCS technology as a response to the regulatory performance standard" (CEPA, 2012: 2018). As outlined in Chapter 5, coal-fired plants equipped with CCS are expensive relative to other generation options. Saskatchewan officials like this approach, however, because "Where the captured CO_2 is used for enhanced oil recovery, it generates additional benefits as a result of incremental oil production" (CEPA, 2012: 2018).[65] The Saskatchewan government is also interested in maintaining employment in the coal mining industry.

The baseline for my analysis assumes that Saskatchewan meets the regulatory performance standard with a combination of conversion to CCS and retirement. I assume that Boundary Dam units IV and V are retrofitted to CCS, allowing them to operate as conventional plants until January 1st, 2025, when they begin to operate as CCS facilities. I assume that Boundary Dam unit VI and both units at Poplar River are retired at the end of their useful lives; they no longer operate as of 2030. I assume that the Shand coal plant

[65] CEPA (2012) estimated that using captured CO_2 for enhanced oil recovery could lead to $6 billion in additional oil extraction (valued at 2012 oil Western Texas Intermediate oil prices 2010 $CAN) between 2015 and 2035. Increases in emissions associated with EOR would total 5.4 Mt CO_2e in that period, lowering GHG reductions created by the policy from 219.2 to 213.8 Mt Mt CO_2e (CEPA, 2012).

is retrofitted in the 2025-2029 time-step to extend its life as a conventional coal plant until the 2040-2044 time-step.[66] Shand then operates as a CCS facility after 2045.

SaskPower's baseline supply plan also includes investment in other technologies. The following investments can be expected in the next fifteen years:

- Existing hydroelectric facilities will be repowered at the end of their scheduled lives and retained as part of the electricity system;
- Investments will be made in wind capacity so that it composes 10% of capacity by 2020 and 20% by 2030. Note that this recent commitment by SaskPower means that Saskatchewan will achieve the wind contribution outlined in White and Noble's (2012) renewable scenario within fifteen years;
- A small investment in biomass of 36-42 MW will be made at Meadow Lake;
- Small solar projects of 5-10 MW will be built to test the suitability of solar for the Saskatchewan electricity system;
- SaskPower has signed a memorandum of understanding to purchase up to 500 MW of power from Manitoba Hydro. In September 2015 SaskPower signed an agreement with Manitoba Hydro to secure 100 MW of power in the period 2020-2040. I assume that SaskPower will purchase the additional 400 MW of hydropower. This additional 400 MW of hydropower will enter service in the period from 2020-2029;
- A 350 MW natural gas combined cycle plant will be built at Swift Current. More investments in natural gas combined cycle and simple cycle will be made to make up any shortfalls in electricity supply;
- SaskPower will pursue at least the lower potential of demand-side management (DSM), but will also seek another 11 MW of peak savings.

Investment according to these assumptions creates an electricity system with 5869 MW of capacity in 2025. After forcing these investments into the SIM model I optimize investment decisions from 2030-2050. In this optimization I do not allow the construction

[66] Environment Canada reports that a repowering of an existing coal plant can be assumed to cost $395/kilowatt (2012 $CDN) (CEPA, 2012: 2024).

of new coal facilities, unless they are equipped with carbon capture and storage (CCS) technology. The resulting electricity generation profile for Saskatchewan is presented in Figure 7-2. The demand forecast matches that presented in Chapter 6.

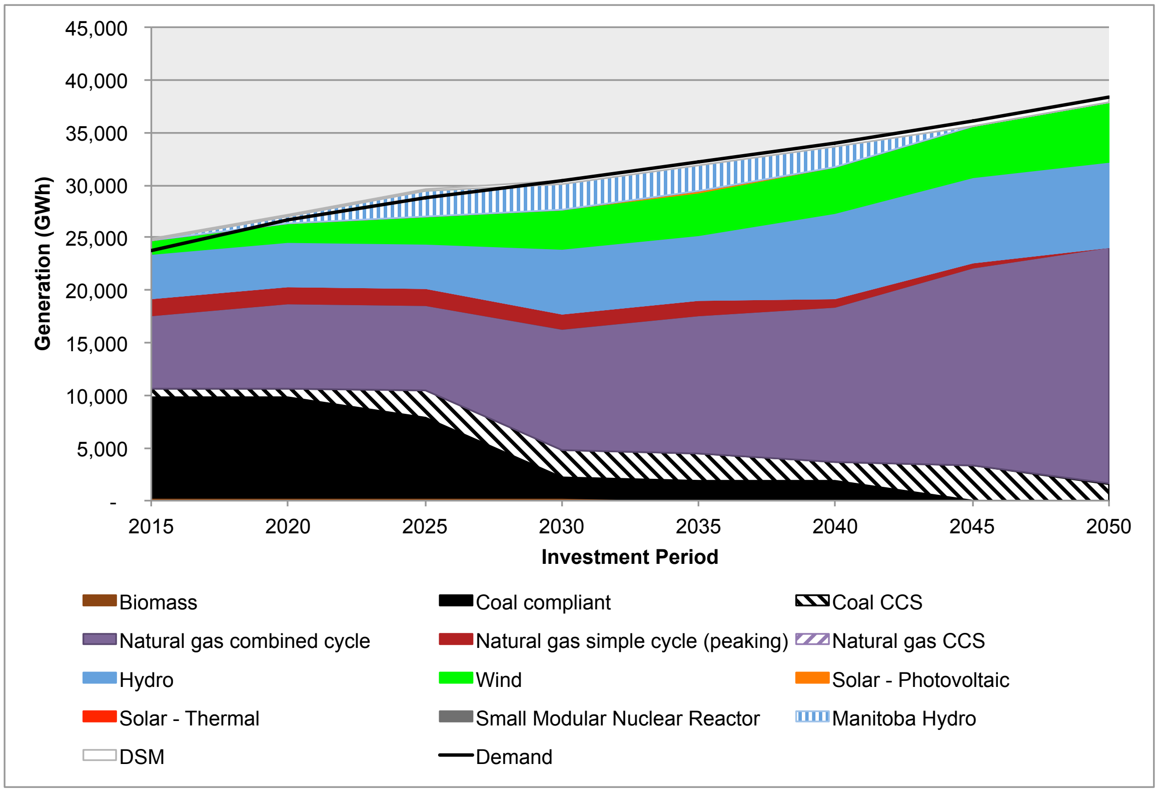


Figure 7-2 SaskPower BAU to 2025 and Optimization to 2050

Coal-fired electricity production decreases steeply in 2030 with the retirement of 845 MW of coal-fired capacity, representing the retirement of Boundary Dam VI, and both units at Poplar River. In this simulation, natural gas combined cycle plants, additional hydroelectric capacity, and wind turbines replace retired coal plants and meet Saskatchewan's growing electricity demand.

The retirement of Saskatchewan's coal-fired plants leads to a substantial reduction in annual GHGs. Figure 7-3 displays the resulting annual GHGs from this SaskPower business-as-usual (BAU) scenario. The thatched area below the x-axis represents annual captured GHGs from CCS. By 2035 total annual GHGs are 11,245 kt CO_2e/yr. When captured CO_2 is subtracted from that total, net GHGs to the atmosphere are 8,467 kt

CO_2e/yr. Note that some of the captured CO_2 will be sold for enhanced oil recovery (EOR). I do not include revenue from the sale of CO_2 in my optimization model, nor do I include royalties due to increased oil production in the model. Conversely, I do not penalize SaskPower for any CO_2 that might escape from storage when it is used in EOR. On balance, the omission of CO_2 sales increases the apparent cost of carbon capture and storage (CCS). However, recent events have shown that contracts to sell CO_2 can also become a liability. As of October 2015 SaskPower had paid $12 million in penalties to Cenovus for failing to deliver an adequate quantity of CO_2 for enhanced oil recovery (Leo, 2015).

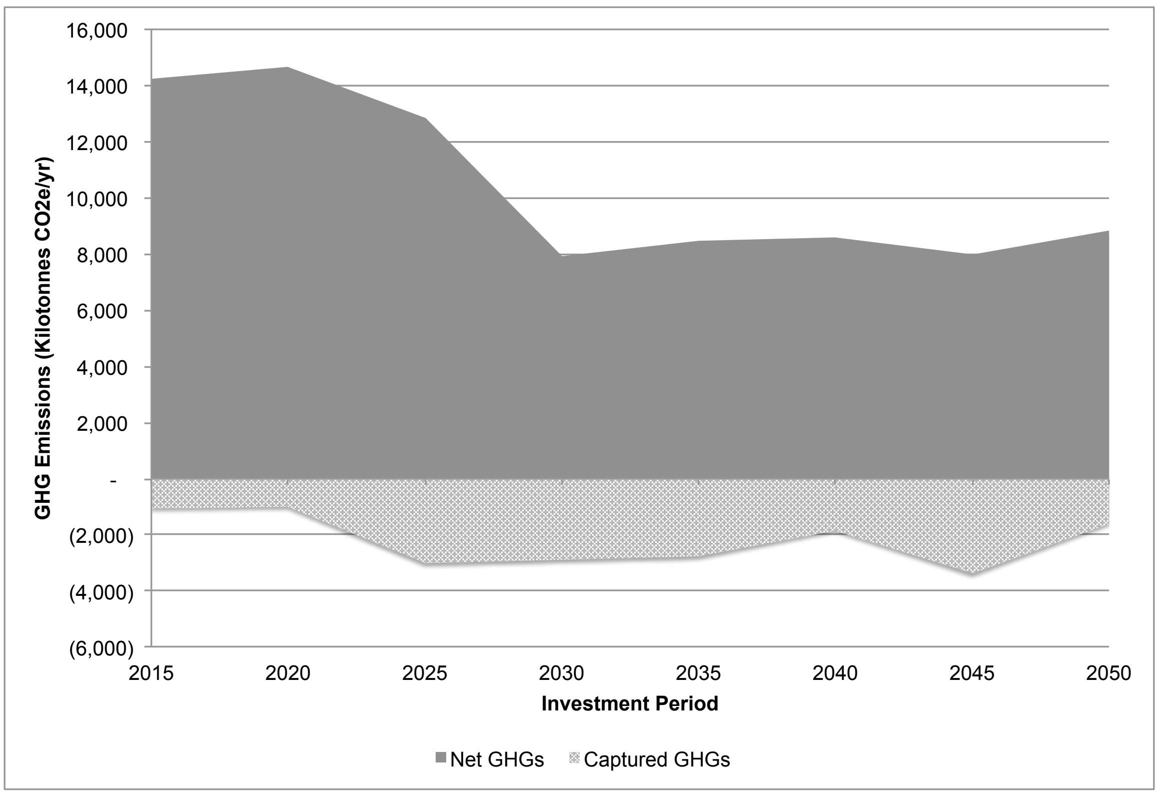


Figure 7-3 SaskPower Greenhouse Gas Emissions in Response to Federal Regulation

I compare this scenario to one without federal regulation by removing the forced investment decisions, allowing old coal facilities to be retrofitted to continue operating at the end of their useful lives, and allowing new coal facilities to be built. Like Environment Canada (CEPA, 2012) I assume that the lifetime of existing coal plants can be extended with an expenditure of $403/kw (2014 $CDN). When I run this scenario I find that Saskatchewan average electricity prices are 1.66 cents/kWh higher by 2035 due to efforts to comply with the federal regulation. This is .74/kWh lower than the estimate by Environment Canada, which is likely due to different cost assumptions between SIM and Environment Canada's E3MC model (CEPA, 2012). Without the federal coal regulation, new coal plants are not built (based purely on cost), but the existing coal-fired generation fleet (1402 MW) are retrofitted and continue operating. In the absence of the federal regulation, total annual GHGs would be 16,612 kt CO_2e/yr by 2035. When the impact of Boundary Dam III is considered, net GHGs to the atmosphere are 15,731 kt CO_2e/yr in 2035. This means that the federal regulation will effectively reduce net GHGs to the atmosphere by 7,264 kt CO_2e/yr by 2035, which is a 46.2% reduction from the total in the scenario without federal regulation. This is a substantial improvement.

Equivalency Agreement

Of course, we can ask, could Saskatchewan reach these GHG reductions at a lower cost? The federal government has shown a willingness to consider equivalency agreements with provinces that would like to meet the intent of the regulatory performance standard in a different manner. Nova Scotia signed such an equivalency agreement and it came into effect July 1, 2015. This agreement requires the province to meet mandatory emission limits for the electricity sector that are equivalent to those that would be produced by the federal regulation. (Environment Canada, 2015c)

By imposing GHG constraints for each time-step in the model I calculate how Saskatchewan could achieve emission reductions equivalent to those driven by the federal regulation. The resulting scenario is presented in Figure 7-4.

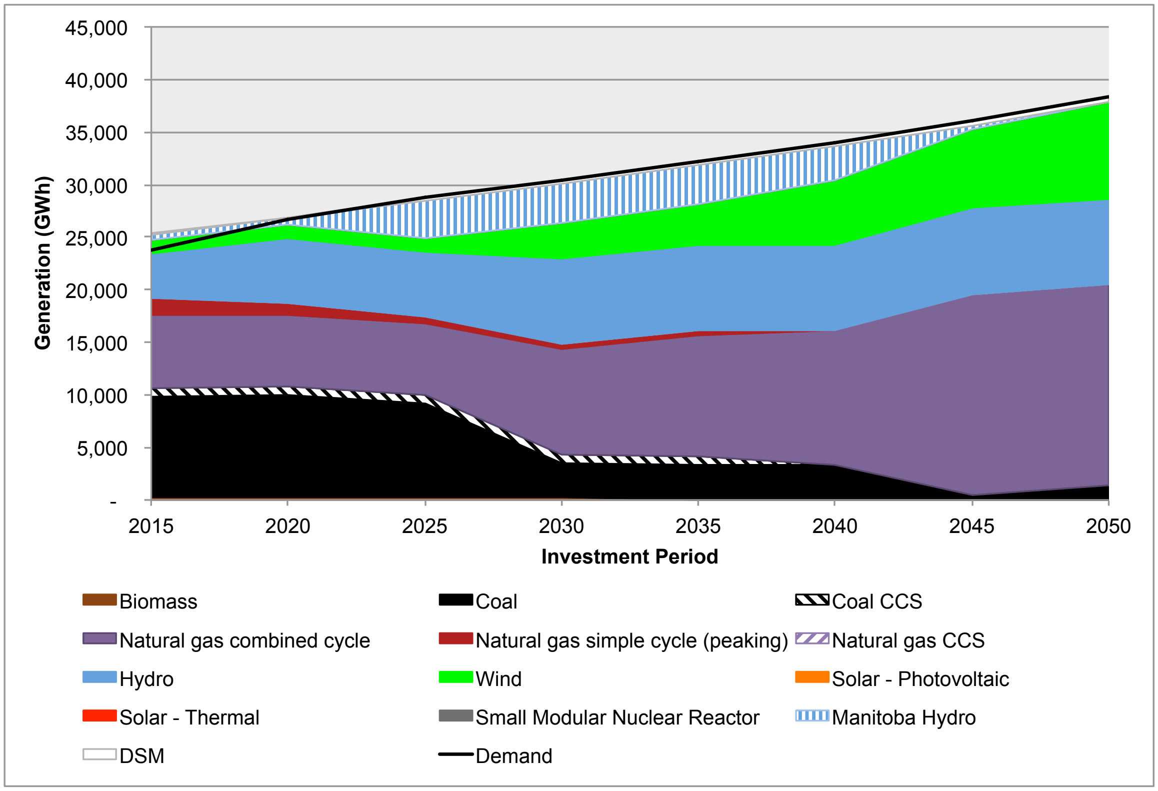


Figure 7-4 Federal Regulation Equivalency Scenario

Two changes are worth noting in this *Equivalency Scenario*. First, the province continues to operate conventional coal plants out to 2050. In the short-term, Boundary Dam units IV and V are retrofitted in 2020 to allow their operation for another 25 years. Second, no coal facilities are retrofitted with carbon capture and storage (CCS). Only Boundary Dam III operates as a CCS facility until its retirement in 2040. As outlined in Chapter 5, CCS is an expensive means of generating electricity and it is not selected by the cost minimizing optimization model. Instead, hydroelectric capacity is expanded in the province and agreements are made with Manitoba Hydro to supply 759 MW of power by 2035. Wind capacity expands substantially once the Poplar River and Boundary Dam VI coal plants are retired in 2030. It is accompanied by increased investments in natural gas-fired combined cycle facilities. In the 2030 time-step this approach increases average electricity costs by .81 cents/kWh relative to a scenario without regulation. Compare this to an increase of 1.70 cents/kWh in the SaskPower BAU scenario. In the 2035 time-step the equivalency approach increases average electricity costs by .86 cents/kWh, while the SaskPower approach, which relies on CCS, increases costs by 1.64 cents/kWh. On average from 2030-2050 the equivalency approach saves .86 cents/kWh relative to the SaskPower approach.

Figure 7-5 compares the pathway of average electricity prices under the three scenarios: SaskPower's BAU response to federal regulations; an equivalency approach to achieving the same GHG reductions; and a scenario where no policy is enacted to limit GHGs. The expected average prices for each scenario are joined by the solid lines. The 5% and 95% confidence intervals are represented using the error bars that surround each price point. Note that the confidence intervals for the equivalency scenario overlap with the no-policy scenario in several time-steps.

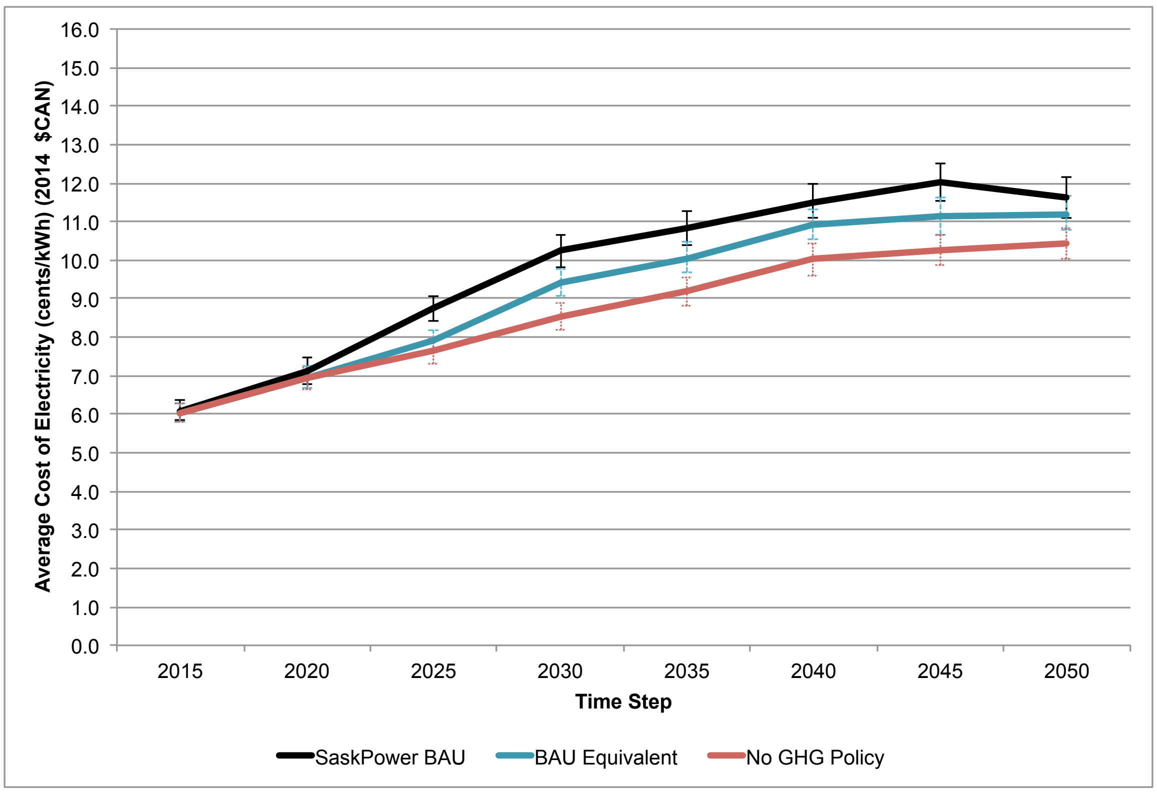


Figure 7-5 Average Electricity Prices Comparing Federal Regulation to Equivalency

The confidence intervals in Figure 7-5 reflect three sources of uncertainty:

1. The rate at which capital costs will change for electricity generation technologies;
2. The rate at which power purchased from Manitoba Hydro will increase in price;

3. The future price of natural gas.

A Monte Carlo analysis was conducted allowing each of these factors to vary within a specified range. Due to lack of data, a Triangular distribution was chosen for each uncertain parameter. The distributions were bounded in the following manner:

1. The autonomous capital cost improvement (ACCI) parameter for each electricity generation technology was bounded by .5% on either side of the preset value. The only exception is nuclear, which has a likely value of 1.54% (the preset value derived from EIA, 2015), and which is bounded by 2.04% on the high side and 0% on the low side. This lower bound for cost improvement is based on historic difficulties achieving cost reductions (Grubler, 2010; Boccard, 2014);
2. The likely cost escalation factor for Manitoba Hydro power was set at 1% and was bounded by a .5% minimum and a 1.5% maximum;
3. The NEB (2013) reference price is set as the most likely price of natural gas, and the distribution is bounded by the high and low NEB (2013) forecast natural gas prices for each time period.

Using these distributions I ran 1000 Monte Carlo trials using Frontline Solver's 'Risk Solver Pro' software. The results from these simulations were used to create the confidence intervals in Figures 7-5, 7-11, 7-18, and 7-22.

Long-Term GHG Reduction

The federal coal-fired regulations achieve a nearly fifty-percent reduction of Saskatchewan's electricity sector GHGs by 2035 followed by no further reduction to 2045. This is a substantial improvement, but as Figure 7-3 indicates, GHG emissions in the electricity sector begin to increase after 2045 as natural gas combined cycle plants expand to meet growing demand.

Further reductions are required if the province is to contribute to global efforts to mitigate climate change. In their Fifth Assessment Report, the IPCC (2014) outlines several scenarios for our future climate. In scenarios where it is likely (although not certain) that average temperature change will remain below two degrees Celsius relative to pre-industrial levels, atmospheric concentrations of GHGs lie in the realm of 450 ppm CO_2e by 2100. To achieve these scenarios, and stabilize atmospheric concentrations at or below 450 ppm CO_2e, global GHG emissions must be near zero by 2100. This requires a significant transformation of our energy systems. Low-carbon energy must compose over 90% of primary energy by 2100 and substantial gains need to be made by 2050. (IPCC, 2014)

Saskatchewan once had a provincial target of reducing GHGs to 80% below 2004 levels by 2050. This target was first proposed by the NDP government, and was upheld by the Saskatchewan Party government in their first term. The Saskatchewan government has since backed away from the 2050 target and instead current legislation reads, “The Lieutenant Governor in Council shall establish a greenhouse gas emission reduction target for Saskatchewan for a year or years selected by the Lieutenant Governor in Council” (Government of Saskatchewan, 2015). A new GHG reduction target has not been set at the time of writing this dissertation.

GHGs from the ‘public electricity and heat production’ sector in Saskatchewan measured 16,705 kt CO_2e in 2004 and decreased to 16,010 kt CO_2e by 2013 (Environment Canada, 2015b). In the scenario below, I use SIM to solve for the least-cost pathway to achieve an 80% reduction in GHGs by 2050 relative to 2015 levels. There are three variations of this scenario; one allowing imports of hydroelectricity from Manitoba of up to 1950 MW, another relying on electricity produced in Saskatchewan alone, and a third that excludes both nuclear power and increased imports from Manitoba Hydro. All of the scenarios include the 100 MW that Manitoba Hydro has already agreed to provide to SaskPower between 2020 and 2040. As a caveat, I focus only on direct GHG emissions and not the life-cycle GHG emissions related to each technology. More work could be done to understand the full lifecycle GHG implications of each electricity scenario.

80% GHG Reduction: Scenario 1 – Interprovincial approach

To generate the first 80% GHG reduction scenario, I run SIM using all available technologies, including hydropower from Manitoba. The resulting electricity generation mix is presented in Figure 7-6 below.

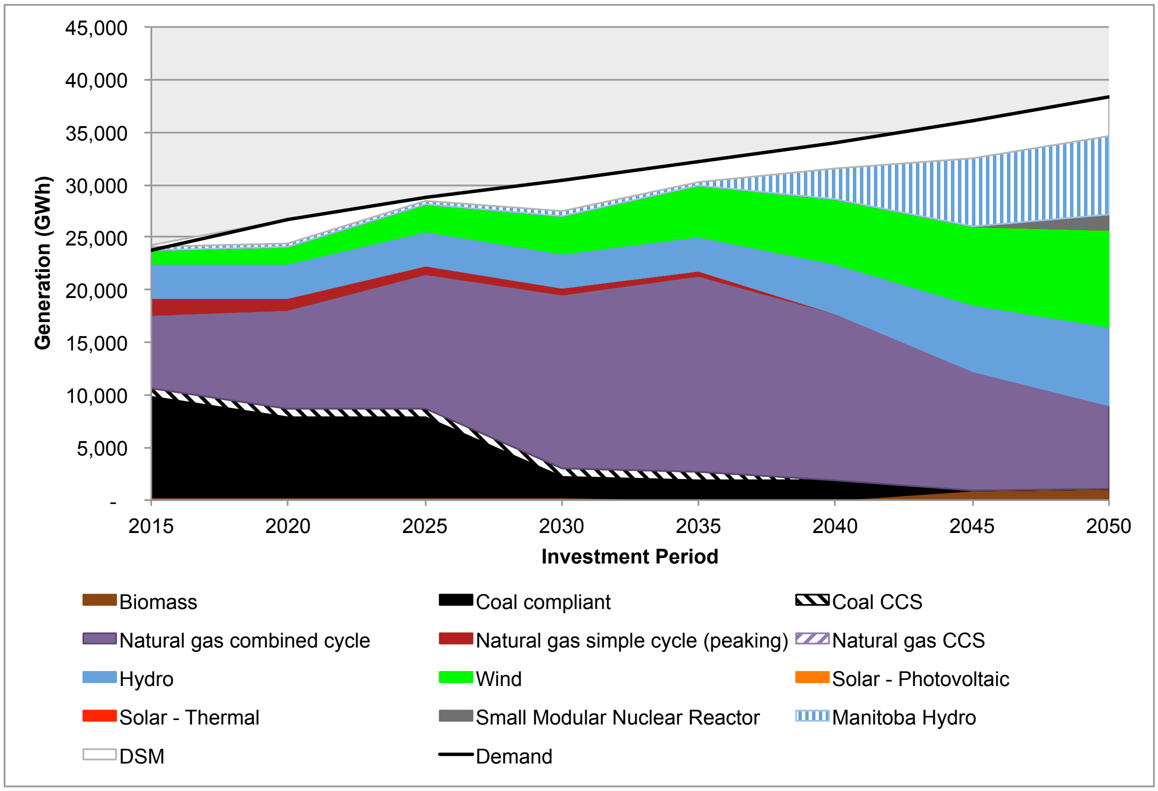


Figure 7-6 80% GHG Reduction: Scenario 1 – Interprovincial Approach

In this future the coal-hydro nexus of Saskatchewan's past is replaced by a wind-hydro nexus. By 2050 wind power meets 24% of electricity demand, domestic Saskatchewan hydro meets 20%, and imported hydro from Manitoba meets another 19% of total demand. Biomass plants provide 150 MW of capacity beginning in 2045, partially replacing the Shand coal-fired station, which is retired in that period. Assuming a continual cost improvement of 1.54%/yr – the relatively optimistic cost improvement factor outlined in Chapter 5 – one 209 MW modular nuclear reactor is built in the province in 2050 and provides about 4% of supplied electricity. Lastly, significant efforts are put into demand side management; conservation efforts offset about 10% of expected electricity demand in 2050.

Note that in this scenario coal plants are retired at the end of their useful lives; options to retrofit existing coal plants are excluded except for the Shand station which continues to operate until 2045. As well, the amount of electricity that can be generated by wind is constrained to 6% in 2020, which corresponds to SaskPower's commitment that wind will compose 10% of capacity by that time. Allowable wind generated electricity then increases by 3% in every time step; in 2030 12% of electricity can be generated by wind, corresponding to SaskPower's commitment that wind will compose 20% of capacity by that time; in 2050 24% of electricity can be generated by wind. This assumes that SaskPower will gain experience integrating wind into the electricity system. This is a broadly accepted assumption; most of the experts that took part in the participatory modelling workshops believed that variable renewables like wind and solar could contribute at least 24% to the Saskatchewan electricity system by 2050.

I use the WIRE model to test whether this scenario could sufficiently meet electricity demand in four representative months: March, June, September and December. The resulting system operation in December of 2050 is displayed in Figure 7-7. The jagged green portion of the image shows the variable contribution of the 2800 MW of wind. Along the bottom, the biomass plants (brown) provide a steady supply of power. The purple bar above shows natural gas combined cycle plants reacting to variations in wind power. Domestic hydroelectric power (light blue) also acts as a balancing technology and ramps up to provide power when wind power drops off. Imports from Manitoba Hydro fill the remaining gap. Because it is December, a period of reduced stream flows, the capacity factors for both domestic and Manitoba hydropower production are constrained to 48% in the WIRE model; the domestic hydro plants achieve this capacity factor, while the 1950 MW Manitoba Hydro link operates at only a 30% capacity factor. The Manitoba Hydro link does provide a peak supply of 1367 MW in hour 523 when wind power production falls to 22 MW. As outlined in Appendix 7B, I assume that the hydroelectric facilities can ramp up to full capacity within an hour and that hydroelectric potential can be stored in reservoirs when not needed.

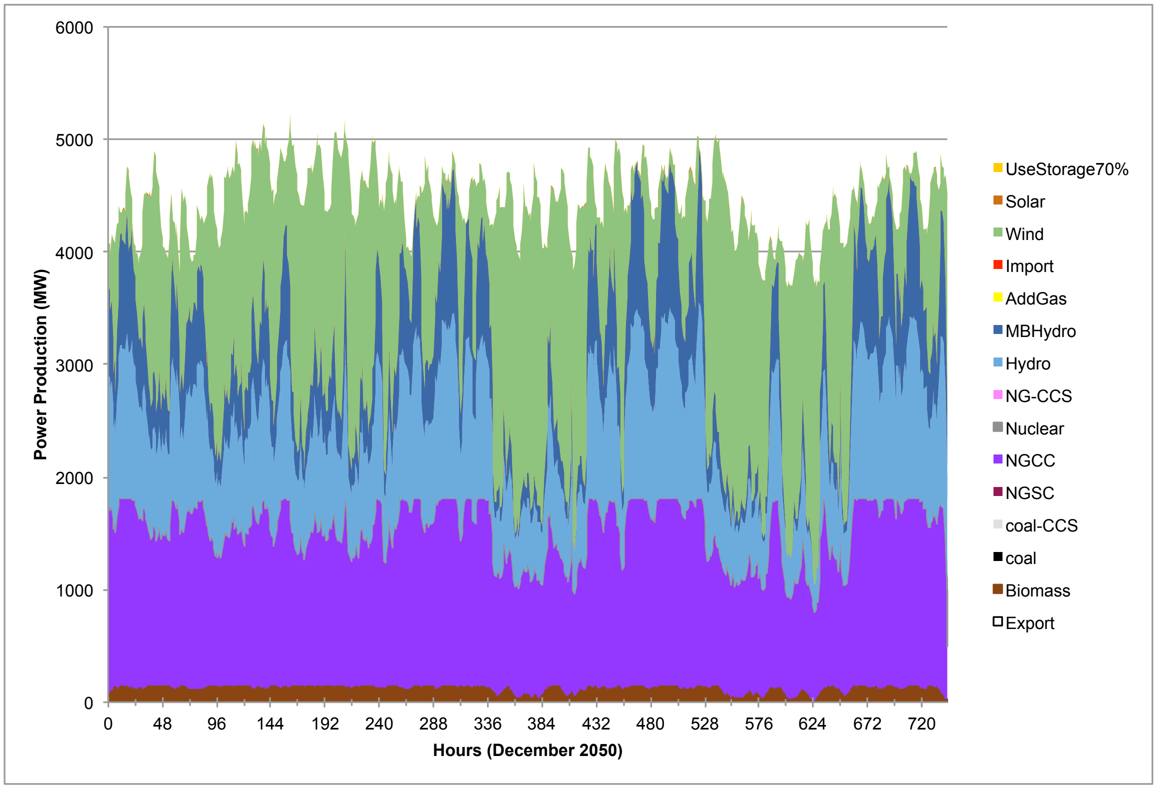


Figure 7-7 80% GHG Reduction Scenario 1 in Operation (December 2050)

This GHG reduction scenario relies on transmission links between Saskatchewan and Manitoba of 1950 MW. SaskPower and Manitoba Hydro have signed a memorandum of understanding for SaskPower to purchase 500 MW, but another 1450 MW would be necessary. This is not outside the realm of possibility. Manitoba Hydro is currently working to construct the Keeyask Generating Station on the Lower Nelson River in the northern Manitoba (Manitoba Hydro, 2015). The Keeyask station will provide 695 MW of capacity, and 4,400 GWh of electricity per year (Manitoba Hydro, 2015). Saskatchewan's purchase of 100 MW from Manitoba Hydro will be provided by the Keeyask station. Manitoba Hydro has recently postponed development of the 1485 MW Conawapa Generating Station. Manitoba's provincial electricity regulator has expressed concerns that export demand is not high enough to justify the project (Puxley, 2014). An export contract with SaskPower could bring that project back to life and supply low-carbon electricity to replace SaskPower's coal plants and meet Saskatchewan's growing electricity demand.

80% GHG Reduction: Scenario 2 – Nuclear Approach

Proposals to purchase electricity from Manitoba may, however, meet with resistance from Saskatchewan citizens and government leaders interested in using the electricity sector as a means of economic development. For that reason, it is useful to look at how SaskPower might achieve an 80% reduction in GHGs by 2050 using only domestic electricity supply (aside from the 100 MW purchase from Manitoba Hydro). When the target of 80% GHG reduction is constrained to Saskatchewan electricity generation sources alone, the following generation mix is selected by SIM (See Figure 7-8).

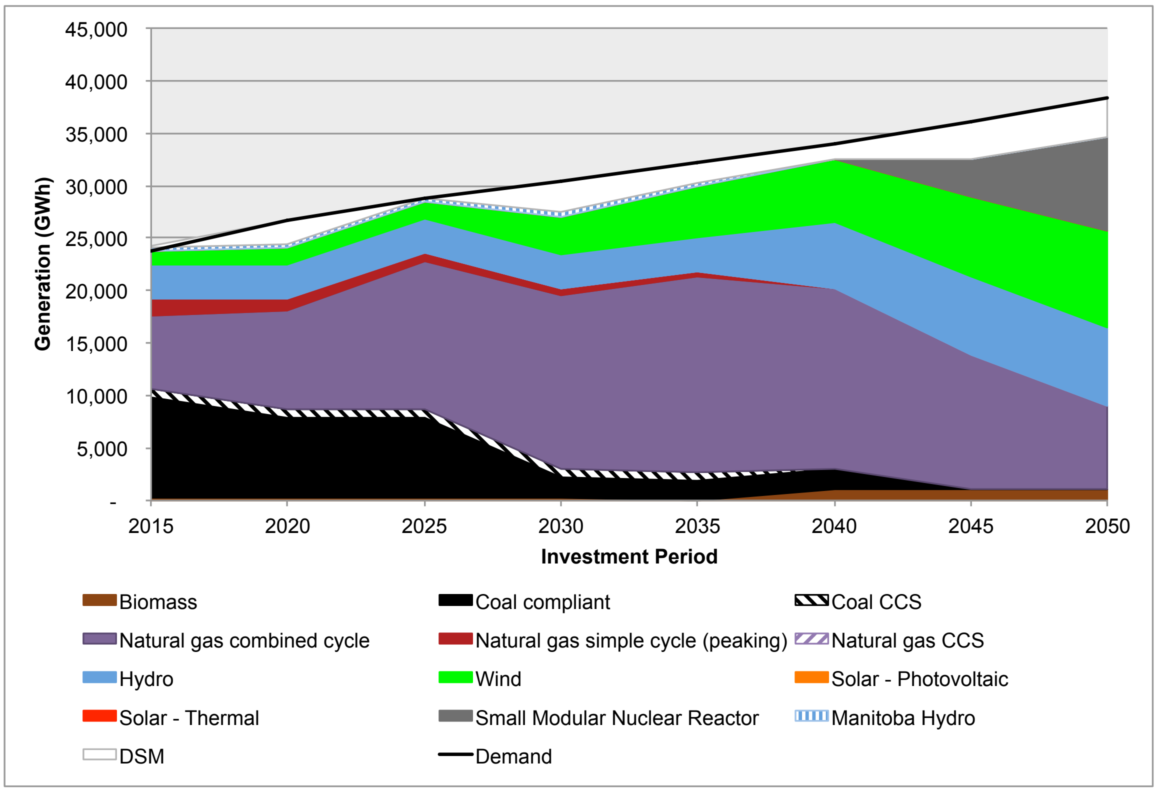


Figure 7-8 Domestic 80% GHG Reduction: Scenario 2 – Nuclear Approach

In this scenario about 500 MW of small, modular nuclear reactor capacity is built in 2045 and another 720 MW of nuclear is built in 2050. In 2050, nuclear generates 23% of electricity. Wind generates 24% of electricity in 2050 and is again limited to this amount by a constraint in the model. In operation, slow-ramping nuclear provides steady "base-load" power, adjusting occasionally for periods of high wind. Natural-gas fired generation makes up 1666 MW of capacity and domestic hydroelectricity makes up about

2000 MW. Both of these more flexible electricity generation sources can be ramped up and down to balance variable wind production (See Figure 7-9).

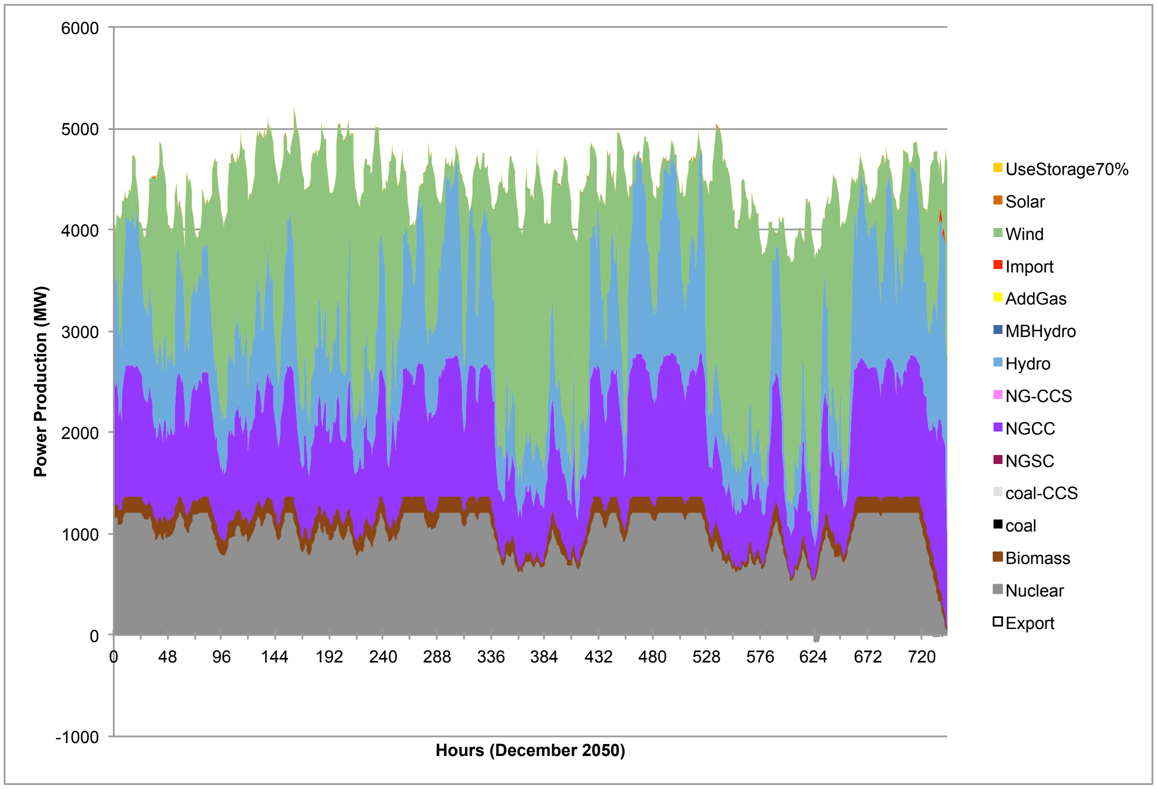


Figure 7-9 80% GHG Reduction Scenario 2 in Operation (December 2050)

80% GHG Reduction: Scenario 3 – CCS Approach

Though this nuclear scenario was selected by SIM, we can ask, is a nuclear powered future desirable? The technology is controversial, even in Saskatchewan where, as one participant noted, "everyone has stocks in (uranium mining giant) CAMECO". There are also substantial costs and risks above and beyond the construction and operation numbers in SIM. Decommissioning a nuclear reactor at the end of its useful life is an expensive endeavour. In Ontario, decommissioning will cost the nuclear utilities \$6 billion (Winfield *et al*., 2006 quoting OPA, 2005). The Ontario Power Authority estimated the "total cost for facility decommissioning" to be \$7.5 billion (2003 \$CDN) (OPA, 2005: 114). Boccard (2014) estimates that decommissioning costs for the French nuclear fleet will be a minimum of 25% of the original investment cost of building the fleet; an increase from the 15% of original investment assumed by the IEA. Nuclear power also poses health risks, which are ill-suited for monetary valuation. For example, a study by Kaatsch *et al*. (2008) found a relationship between Leukaemia in young children and vicinity to German nuclear power plants. These health risks have galvanized opposition to nuclear. When Saskatchewan citizens were asked in 2009 whether they wanted a nuclear power plant, they responded with a resounding “No” (Perrins, 2009). Citing research such as Kaatsch *et al*. (2008) one participant stated, “Any risk to our health or our children’s health is unacceptable” (Dolter and Arbuthnott, 2010).[67]

To address the concerns over the real and perceived risks imposed by nuclear power generation we can ask, what would a domestic 80% GHG reduction scenario look like without nuclear power? Figure 7-10 outlines one pathway.

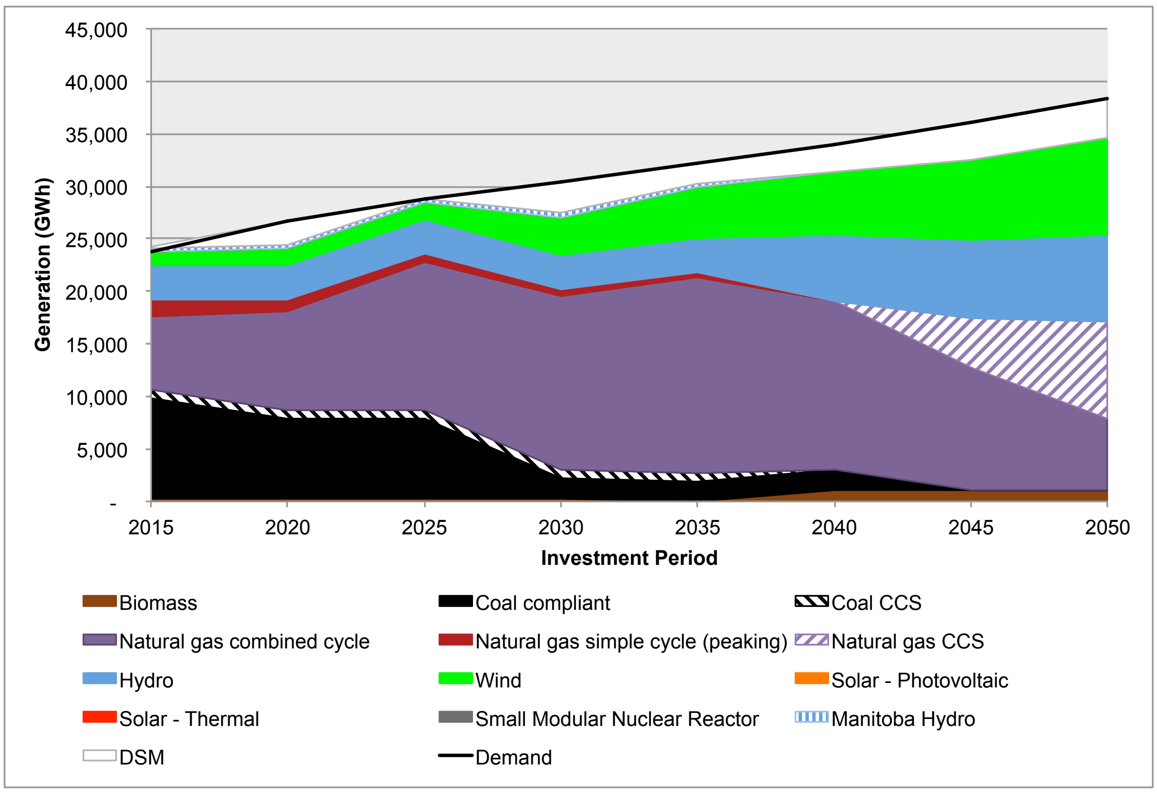


Figure 7-10 80% GHG Reduction: Scenario 3 – Carbon Capture Approach

[67] In Saskatchewan, there has been less public concern over health risks from coal-fired power generation, including mercury exposure. Some concern has been expressed over the health impacts of wind, most notably in the Maclean area (see Chapter 3).

In this scenario, natural gas combined cycle generation (NGCC) with carbon capture and storage (CCS) fills the gap that was previously filled by small, modular nuclear reactors. Biomass again makes a contribution up to the 150 MW limit, wind pushes to the constraint of 24% of total electricity by 2050, and 2194 MW of domestic Saskatchewan hydroelectric capacity is constructed. This scenario relies on the viability of applying CCS technology to natural gas fired plants. Saskatchewan has achieved a world-first in building the coal-fired CCS plant at Boundary Dam III. Could the province also host a pioneering natural gas fired CCS facility? And, importantly, could it be built at the costs assumed in SIM and outlined in Chapter 5?

Cost of the Three 80% GHG Reduction Scenarios

The three scenarios for reducing GHGs by 80% by 2050 generate a range of electricity generation cost impacts. Figure 7-11 compares average electricity costs for the three GHG reduction scenarios against the SaskPower BAU plan. The error bars again indicate 95% confidence intervals, taking into account uncertain technological change, Manitoba Hydro price increases, and natural gas prices.

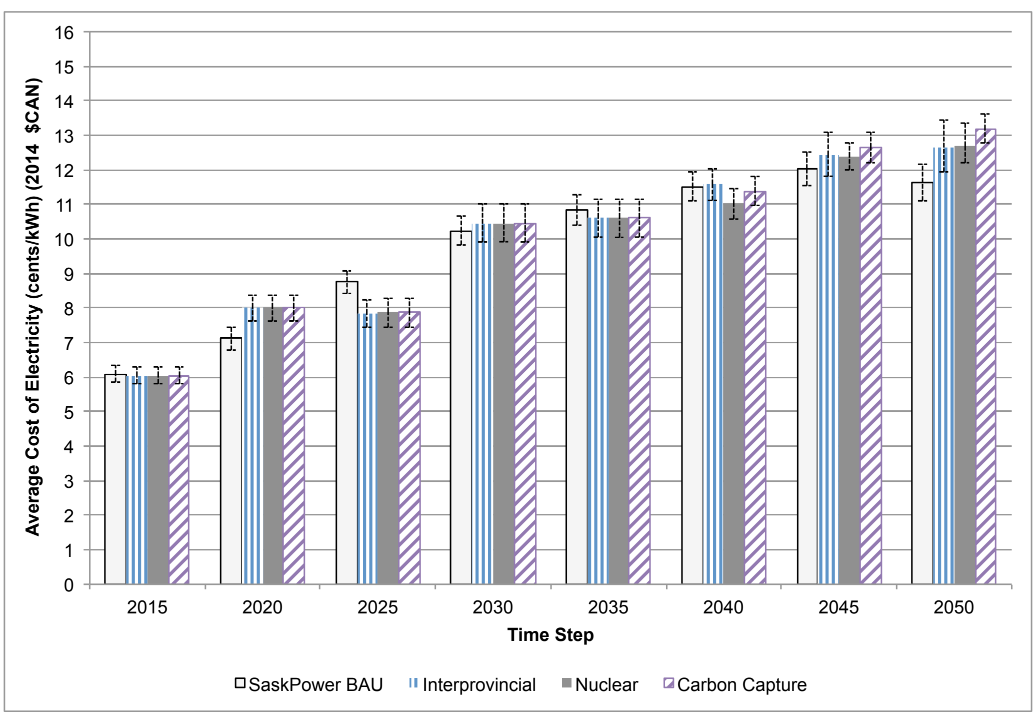


Figure 7-11 The Cost of Achieving 80% Reduction in GHGs by 2050

What is striking about these GHG reduction scenarios is that their costs are not significantly different than costs in the BAU scenario. From 2030 to 2045 the 95% confidence intervals of the GHG reduction scenarios overlap with the confidence interval of the BAU scenario. Even in 2050 – a time when GHG emissions are increasing in the BAU scenario – the interprovincial scenario, which involves importing hydroelectricity from Manitoba Hydro, has a 95% confidence interval that overlaps with the BAU scenario. On the high side, the carbon capture and storage scenario has an average expected electricity price of 1.57 cents/kWh higher than the BAU scenario in 2050. At worst, the gap between the 5% confidence interval for the BAU scenario and the 95% confidence interval for the CCS scenario is 2.52 cents/kWh.

Whether or not action is taken to reduce GHGs, the real cost of electricity will increase in Saskatchewan over time. With significant retirements of coal-fired capacity in the period of 2030 it is possible to plan now to transform the electricity sector in order to achieve lasting GHG reductions by 2050.

80% GHG Reduction: Scenario 4 – Renewable Approach

Besides the three GHG reduction scenarios outlined above, another pathway is possible, one that would focus investment on achieving a high penetration of renewable electricity generated within Saskatchewan. Groups like the *Green Energy Project Saskatchewan* (Bigland-Prichard, 2015; Prebble, 2011; Bigland-Pritchard, 2011; Bigland-Pritchard & Prebble, 2010; Bigland-Pritchard, 2010a & 2010b) and the *Saskatchewan Environmental Society* (Halliday, 2013) have begun to explore such a scenario. I continue this work by outlining a scenario where Saskatchewan reduces GHGs in the electricity sector by 80% by mid-century while also meeting 90% of electricity demand using domestic renewable energy and energy conservation. Figure 7-12 displays one possible generation mix that could fulfill those criteria.

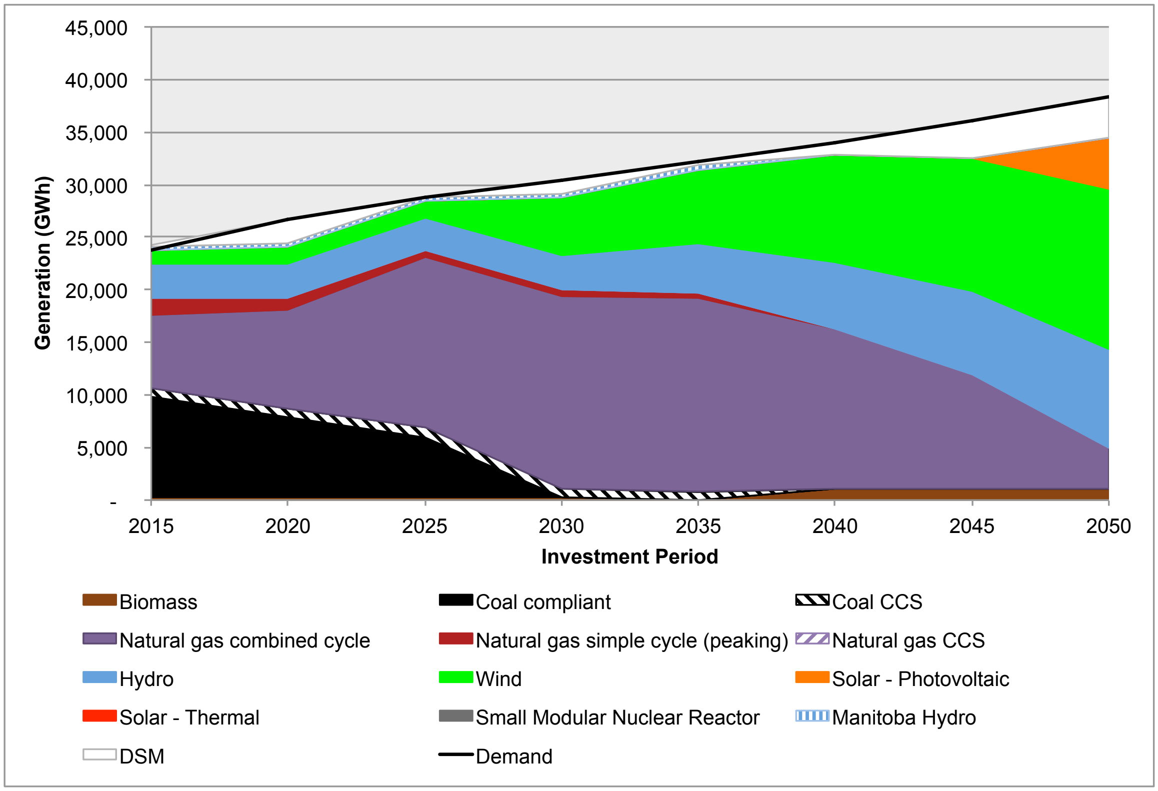


Figure 7-12 80% GHG Reduction: Scenario 4 – Renewable Approach

The first difference worth noting in this scenario is that the constraint on wind energy has been loosened. Rather than capping wind power at supplying 24% of electricity demand in 2050, wind is now allowed to supply up to 40% of total electricity demand in that time step. After subtracting the contributions of demand side management, which meets 10% of electricity supply in 2050, wind provides 44.4% of net electricity demand in this scenario. Solar photovoltaics supply 13% of total demand (14.2% of net demand). Hydroelectric capacity is expanded to reach almost the limit of Saskatchewan's current potential; 2494 MW of capacity is built, which would require several dams along the Saskatchewan River system, as well as the controversial Wintego dam mentioned in Chapter 3. Natural gas combined cycle plants act as the bridge fuel in this scenario, providing the bulk of electricity from 2025-2035, after which time wind capacity begins to increase substantially and natural gas fired facilities are allowed to retire. By 2050, 810 MW of natural gas combined cycle capacity supplies 10% of total electricity demand (11.1% of net demand).

For electricity planners at SaskPower, Scenario 4 probably looks like a reckless nightmare. How could variable wind and solar provide steady power for a growing province? This is exactly the question the WIRE model was created to answer. I use this model to ask, 'Will It Run?' The answer I received was yes; it will run. The results for December are presented in Figure 7-13.

Figure 7-13 80% GHG Reduction: Scenario 4 in Operation (December 2050)

With 4667 MW installed, wind can provide all of the province's power needs during a windy hour. When wind power production drops, fast-ramping natural gas combined cycle plants, hydroelectric facilities, and stored electricity pick up the slack. Figure 7-14 shows total installed capacity in Scenario 4.

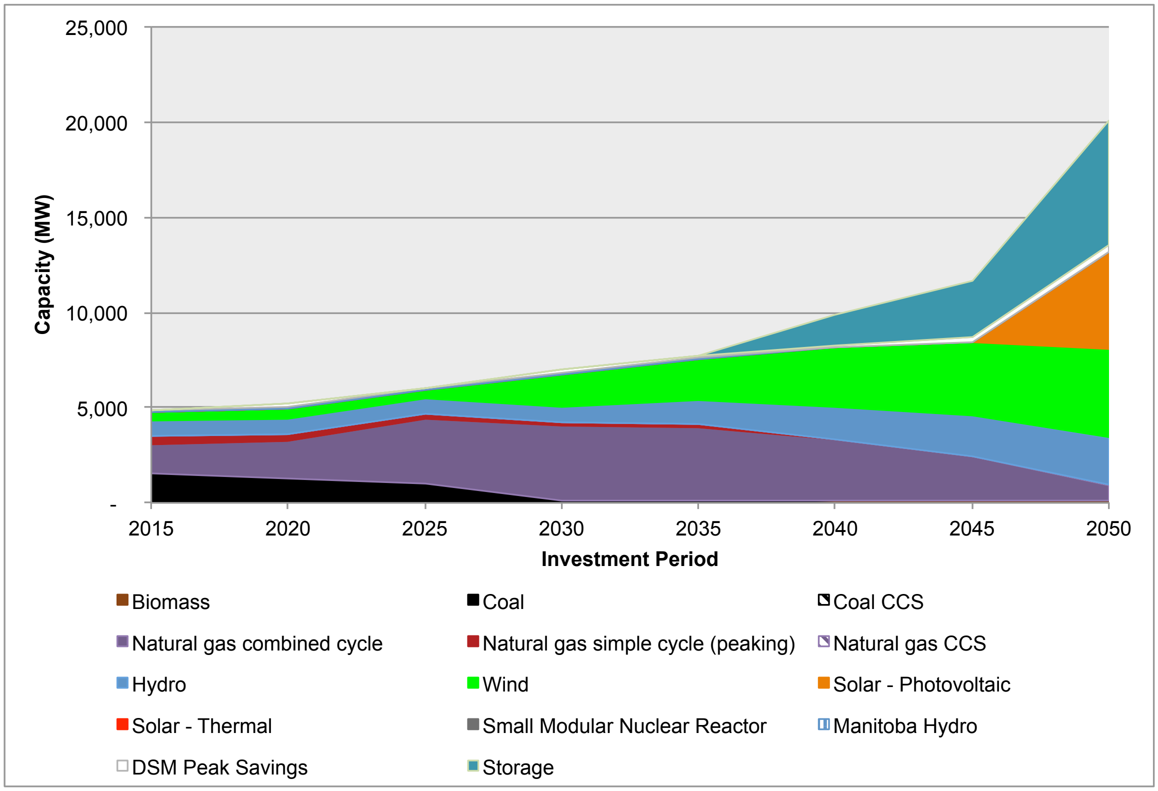


Figure 7-14 Electricity Capacity in Domestic Renewable Energy Scenario

In this scenario storage capacity plays an increasingly important role towards the end of the investment period (see teal blue wedge in Figure 7-14). By 2050 this scenario includes about 6500 MW of electricity storage capacity. This storage capacity is recharged in periods when sun and wind are abundant, and drawn down when it is cloudy and calm. The yellow bits at the peaks in Figure 7-13 (previous page) indicate when electricity storage is drawn upon. As can be seen, the stored energy becomes important in the latter part of the month when natural gas combined cycle plants and hydroelectric facilities are operating at full capacity and further energy is needed to meet demand. On an hourly basis storage capacity helps to smooth out the contribution of wind and solar energy. Storage capacity also adds to the cost of the electricity system.

Grid integration of wind and solar is aided by the demand side management (DSM) strategy of peak shifting. In this scenario 370 MW of peak shaving is allowed. I model this in WIRE by allowing electricity demand to be shifted three hours into the future (see Appendix 7B for further detail). This is introduced with the constraint,

$$Eq. 7.1\ \ DSMsavings_t = DSMspending_{t+3}\ .$$

This peak shaving feature allows DSM to smooth demand. Interestingly, peak shaving has the effect of smoothing *net demand*; this is electricity demand minus the generation of variable wind and solar electricity (recall the duck graph from Chapter 4). Figure 7-15 shows the impact of DSM peak shaving over the course of 72 hours in December 2050. As can be seen, the peaks are, at times, lower and the valleys higher once the DSM peak shaving has been applied. This shows the potential for smart grid technology to aid in variable renewable integration. The assumption that DSM savings can only be pushed three hours into the future means that not all of the peaks are shaved. Greater DSM flexibility, perhaps offered by smart grid technology, would allow for better peak shaving performance.

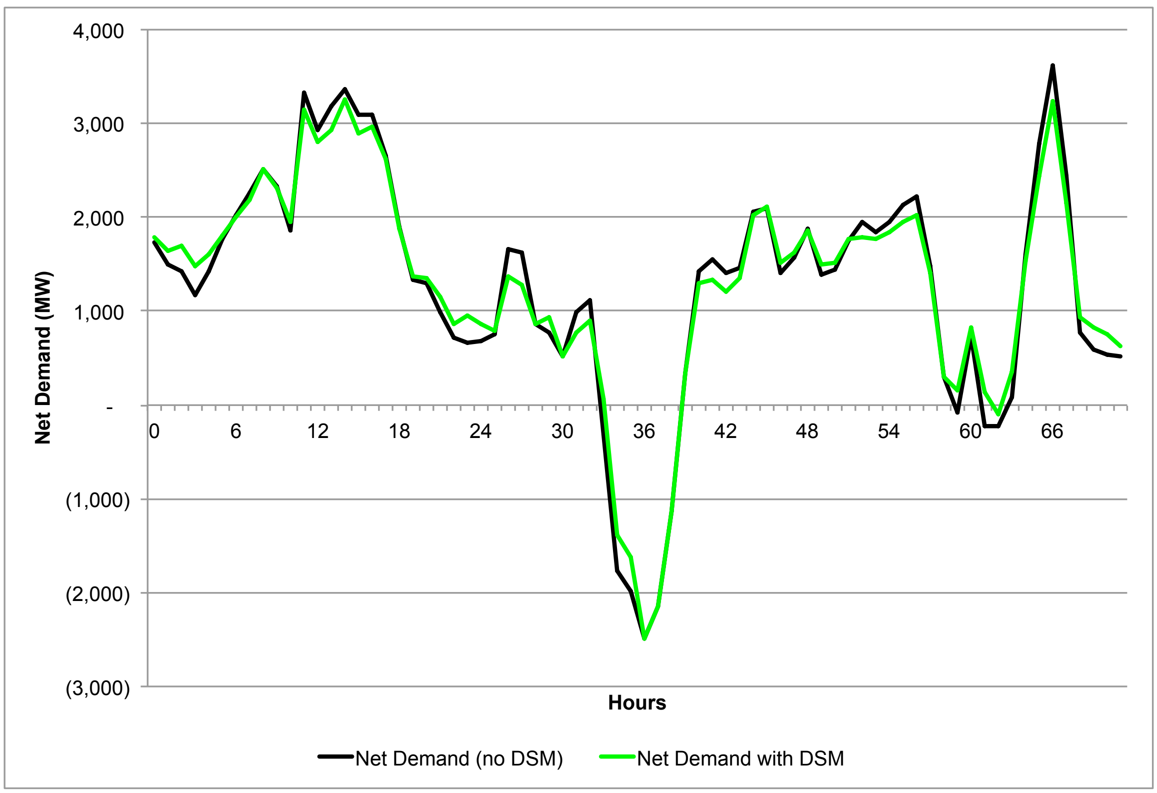


Figure 7-15 Peak Shaving Applied to Net Demand (December 7-9, 2050)

In the domestic renewable energy scenario (Scenario 4), 5085 MW of solar photovoltaics are built by 2050 (Figure 7-14). The contribution of solar power only occurs during the daytime hours as represented by the orange slices in Figure 7-13. Figure 7-16 provides a closer look at the dynamics of solar power over a period of six days in the middle of December. The orange bases indicate solar power that is used when generated. The grey shading at the peaks indicates solar power that is stored for later use. At no point during this six-day period is solar power curtailed. The need to curtail solar power is rare in December, and in total only .3 GWh of solar power is curtailed during the month.

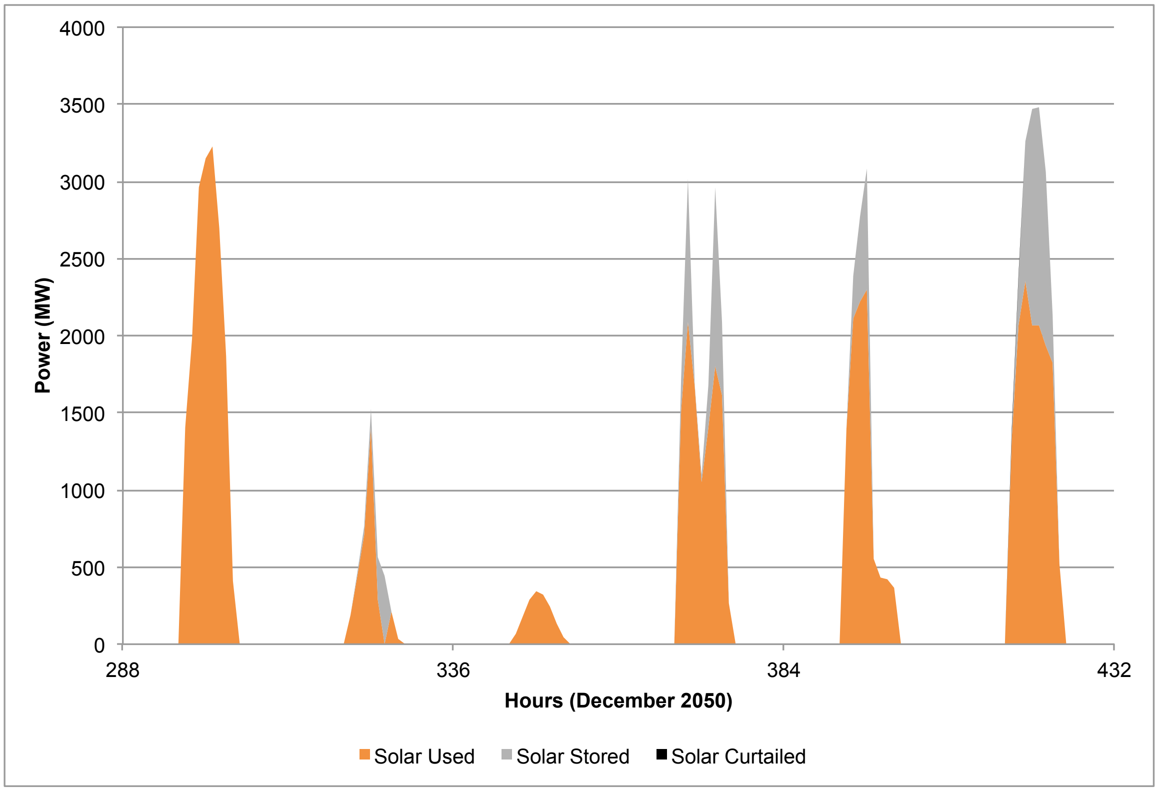


Figure 7-16 Solar Power Operation Domestic Renewable Scenario (December 13-18, 2050)

Figure 7-16 shows that solar power is highly variable from day to day. At its December peak, solar output reaches 4025 MW. Overall, solar achieves a capacity factor of only 11% in December when the shorter days limit the number of clear, sunny hours. As Figure 7-17 shows, solar offers a much larger contribution in June, when the days are longer and the solar capacity factor reaches 16%. Hydroelectricity is also abundant in

June when stream flows are charged from spring melt and hydro capacity factors average 71% in Saskatchewan. The abundance of solar and hydro power allows the electricity system to operate carbon-free in June; natural gas combined cycle plants are not required and the (effectively carbon neutral) 150 MW of biomass plants operate only during a few calm nights.

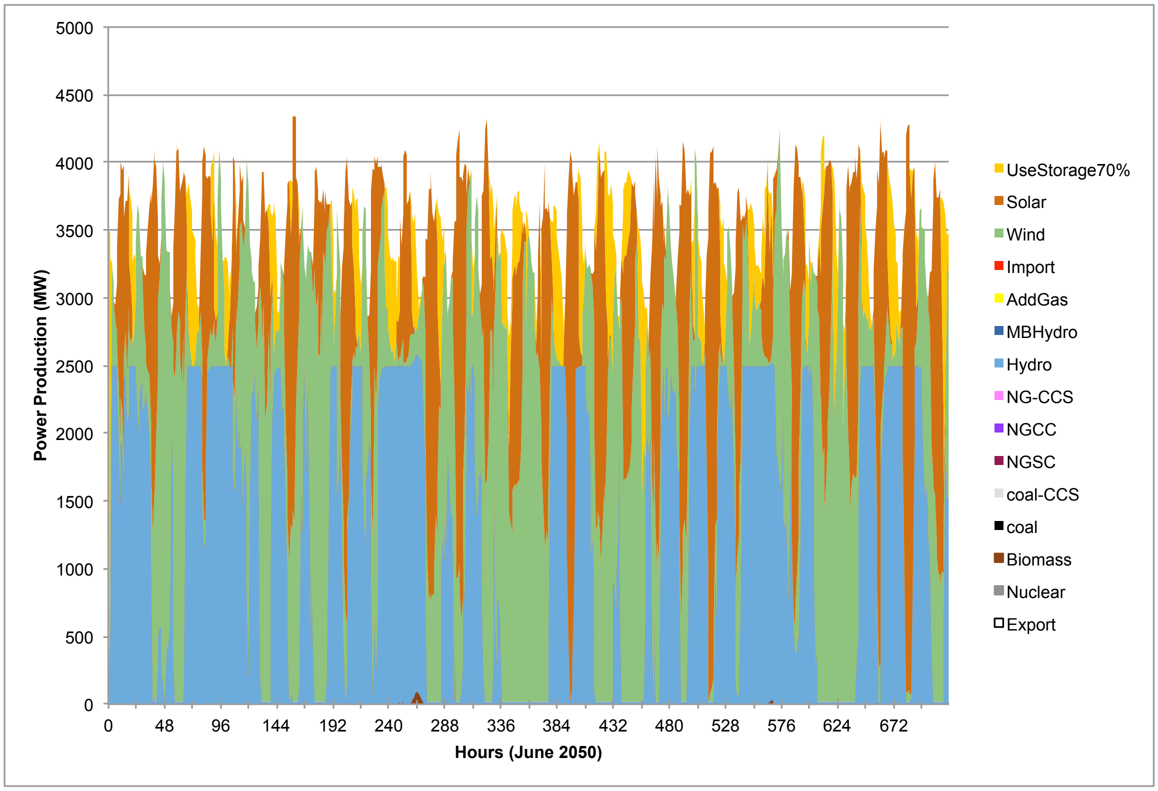


Figure 7-17 80% GHG Reduction: Domestic Renewable Scenario in Operation (June 2050)

This abundance of renewable energy in summer unfortunately does not correspond to peak electricity demand in the province. By scaling hourly electricity demand data for 2013 to anticipated load growth in 2050 (see Appendix 7B) I forecast average hourly electricity demand in 2050 to be 4.5 GWh/hour in December and 3.6 GWh/hour in June. This may prove inaccurate if climate change increases summer temperatures, and summer cooling loads begin to rival winter heating loads. I don't account for that possibility in my forecast. As it stands, the system is forced to curtail 24 GWh of solar power and 32 GWh of wind power in June under this scenario.

Liebig's Law of the Minimum Applied to Renewable Energy Planning

The seasonal differences in output for solar and hydroelectricity point to a renewable energy planning problem; a system sized to meet demand in periods of renewable energy scarcity will be over-sized in periods of renewable energy abundance. Scenario 4 arose out of an interaction between the SIM and WIRE models. The first round of SIM optimization called for more hydroelectricity. However, the optimization was based on an annual average capacity factor of 56% for hydroelectricity. When the scenario was tested in the WIRE model it could not meet demand in March. Due to low streamflows, hydroelectric capacity factors are constrained to 43% during that month and in a hydroelectric dominated system this created a significant electricity shortfall. I ran another optimization using the 43% hydroelectric capacity factor for March. This scenario recommended a greater proportion of solar photovoltaics. When I tested this scenario in WIRE, it would not run in December. The optimization had been based on an average capacity factor of 16% for solar, but in December the capacity factor for solar is 11%. I then allowed more wind to be constructed in order to balance out the low capacity factor for solar, and I ran a SIM optimization using the 11% capacity factor for solar. The result is Scenario 4. It provides adequate electricity in December and March, and an abundance of renewable electricity in June.

In agriculture, Liebig's *Law of the Minimum* describes the relationship between plant growth and levels of nitrogen, phosphorous, and potassium. Nitrogen helps plants grow their leaves, which are necessary for photosynthesis. Phosphorous helps plants create roots that bring in water and nutrients, and flowers and fruit that allow the plant to reproduce. Potassium strengthens the stem of the plant and encourages growth. Liebig's *Law of the Minimum* holds that growth of a plant is constrained by the essential nutrient that is most scarce. If even one of these essential nutrients is in short supply the growth of the plant will be stunted.

Planning for a renewable electricity system is similar. In order for the system to provide sufficient power, adequate supply must be available for the moments when renewable energy is most scarce.

On the arid plains, the spring season introduces a minimum for hydroelectricity. Hydroelectric dominated systems must be sized to provide adequate power in March, especially during periods of extended drought when reservoirs have been run down.

In the northern latitudes, the winter season introduces a minimum for solar power. Systems with a high penetration of solar power must have adequate back-up generation for the long, cold nights of December (see Figure 4-5).

Wind is seasonally variable, and is complementary to solar in that it is often windier during the night (see Figure 4-10) and in winter. Wind is, however, quite variable from hour to hour. In the WIRE model, electricity storage technologies can provide backup power on an hourly scale; the 6462 MW of storage has a capacity to hold 12 GWh of electricity, which when conversion loss is considered, can provide 8.4 GWh of energy at an instantaneous rate of 4.5 GW. This storage capacity helps to smooth the hourly micro-variability of renewables like wind and solar. Storage technologies that could provide this hourly smoothing benefit include lithium-ion batteries, compressed air electricity storage, and pumped hydroelectric storage (McPherson, 2014; Jones, 2015).

To pursue an electricity generation mix with a high penetration of variable renewables, and to ensure energy security, seasonal storage would be an asset. The Lake Diefenbaker hydroelectric reservoir offers 445 GWh of seasonal storage in Saskatchewan (personal communication, 2015). The Nipawin reservoir provides storage of 5 GWh, which may be useful to balance variable wind production over the course of a few hours, while E.B. Campbell provides 33 GWh of storage, which can provide balance over the course of a few days (personal communication, 2015). If future hydroelectric developments were equipped with reservoirs capable of seasonal storage then it would be possible to reduce the overall size of the installed system capacity, avoid curtailment, and lower the cost of Scenario 4. Many of the potential hydroelectric sites in Saskatchewan are, however, suitable for only run-of-the-river projects that would lack reservoir capacity (Interview 31).

One emerging technology that could provide seasonal storage is hydrogen (McPherson, 2014). McPherson writes, "hydrogen storage can mitigate seasonal storage by generating hydrogen from electricity using an electrolyzer and storing that hydrogen in an underground cavity or above ground tank over the course of weeks to months" (2014: 6). This would allow abundant solar and hydro electricity generated in summer to be stored until demand peaks in winter, and in effect, convert variable *flows* of renewable electricity into a *stock* of fuel that can be drawn upon when necessary. Saskatchewan's natural gas storage caverns and solution-mined potash mines offer potentially low-cost options for hydrogen storage caverns (Steward *et al*, 2009). Hydrogen can also be processed into methane by adding carbon dioxide (Jentsch *et al.,* 2014). Germany is exploring methods of converting electric power to methane "biogas" as a way of providing long-term electricity storage,

> The storage concept links power and gas networks by the conversion of power into gas by two major steps: hydrogen (H_2) production by water electrolysis and the following conversion of H_2 and carbon dioxide (CO_2) into methane (CH_4) in the Sabatier reaction. In this way, renewable electricity can be stored in the natural gas infrastructure, accessing the large transport capacities of the natural gas network and gas storage sites that offer the largest storage capacities for energy in Germany.
> (Jentsch *et al.,* 2014:)

Saskatchewan would be well served by directing research efforts towards long-term seasonal storage of energy.

As a note, the current version of WIRE does not include the possibility of seasonal storage. The model proved computationally intractable when making 8760 x *i* generation and storage decisions – *i.e.* the WIRE optimization would run for periods of up to twelve hours without returning a solution. In future research I may work to overcome this limitation, include seasonal storage in the model, and combine SIM and WIRE.

Cost of the Renewable Pathway

The domestic renewable pathway results in lower average electricity prices than the BAU scenario in the time steps from 2025-2040 (Figure 7-18). This is because the constraint on wind energy has been loosened and wind is a low-cost generating technology. The domestic renewable scenario then becomes the most expensive scenario in the last two time steps when solar and electricity storage are constructed in large quantities. In 2050, the expected average electricity price in the domestic renewable scenario is 13.7 cents/kWh. By comparison, in the interprovincial scenario that relies on a 1950 MW connection to Manitoba Hydro, the expected price is 12.5 cents/kWh. Both scenarios meet the same target of reducing GHGs by 80% below 2015 levels by 2050, but the interprovincial scenario relies on renewable energy and energy conservation to meet 75% of demand, while the domestic renewable scenario achieves 90% renewable energy. The ambitious reader may be left wondering, can we do more and how much it would cost?

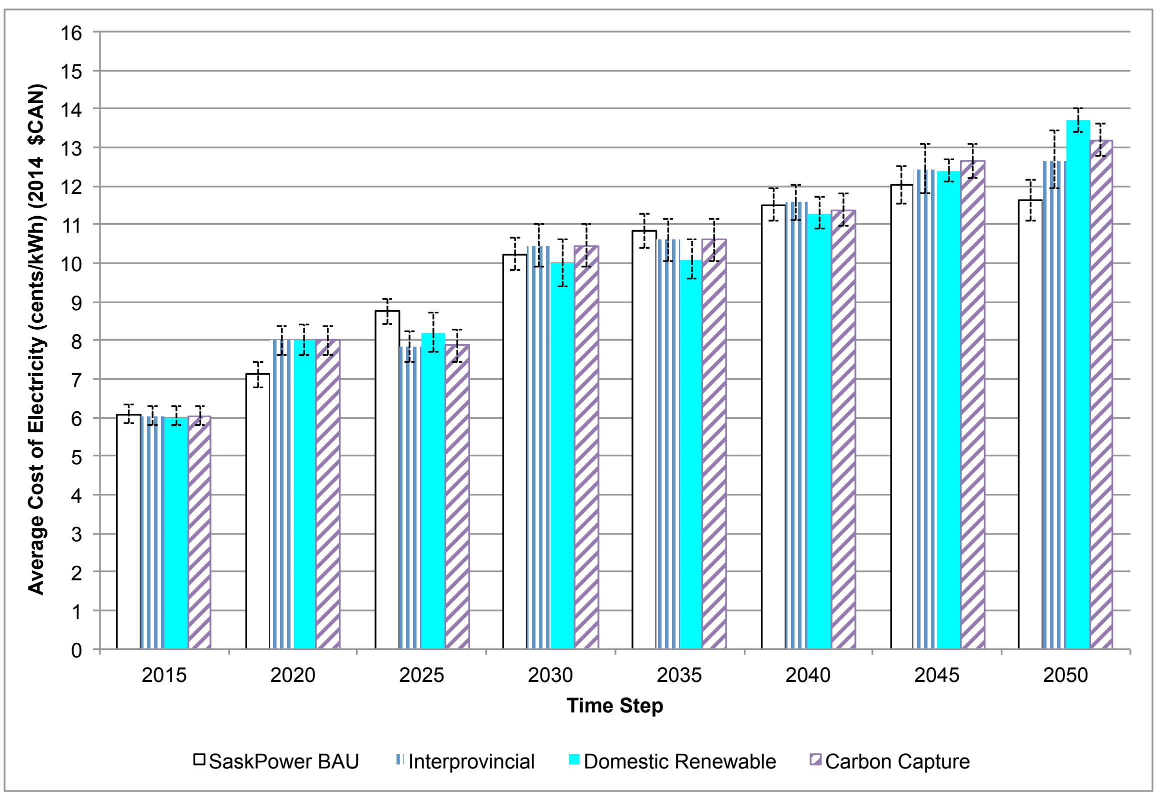


Figure 7-18 Relative Cost of the Domestic Renewable Pathway

Greening the Saskatchewan Grid

As a last task in this Chapter I ask, how much would it cost to achieve an aggressive GHG reduction strategy? This strategy would not wait until 2045 to pursue renewable energy and would instead see SaskPower undertake a complete transformation of the grid in the period following the retirement of Saskatchewan's coal-fired power plants in 2030. This scenario would achieve near-zero GHG emissions by 2040. It would see conventional coal phased out by 2030, and conventional natural gas facilities phased out by 2040. Renewable energy and energy conservation would meet 78% of electricity demand by 2030, 94% by 2040 and 95% by 2050. This achievement would make Saskatchewan one of the leaders in renewable electricity generation in Canada and the world.

In this *Greening the Saskatchewan Grid* scenario, I allow imports of 1950 MW of power from Manitoba Hydro. As the scenarios above show, this helps to keep electricity rates low and helps to balance variable wind and solar energy. I retire the Shand coal-fired power plant in 2025, rather than retrofitting it to run until 2045. I allow wind-powered electricity to meet 24% of total demand by 2030 and 35% by 2050. I then constrain the model to reduce GHGs to 100 kt CO_2e by 2040. When the resulting *Greening the Grid* scenario was tested in WIRE it ran in each of the four representative months. This *Green Grid* scenario is presented in Figure 7-19.

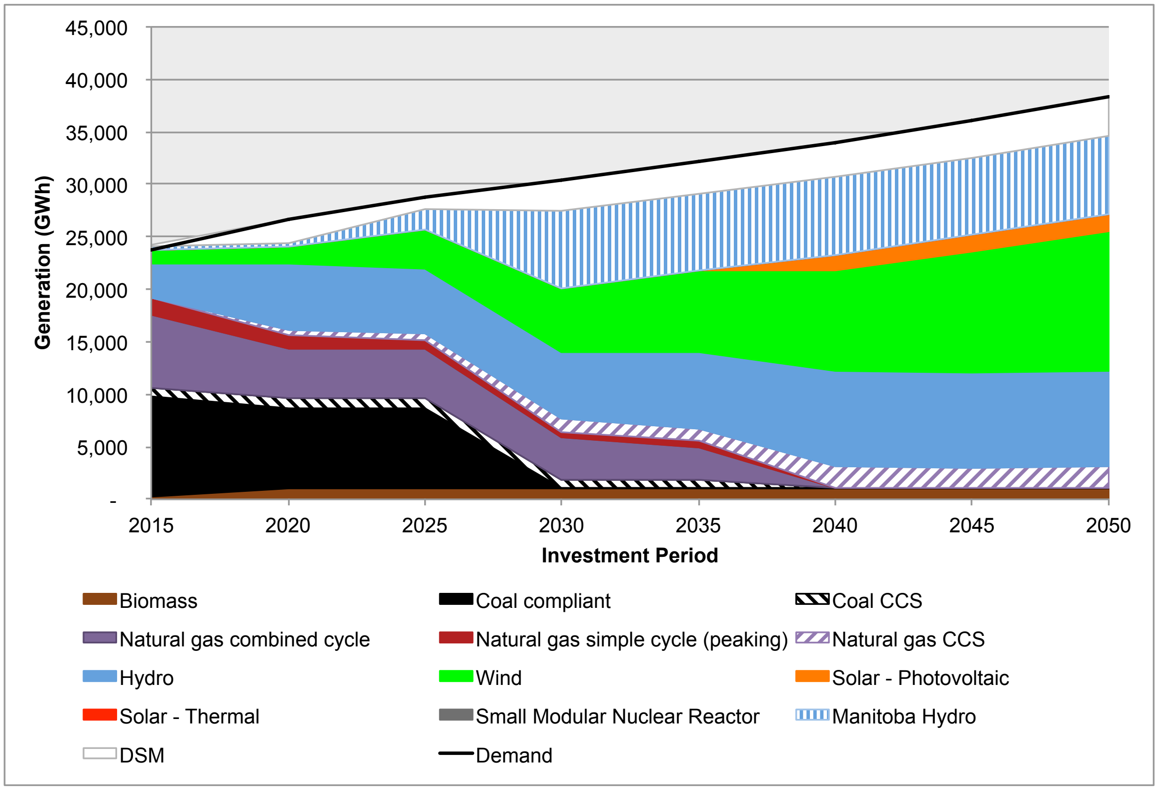


Figure 7-19 Greening the Grid Electricity Generation Mix

Figures 7-20 and 7-21 allow us to compare the GHGs from the *Greening the Grid* scenario to those of Scenario 4: the domestic renewable energy approach. The *Green Grid* scenario results in significantly lower cumulative GHGs, and those cumulative emissions matter. Climate change is not driven by the flow of annual GHG emissions, but instead by the cumulative stock of CO_2 and other GHGs in the atmosphere. Cognitively, citizens and policymakers have trouble recognizing this fact (Sterman and Booth Sweeney, 2007). It is common to assume that simply stabilizing GHG emissions can mitigate climate change. The fact is that flows of GHGs must be reduced to zero by the end of the century in order to stabilize the stock of GHGs in the atmosphere. To actually *reduce* the stock of GHGs in the atmosphere will require a negative flow of GHG emissions, which can be achieved by expanding natural CO_2 sinks, such as wetlands and forests, and artificial CO_2 sinks; for example biomass can be paired with carbon sequestration to create a net removal of GHGs from the atmosphere. Getting to zero quickly is important.

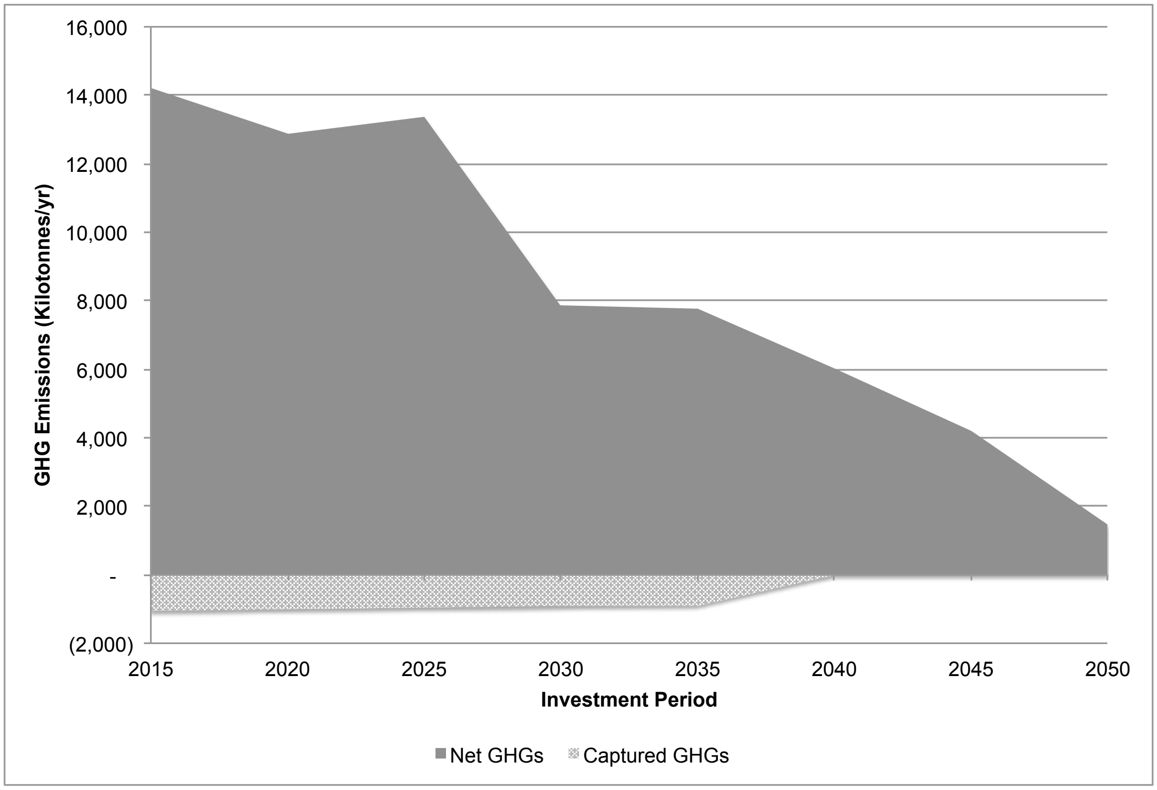


Figure 7-20 Scenario 4: 90% Renewable by 2050 Greenhouse Gas Emissions

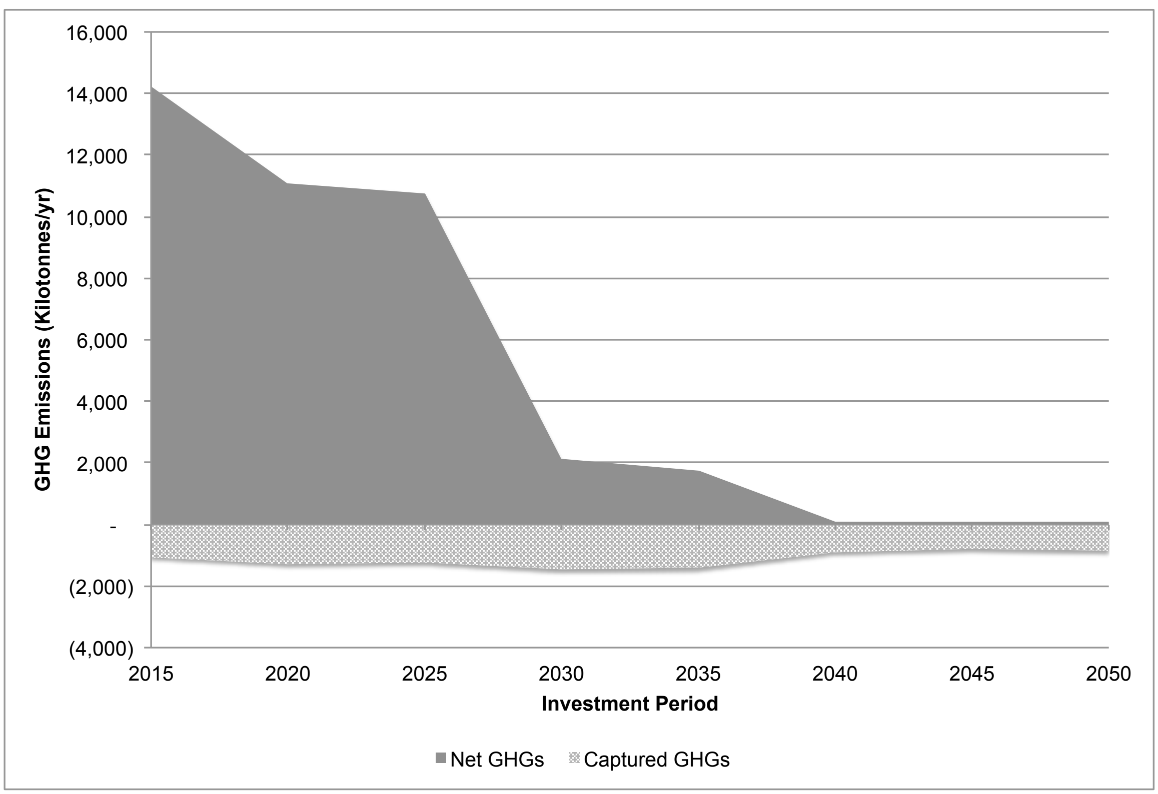


Figure 7-21 Greening the Grid Greenhouse Gas Emissions

Figure 7-22 compares the *Greening the Grid* scenario against the other renewable energy focused pathways.

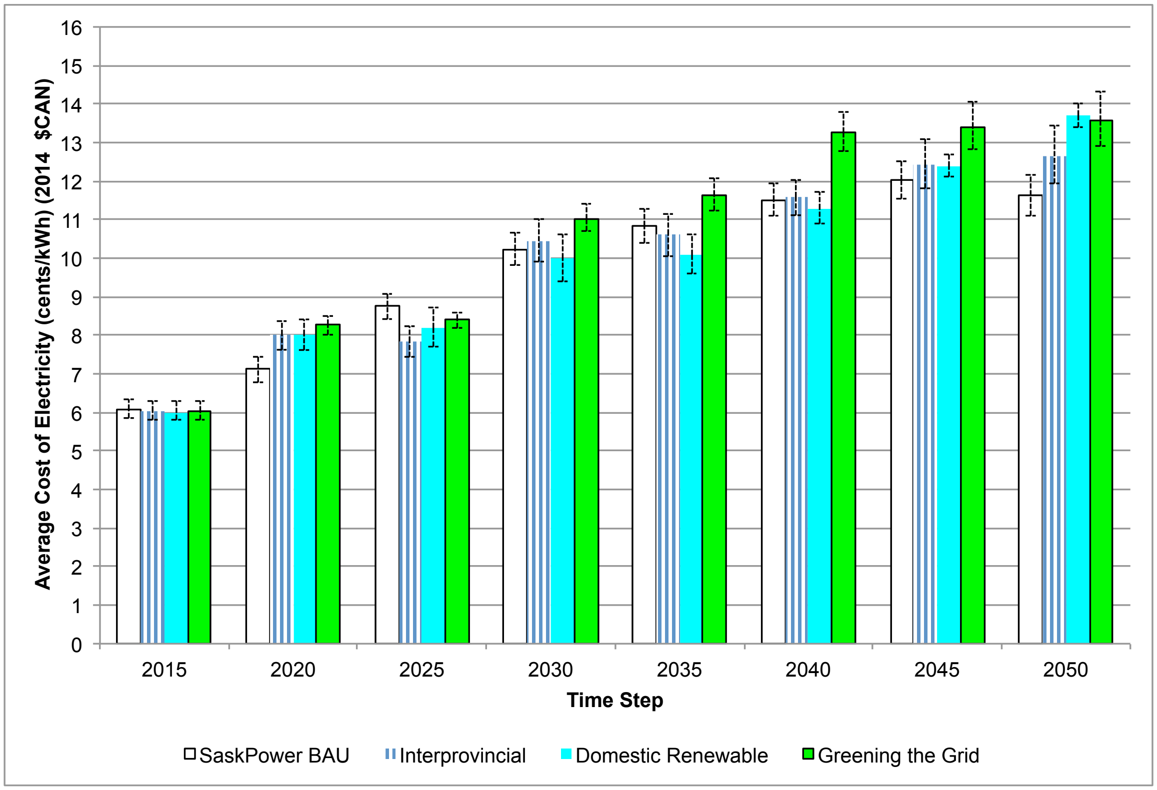


Figure 7-22 The Cost of Greening the Saskatchewan Grid

We can see that there is a premium to be paid for early action. Due to the ambitious actions taken in the *Greening the Grid* scenario, electricity prices from 2030 to 2045 will be higher than they would be otherwise. These high average prices stabilize in the period of 2040-2050, when contributions from wind and solar are protected from fuel price risks. The largest uncertainty in the Greening the Grid scenario comes from the rates charged by Manitoba Hydro for their imported electricity. To reduce uncertainty while pursuing this scenario SaskPower would be wise to sign a long-term power purchase agreement with Manitoba Hydro that contains a clear schedule of electricity price increases. As it stands, the expected average electricity price for the Greening the Grid scenario in 2050 would be 1.94 cents/kWh higher than the SaskPower BAU scenario.

The picture changes, however, if we anticipate carbon pricing in Canada. One potential carbon-price pathway would involve a price of $15/tonne CO_2e in 2015, increasing by $3/tonne/yr so that it reaches $30/tonne $CO2_e$ in 2020 – the current carbon price in British Columbia – and climbs to $120/tonne/yr by 2050. Figure 7-23 compares the *Greening the Grid* scenario against the SaskPower BAU scenario, the nuclear scenario (Scenario 2 for reducing GHGs by 80% by 2050), and the carbon capture and storage scenario (Scenario 3 for reducing GHGs) in the context of this escalating carbon price.

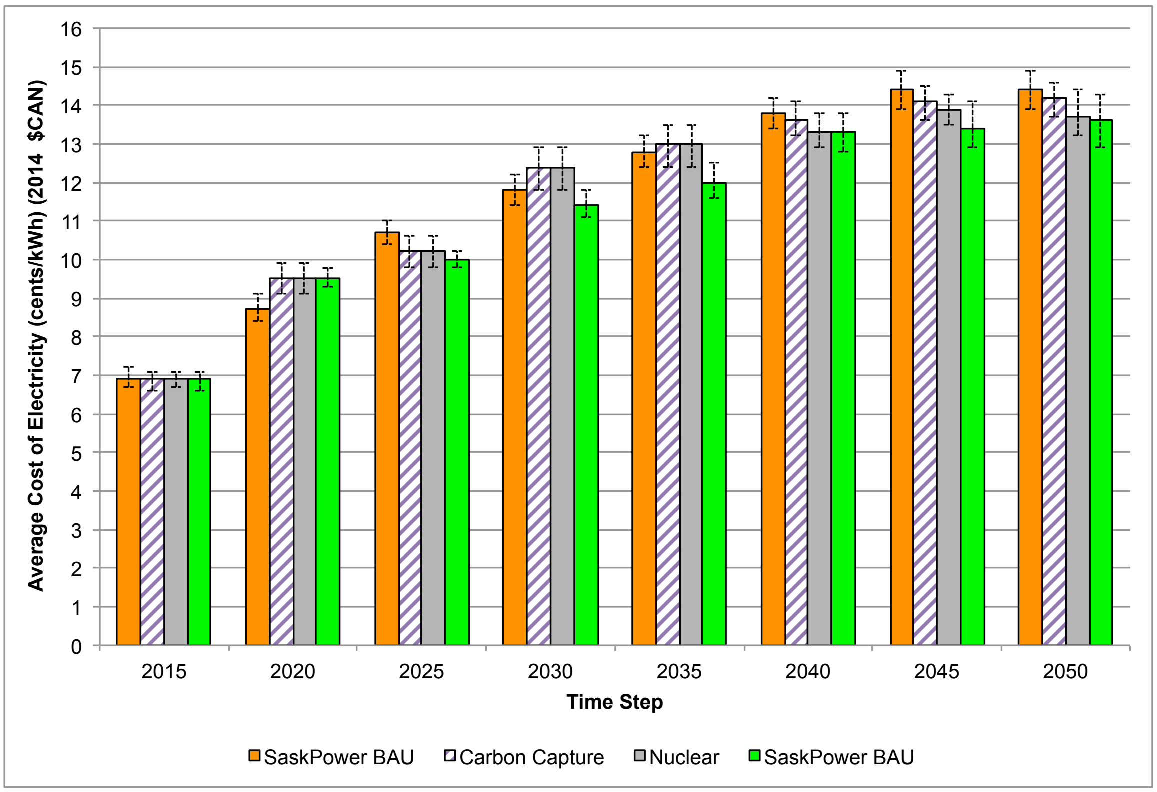


Figure 7-23 Cost Comparison With An Escalating Carbon Price

With this escalating carbon price, the aggressive GHG emission reductions of the *Greening the Grid* scenario pay off. By 2025 it is the lowest cost scenario and this advantage is maintained through to 2050. The average cost of electricity in the SaskPower BAU scenario is .8 cents/kWh more expensive than the *Greening the Grid* scenario in the final time-step. In the *Greening the Grid* scenario GHG emissions are reduced aggressively, leading to near-zero emissions by 2040. If Saskatchewan or

Canada were to implement carbon pricing the *Greening the Grid* scenario would be resilient against a carbon pricing shock.

Conclusions

In this chapter I have compared SaskPower's business-as-usual (BAU) electricity generation plan against a range of other scenarios. The BAU scenario relies on retrofitting coal-fired plants with carbon capture and storage (CCS) to meet federal coal-fired regulations. I found that SaskPower could achieve the same level of GHG emissions reductions at a lower cost by shutting down existing coal plants, investing in wind, hydroelectric and natural gas facilities, and importing more hydroelectricity from Manitoba Hydro. Over the period of 2030-2050 this equivalency approach saves .86 cents/kWh relative to SaskPower approach. However, both the BAU and equivalency scenarios do not lead to lasting GHG emissions reductions. By 2045 GHG emissions begin to increase in both scenarios.

I then explored four scenarios for achieving an 80% reduction in GHG emissions by 2050: an interprovincial approach, which took advantage of low-cost Manitoba Hydro imports; a nuclear approach, in which 1000 MW of small, modular reactor capacity was built by 2050; a carbon capture approach, which relies on investment in natural gas with CCS; and a domestic renewable energy scenario, which meets Saskatchewan's electricity demand with investments in wind, solar, domestic hydroelectric facilities, electricity storage, and energy conservation. Each of these scenarios achieved the goal of reducing GHG emissions by 80% relative to 2015 by 2050. Each scenario also proved capable of reliably supplying electricity when tested using the WIRE model. Electricity generation costs were higher than the SaskPower BAU scenario by 2050, but not significantly so; there was, for example, still overlap between the 95% confidence interval of the interprovincial scenario and the SaskPower BAU scenario.

Lastly, I outlined a *Greening the Grid* scenario in which Saskatchewan moves quickly to phase out coal-fired electricity generation by 2030 and achieves near-zero GHG emissions by 2040 using predominantly renewable energy technologies. This scenario required careful and iterative planning; higher penetrations of renewables meant that I had to pay attention to a 'Liebig's Law of the Minimum' rule related to seasonal solar and hydroelectric potential. After iterating between SIM and WIRE, I found a scenario that could reliably meet Saskatchewan's hourly electricity demand in four representative months of March, June, September and December. In this WIRE simulation a combination of electricity storage, demand side management, and fast-ramping hydroelectric generation capacity (located both within Saskatchewan and imported from Manitoba) allowed high penetrations of variable wind and solar to be integrated onto the Saskatchewan grid.

The *Greening the Grid* scenario did increase the average cost of electricity generation by 1.94 cents/kwh relative to the SaskPower BAU scenario. However, with an escalating carbon price, the *Greening the Grid* scenario becomes the lowest cost electricity pathway. In any scenario, electricity generation costs are anticipated to rise in the future. In the next chapter I explore the implications of this price increase on individuals, businesses, and industry in the province. I also outline scenario impacts that are more difficult, or in some cases impossible, to express in financial terms. These impacts are relevant to a public discussion of Saskatchewan's electricity future.

Chapter 8 – Scenario Impacts

Introduction

The scenarios outlined in Chapter 7 differ in terms of their projected cost of electricity and their greenhouse gas (GHG) emissions. In this chapter I compare the scenarios using a selection of other criteria. My aim is to begin to assess the sustainability of each scenario. A sustainability assessment is, however, an evaluation process that is best undertaken with widespread public input and deliberation (Winfield *et al.*, 2010). White and Noble (2012) provide a good example of a quantitative approach to strategic environmental assessment that could form the basis of a larger public consultation. In this chapter I limit my efforts to providing quantitative indicators and qualitative commentary that can guide a future public sustainability assessment.

Sustainability Criteria

There are a number of criteria with which the sustainability of electricity scenarios can be evaluated. Jaccard (2005) uses four criteria to evaluate energy technology options: projected cost, extreme event risk, geopolitical risk, and path dependence. The first two criteria are fairly self-explanatory; I outlined projected cost for each scenario in Chapter 7 and extreme event risk relates to the possibility that an extreme event may affect the stability of the system or the health and safety of the public. Geopolitical risk is relevant in international markets such as oil, where supply chains can be disrupted by cartels and political embargoes. It is less relevant in an assessment of Saskatchewan electricity; supplies of coal, uranium, and natural gas are produced locally and are not vulnerable to international supply risks. One might, however, reframe this criterion as *energy independence*. Premier Brad Wall has expressed his interest in continued use of coal in order to maintain energy independence (Zinchuk, 2014). Imports of hydroelectricity from Manitoba are interpreted as reducing energy independence. For Jaccard (2005) the fourth criterion, path dependence, is a measure of the degree of fit between a proposed electricity system and an existing system. Scenarios that fit within an existing socio-political-technical institutional context will face lower resistance to adoption than scenarios that disrupt existing institutional arrangements.

Winfield *et al*. (2010) critique Jaccard's (2005) criteria (and other related criteria) for focusing on economic and technical characteristics and "neglecting equity effects, systemic interactions and uncertainty/precautionary factors" (p. 4119). Winfield *et al*. (2010) propose a detailed set of eight criteria that can be applied in a sustainability assessment, as well as six trade-off rules or principles that should be followed when choosing between scenarios. The eight criteria that should be considered in a sustainability assessment are listed below. I include a short quote or summary relevant to each criterion to indicate its meaning:

1. Socio-ecological system integrity – "protect irreplaceable life support functions"
2. Livelihood sufficiency and opportunity – "Ensure that everyone and every community has enough for a decent life"
3. Intragenerational equity – "reduce dangerous gaps in sufficiency and opportunity…between the rich and poor"
4. Intergenerational equity – "enhance the opportunities and capabilities of future generations to live sustainably"
5. Resource maintenance and efficiency – reduce extractive damage, avoid waste, and improve efficiency
6. Socio-ecological civility and democratic governance – "apply sustainability requirements through more open and better-informed deliberations"
7. Precaution and adaptation – "Respect uncertainty, and avoid even poorly understood risks of serious or irreversible damage"
8. Immediate and long-term integration – "Apply all principles of sustainability at once"
   (Winfield *et al*., 2010: 4119)

When two scenarios both pose a threat to any of these criteria it is necessary to consider trade-offs. The six rules for trade-offs outlined by Winfield *et al.* (2010) include:

- Burden of argument on trade-off proponent – "the burden of justification falls on the proponent of the trade-off"

- Avoidance of significant adverse effects – “No trade-off that involves a significant adverse effect…can be justified unless the alternative is acceptance of an even more significant adverse effect.”
  (Winfield *et al*., 2010: 2119)

The remaining trade-off rules call for decision-makers to seek maximum net gains, protect the future, explicitly and openly justify trade-off decisions, and evaluate trade-offs in “processes that include open and effective involvement of all stakeholders” (p. 4119).

White and Noble (2012) used eight criteria in their strategic environmental assessment of Saskatchewan’s electricity system. These criteria bear resemblance to Winfield *et al*. (2010) in that they strive to address equity, but also included is the criterion “security of supply” which is akin to Jaccard’s (2005) “geopolitical risk” criterion. The eight criteria used by White and Noble (2012) are as follows:

1. Adaptive capacity – “Maximizes the ability to accommodate projected, as well as unanticipated future demand growth”
2. Emissions management – “Minimizes emissions to air and water during electricity production, distribution and use over the life cycle of the system”
3. Employment and income sufficiency – “Maximizes short- and long-term income and employment opportunities”
4. Ecological integrity – “Ensures biodiversity conservation and ecological resiliency by minimizing use and disturbance of land and water resources”
5. Security of supply – “Ensures secure and affordable access to energy supply for current and future generations”
6. Energy production and transmission efficiency – “Meets electricity demands while minimizing energy use, raw material use and generation of waste during production and energy loss during transmission”
7. Aboriginal rights – “Minimizes infringement on culture, traditional land use practices and Treaty Rights”

8. Public health and safety – “Minimizes risk to public health and safety during electricity production and transmission.”
   (White and Noble, 2012: 286)

While Winfield *et al*. (2010 and White and Noble (2012) share some overlapping criteria like “ecological integrity”, there are important differences. White and Noble’s (2012) definition of adaptive capacity appears biased towards electricity system growth. They are concerned with efficiency, but define efficiency with respect to “energy production and transmission efficiency”, not in terms of energy demand. Winfield *et al*. (2010) emphasize energy conservation in their definition of resource maintenance and efficiency when they speak of “reducing overall material and energy use per unit benefit” (p. 4119).

As well, Winfield *et al* (2010) recommend an integrative approach to assessment. The language used in White and Noble’s (2012) list is the language of optimization; each criterion is either maximized or minimized. In their strategic environmental assessment, White and Noble (2010) had expert participants weigh and rank the criteria. These weighted criteria were then used to create a score for each scenario. This reductionist approach reduces opportunities for an integrative view of scenario selection.

White and Noble (2012) do however, consider important factors that are implied by criteria listed by Winfield *et al*. (2010), but not explicitly stated. In particular, the criterion ‘Aboriginal rights’ is very relevant in Saskatchewan, which has a high proportion of people identifying as aboriginal in its population (15.6% in 2011, Statistics Canada, 2011b). The Canadian constitution recognizes aboriginal rights and treaty rights, which include the right to traditional livelihoods. The Canadian courts have ruled that government has a duty to consult and accommodate aboriginal peoples on decisions that may impact their livelihoods (Aboriginal Affairs, 2011). Electricity sector projects can impact aboriginal livelihoods (*e.g.* the E.B. Campbell hydroelectric station affected fishing for aboriginals downstream of the dam). Recognition of aboriginal rights and interests has led SaskPower to seek partnerships with First Nations on power projects like the proposed Tazi Twé hydroelectric station.

In this chapter I offer quantitative indicators that can contribute to understanding the sustainability criteria outlined above. The quantitative indicators I provide for each scenario are listed below and grouped by the criterion they help to inform.[68]

- Projected Costs (Jaccard, 2005)
    - Projected cost of electricity in 2050 with and without carbon pricing (cents/kwh);
    - Total discounted cost of meeting electricity demand 2015-2050 with and without carbon pricing ($Millions).
- Intragenerational equity (Winfield *et al,* 2010):
    - Electricity rate impacts to residential customers (cents/kwh); and
    - Electricity rate impacts to commercial customers (cents/kwh).
- Livelihood sufficiency and opportunity (Winfield *et al,* 2010):
    - Electricity rate impacts to industrial customers (cents/kwh);
    - Direct and indirect employment resulting from the electricity scenarios (full-time jobs);
    - Direct and indirect employment divided by electricity price to control for scenario cost (full-time jobs/cents per kwh).
- Emissions management (White and Noble, 2012):
    - Annual direct GHG emissions in 2050 (kilotonnes CO_2e);
    - Cumulative direct GHG emissions 2015-2050 (Megatonnes CO_2e);
    - Cumulative captured CO_2 (km^3).
- Ecological integrity (Winfield *et al*., 2010; White and Noble, 2012):
    - Land impacted by wind and solar facilities (Sections/hectares);
    - Water consumption by all facilities (Gigalitre/Olympic sized pool);
    - Hydroelectricity capacity in Saskatchewan (MW);
    - Hydroelectric dams on the Churchill River (number).
- Energy Independence (modified from Jaccard, 2005)
    - Hydroelectric contracts with Manitoba Hydro (MW).
- Resource maintenance and efficiency (Winfield *et al*., 2010)

[68] All monetary values are reported in 2014 $CAN constant dollars.

- DSM energy savings in 2050 (GWh)

- Precaution (Winfield *et al*., 2010) and public health and safety (White and Noble, 2012):
    - Radioactive waste produced by nuclear power production (tonnes).

These indicators are far from comprehensive, but touch on some of the key issues associated with the various electricity scenarios. For instance, while I give only a passing reference to the land impacts related to coal-fired generation, and do not comment on the land impacts related to natural gas-fired generation (including natural gas extraction), nuclear power (including uranium mining), hydroelectricity generation, or biomass, I list land impacted by wind and solar facilities because these energy sources are often singled out for their low "energy density" (*e.g.* van Kooten, 2011). The measure of land impacted by wind and solar provides a quantitative indicator that can inform a discussion of energy density and land-use impact. As well, when I explore employment impacts, I use data for both direct and indirect employment. However, when I outline cumulative GHG emissions I focus only on direct emissions at the site of electricity production, and not indirect emissions associated with manufacturing and installing a technology, or decommissioning a facility and dealing with its waste. Water use is a measure of direct use during operation and does not include the water associated with manufacturing the technologies. After presenting a selection of these indicators I discuss how they might contribute to our understanding of the sustainability of each electricity scenario.

Projected Costs

In Chapter 7 I presented the electricity cost resulting from each scenario. A summary of the electricity costs in 2050 is presented in Table 8-1. These indicators contribute to understanding Jaccard's (2005) sustainability criterion of projected cost. The lowest cost scenarios are highlighted in light blue while the highest cost scenarios for each indicator are highlighted in rose.

The section marked 'Projected Cost' outlines the expected cost of electricity in 2050, along with the 95% and 5% confidence intervals from the sensitivity analysis. The BAU equivalent scenario is projected to achieve the lowest electricity cost in 2050, reducing electricity costs by .4 cents/kwh relative to the SaskPower BAU scenario. The four scenarios in which GHG emissions are reduced by 80% relative to 2015 have confidence intervals that overlap. The zero-emissions *Greening the Grid* scenario is expected to cost about 1 cent/kwh more than the inter-provincial 80% reduction scenario.

Financial Cost Comparison

Scenario	SaskPower BAU	BAU Equivalent	Inter-provincial	Nuclear	CCS	Domestic Renewable	Greening the Grid
Projected Cost							
Electricity Cost in 2050 (cents/kWh 2014 $CAN)	11.6	11.2	12.6	12.7	13.2	13.7	13.6
Electricity Cost in 2050 95% C.I. (cents/kWh 2014 $CAN)	12.1	11.7	13.4	13.4	13.6	14.0	14.3
Electricity Cost in 2050 5% C.I. (cents/kWh 2014 $CAN)	11.1	10.8	11.9	12.2	12.8	13.4	12.9
Discounted Project Cost							
Total discounted cost mean (million 2014 $CAN)	67,091	62,467	68,173	67,037	67,618	69,477	76,368
Total discounted cost 95% C.I. (million 2014 $CAN)	68,285	63,515	69,767	68,374	68,876	70,729	78,848
Total discounted cost 5% C.I. (million 2014 $CAN)	65,930	61,426	66,641	65,689	66,387	68,243	74,105
Project Cost with Constant Carbon Price ($30/tonne CO2e)							
Total discounted cost mean (million 2014 $CAN)	73,863	69,158	74,745	73,752	74,286	75,379	79,551
Total discounted cost 95% C.I. (million 2014 $CAN)	75,024	70,323	76,370	75,069	75,537	76,545	81,951
Total discounted cost 5% C.I. (million 2014 $CAN)	72,722	68,008	73,156	72,535	73,085	74,061	77,387
Project Cost with Escalating Carbon Price ($15/tonne CO2e in 2015 escalating by $15/time-step)							
Total discounted cost mean (million 2014 $CAN)	80,672	75,984	80,450	79,659	80,091	79,985	80,681
Total discounted cost 95% C.I. (million 2014 $CAN)	81,836	77,056	82,098	81,045	81,291	81,224	83,133
Total discounted cost 5% C.I. (million 2014 $CAN)	79,463	74,929	78,846	78,445	78,833	78,765	78,415

Table 8-1 Projected Costs

The section labeled ‘Discounted Project Cost’ shows the total financial cost of each scenario from 2015-2050, discounted at a rate of 3%. This discounted total cost number is the objective function I minimize in SIM. I show three versions of this number. The first assumes a carbon price of zero. The second assumes a carbon price of $30/tonne CO_2e applied equally to all emissions released to the atmosphere (*i.e.* it is not applied to captured GHG emissions) from the period the 2015-2050. These carbon charges are also discounted to their present value in 2015. The third version assumes an increasing carbon price that begins at \$15/tCO_2e in 2015 and increases by \$15/tCO_2e in each time-step; it is \$30/tCO_2e in 2020, \$45/tCO_2e in 2025, and reaches \$120/tCO_2e in 2050.

Without a carbon price the BAU equivalent scenario is by far the lowest cost scenario, coming in nearly \$14 billion cheaper than the *Greening the Grid* scenario in present value terms. With a carbon price of \$30/tCO_2e the gap narrows to about \$10 billion. Interestingly, at a price of \$30/tCO_2e the four 80% GHG reduction scenarios are very close in cost to the SaskPower BAU scenario. This means that if Saskatchewan were to adopt the carbon price currently charged in British Columbia, it would be a break-even venture to pursue an 80% reduction in GHGs by 2050 (the discounted project costs are all within the 5%-95% confidence intervals of each other). With an escalating carbon price the expected discounted cost of the *Greening the Grid* scenario becomes equivalent to the SaskPower BAU scenario. Carbon prices above the escalating pathway would begin to favour the *Greening the Grid* scenario. This means the least-cost scenario is sensitive to carbon pricing policy in Saskatchewan and Canada.

Electricity Rate Impacts

In each of the scenarios outlined in Table 8-1 the cost of generating electricity, measured in constant dollars to control for inflation, increases over time. Saskatchewan must replace old generating assets, and find a pathway to reduce greenhouse gas emissions (GHGs), as it expands electricity production. Natural gas combined cycle plants are the default means of accomplishing this in the SaskPower business-as-usual (BAU) scenario, and natural gas fuel prices are expected to rise over time.

The costs presented in Table 8-1 indicate the average cost of generating electricity in each time-step and for each scenario. To understand the impact on citizens, businesses, and industry it is necessary to convert generation costs into the electricity rates required to pay for these costs. Historically, electricity rates have not been equal for all SaskPower customers. Large power customers pay less and residential customers pay the most. Appendix 8A explains why this is so and provides a ‘cost of service’ model that converts electricity generation costs into electricity prices.

Residential Sector

In Figure 8-1 I present the expected residential electricity prices that would result from four scenarios: the SaskPower BAU scenario; two scenarios for reducing GHGs 80% below 2015 levels by 2050; and the Greening the Grid scenario, which achieves near zero emissions by 2050. These prices do not include a carbon price.

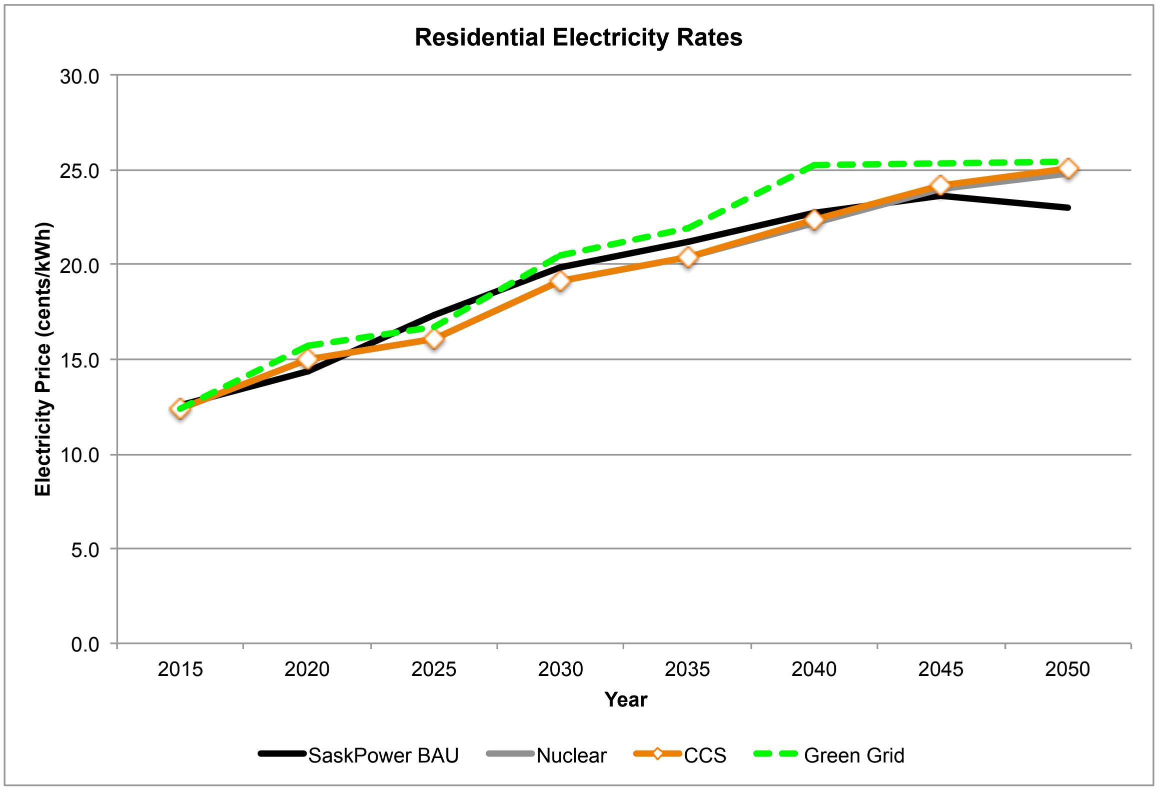


Figure 8-1 Residential Electricity Prices in Saskatchewan (cents/kWh) (2014 $CAN)

In 2040, the Greening the Grid scenario has electricity prices that are 11% higher than the SaskPower BAU scenario. This remains true in 2050 as well. The other two scenarios for reducing GHGs have prices that are 8% and 9% higher than the BAU scenario by 2050. As prices increase, residential customers will have an incentive to conserve electricity. In all four of the scenarios above, residential conservation opportunities are taken up to the ‘upper potential’ of residential DSM. Recall from Chapter 6 that upper potential is calculated by looking at the level of DSM that is economical at an electricity price of 15 cents/kWh. All of the scenarios contain electricity prices higher than that by 2025 and so a broader suite of conservation measures would become economical at that time.

Residential customers will have another reason to seek out additional conservation opportunities. The forecast model outlined in Chapter 6 assumed that residential customers will use more electricity over time; their electricity intensity will increase. Increasing at 1.2%/yr, residential electricity use is forecast to be 52% higher by 2050. Residential electricity prices in the scenarios outlined in Figure 8-1 will increase by a factor of 1.8 (BAU) to 2.1 (Greening the Grid). Table 8-2 shows how the average residential electricity bill might change without energy conservation measures.

Residential Bill	2015	2035 BAU	2050 BAU	2050 Green
Electricity use (kWh)	750	952	1139	1139
Rate (cents/kWh)	12.6	21.2	23.0	25.5
Energy cost ($)	$94.67	$202.31	$261.57	$289.94
Fixed ($)	$20.22	$20.22	$20.22	$20.22
Total ($)	$114.89	$222.53	$281.79	$310.16

Table 8-2 Average Monthly Residential Electricity Bill (constant dollars)

Under the SaskPower BAU scenario an average residential electricity bill increases by $166.89 per month between 2015 and 2015. Subtracting column 3 from column 4 we can see that achieving near zero emissions by 2040 in the Greening the Grid scenario would increase residential bills by an additional $28.37 per month by 2050 (assuming a carbon price of zero).

We would expect residential customers to react to price increases by seeking opportunities for energy efficiency and conservation. Ryan and Razek (2012) estimated that the average elasticity of electricity demand for residential customers in Saskatchewan was -.45 over the period 1960-2006. This means that residential electricity demand is inelastic, but still responsive to price. I have not modelled this price feedback in SIM, but we can assume that, for those who have the financial means, higher prices will result in increased energy conservation efforts. For low-income residents of Saskatchewan, who lack the means to invest in energy efficiency, the increased rates will be a financial hardship.

Residential customers with the financial means to do so may also look to self-generation to lower their electricity bills. Due to its high-cost I did not include residential solar photovoltaics (PV) in SIM, instead I focused on utility-scale solar PV. Rooftop residential panels are falling in cost and, from a customer's point of view, can be expected to achieve grid parity in the coming decades. Grid parity is the point when it will cost residential customers less to generate their own solar electricity than to purchase electricity from the grid. Figure 8-2 shows a range of possible pathways for the price of rooftop solar PV in Saskatchewan. The pathways differ based on the cost of financing (4% or 8% interest) and the rate at which solar panel costs improve (1.3%/yr or 2%/yr).[69]

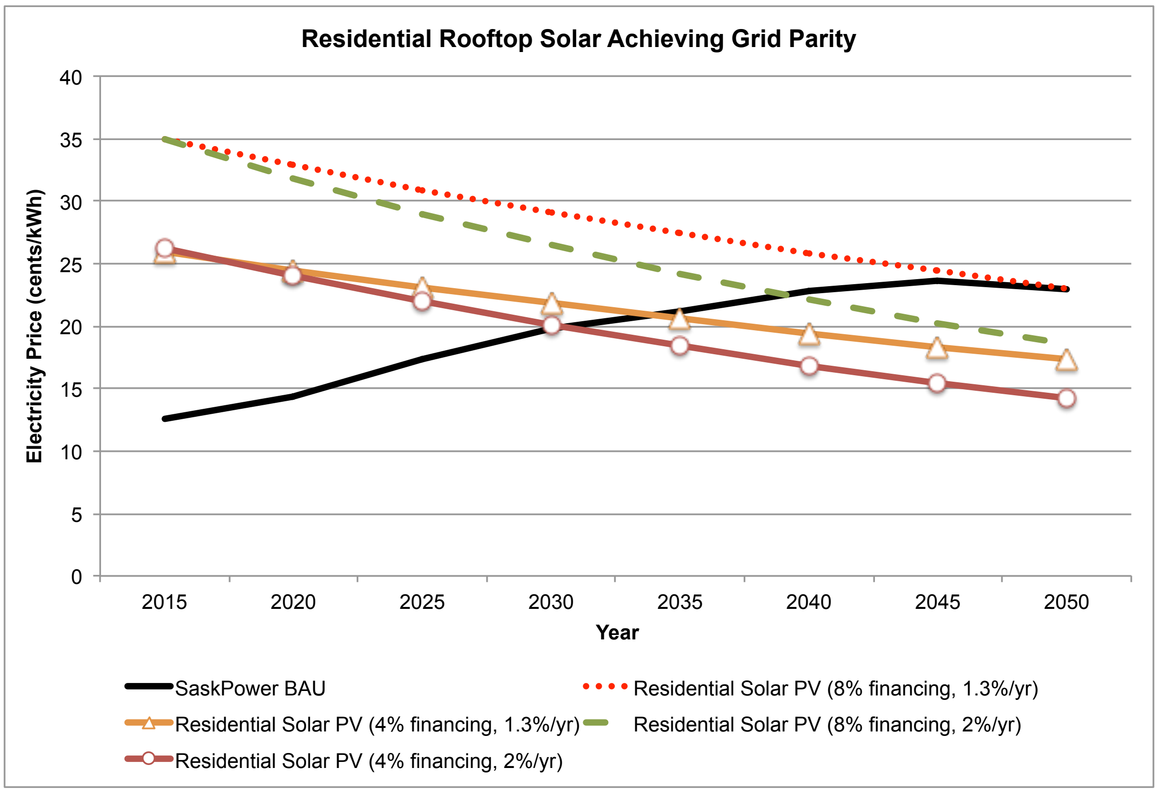


Figure 8-2 Residential Rooftop Solar PV Achieving Grid Parity[70]

[69] Note that 4% financing is currently available for fixed rate mortgages of 3-4 years, while financing for a fixed rate mortgage of 25 years is 8.75% (Royal Bank, 2015). The financing rates of 4% and 8% roughly approximate a homeowner financing a solar installment through a mortgage.

[70] Solar data is from Lazard (2014). LCOE is calculated with an annual capacity factor of 16% and an initial 2015 capital cost of $4643/kw (2014 $CDN).

If solar PV costs continue to decline by 2%/yr (their current rate of cost improvement), then grid parity for residential customers will occur sometime between 2030 and 2040. If the rate of cost improvement slows to 1.3% (the rate used in SIM), solar will achieve grid parity between 2035 and 2050.

Commercial Sector

Commercial customers will see price increases similar to that of residential customers. Figure 8-3 shows the expected electricity prices for commercial customers in four scenarios (the same as shown for residential in Figure 8-1).

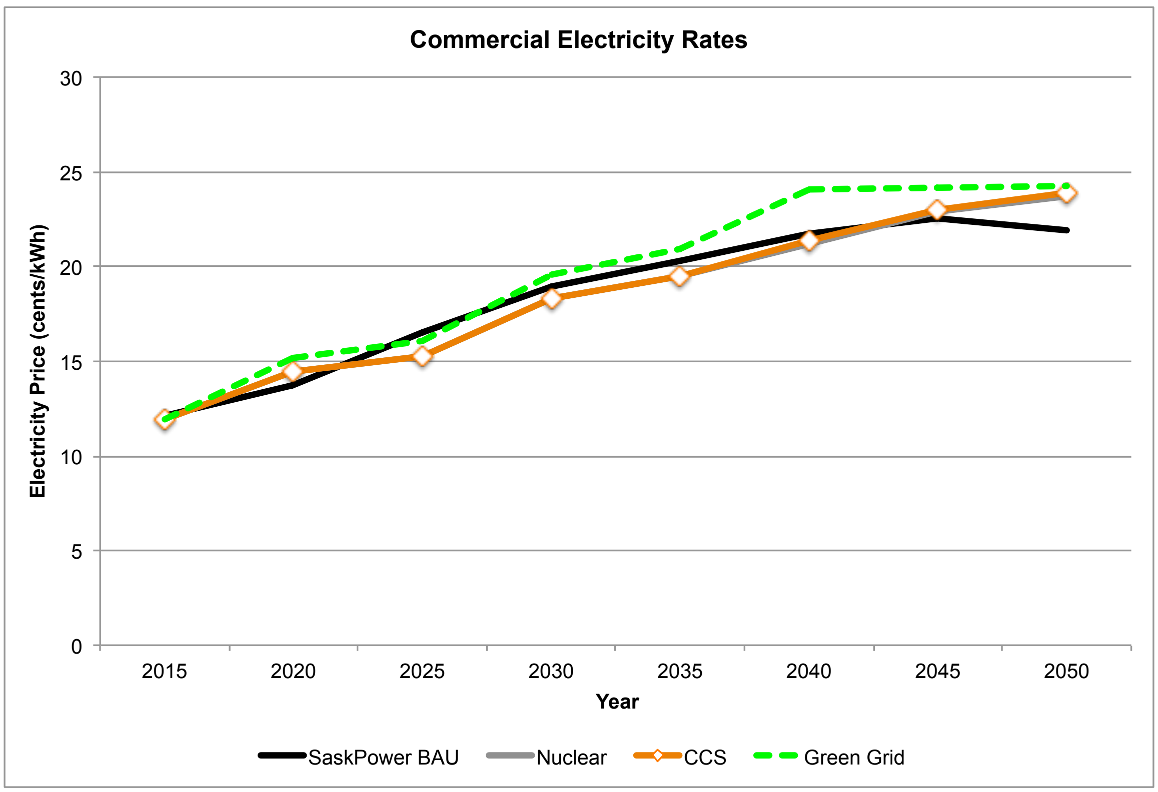


Figure 8-3 Commercial Electricity Prices in Saskatchewan (cents/kWh)

By 2050, electricity costs will have nearly doubled for commercial customers, increasing from the current price of 12.1 cents/kWh to 21.9 cents/kWh (SaskPower BAU), 23.7 cents/kWh (nuclear GHG reduction), 23.9 cents/kWh (CCS GHG reduction), or 24.3

cents/kWh (Green Grid).[71] Table 8-3 shows the impact these higher prices would have on the average monthly commercial electricity bill.

Commercial Bill	2015	2035 BAU	2050 BAU	2050 Green
Electricity use (kWh)	6000	4713	3932	3932
Rate (cents/kWh)	12.1	20.3	21.9	24.3
Energy cost ($)	$727.54	$955.87	$862.18	$955.54
Fixed ($)	$20.22	$20.22	$20.22	$20.22
Total ($)	$747.76	$976.09	$882.40	$975.76

Table 8-3 Average Monthly Commercial Electricity Bill

In the commercial sector the impact of increasing prices is muted by improvements in energy efficiency. In Chapter 6 I forecast that electricity use in the commercial sector would decline at a rate of 1.2%/yr. This leads electricity use to about 2/3 the 2015 level by 2050. Additional energy conservation measures could be undertaken above and beyond that assumed rate of change to further control cost increases.

[71] These estimates of price increases do not account for uncertainty and do not include a carbon price. Refer to Chapter 7 for the range of potential price increases that would result from each scenario and to see the impact of carbon pricing.

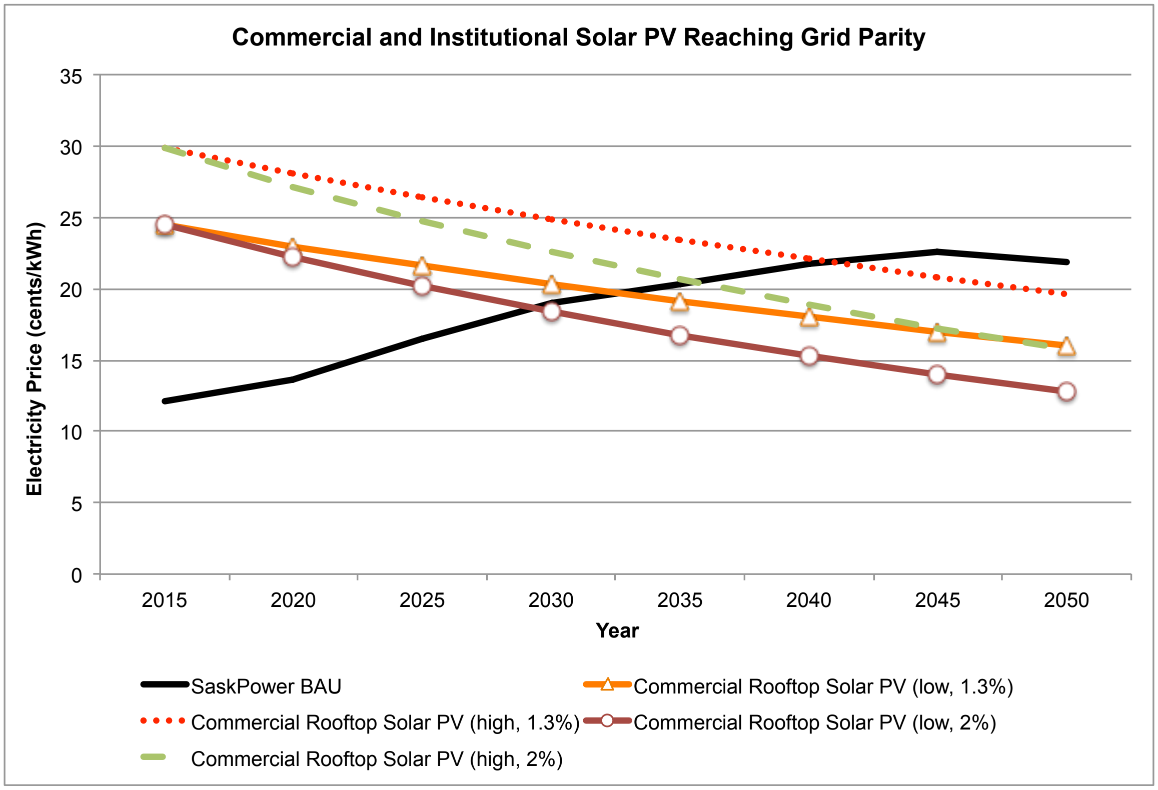


Figure 8-4 Commercial Rooftop Solar PV Achieving Grid Parity[72]

Like the residential sector, the commercial sector also has opportunities for self-generation of electricity. The commercial sector faces lower costs for installing rooftop solar than the residential sector and will reach grid parity even sooner.[73] Figure 8-4 shows that rooftop solar PV for commercial and institutional customers can be expected to achieve grid parity as early as 2030 in the scenario with low initial capital cost and cost improvement of 2%/yr. Even under conditions with higher capital costs and a rate of cost improvement of only 1.3%/yr, commercial rooftop solar PV reaches grid parity by 2045 (Figure 8-4).

[72] Solar data is from Lazard (2014). LCOE is calculated with an annual capacity factor of 16% and a capital cost of $3317/kw (2014 $CDN) in the low scenarios and $3980/kw in the high scenarios.
[73] Commercial costs are lower because projects are typically large and fixed project costs and overhead can be distributed over a larger number of installed solar units (Barbose and Darghouth, 2015).

The Utility Death Spiral

For residential and commercial customers, grid parity is good news. Homeowners and businesses can install solar panels and shield themselves from electricity price increases. Price protection, for those who choose to install solar, would mean that residential electricity users hit a 'peak price' of between 20-25 cents/kWh, while commercial electricity users would hit a peak price of 17-23 cents/kWh (RMI, 2015).

Grid parity makes utilities like SaskPower nervous. What is price protection for individuals is *grid defection* to a utility like SaskPower. When customers choose to generate their own electricity SaskPower loses revenue. With less revenue, SaskPower must raise prices to pay for their capital costs. The higher prices in turn encourage more customers to defect from the grid. This positive feedback loop has been called 'The Utility Death Spiral' (Ford, 1997). Figure 8-5 provides a causal loop diagram showing how this process unfolds. On the right side we see 'the death spiral' where higher prices have a damping effect on electricity consumption (the negative sign indicates an inverse relationship). Lower electricity consumption requires a higher 'indicated price' for electricity (the negative sign again indicates an inverse relationship).

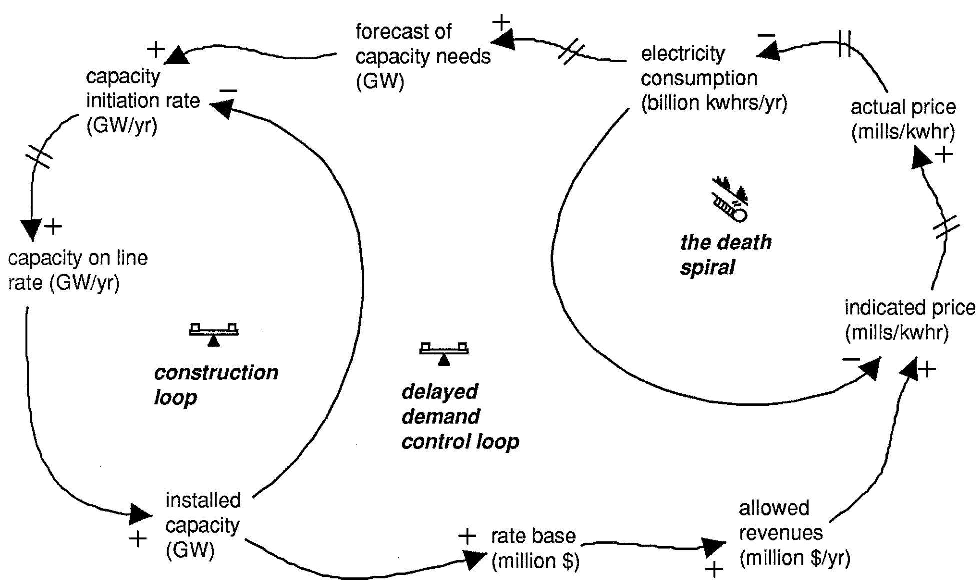


Figure 8-5 Feedback Loops in the Utility Sector (Ford, 1997: 69)

The death spiral is not an inevitable outcome for Saskatchewan. As one workshop participant noted, grid defection leads to stranded assets; power plants that are underutilized or that are shut down prematurely. But, as a crown corporation, these stranded assets belong to the people of Saskatchewan (Workshop 1). SaskPower's debt sits on the Government of Saskatchewan's books and Saskatchewan citizens and businesses will have to pay for it either through electricity payments to SaskPower or taxes at a later date. Anticipation of the death spiral may be one reason why SaskPower has not implemented a policy like a feed-in-tariff that would encourage self-generation.

The possibility of grid defection does point to a potential new role for SaskPower. If it remains a crown corporation – a state of affairs which has been challenged by past Saskatchewan governments such as Devine's Progressive Conservatives in the 1980s (see Chapter 3) – then SaskPower may want to find a peaceable way of encouraging self-generation. Already, SaskPower thinks of residential solar photovoltaic as a DSM measure. In partnership with the Ministry of Environment's Green Initiatives Fund they have offered grants for small-scale residential solar projects. SaskPower also offers a program they call 'net metering' that allows households to generate electricity. However, the 'net metering' policy falls short of encouraging households to generate more than they need; electricity bills can reach an energy charge of zero, but households are not paid for generating surplus electricity. Instead they can accumulate energy 'credits', which expire if they are not used. In this way, the policy is more truly a 'zero metering' policy than a net metering policy.

Further policy innovation is needed. SaskPower could encourage self-generation by offering low-interest financing to customers who want to install solar, or by leasing rooftops and installing the solar panels themselves – a business venture now being popularized by private companies like SolarCity. Resellers could also enter this market. In the City of Saskatoon and the City of Swift Current it would be possible for the utilities to install solar panels on a home or business and recoup the cost through property tax payments. When grid parity is achieved this would mean that customers who sign onto the program would see net savings with electricity bills falling by more than the property tax bill increases. SaskPower and the Government of Saskatchewan have not made it easy for resellers to pursue these types of generation projects (Interview 26).

In general, with electricity storage costs also falling, customers will soon have a cost-effective means of defecting from the grid entirely. SaskPower, and the two resellers, will have to innovate to keep residential and commercial customers on their systems.

Power Customers

The situation for power customers is also filled with uncertainty and opportunity. The largest 100 customers in Saskatchewan currently pay the lowest electricity rates. They will also see the largest proportional increases in the rates they pay. Figure 8-6 shows electricity prices for the largest power customers under four scenarios: SaskPower BAU and three other GHG reduction scenarios.

Because the large power customers do not pay for transmission costs, electricity generation costs compose a larger portion of the prices they pay. In all of the scenarios in Chapter 7 these generation costs increase and become a bigger proportion of cost for all customers. The large power customers currently pay prices of between 5 and 7 cents/kWh. I estimate that, as generation costs increase, power customers could find themselves paying between 10.8 and 14.6 cents/kWh by 2050.

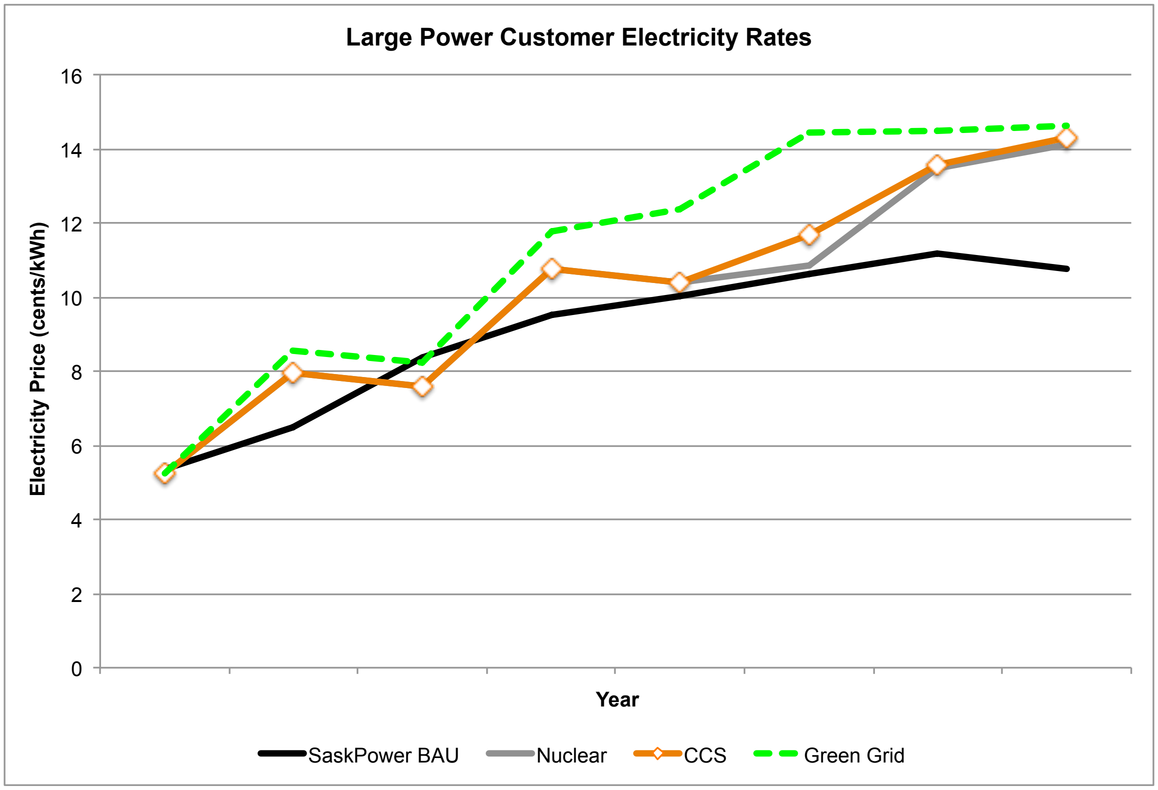
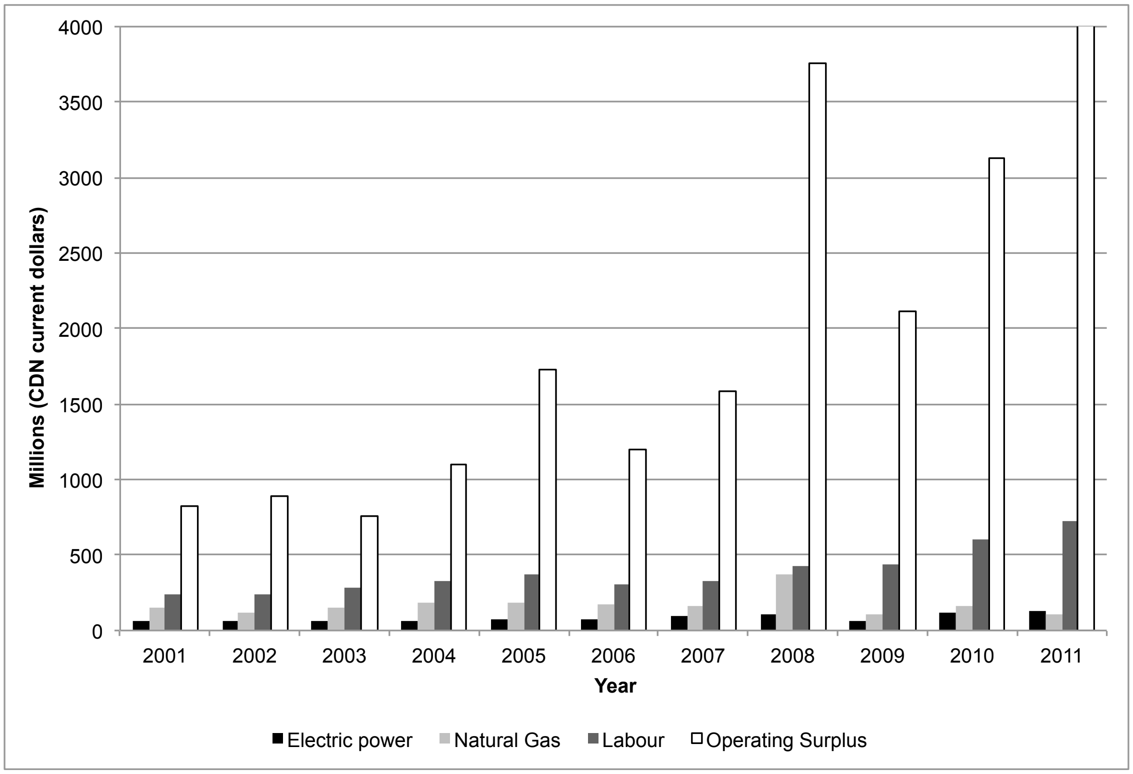


Figure 8-6 Large Power Customer Electricity Prices in Saskatchewan (cents/kWh)

As outlined in Chapter 6, there is plenty of potential for energy conservation in the industrial sector. One response to higher prices will be energy conservation. Depending on the industry and the GHG policy environment, another response could be cogeneration. At the Cory potash cogeneration facility, natural gas is burned to produce electricity and waste heat is used in the process operations of the potash mine. As potash mining is set to expand across the province, opportunities for cogeneration will increase. Cogeneration could allow for the establishment of a price ceiling for electricity purchased by potash operations. If they are to survive as a corporation, SaskPower must again find a way to be involved. If not, cogeneration could easily become self-generation and lead to large customers defecting from the grid.

What do higher electricity rates mean for the viability of industry in Saskatchewan? As mentioned in Chapter 6, while the potash industry is a big electricity user, payments to labour are about five times higher than payments for electricity. Payments for natural gas are also higher than payments for electricity. With a high use of natural gas the potash industry is well suited for natural gas fired cogeneration. Figure 8-7 shows payments for electricity, natural gas, labour, and operating surplus for Canada's potash industry from 2001 to 2011.



(Statistics Canada, 2001-2011)

Figure 8-7 Payments for Inputs in the Potash Sector (current dollars)

That electricity prices will nearly double in the coming decades will surely concern the industry. Assuming that labour costs do not also increase, it would mean that payments for electricity become 40% the cost of labour rather than 20%. Electricity in most years was, however, between 2.4% (2011) and 8.9% (2003) of operating surplus or profit for the industry. While painful, an electricity price increase would not be fatal to the industry.

There are other industries in Saskatchewan that are more electricity intensive than potash mining. Table 8-4 provides a breakdown of the most electricity intensive industries in Canada. I divide electricity by gross output to get a sense of the proportion of input payments spent on electricity in each industry. The table is sorted from most to least electricity intensive.

	Electricity	Gross Output	Electricity / Gross Output	Wages, Salary, Supplementary Income	Electricity / Labour
Pulp, paper and paperboard mills	1559	18033	8.6%	3328	46.8%
Crude oil and other pipeline transportation	216	4466	4.8%	465	46.5%
Non-metallic mineral product manufacturing (except cement and concrete products)	148	5004	3.0%	1372	10.8%
Religious organizations	159	5396	2.9%	2618	6.1%
Basic chemical manufacturing	515	17594	2.9%	1180	43.6%
Arts, entertainment and recreation	49	1905	2.6%	685	7.2%
Animal production	594	23276	2.6%	1784	33.3%
Other aboriginal government services	176	7310	2.4%	2980	5.9%
Other non-metallic mineral mining and quarrying (except diamond and potash)	29	1257	2.3%	244	11.9%
Dry cleaning and laundry services	52	2263	2.3%	703	7.4%
RV (recreational vehicle) parks, recreational camps, and rooming and boarding houses	50	2315	2.2%	788	6.3%
Grant-making, civic, and professional and similar organizations	277	12910	2.1%	5811	4.8%
Coal mining	159	7616	2.1%	789	20.2%
Pesticide, fertilizer and other agricultural chemical manufacturing	104	5062	2.1%	504	20.6%
Other municipal government services	1461	71962	2.0%	29815	4.9%
Cement and concrete product manufacturing	168	9151	1.8%	1945	8.6%
Automotive repair and maintenance	188	10555	1.8%	4270	4.4%
Potash mining	120	8502	1.4%	723	16.6%
Non-conventional oil extraction	715	54026	1.3%	3088	23.2%
Sand, gravel, clay, and ceramic and refractory minerals mining and quarrying	20	1593	1.3%	313	6.4%
Bakeries and tortilla manufacturing	97	8023	1.2%	2014	4.8%
Other chemical product manufacturing	57	4861	1.2%	826	6.9%
Offices of dentists	161	13788	1.2%	3821	4.2%
Metalworking machinery manufacturing	43	3752	1.1%	1410	3.0%
Household and institutional furniture and kitchen cabinet manufacturing	62	5524	1.1%	1963	3.2%
Social assistance	92	8313	1.1%	5827	1.6%
Universities	356	36430	1.0%	17324	2.1%
Local credit unions	73	7584	1.0%	3354	2.2%

(Source: Statistics Canada, 2011)

Table 8-4 Electricity Intensive Industries in Canada (2011)

Several of these industries operate in Saskatchewan including crude oil and pipeline transportation, chemical manufacturing, animal production, pesticide and fertilizer manufacturing, and potash mining. Universities also appear as fairly intensive users of electricity. The question for Saskatchewan is, will companies shut down or relocate due to an increase in electricity costs? Arguably companies in the oil sector and potash mining sector are less likely to leave because they operate where the oil and the potash is located. In industries like chemical manufacturing, however, companies may relocate to locations where electricity is less expensive (Interview 5).

The impact of rate increases will also depend on whether an industry is trade-exposed. Trade-exposed industries compete in international markets and cannot pass costs along to their customers. A good example of a trade-exposed company is the Evraz Steel mill operating in Regina, Saskatchewan. In their 2014 submission to the Saskatchewan Rate Review Panel (SRRP) – the body that arbitrates decisions about utility rates for Saskatchewan crown corporations – Evraz laid out their circumstances,

> EVRAZ Regina Steel is the largest steel company in Western Canada. It is also one of the largest private sector employers in Regina with 1200 employees and spends over $135 million per year on local purchases of goods and services.
>
> The steel industry operates in a highly competitive market on a regional, North American Continent and global level. We currently face stiff competition from domestic producers and imported product from international steel companies. The Regina facility also competes with other EVRAZ global production facilities for investment capital which is based on earnings and return on investment. This requires the Regina plant to maximize operational efficiency and minimize costs on an on-going basis.
>
> Our manufacturing processes are highly energy intensive. Next to raw materials, electricity costs are the next highest cost in producing our steel. As a result of competitive pressures, increases in power costs cannot be passed on to our customers. Consequently, increases in power costs have a direct impact on our bottom line. The EVRAZ Regina location has had a freight advantage in the northern part of the continent, which has kept us competitive against other steel companies in North America and globally. However, this advantage is being eroded by past increases in power costs.

> SaskPower's latest application will further diminish this competitive advantage which is very concerning to us. A decreasing competitive advantage lowers demand for our product which ultimately has an adverse trickledown effect on our company's employees and the demand for local goods and services. We urge the SRRP to carefully evaluate the proposed increases in light of its potentially serious impacts on industrial competitiveness in Saskatchewan.
> (Evraz, 2014)

The electricity costs faced by industrial customers are dependent on the level of energy conservation that is pursued. Table 8-5 shows the potential electricity bill implications of the SaskPower BAU scenario and the 2050 *Greening the Grid* scenario. The *Green* scenario relies on large amounts of energy conservation and lowers the impact of higher electricity rates. In this example energy costs double between 2015 and 2050 in the BAU scenario, and increase by a factor of 2.3 in the *Greening the Grid* scenario. If aggressive energy conservation measures are taken then the final energy costs in the *Greening the Grid* scenario are 17% higher than that of the SaskPower BAU scenario.

Power Customer	2015	2035 BAU	2050 BAU	2050 Green
Electricity use (MWh)	77,851	77,851	77,851	77,851
DSM savings (%)	0%	0%	0%	25%
Net demand (MWh)	77,851	77,851	77,851	58,030
Rate ($/MWh)	$54	$100	$108	$169
Energy cost ($)	$4,172,274	$7,806,115	$8,371,832	$9,784,442

Table 8-5 Average Monthly Power Customer Electricity Bill

With millions of dollars at stake, it is likely that the Saskatchewan Industrial Electricity Consumers Association (SIECA), the public voice of the large power users, will lobby against any proposals that increase energy costs for their customers. With high potential for conservation in the industrial sector SaskPower might reasonably respond by increasing DSM programming for that sector.

Employment Impacts

There have been a number of studies into the employment implications of expanding renewable energy production. Often these studies are conducted in the context of a specific policy proposal such as Ontario's *Green Energy and Economy Act* and related feed-in-tariff for renewable electricity. The outcomes of these studies are related to the methodological approach (and embedded ideology) applied to the analysis (see Winfield and Dolter, 2014).

Studies that use a Leontief multiplier analysis show that jobs will increase when increasing renewable energy investment (*e.g.* Pollin and Garrett-Peltier, 2009). The Leontief approach measures the *direct* jobs that result from manufacturing, installing, operating and maintaining renewable energy facilities. It also measures the *indirect* jobs that are associated with the production of intermediate inputs to the manufacture of renewables, as well as the inputs to those manufacturing processes, and the inputs to those, and so on. A Leontief analysis documents the entire chain of economic activity that must occur in order for renewable technologies to be built and installed. Using a multiplier approach these studies show that the jobs total exceeds the direct jobs created (for a good review of Leontief analysis see Miller and Blair, 2009).

There are two things missing from a Leontief analysis. The first is an acknowledgement that if a renewable electricity pathway costs more than a business-as-usual pathway then the higher electricity prices can reduce economic activity. Money spent on paying for electricity will be diverted away from investment and consumption in other sectors of the economy. Böhringer *et al*. (2012) used CGE modelling to predict a net increase in unemployment resulting from Ontario's feed-in-tariff for renewable energy. Hillebrand *et al.* (2006) use an econometric model to study Germany's feed-in-tariff. They find that the initial investment into renewable energy generates new jobs, but the impact of higher prices reduces jobs in later years. In total, Hillebrand (2006) forecast a net job loss of 6000 by 2010 due to the German feed-in-tariff.

In papers published afterwards, Böhringer and Rivers independently point out that the employment effects of a feed-in-tariff for renewables will depend on factors like the level of the subsidy (Böhringer *et al*., 2013) the mobility of capital (Rivers, 2014), and the share of labour costs in the production of renewable energy (Rivers, 2014). Rivers (2014) concludes that renewable energy subsidies like a feed-in-tariff can create jobs "when the elasticity of substitution between capital and labor is low, when capital is not mobile internationally, and when the labor intensity of renewable generation is high relative to conventional generation" (p. 1). He goes on to say that in any case the impact on employment is "very small" and "the focus of debate around such policies should shift from employment impacts to other more relevant metrics" (Rivers, 2014: 18).

The second thing missing from a Leontief analysis is a sense of the counter-factual; how many jobs would have been created by meeting electricity demand in another manner? What if more natural gas plants had been built instead of more wind turbines? What if more had been spent on energy conservation? Jobs are created any time money is spent on investment and new business activity. Of interest to Saskatchewan is the question, how many jobs are created in the province for each electricity pathway?

Wei *et al*. (2010) provide some numbers to help answer that question. They conduct a meta-analysis of job studies to understand the jobs created by investing in various electricity generation technologies. The job numbers provided by Wei *et al*. (2010) include jobs generated in the construction, installation and manufacturing of the technologies, the operations and maintenance of facilities, and fuel processing for technologies like natural gas-fired and coal-fired generation. The job calculations are converted to a measure of job-years per GWh electricity by considering the capacity factors and expected lifetime of each technology. I revise the Wei *et al.* (2010) numbers using the capacity factors and expected lifetime values from SIM. The resulting job multipliers are presented in Table 8-6. I then use these factors to analyze the seven scenarios presented in Chapter 7. The results for each time-step are presented in Table 8-7.

Generation Technology	Job-years/ GWh
Biomass	**0.23**
Coal	**0.14**
Coal CCS	**0.36**
Natural gas combined cycle	**0.12**
Natural gas simple cycle (peaking)	**0.12**
Natural gas CCS	**0.35**
Hydro	**0.26**
Wind	**0.18**
Solar - Photovoltaic	**1.26**
Small Modular Nuclear Reactor	**0.18**
Conservation	**0.15**
Electricity Storage Capacity	**0.15**

Adapted from Wei et al. (2010)

Table 8-6 Job Multiplier Factors

Solar photovoltaics stand out in Table 8-6 as the largest job creator per GWh electricity generated. This is for three reasons, one positive and two less so. The first is that installing solar photovoltaics is labour-intensive. This means that labour costs are a higher proportion of total costs. The second, and a less positive reason, is because solar is more expensive and so more investment is needed to install each megawatt. The third reason is because solar has a capacity factor of 16% in Saskatchewan, which requires more megawatts to be installed to generate the same amount of electricity as other technologies (Croucher, 2011). On these last two points, it is useful to remember that, while job creation makes for good politics, labour is also a cost of production. The same can be said for coal and natural gas fired plants equipped with CCS. The CCS process adds additional jobs and additional costs to generation from those technologies.

I assume that energy conservation creates .15 job-years/GWh saved. Typically, energy conservation job creation numbers are much higher. The higher numbers come, in large part, from *induced* employment. These are jobs in other sectors that result when electricity customers save money by conserving electricity and then spend it elsewhere in the economy. Since customers will be paying more for electricity, without conservation these induced effects will be negative; customers will have less money to spend elsewhere. Since I do not count the lost spending due to higher prices, I truncate the conservation job numbers and do not include induced effects from energy conservation.

The values in Table 8-6 assume static job multipliers, which is a limitation of the input-output approach (Lambert and Silva, 2012). We should expect these multipliers to change. For example, as solar costs decline over time, labour costs and job multipliers will fall. The multipliers also include manufacturing and indirect jobs created in the manufacturing process, which might not be representative of jobs created in Saskatchewan. Currently, Saskatchewan is home to a Hitachi plant, which manufactures power generation equipment that is used within the province, including the turbine and generator used for the Boundary Dam CCS facility (Hitachi, 2011) (See Figure 8-8).

(Source: Waldner, 2014)

Figure 8-8 Inside the Hitachi Manufacturing Plant

Whether Saskatchewan will be an attractive place to manufacture other power generation equipment remains to be seen. Within Canada, Ontario has the first-mover advantage. *The Green Energy and Economy Act* – including the local content requirement, which was subsequently struck down by the World Trade Organization (WTO) – helped Ontario develop a renewable energy manufacturing base in the province. This makes it more difficult to imagine Saskatchewan becoming a manufacturing centre for solar and wind technologies. In general, the job multiplier numbers should be seen as rough estimates that may change depending on local circumstances in Saskatchewan. With those caveats we can compare employment by scenario (Table 8-7).

Year	2015	2020	2025	2030	2035	2040	2045	2050
SaskPower BAU	4,038	4,296	4,840	5,209	5,415	5,760	6,585	6,484
Equivalency	4,038	4,502	4,362	4,840	5,053	5,398	5,902	6,417
Inter-provincial	3,781	4,121	4,371	4,625	4,843	4,854	5,083	5,727
Nuclear	3,781	4,121	4,301	4,625	4,843	5,525	6,458	7,191
CCS	3,781	4,121	4,301	4,625	4,843	5,609	7,118	8,647
Domestic Renewable	3,781	4,121	4,240	4,649	5,103	5,941	6,614	13,173
Greening the Grid	3,781	4,781	4,947	4,702	5,148	7,754	8,007	8,419

Table 8-7 Job-Years for Seven Scenarios

The numbers in Table 8-7 are calculated using the job multiplier factors from Table 8-6. They are based on the expected number of jobs per GWh electricity production for each technology. In 2050, the interprovincial scenario posts the lowest job numbers. This is because of the large proportion of electricity imported from Manitoba Hydro. Though there may be spillover job creation benefits if Manitoba Hydro builds the Conawapa project, I assume that Saskatchewan job creation is negligible for electricity imported from out of province. The domestic renewable scenario creates the most job-years in the 2050 time-step. This is due to high investment in solar photovoltaics. The CCS scenario and *Greening the Grid* scenarios are next in line. The CCS scenario edges out the *Greening the Grid* scenario because all of the generation is domestic. In the *Greening the Grid* scenario, the loss of in-province jobs due to Manitoba Hydro imports is balanced by jobs in solar, wind and electricity storage.

What all of these scenarios have to contend with is the reality of lost coal jobs. Coal mining in Saskatchewan employs 536 people: 167 at the Poplar River site and 367 at Estevan (Westmoreland, 2015b). In SaskPower's BAU scenario Poplar River will be closed in 2030 and this will have a devastating impact on the local economies of Coronach (pop. 711; Statistics Canada, 2011) and Willowbunch (pop. 286). Unless alterative investments are made in the region, the loss of 167 coal mining jobs and the

130 employees at the Poplar River plant will send this region into the downward spiral that characterizes much of rural Saskatchewan.

Many of the coal-related jobs at Estevan (pop. 11,000, Statistics Canada, 2011) would be protected if the coal-fired plants were retrofit with CCS. This is the plan for Boundary Dam units IV and V in the SaskPower BAU scenario. Shand will continue operating out to 2045 as a conventional coal plant and may be retrofit at that time to comply with the federal coal-fired regulation.

The alternative pathways do not involve coal-fired plants with CCS. Even the scenario I have called the 'CCS scenario' relies on natural gas plants with CCS in order reduce GHG emissions; coal is phased out when Shand closes in 2045. These alternative scenarios may be viewed as a threat to the coal mining regions of Estevan/Bienfait and Coronach/Willowbunch.

Yet Table 8-7 shows that there are employment opportunities in all of the scenarios. The question is, will the coal miners find work, close to home, building and operating another electricity generation technology? Strategic planning could make this possible. Estevan is the sunniest place in the province (and one of the sunniest in Canada) and strategic investment in a *Greening the Grid* scenario could shift the workforce away from coal and towards solar. This would be as much a cultural shift as a technological shift. Coal mining has a long history in the province and has helped to form the identity of the southeast region.[74]

Environmental Impacts

The goal of this dissertation has been to understand pathways to reduce GHG emissions in the Saskatchewan electricity sector. The seven scenarios outlined in Chapter 7 provide

[74] In an historic event in 1931, coal miners were protesting for the right to form a union of their choice. The RCMP opened fire on a union rally in Estevan killing three and wounding many others. A monument to the miners was erected in Bienfait that reads "Lest We Forget. Murdered in Estevan, Sept 29, 1931 by RCMP". The monument still remains, as does the proud coal culture of the region (Endicott, 2002).

alternatives and have unique GHG emissions profiles, especially from a cumulative perspective. I outline the cumulative GHG profiles in this section. As discussed above, there are multiple sustainability criteria that should be considered when comparing scenarios. I look at two indicators that can inform the criterion of ecological integrity: land impacted (especially by wind and solar installations) and water used. I also look at one indicator that can inform the 'precaution' (Winfield et al., 2010) and 'public health and safety' (White and Noble, 2012) sustainability criteria: radioactive waste produced.

Cumulative GHGs

As I mentioned in Chapter 7 climate change is not a problem of annual *flows* of GHG emissions, but is caused by the excessive *stock* of CO_2 and other GHGs in the atmosphere. Each tonne emitted in Saskatchewan adds to this global stock. Table 8-8 shows the net GHG emissions from the Saskatchewan electricity sector (in Megatonnes CO_2e) released to the atmosphere in each 5-year period, as well as the cumulative total from 2015 to 2050.[75]

Net GHGs (Mt CO2e/5-yr)	2015	2020	2025	2030	2035	2040	2045	2050	Cumulative (Mt CO2e)
SaskPower BAU	71.1	73.4	64.2	39.5	42.3	42.9	40.0	44.2	418
Equivalency	71.1	70.0	64.2	39.8	42.7	43.0	40.0	44.2	415
Inter-provincial	71.1	64.4	69.9	46.0	49.4	41.5	22.2	15.3	380
Nuclear	71.1	64.4	72.7	46.0	49.4	44.2	24.9	15.3	388
CCS	71.1	64.4	72.7	46.0	49.4	42.0	23.8	15.3	385
Domestic Renewable	71.1	64.4	66.8	39.3	38.8	30.2	21.1	7.4	339
Greening the Grid	71.1	55.3	53.8	10.6	8.6	0.5	0.5	0.5	201

Table 8-8 GHGs Released to the Atmosphere by Scenario

Early action to reach near-zero emissions in the *Greening the Grid* scenario significantly reduces cumulative emissions by 2050; this scenario releases 50% less GHGs to the atmosphere by 2050 than SaskPower's BAU scenario. This would be a celebrated achievement and would place Saskatchewan in a GHG reduction leadership position. Of the four scenarios that achieve a GHG reduction of 80% below 2015 levels by 2050, the domestic renewable scenario achieves the lowest level of cumulative GHG emissions. In

[75] I assume that annual GHG emissions for each time-step are representative of average annual GHG emissions for the five-year period and multiply by five to get the time-step total.

this scenario I allow wind to generate a higher percentage of electricity. Increased expansion of wind lowers GHG emissions in the earlier time-steps and lowers the cumulative total. From the perspective of climate change mitigation, the pathway to achieving a reduction target is as important as achieving the target itself. The *Greening the Grid* scenario and domestic renewable scenario are low-emission pathways to reaching a 2050 GHG reduction target.

With the inclusion of carbon capture and storage (CCS) options, it is also useful to look at the cumulative stock of captured CO_2 that would result by 2050. Table 8-9 shows the cumulative captured GHGs (Mt CO_2e) that result in each scenario. The equivalency, inter-provincial, nuclear, and domestic renewable scenarios contain captured GHGs from Boundary Dam III alone. SaskPower's BAU scenario adds captured GHGs from Boundary Dam IV and V as well as Shand in the 2050 time-step. The CCS scenario includes natural gas with CCS in the 2045 and 2050 time-step, as does the *Greening the Grid* scenario.

Cumulative Captured GHGs (Mt CO2e)	2015	2020	2025	2030	2035	2040	2045	2050
SaskPower BAU	5	10	25	40	54	63	80	88
Equivalency	5	10	15	20	24	24	24	24
Inter-provincial	5	10	15	20	24	24	24	24
Nuclear	5	10	15	20	24	24	24	24
CCS	5	10	15	20	24	24	34	54
Domestic Renewable	5	10	15	20	24	24	24	24
Greening the Grid	5	12	18	25	32	37	41	45

Table 8-9 Cumulative Captured CO_2 by Scenario

Table 8-10 outlines the volume of space that would be required to store this CO_2 underground, assuming that one tonne of CO2 required 556.2 meters cubed (m3) of volume for storage (ICBE, 2015).

Cumulative CO2 storage volume required (km3)	2015	2020	2025	2030	2035	2040	2045	2050
SaskPower BAU	3	6	14	22	30	35	44	49
Equivalency	3	6	8	11	13	13	13	13
Inter-provincial	3	6	8	11	13	13	13	13
Nuclear	3	6	8	11	13	13	13	13
CCS	3	6	8	11	13	13	19	30
Domestic Renewable	3	6	8	11	13	13	13	13
Greening the Grid	3	6	10	14	18	20	23	25

Table 8-10 Cumulative Storage Required for Captured CO_2

There is likely adequate space for the 49 cubic kilometres of captured CO_2 in the deep saline aquifers below Saskatchewan. This is not a pressing concern. The calculations do, however, highlight that storage is a continually increasing challenge in a CCS focused scenario.

Land Impact

One critique made against wind and solar energy is that they have a low "energy density" compared to technologies like nuclear energy (van Kooten, 2011). This means that more land area is required to produce a given amount of electricity. The United States National Renewable Energy Laboratory (NREL) has estimated the land requirements for wind (NREL, 2009) and solar (NREL, 2013). These are presented in Table 8-11 below.

Land-use factors	Hectares/ MWac
Wind	42.3
Solar photovoltaic (> 20 MW)	3.2
Solar thermal CSP	4.0

(NREL, 2009; NREL, 2013)

Table 8-11 Land-use Factors for Wind and Solar Energy Installations[76]

Where energy density is most relevant is in places where land is scarce. This is not the case in Saskatchewan, which has a low population density throughout the province (see Figure 4-3). However, it is worth understanding the geographic spread of renewables in

[76] For wind I average the high-end estimates of total impact for wind turbines located in areas of grasslands (high-end 52.4 ha/MW) and small grain farming (high-end 32.2 ha/MW). Actual impacted land area may be less.

the various scenarios since the amount of impacted land may be a useful proxy for the likelihood of siting conflicts. Table 8-12 presents the land use from wind and solar in each of the scenarios. For ease of interpretation, hectares have been converted to sections; much of southern Saskatchewan is divided into sections, 1 mile x 1 mile square, and grid roads dissect the province at this spacing.

Year	2015	2020	2025	2030	2035	2040	2045	2050
SaskPower BAU	65	90	127	184	204	221	239	281
Equivalency	65	65	64	169	189	303	376	457
Inter-provincial	65	80	129	182	240	304	376	457
Nuclear	65	80	76	182	240	304	376	457
CCS	65	80	76	182	240	304	376	457
Domestic Renewable	65	80	76	273	348	507	627	825
Greening the Grid	65	80	186	303	385	488	588	681

Table 8-12 Wind and Solar Land Use by Scenario (Sections)[77]

The two domestic renewable and *Greening the Grid* scenarios have the highest area of land impacted by wind and solar. In the domestic renewable scenario wind generates 40% of electricity in 2050 and solar generates 13%. A total of 825 sections would be impacted by this electricity mix. In the *Greening the Grid* scenario, wind generates 35% of electricity in 2050 and solar generates 4%. A total of 681 sections would be impacted by this mix.[78] This is equal to 1.2% of the area of the province seeded in 2014 (Ministry of Agriculture, 2015).

To put this in perspective, the Estevan/Bienfait coalmines are currently licensed to impact 20,331 hectares (ha) or 78 sections, and the Poplar River/Willowbunch coalmines are licensed to impact 7,488 ha or 29 sections, which means that in total, coal operations are licensed to impact 107 sections of land. In the Coronach area, reclamation work has been

[77] A section is equivalent to 640 acres or 260 hectares.
[78] In 2012, cropland in Saskatchewan could be leased for about $23,000/section (Insightrix, 2012). If these costs prevailed, the Greening the Grid scenario would result in land lease agreements of approximately $15.6 million. For land impacted by wind part of the land costs could be made up by cropping or grazing cattle in the project area. From the perspective of electricity generation costs, these land leases would add .09/MWh or .0009 cents/kWh to the cost of wind-generated electricity.

done to restore impacted land back to agricultural quality (Interview 19). In the Estevan area there are still old coalmines in need of reclamation (Interview 19).

It should be noted that measures of land impacted by wind and solar consist of *direct* impacts associated with physical infrastructure such as roads, turbines, solar arrays, transmission lines, as well land that is *indirectly* associated with the project area. Direct land impacts are about 1/100th of the total impacted land area for wind (NREL, 2009). Turbines are 10% of that total (or 1/1000th), while roads make up 79% of the direct impacts of wind (NREL, 2009). This means that much of the impacted land is still available for cropping or grazing. This agricultural activity just so happens to occur in the midst of a wind farm.

Water Impact

Saskatchewan is a semi-arid region. Drought is always a threat and water is precious. As mentioned in Chapter 4, drought has impacted the coal-fired electricity sector in the past (Maathuis and van der Kamp, 2011). Table 8-13 shows the water requirements of the electricity generation technologies included in my analysis. These indicators are the median values for each technology in a 2011 NREL study (NREL, 2011). Nuclear power plants and natural gas combined cycle plants are the greatest water users. Hydroelectric facilities (which use water and then release it downstream) also have large water requirements.

I use these indicators to analyze the water impacts of the seven scenarios from Chapter 7. The results are presented in Table 8-14 in terms of Gigalitres per year (billion litres per year) and in Table 8-15 in terms of thousands of Olympic sized swimming pools (a perhaps more intuitive figure; each Olympic swimming pool contains 2.5 Megalitres of water).

Generation Technology	Type	Water Consumption (L/MWh)	Water Withdrawals (L/MWh)	Total (L/MWh)
Biomass	Steam pond	1,476	1,703	**3,180**
Coal	Generic pond	2,063		**2,063**
Coal CCS	subcritical with CCS	3,202		**3,202**
Natural gas combined cycle	Pond	908	22,523	**23,432**
Natural gas simple cycle (peaking)	Pond	908	22,523	**23,432**
Natural gas CCS	Tower combined cycle with CCS	1,431	1,878	**3,308**
Hydro	Aggregated In-stream and Reservoir	17,000		**17,000**
Wind		0		**-**
Solar - Photovoltaic		98		**98**
Solar - Thermal CSP	Trough dry	295		**295**
Small Modular Nuclear Reactor	Pond		26,687	**26,687**
Conservation				**-**
Electricity Storage Capacity				**-**
Source: NREL (2011)				

Table 8-13 Water Impact Indicators

As a word of caution, these water impacts include consumption and withdrawals, but they do not indicate changes in water quality. Ontario's nuclear plants routinely release tritium into Lake Ontario (Winfield *et al*., 2006). Tables 8-14 and 8-15 do not capture this qualitative impact on water. These figures also only include direct water impacts. The water impact of coal mining, natural gas extraction, and uranium mining is not included, and neither is the water impact of manufacturing processes required to create the electricity generation equipment. This means these numbers are an incomplete measure of water impact, but they are a useful measure of drought resilience. They can be used to determine, once a given scenario is in place, how vulnerable it is to drought conditions.

Water Impact (Gigalitre/yr)	2015	2020	2025	2030	2035	2040	2045	2050
SaskPower BAU	295	334	366	464	500	543	600	668
Equivalency	303	325	363	458	494	501	592	590
Inter-provincial	285	326	397	471	515	506	484	481
Nuclear	285	326	429	471	515	517	526	552
CCS	285	326	429	471	515	490	419	333
Domestic Renewable	285	326	471	508	532	467	392	253
Greening the Grid	285	277	292	349	343	289	288	289

Table 8-14 Water Impact by Scenario (Gigalitres/yr)

Water Impact (1000 Olympic Swimming Pools/yr)	2015	2020	2025	2030	2035	2040	2045	2050
SaskPower BAU	118	134	147	186	200	217	240	267
Equivalency	121	130	145	183	197	200	237	236
Inter-provincial	114	130	159	189	206	202	194	193
Nuclear	114	130	172	189	206	207	210	221
CCS	114	130	172	189	206	196	167	133
Domestic Renewable	114	130	189	203	213	187	157	101
Greening the Grid	114	111	117	139	137	115	115	116

Table 8-15 Water Impact by Scenario (thousands of Olympic sized pools/yr)

The renewable focused scenarios appear most resilient to drought, although losing hydroelectric capacity would make the variability of wind and solar energy more difficult to manage. The CCS approach is next in line. Table 8-13 contained natural gas CCS factors that were lower than conventional combined cycle factors. This is due to the assumption that a cooling tower is used. Water requirements increase substantially if cooling ponds or once-through cooling systems are used. The SaskPower BAU scenario appears to be the biggest water user. In this scenario, combined cycle natural gas plants require a great deal of cooling water. It should also be noted that drought is a particular concern for nuclear power plants, which require a steady supply of cooling water to avoid catastrophic nuclear meltdown.

High-Level Radioactive Waste

Only two scenarios contain small, modular nuclear reactors. These scenarios create an environmental impact wholly unlike the others. Nuclear reactors create intermediate and high-level radioactive waste. High-level radioactive wastes like plutonium must be managed and contained for stretches of time beyond the human imagination (*i.e.* one million years, one hundred times longer than the history of human civilization see Winfield *et al*., 2006). Siting nuclear waste facilities generates conflict. The Yucca Mountain site in the United States was a matter of contention and the nuclear waste storage project has now been cancelled. Proposals to store nuclear waste in northern Saskatchewan led to a high-profile protest walk by northern residents in the summer of 2011. These residents walked 800 kilometers from their home community to the Saskatchewan legislative building. They gathered water from lakes and rivers on their journey and presented it in front of the legislative building, reminding southern residents that water, and its attendant pollutants, unites the province. Table 8-16 shows the quantity of high-level nuclear waste that would result from the inter-provincial scenario and the nuclear scenario.

High-level radioactive waste (cumulative tonnes)	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
SaskPower BAU	-	-	-	-	-	-	-	-
Equivalency	-	-	-	-	-	-	-	-
Inter-provincial	-	-	-	-	-	-	-	28
Nuclear	-	-	-	-	-	-	67	232
CCS	-	-	-	-	-	-	-	-
Domestic Renewable	-	-	-	-	-	-	-	-
Greening the Grid	-	-	-	-	-	-	-	-

Table 8-16 High-Level Radioactive Waste

Quantity is, however, a poor measure of the risks posed by nuclear waste. Even a very small amount of plutonium is dangerous. The choice to embark down the path of nuclear power has been rejected once by the people of Saskatchewan. It should not be taken lightly, and it should be compared in detail to alternative scenarios that do not pose the risk of catastrophic nuclear accident, routine radiation releases, occupational hazard, and long-lived waste products that must be isolated from human systems for millennia.

Contributions to a Sustainability Assessment

The indicators I have outlined in this chapter can contribute to a sustainability assessment of scenarios for Saskatchewan's electricity future. Below I review the indicators and comment on what they say about relevant sustainability criterion. First, I reproduce Table 8-1 to highlight the cost differences between the scenarios.

Projected Cost

The expected electricity costs and total discounted project costs range from the lows of the BAU equivalent scenario to the highs of the Domestic Renewable and *Greening the Grid* scenario. The relative cost are, however, dependent on carbon pricing policy. An escalating carbon price leads the *Greening the Grid* scenario to be roughly equivalent in expected cost to the SaskPower BAU scenario and the four 80% GHG reduction scenarios (Table 8-17).

Financial Cost Comparison

Scenario	SaskPower BAU	BAU Equivalent	Inter-provincial	Nuclear	CCS	Domestic Renewable	Greening the Grid
Projected Cost							
Electricity Cost in 2050 (cents/kWh 2014 $CAN)	11.6	11.2	12.6	12.7	13.2	13.7	13.6
Electricity Cost in 2050 95% C.I. (cents/kWh 2014 $CAN)	12.1	11.7	13.4	13.4	13.6	14.0	14.3
Electricity Cost in 2050 5% C.I. (cents/kWh 2014 $CAN)	11.1	10.8	11.9	12.2	12.8	13.4	12.9
Discounted Project Cost							
Total discounted cost mean (million 2014 $CAN)	67,091	62,467	68,173	67,037	67,618	69,477	76,368
Total discounted cost 95% C.I. (million 2014 $CAN)	68,285	63,515	69,767	68,374	68,876	70,729	78,848
Total discounted cost 5% C.I. (million 2014 $CAN)	65,930	61,426	66,641	65,689	66,387	68,243	74,105
Project Cost with Constant Carbon Price ($30/tonne CO2e)							
Total discounted cost mean (million 2014 $CAN)	73,863	69,158	74,745	73,752	74,286	75,379	79,551
Total discounted cost 95% C.I. (million 2014 $CAN)	75,024	70,323	76,370	75,069	75,537	76,545	81,951
Total discounted cost 5% C.I. (million 2014 $CAN)	72,722	68,008	73,156	72,535	73,085	74,061	77,387
Project Cost with Escalating Carbon Price ($15/tonne CO2e in 2015 escalating by $15/time-step)							
Total discounted cost mean (million 2014 $CAN)	80,672	75,984	80,450	79,659	80,091	79,985	80,681
Total discounted cost 95% C.I. (million 2014 $CAN)	81,836	77,056	82,098	81,045	81,291	81,224	83,133
Total discounted cost 5% C.I. (million 2014 $CAN)	79,463	74,929	78,846	78,445	78,833	78,765	78,415

Table 8-17 Financial Cost Comparison

Other costs are relevant to particular scenarios. The nuclear scenario poses a unique decommissioning hazard and those costs are worth detailing as they are not included in the discounted costs listed above. Radioactive components of a nuclear facility include "spent fuel, and parts of the plant and machinery that have been exposed to radiation" (Winfield *et al*., 2006: 75). These components are so radioactive that nuclear power plants are often shutdown for five to ten years before decommissioning begins to allow the radioactivity to decrease (Winfield *et al*., 2006: 75). Estimates of nuclear decommissioning costs range from 15% to 25% of the original capital cost (Boccard, 2014). In the inter-provincial and nuclear scenarios SaskPower would be required to set aside funds to pay for the decommissioning of small, modular nuclear reactors (Table 8-18). This increases the discounted value of the inter-provincial scenario by between $57-

95 million and the nuclear scenario by $306-510 million (2014 $CAN). The relative ranking of the nuclear scenario, based on project costs, changes at the higher level of decommissioning costs.

Scenario	SaskPower BAU	BAU Equivalent	Inter-provincial	Nuclear	CCS	Domestic Renewable	Greening the Grid
Nuclear Liability							
Installed Nuclear Capacity 2050 (MW)	-	-	209	1,220	-	-	-
Total Capital Cost for nuclear (million 2014 $CAN)	-	-	1,927	10,372	-	-	-
Decommissioning @ 15% (million 2014 $CAN)	-	-	289	1,556	-	-	-
Decommissioning @ 25% (million 2014 $CAN)	-	-	482	2,593	-	-	-
Decommissioning @ 15% discounted from 2070 @ 3% (million 2014 $CAN)	-	-	57	306	-	-	-
Decommissioning @ 25% discounted from 2070 @ 3% (million 2014 $CAN)	-	-	95	510	-	-	-
Total discounted cost mean with 15% nuclear liability (million 2014 $CAN)	80,672	75,984	80,507	79,966	80,091	79,985	80,681
Total discounted cost mean with 25% nuclear liability (million 2014 $CAN)	80,672	75,984	80,545	80,170	80,091	79,985	80,681

Table 8-18 Nuclear Decommissioning Costs

Intragenerational Impacts

Increased electricity costs will impact electricity customers in Saskatchewan. Higher cost scenarios lead to correspondingly higher rates. These rates can pose hardship for low-income households and households on fixed incomes (*e.g.* seniors). Commercial customers will also see the electricity rates impact their bottom line. Scenarios that lower GHG emissions increase rates relative to the SaskPower BAU scenario (Table 8-19). Energy conservation programs aimed at low-income households and vulnerable businesses can provide a means of reducing the impact of higher rates.

Scenario	SaskPower BAU	BAU Equivalent	Inter-provincial	Nuclear	CCS	Domestic Renewable	Greening the Grid
Intragenerational Equity							
Electricity rate for residential customers (cents/kwh)	23.0	22.3	24.0	24.8	25.1	26.3	25.5
Electricity rate for commercial customers (cents/kwh)	21.9	21.3	22.9	23.7	23.9	25.1	24.3
Livelihood sufficiency and opportunity							
Electricity rate for industrial customers (cents/kwh)	10.8	10.3	13.5	14.1	14.3	15.2	14.6
Employment (full-time jobs)	6,484	6,417	5,727	7,191	8,647	13,173	8,419
Employment (full-time jobs)/ Cost of Electricity (mean)	559	573	455	566	655	962	619
Emissions management							
Annual direct net GHGs (kt CO2e/yr)	8,849	8,849	3,054	3,054	3,054	1,485	100
Cumulative direct net GHGs (Mt CO2e)	418	415	380	388	385	339	201
Cumulative captured CO2 (km3)	49	13	13	13	30	13	25
Ecological Integrity							
Land impacted by wind and solar (sections)	281	457	457	457	457	825	681
Water use (1000 Olympic swimming pools/yr)	267	236	193	221	133	101	116
Hydroelectric development in Saskatchewan (MW)	1664	1664	1994	1994	2194	2494	2394
Hydroelectric dams on the Churchill River	0	0	1	1	1	2	1
Energy Independence							
Hydroelectric contracts with Manitoba in 2050 (MW)	0	0	1950	0	0	0	1950
Resource Maintenance and Efficiency							
DSM Energy Conservation measures in 2050 (GWh)	485	485	3777	3777	3777	3777	3777
Precaution and Public Health and Safety							
Cumulative high-level radioactive waste (tonnes)	0	0	28	232	0	0	0

Table 8-19 Scenario Impacts in 2050

Livelihood sufficiency and opportunity

Coal mining and coal-fired electricity generation jobs will be lost in all scenarios; even in the SaskPower BAU scenario, Poplar River is shut down by 2030. In the *Greening the Grid* scenario, which includes a coal phase-out by 2030, all of the 500 coal mining jobs will be lost. However, Saskatchewan's electricity system is forecast to grow and workers will be needed in every scenario. The net impact of manufacturing, constructing, and operating electricity generation facilities will mean that coal mining job losses represent 10% of the full-time jobs available in 2050. The domestic renewable scenario offers the greatest opportunity for employment. This is partly due to its higher cost, but when controlling for electricity cost (using the metric employment/cost of electricity), employment is still higher for the domestic renewable scenario. If the province moves away from coal, the question will be, will the new jobs be available in the same location as existing jobs? Halliday (2013) suggests a solar thermal plant for the Coronach area to provide jobs for coal miners and employees at the Poplar River plant. Opportunities to manufacture components in Saskatchewan would also contribute to employment, but are in no way guaranteed.

While there will be jobs in the electricity sector, higher electricity rates may lead to job losses in other sectors. Energy-intensive industries such as chemical manufacturing and steel manufacturing may choose to leave Saskatchewan for locations with lower rates. Household and business spending would be redirected from other areas of the economy towards their electricity bills. The higher the electricity rates, the greater the threat of job loss throughout the rest of the economy.

Emissions Management

It is a central focus of this dissertation to find electricity scenarios that reduce GHG emissions. The *Greening the Grid* scenario achieves near-zero emissions by 2040 (100 kt CO2e/yr) and maintains this low level of GHG emissions to 2050. This early action leads to cumulative GHG emissions measuring half that of the SaskPower BAU scenario. In contrast, action is delayed in the four scenarios that reduce GHGs by 80% by 2050 and cumulative GHG emission are 137-179 Mt CO_2e higher than the *Greening the Grid* scenario, nearly approaching that of the SaskPower BAU scenario. Early action would enhance Saskatchewan's contribution to global efforts to mitigate climate change. It is also worth noting that the SaskPower BAU scenario, which relies on converting coal-fired generation stations to carbon capture and storage (CCS), requires the largest volume of underground space to store CO_2. To those who advocate using captured CO_2 for enhanced oil recovery this may be a benefit of the scenario.

Ecological Integrity

Four indicators can contribute to our understanding of the ecological integrity of each scenario: land impacted by wind and solar; water use; hydroelectric capacity; and the number of hydroelectric projects on the Churchill River. Land impacted by solar and wind is highest in the domestic renewable scenario. This indicates a higher potential for land use conflicts or wildlife impacts. From the perspective of landowners, this also represents an economic opportunity. Land lease payments for wind turbines are generally in the range of $8000 per turbine per year (Baxter *et al*., 2013).

The domestic renewable scenario has the lowest water impact of all scenarios, followed closely by the *Greening the Grid* scenario. This makes installed wind and solar facilities resilient against drought (although their manufacture may not be). Scenarios that rely on coal-fired generation, natural-gas fired generation, and nuclear generation require the most water. Without a steady supply of cooling water coal-fired and natural-gas fired units must shut down. Without cooling water, a nuclear plant could risk a melt-down. This makes the thermal, and especially nuclear generation facilities, susceptible to drought.

Further work needs to be done to understand the impacts of drought on hydroelectricity production. The domestic renewable scenario and *Greening the Grid* scenario have the highest reliance on hydroelectricity. This power is needed to balance the variability of wind and solar. Though wind and solar may be resilient to drought, an energy system combining wind and solar and hydroelectricity may not be. The *Greening the Grid* scenario was designed to meet electricity demand in periods of seasonally low hydroelectric availability. The possibility of a multi-year mega-drought must also be examined.

Hydroelectric facilities create lasting ecological impacts by modifying river systems. I include the number of facilities assumed to be constructed on the Churchill River as a proxy of hydroelectric impact on ecological integrity. In the late 1970s people rejected the Wintego project on the Churchill River because of the ecological impacts it would cause. At the time the Churchill River Board of Inquiry reported that the proposed 300 MW Wintego dam would create,

> “a new reservoir extending approximately 70 miles upstream from the Wintego site to Drinking Falls on the Churchill River and extending upstream on the Reindeer River for the full extent of the river, some 59 miles upstream to Whitesand Dam…The reservoir so created would flood an additional 112 square miles of land.”
> (Churchill River Board of Inquiry (CRBI), 1978: 10)

All of the GHG reduction scenarios assume that a Wintego type project would proceed on the Churchill River. The domestic renewable scenario assumes that a second hydroelectric facility would be constructed on the Churchill River. The social acceptability of these hydroelectric facilities remains in doubt. Opposition to the Wintego project in the 1970s came from groups ranging from northern First Nations – especially the Cree peoples who have traditionally lived along the Churchill River – northern Métis peoples who have connections to the river dating back to the voyageurs who used it as a key transportation artery for the fur trade, and southern settler groups who value the recreational opportunities offered by the Churchill. The National and Provincial Parks Association spoke of the “triple value” of the Churchill: “it’s a wild river, it is scenic, and it is of historic importance to Canada” (CRBI, 1978: 38). If hydroelectric projects are not built on the Churchill River additional low-carbon firm capacity must be obtained from other sources.

The lessons from Cumberland House should also be remembered. If new hydroelectric projects are used to balance the variability of wind and solar energy, as I have shown them to be used in Chapter 7, the downstream river flows will be highly erratic. As recounted in the quote found on page 59, the erratic outflows from the E.B. Campbell dam created hardship for the people of Cumberland House impacting wildlife, local outfitting businesses, and the way of life of the people of Cumberland House. Limits on the operating range of hydroelectric facilities can reduce downstream impacts, but will also mean that other back-up sources must be brought on-line to balance the variability of wind and solar power.

Energy Independence

Premier Wall has stated that he prefers coal-fired generation with carbon capture and storage to hydroelectricity imports from Manitoba because coal offers a greater degree of energy independence (Zinchuk, 2014). Two scenarios include large scale contracts with Manitoba Hydro in 2050: the inter-provincial scenario and the *Greening the Grid* scenario. These scenarios also have the greatest range of uncertainty around their costs. The risk of relying on Manitoba Hydro electricity is that prices are set outside the province, and outside of SaskPower's control. If this risk is to be mitigated, stable long-term contracts must be signed between SaskPower and Manitoba Hydro.

Some of the 1950 MW of Manitoba Hydro capacity included in the inter-provincial and *Greening the Grid* scenarios would come from the Keeyask project. This 695 MW hydroelectric project is a partnership between Manitoba Hydro and four First Nations. It is currently under construction. The rest of the capacity from Manitoba Hydro would require the construction of the Conawapa hydroelectric project. That project is currently on hold "until more export sales are confirmed" (Puxley, 2014). If Saskatchewan is to access this power in time to replace the coal-fired plants being retired in 2028 and 2030 it will have to act soon to sign import agreements with Manitoba Hydro.

Resource Maintenance and Efficiency

Winfield *et al*. (2010) argue that a sustainable electricity pathway will focus on resource maintenance and efficiency, including end-use energy efficiency. In all of the GHG emission reduction scenarios DSM conservation efforts are pursued to the maximum potential allowed in SIM (3777 GWh in 2050). This stands in contrast to the SaskPower BAU and BAU equivalency scenarios. The difference is explained by industrial DSM becoming cost-competitive in scenarios with higher electricity prices.

Precaution, Public health and safety, Extreme Event Risk

All three sets of sustainability criteria proposed at the beginning of this chapter include mention of something like precaution (Winfield *et al*., 2010), public health and safety (White and Noble, 2012), or extreme event risk (Jaccard, 2005). These criteria seem tailored to bring attention to the unique dangers posed by nuclear energy. Nuclear energy poses an extreme event risk in the form of catastrophic meltdown (*e.g.* Fukushima). It poses public health and safety risks through routine and accidental release of radiation (Winfield *et al*., 2006). The safety of a nuclear facility is fraught with uncertainty and so invites the application of the precautionary principle. These risks are enough to encourage many people – including those who expressed their opposition to nuclear power at the Perrins' (2009) consultation meetings – to strike the inter-provincial and nuclear scenarios off the list of desirable electricity futures.

Path Dependence

Jaccard (2005) and Winfield *et al*. (2010) both list path dependence as a consideration in an assessment of electricity futures. For Jaccard (2005) a scenario is more politically acceptable if it aligns with existing institutions. Path dependence in this instance is something to recommend a scenario. For Winfield *et al*. (2010) path dependence is a potential trap to be avoided. In Ontario, where Winfield *et al*. (2010) focus their research, large nuclear plants have been built. The socio-technical apparatus that surrounds these nuclear plants creates a powerful political lobby for maintaining and expanding nuclear power in the generation mix. Path dependence in the Ontario electricity system reduces flexibility and adaptive capacity, limiting future electricity generation options (Winfield *et al*., 2010).

Saskatchewan does not have nuclear power plants, but it does have a uranium mining industry with strong ties to the nuclear power industry (uranium mining company CAMECO is a part-owner of Ontario's Bruce Power nuclear power corporation). There is a strong sense among the business community and leadership of the Saskatchewan Party that Saskatchewan should build a nuclear power plant. In the UDP (2009) report, nuclear power was represented as a way to "add value" to Saskatchewan's uranium. This creates, if not path dependence, at least path *pressure* to build a nuclear power plant.

Interest in nuclear power also comes from the International Brotherhood of Electrical Workers (IBEW) labour union. Neil Collins, then business manager for the IBEW, had a seat on the UDP (2009) panel that recommended Saskatchewan build a nuclear power plant. The IBEW also signed an agreement with Bruce Power guaranteeing union jobs were a nuclear power plant to be built. The IBEW continued to show their support during the Perrins' (2009) consultations, when at each meeting an IBEW member would stand to advocate for nuclear power and explain why wind and solar power could not supply "baseload power."

In Saskatchewan, where coal has been king since Boundary Dam was commissioned in 1959, path dependence points towards the continued existence of coal-fired electricity. SaskPower staff and senior management have spent their careers working in a coal-based electricity system. This familiarity with coal breeds allegiance, and the effect can be powerful. In Chapter 7 I showed that the GHG emission reductions that will result from the federal coal-fired regulations could be achieved at a lower cost by allowing coal facilities to be retired at the end of their useful lives, and replacing them with natural gas combined cycle plants and wind turbines, instead of converting them to carbon capture and storage. SaskPower and Premier Brad Wall have other plans. In the Fall of 2015 the Premier expressed his continued support for the Boundary Dam III carbon capture and storage plant, despite cost over-runs, and despite the fact that it was still suffering from problems that kept it from running at full capacity,

> "Mr. Speaker, it's going to get to 90 per cent (carbon capture) on a consistent basis. We know that in the coming months the plant will be operational again. And we need it to be operational if we're going to continue to have coal, cleaner coal in the fleet, if we're going to continue to have coal mining jobs in the province."
> (CBC, 2015e)

Members of the IBEW were also quoted expressing their support for the Premier's position on coal (Langenegger, 2015). The large centralized technologies – nuclear and coal - appear to be a good fit for the IBEW workforce. Path dependence may keep Saskatchewan on the trail of carbon capture and storage despite the availability of other options.

Conclusions

The scenarios I outlined in Chapter 7 are diverse in their impacts. The SaskPower BAU scenario posts the second lowest electricity price increases, but the highest cumulative GHGs, stored GHGs, and water requirements. The *Greening the Grid* scenario achieves the lowest cumulative level of GHG emissions, the lowest water requirements, and avoids nuclear waste, but also increases electricity prices and impacts a large area of land. The analysis reveals that there is no consequence free pathway to Saskatchewan's electricity future. Trade-offs are involved and decisions must be made that balance attributes against one another. In a qualitative sense, this was the work of White and Noble (2012) who found a renewable based scenario to be the preferred electricity pathway. Further work can be done to involve the citizens of Saskatchewan in evaluating trade-offs and deciding which pathway is best for the province. The information I have presented in this chapter can inform such a discussion.

It is worth noting the many additional impacts that have not been explored in this chapter. This list includes:

- Health impacts from fossil fuel emissions like sulphur dioxide and particulate matter;
- Environmental impacts from sulphur dioxide (*e.g.* acid deposition in lakes);
- Environmental impacts from mercury released by coal-fired electricity plants;
- Lifecycle environmental impacts from rare-earth elements contained in lithium-ion batteries (if that storage method is pursued);
- Lifecycle energy requirements for technologies that would indicate the 'Energy Return on Investment' of competing options;
- Land impacts from hydroelectricity dams, natural gas extraction, uranium mining;
- Wildlife impacts; and importantly,
- Climate change costs in Saskatchewan avoided through global GHG reduction.

There are also social impacts associated with the various scenarios that include:

- International reputation from contributing to GHG reduction;
- Community division if controversial technologies such as nuclear are pursued;

- Community conflict over the siting of electricity generation technologies;
- Impact of each scenario on Aboriginal Rights.

On this last indicator, the history of electricity development in Saskatchewan has not been kind to Aboriginal people. The E.B. Campbell dam resulted in significant impacts to downstream fishers and outfitters, many of who were Métis or First Nation. The First Nations Power Authority (FNPA) appears to be a step in a better direction. The FNPA works with First Nations to develop electricity generation projects in Saskatchewan. It serves as a bridge between SaskPower and First Nations. Already the FNPA has developed a solar photovoltaic tracking project in Swift Current in partnership with the File Hills Qu'Appelle Tribal Council, an affiliation of eleven First Nations in the province (Interview 7). Continued partnership and consultation could help to ensure that aboriginal rights are respected and the electricity system becomes a vehicle for supporting aboriginal livelihoods (see Martens, 2015).

Chapter 9 – Deliberating Saskatchewan's Electricity Future

Introduction

In this chapter I outline the results of three deliberative energy policy modelling workshops. These workshops allowed stakeholders engaged in Saskatchewan electricity policy to evaluate scenarios for Saskatchewan's electricity future using an interactive version of the Saskatchewan Investment Model (iSIM).

The workshops also presented opportunities for stakeholders to meet one another, exchange views, and, it is hoped, develop a greater understanding of one another's positions. Akin to van den Belt's (2004) *Mediated Modeling*, the deliberative workshops are an opportunity to "increase the level of shared understanding amongst the group" (p. 17). This shared understanding can act as a foundation for "investigating policy, research, or management alternatives" (van den Belt, 2004: 17). Shared understanding is also very much an end in and of itself. One of the most important outcomes of a deliberative modelling process is "the growth of mutual recognition and compassion" (Ravetz, 1999: 652).

Models such as iSIM are idealized representations of the world and "useful ways of disciplining our thinking" when used to support deliberation (Victor, 2015). They provide opportunities for participants to test their understanding of the Saskatchewan electricity system against an empirically grounded model of the system. Conversely, they are intended to allow participants to challenge and improve the manner in which the system is modelled. In both of these ways the model helps to structure a deliberative discussion (van den Belt, 2004).

The deliberative modelling workshops build on the work of Richards *et al*. (2012) who conducted interviews with sixteen individuals in Saskatchewan on the topic of wind energy. Richards *et al*. (2012) found differences in participants' views on whether the rate of expansion of wind energy in Saskatchewan was adequate. Those who believed the pace was adequate cited technological barriers to integrating variable wind energy onto the provincial grid. Those who believed the pace was too slow cited political barriers such as the lack of carbon pricing, feed-in-tariff, or renewable generation targets. Richards *et al*. (2012) theorized “Opposing sides may never agree simply because their perceptions of barriers and what is an appropriate level of investment are based on different underlying values” (p. 7). Deliberative workshops were an opportunity to test whether deliberative exchange could move stakeholders closer to agreement on the potential for renewable energy in Saskatchewan, barriers to renewable energy penetration, and means of overcoming the barriers in Saskatchewan.

Theoretical Approach

The economic costs outlined in Chapter 8 are necessarily incomplete. Some costs, like the damage we can expect from climate change, are inherently uncertain. High-profile attempts to monetize the social cost of carbon (*e.g.* Nordhaus, 1991) have been severely critiqued for hiding uncertainty behind a veil of mathematical precision (Funtowicz and Ravetz, 1994; Pindyck, 2013). Ecological economists have been among the first to recognize that in the face of the “irreducible uncertainties and ethical complexities” (Funtowicz and Ravetz, 1994: 198) posed by issues like climate change we require a new approach to science and a new approach to economic analysis.

“Post-normal science” is one name given to this new approach to economic analysis. It is defined in contrast to “normal science”, which means both normality in the sense of Thomas Kuhn’s idea of “research science as normality” and also the idea that “routine puzzle-solving by experts provides an adequate knowledge base for policy decisions” (Ravetz, 1999: 648). This idea of “routine” normal science does not hold in situations where “facts are uncertain, values in dispute, stakes high, and decisions urgent” (Ravetz, 1999: 649). Climate change fits this description well. We ultimately do not know, and will not know until it occurs, whether our climate is near a tipping point where it will flip into a chaotic and catastrophic new reality. We can have some confidence about the likely costs and impacts of mitigating greenhouse gas emissions (GHGs) – and this was the goal of the work I outline in Chapter 7 and Chapter 8 – but the decision on how quickly to reduce GHG emissions is a moral decision; a judgement of acceptable risk and moral responsibility for action. A cost-benefit analysis, where a social cost of carbon is assigned to calculate the "optimal" level of GHG abatement, is an attempted shortcut to avoid messy ethical debate (Zografos and Howarth, 2010). This "normal" approach to economic analysis places the economist in the authoritative role of expert, while subverting democracy by embedding moral assumptions within the analysis (*e.g.* discounting the impact of climate change on future generations). Citizens, environmental groups, and ecological economists have begun to ask for better.

A post-normal approach to ecological economics begins with the assertion that the economic or technical expert is not the final arbiter of truth. It rejects the idea that we can arrive at certainty when studying complex problems such as climate change. It invites an "extended peer community" to partake in deliberation to ensure high-quality research is conducted (Ravetz, 1999). It admits that subjective and ethical values enter into the research and decision-making process. Rather than awareness of subjectivity weakening the research process, post-normal science provides a degree of transparency that is lacking in "normal" science.

Deliberative ecological economics has arisen as a method of operationalizing post-normal science (Zografos and Howarth, 2010). The goal of deliberative ecological economics is to "generate consensus solutions through dialogue, reflection and preference change" (Zografos and Howarth, 2010: 3405). Representative stakeholders are selected to participate in a deliberative discussion on a particular topic. Typically, these discussions occur in a small group setting of 15 people or less (Zografos and Howarth, 2010). A facilitator works to organize the session so that respectful and productive dialogue can occur. Ecological economists, with their experience working in a trans-disciplinary environment, are well suited to the task of facilitating a deliberative discussion (Norgaard, 2007; Norgaard, 1989).

Deliberative Energy-Economy-Environment Modelling

I used a deliberative approach to explore potential futures for the Saskatchewan electricity system. After developing the Saskatchewan Investment Model (SIM) and Will

It Run Electricity Model (WIRE) I held three workshops with invited stakeholders. The purpose of the workshops was twofold. First, I wanted to present the models I had developed and receive feedback on their strengths and weaknesses. Second, I wanted to host a deliberative exchange between people with different views on the future of the electricity system. This deliberative exchange, it was hoped, would encourage participants to reach a shared understanding of the options for the future of the Saskatchewan electricity system. It was also a chance for participants to meet each other; while they had all been working on electricity policy in some fashion, many had never met in person.

Participants were drawn from the pool of thirty-one experts that I interviewed when developing SIM and WIRE, their colleagues, as well as others who are actively engaged on the topic of Saskatchewan's electricity future. The pool of invited participants included representatives from utilities, government, private consulting firms, research institutes, industry, and environmental non-governmental organizations (ENGOs). Twenty-one individuals participated in the workshops: 11 in the first workshop, 6 in the second workshop, and 6 in the third (this workshop also included an observer from my supervisory committee). One individual participated in all three workshops. Participants in the workshops represented electricity utilities, environmental non-governmental organizations, private industry working in the field of energy conservation, and independent power producers. The first two workshops featured the most diverse participant groupings. Workshop 1 was attended by six utility representatives, two ENGO representatives, two private industry energy conservation representatives, and one independent power producer representative. Workshop 2 was attended by two utility representatives, three ENGO representatives, and one private industry energy conservation representative. Workshop 3 was attended by six ENGO representatives.

Pre-Workshop Survey

Before the workshops I invited participants to fill out an on-line survey containing seven questions (Appendix 9D). This survey sought to identify the starting positions each participant would bring to the discussion. Sixteen invited participants responded to the survey. This included one respondent who did not end up attending the workshops, one respondent who did not provide a name, and fourteen participants who took part in the workshops. Participants in the third workshop did not fill out a pre-workshop survey.

I first asked questions to understand each participant's position on GHG emission reductions and the technologies that could help achieve GHG reductions:

- Thinking ahead to the future, what GHG intensity should Saskatchewan strive to achieve in the electricity sector by 2050? (Question 1)
- Several technologies might contribute to lowering the GHG intensity of Saskatchewan's electricity system. Seventeen of these technologies are listed below in alphabetical order. Please rank the technologies in terms of their importance for reducing the GHG intensity of Saskatchewan's electricity system. (Question 2)
- Imagine a preferred electricity generation mix in the year 2050 that achieves the electricity GHG intensity you listed in Question 1. What proportion of total electricity generation is provided by each of the following technologies in your preferred scenario? (Question 3)

There was a range of responses to the first question (Figure 9-1). One of the participants who wanted GHG intensity to be 0-99 grams CO_2e/kWh included the note,

> It is clear from the 2013 IPCC WG3 AR5 report that the whole world needs to decarbonize fully by 2070 - and even then there will need to be multiple decades during which we are net carbon negative after that time - if we are to prevent climate change from going into unpredictable, likely irreversible territory. Decarbonisation of electricity is a relatively easy component, and a necessary prerequisite for decarbonisation of certain other sectors. Hence a failure to decarbonize electricity by 2050 worldwide (and that includes Saskatchewan!) would put us in a very perilous position.
> (Workshop Participant)

From this comment, it appears that belief in the urgency of climate change encourages a stronger desire to reduce the GHG intensity of the electricity sector.

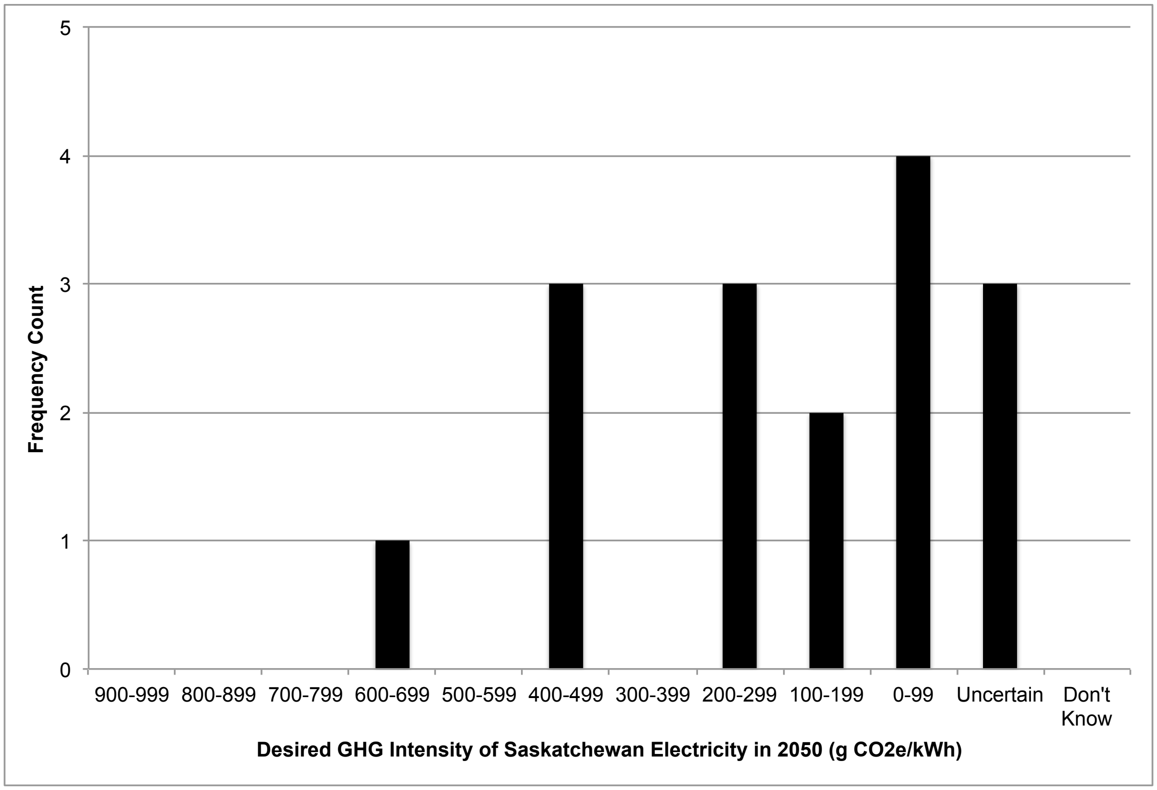


Figure 9-1 Responses to Question 1 of the Pre-Workshop Survey

On the other side of the ledger, the lone respondent who stated Saskatchewan should achieve a GHG intensity of 600-699 g CO_2e/kwh by 2050 felt Saskatchewan had a differential responsibility in the world,

> Most of the country, with the exception of Saskatchewan, Alberta, and possibly Nova Scotia, do not have an abundance of cheap hydro so we need to rely on coal and gas to have a reliable, economic source of electricity. Improvements can and should be implemented, but Saskatchewan should not have to meet the same targets as the hydro-rich provinces like Manitoba, BC and Quebec.
> (Workshop participant)

In 2014 SaskPower's GHG intensity was 660 g CO_2e/kwh (SaskPower, 2015). This participant calls for a holding pattern at SaskPower's current GHG intensity. Lack of agreement between workshop participants on the need to act on climate change may reflect the different value positions Richards *et al*. (2012) observed in their interviews.

Some of those who selected 'uncertain' also provided comments with their selection. One participant stated that asking about the desired GHG intensity was, "Too much of a loaded question. Climate change is a global problem and needs appropriate action worldwide to mitigate the risks." This response implied that Saskatchewan alone could not mitigate climate change risks; mitigation depends on global efforts. A second participant who responded with 'uncertain' offered, "Should likely be concentrating on reductions rather than picking a target for GHG intensity." For this participant absolute reductions were important, lowering GHG intensity might still lead to increased GHG emissions if growth in electricity demand overwhelmed intensity improvements.

In total, the responses show a diversity of thought around GHG emission reductions. This diversity carried into the desired scenarios for achieving GHG emission reductions (Question 3). There were no clear trends in the scenarios selected by participants before the workshop. Instead participants selected a wide range of possible scenarios that could describe the Saskatchewan electricity sector in 2050 (Figure 9-2).

I then asked participants for their thoughts on the potential for renewable energy to contribute to Saskatchewan's electricity supply.[79] In particular, I asked:

- What is the maximum proportion of Saskatchewan electricity that renewables can supply in the medium-term (i.e. by 2030-2035) (Question 4)?
- What is the maximum proportion of Saskatchewan electricity that renewables can supply in the long-term (i.e. by 2045-2050) (Question 5)?

[79] Note that survey respondents were required to answer each question before heading on to the next. This was to ensure that the discussion of renewable energy did not bias answers to the first three questions. Unfortunately this frustrated one potential participant who opted not to fill out the survey because questions like Question 3 and Question 6 were too time consuming and could not be easily skipped.

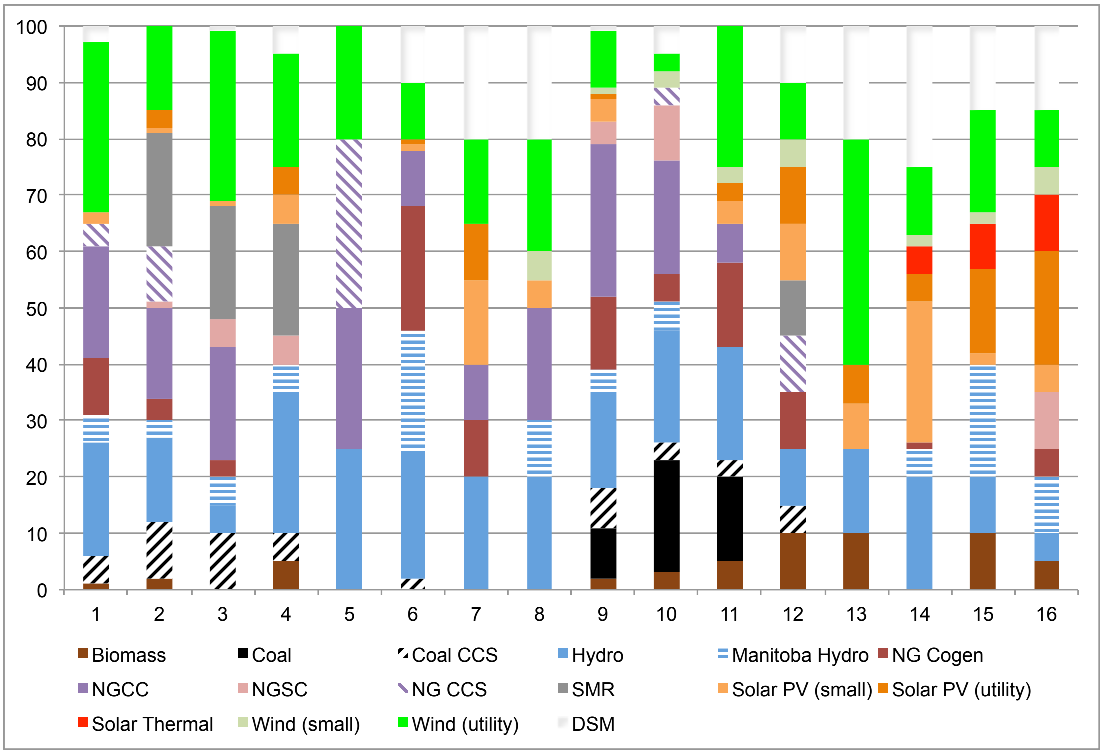


Figure 9-2 Scenarios to Achieve Desired GHG Intensity (Pre-Workshop Survey)

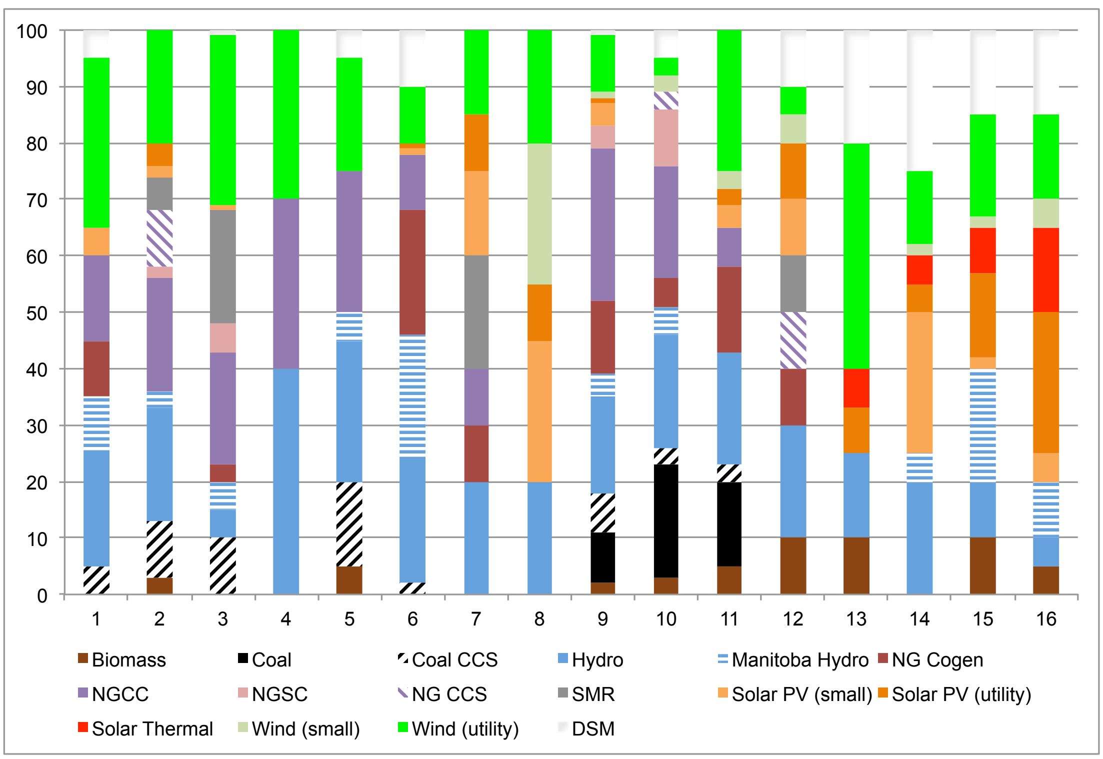


Figure 9-3 Scenarios to Achieve High Level of Renewables (Pre-Workshop Survey)

- What electricity generation mix would achieve the maximum renewable potential you identified in Question 5 (Question 6)? (Summarized in Figure 9-3)

Questions 4 and 5 were used as markers to understand whether participants' views would shift through the process of deliberation at the workshop. Identical questions were asked in the post-workshop survey (Appendix 9A). Question 6 produced a range of scenarios that differed from those presented in response to Question 3, and were still diverse (Figure 9-3).

The seventh and final question asked participants about barriers to expanding renewable energy in Saskatchewan. Participants were asked to rank ten barriers in terms of whether they were 'Not important', 'Somewhat important', or 'Very Important' (Table 9-1). The list of barriers overlaps with the categories of "agreement, knowledge, technology, economy, social, and political" used by Richards *et al*. (2012), but is more specific in many instances. For example, rather than asking whether technology is a barrier I asked specifically if the intermittency of renewable energy is a barrier. The ten barriers I asked about in the pre-workshop survey emerged from the thirty-one interviews I conducted during the research process (see Chapter 2).

Beliefs about cost and intermittency appear to be strongly related to the level of renewable penetration participants felt was possible. Intermittency was particularly polarizing, 44% of participants (7 of 16) believed it was not important, 38% of participants (6 of 16) believed it to be very important, and only 19% (3 of 16) took the more neutral stance that it was somewhat important.

Participants who believed cost and intermittency were 'not important' barriers were more likely to believe that 100% renewable electricity generation was possible by 2050.[80] These participants were also more likely to be from an ENGO background; three of the

[80] Three of the four participants who believed cost was not important believed renewable electricity could meet 100% of electricity demand by 2050; three of the five who believed intermittency was not important believed 100% renewable was possible by 2050.

four participants who thought cost was not an important barrier were from ENGOs, as were four of six participants who thought intermittency was not an important barrier.

Barrier	Not Important	Somewhat Important	Very Important
Cost: The price of renewable electricity is too high.	25%	44%	31%
Feed-in-Tariff: Saskatchewan does not pay preferred rates for renewable power.	19%	50%	31%
Grid design: The Saskatchewan grid is built for centralized, not distributed, generation.	13%	44%	44%
Job loss: A focus on renewables will lead to lost jobs in the coal-power industry.	81%	19%	0%
Intermittency: Renewables cannot provide reliable electricity.	44%	19%	38%
Physical limits: Saskatchewan lacks adequate hydro, solar, wind resources.	56%	31%	13%
Political will: Political leaders in Saskatchewan have not prioritized renewables.	25%	25%	50%
Preference for coal: SaskPower has a preference for coal-fired generation.	31%	31%	38%
Public ownership: A private market would increase renewables more quickly.	56%	31%	13%
Social acceptance: People do not want to live near renewable energy generation.	31%	63%	6%

Table 9-1 Important Barriers to Renewable Energy (Pre-Workshop Survey)

In contrast, those who believed cost and intermittency were 'very important' on average believed that renewables could provide 40-41% by 2030-2035 (maximum 85%) and 55-67% by 2050 (maximum 75%). These responses were also associated with the background of the participants. Four of five of the participants who believed cost to be an important barrier came from a utility background, as did five of six participants who believed that intermittency was an important barrier. Only one of the seven participants from a utility perspective thought that intermittency was *not* an important barrier. The relationship between perception of barriers and group membership may reflect different knowledge of the barriers or, as Garrett *et al*. (2012) propose, a difference in value orientations between the utility and ENGO groups.

The greatest degree of consensus was found on ranking the importance of job loss. Job loss was not seen as 'very important' by any of the respondents, and instead 81% (13 of 16) believed it was not important. This may be a reflection of the composition of the participants in the deliberative workshops; affected labour groups were not represented. The diversity of responses to the ranking of barriers showed that deliberation could be productive. The split between representatives from utility and ENGO backgrounds indicated a potential for conflict at the workshops.

Deliberative Modelling Workshop

The workshop was divided into six parts (see workshop script in Appendix 9B for more detail):

1. Welcome, introductions and ground rules
2. Presentation of the history and context of the Saskatchewan electricity system
3. Model introduction and workbook exercises to examine the assumptions
4. Scenario creation
5. Opportunities and barriers discussion
6. Post-workshop survey

In the first segment I worked to generate an atmosphere of openness and respect. In particular, participants were encouraged to "disagree without being disagreeable."[81] The second segment was meant to provide a common basis of understanding. I presented a condensed history of the Saskatchewan electricity system (a summary of Chapter 3), and explained the need for investment in the electricity system to replace aging infrastructure, meet growing demand, and comply with federal GHG legislation (a summary of Chapter 1). I also outlined the physical potential for renewable energy in Saskatchewan (a summary of Chapter 4).

In the third segment I asked participants to break into smaller groups of 3 or 4 people. Participants were provided with a workbook that outlined the assumptions I used in the

[81] I had a facilitator helping with workshop 1, but not workshops 2 and 3. The facilitator worked to ensure that everyone had a chance to speak and be heard.

Saskatchewan Investment Model (Appendix 9C). In the first workshop, three sub-groups were formed. Sub-groups were selected to maximize the institutional diversity of representation within each group. These sub-groups were each assigned a specific part of the workbook to review: electricity generation costs, renewable potential, or electricity conservation cost and potential. I asked each group to discuss the assumptions I had made and record suggestions for improvements within the workbook. The goal was to seek agreement on the underlying assumptions before testing scenarios. After the first workshop I received feedback that the sub-groups did not have enough time to adequately review the workbook and felt rushed. In subsequent workshops this segment was combined with scenario creation.

In the fourth segment sub-groups were tasked with generating scenarios that could be analyzed using iSIM (Model 9A). In the first workshop, the sub-groups formed to evaluate the workbooks were shuffled so that a representative from each original sub-group (and with knowledge of the particular model area they had focused on: cost, renewable potential, or energy conservation potential) was present in every scenario-building group. This step was also used to increase interactions between diverse participants. In subsequent workshops the groups did not exchange members, but instead worked as teams to compete against the other group in their scenario achievement. Once the sub-groups had come to an agreement on a scenario for Saskatchewan's electricity future, that information was placed in SIM either by a 'modeller'; *i.e.* a participant assigned to interact with the laptop in each group, or by me.[82]

The interactive SIM model was designed to strike a "balance between the simplicity needed to make the model 'fun to use' and the complexity required to make it 'true to life'" (Carmichael *et al*., 2004: 173). It was built in Excel, since it is a commonly used software and many participants have experience using it. It was accompanied by a

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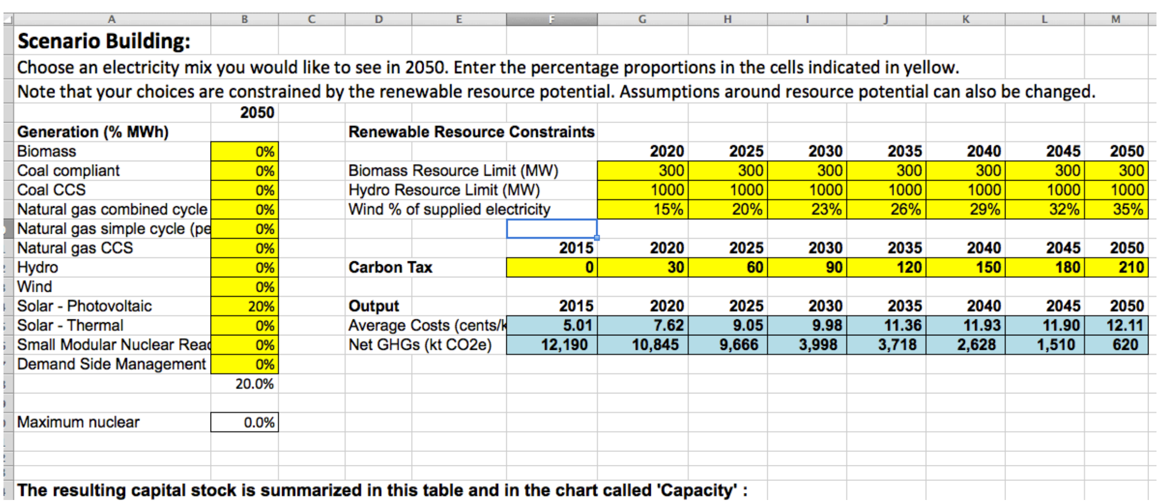
[82] This worked well in the second and third workshops, which had two scenario building groups, but proved challenging in the first workshop where there were three scenario-building groups.

workbook (Appendix 9C) that walked participants through the various inputs they could control in the model. Participants could design scenarios in SIM by:

1. Changing assumptions used in the model related to capital cost, O&M costs, and cost improvement factors;
2. Changing constraints used in the model related to conservation potential, wind integration potential, hydroelectric potential, and biomass potential;
3. Changing assumptions regarding growth of electricity demand;
4. Assigning a carbon price in each time-step;
5. Assigning a minimum proportion of electricity generated in 2050 for desired technologies;
6. Assigning a maximum proportion for small, modular nuclear reactors, which allowed groups to turn the nuclear option on or off.

The customized scenario was then optimized using Frontline Solver in Excel. The objective function in the interactive model is the same as that found in SIM (see Appendix 7A). The optimization finds the least-cost path to supplying Saskatchewan's electricity, while meeting the constraints specified by the group, and using the cost, renewable potential, conservation potential, and demand growth assumptions assumed by the group. Figure 9-4 presents a screen-shot from the scenario design interface of iSIM.



Scenario Building:

Choose an electricity mix you would like to see in 2050. Enter the percentage proportions in the cells indicated in yellow.

Note that your choices are constrained by the renewable resource potential. Assumptions around resource potential can also be changed.

Generation (% MWh)	2050
Biomass	0%
Coal compliant	0%
Coal CCS	0%
Natural gas combined cycle	0%
Natural gas simple cycle (pe	0%
Natural gas CCS	0%
Hydro	0%
Wind	0%
Solar - Photovoltaic	20%
Solar - Thermal	0%
Small Modular Nuclear Read	0%
Demand Side Management	0%
	20.0%
Maximum nuclear	0.0%

Renewable Resource Constraints	2020	2025	2030	2035	2040	2045	2050
Biomass Resource Limit (MW)	300	300	300	300	300	300	300
Hydro Resource Limit (MW)	1000	1000	1000	1000	1000	1000	1000
Wind % of supplied electricity	15%	20%	23%	26%	29%	32%	35%

	2015	2020	2025	2030	2035	2040	2045	2050
Carbon Tax	0	30	60	90	120	150	180	210

Output	2015	2020	2025	2030	2035	2040	2045	2050
Average Costs (cents/k	5.01	7.62	9.05	9.98	11.36	11.93	11.90	12.11
Net GHGs (kt CO2e)	12,190	10,845	9,666	3,998	3,718	2,628	1,510	620

The resulting capital stock is summarized in this table and in the chart called 'Capacity' :

Figure 9-4 Scenario Building Screen in SIM

After the optimization is run, the model returns information on average electricity cost, investment in each technology (MW), the generation (GWh) and capacity (MW) mix, and GHG emissions for each time-step. This information is summarized in easy to view Excel charts identical to those presented in Chapter 7. A radar diagram for each scenario summarizes wind and solar land requirements, GHG emissions, price impacts, the volume of CO_2 storage required, and radioactive waste generated. These indicators are all presented relative to the business as usual scenario. Throughout the scenario creation process participants were encouraged to consult the feedback offered by the model and refine their scenarios. Seven distinct scenarios were created over the course of the three workshops (Figure 9-5). These scenarios emerged from the conversations and negotiations that occurred in each sub-group.[83]

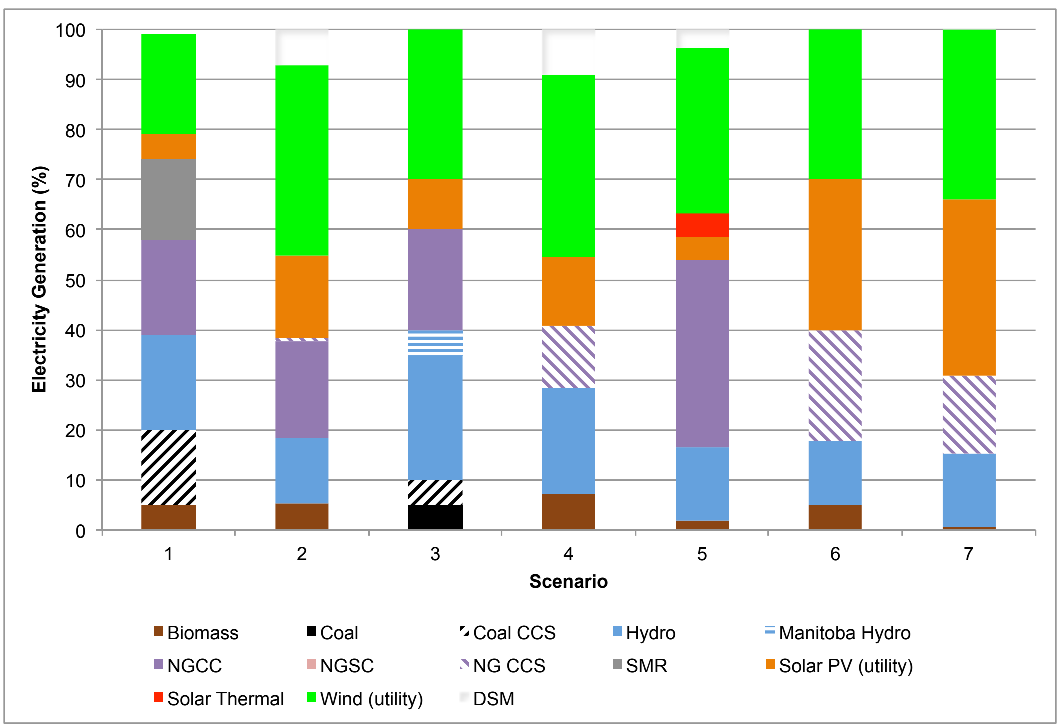


Figure 9-5 Workshop Scenario Outputs[84]

[83] As a note, scenarios 2, 4, and 6 all contained a common member; the one participant who attended all three workshops. The close similarity of the scenarios is undoubtedly related to this participant's presence in the group.
[84] The interactive SIM model did not differentiate between small-scale and utility-scale wind and solar technologies and so Figure 9-5 contains fewer technologies than Figures 9-2 and 9-3.

I travelled around the room helping the sub-groups as they created their scenarios. In the first workshop I heard feedback that participants would like improvements to the user interface. I improved the interface for the subsequent workshops. In the second workshop, one participant expressed dismay that the model had added in natural gas combined cycle with CCS “against our wishes” (scenario 4 in Figure 9-5). The participant did not like this technology and disagreed that it should be included. This was an opportunity to discuss the model assumption that dispatchable capacity must meet peak demand; natural gas with CCS has been added to ensure peak demand could be met. This discussion led the participant to revisit the model and redesign the scenario. It appeared to me to be a good example of learning through the discipline imposed by the model.

At the end of the scenario creation exercise the sub-groups were brought together at a plenary roundtable to discuss the scenarios they had generated. Each sub-group was asked to present their scenario. A reporter from each sub-group discussed the electricity generation mix they had generated and explained their group’s choices. I was sure to note the final price and GHG emission implications of each scenario to encourage a competitive spirit between the teams.

The final interactive component of the workshop was a brainstorming exercise to identify barriers to renewable energy in Saskatchewan and opportunities for overcoming these barriers. Participants were each given a pad of sticky notes and asked to write down as many barriers as they could think of in five minutes. Myself, with help from the facilitator in workshop 1 and a member of my supervisory committee in workshop 2, walked around the room grabbing the sticky notes when they were completed and posting them on a wall. We organized the barriers into related clusters as we posted them on the wall. Following this, participants were asked to volunteer explanations for the barriers they had posted. This provided a chance for clarification and discussion. We then repeated the exercise with different coloured sticky notes and asked participants to brainstorm opportunities for overcoming the barriers. Means of overcoming barriers were posted alongside related barriers. Another round of discussion followed before the workshop closed and participants were asked to fill out a six question post-workshop survey (Appendix 9A).

Analysis

The pre-workshop and post-workshop surveys provided a means of evaluating the impact of the deliberative workshops. In the first instance the surveys allowed me to understand whether interactions with the model and deliberative discussion affected participants' views on the percentage of renewables possible in the medium-term (2030-2035) and long-term (2050).

Workshop	Participant	2030-2035 Pre-Workshop (%)	2030-2035 Post-Workshop (%)	+/-	2045-2050 Pre-Workshop (%)	2045-2050 Post-Workshop (%)	+/-	Has your response changed?
1	ENGO	85	65	-	100	100	=	No
1	ENGO	100	45	-	100	85	-	No
1	Industry	45	40	-	65	60	-	Unsure
1	Industry	45	35	-	85	45	-	Unsure
1	Industry	35	35	=	35	47	+	Yes
1	Utility	35	60	+	55	100	+	Unsure
1	Utility	35	35	=	65	70	+	Unsure
1	Utility	45	35	-	55	45	-	No
1	Utility	35	30	-	45	65	+	No
2	ENGO	85	60	-	100	100	=	No
2	ENGO	75	80	+	95	90	-	No
2	Industry	45	40	-	65	60	-	No
2	Utility	35	45	+	55	75	+	No
2	Utility	35	35	=	55	50	-	No
	Average	52.5	45.7	-	69.6	70.9	=	
	Standard Deviation	23.1	14.8		22.1	21.0		
	t-test	1.375	*		-0.232			

Numbers indicate midpoint of indicated 10% range
* Statistically significant at the 90% confidence interval using paired difference t-test

Table 9-2 Maximum Percentage of Renewables Possible in Saskatchewan

The workshops appeared to have a small, but statistically significant, impact on participants' views of the medium-term potential for renewable energy (Table 9-2). Eight participants indicated a lower potential for renewables in the medium-term (2030-2035) after the workshops, while three participants indicated a higher potential. I tested the difference between the pre-workshop and post-workshop responses using a t-test and found a statistically significant decrease in participants' views on medium-term renewable potential at the 90% confidence interval. Using this same approach I find that the workshops did not have a statistically significant impact on participants' views of renewable potential in the long-run (2045-2050). This lack of movement on participants' responses was echoed by their answers to the question: "Has your response changed from the earlier survey?" Nine participants stated their response did not change; any difference may have been an error of memory, rather than a change in perspective. Only one person stated their response did change as a result of the workshops. This person explained that they, "Learned more about actual potential and costs of various resources through interaction with informed participants."

The pre- and post-workshop surveys also allowed me to understand whether perspectives had shifted on the barriers to renewable energy expansion in Saskatchewan. The discussion of barriers in the workshops uncovered themes very similar to those outlined by Richards *et al*. (2012) (see Table 9-3). The barrier mentioned most often (35 responses) was the lack of political and policy support for renewables. This lack of support was expressed with notes such as:

- Lack of federal emissions targets;
- Lack of government leadership;
- Lack of political will to address climate crisis;
- Lack of support mechanisms such as Feed-in-Tariff (FIT);
- Lack of carbon pricing.

To overcome this barrier participants recommended implementing many of the policies currently lacking such as GHG emission reduction targets, carbon pricing, and feed-in-tariffs.

Barriers		Opportunities to Overcome Barriers	
Theme	#	Theme	#
Politics and Policy	35	Public education & advocacy	21
		GHG targets	3
Grid integration	25	Smart grid	9
		Storage	8
		Manitoba Interconnection	5
		Flexible natural gas generation	5
		Distributed generation	2
Cost	20	Carbon price	8
		Feed-in-tariff	5
		Time of use pricing	2
SaskPower Monopoly	17	Deregulate/Reregulate	4
Demand growth	5	Demand side management	11
Social license	3	Community ownership	5
		Jobs	4
Infant technology	3	Research/Demonstration	11
Uncertainty	3	Improve decision-making	3
Diverse portfolio reduces risk	3	No fuel price risk	2
Resilident to mega-drought?	2	Lower water usage than thermal	1
Environmental Impact	2	Great wind, solar resources	3
SaskPower debt	2	Investment needed	5

Table 9-3 Coded Results of Opportunities and Barriers Exercise

The second most prominent barrier was grid integration, which includes the challenge of addressing the variability of renewable energy. The grid integration barrier was mentioned in 25 separate notes. To overcome this barrier participants suggested the need for smart grid technology, storage for renewable energy, and a stronger grid connection to Manitoba to balance wind's variability. In the first workshop a good discussion was held about the merits of next generation flexible natural gas generation. The new natural gas-fired turbines are able to ramp up and down quickly and follow the variability of output from wind and solar. There was also mention of dispersing renewables geographically and generating renewable energy close to communities as a way to minimize system-wide variability.

The importance of the grid integration barrier aligns with Richards *et al*. (2012) who found that technology was the most frequently mentioned barrier. Richards *et al*. (2012) also heard participants offer many of the same solutions, such as smart grids, storage and geographic dispersion.

The cost of renewable technology was mentioned as a barrier on twenty separate sticky notes. To overcome this barrier, real or perceived, participants suggested changing the pricing system. Carbon pricing would level the playing field with fossil-fuel technologies, as would an end to fossil-fuel subsidies. A feed-in-tariff would provide a better price to private power producers. Full-cost accounting would ensure that externalities besides GHG emissions were considered. The study by Richards *et al*. (2012) also found that cost was a perceived barrier.

Other barriers that appeared were complaints about SaskPower's monopoly control of the Saskatchewan grid. This control led some to call for deregulation and a competitive market, while others disagreed and suggested *re*-regulation would be better. Re-regulation would keep the power system in public control, while also opening up the possibility of community generation of renewable energy. Other barriers mentioned on only a few occasions, were social license, the challenge of making decisions under uncertainty, and the environmental impacts of renewables (one note read "concern about wildlife impact, real or not"). Frequently mentioned means of overcoming barriers were further renewable energy research projects and renewable energy demonstration projects in Saskatchewan.

The promise of a deliberative exchange is that understanding can be gained and positions can shift. To understand whether participants had shifted their thinking about the barriers that face renewable energy in Saskatchewan, the post-workshop survey included a final question asking people to indicate which barriers were "very important". It was possible to compare the answers to the pre-workshop survey and post-workshop survey for fourteen participants (Table 9-4). The results show that the four-hour workshop did not lead to substantial shifts in thinking about barriers. In only two instances did a participant switch their rating of a barrier from being "not important" to being "very important." In nine instances, a participant listed a barrier as "very important" in the pre-workshop survey, but then did not subsequently check the barrier as "very important" in the post-workshop survey. This occurred in three instances for the barrier "grid design", and occurred twice for "preference for coal" and "public ownership". The latter two barriers were interesting. After the first workshop I received feedback from a number of other participants that they were impressed at how open the participants from a utility background were to discussing a wide variety of technologies. One note on the post-workshop survey read, "found interesting (the utility's) position on various areas, specifically being non-biased when it comes to generation/technologies." At the very least the workshops appeared to generate an increase in understanding and compassion between utility and non-utility actors. This was indicated by a decrease in the number of participants who thought the culture at SaskPower ("preference for coal"), or the monopoly ownership structure of SaskPower, were barriers to renewable expansion.

	Pre-Workshop				**Post-Workshop**
Barrier	**Not Important**	**Somewhat Important**	**Very Important**		**Very Important**
Cost: The price of renewable electricity is too high.	25%	44%	31%		50%
Feed-in-Tariff: Saskatchewan does not pay preferred rates for renewable power.	19%	50%	31%		50%
Grid design: The Saskatchewan grid is built for centralized, not distributed, generation.	13%	44%	44%		57%
Job loss: A focus on renewables will lead to lost jobs in the coal-power industry.	81%	19%	0%		0%
Intermittency: Renewables cannot provide reliable electricity.	44%	19%	38%		36%
Physical limits: Saskatchewan lacks adequate hydro, solar, wind resources.	56%	31%	13%		7%
Political will: Political leaders in Saskatchewan have not prioritized renewables.	25%	25%	50%		86%
Preference for coal: SaskPower has a preference for coal-fired generation.	31%	31%	38%		29%
Public ownership: A private market would increase renewables more quickly.	56%	31%	13%		7%
Social acceptance: People do not want to live near renewable energy generation.	31%	63%	6%		21%

Table 9-4 Importance of Barriers Pre- and Post-Workshop Survey Comparison

There was little shift in ranking of the barrier “intermittency”. Of the fourteen respondents for which I had both pre- and post-workshop surveys, five had indicated intermittency was very important before the workshop and four continued to indicate that intermittency was very important after the workshop. One participant changed their ranking of intermittency from “somewhat important” to “very important.” This highlights the problem that may have been created by switching the format of the question from a three-option scale in the pre-workshop survey to a simple checkmark to indicate “very important” in the post-workshop survey. The post-workshop survey was, however, designed to be quick and easy to answer so that participants would be willing to fill it out before leaving the workshop.

The one area where thinking did seem to converge was in regards to the barrier “political will”. In the pre-workshop survey 50% (8 participants) thought a lack of political will was a “very important” barrier, 25% (4 participants) thought it was “somewhat important”, and 25% (4 participants) thought it was “not important”. Following the workshops, 86% of participants (12 of 14) thought lack of political will to be a “very important” barrier. Three participants had upgraded the barrier from being “somewhat important” to being “very important” and one participant upgraded the barrier from being “not important” to “very important.” This is particularly telling when compared with the results in Table 9-3. Political leaders have failed to introduce the policies that would see renewables thrive. With political will it would be possible to change the relative costs of renewables, give increased impetus to GHG emission reductions, fund research and education on climate change and renewable energy, negotiate co-operative agreements with Manitoba Hydro, and provide SaskPower with a clarity of purpose. Lacking political will, renewables will continue to face barriers to expansion.

Conclusions

The deliberative modelling workshops were an attempt to nurture a shared understanding between Saskatchewan’s electric utilities and ENGOs calling for more renewables. Over the course of four hours, participants were asked to work together to imagine scenarios for Saskatchewan’s electricity future. The exercise succeeded, to a certain extent, at creating sentiments of compassion and mutual respect. All of the workshop participants responded yes to the questions, “Have you learned anything from this workshop?” and “Did you enjoy the experience of interacting with others at the workshop?” Post-workshop surveys included comments like “useful discussion” and “very stimulating – always fun to talk to folks with different priorities and backgrounds.” The participants appeared genuinely curious to learn about each other’s perspectives.

The four-hour workshop did not appear to substantially shift the perspectives of participants. The only noticeable change was a slight decrease in the level of renewable energy participants felt was possible in the medium-term (2030-2035; Table 9-2). This may mean that the workshop created a better understanding of the constraints that currently affect the electricity system, which caused participants to revise renewable potential downwards. Participants generally did not shift their perspectives on the barriers to renewable energy expansion. They did, however, achieve a near consensus that ‘lack of political will’ is a barrier to encouraging renewables in the province.

Shortcomings

The deliberative modelling workshops I hosted required a specialist level of knowledge of the electricity sector. I realized that it would be difficult to find a group of participants that were knowledgeable enough of the specifics of the electricity industry to offer useful advice on the modelling assumptions and who were also representative of the Saskatchewan population. Participants at the workshops were skewed to representatives from utilities, private consulting companies in the electricity conservation sector, and ENGOs. This highlights the “representation problem” of deliberative exercises (Zografos and Howarth, 2010). The workshop participants were not representative of Saskatchewan society at large. Participants were predominantly from European-settler backgrounds and all but two were men. This reflected the pool of potential participants I had invited; only four of the thirty-one stakeholders I interviewed were female. The Saskatchewan utility sector and ENGO sector appear to be predominantly male; at least at the management-level or board-level.

To host a deliberative conversation with members of the broader, non-specialist, Saskatchewan public, I would need to make modifications to the workshop format. Less time would be spent investigating assumptions, and more time could be spent presenting a range of pre-set scenarios and indicators. The conversation could then focus on the trade-offs faced when choosing between electricity scenarios.

van den Belt's (2002) *Mediated Modeling* approach offers a deeper level of participant engagement than the deliberative modelling process I carried out. In the mediated modelling process participants sign on to participate over the course of months or years. Participants meet regularly, providing input on the research questions, the structure of the model, and contributing research effort to developing and improving the model. The advantage of the much less elaborate deliberative modelling approach I used was that participation was easy; only a brief pre-workshop survey was completed beforehand, the workshop was scheduled for one four-hour afternoon session, and participants were not assigned any homework when they left.

The light level of participation in the deliberative workshops was not enough to generate significant movement towards consensus. If financial resources allowed, it would be interesting to trial a more intensive mediated modelling process to see if a greater degree of consensus could be achieved.

There would likely be substantial barriers that could prevent stakeholders from participating in a mediated modelling process. I found that, even with the relatively light commitment required, there were barriers to participation in the deliberative workshops. One invited participant could not participate because his organization did not have the budget to spare his time during work hours. Another invited participant chose not to participate because he felt he could be more candid in an interview setting than in a setting with professionals from the electricity field, especially representatives from the SaskPower utility. The comment from this would-be participant highlighted that "power relations are not simply left at the door of deliberative forums" (Howarth, 2010: p. 3409). Power – political and social – is present in a deliberative modelling exercise.

In Saskatchewan, as in many regulated electricity markets, SaskPower has a monopoly on the supply of electricity. This market power is enshrined in the *Saskatchewan Power Corporations Act*. Self-generation of renewables is a threat to the market power that SaskPower fought to gain, from its incorporation in 1949 to the purchase of the Regina power plant in 1965. This may explain the different perception of barriers between ENGO and industry representatives. To a renewable energy advocate a feed-in-tariff is a way to encourage renewables in the province. To SaskPower a feed-in-tariff is a cost; it requires the corporation to pay market rates (or above) for electricity generated by producers who are meanwhile eroding SaskPower's market share, and thereby creating "stranded assets" out of existing generation and transmission equipment. The issue of integrating variable renewables is similar. For renewable advocates, the solutions to intermittency are readily available. But, as Sovacool (2009) observes, "Technically, these technologies can be incorporated into the grid easily. Socially, much institutional resistance remains" (p. 4506). Utilities find more comfort in "conservative inventions" like coal-fired generation with carbon capture and storage (CCS) or small, modular nuclear reactors because these centralized technologies maintain monopolistic market power (Sovacool, 2009). This preference was certainly expressed in the pre-workshop survey where respondents from SaskPower typically ranked coal with CCS as the 3rd most important technology for achieving a desired 2050 GHG intensity (mode ranking, median was 3.5) and ranked small, modular nuclear reactors 6th most important (mode and median both 6). The other respondents most often ranked coal with CCS or small, modular nuclear reactors dead last (the median ranking of coal with CCS amongst non-SaskPower participants was 12th and the mode was 17th, while the median ranking of small, modular nuclear reactors was 13th and the mode was again 17th). There is a very clear split in support for these "conservative inventions." Concerns over intermittency may be less a technical barrier, and more a result of institutional resistance. An open-ended discussion in a deliberative modeling workshop may not be the best way to discuss these issues, as it involves questioning the motivations of some of the participants. It may be hard to "disagree without being disagreeable" when entering into such a discussion.

Chapter 10 – Conclusions and Next Steps

Findings

In this dissertation I set out to ask, what is the cost of *Greening the Saskatchewan Grid* by lowering greenhouse gas (GHG) emissions by 80% or more by 2050 with a renewable energy focused electricity pathway? To understand the relative cost of a renewable energy pathway I needed to know the costs of alternative scenarios, including a business-as-usual scenario (SaskPower BAU), and scenarios for lowering GHG emissions that featured technologies like carbon capture and storage (CCS) and small modular nuclear reactors. I built the Saskatchewan Investment Model (SIM) to understand the costs of these various scenarios.

Building SIM required me to answer a number of intermediate questions. I needed to know how electricity demand might change between 2015 and 2050. I created an electricity demand forecast in Chapter 6 to answer that question. I needed to know how much potential there is in Saskatchewan to generate renewable electricity from wind, water, sun, and biomass. I outlined Saskatchewan's renewable potential in Chapter 4. I needed to know the relative costs and operating characteristics of competing electricity generation technologies, including their capital costs, operating costs, capacity factors, expected life, and fuel efficiency. Those costs and characteristics are examined in Chapter 5. I also needed to know how these costs and characteristics would change over time; SIM includes exogenous cost improvement factors that forecast changes in capital and operating costs due to technological progress. I also created fuel price forecasts to understand how the price of coal, natural gas, biomass and uranium might change over time. Both the cost improvement factors and future fuel prices are uncertain and so I conducted a sensitivity analysis to account for the uncertainty of these estimates (Chapter 7).

After conducting this analysis I found that a *Greening the Grid* leadership scenario would cost about two cents per kilowatt-hour (kWh) more than a business-as-usual scenario by 2050. The *Greening the Grid* scenario would, however, cut cumulative GHG emissions in half, reduce water use, and create more jobs (Chapter 8). It would also reduce emissions without adding significantly to the volume of stored CO_2 and would not result in the creation of any long-lived radioactive waste (Chapter 8). The *Greening the Grid* scenario would also be resilient to carbon pricing. If Canada or Saskatchewan were to implement an escalating carbon pricing policy, that begins at $15/tonne in 2015 and increases by $15 every 5-year time-step, the total discounted cost of the *Greening the Grid* scenario would be comparable to the other scenarios.

Because of my focus on a renewable energy pathway I paid particular attention to the issue of variability. Renewable energy sources like wind, water, and solar are naturally variable in their electricity output. From the Premier of Saskatchewan to SaskPower management there is a concern that the variability of renewable energy will create a shortage when it is needed most. In this dissertation I asked, what is the cost of building adequate storage capacity and back-up capacity to ensure a renewable focused scenario can provide a reliable supply of electricity?

To answer this question I allowed electricity storage to be built in tandem with wind and solar facilities in SIM. I then created an hourly operations model, the WIRE model (Appendix 7B). I used the WIRE model to test whether each of the scenarios outlined in Chapter 7 could meet forecast hourly electricity demand in 2050 while responding to variations in renewable energy output and electricity demand.

This step led to an iterative process of creating an investment scenario in SIM and then checking to see 'Will-it-Run?' in the WIRE model. I found that, in order to provide reliable electricity, a renewable energy focused scenario must be resilient to the seasonal availability of solar power and hydroelectricity. Applying a 'Liebig's Law of the Minimum' for electricity planning, I revisited assumptions in the SIM model and created the *Greening the Grid* scenario based on the minimum capacity factor for solar (11% in December) and the minimum average capacity factor for hydroelectricity (43% in March). By planning for the times when renewable electricity generation technologies are at their seasonal low points, I found that a renewable focused *Greening the Grid* scenario could reliably meet hourly electricity demand even in the depths of winter when electricity demand peaks.

Key to managing the variability of renewable energy are technologies like electricity storage, demand side management (DSM) peak shifting, and hydroelectric facilities that can store water in reservoirs. Electricity storage and hydroelectric facilities with reservoirs provide dispatchable power that balances the variability of the wind. DSM peak shifting helps to smooth out net electricity demand, reducing the peaks and increasing the troughs.[85]

This finding is not in itself enough to prove the technical viability of the *Greening the Grid* scenario. A model is after all a simplification of a real-world system. I have abstracted from the workings of the Saskatchewan electricity system in several ways. First, my analysis was not spatial; I did not map the location of proposed electricity facilities for each scenario, nor did I explicitly model the transmission and distribution system. More engineering analysis could be done to design, model and test a *Greening the Grid* scenario for Saskatchewan.

What I did succeed in modelling were the likely costs of lowering GHG emissions in the Saskatchewan electricity sector using renewable energy. I found that planning for a renewable energy system using a modified 'Liebig's Law of the Minimum' results in an overbuilt system and this increases costs. In the summer, when solar power and hydroelectricity are abundant, electricity production from wind and solar exceeds total electricity demand and has to be curtailed. Seasonal energy storage using a technology like electrolytic hydrogen could provide a means of using that curtailed energy. This would allow an electricity system planner to reduce the size of the *Greening the Grid* system. Whether this would save money would depend on whether the value of curtailed electricity is high enough to pay for the hydrogen conversion facilities. My research could be extended by pursuing that line of inquiry.

[85] Net electricity demand equals electricity demand minus variable renewable electricity output.

Barriers to Renewable Energy Expansion

In general, the results of the WIRE modelling indicated that renewable energy variability does not appear to be a technical barrier to a *Greening the Grid* scenario. Technologies exist that can balance the variability of wind and solar, at a cost. The premium paid for balancing renewable energy variability using electricity storage, hydroelectricity, and an overbuilt system increases the cost of electricity, but not drastically.

If renewable energy variability and cost are not barriers to the pursuit of a *Greening the Grid* scenario, then what barriers might exist? I worked to explore barriers to and opportunities for renewable expansion in three deliberative modelling workshops. As expected, several workshop participants felt that cost and "intermittency" were significant barriers to higher penetrations of renewable electricity in Saskatchewan. These positions did not appear to shift over the course of a four-hour workshop and were largely associated with utility-affiliated participants. But stakeholders from a variety of backgrounds also came to a near consensus that renewable energy expansion is held back by political barriers.

Nationally, Canada lacks a carbon price or hard GHG emission reduction targets. The federal government did introduce a coal-fired electricity regulation and SaskPower plans to meet (but not exceed) the requirements of the regulation by outfitting select coal plants with carbon capture and storage. That regulation will reduce Saskatchewan's electricity sector GHG emissions by approximately half, but the gains will be temporary. I project that GHG emissions in the SaskPower BAU scenario will begin to increase by 2045 as natural-gas fired plants expand to meet growing electricity demand.

Provincially, Saskatchewan also lacks a carbon price and a GHG emission reduction target. The Saskatchewan Party government also lacks motivation to get serious on the climate change file. Premier Brad Wall told media in October 2015 that he would attend the 2015 Paris climate change summit "to make sure that whatever Canada is committing to doesn't kneecap our economy in the west" (CBC, 2015). Aside from the Boundary

Dam III carbon capture and storage project Premier Wall has not taken any significant action to reduce GHG emissions in the province.

Within SaskPower there is path dependence and a coal culture that has made coal with carbon capture and storage (CCS) the preferred GHG emission reduction solution; at least until small modular nuclear reactors prove out. Both coal with CCS and nuclear reactors support SaskPower's centralized control of the grid. They are "conservative" technologies in that they maintain the existing institutional arrangements and institutional power of SaskPower (Sovacool, 2009).

SaskPower is living through a critical time, however, when their credibility has been damaged. CEO Robert Watson was forced to resign in 2014 after smart meters installed in the province began to spontaneously start on fire. The heat was on SaskPower again in Fall 2015 when it was revealed that the Boundary Dam III CCS plant was not operating at full capacity, and was instead paying millions of dollars in penalties to Cenovus for failing to deliver CO_2 (Leo, 2015).

As the costs mount for the Boundary Dam III project, and criticism builds, SaskPower may wish to recall Ross Thatcher's test for public ownership. A crown would be held in public ownership if it provided "an essential service which private firms are unable to supply at a comparable cost to the public", offered "a particularly satisfactory return on invested public funds", or provided "useful employment which otherwise would not be available" (Thatcher quoted in Rediger, 2004: 76). The first criterion is currently in question. SaskPower has used its monopoly position to subsidize the Boundary Dam III CCS project, increasing the cost of electricity generation relative to other pathways for meeting the federal coal-fired GHG regulation. On the second criterion, the crown corporation has been raising rates, but its financial situation is so tenuous that it will not offer dividends to the Saskatchewan government anytime in the foreseeable future. The third criterion, providing "useful employment" appears to be the saving grace as the government works to save jobs in the coalmines. A hard look at employment in competing pathways, especially renewable pathways, could change that perspective. I found that renewable-focused scenarios offered more job opportunities than the SaskPower BAU pathway focused on preserving coal jobs.

There were people I interviewed who argued that deregulation would be the best path forward for the Saskatchewan electricity system. Opening the grid up to private power producers would continue the work begun by CEO Jack Messer in the early 1990s. Advocated of de-regulation believed that it would spur the wide-scale adoption of low-cost wind power. Others argued that *re*-regulation was needed. They argued the *Saskatchewan Power Corporation Act* should be amended to allow independent electricity producers into the market, but that electricity generation was best carried out by municipalities, community co-operatives, and residential and commercial customers. SaskPower's role in this context would be as keeper of the electricity commons; the shared transmission and distribution network that has been built up over the past eighty-five years. In Chapter 8 I outlined the possibility of grid defection and the utility death spiral. Death in this instance could refer to death of SaskPower's current business model. The question remains, will SaskPower continue to resist private power generation and the grid defection it might encourage? Or will SaskPower embrace a new business model?

People Power

From my analysis of the Saskatchewan electricity system I find support for Sovacool's (2009) assertion that an electricity system is more than a collection of electricity generators connected by wires. Instead, it is "a set of social, cultural, economic, and political interests fused together with technology" (Sovacool, 2009: 4502). The coal-hydro nexus that defined the past sixty years of electricity generation in Saskatchewan has created a political constituency of coalminers, SaskPower employees, and politicians committed to keeping coal alive. A focus on centralized power generation has made nuclear energy a popular substitute if coal is to be abandoned. It is difficult to tell where technological and economic analysis ends and cultural and political interests begin.

Schumpeter (1942) argued that capitalism is driven by creative destruction. Renewable electricity technologies like wind and solar, as well as storage technologies like lithium-ion batteries, have disruptive potential. They do not fit into the existing socio-technical structure of the Saskatchewan electricity system. They do, however, fit well in the low-density, dispersed Saskatchewan electricity grid.

Creative destruction is not pretty. There are winners and losers. Without continued enthusiasm for CCS, the coalminers fear they will lose their jobs. However, with strategic investment in wind, solar, and electricity storage, especially in southeast Saskatchewan, these power workers can transition from mining the Earth to harnessing the power of the wind and sun.

Without questioning their commitment to large-scale, costly ventures like coal with CCS and nuclear power, SaskPower is likely to lose. The utility death spiral beckons utilities that do not realize the potential for increasing electricity prices and increasingly affordable renewable technologies to encourage grid defection.

The winners will be those who see the opportunities presented by greenhouse gas emissions reductions and disruptive renewable technologies, and who are able to inspire public support for their ideas. Saskatchewan citizens are intelligent, hard-working, progressive people. They have been leaders in agricultural innovation. They have been leaders in social policy innovation (*e.g.* socialized medicine). They have been leaders in energy conservation (the German sounding Passivhaus concept was inspired by the Saskatchewan Conservation House; Huck, 2015). That leadership is present in projects like the Cowessess wind and storage facility located east of Regina, which is demonstrating that we have overcome the technical barriers to renewable energy expansion. Applied to the electricity system, there is no telling what that leadership could achieve; five hundred landowners could change the course of history if they committed to installing wind and solar facilities on their lands.

Saskatchewan people also take pride in being neighbourly, offering a hand when it is needed. Climate change demands that we pitch in and lend a hand. It demands that we contribute our fair share to efforts to stop catastrophic climate change. If the consequences of climate change were broadly understood (and the voices of climate change denial rightly quieted), I believe the people of Saskatchewan would rally for change.

And change can happen quickly. The T.C. Douglas government brought electricity to rural Saskatchewan within a four-year term. The achievement took political will and it took the will of the people to get involved. Rural families worked to erect power poles and string lines to bring electricity to their farms. There is a window opening to *Green the Saskatchewan Grid*. Will the citizens of Saskatchewan seize the opportunity?

Least-cost economic analysis is likely not enough to inspire citizens to *Green the Saskatchewan Grid*. A quote from David Orr summarizes the failings of this approach,

> "A great deal has been said about the potential for least-cost, end-use analysis that hitches narrow economic rationality to the efficient use of resources with better technology. This is all to the good. However, problems arise when the same economic rationality causes consumers to observe that least cost is not the same as full cost. For example, the fully informed consumer, armed with least-cost reasoning, would certainly choose to buy compact fluorescent lightbulbs that have lower lifetime costs than incandescent bulbs. But the same narrow economic rationality would cause that consumer to refuse to pay higher utility costs to clean up nuclear wastes and decommission reactors used to generate the electricity that is used with greater efficiency. At this point, economic rationality stops and virtue begins. Least-cost reasoning applies to those costs that must be paid now; full cost applies to those costs that can be pushed onto others or deferred to our children. Only people who take their obligations seriously, people of virtue, would willingly pay the full costs of their actions or even demand to do so."
> (Orr, 1994: 63)

The UDP process of 2009 presented citizens with a vision of a nuclear-powered electricity future. Citizens asked, why was renewable energy not considered? Critics responded that the variability of renewable energy and cost were significant barriers. This dissertation has shown that a renewable energy pathway is not only possible, it is affordable, and it creates jobs. The barriers to *Greening the Saskatchewan Grid* are political, not technical or economic.

Democracy begins where least cost economic analysis ends. The scenarios I have outlined in this dissertation produce a range of impacts: economic, ecological and social. Choosing which electricity pathway to embrace is a political and moral decision, not an economic decision.

The real work begins now that the dissertation is complete; the work of building understanding of climate change; the work of deliberating pathways for a *Green* electricity future; and the work of calling on the citizens of Saskatchewan to act with virtue and determination to make a better world. As Tommy Douglas once said, it is not too late to build one.

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Appendix 5A - LCOE Methodology

Electricity generation technologies can be compared by calculating the 'levelized cost of electricity' (LCOE). This calculation determines the price per kilowatt-hour required in order for an electricity generation project to obtain a net present value of zero. This means LCOE is the break-even price required in order to pay for the cost of generating electricity over the lifetime of the generation technology. (Citi GPS, 2015: 44)

Calculating LCOE requires cost data, including the following:

- *C*o – Capital cost of constructing the generation technology ($/kilowatt)
- *V*o – Variable operations & maintenance (O&M) costs incurred while operating the technology ($/megawatt-hour)
- *F*o – Fixed operations & maintenance (O&M) costs ($/kw/yr)
- $Fuel_t$ - Fuel price (when relevant) in year *t.*

Financing information is required to calculate the costs of obtaining the funds necessary to build the electricity generation technology. Financing information includes the type of financing used (debt or equity) and the rate of interest on debt or return on equity.

Calculating the LCOE also requires engineering data to determine the electricity generated by the technology and the fuel used over its lifetime:

- Capacity – Size of the project being built (megawatts)
- Lifetime – Expected life of the generating technology (years)
- Capacity factor – Expected percentage of electricity generated over the course of a lifetime relative to electricity that would be generated if the technology operating at full capacity all of the time (percentage %)
- Heatrate / fuel efficiency – a measure of how much fuel is required in order to generate electricity (measured in btu/kwh or kwh/kwh for heat rate and % for fuel efficiency)

- Energy content of fuel – conversion factors may also be necessary to calculate the energy content in fuels such as coal and natural gas.

There are two approaches to calculating the levelized cost of electricity (LCOE). In the first approach, average annual costs and average annual electricity generation are determined for each technology. The annual costs are divided by annual electricity generation to calculate LCOE as follows:

$$Eq. 5A.1 \quad LCOE\ (\$/MWh) = \frac{Average\ Annual\ Cost\ (\$)}{Average\ Electricity\ Generation\ (MWh)}$$

This annual approach requires capital costs to be amortized into equal annual payments. It also assumes that fuel prices, operations and maintenance costs, and electricity generation all remain constant over the life of the technology.

The second approach, and the one used in this study, involves producing a stream of annual costs and a stream of electricity generation output for each year of the technology's life. These costs and the generation quantities are then discounted back to the present to obtain the net present value of costs and benefits:

$$Eq. 5A.2 \quad LCOE\ (\$/MWh) = \frac{\sum_1^t \frac{Average\ Annual\ Cost_t (\$)}{(1+r)^t}}{\sum_1^t \frac{Electricity_t\ (MWh)}{(1+r)^t}}$$

Where r equals the discount rate and t equals time in years. (Short *et al.*, 1995)

Note that while it may seem unusual to discount the physical quantity of electricity generated, this physical quantity does have a monetary value. When the stream of annual costs and annual electricity generation are constant and equal to the average these two methods produce identical results.

Electricity Generation Calculation

Equation 5A.3 provides the formula I used to calculate the amount of electricity generated by a given project in a given year *t*:

$$Eq. 5A.3 \quad Electricity_t = Capacity * Capacity\ Factor_t\ \% * \ 8760$$

Capacity factor is a measure of how much electricity a given technology generates relative to a theoretical maximum. It is calculated as follows:

$$Eq. 5A.4\ \ Capacity\ Factor\ (\%) = \frac{Electricity\ Generated\ (MWh)}{Theoretical\ Maximum\ (MWh)}$$

Where,

$$Eq. 5A.5\ \ Theoretical\ Maximum\ (MWh) = \ Capacity\ (MW) * \ 8760$$

The last number, 8760, refers to the number of hours in a non-leap year. If a generation technology runs quite continuously at its maximum rate capacity it may obtain a capacity factor of 85-90%.

For this analysis I have assumed constant capacity factor and a constant level of electricity generation for each technology. This allows me to use the simple approach in Equation 5A.1.

Fuel Use Calculation

I calculate fuel use for coal-fired plants, natural gas-fired plants, nuclear plants, and biomass plants. The process of calculating fuel use begins by ensuring that data is in comparable units. Electricity generation is measured in kilowatt-hours (kwh) while fuel is measured in a variety of units including gigajoules (GJ), tonnes (t), and imperial measures such as millions of British thermal units (MMbtu) and short tons in the United

States. The following conversion factors are useful for converting these various energy measures.

Energy 1 MWh equals	3.6	GJ
Coal 1 tonne lignite coal equals	14.4	GJ
Natural Gas 1 m3 equals	0.037244529	GJ
Energy 1 MMBtu equals	1.0551	GJ
NG Volume 1 cubic foot equals	0.0283	m3
NG vol 1000 cubic feet equal	28.3	m3
1 btu equals	0.000293071	kwh

(Source: NEB, 2012)

Figure 5A-1 Energy Conversion Table

I calculated fuel requirements using the following steps:

1. Translate electricity generation from megawatt-hours (kwh) to gigajoules (GJ):

$$Eq. 5A.7 \quad Electricity\ (MWh) * 3.6 = Electricity\ (GJ).$$

2. Match units in numerator and denominator of heatrate measure by transforming (btu per kwh) to common units (kwh fuel per kwh electricity):

$$Eq. 5A.8 \quad Heatrate\ (Btu/kwh)\ *\ .00029307107 = Heatrate\ (kwh/kwh).$$

3. Calculate fuel efficiency percentage using heat rate:

$$Eq. 5A.9 \quad Fuel\ Efficiency\ (\%) = \frac{1}{Heatrate\ (kwh/kwh)}$$

4. Divide electricity generated (GJ) by the fuel efficiency percentage to calculate required fuel (GJ):

$$Eq. 5A.10 \quad Fuel\ Required\ (GJ)_t = \frac{Electricity\ (GJ)_t}{Fuel\ Efficiency\ (\%)}$$

5. Calculate the cost of the fuel bill. For fuels like natural gas, gigajoules (GJ) are a convenient unit of measurement. Natural gas prices are often listed in terms of $/GJ, at least in Canadian data. For other fuels, like coal or uranium, conversions may be needed, depending on the original data source. In general the fuel bill is calculated as follows:

$$Eq. 5A.11 \quad Fuel\ Bill_t = Fuel\ Required\ (units)_t * FuelPrice\ (\$/unit)_t$$

Note the time subscripts in equation 5A.9. These allow for the possibility that fuel prices are not constant over time. The LCOE measures presented in Chapter 5 assume constant fuel prices. However, fuel prices generally escalate over time. In the linear programming model (see chapter 7) natural gas prices are allowed to increase over time. Forecasts of natural gas price increases are taken from the National Energy Board (2013) *Energy Forecast for Canada* from 2015 to 2035. Forecasts for natural gas are then extended by continuing to increase natural gas prices at the annual rate of increase recording during the period of 2030-2035 in the forecast. The linear programming model also assumes that coal prices escalate at 1.25%/year (constant 2014 $CAN dollars). Conversations with relevant experts have indicated that 1.25%/year is an appropriate number for coal price escalation (Workshop 1).

Capital Cost and Financing Cost Calculation

The installed capital cost of a given electricity generation project can be found by multiplying the cost per kilowatt installed by the size of the planned installation:

$$Eq. 5A.12 \quad Capital\ Cost_t = Cost\ per\ kilowatt_t * Size\ (kw)$$

The method of financing the installation of an electricity generation project is another important part of the cost. There are many different ways to finance capital projects. The Lazard 8.0 (2014) calculations of LCOE assume the following financing structure:

- 40% equity-financed at 12% return;
- 60% debt-financed at 8%/year interest.

In my calculations of LCOE I assume that 100% of the capital cost is debt-financed at 4%/yr compounding interest. This is a debt-structure that is consistent with SaskPower's operations. I calculate financing costs using a monthly periodic interest rate:

$$Eq. 5A.13 \quad Periodic\ Interest\ Rate\ (i) = \ (1 \ + \ Annual\ Interest\ Rate)^{1/12} \\ = \sqrt[12]{Annual\ Interest\ Rate}$$

During the period of construction, interest is charged on the amount of capital required to construct the project. These interest payments are accumulated during the construction period, added to the principle, and then capitalized using debt-financing. Pre-commissioning interest on the amount borrowed is calculated as follows,

$$Eq. 5A.14 \quad Interest\ During\ Construction\ (IDC) = \ c * i * Capital\ Cost_0$$

Where c refers to the number of months of construction and i is the periodic interest rate. Note that interest charged during the construction period is not compounding, but accumulates and is amortized upon commissioning.

This approach to interest during construction is meant to mirror SaskPower's practices. SaskPower's policy on capitalizing interest reads as follows:

> "Where construction or development of a capital project is ongoing for a period of time, the asset is not of any productive use to the Corporation, but funds that could be used elsewhere are being tied up by the

construction process. To recognize this inherent carrying cost, interest must be capitalized on projects that are anticipated to be under construction or development for a period of 6 months or longer. Interest is not capitalized on projects that are under construction or development for less than 6 months." (SaskPower, 2011: 7)

The costs that are eligible for interest are treated in the following manner:

- "Interest is applied monthly on the ending asset under construction balance – excluding previously accumulating interest charges" (SaskPower, 2011: 7);
- "The annual interest capitalized during construction is calculated at a simple interest rate based on the previous year's weighted average cost of long-term debt and short-term borrowings" (SaskPower, 2011: 7).

To calculate annual amortized capital costs I assume an amortization period equal to the lifetime of the technology (measured in years *n*). Annual amortization payments are then calculated using this amortization formula:

$$Eq. 5A.15\ \ Monthly\ Payment = \frac{(Principal + IDC) * i}{1 - (1 + i)^{-m}}$$

Where *m* equals the number of months in the amortization period, which is found by multiplying the number of years (*n*) by twelve. Annual capital payments are equal to:

$$Eq. 5A.16\ \ Annual\ Capital\ Payment_t = \sum_{1}^{12} Monthly\ Payment$$

Operations & Maintenance Costs

Once electricity generation numbers are calculated it is straightforward to calculate variable operations and maintenance (O&M) costs:

$$Eq. 5A.17\ \ Variable\ O\&M\ Cost\ (\$)_t = VariableO\&M\ (\$/MWh)_t * Electricity\ (MWh)_t$$

Fixed O&M costs are calculated simply in the following way:

$$Eq. 5A.18\ \ Fixed\ O\&M\ Cost\ (\$)_t = FixedO\&M\ (\$/kw/yr)_t * Capital\ (MW)_t$$

Average electricity cost is then calculated by adding up the following:

$$Eq. 5A.19\ \ Average\ Annual\ Cost_t = Fixed\ O\&M\ Cost_t + Variable\ O\&M\ Cost_t + Annual\ Capital\ Payment_t + Fuel\ Bill_t$$

Note that this does not include charges for GHG emissions. If a policy path included a carbon price then additional costs would be added to the average annual cost. The LCOE numbers in Figure 5-10 do not assign a cost for GHG emissions.

References for Appendix 5A

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Appendix 7A – Technical Documentation for the Saskatchewan Investment Model (SIM)

Introduction

The Saskatchewan Investment Model (SIM) is a linear programming model of the Saskatchewan electricity sector. The model was built in *Excel for Mac 2010* and solved using the 'Solver' optimization tool (Frontline Solvers, 2014). In creating a linear programming (LP) model it is necessary to specify three components of the model:

1. The *objective function* defines the value to be minimized or maximized;
2. The *decision variables* are values that can be increased or decreased in order to change the value of the objective function;
3. *Constraints* are necessary to define the problem and restrict the feasible solution space.

Objective Function

SIM optimizes investment decisions taken in five-year time-steps beginning in 2016-2020 and ending in 2046-2050. The objective function is defined as the total discounted cost of supplying electricity over the period (Eq. 7A.1). SIM minimizes $C(I_{it})$ by selecting appropriate investments (I_{it}) in each five-year time-step.

$$Eq.7A.1 \quad \min C(I_{it})$$

$$= \sum_{i=1}^{n}\sum_{t=1}^{35}\left(\frac{AnnualKCost_{it} + O\&M_{it} + FuelBill_{it} + Carbontax * NetGHGs_{it}}{(1+r)^{t}}\right)$$

Where,

- i is a subscript indicating electricity technologies, which include generation technologies, demand side management measures in the residential, commercial and industrial sectors, one electricity storage technology, and one technology to represent contracts for imported hydroelectricity from Manitoba Hydro;

- t is a subscript indicating time. There are seven five-year time steps in SIM representing five-year investment periods beginning in 2016-2020 and ending in 2046-2050. Values in each time-step are assumed to be representative of a five-year average within that time-step. This means that average values are counted five times, but are discounted by a discount factor corresponding to the specific year they are incurred. For example, the average values in the 2020 time-step would be discounted at t=1, t=2, t=3, t=4 and t=5 and added to the cost total;
- C refers to a cost (C) function;
- I stands for investment;
- $AnnualKCost$ refers to the annual payment made to cover the cost of capital investments. Capital is amortized over its lifetime in the same manner outlined in Equations 5A.12 to 5A.16 in Appendix 5A. I assume an annual interest rate of 4% for debt-based capital financing costs;
- $O\&M$ refers to operations and maintenance expenditures and is the sum of fixed ($FixedO\&M$) and variable ($VariableO\&M$) O&M expenditures. These are calculated in the same manner as shown in Equations 5A.17 and 5A.18 in Appendix 5A;
- $FuelBill$ is the cost of purchasing natural gas, coal, biomass and uranium. It is calculated in the same manner as shown in Equations 5A.7 to 5A.11 in Appendix 5A. In SIM, however, fuel prices are not static and so $FuelPrice\ (\$/unit)_t$ varies with each time-step (Table 7A.1);
- $Carbontax$ refers to a tax on greenhouse gas emissions, measured in $CAN per tonne carbon dioxide equivalent (CO_2e). A carbon tax can be assigned in the model to impact optimization decisions. In creating the scenarios in Chapter 7 I did not assume a carbon price (Carbontax=0). Carbon prices could be selected by participants in the modelling workshops who used iSIM (see Chapter 9);
- $NetGHGs$ refers to direct greenhouse gas emissions resulting from electricity generation (measured in tonnes of CO_2e) that are released to the atmosphere. Emissions captured using carbon capture and storage technology are not charged a carbon tax; and
- r is the discount rate.

Fuel Costs

Fuel is required for electricity generated by coal-fired natural gas-fired generation facilities, biomass plants, and small modular nuclear reactors. In SIM I assume that coal and natural gas costs increase over time (Table 7A.1) (see Figure 5-6 in Chapter 5 for the natural gas price forecast).

Fuel Costs	2015	2020	2025	2030	2035	2040	2045	2050
Biomass (2014 CAN/GJ)	0.95	1.09	1.22	1.36	1.49	1.63	1.76	1.90
Coal (Westmoreland price + forecast @ 1.25%) (2014 CAN/tonne)	23.18	24.68	26.27	27.96	29.77	31.69	33.73	35.91
Natural Gas (NEB SK Industrial REF to 2035 + forecast @ 1.41%) (2014 $CAN per GJ)	3.21	4.04	4.64	5.07	5.44	5.83	6.25	6.70
Natural Gas (NEB SK Industrial HIGH to 2035 + forecast @ 1.11%) (2014 $CAN per GJ)	4.82	5.64	6.24	6.67	7.05	7.45	7.87	8.31
Natural Gas (NEB SK Industrial LOW to 2035 + forecast @ 2.09%) (2014 CAN per GJ)	2.53	2.55	3.03	3.46	3.83	4.25	4.72	5.23
Uranium for Nuclear SMR (2014 CAN per GJ)	0.38	0.43	0.49	0.54	0.60	0.65	0.71	0.76

Natural gas forecast from NEB (2013); Biomass and uranium prices from Lazard (2014); Coal price from Westmoreland (2015)

Table 7A.1 – Fuel Costs

Coal prices for Saskatchewan are based on the prices reported in the annual reports of coal mining company Sherritt (Sherritt, 2003; Sherritt, 2012). Sherritt was the primary coal mining company supplying SaskPower's coal plants in Saskatchewan until they sold their coal mining assets to Westmoreland in December of 2013 (Younglai, 2013). Between 2002 and 2012 Sherritt's coal prices increased at an annualized compound growth rate of 1.25%. Future coal prices are forecast using that growth rate.

Natural gas prices from 2014-2035 are taken from the industrial reference scenario of the National Energy Board (NEB, 2013) report *Canada's Energy Future 2013*. Prices from 2036-2050 are forecast using the annualized growth rate implied from price changes from 2030-2035 in the NEB reference forecast. I calculated this annualized growth rate to be 1.41%.

Biomass and uranium prices are taken from Lazard (2014). Lazard (2014) provides low and high values for both biomass and uranium. I assume that prices begin at the low values and increase in a linear fashion to reach the high value by 2050.

Greenhouse Gas Emissions

Annual greenhouse gas emissions (GHGs) for each time step are calculated using by multiplying the natural gas and coal required to generate electricity in that time step against the GHG intensity of the fuels, measured in CO2e (Equation 7A.2).

$$Eq.7A.2\ GHGs_{it} = FuelRequired(GJ/GWh)_{it} * Electricity(GWh)_{it} * GHGIntensity_{j}$$

Where,

- j is a subscript indicating fuel type ($j \in 1,2$ where 1 = natural gas, 2 = coal);
- $FuelRequired(GJ/GWh)_{it}$ indicates the fuel efficiency of each technology. For coal fuel use gigajoules (GJ) are converted to metric tonnes;
- $Electricity(GWh)_{it}$ is the total amount of electricity generated by fossil-fuel technology i in time-step t;
- $GHGIntensity_{j}$ is the GHG intensity per unit of fuel expressed in kg CO_2e per GJ for natural gas and tonnes CO_2e per tonne for lignite coal.

GHG intensities used in this paper are: 1.46 tonnes CO2e per tonne lignite coal (the coal burned for electricity production in Saskatchewan is entirely lignite coal); and 49.51 kilograms of CO2e per Gigajoule (GJ) natural gas (Environment Canada, 2014 Part 2 pp. 183-187).

Capital Stock Model

SIM is a capital-stock model. Capital in the model is created through investment, maintained for its expected lifetime, and retired at the end of its expected lifetime. Equation 7A.3 shows that the capital stock for any given technology in time-step t (K_{it}) is equal to the capital stock in the previous time-step ($K_{i,(t-1)}$) plus investment (I_{it}) and minus retirements (R_{it}),

$$Eq.7A.3\ K_{it} = K_{i,(t-1)} + I_{it} - R_{it}\ .$$

The capital stock determines the amount of electricity generated ($Eq. 7A.4$, which is the same as $Eq. 5A.3$ in Appendix 5A). For electricity generation technologies, the capital stock (K_{it}, measured in MW) is multiplied by its ($Capacity\ Factor_{it}$) and also the number of hours in a year (8760) to determine the quantity of electricity generated ($Electricity_{it}$, measured in MWh),

$$Eq. 7A.4\ \ Electricity_{it} = K_{it} * Capacity\ Factor_{it} * 8760.$$

I assume that electricity generation technologies produce electricity at their average $Capacity\ Factor_{it}$ throughout their lifetime. The capacity factor indicates the relationship between electricity generated by a technology over the course of a period of time and the theoretical maximum the technology could have generated in that period of time (See $Eq. 5A.4$ and $Eq. 5A.5$). In SIM the capacity factors translate megawatts (MW) of installed capacity into Megawatt-hours (MWh) of electricity generated (See $Eq. 7A.3$). Capacity factors range from a high of 83% for biomass and small, modular nuclear reactors to lows of 10% for solar thermal and 16% for solar photovoltaic installations. Due to its strong wind resource, Saskatchewan wind installations are able to achieve a capacity factor of 37.5%, which is quite high relative to other regions (Interview 5).

By assuming constant capacity factors the model remains linear. A variation to the model would allow capacity factors to vary. This could increase the realism of the model, but would introduce a non-linearity as SIM would have to choose both the capital investment and the capacity for each technology. Electricity generation for each technology would then be a multiplicative relationship between two decision variables. For computational ease, and to ensure the interactive SIM (iSIM) can run in Excel, I have kept relationships in the model linear.

Decision Variables

The decision variables in SIM are physical capacity investments (measured in megawatts – MW) in twelve competing electricity generation technologies and one electricity storage technology, as well as demand side management (DSM) efforts (measured in GWh/yr saved) in three sectors: residential, commercial, and industrial. Investment decisions are made at five-year intervals beginning in the 2016-2020 interval and continuing until the 2046-2050 interval.

Electricity Generation Technologies

The twelve electricity generation technologies represented in the model are:

- Biomass
- Conventional coal-fired generation
- Coal-fired generation equipped with carbon capture and storage (CCS)
- Hydroelectric facilities in Saskatchewan
- Hydroelectric capacity purchased from Manitoba Hydro
- Natural gas combined cycle turbines
- Natural gas simple cycle turbines
- Natural gas combined cycle turbines equipped with CCS
- Small, modular nuclear reactors
- Solar – photovoltaic (PV) installations
- Solar concentrating thermal stations
- Wind generation facilities

Investment in each technology is made in terms of megawatts (MW). The capital costs vary for each technology and also change over time in response to an 'Autonomous Capital Cost Improvement' (ACCI) factor (See Table 5-1). I use Equation 5.1 to model cost improvement. It is reproduced here as Equation 7A.5,

$$Eq.7A.5\ \ Cost_t = Cost_0 * exp^{-\gamma t}.$$

This cost improvement equation is also used to calculate cost improvements for fixed O&M costs ($FixedO\&M$) and variable O&M costs ($VariableO\&M$). The autonomous cost improvement factors for Fixed O&M and Variable O&M costs are summarized in Table 5-1.

Hydroelectric Facilities

Hydroelectric facilities in Saskatchewan receive special treatment when it comes to capital costs and investment decisions. Existing hydroelectric facilities can be retrofitted at the end of their useful life at a cost of $900/kw. This reflects feedback I received that SaskPower will continue to operate the existing hydro facilities indefinitely. Now that they have been built, the costs of extending the lives of hydroelectricity facilities is much lower than construction costs. I received feedback at workshop 1 (see Chapter 9) that hydroelectric facilities could be "repowered" for 10-15% the cost of building a new hydroelectric facility. The best hydroelectric sites in Saskatchewan can be developed at a cost of $6000/kw. In SIM I assume that the cost of retrofitting existing hydro facilities is 15% of that value: $900/kw. The cost of developing new hydroelectric facilities varies by site. There are projects on the Saskatchewan River system that can be built for less than $10,000/kw. Costs rise as the best sites are developed. I represent the increasing cost of new hydroelectricity by including six hydroelectric sites in SIM (Table 7A.1) each with a unique capital cost ($/kw) and potential capacity (MW). The sites are named to indicate the watershed where they would be located. Note that the 'Churchill River I' project corresponds to the Wintego project that had been rejected in the 1970s (see Chapter 3).

Hydroelectric Site	Capital Cost ($/kw)	Cost Improv-ment (%)	Potential Capacity (MW)
Repower existing hydro facilities	900	0.00%	864
Saskatchewan River II	6,000	0.50%	400
Saskatchewan River II	8,000	0.50%	400
Churchill River I	10,000	0.50%	330
Saskatchewan River II	11,000	0.50%	200
Northern Hydro	13,000	0.50%	200
Churchill River II	15,000	0.50%	100
Total			**2,494**

Table 7A.1 Hydroelectric Potential Projects in Saskatchewan

This representation of hydroelectric potential in Saskatchewan means that SIM makes seven investment decisions related to domestic hydroelectricity investment in each time-step making 49 decisions in total (7 hydroelectric projects multiplied by 7 time-steps). SIM also makes investment decisions for the 11 other electricity generation technologies in each time-step, creating an additional 77 decisions. Note that total hydroelectric potential modelled in SIM (2494 MW) is 150 MW less than the provincial hydroelectric potential outlined in Chapter 4 (2644 MW). Some smaller sites in northern Saskatchewan have hydroelectric potential, but have capital costs that exceed $20,000/kw and have been excluded from this analysis.

Electricity Storage

SIM must also make 7 decisions on whether to build electricity storage (7 decisions = 1 decision per time-step). Electricity storage does not generate electricity, but instead can be paired with variable renewables like wind and solar in order provide firm capacity and meet the peak demand constraint outlined in the next section. This brings the total number of decisions to 133 related to electricity generation and storage.

Demand-Side Management

Lastly, SIM must decide the level of effort to put into demand side management (DSM) measures. DSM costs and potential are outlined in Chapter 6. In each time-step SIM decides how many Gigawatt-hours (GWh) of DSM savings to pursue in each of the three sectors: residential, commercial and industrial. This creates 3 decisions per time-step for an additional 21 decisions over the course of the optimization. DSM efforts contribute to electricity generation in a manner akin to ‘negawatt-hours’; that is, they are modelled as if they are another electricity generation technology that meets electricity demand. DSM efforts are also converted into DSM peak savings in the manner described in Chapter 6 (see Equation 6.3). These peak savings contribute to the required capacity necessary to meet peak load, a constraint described in the next section.

In total there are 154 independent decisions made in each run of SIM: 49 decisions related to Saskatchewan hydroelectric investment, 77 decisions related to investment in

11 other electricity generation technologies, 7 decisions related to electricity storage, and 21 decisions related to DSM.

Note that in all but the equivalency scenario conventional coal-fired generation technologies are not permitted to compete for investment in the model. This acknowledges the 2012 Canadian coal-fired electricity regulations, which prohibit investment in electricity generation technologies that emit greenhouse gas emissions in excess of 420 tonnes carbon dioxide (CO2) emissions per Gigawatt-hour (GWh) of electricity (CEPA, 2012). This regulation came into effect July 1, 2015 (CEPA, 2012). In the equivalency scenario it is possible to retrofit existing coal-fired facilities at the end of their life to extend their longevity. I assume this retrofit option costs $400/kw, a figure that aligns with Environment Canada's analysis of the coal-fired regulations (CEPA, 2012).

Constraints

Without constraints, the simplest approach to minimizing the cost of operating the electricity system would be to sell all of the generation assets and produce zero or even negative electricity. To motivate a non-trivial solution it is necessary to constrain the feasible solution set.

Meeting Electricity Demand

The first constraint in the LP model requires that electricity generation is greater or equal to electricity demand. The forecast for electricity demand used in SIM is presented in detail in Chapter 6. To match the seven time-steps in the LP model the electricity forecast has been simplified to seven points (Figure 7A.1).

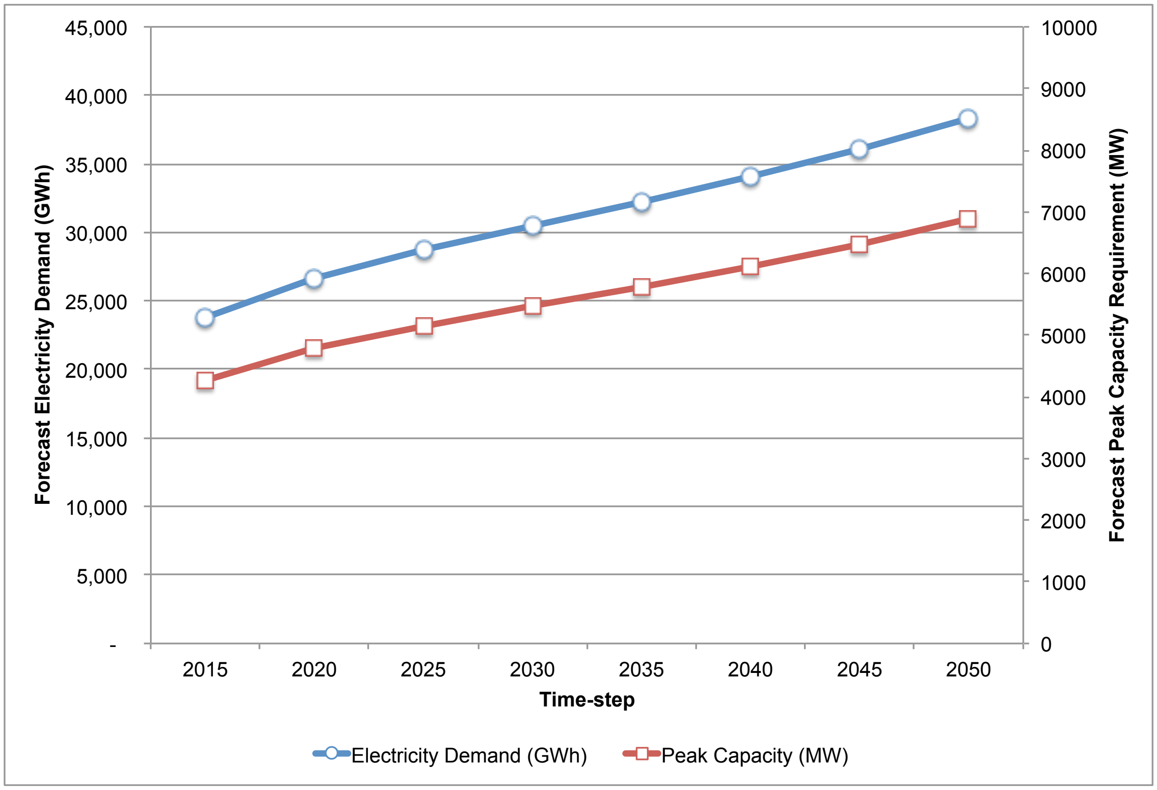

Figure 7A.1 – SIM Electricity Generation and Peak Capacity Constraints

The second constraint in the LP model is the requirement that available firm capacity is large enough to meet peak electricity demand. The forecast for firm capacity is also outlined in Chapter 6. The simple relationship estimated from historical data is that peak electricity demand (MW) is equal to 15.6% of electricity demand (GWh). This simplifying assumptions means that as the electricity system grows, so to does peak demand. This assumption could be adjusted in future versions of the model to allow the relationship between electricity demand (GWh) and peak demand (MW) to vary based on the profile of electricity demand. This might mean that peak demand is a lower percentage of electricity generation if, as in this case, electricity demand growth occurs in industry, which has a flatter demand profile than residential electricity demand. In the scenarios like *Greening the Grid* this would mean less electricity storage would be required. For this analysis I maintain the assumption of a static relationship between electricity demand and peak demand.

Firm capacity includes the fossil fuel generation assets (coal- and natural gas-fired plants), hydroelectric stations, biomass plants, and small modular nuclear reactors. To allow higher integration of variable renewables, five-eighths of the available electricity storage capacity is counted towards firm capacity. Wind receives a partial 'capacity credit' in recognition that it is often available; 10% of wind capacity is counted towards firm capacity (Interview 11). Solar-photovoltaic and solar thermal capacities are not counted towards the firm capacity total. DSM peak savings are counted as contributing to firm capacity.

In SIM the retirement schedule for existing electricity generation infrastructure (presented in Figure 1-3) has also been simplified to seven time steps (Figure 7A.2). After the optimizations are run I find that existing hydroelectric facilities are maintained in all scenarios through investments in repowering when retirement is scheduled to occur. In all but the *Greening the Grid* scenario, the Shand power plant is retrofitted in 2025 to extend its life until the 2045 time-step. In the SaskPower BAU scenario Boundary Dam IV and V are allowed to operate until 2025 when they are then converted to CCS. In all scenarios, the facilities are retired as scheduled in 2020.

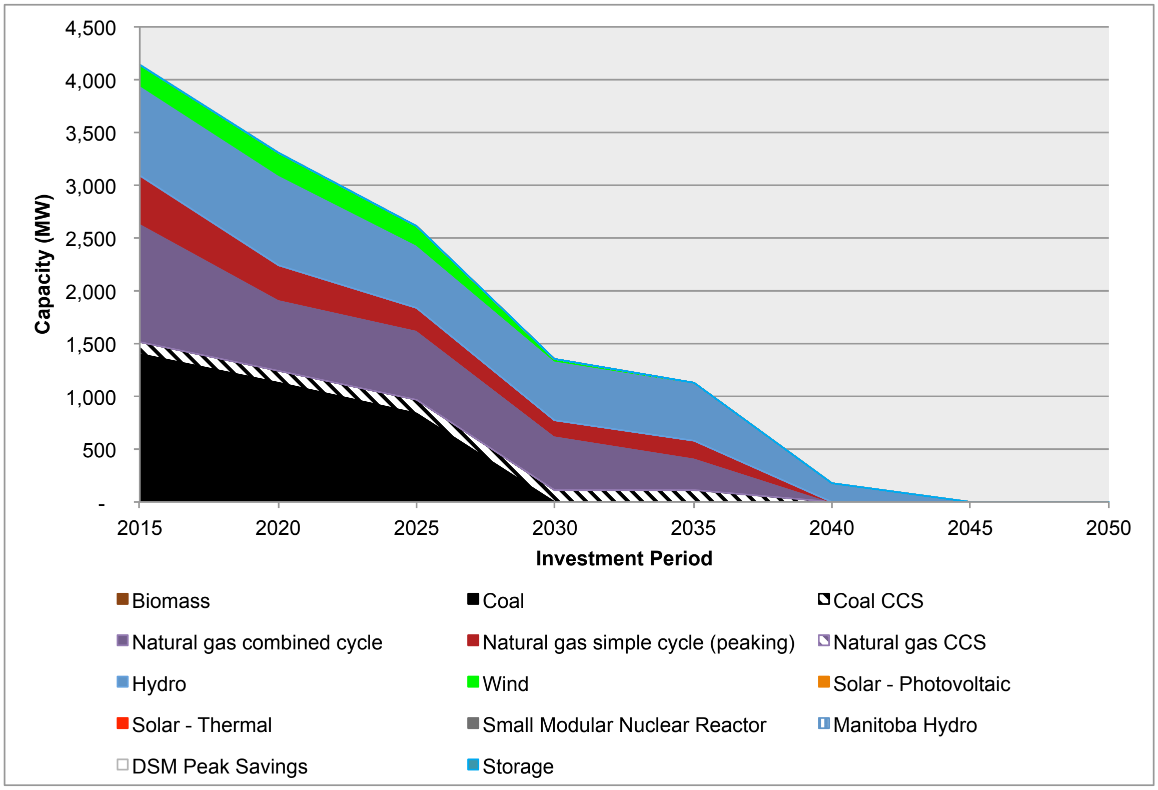

Figure 7A.2 – Simplified Capacity Retirement Schedule (adapted from SaskPower, 2011)

Renewable Energy Constraints

There are constraints that define the possible contributions of renewable electricity generation technologies. Biomass capacity is constrained to 150 MW (see Chapter 4). Hydroelectric capacity is restricted to the potential capacity (MW) indicated for each investment project listed in Table 7A.1. The contribution that wind can make to total electricity generation is restricted by constraints in each time-step. In most of the scenarios wind is constrained to 6% of total electricity generation in 2020, 9% in 2025, 12% in 2030, and continues to increase by 3% per time-step until it reaches 24% of electricity generation in 2050. The increases represent progress in understanding how to integrate variable wind generation into the electricity system. The domestic renewable energy and *Greening the Grid* scenarios loosen these constraints on wind (see discussion of these scenarios in Chapter 7).

Electricity Storage Constraint

Electricity storage is constrained to have a value less than or equal to 50% of the total capacity of the variable renewable technologies: wind, solar-PV, and solar thermal. This constraint ensures that electricity storage is matched with variable electricity supply. It is modelled after the relationship found at the Cowessess Wind Battery Storage project, where an 800-kilowatt (kW) Enercon wind turbine is matched with 400 kW of lithium-ion battery storage (Jansen, 2014).

Demand Side Management Constraints

Demand side management (DSM) efforts are constrained in each time-step to the potential outlined in Chapter 6 (see Tables 6-4, 6-5, and 6-6). DSM efforts are reset to zero in each time-step. This assumes that for energy conservation gains to be maintained, sustained effort must be put into DSM programming. This is a way of recognizing the potential for rebound effects following from energy conservation efforts.

Policy Constraints

The greenhouse gas (GHG) emissions reduction scenarios are motivated using constraints. The equivalency scenario involves constraining GHG emissions in 2020 to be equal to those achieved in the SaskPower BAU scenario. The four scenarios for reducing GHG emissions by 80% below 2015 levels by 2050 each constrain GHGs from electricity to that level. The domestic renewable energy scenario also requires that total electricity generated by the combination of biomass plants, hydroelectric stations, wind turbines, solar-PV installations, solar thermal installations, and DSM efforts, equals or exceeds 90% of total electricity generation in 2050.

The third scenario, an escalating carbon tax, does not require an additional constraint. Instead the carbon tax affects the objective function directly and penalizes fossil fuel generation options for the GHGs released to the atmosphere. GHG emissions stored underground through carbon capture and storage (CCS) are not charged a carbon tax. Emissions that emerge from underground when captured carbon is used to extract oil are also not charged to the electricity system; it is assumed that these GHGs would become a liability of the fossil fuel extraction sector.

Limitations

Because the linear program is set up to minimize the total discounted operating cost of meeting Saskatchewan's electricity demand the relative costs of the various technologies are important. The linear programming model will select the least cost option that meets the necessary constraints. This is true even if costs differ only slightly. Linear programming (LP) models are often critiqued for "penny-switching" (Jaccard *et al*., 2003). This means that the LP model will switch from one preferred electricity generation technology to another even if the costs of the technologies differ by a fraction of a cent (Jaccard *et al*., 2003). Because of the importance of relative costs, I conduct a sensitivity analysis of key cost assumptions in Chapter 7. I also encourage readers not to interpret the scenarios resulting from SIM as 'optimal'; the optimization program merely provides a decision-rule for assembling scenarios at the least financial cost to SaskPower. Chapter 8 explores the impacts of these scenarios that are not easily translated into financial cost.

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Appendix 7B – Technical Documentation for the WIRE (*'Will It Run Electricity'*) Model

Introduction

The Will It Run Electricity Model, or WIRE model for short, is an operational model of the Saskatchewan electricity system. Its purpose is to test scenarios developed in the Saskatchewan Investment Model (SIM) to understand whether they will sufficiently meet hourly electricity demand. In interviews and workshops, participants expressed concern that the "intermittency" of variable renewable energy technologies is a barrier to their adoption in Saskatchewan. The WIRE model tests scenarios to determine whether they are able to adequately supply consistent power to Saskatchewan homes, businesses, government, and industry. Each scenario is tested for four representative months: March, June, September, and December. If a scenario does not adequately supply reliable power in the WIRE simulation then I revisit the SIM model and its assumptions – for example in the *Greening the Grid* scenario mentioned in Chapter 7 I adjusted the hydroelectric capacity factor and solar capacity factors to correspond to annual minimum capacity factors, rather than average annual capacity factors. I then re-run SIM and test the model again using WIRE (See Figure 7B-1). The process continues until a scenario is found that achieves the long-run objectives of SIM, while satisfying the hourly objectives of WIRE.

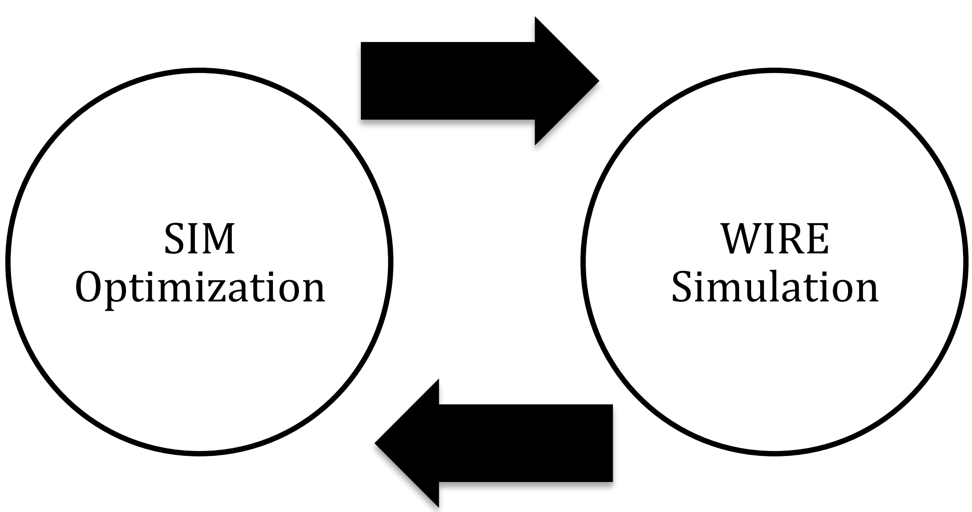


Figure 7B-1 Iterative Exchange Between the SIM and WIRE Models

Related Literature

The WIRE model builds on the work of Benitez, Benitez and van Kooten (2008) who use an hourly electricity model to understand the economic impact of increased wind power penetration in Alberta. Benitez *et al*. (2008) also consider the economic impact of using wind in combination with hydroelectric power storage in the province. The formulation for ramp rate constraints (identified below) is drawn from van Kooten (2012).

Model Description

The WIRE model is a non-linear programming optimization model. It is coded in the GAMS (General Algebraic Modelling Software) language and solved with a non-linear programming solver. The GAMS code for this model is included at the end of this appendix.

The WIRE model is designed to model a one-month time span with hourly (h) time steps. Months with 30 days have 720 time steps (hours), while months with 31 days have 744 time steps. In each time step electricity generation must be large enough to meet electricity demand.

Electricity Demand

Hourly electricity demand data and hourly wind power production data for 2013 were supplied by SaskPower and compiled by Dr. Mark Bigland-Pritchard (2015a). This hourly data is separated out by 'power class', 'oilfield', and 'other'. I scale this hourly electricity demand for each category to represent the composition of demand in 2050. There are three scenarios for demand; a business as usual (BAU) scenario where few demand side management (DSM) actions are taken by 2050, a medium scenario with greater levels of DSM, and a high scenario that achieves the greatest level of DSM. In the BAU scenario, power class electricity demand is forecast to grow by a factor of 2.13 from 2015 to 2050. To represent this scenario in WIRE I scale the hourly power class data from 2013 by multiplying by 2.13. The scaling factors I use for each of the scenarios and customer categories are as follows:

Customer Type	BAU	Med. DSM	High DSM
Power class	2.13	1.99	1.94
Oilfield	1.00	0.94	0.92
All other	1.47	1.38	1.34

Table 7B.1 Scaling Factors for Electricity Demand

Objective Function

The objective function in WIRE is a cost function that adds up the variable operations and maintenance costs and fuel costs of operating a given electricity system. The objective function also includes the capital cost of building an additional natural gas peaking plant if supply is insufficient to meet demand. The cost function (z) is represented by the following equation:

$$Eq. 7B.1 \ \ Cost\ (z) = \left(\sum_1^h \sum_1^i (VOM_i + Fuel_i) * Gen_{h,i}\right).$$

In GAMS code, this equation is represented as follows:

cost .. z =e= (sum(h,(sum(i,(VOM(i)+Fuel(i))*(Gen(h,i)))))).

Where,

- *h* is an index of the number of hours in the month;
- *i* is an index of electricity generation technologies;
- VOM(*i*) is the variable operations and maintenance cost per MWh of electricity generated for technology *i*;
- Fuel(*i*) is the fuel cost per MWh of electricity generated for technology *i*;
- Gen(*h,i*) is the electricity generated (in MWh) in hour *h* by technology *i*;

The summation brackets indicate that the objective function sums variable O&M costs and fuel costs over each technology (*i*) for each hour (*h*). The WIRE model works to minimize cost by adjusting available decision variables and adhering to constraints imposed on the model. The WIRE model prioritizes the lowest cost generation options for each hour.

Decision Variables

Within the objective function the decision variable is Gen(h,i) which requires the WIRE model to make h x i decisions to decide how much electricity is generated by each generation technology (i) in each hour (h).

The WIRE model also contains several other decision variables related to variable renewable electricity generated by wind and solar, and demand side management peak shifting opportunities. I explore these below.

Wind Energy

Wind electricity generation in each hour is taken as a given in WIRE. Wind electricity generation is calculated by multiplying the hourly capacity factors achieved by Saskatchewan wind turbines in 2013 with installed wind capacity in the given SIM scenario:

$$Eq.7B.2\ \ WindGen_h = WindCap * WindCF_h\ .$$

In GAMS code, this equation is represented as:

WindGen(h)=WindCap*WindCF(h).

Where,

- WindGen(h) is the amount of electricity generated in hour (h) by wind turbines in Saskatchewan;
- WindCap is the total MW of installed capacity of wind power in the province;
- WindCF(h) is the capacity factor in hour (h) of Saskatchewan wind turbines. This data was obtained from SaskPower by Mark Bigland-Pritchard. It is loaded into the model as a set of hourly parameters.

The optimization model must determine how much wind electricity to use to meet demand, how much to store for later use, and how much to curtail if production exceeds demand or the other generation technologies cannot ramp up or down fast enough. These decisions are represented by the following variables:

- UseWind(h) is a decision variable indicating the amount of wind electricity used to meet electricity demand in hour h;
- WindStore(h) is a decision variable indicating the level of wind electricity to store in hour h;
- Curtail(h) is a decision variable indicating the amount of wind electricity to curtail in hour h;

The sum of these three variables must equal total wind electricity generation (WindGen(h)). This is represented in WIRE by the following equation:

$$Eq.7B.3 \quad WindGen_h = UseWind_h + WindStore_h + Curtail_h \ .$$

In GAMS code this is represented by the equation:

Windy(h) .. WindGen(h) =e= Windstore(h) + Usewind(h) + Curtail(h).

Solar Energy

Like wind, solar energy is taken as a given in the WIRE model. Hourly solar photovoltaic capacity factors for Estevan in 2003 were calculated by Dr. Mark Bigland-Pritchard (2015b) using data from Environment Canada's CWEC weather database. Of interest, these solar capacity factors display significant seasonal variation.

	Estevan	Kindersley	LaRonge	North Battleford	Prince Albert	Regina	Saskatoon	Monthly Averages
January	11.3%	10.5%	11.2%	10.0%	13.0%	12.0%	11.5%	11.4%
February	16.4%	13.7%	13.5%	12.4%	13.1%	12.7%	12.6%	13.5%
March	22.9%	23.3%	18.7%	22.1%	21.3%	22.0%	22.3%	21.8%
April	22.8%	21.2%	26.0%	20.0%	21.5%	20.0%	20.0%	21.7%
May	25.8%	25.2%	27.2%	25.5%	27.9%	27.3%	27.5%	26.6%
June	24.3%	24.4%	23.9%	23.3%	25.4%	26.3%	24.8%	24.6%
July	28.6%	29.8%	25.8%	26.0%	25.5%	30.3%	27.3%	27.6%
August	29.9%	28.9%	23.9%	27.1%	26.9%	28.9%	27.4%	27.6%
September	22.0%	23.2%	14.7%	18.3%	18.6%	21.2%	18.7%	19.5%
October	18.3%	19.1%	11.5%	16.8%	16.0%	17.2%	16.8%	16.5%
November	16.6%	13.5%	9.6%	13.1%	13.8%	14.7%	13.6%	13.6%
December	11.3%	10.1%	7.5%	10.1%	10.5%	9.9%	10.5%	10.0%
Annual	20.1%	19.7%	17.5%	18.1%	18.8%	19.4%	18.6%	

(Source: Bigland-Pritchard; author's calculations)

Table 7B.2 Monthly Solar Photovoltaic Capacity Factors

Mirroring the approach to wind generation, hourly solar capacity factors for each representative month are applied to the installed photovoltaic capacity:

$$Eq. 7B.4 \;\; SolarGen_h = SolarCap * SolarCF_h \;.$$

In GAMS code this is represented by the equation:

SolarGen(h)=SolarCap*SolarCF(h).

Solar energy decisions are represented by the following decision variables:

- UseSolar(h) is a decision variable indicating the amount of solar electricity used to meet electricity demand in hour h;
- SolarStore(h) is a decision variable indicating the level of solar electricity to store in hour h;
- SolarCurtail(h) is a decision variable indicating the amount of solar electricity to curtail in hour h.

The sum of these three variables must equal total solar electricity generation (SolarGen(h)). This is represented in WIRE by the following equation:

$$Eq.7B.5\ \ SolarGen_h = UseSolar_h + SolarStore_h + SolarCurtail_h\ .$$

In GAMS code this is represented by the equation:

Sunny(h) .. SolarGen(h)=e= SolarStore(h) + UseSolar(h) + SolarCurtail(h).

The WIRE model will choose to store solar electricity in any one hour if it can be used at a later hour to meet electricity demand and lower total costs for the month. The WIRE model will choose to curtail solar electricity in any given hour if excess electricity is being generated at that hour and electricity storage is at full capacity.

Electricity Storage

The possibility of storing electricity has been built into the model in order to address issues of renewable energy variability. The storage technology resembles the characteristics of a lithium-ion battery, pumped-hydro storage, or compressed air storage. Because the model is run within each representative month independently, seasonal storage is not represented in the model. Future versions of WIRE may improve upon this.

There are three main factors that determine the characteristics of electricity storage in WIRE:

- Storecap: the capacity of electricity storage in the SIM scenario, expressed in MW. Efforts are made to iteratively reduce the storage capacity when possible;
- Storage.up: the maximum amount of electricity – expressed in MWh – that can be held in storage. I assume that a 400 MW electricity storage facility can store 744 MWh of electricity. This relationship is consistent with the Cowessess wind storage project located east of Regina where a 400-kilowatt lithium-ion battery is able to store 744 kWh of electricity (personal communication Ryan Jansen, June

2014). This relationship is expressed with the following constraint in GAMS: Storage.up(h) = Storecap * (744/400)

- UseStore(h): is a decision variable determined by the optimization solver. The WIRE model determines the amount of stored electricity to use in each hour (h). Importantly, there are conversion losses in the process of storing electricity. To model these conversion losses, only 70% of the electricity pulled from storage can be used to meet supply. This represents a 30% conversion loss from storage.

Demand Side Management Peak Shifting

The WIRE model is built to allow peak shifting demand side management (DSM). I allow electricity demand from one hour (h) to be shifted ahead three hours (h+3). This is introduced with a simple equality:

$$Eq.7B.6\ DSMsave_h = DSMspend_{h+3}\ .$$

In GAMS code, this is represented by:

DSM(h) .. DSMsave(h) =e= DSMspend(h+3);

The WIRE model must then determine how much electricity demand to save in a given hour (h) in order to shift it ahead three hours. This peak shifting is limited by an upper bound that corresponds to the peak savings that result in a given SIM scenario. The upper bound is indicated in GAMS as follows:

- DSMsave.up(h) = 67;
- DSMspend.up(h) = 67.

In this illustrative scenario 67 MW of peak shaving capacity are available.

Meeting Supply

The key constraint in the WIRE model is ensuring that electricity demand, net of DSM, is lesser or equal to electricity generation in each hour. This constraint is characterized as follows:

$$Eq.7B.7\ \ Demand_h - DSMsave_h + DSMspend_h \leq \sum_{1}^{i} Gen_{h,i} + UseWind_h + UseSolar_h + (.7 * UseStore_h)$$

And in GAMS code is represented as:

Meetsupply(h) .. Demand(h) - DSMsave(h) + DSMspend(h) =l= sum(i, (Gen(h,i))) + Usewind(h) + UseSolar(h) + .7*Usestore(h) .

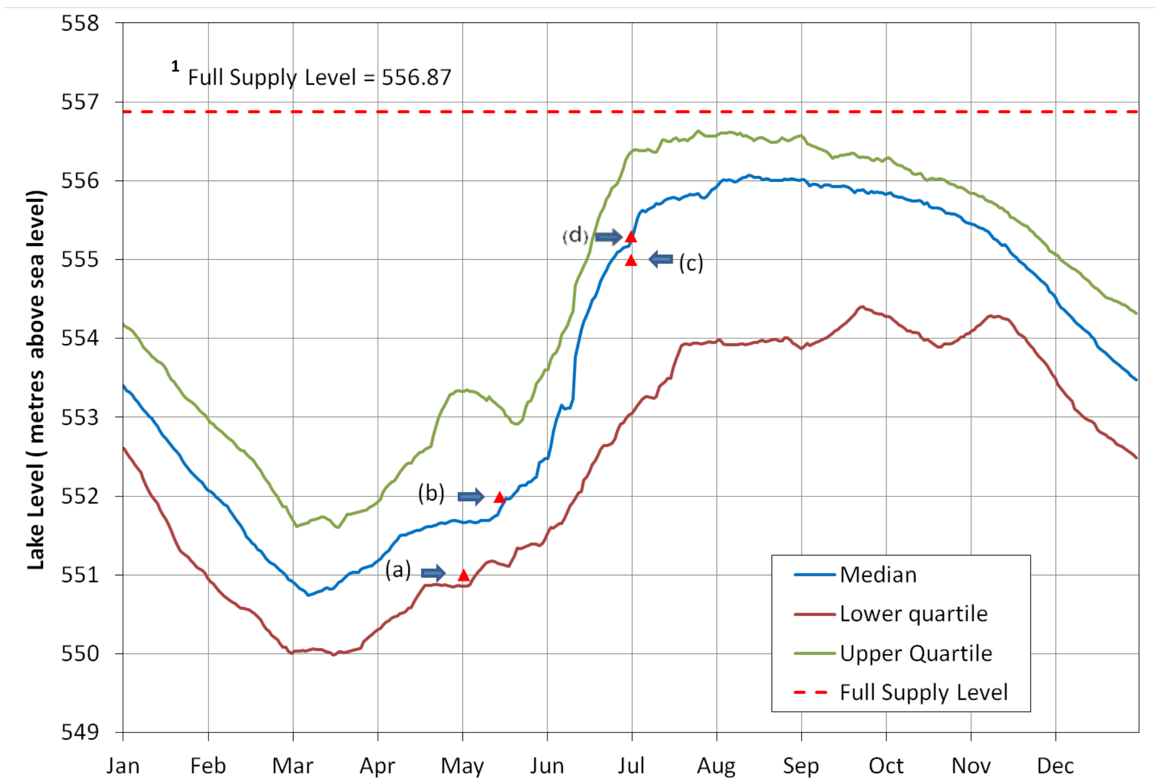
Where,

- $Demand_h$ is electricity demand in each hour;
- $Gen_{h,i}$ is the amount of electricity generated by technology *i* in hour (*h*);
- The other factors are as explained above.

Capacity Constraints

I constrain the total contribution that thermal, nuclear, biomass, and hydroelectric electricity technologies can provide over the course of a month. For the thermal, nuclear, and biomass technologies, these constraints largely align with the default settings in SIM. Occasionally, and usually when running WIRE for December when demand is highest, I allow the capacity constraint for a technology like natural gas combined cycle plants to achieve a value of 85%. This is a value that can be achieved when a natural gas plant is running as a source of “baseload” power.

Hydroelectric capacity is limited by seasonal capacity factors. Due to winter snowmelt, streamflow in Saskatchewan is highest in the late spring. Water storage is available at Lake Diefenbaker where the Coteau Creek generating station is located. Coteau Creek is upstream of Nipawin and E.B. Campbell and so when water flows from Lake Diefenbaker it increases flows to the two stations downstream. Lake Diefenbaker is also managed to ensure recreation opportunities in the summer, protect piping plover habitat in the spring, and to provide irrigation in the case of severe drought (Interview 42). This means that the reservoir is filled slowly in the spring to avoid flooding piping plover habitat, maintained at a high level in the summer to allow recreational activities, and then drawn down in the winter to provide hydroelectric power during periods of high demand. A typical operating year is shown in Figure 7B.1.



(Source: Saskatchewan Watershed Authority, 2012)

Figure 7B.1 Lake Diefenbaker Lake Levels

Lacking hourly hydroelectric production data I constrain hydroelectric production to reflect historic monthly averages from 2009-2013 (SaskPower, 2014). Historic monthly averages are shown in Table 7B.3. These averages aggregate all existing hydroelectric facilities in the province. I apply these aggregated average hydroelectric capacity factors to both domestic hydroelectric production and hydroelectricity imported from Manitoba. More work could be done in the future to model streamflow and reservoir levels directly to determine available hydroelectric production.

	2013	2012	2011	2010	2009	Average
January	55%	51%	43%	51%	53%	51%
February	57%	49%	49%	47%	54%	51%
March	44%	42%	57%	36%	37%	43%
April	51%	48%	73%	40%	42%	51%
May	75%	62%	88%	32%	38%	59%
June	83%	71%	89%	75%	35%	71%
July	82%	89%	94%	81%	35%	76%
August	60%	72%	56%	52%	31%	54%
September	49%	48%	53%	49%	30%	46%
October	53%	48%	44%	57%	33%	47%
November	45%	44%	43%	44%	38%	43%
December	52%	48%	47%	48%	44%	48%

(Source: SaskPower, 2014)

Table 7B.3 Hydroelectric Capacity Factors in Saskatchewan 2009-2013

Ramp Rate Constraints

A final constraint that shapes the WIRE model relates to the ability of electricity generation technologies to ramp up and ramp down their electricity production. Technologies like coal and nuclear plants are slow at ramping, while technologies like hydroelectric plants and natural gas combined cycle plants can ramp quite quickly. Fast-ramping technologies are complementary to variable renewable electricity technologies like wind.

Ramp rate controls enter the WIRE model with the following equations:

$$Eq.7B.8\ \ Gen_{h+1,i} - Gen_{h,i} \ \leq Ramp_i \ ;$$

$$Eq.7B.9\ \ Gen_{h+1,i} - Gen_{h,i} \ \geq -Ramp_i \ .$$

In GAMS coding those relationships are expressed with these equations:

$$Rampup(h,i) \text{ .. Gen(h+1,i) - Gen(h,i) =l= Ramp(i);}$$

$$Rampdown(h,i) \text{ .. Gen(h+1,i) - Gen(h,i) =g= -Ramp(i).}$$

Where,

- $Ramp_i$ is the ramp rate in MW/hour for electricity generation technology i.

van Kooten (2012) expressed ramp rates in terms of the percentage of capacity that can be ramped each hour. SaskPower provided me with ramp rates for thermal and hydroelectric facilities in Saskatchewan in terms of MW/hour (personal correspondence, June 2015). For each scenario I customize the ramp rates to relate to the total installed capacity for each technology using the constraints outlined in Table 7B.4.

Capital Stock (MW)	% capacity/ hour
Biomass	10%
Coal	10%
Coal CCS	10%
Natural gas combined cycle	30%
Natural gas simple cycle (peaking)	50%
Natural gas CCS	30%
Hydro	100%
New Hydro	100%
Small Modular Nuclear Reactor	4%

Table 7B.4 Ramp Rates Per Hour

References for Appendix 7B

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Bigland-Pritchard, Mark (2015b) *Hourly Solar Capacity Factors for 2003 calculated from Environment Canada's CWEC weather database.* Saskatoon, SK: Low-Energy Design.

Jansen, Ryan (2014) *Personal Correspondence*. Meeting at the Cowessess Wind Storage Demonstration Project, Regina, SK, June 2014.

Saskatchewan Watershed Authority (2012) *Developing a New Reservoir Operating Plan for Lake Diefenbaker*. Document Prepared for Consultation Meeting May 30, 2012. Regina, SK: SWA.

SaskPower (2014) *2014, 2015, 2016 Rate Application: Response to SIECA Second Round Information Requests*. Available on-line at: http://www.saskratereview.ca/index.php?option=com_content&view=article&id=50&Itemid=16. Last accessed October 16, 2015.

van Kooten, G. Cornelis (2012) "Natural Gas, Wind and Nuclear Options for Generating Electricity in a Carbon Constrained World." *Resource Economics & Policy Analysis Research Group Working Paper 2012-01*. Victoria, BC: University of Victoria Department of Economics.

GAMS Code for the WIRE Model

```
$Title Will It Run Electricity Model – aka the WIRE model
$Ontext
Scenario: BAU + DSM in March 2050
Version: October 13, 2015
This is a model of the operational characteristics of electricity scenarios generated by the
SIM model. It is built to run over the course of one month and to minimize the cost of
generating electricity over that month.
$Offtext
```

set

```
h hours /1*744/      ;
set
i gentype /coal, coal-CCS, NGSC, NGCC, NG-CCS, Hydro, MBHydro, Biomass,
Nuclear, Import /;
```

Parameters

```
*The $include command allows data to be imported from a .csv file
D(h) Electricity demand    /
$ondelim
$include March2050Demand.csv
$offdelim
/

WindCF(h) Wind capacity factor at each hour in 2013 on SaskPower system /
$ondelim
$include March2050WindCF.csv
$offdelim
/
```

```
SolarCF(h) Solar capacity factor at each hour in 2003 on SaskPower system at Estevan/
$ondelim
$include March2050SolarCF.csv
$offdelim
/
;
```

Scalars

```
WindCap /1720/
StoreCap /0/
SolarCap /10/;
```

Parameter

```
WindGen(h) ;
WindGen(h)=WindCap*WindCF(h)  ;
```

Parameter

```
SolarGen(h) ;
SolarGen(h)=SolarCap*SolarCF(h);
```

Parameters

```
VOM(i) Variable Operating Costs ($perMWh)
/Coal        5.6
 Coal-CCS    5.4
 NGSC       11.9
 NGCC        2.4
 NG-CCS      8
 Hydro       2.9
 MBHydro    85
 Biomass     0
```

Nuclear 0
Import 120
/

GCAP(i) Generation Capacity (Megawatts)
/Coal 0
Coal-CCS 0
NGSC 0
NGCC 4955
NG-CCS 0
Hydro 1664
MBHydro 0
Biomass 0
Nuclear 0
Import 1000
/

Fuel(i) Fuel costs in 2050 for generation technologies $-per-MWh
/Coal 26.31
Coal-CCS 35.08
NGSC 84.83
NGCC 56.55
NG-CCS 67.86
Hydro 0
MBHydro 0
Biomass 14.50
Nuclear 7.31
Import 0
/
*Note: Nuclear and biomass costs do not change from 2015

Ramp(i) Ramp rate constraint for each technology

```
/Coal        180
 Coal-CCS     180
 NGSC         480
 NGCC        1500
 NG-CCS     1500
 Hydro       1800
 MBHydro  1000
 Biomass      180
 Nuclear       60
Import      1000
 /
```

*Ramp rates are dependent on the scale of the system. They are changed to fit each scenario.

CapFact(i) Capacity factor for each generating technology

```
/Coal          .78
 Coal-CCS   .78
 NGSC        .40
 NGCC       .54
 NG-CCS     .49
 Hydro        .43
 MBHydro  .43
 Biomass     .83
 Nuclear       .83
Import      1
```

HydroCap Annual capacity factor for hydro in January (%)

```
/.43/
 ;
```

```
Variable
Gen(h,i) Generation per hour by electricity source
;

Positive variable
Gen
Storage
WindStore
UseStore
UseWind
Curtail
SolarStore
UseSolar
SolarCurtail
DSMsave
DSMspend;

*Setting Upper (.up) and Lower (.lo) Bounds and Initial values (.l)
Gen.up(h,i) = GCAP(i)                    ;
Gen.lo(h,'hydro') = 20;
*The lower bound for hydro corresponds to the minimum streamflow, and resulting
electricity generation, that must be maintained at E.B. Campbell
Storage.l('1') = 0 ;
Storage.up(h) = Storecap * (744/400)          ;
DSMsave.up(h) = 67;
DSMspend.up(h) = 67;

Variable
z total operating cost;
```

Equations

cost define objective function

MeetSupply(h) electricity generated will meet demand

Rampup(h,i) how quickly generation technologies can ramp up

Rampdown(h,i) how quickly generation technologies can ramp down

CapacityLimit(i) constrains generation technologies to operate within capacity factor

Store(h) specify how storage works

Windy(h) specify how wind power works

Sunny(h) specify how solar power works

DSM(h) allow peak shifting by 3 hours

;

*The equations are defined below.

*Ramping constraints limit the speed at which generation capacity can change

Rampup(h,i) .. Gen(h+1,i) - Gen(h,i) =l= Ramp(i);

Rampdown(h,i) .. Gen(h+1,i) - Gen(h,i) =g= -Ramp(i);

Meetsupply(h) .. d(h) - DSMsave(h) + DSMspend(h) =l= sum(i, (Gen(h,i))) + Usewind(h) + UseSolar(h) + .7*Usestore(h) ;

cost .. z =e= (sum(h,(sum(i,(VOM(i)+Fuel(i))*(Gen(h,i)))))) + (GasAdd*CapCost) ;

CapacityLimit .. (sum(h,Gen(h,i))) =l= CapFact(i)*744*GCAP(i) ;

Store(h) .. Storage(h+1) =e= Storage(h) + Windstore(h+1) + Solarstore(h+1) – Usestore(h+1);

Windy(h) .. WindGen(h) =e= Windstore(h) + Usewind(h) + Curtail(h) ;

Sunny(h) .. SolarGen(h)=e= SolarStore(h) + UseSolar(h) + SolarCurtail(h);

DSM(h) .. DSMsave(h) =e= DSMspend(h+3);

Model WIRE /all/ ;

Option Reslim = 1000000 ;
Option Iterlim = 1000000 ;

Solve WIRE using nlp minimizing z ;

*Unload results to GDX file in order to then export them to Excel
execute_unload "results1013March2050BAU.gdx" Gen.L Windstore.l Usewind.l Curtail.l Usestore.l UseSolar.l DSMsave;

Appendix 8A – Cost of Service Model

SaskPower has a cost of service model that they use to translate the cost of generating and distributing electricity into the electricity rates paid by customers. This cost of service model adheres to a few general principles:

1. **Cross-subsidization** is minimized. Cross-subsidization refers to charging more for electricity to some electricity users in order to charge less, or subsidize, others. SaskPower tries to avoid cross-subsidization in their current cost of service model;
2. Large power customers pay for the **transmission**, but not for the **distribution** of electricity. Transmission lines are the large, high-voltage lines that carry electricity from power plants to major load centres. These lines will often serve major power users like potash mines or oil refineries directly. Transmission lines in Saskatchewan are typically 230 kilovolts (kV), 138 kV, 115 kV, or 110 kV. Lower voltage lines (25 kV and 14.4 kV), linked to transmission lines at substations, are used to provide electricity to commercial and residential customers (SaskPower, 2011). These low-voltage distribution lines are the power lines we see throughout towns and cities in the province. Figure 7A.1 shows a transmission line with a smaller distribution line running beneath. Because large power users do not use the distribution network, they do not pay the costs of building and maintaining the network of low voltage lines;
3. Customer groups that use more power at **peak times** pay a premium for their electricity. The electricity system must be sized large enough to meet peak demand. As shown in Figure 6-5, electricity demand from large industrial power customers is relatively stable. Electricity demand from residential and commercial customers displays peaks in periods of high demand. These peaks require additional generation capacity to be made available and, as a consequence, residential and commercial customers pay more for their electricity.

Figure 8A.B SaskPower Transmission and Distribution Lines Near Balgonie, SK

The specific formulas SaskPower uses in their cost of service model are not publicly available. I have worked to approximate their cost of service model in the following steps:

Step 1: Allocate line losses to customer categories

I begin with line loss factors from SaskPower's (2008) submission to the Saskatchewan Rate Review Panel's review of SaskPower's cost of service model. Table 8A.1 shows the expected line loss as a percentage of demand in each category.

Responsibility for line losses (% of Demand)	
Potash, Northern Mining & Pipeline Load	6.1%
All Other Power Class Load	6.5%
Oilfields	14.0%
Commercial	15.6%
Residential	15.9%
Farms	14.9%
Resellers	5.4%

Table 8A.1 Responsibility for Line Losses (% of customer category demand)

Table 8A.1 shows that electricity demand from the potash, northern mining and pipeline load power customers is anticipated to lead to line losses of 6.1%. This means if customers in that category desired 100 GWh of electricity, 6.1 GWh would be lost in the process of transmission. Losses in the commercial and residential categories are higher because electricity must travel through the distribution networks and more is lost before reaching the customer. I use these line loss factors as a basis for allocating total line losses to each customer category. Table 8A.2 shows the line loss estimates that result for each time step.

Year	2015	2020	2025	2030	2035	2040	2045	2050
Potash, Northern Mining & Pipeline	214	294	336	378	425	471	524	586
All Other Power Class Load	175	189	200	214	228	242	258	275
Oilfields	328	365	399	395	382	368	355	342
Commercial	406	429	446	464	484	503	524	545
Residential	353	396	437	484	536	592	655	724
Farms	133	137	137	139	140	141	143	144
Resellers	48	50	51	53	54	56	57	58

Table 8A.2 Line Losses Assigned to Each Demand Category (GWh)

Step 2: Allocate Line Loss to Demand Customer Categories

I then allocate line loss to demand for each category to calculate required generation:

$$Eq. 8A.1\ \ Required\ Generation_{c,t} = \ Demand_{c,t} + Line\ Loss_{c,t}$$

Where,

- *c* indicates customer category;
- *t* indicates time-step;
- $Required\ Generation_{c,t}$ refers to the amount of electricity (GWh) SaskPower must generate in order to satisfy demand for customer group *c* in time-step *t*;
- $Demand_{c,t}$ refers to electricity demand by end-user *c* in time-step *t* (GWh);
- $Line\ Loss_{c,t}$ refers to line loss incurred to meet demand for end-user *c* in time-step *t* (GWh).

The results are presented in Table 8A.3.

Year	2015	2020	2025	2030	2035	2040	2045	2050
Potash, Northern Mining & Pipeline	5,314	7,136	8,086	9,018	10,054	11,047	12,192	13,514
All Other Power Class Load	4,075	4,305	4,545	4,800	5,068	5,352	5,651	5,967
Oilfields	3,728	4,062	4,419	4,338	4,151	3,970	3,798	3,634
Commercial	4,186	4,329	4,470	4,616	4,768	4,923	5,084	5,251
Residential	3,573	3,927	4,308	4,728	5,189	5,695	6,249	6,858
Farms	1,433	1,437	1,437	1,439	1,440	1,441	1,443	1,444
Resellers	1,348	1,372	1,394	1,418	1,441	1,465	1,490	1,515
Corporate	88	99	107	113	119	126	134	142
Line Losses	**ASSIGNED TO CUSTOMER CLASSES**							
Total	*23,745*	*26,666*	*28,767*	*30,469*	*32,231*	*34,020*	*36,040*	*38,324*

Table 8A.3 – Electricity Demand With Line Loss Assigned (GWh)

Step 3: Allocate Transmission and Distribution Costs to Customer Categories

In SIM, transmission and distribution costs are charged per kilowatt-hour of electricity demand. This is meant to approximate the fixed costs of building and maintaining the Saskatchewan electricity grid. Costs are taken from EIA (2014) and are summarized for each time-step in Table 8A.4.

Transmission and Distribution (cents /kwh)

Transmission	**1.08**	**1.21**	**1.32**	**1.46**	**1.63**	**1.85**	**1.85**	**1.85**
Distribution	**3.05**	**3.11**	**3.20**	**3.46**	**3.85**	**4.26**	**4.26**	**4.26**

(Source: EIA, 2014)

Table 8A.4 – Transmission and Distribution Costs

For each time step, the average transmission cost (in cents/kWh from Table 8A.3) is multiplied by total electricity generation to obtain total transmission cost. The total transmission cost is then allocated to all categories of electricity demand based on their proportional share of $Required\ Generation_{c,t}$. Corporate use is exempted from this calculation; I assume corporate use occurs on-site at power plants (see Table 8A.5).

Year	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Potash, Northern Mining & Pipeline	22.5%	26.9%	28.2%	29.7%	31.3%	32.6%	34.0%	35.4%
All Other Power Class Load	17.2%	16.2%	15.9%	15.8%	15.8%	15.8%	15.7%	15.6%
Oilfields	15.8%	15.3%	15.4%	14.3%	12.9%	11.7%	10.6%	9.5%
Commercial	17.7%	16.3%	15.6%	15.2%	14.8%	14.5%	14.2%	13.8%
Residential	15.1%	14.8%	15.0%	15.6%	16.2%	16.8%	17.4%	18.0%
Farms	6.1%	5.4%	5.0%	4.7%	4.5%	4.3%	4.0%	3.8%
Resellers	5.7%	5.2%	4.9%	4.7%	4.5%	4.3%	4.1%	4.0%
Corporate	**NOT CHARGING CORPORATE FOR TRANSMISSN AND DISTRBN**							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 8A.5 Transmission Cost Allocation (%)

A similar approach is used for distribution costs. The average distribution cost (in cents/kWh from Table 8A.4) is multiplied by commercial, residential, and farm demand, as well as half of oilfield demand to obtain total distribution cost at each time step. Total distribution cost is then allocated to each customer category based on their contribution to the total (percentages are shown in Table 8A.6). Resellers do not pay distribution cost. Instead, Saskatoon Light and Power and Swift Current Light and Power maintain their own distribution networks.

Year	2015	2020	2025	2030	2035	2040	2045	2050
Potash, Northern Mining & Pipeline	POWER CUSTOMERS DO NOT PAY FOR DISTRIBUTION COST							
All Other Power Class Load	POWER CUSTOMERS DO NOT PAY FOR DISTRIBUTION COST							
Oilfields	17%	17%	18%	17%	15%	14%	13%	12%
Commercial	38%	37%	36%	36%	35%	35%	35%	34%
Residential	32%	33%	35%	37%	39%	41%	43%	45%
Farms	13%	12%	12%	11%	11%	10%	10%	9%
Resellers	RESELLER CUSTOMERS DO NOT PAY FOR DISTRIBUTION COST							
Corporate	NOT CHARGING CORPORATE FOR TRANSMISSN AND DISTRBN							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 8A.6 Distribution Cost Allocation (%)

Step 4: Allocate Electricity Generation Costs

Electricity generation costs include the annual amortized cost of capital, fixed O&M, variable O&M, fuel costs, and carbon charges (in scenarios where a carbon price is applied). These costs are allocated based on electricity demand for each category. For example, if residential customers are responsible for 15% of electricity demand, that category is assigned 15% of the electricity generation costs. Table 8A.7 presents the proportions of electricity demand responsibility. These percentages are multiplied against annual electricity generation costs.

Year	2015	2020	2025	2030	2035	2040	2045	2050
Potash, Northern Mining & Pipeline	22.4%	26.8%	28.1%	29.6%	31.2%	32.5%	33.8%	35.3%
All Other Power Class Load	17.2%	16.1%	15.8%	15.8%	15.7%	15.7%	15.7%	15.6%
Oilfields	15.7%	15.2%	15.4%	14.2%	12.9%	11.7%	10.5%	9.5%
Commercial	17.6%	16.2%	15.5%	15.2%	14.8%	14.5%	14.1%	13.7%
Residential	15.0%	14.7%	15.0%	15.5%	16.1%	16.7%	17.3%	17.9%
Farms	6.0%	5.4%	5.0%	4.7%	4.5%	4.2%	4.0%	3.8%
Resellers	5.7%	5.1%	4.8%	4.7%	4.5%	4.3%	4.1%	4.0%
Corporate	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Line Losses	ASSIGNED TO CUSTOMER CLASSES							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 8A.7 Electricity Demand Proportions (%)

Step 5: Add All of the Costs Together

The total cost responsibility for each customer category is captured by adding together electricity generation costs, and the transmission and distribution costs assigned to each respective category (where applicable). This sum equals the total cost responsibility for each category.

Step 6: Calculate Net Demand for Electricity

To establish the net demand for electricity we need to subtract electricity saved through demand side management (DSM) from total demand. DSM savings are allocated to each customer category based on the assumptions made in Chapter 6 regarding DSM potential. To recap,

Industrial DSM savings are allocated based on their contribution to the total of the following:

- Potash, northern mining, and pipeline load +
- Oilfields +
- 75% of Other power users.

Commercial DSM savings are allocated based on their contribution to the total of the following:

- Commercial +
- 50% of Reseller +
- 25% of Other power users.

Residential DSM savings are allocated based on their contribution to the total of the following:

- Residential +
- Farms +
- 50% of Reseller.

Tables 8A.8 to 8A.10 show the proportions of DSM savings assigned to each customer category. The proportions vary by year depending on relative electricity demand from each customer category.

Industrial DSM Allocation (%)	2015	2020	2025	2030	2035	2040	2045	2050
Potash, Northern Mining & Pipeline Load	45%	50%	52%	54%	57%	59%	61%	63%
All Other Power Class Load - industrial	26%	23%	22%	21%	21%	21%	21%	21%
Oilfields	30%	27%	27%	25%	22%	20%	18%	16%
	100%	100%	100%	100%	100%	100%	100%	100%

Table 8A.8 Industrial DSM Proportions (%)

Commercial DSM Allocation (%)	2015	2020	2025	2030	2035	2040	2045	2050
Commercial	70%	70%	70%	69%	69%	69%	69%	69%
All Other Power Class Load - Commercial	18%	18%	19%	19%	20%	20%	20%	21%
Reseller - commercial	12%	12%	12%	11%	11%	11%	11%	11%
	100%	100%	100%	100%	100%	100%	100%	100%

Table 8A.9 Commercial DSM Proportions (%)

Residential DSM Allocation (%)	2015	2020	2025	2030	2035	2040	2045	2050
Residential	62%	64%	66%	68%	70%	72%	74%	75%
Farms	25%	24%	22%	21%	20%	18%	17%	16%
Resellers - residential	13%	12%	11%	11%	10%	10%	9%	9%
	100%	100%	100%	100%	100%	100%	100%	100%

Table 8A.10 Residential DSM Proportions (%)

Table 8A.11 shows how those savings are allocated across the customer categories for the *Greening the Grid* scenario.

Year	2015	2020	2025	2030	2035	2040	2045	2050
Potash, Northern Mining & Pipeline	0	1009	436	1427	1546	1698	1874	2077
All Other Power Class Load - Ind	0	455	183	568	583	615	650	686
All Other Power Class Load - Comml	20	29	35	40	42	45	47	50
Oilfields	0	545	226	651	605	578	553	529
Commercial	78	110	131	144	150	155	160	165
Residential	13	41	78	121	140	153	168	184
Farms	5	15	26	37	39	39	39	39
Resellers - residential	3	8	14	20	21	21	21	22
Reseller - commercial	13	19	22	24	24	25	25	25
Total	132	2230	1151	3032	3149	3329	3537	3777

Table 8A.11 Illustrative DSM Savings in the *Greening the Grid Scenario* (GWh)

As a note, the one downfall of this approach is that line loss is not adjusted to account for DSM. I treat line loss as part of electricity demand and DSM as part of electricity supply. If the two were to be made interactive the model would become non-linear and would be more difficult to solve, especially in Excel. Allowing DSM to effect line loss would, however, meant that the benefits of DSM would be amplified. This could be an avenue for future model improvement.

Step 7 – Calculate Required Rate

The next step is to divide the total cost responsibility for each customer category by the net demand for each category,

$$Eq. 8A.2\ \ Required\ Rate_{c,t} = \frac{Total\ Cost\ Responsibility_{c,t}}{Net\ Demand_{c,t}}.$$

This required rate is the rate that SaskPower would have to charge in order to recoup their costs. It is differentiated based on different responsibilities for line loss, and transmission and distribution costs.

Step 8 – Add Return on Equity Target

The required rate only just meets costs, but SaskPower does aim for a return on equity of 8.5% in the long-term. I multiply required rates for each customer category and time-step by 1.085 to reflect this return on equity target.

Step 9 – Applying a Peaking Penalty

Table 8A.12 displays representative electricity rates for SaskPower customer categories.

Customer Category	Monthly Fixed Charge	Energy Cost (cents /kwh)	Normalized (Potash = 1.0)	Rate Category	Size (kV)
Potash, northern mining and pipel	$7,081	5.4	1.0	E25	230 kv
Other Power customers*	$215	6.4	1.2	E07	25 kV and <
Oilfield*	$55	6.7	1.2	E43	72 kV
Commercial*	$28	12.1	2.2	E75	
Residential (urban)	$20	12.6	2.3	E01	
Farm*	$31	11.2	2.1	E34	
Reseller (Saskatoon)*	$13,000	4.1	0.7	E33	138 kV

*Monthly fixed charge increases per kVa demand

Table 8A.12 Representative Electricity Rates

Commercial, residential and farm customers pay energy costs (cents/kWh) roughly twice that of the large power customers. Part of the higher energy cost payment is due to the contribution commercial, residential and farm customers make to peak demand. In order to arrive at a rate schedule roughly equivalent to the SaskPower schedule I charge peaking penalties to commercial, residential, farm, and other power customers. The peaking penalties are as follows:

- Commercial – 42.5%
- Residential – 50%
- Farm – 34%
- Other power customers – 19.5%

The peaking penalties are held constant from 2015-2050 when analyzing likely rate impacts. These peaking penalties make the required rate in the 2015 time-step roughly equal to the representative rates outlined in Table 8A.12. Illustrative required rates for the SaskPower BAU scenario from Chapter are presented in Table 8A.13.

Year	2015	2020	2025	2030	2035	2040	2045	2050
Potash, Northern Mining & Pipeline	63	83	106	112	122	131	137	138
All Other Power Class Load	76	99	127	135	147	158	165	166
Oilfields	78	98	121	129	140	152	158	158
Commercial	135	163	197	215	234	254	263	263
Residential	140	171	206	225	245	266	275	276
Farms	125	152	184	201	219	237	246	247
Resellers	64	83	106	116	126	135	141	142
Corporate	51	69	91	96	104	111	117	117

Table 8A.13 Expected Electricity Rates in SaskPower BAU Scenario ($/MWh)

Appendix 9A – Post-Workshop Survey

Opportunities and Barriers for
Renewable Energy and Energy Conservation in Saskatchewan

Post-Workshop Survey

Thank-you for participating in the energy-modelling workshop focused on 'Opportunities and Barriers for Renewable Energy and Energy Conservation in Saskatchewan.'

Please answer the 6 questions below to the best of your ability. This workbook should take approximately 10 minutes to complete.

For comparative purposes with our earlier survey responses please indicate your name:

Name: ____________________________

Note that your response will not be attributed to you personally.

Thank-you,
Brett Dolter
PhD researcher
York University

Question 1 - Renewable electricity generation technologies include: biomass, hydroelectric, solar photovoltaic, solar thermal, and wind generation. In 2014, renewables supplied 23% of Saskatchewan's electricity demand with hydroelectricity providing 20%, wind providing 3%, and small contributions from solar photovoltaics and biomass.

What is the maximum proportion of Saskatchewan electricity that renewables can supply in the medium-term (i.e. by 2030-2035)?

Insert Response Here (%): ________________________

Question 2 - What is the maximum proportion of Saskatchewan electricity that renewables can supply in the long-term (i.e. by 2045-2050)?

Insert Response Here (%): ________________________

Question 3 – Has your response changed from the earlier survey?

YES / NO / UNSURE

If yes, why?

Question 4 – Have you learned anything new from this workshop? (Please circle one)

YES / NO / UNSURE

Please explain:

Question 5 – Did you enjoy the experience of interacting with others in this workshop setting?

YES / NO / NEUTRAL

Comments:

Question 6 – Please indicate with a checkmark which of the following are **VERY IMPORTANT** barriers for increasing renewable energy and energy conservation in Saskatchewan:

___ **Cost**: The price of renewable electricity is too high.

___ **Feed-in-Tariff**: Saskatchewan does not pay preferred rates for renewable power.

___ **Grid design**: The Saskatchewan grid is not optimized for renewables.

___ **Job loss**: A focus on renewables will lead to lost jobs in the coal-power industry.

___ **Intermittency**: Renewables cannot provide reliable electricity.

___ **Physical limits**: Saskatchewan lacks adequate hydro, solar, wind resources.

___ **Political will**: Political leaders in Saskatchewan have not prioritized renewables.

___ **Preference for coal**: SaskPower has a preference for coal-fired generation.

___ **Public ownership**: A private market would increase renewables more quickly.

___ **Social acceptance**: People do not want to live near renewable energy generation.

___ **Other:** ______________________________

___ **Other:** ______________________________

General Comments:

Thank-you for your time and participation! I look forward to sharing the results of this project with you!

Best wishes,
Brett

Appendix 9B – Workshop Script

Workshop Outline

Session I – Introduction & Context: 1:00 p.m. – 2:30 p.m.

1:00-1:30 – WELCOME, INTRODUCTIONS, GROUND RULES

Points to Convey

- ***Thank-you | Grateful for time***
- ***Introduce myself | As many of you know, I'm Brett Dolter, I'm the PhD student who invited you to this meeting.***
- ***Introduce Scott | I'm joined today by Scott Fulton our facilitator for the day.***
- ***Round Table | Before we get started I'd just like to do a round table so let's go around the room and please state your names and your affiliation if you'd like to state it***
    - ***ROUND TABLE***
- ***Great – we have a lot of expertise around the table. We're going to have a great session.***
- ***Big Picture | We are at a seminal moment in climate change policy.***
    - ***BRETT – spell out climate policy context***
        - ***To achieve 2DS we need to stop the growth of GHGs and reduce to near-zero by 2050;***
        - ***It will take a heroic effort to achieve it. Some have likened the task to a second 'moon-shot'.***
        - ***This time the goal is to transition away from fuels that release GHGs to the atmosphere.***
        - ***Renewable energy such as: hydroelectricity, wind, solar, and biomass offer the potential to decarbonize the electricity grid.***
        - ***In my research project I am seeking to understand the costs, barriers, opportunities, and trade-offs involved in pursuing a renewable energy pathway to a low-GHG future.***
- ***There Are Three Objectives for Today |***
    1. ***I've invited you here today to <u>ground-truth</u> the models I've created.***
        - ***You have been invited to this workshop because you have expertise on the Saskatchewan electricity system. Your participation will help to ensure that the results of this research are valid and useful for the Saskatchewan public, and, I hope, SaskPower.***
        - ***"Models are a way of disciplining our thinking." I want to test the assumptions and the structure of the models I've created.***
    2. ***Use the Models to <u>Create A Sunny skies, Winds of Change scenario</u> for renewable energy in Saskatchewan. Goal is to leave here with clear***

scenarios in our minds that provide a picture of a renewable energy future and a roadmap of how we would get to that future.

3. ***In the process Develop a shared understanding of the opportunities, costs, technical barriers, and environmental impacts of increasing the amount of renewable energy generated in the province***
    - ***I've invited participants with diverse perspectives to the meeting so that we can learn from each other.***
    - ***We can take that learning back to our respective professional worlds.***

- ***SCOTT | FACILITATION INTRODUCTION I'm Scott Fulton. I'm a teacher and educator. My role today is to host the conversation, and ensure that everyone has the chance to participate, and that we move through the agenda and stay on time so that we can all leave on time.***
    - ***Do I have everyone's permission to intervene to ensure everyone has the opportunity to speak and to keep the conversation moving?***
    - ***Also – there will likely be different perspectives on the table today. They are all welcomed. We can disagree without being disagreeable.***
- ***BRETT | GROUND RULES FOR HOW INFORMATION IS USED***
    - ***Here are some ground rules:***
        - ***To encourage people to speak freely I'd like us all to recognize that what is said today is not to be interpreted as the official position of any of the organizations present.***
        - ***Basically, what is said in the room stays in the room, or at least is not attributed to any individual or organization.***
            - ***Do I have agreement on that?***
    - ***We'll be recording the session using audio and visual equipment. This is a way to take notes so the discussion can inform my dissertation.***
    - ***I've asked everyone to sign a consent form to participate in the workshop. If you haven't signed one please do so now. There is a clause at the back that states I will not release footage or audio of any participant without following up to again ask for written consent.***
    - ***With that I'd like to encourage everyone to bring curiousity, a willingness to listen, and creativity to the tasks ahead.***
- ***ICEBREAKER***

1:30-2:00 – HISTORY AND CONTEXT

- ***BRETT |*** I want to walk you through some of the history of the Saskatchewan electricity system so we understand where we are today, how we got here, and some of the challenges for the future.
- ***PRESENTATION***

A Walk Through History

- Saskatchewan's electricity system began in **municipalities**. Towns and cities built power plants to provide street lighting to residents. These were run on a '**moonlight basis**', which means they were only turned on at night when the moon was not expected to shine.
- When the potential for electricity to transform Saskatchewan society became evident there were calls for rational development of the system.
- The **Saskatchewan Power Commission was created in 1929** to work to coordinate and consolidate the Saskatchewan electricity system.
- With a centralized electricity system the Saskatchewan Power Commission could exploit '**Cheap, lignite coal'** in South-eastern Saskatchewan and hydroelectric potential along the Saskatchewan River system.
- The Depression crushed demand for electricity. Demand only began to grow again leading into World War II. But Wartime rationing kept the system from expanding.
- Rapid and exponential growth of the electricity system began in the late 1940s and 1950s.
- In **1949 the Saskatchewan Power Commission became the Crown Corporation we now call SaskPower.**
- SaskPower's immediate task was to bring **electricity to rural Saskatchewan**. In the 1952 election Tommy Douglas had promised to electrify 40,000 new farms. This was a huge challenge for SaskPower.
- [READ QUOTE]
- Rural electrification was a success and Tommy Douglas called it his greatest achievement as Premier (greater than introducing Medicare to Canada)
- I think it is a useful **historic lesson for two reasons**:
    - 1. It shows great change is possible
    - 2. It shows how political promises and government policy can influence SaskPower's business
- SaskPower continued to **promote load growth** in the 1950s, hiring people like Lillian McConnell to speak as "Penny Power" educating Saskatchewan citizens about the virtues of electricity.
- She appears to have been successful [Point to load growth graph]
- In 1965 SaskPower's first hydroelectric facility was commissioned: E.B. Campbell.
- This was good news for most of the province, but did have impacts on the people of Cumberland House downstream from the dam. [QUOTE]
- 1965 was also the year that Regina City Council agreed to let SaskPower sell and distribute electricity in the city.
- Regina was the last brick on the wall of creating a centralized electricity system in Saskatchewan.
- Centralization lowered costs and allowed power created by 'cheap, lignite coal' and hydroelectricity to be transmitted around the province.

- The **1960s were the golden age** of power production in the province, and across North America: demand was increasing, revenues and profits were rising, all was well.
- The **1970s were a more difficult period**. The energy price shocks of the early 1970s led to inflation, making large capital projects like power plants more expensive.
- It was at this time that **Penny Powers became a Penny Pincher** and SaskPower shifted its focus from load promotion **to energy conservation**. Energy conservation could allow large capital projects to be deferred.
- To combat inflation, **interest rates** were increased. They reached a peak in the early 1980s. This meant that **financing charges** skyrocketed creating difficulties throughout the 1980s. By 1989 SaskPower's debt had reached $2 billion dollars.
- The Progressive Conservatives planned to sell SaskEnergy to help pay off the debt. Privatization was now a clear threat for SaskPower.
- The late 1980s were also a time of increasing environmental awareness. SaskPower was caught in the thick of this with the proposed **Rafferty-Alameda dam.**
- The dam was given a federal government green light without an environmental assessment. The **Canadian Wildlife Federation** took the federal government to court and asked them to enforce their own guidelines for environmental assessment. The Wildlife Federation won their case, even though construction had started on the dam. Rafferty-Alameda now stands as a historic precedent in environmental law.
- It was in the 1990s that climate change concerns began to gain prominence. SaskPower recognized they would need to reduce their emissions in the future. By the late 1990s SaskPower began to diversify their operations, partnering to build a **cogeneration** plant at Lloydminster. The Corey Potash mine soon followed.
- The first **wind projects**: SunBridge and Cypress were completed in the early 2000s, and the 150 MW Centennial wind farm was put in place in time for the Centennial.
- Demand growth in recent years has been met with **natural gas simple-cycle** turbines, and **combined cycle plants** with some additions of wind to help reduce natural gas bills.
- There are challenges ahead.
  - o The federal government has introduced regulations on coal-fired electricity that require coal plants to be retired or retrofit to achieve a standard of 420 grams CO2e/kwh.
  - o Much of the SaskPower fleet is aging and is scheduled to retired in the next 15 years.
  - o Demand is still growing.
- So now in this workshop we'll explore opportunities for renewable energy and energy conservation to help meet those challenges.
- ***INFORMATION IN:***
  1. ***Comments? Reactions? Anything Surprising? Anything missing?***
  2. ***If there is anything missing let me know and I'll add it to the timeline using a sticky note.***

2:00-2:30 – INTRODUCE THE MODEL & EXAMINING THE ASSUMPTIONS

- ***BRETT | We've talked about the past, now we're going to look towards the future. In order to do that we're going to use modelling as a tool.***
- ***MODELLING 101***
  - ***Some people in the room are better modellers than me. If you have reflections please contribute. Here is a little modelling 101.***
  - ***What is a model?***
    - ***Partial representation of reality***
    - ***We choose what to include, what to exclude***
  - ***What can a model do?***
    - ***"Models are tools for disciplining our thinking"***
  - ***What can a model not do?***
    - ***"All models are wrong. Some models are useful."***
- ***SASKATCHEWAN INVESTMENT MODEL***
  - ***Today we're focusing on a model to decide what generation technologies to invest in in order to meet electricity demand by 2050.***
  - ***In technical terms the model is a linear programming optimization model. The goal is to minimize the cost of generating electricity in Saskatchewan subject to constraints:***
    - ***Constraint 1 – electricity supply must meet demand***
    - ***Constraint 2 – firm, dispatchable capacity must be available to meet peak demand***
    - ***Supply Constraints:***
      - ***biomass potential limited to 300 MW***
      - ***in most runs wind limited to 20% of electricity generation***
      - ***hydro limits and increasing costs***
- ***WORKBOOK***
  - ***A model is only as good as the assumptions that go into it. I want to draw upon the expertise in the room to test the assumptions that have gone into this model.***
  - ***There are three important areas I'd like feedback on:***
    - ***Costs: capital costs now and in the future, fuel costs***
    - ***Demand forecast & conservation potential: how much will demand grow into the future? What is possible for energy conservation?***
    - ***Renewable energy potential: how much biomass, hydro, wind, solar is possible?***
  - ***We're going to break into three groups. One group for each focus area.***
  - ***Please take 5 minutes to work through the workbook on your own and then you'll have 10 minutes to discuss your thoughts as a group.***
  - ***I'll then ask for one person from each group to provide a 5-minute report on the discussion.***
  - ***I'm also going to keep these recorders running in the groups so that I can go back and track the input I've received.***
  - ***I'll take this input and use it to improve the model.***

BREAK 2:30 – 2:45

- ***SCENARIOS – 2:45 – 3:45***
    - ***Lisa White surveyed a group of experts in her research and they recommended a renewable energy pathway.***
    - ***I'd like to flesh out what this renewable scenario looks like. We're going to create three new groups – I'd like members of the first groups to spread themselves around, so that each new group has representatives from the former groups.***
    - ***Each group is going to build a scenario for a renewable energy future.***
        - ***Select which technologies to build, their quantities***
    - ***Survey response notes: there are different perspectives on what is possible so each group can create two scenarios:***
        - ***An ambitious 'sunny skies' or 'winds of change' scenario with a high penetration of renewable energy***
        - ***A moderate scenario with some penetration of renewables***
    - ***As individuals you may disagree about which is most likely or best, but the question to ask is:***
        - ***What would have to be true in order for this scenario to be preferred?***
        - ***For example, perhaps the ambitious scenario is only possible if we achieve low-cost electricity storage.***
        - ***Please track these caveats.***
    - ***I'll move around to each group and input these scenarios into the model so we can test them for their performance in terms of cost, GHGs, and other environmental indicators. Points for low-cost, low-GHG scenarios.***
    - ***At the beginning of the session please select a person in your group to report back to the group. At the end I'll ask a representative from each group to present the scenarios the group has created.***
    - ***MODEL on the screen:***
        - ***Here are the areas for entry into the model***
            - ***Change demand growth rates***
            - ***Change cost inputs***
            - ***Plan investment path***
        - ***Here are the ways to see what the model has created***
    - ***SCOTT – [moving around the room, sitting in and listening, making sure that everyone has a chance to be heard.]***

- ***REPORT BACK – 3:45 – 4:15***
    - ***Let's have a reporter from each group. Each reporter has 5 minutes to present the scenario. We'll have ten minutes of discussion at the end.***
    - ***I'll take these scenarios away and test them in the 'Will It Run Electricity Model'.***

- ***OPPORTUNITIES AND BARRIERS 4:15 – 4:45***

- *[Start: SCOTT ensure everyone has a sticky-note pad and a sharpie]*
- *RECAP:*
  - *We've talked about the assumptions going into the model*
  - *We've talked about scenarios for the future*
  - *Now let's talk about how we could make them real.*
- *In the survey I asked what the barriers were to more renewable energy in the province. The barriers people identified as most important were: x,y,z. I've listed all of those barriers on the wall here.*
- *You're going to use the sticky notes to add to the list of barriers and to also create a list of opportunities to overcome the barriers. For example, the Cowessess wind and storage project is showing how wind power might be made less variable.*
- *We can also talk about opportunities outside the discussion of barriers. The FNPA has created an opportunity to expand renewable energy in the province in partnership with First Nations. Renewable energy here is an opportunity for inclusion of First Nations in the Saskatchewan economy.*
- *Take 5 minutes and come up with as many barriers and opportunities as you can think of.*
  - *Barriers are XX colour*
  - *Opportunities to overcome barriers are XX colour*
  - *[Facilitators – grab and post, encouraging them, reading them].*
- *I see a few people here mentioned XX, did someone who put that up want to explain it?*
- *Organize into themes. Conversation by theme.*

- *THANK-YOU 4:45 – 5:00*
  - *Thank-you so much for your time. There is a quick survey I'd like you to fill out before you leave.*
  - *There are a tremendous number of great ideas put on the table today.*
  - *Here are some I'm going to take away:*
    - *NOTE THINGS I'VE HEARD*
  - *I'm going to use this input to improve the model. I'll share the results with you when I've incorporated your input.*
  - *I just want to thank-you for this fantastic session. I think everyone deserves a round of applause. [start clapping]*
  - *[SCOTT and I will start handing out the surveys]*

Introduction

This workbook is designed to provide:

1. Information on how the model was created, and
2. An opportunity for you to contribute to the model.

The model you will interact with today is a linear programming optimization model built in Excel.

The model is used to determine the **least-cost** means of producing electricity in Saskatchewan.

The model is shaped by **constraints**, including the constraint that the supply of electricity must equal demand.

The model solves by selecting **investments** in five-year planning periods to 2050.

1.0 Costs

Costs are key inputs to the economic model. Generation technologies differ with respect to the following costs:

- **Capital cost**: cost of building new generation facilities measured in $CDN per kilowatt ($/kw)

- **Fixed Operations & Maintenance (FOM) cost**: annual fixed cost of operating generation facilities measured in $CDN per kilowatt per year ($/kw/yr)

- **Variable Operations & Maintenance (VOM) cost:** cost of operating facilities and repairing wear-and-tear based on electricity output, measured in $CDN per Megawatt-hour ($/MWh)

- **Fuel use and efficiency:** thermal generation uses coal or natural gas.

1.1 Capital Costs

Cost data was taken largely from the U.S. Energy Information Agency (EIA). The EIA (2015) provides data on current and expected costs of electricity generation technologies in 2040.

The EIA (2015) costs were compared to Saskatchewan and Canadian published reports of the costs of recent Saskatchewan and Canadian projects. A **Saskatchewan multiplier** was calculated to reflect differences between EIA costs and Saskatchewan achieved costs.

In this model, costs change over time according to a pre-set rate. I call this the **cost improvement rate**.

Explore the implications of changing cost parameters in the worksheet: '1.0 *Cost Tables*.' Record revisions in Table 1b.

Capital cost parameters	EIA 2015 Capital Cost ($/kw)*	Sask Multiplier	Cost Improv-ment (%)	Sask Cost ($/kw)
Biomass	3,641	1.87	1.16%	8,409
New coal scrubbed	2,903	1.82	0.94%	6,524
Adv Pulverized Coal with CCS	6,460	1.82	0.54%	14,520
Natural gas combined cycle	1,012	2.60	1.15%	3,249
Natural gas simple cycle (peaking)	963	1.81	0.92%	2,153
Natural gas CCS	2,062	2.60	1.50%	6,620
Hydro	2,638	2.38	0.37%	7,754
Wind	1,970	0.90	0.87%	2,190
Solar - Photovoltaic	3,263	1.48	1.25%	5,964
Solar - Thermal	4,032	1.48	1.26%	7,370
Small Modular Nuclear Reactor	6,380	1.90	2.02%	14,970
Electricity Storage	2,500	1.00	1.50%	3,088

**All costs in 2012 CDN dollars*

Table 1a – Existing Capital Cost Parameters

Capital cost parameters	Initial Capital Cost ($/kw)	Sask Multiplier	Cost Improvement Low (%)	High (%)
Biomass				
New coal scrubbed				
Adv Pulverized Coal with CCS				
Natural gas combined cycle				
Natural gas simple cycle (peaking)				
Natural gas CCS				
Hydro				
Wind				
Solar - Photovoltaic				
Solar - Thermal				
Small Modular Nuclear Reactor				
Electricity Storage				

Table 1b - Suggested Capital Cost Parameter Revisions

Figure 1 shows the impact of changing the cost improvement factor on the capital cost ($/kw) of solar photovoltaic (PV).

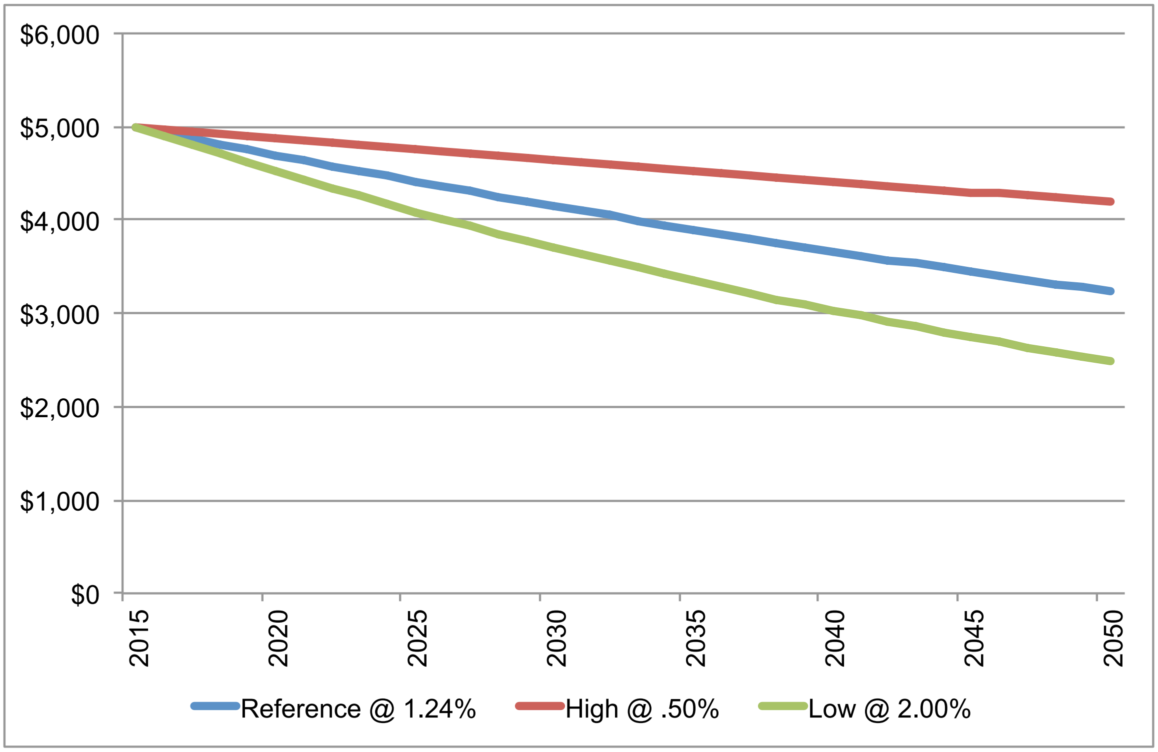


Figure 1 – Solar-PV Capital Cost Improvement

Costs decrease according to the following equation:

$$Capital_t = Capital_0 * (\exp(-CI * t))$$

Where t indicates time and CI is the cost improvement.

The **Saskatchewan multiplier** is based on the following projects.

Name	Type	Size (MW)	Cost ($M current)	Dollars
Boundary Dam III	Coal CCS	110	$1,467	2014
Queen Elizabeth Repowering	Combined cycle	170	$514	2014
North Battleford Generating Station	Combined Cycle	260	$700	2013
Spy Hill	Simple-cycle	86	$150	2012
Yellowhead	Simple-cycle	138	$250	2011
Ermine	Simple-cycle	94	$150	2008
Chaplin	Wind	177	$355	2014
Morse	Wind	23	$81	2014
Red Lily	Wind	26.4	$69	2011
Tasi Twe	Hydro	50	$400	2015
Ontario Power Generation RFP	Nuclear	2400	$26,000	2009

Figure 2 - Saskatchewan Project Costs

Explore the Saskatchewan multipliers in the worksheet: "1.0 *Sask Multiplier*." Record your revisions in Table 1b above.

Record revisions for Fixed O&M and Variable O&M costs, learning rates, and Saskatchewan multipliers in Tables 2b (Fixed) and 3b (Variable) below.

Fixed O&M Parameters

Table 2a - Existing Fixed O&M Cost Parameters

Fixed O&M cost parameters	**EIA 2015 FOM Cost ($/kw)***	**Sask Multiplier**	**Cost Improv-ment (%)**	**Sask Cost ($/kw/yr)**
Biomass	105	1.0	-0.06%	105
New coal scrubbed	31	1.0	-0.10%	31
Adv Pulverized Coal with CCS	72	1.0	-0.43%	72
Natural gas combined cycle	15	1.0	0.00%	15
Natural gas simple cycle (peaking)	7	1.0	-0.15%	7
Natural gas CCS	32	1.0	-0.10%	32
Hydro	15	1.0	-0.37%	15
Wind	39	1.0	-0.06%	39
Solar - Photovoltaic	25	1.0	-0.57%	25
Solar - Thermal	67	1.0	-0.07%	67
Small Modular Nuclear Reactor	34	1.0	-0.07%	34
Electricity Storage	15	1.0	0.00%	15

**All costs in 2012 CDN dollars*

Table 2b - Suggested Fixed O&M Cost Parameters

Fixed O&M cost parameters	**Initial 2015 FOMI Cost ($/kw/yr)**	**Sask Multiplier**	**Learning Rate Low (%)**	**Learning Rate High (%)**
Biomass				
New coal scrubbed				
Adv Pulverized Coal with CCS				
Natural gas combined cycle				
Natural gas simple cycle (peaking)				
Natural gas CCS				
Hydro				
Wind				
Solar - Photovoltaic				
Solar - Thermal				
Small Modular Nuclear Reactor				
Electricity Storage				

Variable O&M Parameters

Variable O&M cost exogenous parameters	EIA 2015 VOM Cost ($/kw)*	Sask Multiplier	Cost Improv-ment (%)	Sask Cost ($/kw/yr)
Biomass	5.23	1	0.001	5.23
New coal scrubbed	4.45	1	-0.001	4.45
Adv Pulverized Coal with CCS	8.40	1	0.005	8.40
Natural gas combined cycle	3.25	1	-0.013	3.25
Natural gas simple cycle (peaking)	15.36	1	-0.012	15.36
Natural gas CCS	6.75	1	-0.013	6.75
Hydro	5.73	1	-0.006	5.73
Wind	0.00	1	0.000	0.00
Solar - Photovoltaic	0.00	1	0.010	0.00
Solar - Thermal	0.00	1	0.000	0.00
Small Modular Nuclear Reactor	11.29	1	-0.003	11.29
Electricity Storage	0	1	0.000	0.00

**All costs in 2012 CDN dollars*

Table 3b - Suggested Variable O&M Cost Parameters

Variable O&M cost parameters	Initial 2015 VOM Cost ($/MWh)	Sask Multiplier	Cost Improvement Low (%)	High (%)
Biomass				
New coal scrubbed				
Adv Pulverized Coal with CCS				
Natural gas combined cycle				
Natural gas simple cycle (peaking)				
Natural gas CCS				
Hydro				
Wind				
Solar - Photovoltaic				
Solar - Thermal				
Small Modular Nuclear Reactor				
Electricity Storage				

2.0 Fuel Prices

There are two important fuel prices in this model: natural gas and coal.

Natural gas prices to 2035 are taken from the National Energy Board reference forecast for SK industrial buyers (NEB, 2013). The NEB forecast is extended to 2050 using the 2030-2035 growth rates.

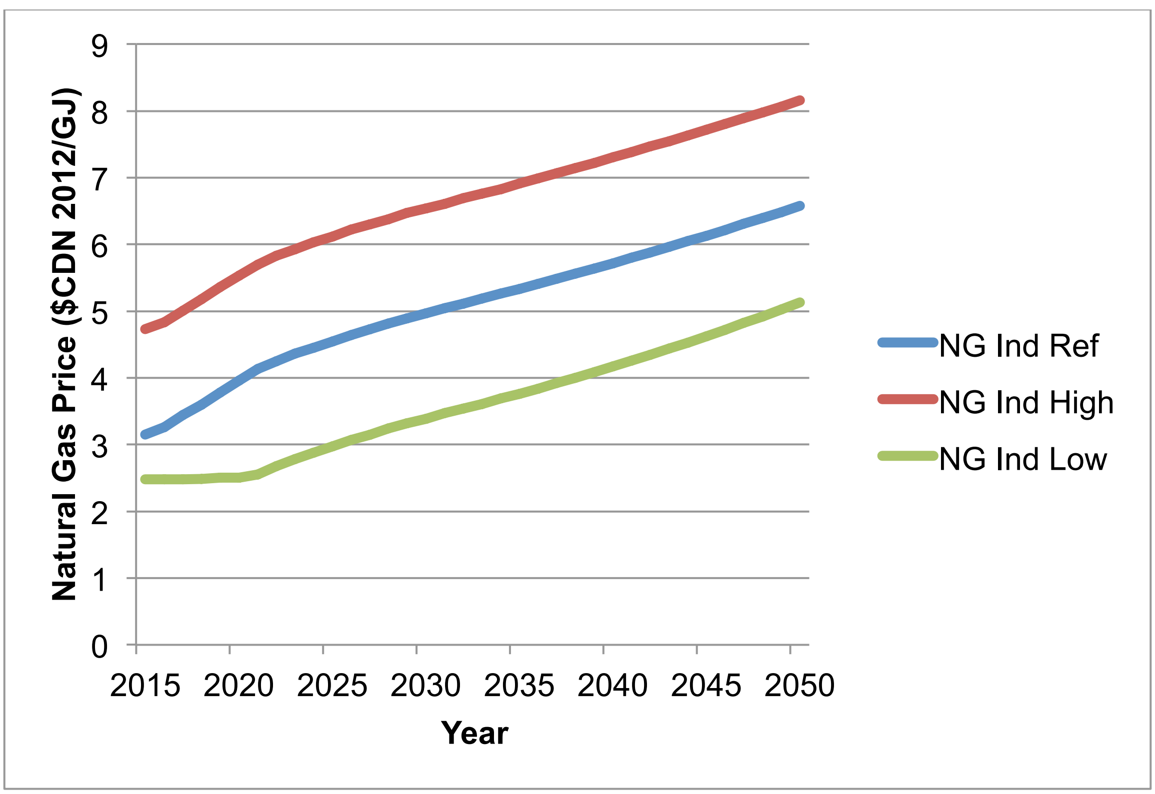


Figure 3 – Natural Gas Price Forecasts (NEB, 2013; author's calculations)

Coal Prices are calculated using Westmoreland annual reporting. Two 2015 coal prices are listed in the worksheet ‘Fuel Prices’: $18.20/tonne and $22.51/tonne.

I assume these prices grow at a constant rate of 2% per year from 2015-2050.

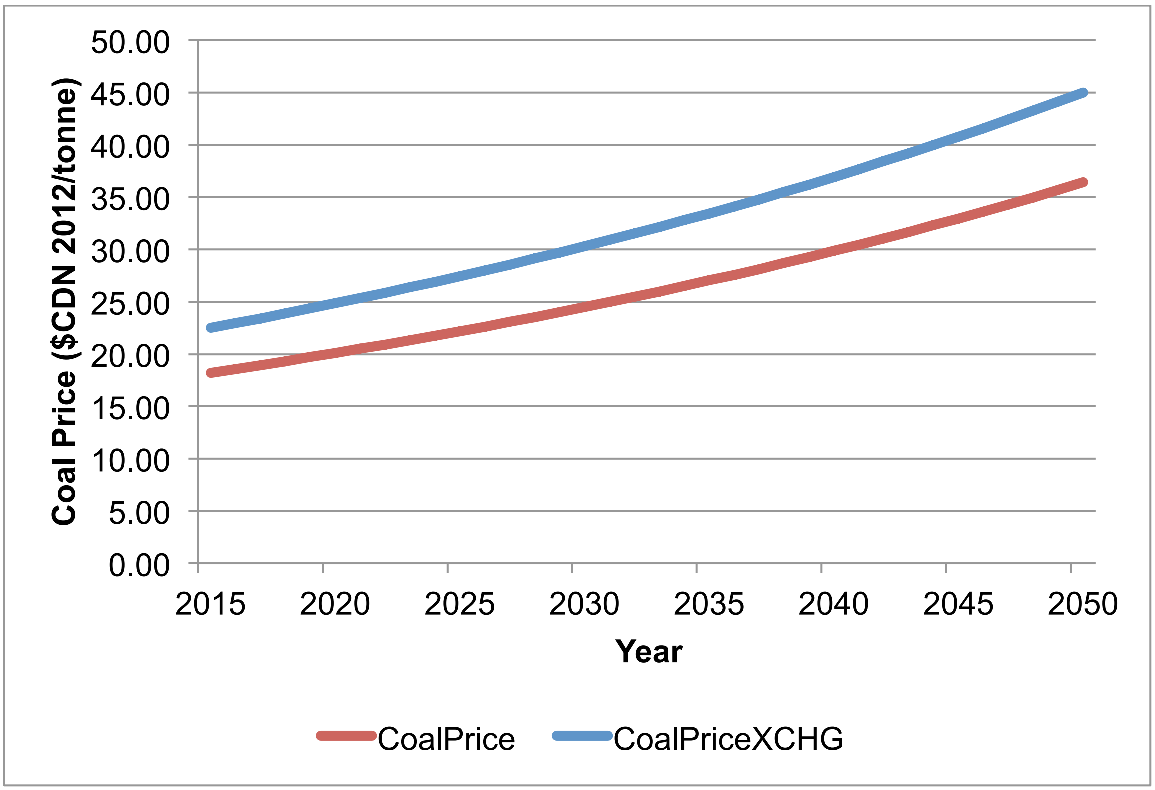


Figure 4 – Coal Prices
(Westmoreland 2014 Annual Report, author’s calculations)

Please answer the following three questions:

Q1. Which natural gas price forecast would you recommend using?

- O Reference
- O Low
- O High

Q2. What 2015 coal price would you recommend using?

- O $18.20
- O $22.51
- O Other ________________

Q3. What growth rate would you recommend using for coal price escalation?

- O 2%/yr
- O 1%/yr
- O Other ________________

3.0 Renewable Constraints

To reflect Saskatchewan's renewable energy potential and existing technical constraints and policy the following constraints have been introduced in the model:

1. Conventional **hydroelectricity** is limited to 1000 MW.
2. **Biomass** capacity is limited to 300 MW.
3. **Wind** generation is originally limited to 20% of total electricity generated in 2020. The wind generation constraint is allowed to grow 3% each 5-year investment period, reaching 38% by 2050.
4. Wind and solar generation does not contribute to firm capacity to meet peak demand.
5. **Electricity storage** must be paired with wind and solar to meet peak demand.
6. **Electricity storage** capacity cannot exceed 50% of wind & solar capacity.

7. Only 40% of **electricity storage** capacity contributes to meeting peak demand. This is based on some of the findings of the Cowessess wind project.

Please discuss these constraints and record suggested revisions below. When discussing each constraint it may be useful to ask:

"What conditions would have to hold true in order for this constraint to be valid?"

Discussion/Recommendations

Biomass:

Hydroelectricity:

Wind percentage:

Electricity storage treatment:

4.0 Demand Growth

I have created an electricity demand forecast to 2050 by extending the SaskPower 2014 Load Forecast to 2025 using annual growth rates.

You can create your own forecast by adjusting the growth rates in the worksheet: ‘4.0 Electricity Demand.’

The existing forecast is summarized in Figure 5 on the following page.

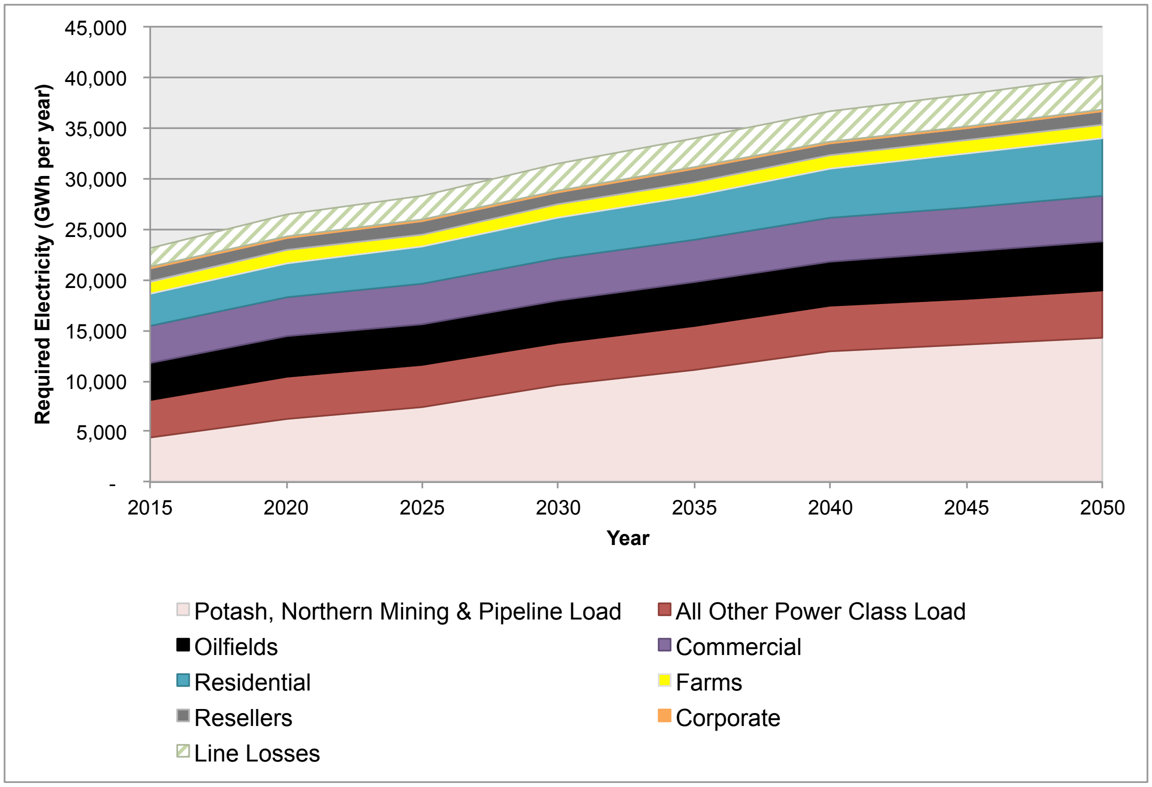


Figure 5 - Saskatchewan Electricity Load Forecast

Q4. Which description best characterizes the probability that this electricity load forecast will be realized? Please check the response that best fits.

- ○ Very likely (80-100%)
- ○ Somewhat likely (55-79%)
- ○ Equally likely and unlikely (46-54%)
- ○ Somewhat unlikely (21-45%)
- ○ Very unlikely (0-20%)
- ○ Within the probable range of future demand, but cannot attach a probability
- ○ Uncertain - do not want to hazard a guess

Q5. How would you improve upon this forecast? Please answer in the space provided below. You can also save preferred growth rates in the excel file.

5.0 Energy Conservation

ICF Marbek completed a 'Conservation Potential Review' for SaskPower in 2011. Summaries of their findings for the residential, commercial, and industrial sectors are included in worksheet: '*5.0 ICF-Marbek CPR'* and in Figure 6.

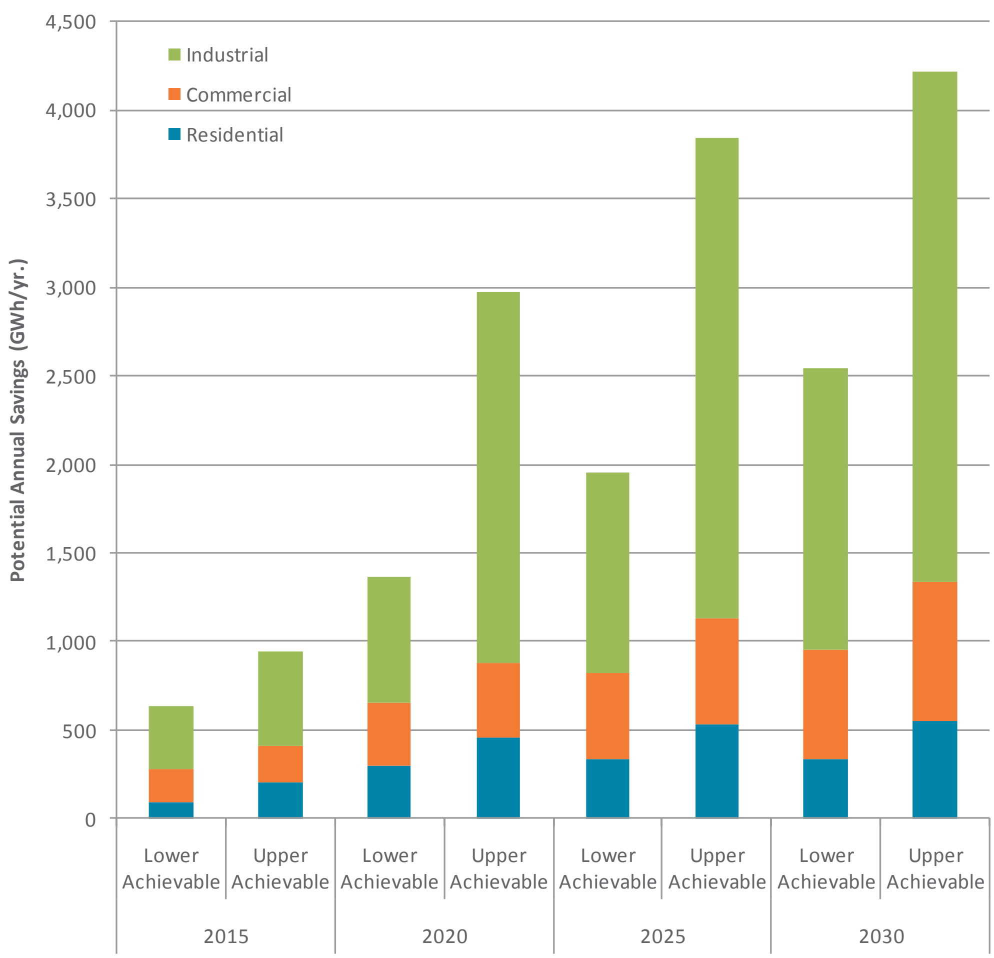


Figure 6 – Sask Conservation Potential

To understand the costs of undertaking energy conservation in Saskatchewan I looked to the Ontario Conservation Potential Review (CPR) also written by ICF-Marbek. The Ontario documents provide cost information including the expected program costs that would be spent to achieve certain levels of energy conservation.

I used the Ontario cost data and scaled it to match the Saskatchewan conservation potential. I then estimated a linear relationship between electricity savings and program costs. Figures 7-9 summarize the relationships.

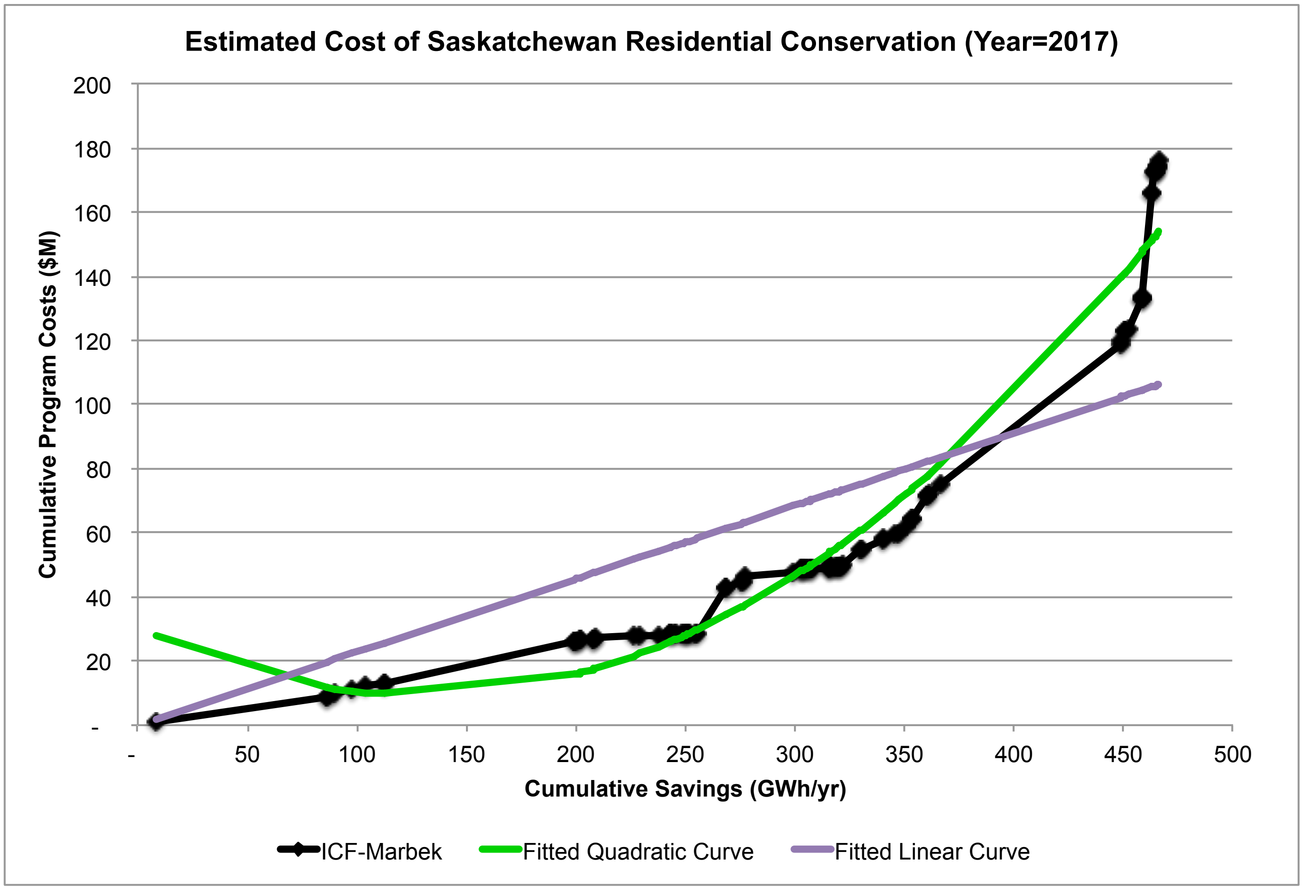


Figure 7 – Residential DSM Program Costs

About Figure 7:

- The slope of the purple line is .23 meaning a program cost of $230,000/GWh saved;
- I assume DSM savings last for 5 years before expiring.

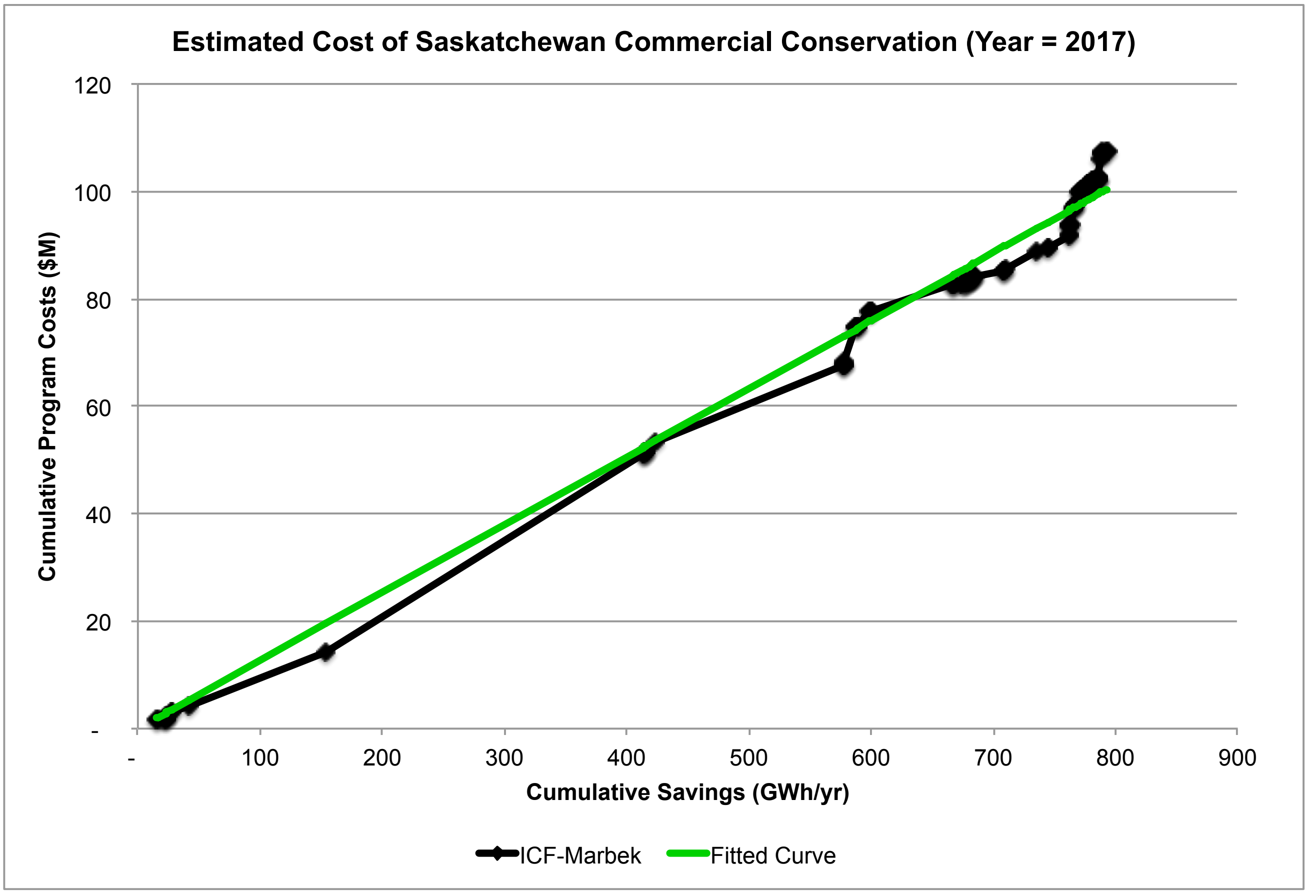


Figure 8 – Commercial DSM Program Costs

About Figure 8:

- The slope of the green line is .13 meaning a program cost of $130,000/GWh saved;
- I assume DSM savings last for 5 years before expiring;
- DSM potential in each period is limited by the upper potential outlined in ICF-Marbek (2011) for SaskPower;
- Upper potential grows over time allowing more energy conservation in future periods.

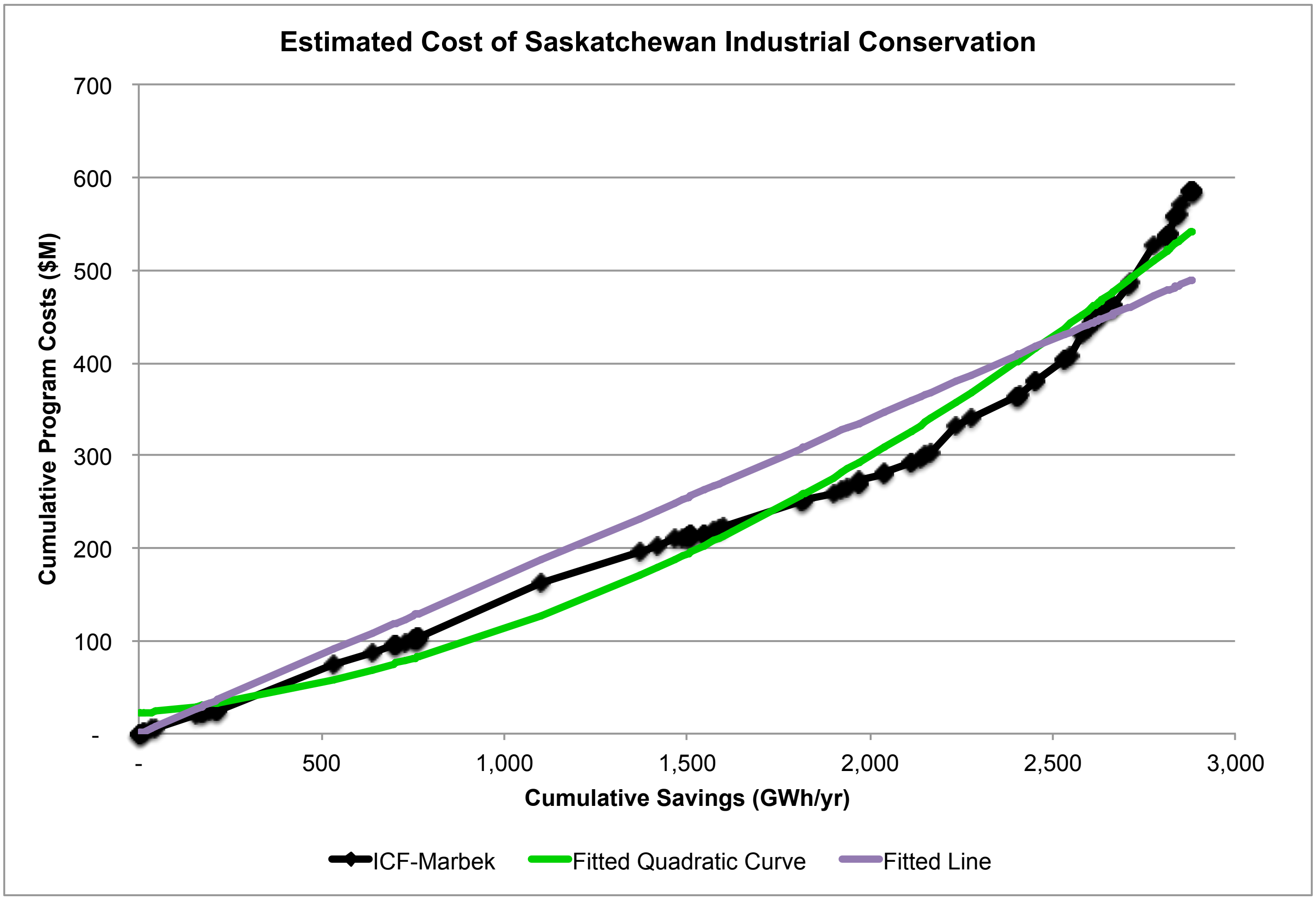


Figure 9 – Industrial DSM Program Costs

About Figure 9:

- The slope of the purple line is .17 meaning a program cost of $170,000/GWh saved;
- I assume DSM savings last for 5 years before expiring;
- DSM potential is limited by the potential outlined in ICF-Marbek (2011) for SaskPower.

In the ICF-Marbek reports, program costs per Gigawatt-hour saved begin to increase with higher energy conservation achievement. This reflects the need to pay more for incentives to encourage conserving actions.

To keep the model linear I used the upper technical potential numbers as hard constraints on the potential DSM in each investment period and kept the program costs constant over time.

Please consider the following questions:

Q6. Is it valid to draw upon Ontario's program costs when analyzing Saskatchewan's conservation costs?

Q7. Is it valid to use constant program costs up to a hard limit in each period?

Q8. Are the program costs ($/GWh saved) accurate? Note that they do not change over time. This assumes that 'low-hanging fruit' appears as quickly as we can 'pick it'.

Peak Demand Savings

Energy saved (measured in Gigawatt-hours) is converted into peak demand savings using different formulas for residential, commercial, and industrial savings. Conversion factors are highlighted in yellow in the worksheet: '*5.0 ICF-Marbek CPR'*.

The conversion factors were selected to calibrate to the ICF-Marbek relationship between GWh saved and peak demand shaved.

I assume that industrial peak demand reduction is half that of the ICF-Marbek report.

Q9. Is this a valid method of estimating peak demand reduction?

References for Appendix 9C

EIA (2015) *Assumptions to the Annual Energy Outlook 2014 – Electricity Market Module*.

EIA (2014b) *Assumptions to the Annual Energy Outlook 2014 – Appendix: Tables for 2040 (Table A5)*. Retrieved from: http://www.eia.gov/forecasts/aeo/pdf/appendix_tbls.pdf, Last accessed October 1, 2014.

ICF-Marbek (2011) SaskPower Conservation Potential Review Summary Report. Regina, SK: SaskPower.

ICF-Marbek (2010a) Achievable Potential - Residential Sector Final Report - Estimated Range of Electricity Savings Through Future Ontario Conservation Programs. Ontario Power Authority (OPA).

ICF-Marbek (2010b) Achievable Potential - Commercial Sector Final Report - Estimated Range of Electricity Savings Through Future Ontario Conservation Programs. Ontario Power Authority (OPA).

ICF-Marbek (2010b) Achievable Potential - Industrial Sector Final Report - Estimated Range of Electricity Savings Through Future Ontario Conservation Programs. Ontario Power Authority (OPA).

NEB (National Energy Board) (2013) *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*. Ottawa, ON: National Energy Board.

SaskPower (2014b) *2014 Load Forecast*. SaskPower Load & Revenue Forecasting. Regina SK.

Renewable Electricity in Saskatchewan

Pre-Workshop Survey

Thank-you for agreeing to participate in an energy-modelling workshop focused on 'Opportunities and Barriers for Renewable Energy and Energy Conservation in Saskatchewan.' This survey is being used to get a sense of the range of perspectives that will be present at the workshop.

Please answer the 8 questions below. This survey should take 10-12 minutes to complete.

Note that your responses will not be attributed to you personally and your identity will be kept in confidence. Your responses will be made anonymous and presented at the workshop along with the responses provided by the other participants.

Thank-you for your time,
Brett Dolter
PhD researcher
York University
brett.dolter@gmail.com

Renewable Electricity in Saskatchewan

Background

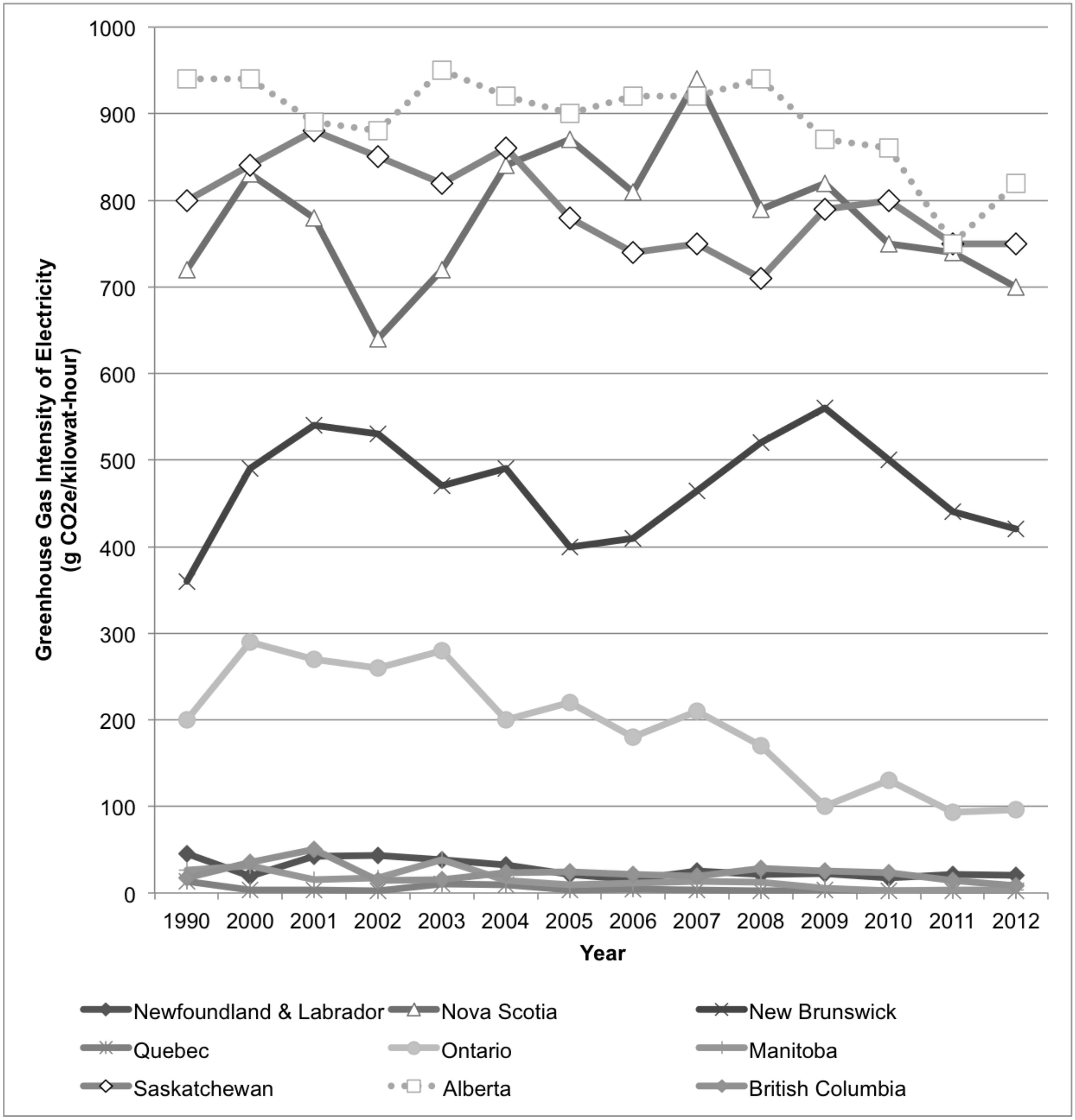
Global greenhouse gas emissions (GHG) must be reduced to mitigate climate change. In 2012, Saskatchewan's electricity sector released 15.8 Megatonnes (Mt) of carbon dioxide equivalent (CO_2e), which comprised 21.1% of Saskatchewan's GHG total (Environment Canada (2014) National Inventory Report Part III).

Saskatchewan's electricity sector has one of the highest GHG intensities of industries of its kind in Canada (see Figure 1 below). This intensity has been falling in recent years. SaskPower reports that the GHG intensity of Saskatchewan electricity was reduced to 660 grams (g) CO_2e/kwh in 2014 (SaskPower 2014 Annual Report, p. 49).

Canadian federal regulations will cause Saskatchewan's electricity GHG intensity to fall further. In 2014, 44% of electricity generated in Saskatchewan was from coal-fired plants. Federal electricity regulations require that coal-fired electricity plants achieve a GHG intensity of 420 gCO_2e/kwh if they are to continue operating at the end of their service life. A typical coal-fired plant has a GHG intensity of 800-1100 gCO_2e/kwh. Conventional coal plants must be either retired or retrofit with carbon capture and storage (CCS) to comply with the federal regulation. Coal-fired plants equipped with CCS are expected to have a GHG intensity of 100-150 gCO_2e/kwh.

In comparison, a combined cycle natural gas power plant typically has a GHG intensity of 436 gCO_2e/kwh. Renewables like hydroelectricity, solar, and wind generation do not emit GHGs during their operation. They do however contain embodied GHGs that are released during their manufacture and construction processes. Biomass plants release GHGs, but these are recaptured when the feedstock grows back (e.g. CO_2 is recaptured by growing trees). Nuclear reactors do not emit CO_2 during operation, but do embody GHGs released during the mining of uranium and construction and decommissioning of the plants.

Figure 1 - Provincial Electricity Sector GHG Intensities
(Source: Environment Canada National Inventory Report (2014) Part III)



Renewable Electricity in Saskatchewan

Question 1 - Long-Term Target for the GHG Intensity of Saskatchewan Electricity

* 1. Thinking ahead to the future, what GHG intensity should Saskatchewan strive to achieve in the electricity sector by 2050?

- ○ 900-999 gCO2e/kwh
- ○ 800-899 gCO2e/kwh
- ○ 700-799 gCO2e/kwh
- ○ 600-699 gCO2e/kwh
- ○ 500-599 gCO2e/kwh
- ○ 400-499 gCO2e/kwh
- ○ 300-399 gCO2e/kwh
- ○ 200-299 gCO2e/kwh
- ○ 100-199 gCO2e/kwh
- ○ 0-99 gCO2e/kwh
- ○ Uncertain - don't want to hazard a guess
- ○ Don't Know

Comment

Renewable Electricity in Saskatchewan

Question 2 - Technologies for Reducing Saskatchewan Electricity GHG Intensity

2. Several technologies might contribute to lowering the GHG intensity of Saskatchewan's electricity system. Seventeen of these technologies are listed below in alphabetical order. Please rank the technologies in terms of their importance for reducing the GHG intensity of Saskatchewan's electricity system, with 1 indicating most important and 17 indicating least important. **Note:** You can drag and drop each listed technology to the position you like.

	Battery storage (e.g. lithium-ion, hydrogen)	☐ N/A
	Biomass	☐ N/A
	Coal with Carbon Capture & Storage (CCS)	☐ N/A
	Demand Side Management (e.g. peak load shifting, energy conservation, smart grids)	☐ N/A
	Hydroelectricity (Saskatchewan)	☐ N/A
	Hydroelectric imports from Manitoba	☐ N/A
	Natural Gas Cogeneration (partner with industry e.g. potash mining)	☐ N/A
	Natural Gas Combined Cycle	☐ N/A
	Natural Gas Simple Cycle	☐ N/A
	Natural Gas with Carbon Capture and Storage (CCS)	☐ N/A
	Pumped Hydro Electricity Storage	☐ N/A
	Small Modular Nuclear Reactors (360 MW or smaller)	☐ N/A
	Solar Photovoltaics (small-scale distributed generation <10 MW)	☐ N/A
	Solar Photovoltaics (utility-scale 10 MW or greater)	☐ N/A
	Solar Thermal (utility-scale 10 MW or greater)	☐ N/A
	Wind (small-scale distributed generation, turbines <1 MW)	☐ N/A
	Wind (utility-scale, turbines 1 MW or larger)	☐ N/A

Question 3 - Preferred Electricity Generation Scenario

* 3. Imagine a preferred electricity generation mix in the year 2050 that achieves the electricity GHG intensity you listed in Question 1. What proportion of total electricity generation is provided by each of the following technologies in your preferred scenario?

Please respond by typing the desired proportions in the appropriate boxes.

Please respond in terms of proportion of*electricity generated* (% Gigawatt-hours) rather than proportion of *capacity installed* (% Megawatts).

The choices need to add up to 100.

Biomass	
Coal-fired Generation with Carbon Capture and Storage (CCS)	
Conventional Coal-fired Generation	
Demand Side Management (e.g. peak load shifting, energy conservation, smart grid)	
Hydroelectricity (Saskatchewan)	
Hydroelectric Imports from Manitoba	
Natural Gas Cogeneration (partner with industry e.g. potash mining company)	
Natural Gas Combined Cycle	
Natural Gas Simple Cycle	
Natural Gas with Carbon Capture and Storage (CCS)	
Small Modular Nuclear Reactors (360 MW or smaller)	
Solar Photovoltaics (small-scale distributed generation <10 MW)	
Solar Photovoltaics (utility-scale 10 MW or larger)	
Solar Thermal (utility-scale 10 MW or larger)	
Wind (small-scale distributed generation, turbines <1 MW)	
Wind (utility-scale, turbines 1 MW or larger)	

Renewable Electricity in Saskatchewan

Question 4 - Medium-Term Renewable Energy Potential in Saskatchewan

* 4. Renewable electricity generation technologies include: biomass, hydroelectric, solar photovoltaic, solar thermal, and wind generation. In 2014, renewables supplied 23% of Saskatchewan's electricity demand with hydroelectricity providing 20%, wind providing 3%, and small contributions from solar photovoltaics and biomass.

What is the maximum proportion of Saskatchewan electricity that renewables can supply in the medium-term (i.e. by 2030-2035)?

- ◯ 100%
- ◯ 90-99%
- ◯ 80-89%
- ◯ 70-79%
- ◯ 60-69%
- ◯ 50-59%
- ◯ 40-49%
- ◯ 30-39%
- ◯ 20-29%
- ◯ 10-19%
- ◯ 0-9%

Other (please specify)

Question 5 - Long-Term Renewable Electricity Potential in Saskatchewan

* 5. **What is the maximum proportion of Saskatchewan electricity that renewables can supply in the long-term (i.e. by 2045-2050)?**

- 100%
- 90-99%
- 80-89%
- 70-79%
- 60-69%
- 50-59%
- 40-49%
- 30-39%
- 20-29%
- 10-19%
- 0-9%

Other (please specify)

Question 6 - Desirable Renewable Electricity Generation Mix

* 6. What electricity generation mix would achieve the maximum renewable potential you identified in Question 5?

Please indicate the proportion of electricity generated by each of the following technologies in the long-run maximum renewable potential scenario.

Please respond in terms of proportion of*electricity generated* (% Gigawatt-hours) rather than proportion of *capacity installed* (% Megawatts).

The choices need to add up to 100. If necessary, please include non-renewable elements that would be complementary to the renewable contributions to take the total to 100.

Biomass	
Coal-fired Generation with Carbon Capture and Storage (CCS)	
Conventional Coal-fired Generation	
Demand Side Management (e.g. peak load shifting, energy conservation, smart grids)	
Hydroelectricity (Saskatchewan)	
Hydroelectric Imports from Manitoba	
Natural Gas Cogeneration (partner with industry e.g. potash mining company)	
Natural Gas Combined Cycle	
Natural Gas Simple Cycle	
Natural Gas with Carbon Capture and Storage (CCS)	
Small Modular Nuclear Reactors (360 MW of smaller)	
Solar Photovoltaics (small-scale distributed generation < 10 MW)	
Solar Photovoltaics (utility-scale 10 MW or larger)	
Solar Thermal (utility-scale 10 MW or larger)	
Wind (small-scale distributed generation, turbines <1 MW)	
Wind Power (utility-scale, turbines larger than 1 MW)	

Question 7 - Barriers to Renewable Electricity

7. In speaking to diverse stakeholders about the future of electricity in Saskatchewan I heard about barriers to increasing renewable electricity in Saskatchewan. Participants in the interviews listed the following barriers. How important is each barrier?

	Not important	Somewhat important	Very important
Cost: The price of renewable electricity is too high.	◯	◯	◯
Feed-in-Tariff: Saskatchewan does not pay preferred rates for renewable power.	◯	◯	◯
Grid design: The Saskatchewan grid is built for centralized, not distributed, generation.	◯	◯	◯
Job loss: A focus on renewables will lead to lost jobs in the coal-power industry.	◯	◯	◯
Intermittency: Renewables cannot provide reliable electricity.	◯	◯	◯
Physical limits: Saskatchewan lacks adequate hydro, solar, wind resources.	◯	◯	◯
Political will: Political leaders in Saskatchewan have not prioritized renewables.	◯	◯	◯
Preference for coal: SaskPower has a preference for coal-fired generation.	◯	◯	◯
Public ownership: A private market would increase renewables more quickly.	◯	◯	◯
Social acceptance: People do not want to live near renewable energy generation.	◯	◯	◯

Other (please specify)

Respondent Information

* 8. **Please provide your name, affiliation, and a means of contacting you.**

Name	
Company/Affiliation	
Email Address	
Phone Number	

Thank-you!