COST BENEFIT FRAMEWORK FOR COLD CLIMATE MICROGRIDS

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ABSTRACT

For a quarter of a century, global energy policy has shifted electric utility investments away from fossil fuels toward renewable substitutes. Reducing greenhouse gas emissions is motivating improvements in the cost and efficiency of renewable energy technologies. Historically, the social and environmental values of communities were not considered in electric utility decision making in Canada. Today, community capacity building and reducing household costs are important social objectives for renewable energy integration in Canada's northern, remote and Indigenous communities. This intersection of policy goals is encouraging the development of new decision-making tools for communities using cold climate microgrids and the utility companies who own and operate them. The purpose of this research is to understand, quantify, value and qualify the social and economic implications of alternative energy investments in remote, northern and Indigenous communities. This research adopts a case-study approach to describe the impacts of renewable energy integration, represented by a comprehensive suite of costs and benefits using cost benefit analysis. The goal of using cost benefit analysis as an economic method is to compare alternative renewable energy investments and evaluate them based on a measure of efficiency. The framework is applied using a spread sheet type model. The application includes an analysis of two scenarios (i) the baseline scenario, based on diesel generation compared to (ii) solar photovoltaic integration. The results show that social surplus in remote, northern and Indigenous communities can improve with renewable energy integration into cold climate microgrids. The findings also emphasize the enhanced effects of incorporating demand side management investments to improve economic efficiency. Moreover, renewable energy integration into cold climate microgrids has the potential to correct market failures by reducing information asymmetry and providing numerous positive externalities.

DEDICATION

"To all with a passion for learning and teaching."

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GLOSSARY OF TERMS

Term	Definition
Annual Consumption	Energy consumed within microgrid per year (kWh).
Capacity	The greatest load that can be supplied by a generating unit, power station or an entire provincial grid system.
Capacity Factor	The utilization rate of a power source.
Distribution	Process of moving electric energy at lower voltages from major substations to customers.
Energy	Electricity converted from a renewable or non-renewable source.
Kilowatt Hour (kWh)	A unit of bulk energy; 1000-watt hours. The measurement is generally used for billing residential customers.
Megawatt (MWh)	A unit of bulk power; 1000 kilowatt hours.
Power	The rate at which energy is consumed. Active power is measured in kilowatt hours (kWh).

LIST OF ABBREVIATIONS

Abbreviation	Definition
BCR	Benefit Cost Ratio
CASES	Community Appropriate Sustainable Energy Security
CBA	Cost Benefit Analysis
CCM	Cold Climate Microgrid
CO_2e	Carbon Dioxide Equivalents
DSM	Demand Side Management
HH	Household
NPV	Net Present Value
PBCN	Peter Ballantyne Cree Nation
PBGOC	Peter Ballantyne Group of Companies
PV	Photovoltaic
RE	Renewable Energy
REA	Renewable Energy Alternative
SaskPower	Saskatchewan Power Corporation

1.0 Introduction

A microgrid is an autonomous energy system. Microgrids provide localized heat and power, dependent or independent of connection to a utility-scale grid (Giddings & Underwood, 2006). In Canada, there are 250 remote communities utilizing microgrids to heat and power schools, homes and social infrastructure (Hossain et. al., 2016; Rezaei & Dowlatabadi, 2016). Remote communities share some distinct physical and social characteristics. Hanley & Nevin (1999) list: "low population densities, limited conventional energy sources, lack of infrastructure, low levels of economic activity, physical access constraints and long distances to external markets" (Hanley & Nevin, 1999, 528) as traits that define remoteness. Cold climate microgrids (CCMs) are those operating in arctic and subarctic regions; they provide electricity to remote communities with high proportions of Indigenous populations, using diesel fuel generators. Absent of imported or exported power, CCMs are designed so that all electricity generation and consumption is balanced within them (VanderMeer et. al., 2017) through the maintenance of grid frequency and voltage (Green et. al., 2017).

Many of Canada's electric utility corporations act as natural monopolies, defined by high fixed costs (technological constraints), declining average cost over demanded output and high barriers to entry (legal and regulatory) resulting in economies of scale (Weimer & Vining, 1992). The immense capital outlay required to design and install electricity generation and distribution infrastructure makes it one of the costliest industries to establish and manage (Bodmer & Waldman, 1995). The lack of competition in natural monopolistic markets means that electricity supply is subject to inelastic demand whereby an increase in electricity prices to consumers results almost exclusively in an increase in revenue for the utility (Weimer & Vining, 1992) and inefficiencies on both the demand and supply sides (Elmaghraby et. al., 2004).

The first CCMs were installed in Canada's remote communities roughly 50 years ago (Karanasios & Parker, 2018). Issues with CCMs include: their high cost, inefficiencies with imported fuel that have unreliable delivery schedules, inefficient energy use (Reddy & Xie, 2017) and difficulty repairing outages (Giddings & Underwood, 2007). The high costs can lead to trade-offs between northern, remote and Indigenous residents choosing to heat their home and purchasing other essential goods including nutritious foods (Hossain et. al., 2016). The costs to consumers, utilities and governments, coupled with desire for northern, Indigenous communities to be energy sovereign, led to interest in developing renewable energy alternatives (REAs) in northern Canada in the 1980's (Weis et. al., 2008).

Affordability is often a top concern when analyzing northern energy issues (Quitorias et al., 2020). Remote Alaskan communities have reported household (HH) energy costs totaling 47% of annual income (Schmidt et. al., 2021). In British Columbia, off grid HHs pay up to three times more for electricity than grid connected HHs (Rezaei & Dowlatabadi, 2016). In Saskatchewan, all HHs pay, on average, $172 per month for electric power (Canada Energy Regulator, 2021a). In contrast, in northern Saskatchewan, HHs can have monthly power bills reaching up to $1000 (Quesnel, 2019). These inequities highlight the importance of understanding the potential to enhance social welfare through investments in REAs (Edenhoffer et al., 2013). REAs that are reliable and whose operation and maintenance can be addressed locally are deemed to be notably effective for enhancing welfare in remote communities (Giddings & Underwood, 2007). Gauging the economic potential for renewable energy (RE) development in northern, remote and Indigenous communities requires an analysis of the social costs and benefits associated with specific technology choices, project locations and timing (Miller & Richter, 2014).

One way to economically quantify how REAs impact social welfare is to examine the market costs and benefits and non-market externalities generated by their integration. Externalities are the costs and/or benefits of a policy or project decision that affect agents other than the decision maker (Varian, 1992); their value can be estimated using economic valuation methods. Traditionally, utility corporations analyze electricity alternatives by comparing the net present value of their revenue requirements (Bodmer & Waldman, 1995), absent of externalities. Academic literature examining the externalities of REA integration in northern, Indigenous communities is limited (Hanna et. al., 2019). Therefore, a total economic valuation framework is beneficial for understanding the long-term benefits of RE developments in northern locations; this can be achieved by including direct use, indirect use, option, existence, altruistic and bequest values when valuing externalities (Cook et. al., 2016) into economic models. Moreover, a "multi-layer approach" is beneficial for monetizing the externalities of energy systems; it begins with identifying community-specific social and economic values relating to energy and extends to determine how those values may be impacted with the implementation of a new energy system (Miller et. al., 2015).

1.1 Research Purpose and Objectives

The purpose of this research is to understand, estimate, and where possible, quantify the social welfare implications of alternative energy investments in remote, northern and Indigenous communities. This research will adopt a case-study approach to describe and quantify the impacts of renewable energy system development, represented by a comprehensive suite of costs and benefits for a specific northern community. More specifically, this research sets out to:

- Characterize a case study community,
- Identify, quantify and/or qualify the relative costs and benefits of alternative energy systems,
- Evaluate the net effect of establishing energy system alternatives, and
- Develop recommendations for community evaluation and policy development.

1.2 Research Methods

This research began with a review of peer-reviewed articles, industry documents and government reports relevant to northern diesel microgrids and the effects alternative energy systems may have on northern, remote and Indigenous populations. The literature review will inform all interviews used for data collection and provide background information on the main energy system characteristics important to communities. A theoretical model is developed to represent the economic theory used to illustrate the net social welfare implications of integrating REAs in northern, remote communities. This preliminary research frames the case study outlining the social, biophysical, technical and political context relating to energy development in northern and remote communities. To assess the case study community's perceived value of renewable energy externalities, a survey will be developed and administered to residents and business owners of the northern, remote community. The research will involve participatory consultation with the electric utility administrator and community representatives. The results of the community and utility-sector interviews will be used to outline the impacts of the REAs included in the scope of the model. The summation of quantifiable and valued impacts will capture the utility derived from each system alternative inclusive of market and nonmarket (social) costs and benefits. The predictions made through the analysis will be further assessed using scenario analysis to adjust certain parameters. The final methodological step is to interpret the data gathered to inform policy, investment and/or community capacity and development recommendations.

1.3 Thesis Organization

This thesis is structured in chapter style format and consists of six chapters, the first of which is concluded here. Chapter two of the thesis provides a literature review of the remote energy system management impacts, opportunities and challenges proving most influential to this research. Chapter three presents the theoretical CBA framework, from which applicable economic foundations and ideas will be described. Chapter four outlines the applied analytical framework, including a description of the participatory interviews and methods for quantifying and valuing costs and benefits. Chapter five contains the research results and discussion. Finally, chapter six holds the conclusions of the thesis.

2.0 Literature Review

This chapter presents a review of the relevant literature describing the policy motivations and economic implications of CCM energy systems. Specifically, the global and regional factors influencing the costs, benefits and impacts of integrating renewable energy alternatives in northern, remote and Indigenous communities are explored. This review covers studies from multiple disciplines that have assigned value to and/or assessed the impacts of renewable energy development in remote, northern and Indigenous communities.

2.1 Policy Overview

A policy is a formal directive that informs how a country, region, organization, group or individual ought to allocate its resources to achieve a desired goal. Government energy policies often direct investments into renewable and non-renewable energy sources and technologies in different locations and contexts. Energy system management includes aspects involving "supplies, demands, pricing, ownership, investment, energy management, regulation, efficiency, conservation and environmental maintenance." (Berrie, T.W., 1992, page xvi). Thus, energy policy and administration have vast and varying directives. This overview is intended to provide a general summary of the political history and multi-disciplinary motivation for investment into remote, northern and Indigenous community energy systems.

2.1.2 Global Energy Policy

Countries around the world have attempted to implement global climate change agreements that limit the production of GHGs. Reducing the amount of greenhouse gases emitted by the world's industrialized nations is the goal of the Kyoto Protocol (UNFCCC, 2021), the first global agreement that included greenhouse gas mitigation objectives. Since the Protocol's adoption in 1997, the global energy sector has been reshaped by emerging climate change policies, many of which support the growth of regional RE markets (Akella et. al., 2009; Murray, 2009). In 2015, The United Nations Framework Convention on Climate Change presented the Paris Agreement, a policy designed to reduce and assist in the adaptation of climate change impacts around the globe. In accordance with the Paris Agreement, over 180 countries legally committed to reduce carbon-based greenhouse gas emissions. This included providing support to developing nations who are greatly impacted by climate change and investing in research aimed to improve our understanding of the potential risks and costs of climate change (European Union, 2020;

Government of Canada, 2016). The goal of the Paris Agreement is to sustain a global average temperature increase of no more than 2ºC by 2050 (Government of Canada, 2016). In 2021, the Paris Agreement was enriched with the Glasgow Climate Pact, where targets were set for net-zero emissions by mid-century and fossil fuels were identified as contributors to GHG emissions, calling for a global phase down of coal power (Government of Canada, 2021b).

Global advancements in RE technologies are largely influenced by policy and government investment (Edenhoffer et. al., 2013; Glynn, J., Fortes et. al., 2015; Subtil Lacerda, 2019). From 2007 to 2011, global government investment into RE doubled to reach $88 billion USD (Bölük & Mert, 2014). In 2018, global investment into RE from both the private and public sectors reached $288 billion USD (Ren21, 2019). Today, the global energy transition to RE sources is promoting local generation and energy storage, at the remote community level (Gjorgievski, 2021).

Remote communities around the world rely on various non-renewable and renewable sources of modern electricity to supply basic needs (Arriaga et. al., 2014). Renewable resources are those available in perpetual supply from the natural world. The most common renewable resource employed for energy generation is biomass, where, for example, wood in temperate climates is used as fuel for heating and cooking (Akella et. al, 2009). Other renewable resources suitable for energy generation include solar, wind, biofuels, geothermal and hydropower. Classically, the degree to which renewable resources are considered and investigated as alternatives to fossil fuel is a function of technological advances (costs and reliability) and unpredictable fossil fuel prices (Akella et. al, 2009).

The World Bank (2017) estimates that globally 1.06 billion people lack access to grid-based electrical resources. One of the 17 goals outlined in the United Nations 2030 Agenda for Sustainable Development, where equitable access to modern energy supplies is affirmed as a priority, directs policy to address electricity supply in remote regions (United Nations, 2015). The policy mechanisms needed for REA uptake in remote communities differs from grid-connected centres (Boute, 2016; Moner-Girona M, 2009; Moner-Girona M., et. al., 2016), as higher costs limit integration feasibility, even though socioeconomic benefits are gained from using local energy sources (Silva & Nakata, 2009).

2.1.3 Canadian Energy Policy

One initiative taken by the Government of Canada to back its climate change mitigation goals and commitment to the Paris Agreement and Glasgow Climate Pact is the founding of the Powering Past Coal Alliance (the Alliance) with the United Kingdom. Consisting of 111 members from federal, state, provincial and municipal governments, the Alliance's mandate is to sustainably cease coal fired power generation by 2030 (Government of Canada, 2020a). As the greatest proportion (25%) of GHG emissions worldwide comes from electricity and heat production (EPA, 2020; IPCC, 2014), the Alliance is structured to contribute to reducing global GHG emissions. In 2017, Canada's electricity production accounted for 10.9% of national GHG emissions (722 Mt CO_2 eq), with 3.2% of those from burning oil and diesel fuel (Canada Energy Regulator, 2022). By committing to phasing out coal fired electricity, a rapid transition to RE technologies is both apparent and imminent.

In 2018, the Federal government of Canada introduced a national carbon pricing policy called the Greenhouse Gas Pollution Pricing Act (Government of Canada, 2022a), which is impacting the electricity sector. The policy requires (i) a fuel charge and (ii) a charge for industrial carbon pollution. The development and execution of a carbon pricing system was the responsibility of each of Canada's twelve provinces and territories (Government of Canada, 2021a), using the federally determined carbon tax rate. In April 2022, the Federal carbon tax was set at $50 CAD per tonne of emitted CO_2 equivalents, with a $15.00 annual rate increase until the price per tonne reaches $170 CAD in 2030 (Government of Canada, 2022d). All provincial and territorial governments have implemented a cap and trade, output-based pricing system and/or carbon tax on fuels (Government of Canada, 2022c).

The Canadian utility market can be divided into three sectors, residential, commercial and industrial (Qudrat-Ullah, 2013). The residential sector provides goods and services necessary to supply energy to HHs for "space and water heating, air conditioning, appliances and other end use energy devices." (Qudrat-Ullah, 2013, 286). The cost of electricity for HHs in grid connected regions of Canada ranges from $0.08/kWh to $0.19/kWh (Government of Canada, 2020a). The cost of electricity is typically positively correlated to a community's level of remoteness (IEEE, 2014). For CCM consumers, the cost of electricity can range from $0.45/kWh to $2.50/kWh CAD (IEEE, 2014), highlighting the inequities faced by northern, remote residents.

In Canada, federal and provincial government organizations spend over $1 billion on renewable and non-renewable energy research and development annually (Natural Resources Canada, 2021). Investments into energy projects are not solely taken on by government agencies, however. In 2019, Canadian companies invested $1.6 billon into research and technology development for the energy industry (Natural Resources Canada, 2021). Spending by federal government agencies specific to clean energy development combined totalled $786 million in the 2019/2020 fiscal year (Natural Resources Canada, 2021). It is expected that research and feasibility planning by Saskatchewan's electric utility operator, SaskPower, will total $140 million from 2022 to 2029 (Opseth, 2022).

Investment into northern and remote energy projects is a priority for Canadian provincial, territorial, the Federal government and nongovernment organizations (Government of Canada, 2018). Between 2001 and 2016, reducing capital cost and providing both technical assistance and financial benefits via net metering were key policy objectives supporting energy investments in remote, northern and Indigenous communities (Karanasios & Parker, 2018). Rezaei & Dowlatabadi (2016) report that the high costs of diesel, energy efficiency, policy mandates and the socio-economic benefits are motivating REA integration in CCMs by government stakeholders. Federal programs like Natural Resources Canada's "Clean Energy for Rural and Remote Communities" aims to reduce the number of Canadian communities' that are reliant on diesel-based energy systems (Government of Canada, 2019), while others like the "Building Capacity with the Smart Renewables and Electrification Pathways Program" seek to build energy capacity explicitly (Government of Canada, 2022e). In 2022, the Clean Energy for Rural and Remote Communities program received a $300 million funding commitment by the federal government (Government of Canada, 2022).

Energy transition is a process where a region or community moves away from a main energy source by investing in alternatives (Hache, 2018). Administered both federally and provincially, Canada's targeted policy measures improve northern communities' capacity to participate in culturally sustainable energy transitions (Karanasios & Parker, 2018). According to Karanasios & Parker (2018), culturally sustainable energy transitions are those informed by experimental learning, where Indigenous community leaders and utility personnel have identified factors that maximize cooperation for all stakeholders involved. Moreover, government policies, focused on capacity-building in the energy sector represent a “missing market” (Varian, Hal. R., 1992) by assisting communities to express their demand for REAs, thus providing a mechanism to improve community welfare.

Technological advancements (and investments) may impact how various RE technologies operate in Canada’s unique northern, remote and Indigenous communities. Qudrat-Ullah (2013) employed a systems dynamics approach to estimate the efficiency of investments into the Canadian electricity sector, given the technological trends. The systems dynamics approach in this study uses: “demand, investments, production capacity, electricity generation cost, pricing of electricity, environmental sensitivity and investments in R&D” (Qudrat-Ullah, 2013, page 288) as model variables. Overall, the results of the modeling imply that Canadian investments of $10 billion from 2015-2025 into new capital assets focused on productivity and efficiency can close supply and demand gaps and lead to a greener electrical utility sector (Qudrat-Ullah, 2013).

Welfare in remote, northern and Indigenous communities can increase from policy investments aimed at improving energy efficiency at the HH level; this policy arena is known as demand side management. Demand side management in buildings, through energy efficiency initiatives, can benefit power producers by reducing demand for new generation assets (Pembina Institute, 2004). Consumer preferences and government incentives influencing HH behaviour have been shown to have the greatest impact on residential electricity use (Qudrat-Ullah, 2013), which in 2016 accounted for 33% of total national usage (Government of Canada, 2020a). New technology or updated infrastructure can reduce consumer energy consumption and billing and delay future investments in certain household appliances and/or housing upgrades (Pembina Institute, 2004). According to Qudrat-Ullah (2013) the demand side factors influencing the Canadian electricity system dynamics include: fuel substitution (from electric space and water heating to gas), informational flow, cogeneration (combined heat and power) and energy efficiency. In his review of demand side management policies from over 30 countries, Warren (2019) concludes that lack of monitoring (follow up evaluation) and technical implementation issues are the greatest obstacles influencing the success of demand side policies. He goes on to state that appropriate regulatory frameworks and specifically designed incentives prove to generate success for demand side policy investments (Warren, 2019).

Rezaei & Dowlatabadi (2016) state that governments emphasize demand side management and reductions in HH energy use as key energy strategies for Canada's Indigenous communities. In 2019, a pilot project co-funded by the Government of Canada and Province of Nova Scotia invested over $13 million to install energy efficiency upgrades on over 100 Mi'kmaw residences in Nova Scotia (Government of Canada, 2019). The Indigenous people of the Mi'kmaw First Nation live in 13 communities and on 42 reservation lands (Government of Nova Scotia, 2015). The Mi'kmaw Home Energy Efficiency Project reportedly invested in a combination of insulation upgrades, moisture mitigation measures, ventilation upgrades and installed heat pumps into dwellings owned by the First Nation. On behalf of the Canadian Climate Institute, Arnold (2021) reports that every $6000-$7000 spent on a Mi'kmaw home retrofit upgrade resulted in $750 in energy cost savings per household per year.

2.2 Cold Climate Microgrid Management

CCMs account for 80% of Canada's off-grid community energy provision (Rezaei & Dowlatabadi, 2016). These communities are often accessible only by plane, seasonal roads, or water and can be characterized as having a mixed subsistence/wage earning economy (Schmidt, et. al., 2021). It is estimated that traditional Indigenous subsistence activities are undertaken by up to 80% of CCM households (Schmidt, et. al, 2021). Rezaei & Dowlatabadi (2016) interviewed four communities in British Columbia utilizing CCMs who reported that inconsistent system operation and maintenance can lead to long periods during the winter months where HHs are without power. Longstanding legal and political issues has led to mistrust between many Indigenous communities and Canadian electricity service providers (Rezaei & Dowlatabadi, 2016). Hydroelectric dams built in British Columbia (Rezaei & Dowlatabadi, 2016) and Saskatchewan (Maxwell, 2021) have displaced Indigenous people and may reduce opportunities for subsistence activities on traditional Indigenous territory (Maxwell, 2021).

Most remote, northern and Indigenous communities depend on diesel-fueled generators to power their CCMs. Importing diesel fuel to service CCMs can be expensive (Schmidt et. al., 2021), inefficient (Reddy & Xie, 2017) and presents a variety of environmental risks depending on the transport method (Quitoras et al., 2020). Green et. al. (2017) estimated that 40% of the diesel combusted by high quality CCMs is converted to electricity and 60% is converted to heat. As a fossil fuel, burning diesel for heat and power in remote communities emits CO_2 contributing to climate change (Boute, 2016). Rezaei & Dowlatabadi's (2016) qualitative research with utility personnel highlights that despite the downsides to dependence on diesel generators, provincial utility service providers still see diesel generation as the most reliable way to deliver power in remote, Canadian communities.

VanderMeer et. al. (2017) report that in Alaska, reducing diesel dependence and improving local welfare are motivations for REA integration into CCMs. Integration describes how CCMs can be physically modified to include renewable energy technologies in some capacity (VanderMeer et. al., 2017). Giddings & Underwood (2006) argue that sustainable remote, community RE integration results in an energy system that is technologically sound, carbon neutral, community appropriate, secure and meets community energy demands. REA integration is effective when an energy system supplies heat and power and is technically operational by trained community members (Giddings & Underwood, 2006).

To assist in the development of a computational approach to understand the value of REAs in northern Canadian communities, Quitoras et al. (2020) produced a multi-objective CCM optimization model to help identify the economic and environmental trade offs associated with their integration. The multi-objective integrated energy system method utilized a genetic algorithm to offer viable REAs given specific economic and technical constraints, using Pareto front, with the levelized cost of electricity, as the decision-making criteria (Quitoras et al., 2020). The model focuses on analyzing outcomes related to energy security (security of supply), affordability (cost minimization) and environmental impacts (including diesel offset) and estimates changes in government investment associated with specified alternatives (Quitoras et al., 2020). In the application case of REA integration for a community in the Northwest Territories, Quitoras et al. (2020) concluded that 353,407 litres of diesel fuel can be saved per year and that wind appeared to be the most viable RE technology for the case study.

Rezaei & Dowlatabadi (2016) examined how First Nations' community wellbeing relates to utilizing local REAs to supplement off-grid diesel generators in British Columbia. Eleven study participants including community leaders, utility company personnel and energy consultants were asked to explain their motivation relating to energy development. It was discovered that when communities invest in REA integration, the motivation for doing so included increased self sufficiency, employment opportunities, economic development stemming from cheaper power, improved electrical reliability, local revenue generation and environmental benefits (Rezaei & Dowlatabadi, 2016). One aspect of self sufficiency in the Indigenous energy context is a communal desire to acquire microgrid property rights (Rezaei & Dowlatabadi, 2016), which may ease CCM operation and maintenance and lead to enhanced political autonomy (Rezaei & Dowlatabadi, 2016).

2.2.1 Barriers to Northern Energy Transitions

Current Canadian energy policy directives have led to many northern communities experiencing energy transitions. Several works have assessed the challenges and opportunities of energy transition in Canada's northern, Indigenous communities (see Karanasios & Parker, 2018; Weis et.al., 2008). Some of the barriers to renewable energy development in fossil-fuel dominant regions of northern Canada are technological infeasibility (Giddings & Underwood, 2006) and political and economic factors (Giddings & Underwood, 2006; Mercer et al., 2017). In their discussion of northern energy transition, Karanasios & Parker (2018) contend that the specific political and economic barriers to supplementing CCMs with RE sources in Canada are: "institutional weaknesses and capacity issues, vested interests in diesel generated electricity, lack of capital, high capital costs, lack of expertise, missing infrastructure, and limited community acceptance." (Karanasios & Parker, 2018, 169). A barrier identified by Rezaei & Dowlatabadi (2016) is the inability for CCM communities to benefit from economies of scale, as all generated energy is consumed within the system.

Realizing the benefits associated with RE integration into CCMs involves overcoming systemic barriers including "the absence of long-term tariff and contractual guarantees at the time of investment decisions, and subsidies designed to cover diesel expenses rather than the capital costs of RE investment." (Boute, 2016, page 1035). Specific to the northern, remote context, Boute (2016) highlights the logistical and high capital expenditure complexities that arise as key obstacles to successful RE integration. Karanasios & Parker (2018) emphasise that the technical barriers limiting RE integration into CCMs include: "the need for developer, installer and operator expertise, the availability of distribution infrastructure, information systems, smart grids, lower cost storage, packaged systems control technologies, and robust equipment able to operate in extreme climatic conditions and variable load configurations." (Karanasios & Parker, 2018, 169). Moreover, Boute (2016) affirms that in the northern context, extreme weather and the uncertainty of future CC impacts are making feasibility assessment increasingly complex.

2.3 Costs of Renewable Energy Integration into CCMs

The market and nonmarket costs of REA integration into CCMs can be articulated from the community and utility perspectives. Electricity markets are lumpy, meaning that the fixed costs attributed to generation and distribution proportionally outweigh the variable costs. Lumpy start up costs and minimum output levels are reflected by inefficiency in both the short and long run (Elmaghraby et. al., 2004). This unique supply characteristic can only result in an efficient market allocation when consumers, as price takers, exhibit the same willingness to pay as the market price (Elmaghraby et. al., 2004).

Spiegel-Feld et al. (2016) describe how the costs and benefits of RE integration are allocated between various stakeholders on Small Island Development States, which mimic the characteristics of remote, northern communities. Data was collected through workshopping with utility company personnel operating on remote islands, RE technology developers, banks, NGOs and academics (Spiegel-Feld et al., 2016). The results showed that REA integration lowers the cost of electricity production but that utilities are hesitant to reduce the rate structure for consumers because the ongoing maintenance costs are largely unknown (Spiegel-Feld et al., 2016). Spiegel-Feld et al. (2016) conclude that funding policy designed to alleviate the risks of integration and maintenance borne by utilities (or infrastructure investors) may allow consumers to benefit from lower power bills.

O'Mahoney et. al. (2013) used cost benefit analysis to assess the net welfare effects of cofiring biomass as a carbon neutral renewable energy source in Ireland. Cofiring is the process of burning biofuels in addition to fossil fuels to generate electricity. O'Mahoney et. al. (2013) note that challenges with data collection limited the number of costs and benefits that could be valued. The costs included in the analysis were: biomass fuel, operations and maintenance and infrastructure capital costs (O'Mahoney et. al., 2013).

A 2019 study by Wilber et. al. examined the costs of integrating solar PV technology into Alaskan microgrids at the community scale. Private cost data from 21 community solar projects was compiled through interviews with community development leaders and project managers

(Wilber et. al., 2019). The system sizes under analysis ranged from 2.2-138 kW, with installed costs ranging from $1.25 – $13.33 (USD) per W (Wilber et. al., 2019). The authors note access to cost data as a barrier for economic analysis of solar PV projects in Alaska, as most projects are awarded to contractors as a lump sum (Wilber et. al., 2019). Upon completing interviews with solar PV contractors, Wilber et. al. (2019) state that up to 30% of a project's costs can be attributed to logistics and planning, with 15% allocated to labour and the remaining 55% going to materials. Land preparation, fencing and security, interconnection and equipment rentals are other cost categories routinely used by solar PV contractors (Wilber et. al., 2019).

The costs of integrating wind technology into CCMs were investigated by VanderMeer et. al., (2017). Data was collected from 24 funding applications accessed via the State of Alaska's Renewable Energy Fund grant program, where all of the applications included projected project costs (VanderMeer et. al., 2017). The categories used by VanderMeer et. al. (2017) to assess integration costs included supervisory control and data acquisition, hardware, integration and testing, thermal storage and electrical storage. The authors estimate that a 1% increase in wind penetration increases integration costs by $27/kW (USD) (VanderMeer et. al., 2017). It was found that when incorporating thermal or electrical storage, the average control integration cost represents 66% of the total cost and storage the other 34% (VanderMeer et. al., 2017).

2.4 Benefits of Community Renewable Energy Development

To date, there has been limited research focused on quantifying the social benefits of renewable energy development in remote communities in northern Canada. Social benefits equate to indirect economic benefits. They are the effects of project actions that raise the wellbeing of people or firms in a community electricity market (see Table 2-1) beyond a reduction in a HH power bill or the direct value garnered from its use in HHs, for example. Recent work by Gjorgievski et. al. (2021) asserts that the indirect benefits of community energy projects include: "social cohesion, improved energy literacy, the development of social networks, the promotion of global partnerships and reduced energy poverty" (Gjorgievski et. al., 2021, page 1151) and that overall, a framework that quantifies the benefits and impacts of community energy projects is lacking (Gjorgievski et. al., 2021).

Akella et. al. (2009) examined various social, economic and environmental effects of RE under the Kyoto Protocol's clean development mechanism. The clean development mechanism is a carbon-sharing mechanism, where wealthy countries can invest into ownership of RE projects in developing countries and, in turn, collect carbon credits. The authors define the social benefits of RE in low-income communities as: “(i) improved health, (ii) consumer choice, (iii) greater self-reliance, (iv) work opportunities and (v) technological advances.” (Akella et. al., 2009, 391). The authors further define the environmental benefits of RE in low-income communities as: “(i) reduced air pollution, (ii) lower greenhouse gas emissions, (iii) lower impacts on watersheds, (iv) reduced transportation of fuels and (v) leaving non-renewable resources in situ.” (Akella et. al., 2009, 391). Lastly, the authors note that RE generates many economic benefits and highlight job creation and the “multiplier effects” of improved incomes, technological cost savings and economic diversification in their analysis.

Edenhoffer et al. (2012) provide an objective look at how RE integration is modeled into traditional (fossil fuel dominated) electricity sectors using global reporting data from ~2004 to 2009, where the modelling assesses climate change mitigation scenarios. This analysis asserts that various policy directives benefit from RE adoption including energy security, green jobs, green growth, reduced environmental impacts and poverty alleviation (Edenhoffer et al., 2012). The authors argue that in the socio-economic context, RE, because of its scalability and the energy independence it provides, can be beneficial, especially in remote and poor rural areas. Greater access to schools, health facilities and food security are additional benefits adding to social welfare, particularly in regions that rely on traditional wood stoves or have no electricity (Edenhoffer et al., 2012). Reconciliation of past grievances is seen as a potential benefit for successful community RE projects that build self sufficiency (Rezaei & Dowlatabadi, 2016).

Foundational work by Hanley & Nevin (1999) examined the public perception of various RE technology benefits by surveying tourists near a remote coastal community in northern Scotland. Seventy-six people were interviewed, in person, as they visited the North Assynt Estate development site. Survey results indicate that society views wind and hydro technologies as being environmentally positive, while biomass technology is perceived as having negative environmental effects (Hanley & Nevin, 1999). Overall, the authors note improved employment and income as key benefits reaped by remote communities when harnessing energy from local renewable resources (Hanley & Nevin, 1999). In their research examining the barriers to wind and solar integration in Russia’s remote, northern communities, Boute (2016) notes that off-grid

REA integration avoids the high planning and building costs of grid transmission and lessens the energy security risks from remote power line disruptions.

The complexities of delivering reliable power to remote communities in Britain was examined by Giddings & Underwood (2006) who name sustainability as one of the benefits of adopting REAs in the remote context (Giddings & Underwood, 2006). The communities in the analysis are characterized by a "boom and bust" cycle, meaning that a wave of local economic prosperity brought upon by natural resource development has ended, leaving little to no opportunity for new economic growth. The components linking sustainability to remote RE uptake involves the utilization of local energy resources and the benefits reaped from building regional prosperity. The authors cite local decision-making regarding energy preference and employment as broader benefits of RE adoption (Giddings & Underwood, 2006).

The integration of different REAs can result in different benefits at the community level. It is widely accepted however that overall, REA integration into CCMs directly benefits the environment by reducing carbon emissions (Boute, 2016). Akella et. al. (2009) argue that biomass has specific environmental and social benefits; the carbon sequestration from plant growth and root storage outweighs atmospheric releases during combustion and the labour-intensive process of biomass fuel production creates local jobs.

Table 2-1: Benefits of community RE integration as identified in the literature

Economic Benefit(s)	**Author(s)**
Social cohesion, improved energy literacy, the development of social networks, the promotion of global partnerships and reduced energy poverty	*Gjorgievski (2021)*
Improved health, consumer choice, greater self-reliance, work opportunities and technological advances	*Akella et. al. (2009)*
Greater access to schools, health facilities and food security	*Edenhoffer et al. (2012)*
Reconciliation of past grievances, building self-sufficiency	*Rezaei & Dowlatabadi (2016)*
Economic sustainability, employment, local decision making	*Giddings & Underwood (2006)*
Avoid high planning and building costs of grid transmission, reduced energy security risks from remote power line disruptions	*Boute (2016)*
Environmental Benefit(s)	
Reduced air pollution, lower greenhouse gas emissions, lower impacts on watersheds, reduced transportation of fuels and leaving non-renewable resources in situ	*Akella et. al. (2009)*
Reduced carbon emissions	*Boute (2016)*

2.5 Economic Analysis of Remote Community REAs

The impacts of investments into REA integration can be articulated by estimating how the investments improve social welfare (Varian, 2002, page 404). Cost benefit analysis is a traditional economic method for comparing the impacts borne through project investments via the estimation of net social benefits (Varian, 2002, page 404), a criterion for evaluating welfare improvements. In their cost benefit analysis valuing cofiring biomass systems in Ireland, O'Mahoney et. al. (2013) included fuel cost savings and carbon dioxide emissions savings as social benefits. Using a 6% discount rate based on the weighted average cost of capital, O'Mahoney et. al. (2013) found that biomass cofiring in Ireland produces negative net social benefits. The negative result was constant under varying discount rates and fuel prices.

Cost benefit analysis was conducted using a software program (HOMER) to model energy systems containing multiple technologies by Mudasser et. al. (2015), where the net welfare implications of integrating wind-biogas hybrid energy systems into the grid in three regions of Nova Scotia, Canada were estimated. While HOMER is heavily focused on technical system parameters, the economic parameters included in the model included the capital costs of infrastructure, infrastructure replacement costs and operations and maintenance (Mudasser et. al., 2015). Using a 6% discount rate and a 20-year timeline, the results suggest that wind-biogas hybrid energy systems can provide positive net social benefits in regions with extremely high wind speeds and frequency (Mudasser et. al., 2015). Furthermore, Mudasser et. al. (2015) concluded that the current feed-in tariff rates in Nova Scotia are not sufficient to make these systems feasible in regions with only moderate wind speeds and frequencies.

Conducting socioeconomic impact analysis for RE projects requires access to data that is typically not public. Hanley & Nevin (1999) note the difficulties of obtaining engineering and financial data for valid survey design in a REA valuation study for a remote coastal community in northern Scotland. The authors disclose that describing complex project options makes data collection tedious and onerous, and that surveying residents allows their RE preferences to be revealed (Hanley & Nevin, 1999). Hanley & Nevin (1999) used contingent valuation, a nonmarket valuation method, to assess the value of environmental costs and benefits for small-scale hydro, biomass and wind-farm developments in a remote Scottish community. Hanley & Nevin (1999) state that the amount of information needed to inform residents of project details (most notably, project costs) can make it challenging for them to then assign willingness to pay (WTP) or willingness to accept (WTA) values to environmental impacts. The concept of WTP or WTA is grounded in welfare economics and for stated preference applications an individual is asked to assign a market value to a social cost or benefit borne onto them by a project. An individual's stated WTP reflects the amount of compensating surplus, or monetary value they deem as appropriate to gain and sustain a social benefit (Champ et. al., 2003, page 12). An individual's stated WTA reflects the amount of equivalent surplus, or value of compensation required to keep them at the same level of wellbeing if they had to forgo a social benefit (Champ et. al., 2003, page 13). The economic valuation work was completed in addition to a local economic impact study for a coastal, northern, agricultural community. The results showed that the community ranked hydro, wind and biomass as most to least preferential, with the HHs mean WTP of £54.93, £52.25 and £25.54 annually for implementation of the respective technologies (Hanley and Nevin, 1999).

Discrete choice experiments describing situational attributes have been used to assess nonmarket WTA for the security of energy supply (Motz, 2021). Motz (2021) surveyed 1006 individuals in Switzerland to gather information on how utility is impacted by the frequency and duration of power outages generated from varying renewable and non-renewable technologies. Motz (2021) notes that WTA for power outages largely depends on the technology from which the power is generated. In Switzerland, consumers may tolerate increases to their HH power bill more readily if the power is generated from hydro or solar technologies, compared to wind or nuclear power (Motz, 2021). Overall, the power outage attributes and trade offs described in the study resulted in consumer WTA of up to 10 times the rate of electricity in cents per kWh (Motz, 2021).

Nonmarket valuation methods provide an approach to place a social cost on the operational and maintenance challenges of electricity generation (Kjølle et. al., 2008). The quality of electricity supply in remote, northern communities can be evaluated taking an approach that considers the "cost of energy not supplied" (Kjølle et. al., 2008, page 1030) to consumers, where an emphasis is placed on the system's voltage quality (Kjølle et. al., 2008). The cost of energy not supplied can be estimated quantitatively using the preparatory action method (PAM). PAM estimates the costs a HH incurs to avoid the loss in utility experienced from power interruptions (Kjølle et. al., 2008).

The integration of REAs in northern, remote and Indigenous communities may impact the amount of electricity demanded by HHs. Price elasticity of demand measures by what percentage a HH's demand for electricity may change with a 1 percent change in price (Munoz-Garcia, 2017, page 93). In the remote community context, HHs are characterized by budget constraints and electricity is still considered to be a critical good, meaning that it exhibits inelastic demand, where a 1% change in price will have almost no impact on the quantity of electricity demanded (Muller et. al., 2018). In their work estimating the price elasticity of demand for an off-grid community in Nepal, Muller et. al. (2018) note that HH energy consumption data is a key input and often limiting factor in developing valid price elasticity of electricity demand estimates for off-grid communities. The price elasticity of demand presented in their work is (-0.15) (Muller et. al., 2018), suggesting that demand for off-grid electricity is unlikely to change given a change in its price.

2.6 Conclusion

For a quarter of a century, global energy policy has gradually shifted electric utility investments away from fossil fuels toward renewable substitutes. Reducing GHG emissions is a significant factor influencing rapid changes in the cost and efficiency of RE technologies. In Canada, community capacity building and cost inequity are important motivations for RE policy investments in northern, remote and Indigenous communities. The intersection of policy goals is changing investment decision making for Canadian communities employing CCMs and the electric utilities who own and operate them. Understanding and quantifying the market and social costs and benefits of REA investments in northern, remote and Indigenous communities can play a role in determining which REAs have the greatest potential to support culturally sustainable energy transitions in these regions.

3.0 Theoretical Framework

Chapter two provided evidence from previous research that community welfare could be increased through REA integration into CCMs. However, to understand potential welfare effects the identification and economic estimation of social costs and benefits of various RE technologies is necessary. It is suggested that the illiquidity of current diesel generation technologies can make investment into REAs by utility providers undesirable and that policy, like Canada's GHG Pollution Pricing Act, is encouraging the development of remote, northern REA integration. The complex stakeholder and delivery dynamics of the northern, remote energy landscape requires that financial feasibility, technological lifespan, and system operations and maintenance requirements be included as criteria to assess the value of integrating RE technologies into CCMs (Giddings & Underwood, 2006).

Chapter three presents the theoretical cost benefit framework created to estimate the total net benefits associated with the development and integration of REAs in remote, northern and Indigenous communities. The focus of this chapter is on the conceptual framework/model, which provides the theoretical economic foundations of quantifying the costs and benefits of alternative investments into remote, northern energy systems. The objective of this work is to understand, estimate, quantify and/or qualify the social welfare implications of alternative long-term investments into remote, northern energy systems. It is my goal to describe and quantify the impacts of RE integration, represented by a comprehensive suite of costs and benefits using a cost-benefit analysis (CBA) framework. This framework provides guidance for an applied qualitative and quantitative approach to data collection. All social costs and benefits, including those that can not be assigned a representative monetary value, will be described qualitatively.

3.1 Market Failure in Northern, Remote Energy Management

In competitive markets, efficiency is enabled by complete market signals, where the price of goods and services (P_C) are determined and supplied (Q_C) at the point where marginal costs equal marginal benefits (see Figure 3-1). In contrast, traditional energy markets are often characterized as natural monopolies, where the price (P_M) of electricity supplied (Q_M) is set through a regulatory body where average costs equal marginal benefits. In this market, the natural monopoly will charge higher prices for electricity ($P_M > Pc$) and supply less electricity ($Q_M < Q_C$) than a competitive market resulting in lower levels of community welfare.

In the natural monopoly, electricity supply exhibits constant marginal costs up to a capacity constraint (Boardman et. al., 2018, page 451). The fixed costs of generation, transmission and distribution are high relative to the variable costs. In the long run the marginal costs (MC_M) of production fall below average costs (AC_M). As the long run average costs decrease with output, the conditions favor economies of scale. The supply inelasticity of electricity is characteristic of the high costs of storing it (Ockenfels et.al., 2013).

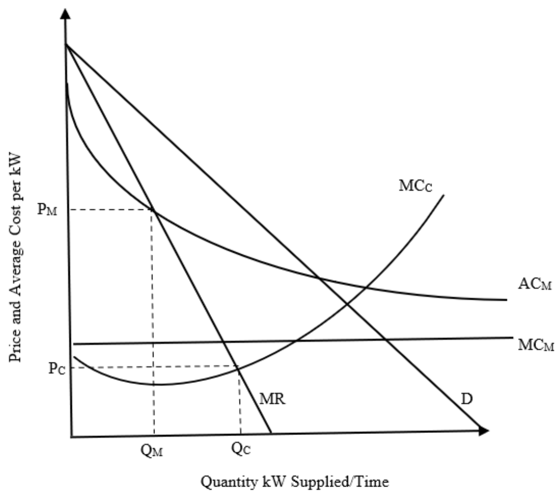

Figure 3-1: Illustration of natural monopoly electricity market

Market failures can arise when corporations in a sector lack incentive to supply goods and services demanded by the public. Economic theory shows that market failure in the natural monopoly may occur from unproductive use of resources, inefficient pricing and lack of investment into new, innovative technology (Weimer & Vining, 1992). By assuming consumers have perfectly inelastic demand (the demand curve is vertical) for electricity, innovation by electric utility corporations is dissuaded (Elmaghraby et. al., 2004) as investments in technology are not predicted to increase revenue from electricity sales.

As price takers for electricity in remote locations, consumers in northern communities may be subjected to higher prices as natural monopoly regulators may implement a multi-price system, charging higher prices to some consumers and lower prices to others (Munoz-Garcia, 2017, page 533). As the sole provider of a good or service, natural monopolies may lack incentive to prioritize customer engagement or satisfaction as consumers have traditionally had no alternative means to generate or access electricity. This results in a transfer of surplus away from northern HHs (Boardman et. al., 2018, page 89), who demand and pay more for electricity than grid-supplied consumers and consumers with access to alternative types of energy, such as natural gas. The price inequity exacerbates low socioeconomic conditions in communities, where the lack of other sources for energy and heat (i.e. natural gas infrastructure) decreases the number of options for home heating. For the natural monopoly, addressing market failures is possible through investment from external agents (Varian, 2002, page 434), such as the federal government, via RE technology, demand side management and capacity building initiatives. In the absence of appropriate regulation, failure in northern electricity markets is also exhibited through the presence of information asymmetry and externalities.

The northern, remote electric utility market can also be characterized by the presence of market externalities. Externalities exist when the action of one agent in a market affects another agent and those effects go unvalued in market transactions (Varian, 2002, page 432); they are often related to social and environmental outcomes. On the production side, externalities exist when firms impose external benefits or costs that are not compensated for through markets (Weimer & Vining, page 135). For example, fossil fuels stored in remote, forested areas can impact the wellbeing of fauna and plant life. With externalities present, competitive markets will not operate efficiently.

Investments from external financiers (i.e., the federal government) for REA integration into CCMs will change the local energy market dynamic for remote, northern, and Indigenous communities. As two energy operators now exist, REA integration into CCMs creates a duopolistic electricity delivery scheme where two agents, the electric utility and the community, both supply electricity to HHs. In this case, I assume that the electric utility will continue to operate as a profit-maximizing entity over the long run and that the community will be motivated to employ decision making criterion that will minimize costs over the long run. With the addition of a REA substitute by the community, the quantity of diesel-based electricity demanded by the community is expected to decrease, resulting in lower electricity costs to the HHs.

CBA can be used to help understand how a duopolistic electricity market structure in remote, northern, and Indigenous communities reduces or corrects market failures in the long run. For example, introduction of community-managed REA can reduce or eliminate localized air pollution. As a public decision-making tool, CBA requires the quantification of the full range of market and nonmarket (social) costs and benefits of a specific policy or project on society (Boardman et al., 2018). Measuring the change in total social welfare specific to the energy system alternatives can be accomplished by applying a CBA framework. It is an appropriate method for valuing the economic impacts of renewable energy projects because it enables financial investors to understand the value of various system options (de Nooij, 2011). The full quantification and communication of a project's costs and benefits can help negotiating agents reach socially optimal outcomes (Munoz-Garcia, 2017, page 661).

3.2 Canadian Cost Benefit Analysis

First enacted in 1999 (Treasury Board of Canada Secretariat, 2007), the Government of Canada's Policy on Cost Benefit Analysis (2018) states that all regulatory proposals, including those in the electricity sector, expected to impose a cost on the federal government, require a CBA (Government of Canada, 2020b). It is expected that the analyst, in conclusion, will report "the recommended option [that] maximizes the net economic, environmental, and social benefits to Canadians, business, and government over time more than any other type of regulatory or nonregulatory action." (Treasury Board of Canada Secretariat, 2007, page 1). The Treasury Board of Canada Secretariat (2007) outline five steps to conduct cost benefit analysis, including: (1) Identifying Issues, Risks, and the Baseline Scenario, (2) Setting Objectives, (3) Developing Alternative Regulatory and Non-Regulatory Options, (4) Assessing Benefits and Costs and (5) Preparing an Accounting Statement. The discount rate suggested for use in cost benefit analysis by the Treasury Board of Canada Secretariat (2007) is 8 percent.

The criteria for the depth of a regulatory cost benefit analysis depends on the proposed federal project costs. For projects with costs under $1 million CAD annually, cost benefit analysis can be completed using largely qualitative analysis, in the absence of available monetary data. When project costs are estimated to be over $1 million CAD annually, work must be completed to identify, quantify and/or qualify all costs and benefits (Government of Canada, 2020b).

3.3 Conceptual Cost Benefit Framework

The conceptual model for this research closely follows models developed by Pannell (2021a) and Boardman et. al. (2018) where net welfare effects of project alternatives are articulated through the design and application of a CBA framework. The CBA framework systematically assesses all costs and benefits of a 'with and without project scenario(s)' and reports them for a specific timeframe over the long run, in present value terms. A ‘without project’ scenario is modeled assuming no investment in northern, community energy or supply from a community standpoint. It provides the standard against which alternative investment paths can be compared. ‘With project’ scenarios are modeled to highlight the net social benefits of alternative energy investment paths in northern, remote communities given community investment into REA integration.

The CBA method enables REA trade offs, based on the with and without project scenario(s), to be examined and expressed monetarily. For example, one REA may provide high local employment but is complex to service remotely, and another REA may provide little employment but provide ease of service and manageability. The value of each alternative is expressed monetarily to determine overall, which benefits a community more, relative to the status quo. CBA frameworks can be applied ex ante or ex post. For this thesis, an ex-ante application is developed.

This framework adopted in the present research applies a participatory modeling approach (see Inam et. al., 2015) where stakeholders are engaged in one-on-one interviews to gather information about electricity demand, supply, and forecasting in relation to REA integration at the community scale. Participatory modeling allows local biophysical and socioeconomic issues (costs and benefits) to be identified and included in the study, enhancing the framework’s rigor (Inam et. al., 2015). Identifying important costs and benefits specific to the project alternatives can help the analyst define unique parameters and variables to tailor the CBA to the case study site. In some cases, participatory modeling may assist with understanding behaviour and values specific to community energy dynamics, which is important for valuing the impacts of project alternatives. For example, the community may report details regarding the duration or frequency of power outages or be able to describe the effects of how various power system specifications impact the local subsistence economy. Overall, this approach may increase the validity of results by reducing the magnitude and frequency of forecasting and omission errors.

Participatory household surveys and interviews with community leaders, energy experts and utility personnel are undertaken to provide the modeling data inputs. The intent is to identify the project alternative that improves allocative efficiency, or net social benefit (NSB), where the total benefits represent the sum of all monetized market and nonmarket costs and benefits. A combination of financial and economic analysis allows the market and nonmarket costs and benefits of alternatives to be quantified. CBA frameworks are often developed as a spread sheet type model. The six elements (see Table 3-1 below) of the CBA framework for CCMs are detailed in the remainder of this chapter.

Table 3-1: Six elements of the CBA framework

1. Scoping
2. Identify Impacts
3. Quantify, Value and Qualify Impacts
4. Conduct Scenario Analysis
5. Apply Discounting
6. Compare Alternatives

Adapted from Pannell (2021a) and Boardman et. al. (2018).

3.3.1 Scoping

A CBA is applied to help understand the sequence of costs and benefits associated with alternative energy investments over a specific time frame and to assemble data to describe and/or quantify these costs and benefits. In the present study, the first step in CBA is to fully define the project specific to the overall goals, energy demands, energy supply alternatives and temporal and financial constraints specific to the study community (Pannell, 2021a). Data related to the project budget, local energy assets and community sociotechnical capacity can be collected through discussions with community project managers. It is also important to identify utility personnel and RE experts who will assist with impact identification and quantification (Pannell, 2021b). If municipal, territorial, provincial and/or federal government agencies or non-profit groups are engaged in the project development, they are specified in this step.

Impact stakeholders can be those directly located in primary markets, or indirectly located in secondary markets (Boardman et. al., 2018, page 78; Pannell, 2021c). In the context of this CBA, primary stakeholders are those who are directly affected, for example, as end consumers of electricity distributed in a microgrid operating in a northern, remote or Indigenous community. In contrast, secondary stakeholders operate in markets that are indirectly affected by project alternatives; for example, the RE development may decrease GHG emissions associated with meeting energy needs and general society benefits from these reduced GHG emissions.

Defined scoping allows for a rational number of REAs to be researched and included in the analysis, alongside the without-project scenario. A community's commitment to installing and maintaining integrated REAs is a sociotechnical risk. If the technology is not functioning or serviceable, the benefits linked to the alternative may decline or be eliminated. A RE technology may be considered as a feasible alternative based on the unique socio-technical, biophysical and/or financial goals and constraints defined by a community. Based on the participatory information gathered from community leaders, a defined scope of the community's environmental, social, and economic goals specific to REA integration into the CCM is developed (see Table 3-2). At a minimum, a unique suite of costs and benefits are defined under two scenarios, a baseline (without project) scenario and an alternative (with project) scenario. The timeframe of the analysis is decided in the scoping step (see Table 3-2). This is important to begin to understand the flow of relevant costs and benefits for each alternative (Pannell, 2021d). As the CBA commences with scoping, it is assumed that the analysis is a trigger or a requirement for project planning or financing.

Table 3-2: CBA scoping

Scoping Requirement	Method
1. Identify community energy assets, demand, supply, physical, economic and social constraints and key energy stakeholders	***A. One-on-one interviews with community leaders and utility personnel to identify:*** ▪ Current community energy assets; ▪ Current business and/or feasibility planning for REA integration; ▪ Current electricity load; ▪ Electricity load forecasts; ▪ Project budget and timelines; ▪ Key community, utility and government stakeholders available for data collection. ***B. One-on-one interviews with households to identify:*** ▪ Preferences and values toward community energy and RE technologies.
2. Define feasible set of modeled alternatives	***A. One-on-one interviews with community leaders and utility personnel to identify:*** ▪ Any funding restrictions that may limit alternatives available for modeling; ▪ Current business and/or feasibility planning for REA integration. ***B. Conduct literature review to compile:*** ▪ Relevant renewable energy integration modeling trends.
3. Define timeline	***A. One-on-one interviews with community leaders and utility personnel to identify:*** ▪ Relevant renewable energy integration modeling trends. ***B. Literature Review:*** ▪ Review relevant renewable energy integration market models.

3.3.2 Identify Impacts

Within the CBA framework for CCMs the impacts of energy alternatives are recognized and expressed in monetary or monetary-equivalent terms in a spreadsheet model. It provides a systematic approach for capturing all the market and nonmarket costs and benefits relating to REA integration in remote, northern and Indigenous communities. This facet of the framework focuses on understanding, identifying and cataloguing the market and non-market impacts of the with and without project scenarios (see Table 3-3). The objective is to define, understand and predict the local market and nonmarket impacts that will be created with the integration of REAs (with project scenario(s)) and how the energy landscape of the community may change without community-led REA integration (without project scenario). It is important to specify the actions required to generate the benefits associated with the implementation of each alternative, to predict the probability of the benefits actualizing over time (Pannell, 2021e).

The impacts will vary in all project scenarios, based on the outcomes correlated to their delivery (Pannell, 2021f). A literature review may be used to help identify the broad impacts, their measurement indicators and the market outcomes of integrating alternatives, while participatory interviews inform the estimation of the magnitude of impacts (Weimer & Vining, 1992, page 325). For example, when estimating the aggregate community demand for electricity, elasticity values may be drawn from the literature and modified, to estimate the demand curve for electricity generated from specific RE technologies. However, how the integration of REAs affects northern, remote and Indigenous household's electricity consumption will require one-on-one interviews with households and utility and Indigenous energy specialists.

Table 3-3: CBA market and nonmarket impact analysis

CBA Scenario	Method
1. Without Project	***A. Conduct literature review to identify:*** ▪ Current trends related to utility management of CCMs; ▪ Current trends related to utility investment into REA integration in Canadian microgrids; ▪ Market models of CCM management in remote, northern and Indigenous communities. ***B. Participatory one-on-one interviews with community leaders and utility personnel to identify:*** ▪ Non-market impacts of CCMs and REA integration. ▪ The probability of market and non-market impacts occurring over time; ▪ The probability of risks occurring over time.
2. With Project(s)	***A. Conduct literature review to identify:*** ▪ Current trends related to community management of REA in remote, northern and Indigenous context; ▪ Current trends related to community investment into REA integration in CCMs; ▪ Market models of RE management in remote, northern and Indigenous communities. ***B. Participatory one-on-one interviews with community leaders and utility personnel to identify:*** ▪ Non-market impacts of CCMs and REA integration. ▪ The probability of market and non-market impacts occurring over time; ▪ The probability of risks occurring over time. ***C. Participatory one-on-one interviews with households to identify:*** ▪ Where community members intend to invest potential electricity cost savings generated from REA integration; ▪ If residents intend to increase their electricity consumption post REA integration.

3.3.3 Quantify, Value and Qualify Impacts

In the development of projects, not all stakeholders may benefit equally. The actions specific to one REA may impose a cost to one stakeholder, while another reaps the benefits. During impact valuation, the costs and benefits are estimated in monetary terms, and values are assigned to who pays and who gains. Consumer surplus (CS) is the measure of net benefits reaped for market and nonmarket impacts experienced by the community. One example of CS gained from community RE integration may be the localized learning opportunities from having new technology present. Producer surplus (PS) is the net benefits reaped by the energy producer from sale of energy-related goods and services in remote, northern, and Indigenous communities. PS for the government utility is corporate profit. For a remote, northern, or Indigenous community one example of PS may be the self-sufficiency or autonomy gained from RE integration and ownership. The total sum of net benefits is the social surplus (SS), where:

$$SS = CS + PS \tag{3.1}$$

The SS can be quantified using market models and valued using nonmarket economic methodology described in the remainder of this subsection.

3.3.3.1 Market Valuation

Market models normally represent business accounting and investment analysis methods used by firms engaged in production. Market prices are established through interactions between producers and consumers within market institutions. These prices represent the market values of the goods or services and assist in financial planning and decision making as it relates to a firm's output, efficiency, and risk. Ultimately, market models provide prices to quantify the costs and benefits used in the CBA.

Costs

The community specific costs of managing CCMS and integrating REAs are identified through a review of relevant literature and/or participatory consultation with community leaders or local experts. These costs will represent direct market, environmental and social costs of CCM management and REA integration over the timeframe of the analysis. The costs can be understood by obtaining projected and realized financial statements and budgets from the community and utility. It is important to know who pays the costs and in which year(s) the costs occur (Pannell, 2021g). Specifically, data will be obtained for any costs related to management salaries, employee salaries, contractors, office costs, machinery, equipment, materials, insurance, publicity, communications, legal, permits, research, data collection, subsidies, tax breaks and in-kind costs (Pannell, 2021g) for the with and without project scenarios. The costs of outside organizations who assist with project planning or implementation are included for CBA applied to publicly funded projects (Pannell, 2021g).

Benefits

Benefits are actions or outcomes that improve the utility of a project stakeholder (Pannell, 2021h). CBA requires a clear understanding of the socio-economic patterns and behavior of the community and utility, relating to the CCM and REA integration. To understand the benefits provided by a project, a case study approach can be applied to address foundations in behavioral economics, where understanding the connections between stakeholder behaviors and their influence on societal wellbeing is studied. Understanding the flow of costs and benefits that are based on local behavior and preferences allows the benefits to be expressed on the HH and aggregate community levels. Direct benefits received by the utility, the community, or society at large can include revenue, a reduction in risk, cost savings or delays and changes in asset values (Pannell, 2021a). Nonmarket benefits can also be included in the analysis and include those benefits that are unpriced (or incompletely priced) in the market and are often related to health, environmental and social outcomes (Pannell, 2021h).

3.3.3.2 Nonmarket Valuation

Occasionally, goods and services that provide value or impacts peoples' quality of life in some way have incomplete or no prices in the market representing their value to society. Nonmarket impacts represent a loss (nonmarket cost) or gain (nonmarket benefit) in social welfare due to the CBA project scenarios. This can include access to culturally important activities or knowledge, air quality impacts, meaningful employment, or social fulfillment (Pannell, 2021h). Decision makers in natural monopolistic markets do not typically value nonmarket impacts, however it is important to monetize and include them in CBA to understand the total net welfare effects of energy investments in northern, remote and Indigenous communities.

Theoretically, all nonmarket impacts identified in CBA require the application of a unique method for monetization and an original research study. For a primary valuation study, community preferences are documented and values may be estimated via surveying to represent, for example, a community's WTP for improved energy autonomy. Nonmarket valuation methods include stated preference methods (contingent valuation and choice experiment), which pose trade-off questions to individuals through surveys and revealed preference methods (e.g. hedonic pricing and travel cost) which are related to actual behaviour and trade-offs people have made (Boardman et. al., 2018). Monetizing impacts from quantifiable market transactions can also be completed using market analogy, trade-off, intermediate good, asset valuation and defensive expenditures methods (Boardman et. al., 2018). Typically, conducting original nonmarket valuation studies to monetize nonmarket impacts require extensive expertise, time and financial resources.

When conducting CBA, a lower cost approach that can be applied is the benefit transfer method (see Boardman et. al., 2018, page 407). It can be a suitable nonmarket valuation approach if the biophysical conditions, socioeconomic characteristics of the population and benefits of the project (Pannell, 2021i) are similar between the original study and the CCM community. With equity being a concern and motivation for policy investments in community-scale REAs, distributional weighting of the value of the impacts can be an option for estimating important spiritual, cultural or locally sensitive externalities (Boardman et. al. 2018, page 491). Distributionally weighted CBA involves adjusting the net present value formula by multiplying the costs incurred and benefits (Boardman et. al. 2018, page 496) received by the community by a factor, for example 5, to reflect the magnitude of significance that REA investments are expected to have over time.

Manero et. al. (2022) suggest that the classic assumptions guiding utility theory for eliciting welfare measures relating to nonmarket goods and services may not apply to Indigenous populations, as ancient northern cultures have a worldview that is based relationally on spiritual and cultural principals and not socioeconomic trade offs. Estimation of the nonmarket benefits identified by community leaders may require substantive qualitative survey work before original and valid stated and revealed preference studies can be completed. Eliciting nonmarket values specific to Indigenous people requires special planning, understanding and collaboration between impacted communities and the analyst (Manero et. al., 2022). Baseline household-level data regarding individuals current satisfaction level with the local energy system and preference specific to the integration of renewable energy technologies and demand side management projects is required for estimating welfare changes.

3.3.4 Scenario Analysis

CBA enables the calculation of a point estimate of the net present value of investment alternatives and the scenario analysis is designed to understand niche project risks at a single moment in time. Scenario analysis can be used to help decision makers understand how changes to technical and financial constraints may impact the net benefit of alternative investment paths to the community. For example, multiple parameters in the model can be altered to estimate how variations in technological investment (MW installed) effect HH power bill savings or NPV. Inference can then be made to gauge how the different technologies perform under varying conditions, in terms of the net benefits provided to the community in the long run. Sensitivity analysis may also be used to identify sensitive or important variables that may have a substantial influence on results (Pannell, 2021j).

3.3.5 Discounting

Community scale energy projects often provide a stream of benefits and costs over a planning horizon of many years. To effectively combine and compare benefits and costs that occur in the present or near future with benefits and costs that occur in the more distant future, some form of discounting is required. Discounting allows future costs and benefits to be expressed in their present value. To do this, the future values of costs and benefits are adjusted by a discount factor which includes the chosen discount rate (r) and considers the year of the project impact (t). Present value is calculated based on the following equation:

$$Present\ Value = Future\ Value_t \times \frac{1}{(1+r)^t} \tag{3.2}$$

Discount rates are commonly chosen to reflect the time value of money, positive time preference and perceived project risk. The time value of money represents the opportunity cost of capital, or the interest gained by utilizing energy investment resources at their next best use. Positive time preference reflects impatience, meaning a community may prefer, in general, to receive REA investment payoffs today than at some time in the future. The perceived project risk of REA integration in northern, remote communities may be higher than is typically modeled due to unique climactic, transport, generation and serviceability issues. If discounting was not applied, benefits and costs that occur far in the future would likely be over estimated (Pannell, 2021d), and the present value should be as accurate as possible when we evaluate and compare the overall net benefits of the project alternatives.

Social Discount Rate

Social discount rates may be applied to analysis when HH consumption or environmental regeneration is a key project outcome (Treasury Board of Canada Secretariat, 2007). Social discount rates are often lower (~3%) than rates used in traditional investment analysis (~6-8%) because there may be no readily available substitute for the good or service being analyzed. For CBA being undertaken from the community perspective, as is the case for this framework, a social discount rate is often more appropriate.

3.3.6 Comparing Alternatives

There are several approaches to compare the project alternatives. When considering the alternatives on behalf of the community, the most common measures are net present values and benefit cost ratios (see Table 3-4). Less commonly used for public projects are techniques used in investment analysis, specifically the internal rate of return and modified internal rate of return (Pannell, 2021k). The internal rate of return expresses the time value of money by reporting at what interest rate a financier would need to achieve to break even on the net present value of an investment. Similarly, the modified internal rate of return examines the rate at which a financier would need to achieve to break even, however it also considers the timing of cash inflows and outflows.

Table 3-4: Criteria for comparing projects

Criteria	**Equation**	**Unit**	**Decision Rule**
NPV	NPV = PV(B) - PV(C)	Monetary ($)	NPV > 0
BCR	BCR = PV(B)/PV(C)	No unit	BCR > 1

Net Present Value (NPV)

NPV represents the present value of a stream of investment costs and payoffs, including the cost of the original investment. If for an alternative the NPV exceeds zero, the public investment is predicted to provide a level of welfare improvement. By comparing alternatives based on their NPV, we can see which investments have the greatest potential welfare improvement, over the term of the analysis. As the NPV is a measure of overall NSB, it is a superior method to analyze projects restricted by a budget constraint (Boardman et. al., 2018, page 32). Using this logic, the project alternative with the highest NPV will provide the largest NSB for a community.

Benefit Cost Ratio (BCR)

As a unitless measure, the benefit cost ratio (BCR) allows the alternatives to be compared based on the magnitude of benefits reaped to costs paid. If a BCR exceeds 1, that implies a welfare improvement as the benefits related to the alternative exceed the costs. In cases with no budgetary constraints, BCR can be used to rank projects. It is a logical approach to gauge which stakeholder gains in the largest proportion and which stakeholder group pays in the largest proportion, specific to each alternative.

3.4 Conclusion

The theoretical CBA framework for cold climate microgrids was developed to guide the evaluation of community investments into REA integration in northern, remote and Indigenous communities. The real-world trigger for application of the framework may come as a requirement for remote REA project planning or financing. As unique project scenarios (technological investments) are predicted to provide different outcomes for a community, understanding and estimating the net social benefit of REA integration into CCMs will assist in describing the overall welfare effects of these varying policy investments.

4.0 Model Application

The application of the cost benefit framework for CCMs was carried out to evaluate alternative energy investment paths for remote, northern and Indigenous communities. Conceptually, community investment into varying RE technologies will lead to social, economic and environmental trade-offs, or outcomes. Using CBA, these trade-offs may be monetarily quantified, valued and/or qualitatively described. Analyzing trade-offs may help decision makers consider investment pathways with the greatest potential to improve the welfare in Canada's remote, northern and Indigenous communities.

Data was collected using voluntary interviews with individuals representing the community's leadership and the government utility operator (see Appendix A). Thirteen interviews were conducted over nine months in 2021 and 2022, with the majority (62%) taking place over five weeks in February and March of 2022. Interviewees asked to participate based on their knowledge of the energy system in Kinoosao. In initial interviews, participants were asked about the system operations of the CCM, their organization's vision of the community energy system and subsequent financial implications. In subsequent interviews, participants were presented with a list of market and nonmarket costs and benefits specific to the alternative scenarios and were asked if they thought any costs or benefits should be excluded from an analysis of a remote community CCM and if there were any costs and benefits not included that should be included in the analysis. A detailed application of the results of the interviews, including the scoping, impact identification, impact quantification, valuation, scenario analysis and discounting steps of the cost benefit framework for CCMs are presented in this chapter.

4.1 Scoping

The important outcomes of scoping are: (i) identifying community energy assets, electricity demand, electricity supply, economic and social constraints, and key stakeholders (ii) determining the feasible set of modeled alternatives and (iii) defining the timeline used in the analysis. This approach to determining the project scope echoes a traditional case study. A case study approach exemplifies an appropriate research method for analysis applied to northern, Indigenous communities because attention can be paid to the socioeconomic impacts of remoteness (Beatty et. al., 2012). This subsection presents the results of primary research, desktop research and initial interviews. The results of the scope are summarized at the end of the subsection.

4.1.1 Government Utility Profile

Generation, transmission and distribution of Saskatchewan's electricity supply is managed by Saskatchewan Power Corporation (SaskPower). SaskPower was established in 1929 and incorporated as a Crown corporation in 1949 under the Power Corporation Act. With exceptions in the City of Saskatoon and the City of Swift Current, SaskPower has the exclusive right to supply, transmit and distribute electricity in Saskatchewan. It is estimated that SaskPower has an electrical generating capacity of 4,987 MW with infrastructure assets valued at approximately $12 billion CAD (SaskPower, 2021c). Currently, 26% of SaskPower's generation capacity comes from renewable energy sources (SaskPower, 2021c). According to their Annual Report, SaskPower (2021c) spends almost $700 million on infrastructure annually; roughly half of this investment goes toward new projects and half is directed to upgrading infrastructure.

SaskPower anticipates that increasing investment in renewable electricity generation will reduce CO_2 emissions by 50% from 2005 levels (SaskPower, 2021c), as all of the company's coal generating facilities will be phased out by 2030 in compliance with Federal government regulations to address climate change. Currently, SaskPower's generation capacity from hydro-powered electricity is the largest of all renewable sources, totaling 20% of total generation capacity (SaskPower, 2021c, page 4). Three major wind projects with a combined 385 MW of generation capacity are currently under construction, as SaskPower plans to increase its wind generation from 2021 levels by 300% by 2026 (SaskPower, 2021c, page 14). This will bring wind resources to provide 15% of SaskPower's generating capacity. The company's solar projects are expected to remain relatively small scale over the coming years, with electricity generated from this resource to double from 1% to 2% of total generating capacity (SaskPower, 2021c, page 14). With wind and solar resources at the forefront of project implementation, the company also plans to evaluate and implement small modular nuclear reactors before 2032 (SaskPower, 2021c, page 9). In 2020, SaskPower announced plans to build a 20 MW "utility-scale battery energy storage system" (SaskPower, 2021c, page 15) in Regina, Saskatchewan that will help the company distribute power from renewable energy sources more effectively (SaskPower, 2021c).

SaskPower operates a 230 kV I1K transmission line that powers all of Saskatchewan's northern and remote communities, apart from one off-grid community, Kinoosao. In 2016, the line received a $327 million upgrade (SaskPower, 2019). Power on the northern grid comes from the 25 MW Manitoba Hydro Northern Power Purchase Agreement, and from SaskPower hydro generating assets located at Island Falls on the Churchill River. The I1K line goes from Island Falls, bordering Manitoba on the east, to Key Lake, located in the north central part of Saskatchewan. Transmission lines extend south from Island Falls and north from Key Lake to complete the northern grid. In their 2020-2021 Annual Report, SaskPower (2021c, page 13) announced a new project, the Indigenous Customer Care Centre, that will monitor issues specific to northern, remote and Indigenous communities. Key issues specific to northern, remote and Indigenous communities include high bills and challenges with bill collection (SaskPower, 2021c).

4.1.2 Study Community

The remote village of Kinoosao is located in northern Saskatchewan, Canada, in Treaty 10 territory, at 57.08º N latitude (Huang et. al., 2016). The region is abundant in renewable and non-renewable resources, particularly uranium, gold, oil, forest, and non-timber forest products (Beatty et. al., 2012). Kinoosao is on the eastern edge of Reindeer Lake (see Figure 4-1). It was established in 1952 as a commercial fishing community (PBCN, 2022). The residents of Kinoosao organize multiple traditional subsistence hunts each year to harvest moose in the fall season and caribou in the winter (PBCN, 2022).

Approximately 100 people live in Kinoosao (PBCN, 2022) and it is one of eight communities under the governance of Peter Ballantyne Cree Nation (PBCN). PBCN a sizable First Nation in Canada, with a census population of 4550 (Government of Canada, 2019). On average, each residence in the First Nation houses 12 people (Huang et. al., 2016); it is estimated that there are 8-10 residents living in each home in Kinoosao (PBCN, 2022). Fourteen of the 16 permanent dwellings in Kinoosao use the CCM to heat their homes with a wood stove to supplement; two dwellings and the local school use propane for heat (PBCN, 2022). In 2015, residents and PBCN paid $106,215 in total household and commercial charges for diesel-generated power (SaskPower, 2015), equating to an average cost of $1,062 per permanent resident per year.

Figure 4-1: Map illustrating the location of Kinoosao, near the Saskatchewan and Manitoba Provincial Border, Canada (Government of Canada, 2022).

Kinoosao is accessible by an all-season road through the east neighbouring province of Manitoba and by boat via the community of Southend, located two hours away on the southern edge of Reindeer Lake (PBCN, 2022). Located in the Canadian Precambrian Shield, Reindeer Lake has an average depth of 150 m (Johnson and Thomas, 1984) and a surface area of 6700 square kilometers (Angler's Atlas, 2022), making it the ninth largest lake in Canada (Johnson and Thomas, 1984) and second largest lake in Saskatchewan (Provost, 2021). According to Angler's Atlas (2022), common fish species in Reindeer Lake include lake trout (*Salvelinus namaycush*), northern pike (*Esox lucius*) and walleye (*Sander vitreus*). The value of Reindeer Lake's commercial fishery is estimated to be $1.6 million annually (Provost, 2021). Local seasonal employment opportunities in Kinoosao are highest from June to September (PBCN, 2022) and are dominantly in the forestry, fishing and ecotourism sectors (PBCN, 2022). Ice harvesting is an important service supporting the local fishery, employing over 200 people seasonally (Provost, 2021). There are 5 permanent jobs in Kinoosao: a teaching position, general store staff, community maintenance staff and there is one resident in the community, employed by the electric utility, who provides day-to-day repairs and maintenance on the CCM (PBCN, 2022). The First Nation's economic development corporation, the Peter Ballantyne Group of Companies (PBGOC), is currently developing biomass boiler installations in two of its grid-connected communities (Pelican Narrows and Deschambault Lake) to offset propane use for space-heating in the high schools. Energy security and job creation are key motivators for PBGOC's investment into REAs (Huang et. al., 2016).

4.1.2.2 CCM System Specifications

Today, Kinoosao's CCM consists of three 100 kW phase 1 commercial grade diesel generators and an enclosed distribution system with 3800 meters of line and 52 poles (SaskPower, 2022a). The three generators were most recently replaced in 2016, 2017 and 2018, respectively (PBCN, 2022) and have received annual maintenance/refurbishing since that time (SaskPower, 2022a). The system rotates, with a single generator operating 24 hours per day. Each enclosed generator is linked to a 1171 litre fuel tank with a total of 70,000 litres of diesel fuel stored on-site in the community (see Figure 4-2). The diesel fuel used to generate electric power in Kinoosao is trucked in three or four times per year. The fuel cost for the most recent year was estimated to be $1.44 per litre, including transportation (SaskPower, 2021b). 177 MWh of diesel-generated power was consumed in Kinoosao in 2020 (SaskPower, 2021b). SaskPower (2022a) has indicated that the current generator model operating in Kinoosao is discontinued, and so the CCM system will likely be upgraded to support new diesel generation technology in coming years.

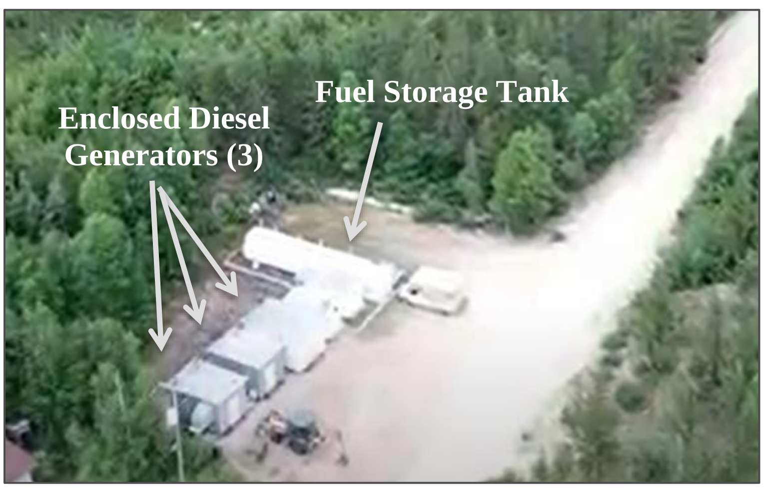

Figure 4-2: Aerial photograph of the CCM generation assets located in Kinoosao, Saskatchewan

SaskPower has two rate categories for residential electricity service, a standard rate and a rate for residences served by diesel generators. Household bills include three parameters, a basic monthly charge, an energy charge and a federal carbon charge. Electricity rates start at $32.90 per residence per month. CCM households pay $0.14 for their first 650 kWh/month of electricity consumption and $0.53 per kWh/month after that. The rate that all households pay for the

Federal Carbon Tax is $0.01 per kWh of electricity consumed. SaskPower (2021c) estimates that Saskatchewan residents will demand 2% more electricity in 2022, compared to 2021.

Table 4-1: Saskatchewan residential electricity rates (2018-2021)

Residential Category	Minimum Monthly Charge ($CAD/month)	Rate Usage <650 kWh/month ($CAD/kWh)	Rate Usage >650 kWh/month ($CAD/kWh)	Federal Carbon Charge ($CAD/kWh)
Diesel (Off Grid)	32.90	0.14	0.53	0.01
Standard (Grid Connected)	32.90	0.14	0.14	0.01

Adapted from SaskPower (2021a).

4.1.3 Selecting Feasible Project Alternatives

The set of feasible project alternatives includes the without project scenario, based on no community investment and one or more alternatives, based on REA integration by a northern, remote and/or Indigenous community. The literature review presented evidence that wind (see Mudasser et. al., 2015; Hanley & Nevin, 1999) and biomass (see O'Mahoney et. al., 2013; Hanley & Nevin, 1999) may be feasible REAs for integration into CCMs. In 2016, the Alaska Center for Energy and Power, the University of Saskatchewan and SaskPower published a report (see Huang et. al., 2016) describing the local energy resources available for community energy projects in PBCN. The REAs considered in the analysis included solar PV, solar thermal, wind, air source heat pumps, ground source heat pumps, water source heat pumps, biomass heat and biomass combined heat and power. Huang et. al. (2016) recommended solar PV for all PBCN communities and biomass as a feasible option for Kinoosao, specifically. Interviews with PBCN and SaskPower in the fall and winter of 2021 revealed that for Kinoosao, the most suitable REA for integration are solar PV and biomass heat technologies. Based on the scope of this thesis, solar PV integration is modeled, in addition to the baseline diesel generation scenario. Each of the modeled scenarios are introduced in the following two sub-sections.

4.1.3.1 Baseline: No Community Investment

Modeling the 'without project' scenario, assuming no community investment into RE integration, represents the baseline for evaluating the net welfare effects of community investment into RE integration. In this scenario it is assumed that the electric utility operator, SaskPower, will continue to distribute electricity to the community as described earlier in section 4.1.2.2 "CCM System Specifications".

4.1.3.2 Community Investment: Solar Photovoltaic

The climatic characteristics often experienced by northern communities, namely clear skies in all seasons and long periods of snow cover in winter resulting in a high albedo effect (Panchuk, 2019), are ideal for generating electricity from solar photovoltaic (PV) technology (Whitney & Pike, 2017). Solar PV generated power is being considered for integration in Kinoosao because it has proven to be effective in other communities located in high latitudes (see NTPC, 2022; Pike et. al., 2018; Whitney & Pike, 2017). In their study of a community energy system in the community of Eagle, Alaska, Pike et. al. (2018) report that the CCM operated effectively after a 24-kW solar PV array was integrated and that solar PV technology required minimal maintenance. These characteristics make solar PV a good option for northern communities in Saskatchewan since infrastructure replacement and repair times can be extensive (Huang et. al., 2016).

The capacity factor for solar PV technology estimates the electric generation potential, or efficiency of the panels, for a certain location on the planet. The amount of sunlight in a region is positively correlated to the generating capacity of solar PV technology. In their analysis for solar projects in southern Saskatchewan, SaskPower assumes a capacity factor for PV technology of 19% (SaskPower, 2021b). This means that a 100-kW capacity solar PV array may generate 19 kW of electricity at a single point in time. Data provided by SaskPower (2021b) shows that solar PV technology in northern Saskatchewan (see Appendix C) has a lower capacity factor because of the reduced number of light hours per year. Applying the assumption that in southern Saskatchewan, 100% solar output equates to a 19% capacity factor, the capacity factor for solar PV technology in the northern Saskatchewan ranges from 12 – 19%, with the average being 16%. The capacity factor used to model the solar PV scenario in this analysis is 16%.

Electrical systems powered by diesel generators are not designed to integrate large volumes of renewable energy (Ross, 2022) and therefore must be modeled with a technical constraint. The intermittent nature of solar PV power generation allows a maximum 20% penetration from this resource into the CCM (Ross, 2022). The required generation capacity for the modeled solar PV integration in Kinoosao is 30-kW (See equation 4.1). It was selected based on the assumption that a 30-kW solar system with a 16% capacity factor will offset up to 20% of the diesel-generated power consumed in the study community. Additionally, it is assumed that the annual electricity demanded is 200 MWh and that there are 8760 hours in one year.

$$Solar\ PV\ Generating\ Capacity\ = \frac{\left(\frac{Annual\ Electricity\ Demanded\ \times .20}{Capacity\ Factor}\right)}{Hours\ Per\ Year} \tag{4.1}$$

4.1.4 Timeline

The defined timeline of the analysis allows for the cost and benefits to be both identified and quantified or valued over a set duration, in years. Interviews with SaskPower (2021b) revealed that the timeline used for financial forecasts of electricity projects depends largely on the lifespan of the generation technology being analyzed, with 25 years being the most frequently used. FNPA (2022) stated that their financial models usually use a 20-year timeframe, based on the length of power purchase agreements. For this analysis, I will use a 25-year timeline, beginning in 2022. The model will consider two years for project planning, with solar PV generation to begin in 2024.

Table 4-2: Scoping summary

Scoping Step	**Summary**	
1. Identify community energy assets, demand, supply, physical, economic and social constraints and key energy stakeholders	SaskPower operates 3-100 kW diesel generators. 70K litres of diesel fuel are stored in the community. PBCN and SaskPower are key project stakeholders. 177 MWh were consumed by residences and community buildings in Kinoosao in the year ending March 31st, 2021.	
2. Define feasible set of modeled alternatives	*Baseline: No Community Investment*	*Community Investment: Solar PV*
	Business as usual scenario. SaskPower operates CCM with no RE integration.	Solar PV. 16% capacity factor. 30 kW generating capacity.
3. Define timeline	The start year for the CBA is 2022. The modeled timeline of analysis will be 25 years, ending in 2047.	

4.2 Identify Impacts

Foundationally, CBA entails that the impacts of the feasible set of modeled alternatives be identified and where appropriate, quantified, valued and/or qualified. Electricity generation by SaskPower provides direct benefits to the residents of Kinoosao as households and the community use this service to heat and power their homes. This research sets out to identify the costs and benefits of CCM power generation in Kinoosao beyond the value garnered from this direct use. This subsection details the approach taken to estimate the costs of CCM management, the costs of REA integration and the market and nonmarket benefits of the set of feasible project alternatives (see Table 4-2). While RE integration in northern, remote and Indigenous communities may have effects regionally, provincially and/or nationally, this analysis limits estimates to those observed by the community and the government utility in the village of Kinoosao, Saskatchewan.

The impacts of project alternatives in Kinoosao, Saskatchewan were identified through literature review and confirmed via participatory interviews with PBCN and SaskPower. Three participatory interviews were conducted with SaskPower staff members between November 2021 and February 2022. Two of the interviews were with the Director of Business Analysis. One group interview was held with a manager in Grid Modernization, an industrial engineer, and the Manager of Indigenous Customer Care. There were two main goals of the interviews: (i) ask the utility representatives to confirm the impacts of project alternatives identified in the literature and discussions with CASES project leaders and (ii) to inform the quantification, valuation and qualification data and methods used in the application of the CBA framework. The information received from the interviews informed both the ‘without project’ and ‘solar PV’ scenarios.

Interviews were also held with a solar developer from the PBCN community Southend, and the current CEO of PBGOC. Between June 2021 to March 2022, I conducted four one-on-one meetings with the developer to discuss and model the solar PV integration in Kinoosao. These meetings were designed to gather social and economic data about the community and technical details about the solar PV modeling. A directed email exchange with the CEO of PBGOC helped to confirm the impacts of the community solar PV scenario. Details of the two modeled scenarios are provided in the following sub-sections.

4.2.1 Without Project: No Community Investment

In this scenario, I assume that the costs borne by the utility include diesel fuel, federal carbon tax, capital expenditures, operations and maintenance, depreciation, fuel spill risk and environmental catastrophe risk. The revenue earned from the sale of electricity is estimated as the sole benefit in this scenario, assuming the rate paid for electricity by Kinoosao households is equal to or less than the value of that power to the household. I assume that the social costs of ongoing diesel generation borne by the community includes fuel spill risk, environmental catastrophe risk and noise pollution (see Table 4-3).

4.2.2 Community Investment: Solar PV

For the community investment solar PV scenario, pre-project planning is a new quantifiable market cost for SaskPower. The nonmarket benefits of solar PV integration identified by SaskPower include reduced legal or administrative costs, reconciliation and knowledge building. From the community standpoint, pre-project planning was also reported as a cost, in addition to capital expenditures, operations and maintenance and depreciation expenses for the purchase, installation and management of the solar infrastructure over time. Energy security, reconciliation, pride, knowledge sharing and building, improvements to energy literacy, local air quality improvement and power bill cost savings are the nonmarket community benefits identified in this scenario (see Table 4-3).

Table 4-3: CBA impacts

A	**WITHOUT PROJECT: NO COMMUNITY INVESTMENT**	
	UTILITY	
	COSTS	**BENEFITS**
	Fuel	*Revenue*
	Federal Carbon Tax	
	Capital expenditures	
	Operations and Maintenance	
	Depreciation	
	Fuel Spill Risk	
	Environmental Catastrophe Risk	
	COMMUNITY	
	COSTS	**BENEFITS**
	Fuel Spill Risk	
	Environmental Catastrophe Risk	
	Noise Pollution	
B	**COMMUNITY INVESTMENT I: SOLAR PV**	
	UTILITY	
	COSTS	**BENEFITS**
	Pre-project Planning	*Revenue*
	Fuel	*Reduced Administrative and Legal Costs*
	Federal Carbon Tax	*Reconciliation*
	Capital expenditures	*Knowledge Building*
	Operations and Maintenance	
	Depreciation	
	Fuel Spill Risk	
	Environmental Catastrophe Risk	
	COMMUNITY	
	COSTS	**BENEFITS**
	Pre-project planning	*Energy Literacy*
	Capital expenditures	*Energy Security*
	Depreciation	*Reconciliation*
	Operations and Maintenance	*Pride*
	Fuel Spill Risk	*Knowledge Building and Sharing*
	Environmental Catastrophe Risk	*Local Air Quality Improvement*
	Noise Pollution	*Power Bill Cost Savings*

4.3 Quantifying, Valuing and Qualifying Impacts

The costs and benefits of the feasible REA integration paths in northern, remote and Indigenous communities are modeled to extend over a period of 25 years (N=25), from 2022 to 2047. In the community investment scenario, solar PV integration is assumed to augment the energy landscape in Kinoosao. In both cases, the CCM will continue to operate as usual, with the modeled impacts reflecting the effects of integrated RE technologies into the community energy landscape. This means that for the community investment scenario, the diesel generation costs and benefits will be reported along with the costs and benefits specific to solar PV scenario. This subsection lists the parameters, variables and indices included in the analysis. It also describes how the impacts identified in section 4.3 are quantified and valued. The parameters (Table 4-4) are estimates containing two or more variables. The variables (Table 4-5) are single point estimates that may be used independently or in combination with other variables. The indices (Table 4-6) are used to clarify the parameters and variables in both project scenarios. Impacts that were not quantified or valued in the scope of this thesis are qualitatively described and reported in Chapter 5.

Table 4-4: Parameters for CBA estimates

Notation	Parameter
R	Revenue ($/year)
δ	Diesel Fuel Cost ($/year)
ρ	Annual Volume of Diesel Fuel Consumed (Litres/Year)
η	Carbon Tax Expense ($/year)
γ	Diesel Emissions (Tonnes CO_2e/year)

Table 4-5: Variables for CBA estimates

Notation	Variable
E	Annual Electricity Demanded (MWh/Community)
D	Diesel Fuel Combusted (Litres/MWh)
F	Diesel Fuel Cost ($/Litre)
C	Capital Expenditures (Generation Infrastructure) ($/year)
OM	Operations and Maintenance ($/year)
α	Depreciation (Diesel Generation Infrastructure) ($/year)
A	Asset Value (Diesel Generation Infrastructure) ($/year)
β	Rate of Depreciation (% of Asset Value/year)
μ	Emissions from Diesel Combustion (Tonnes CO2e/litre)
T	Federal Carbon Tax Rate ($/Tonne CO2e)
π	Consumer Power Rate ($/kWh)
P	Pre-project Planning ($/year)

Table 4-6: Indices for CBA estimates

Notation	Index
N	Timeframe (total years)
n	Year
i	Diesel generation
j	Solar generation
u	Utility
t	Community

4.3.1 Without Project: No Community Investment

For the ‘without project’ scenario, a market-based approach is used to estimate the costs of production and the revenue benefit to estimate net social benefits (NSB) of the scenario. A qualitative approach is used to describe the social costs incurred by both the electric utility operator and the community.

$$\text{NSB} = \sum_{n=0}^{N} \left[\left[R_{iu} = E_{i(n)}\, \pi_{i(n)} \right] - \left[\delta_{iu} + \eta_{iu} + C_{iu} + OM_{iu} + \alpha_{iu} \right] \right] \tag{4.2}$$

Where:

The revenue from electricity sales (R_{iu}) in Kinoosao is estimated using two variables, the annual quantity of electricity demanded by the community (E_i) and the power rate (π) ($R_{iu} = E_{i(n)}\, \pi_{i(n)}$). The assumed annual quantity of electricity demanded by the community used in the start year (2022) is 200 MWh. As SaskPower (2021c, page 9) projects a 2% increase in the quantity of power demanded, this is modeled from n=1 to n=25. The formula used to calculate the power rate comes from a SaskPower solar planning study (2015) describing the power rate for Kinoosao (in cost per kWh). In this analysis, the 2015 power rate formula has been modified to include the $0.01/kWh federal carbon charge borne onto consumers by the utility (see Table 4-1). The power rate used in the start year is $0.24/kWh and is modeled to increase by 2% from n=1 to n=25.

The annual fuel expense (δ_{iu}) is a function of the volume of fuel used in the CCM (ρ_i) and the cost of diesel fuel (F_i) per litre (see Equation 4.3). The volume of diesel fuel used (ρ_i) is calculated by multiplying the annual quantity of diesel generated power demanded by the community (E_i) and volume of diesel fuel consumed (D) per MWh of electricity generated (see Equation 4.3). In this model, it is assumed that in n=0 Kinoosao will use 200 MWh of diesel generated power. SaskPower (2021b) provided data that revealed the CCM in Kinoosao utilizes 554 litres of diesel fuel to generate 1 MWh of electricity. The cost of diesel fuel paid by SaskPower in 2021 was $1.44 per litre (SaskPower, 2021b). The model assumes that the cost of diesel fuel paid in n=0 is $1.44 per litre and that this expense will increase by 2% per year through the duration of the analysis.

$$\delta_{iu(n)} = \rho_{i(n)}\, F_{i(n)} = E_{i(n)}\, D\, F_{i(n)}, n = 0, 1, \ldots, N \tag{4.3}$$

The Greenhouse Gas Pollution Pricing Act (or federal carbon tax) is a policy set by the Canadian government, and applies in the province of Saskatchewan, that imposes a price for industrial based carbon emissions. In this analysis, the estimate for the federal carbon tax expense (η_i) (see Equation 4.4) is a function of the total annual carbon emissions from diesel (γ_i) and the carbon tax rate (T) (see Table 4-7). The carbon tax rate is modeled to stay at $170 from 2031 to 2047 (n=9 to n=25). The annual carbon emissions from diesel (tonnes CO_2e) are estimated based on the annual volume of diesel fuel used (ρ_i) and the concentration of CO_2e emitted per litre of diesel fuel used (μ) (see Equation 4.5). The University of Calgary (2015) reports that .0026 tonnes of CO_2e are released per liter of diesel fuel combusted in diesel electricity generation. This estimate for μ is constant throughout the analysis.

$$\eta_{iu(n)} = \gamma_{i(n)} T_{(n)}, n = 0, 1, \dots, N \tag{4.4}$$

$$\gamma_{i(n)} = \rho_{i(n)} \mu, n = 0, 1, \dots, N \tag{4.5}$$

Table 4-7: Canadian federal carbon tax rate

Year	Tax Rate ($/tonne CO_2e)
2022, n=0	50
2023, n=1	65
2024, n=2	80
2025, n=3	95
2026, n=4	110
2027, n=5	125
2028, n=6	140
2029, n=7	155
2030, n=8	170

Source: Government of Canada (2022d).

The estimate for capital expenditures (C_i) was obtained through participatory interviews with SaskPower (2022a). This cost category is specific to the infrastructure assets that generate and distribute electricity in the CCM including generators, distribution lines and poles. This estimate is reported annually. SaskPower last installed generators in Kinoosao in 2016, 2017 and 2018. New generators are modeled to be installed every eight years, beginning in 2024 at a cost of $50,000 each. In total, I assume that nine generators are purchased over the term of the analysis (n=2,3,4,10,11,12,18,19,20). SaskPower estimates the replacement life of distribution lines and poles to be 65 years; with the current assets estimated to have been last replaced in 1998, I do not model any replacement to distribution assets in this analysis.

Interviews with SaskPower (2021b) revealed that operations and maintenance (OM_{iu}) for electricity projects are estimated based on the annual capital expenditures (C_i) and fuel expense (δ_i). OM_{iu} includes costs for operating inputs that used annually during the production process. This includes employee salaries, general administration and bill collection. In this analysis, OM_{iu} is calculated to be 25% of the annual sum of the capital expenditures and fuel expense. Annual maintenance costs (OM_{iu}) also includes one on-site visit to Kinoosao involving air travel, accommodations and expenses for SaskPower employees totalling \$50,000 (SaskPower, 2022a) (see Equation 4.6).

$$OM_{iu(n)} = [0.25(C_{i(n)} + \delta_{i(n)})] + 50{,}000, n = 0, 1, \dots, N \tag{4.6}$$

Depreciation is a fixed cost of production. The depreciation expense (α_{iu}) reflects the loss in value that occurs each year from the use of an income generating asset or, the future costs that will inevitably occur for the replacement of that asset. This analysis uses a declining balance approach to calculate the depreciation of the CCM generation assets. For this approach, the asset value (A_i) is depreciated by a consistent proportion each year (β) (see Equation 4.7).

$$\alpha_{iu(n)} = (A_i)_{(n)} (\beta), n = 0, 1, \dots, N \tag{4.7}$$

The Government of Canada's central accounting bureau, the Canada Revenue Agency, uses a common rate scale for depreciable assets. The CCM generation assets belong to the Class 43 rate, where infrastructure assets that generate goods for sale can be depreciated by 30% per year (Government of Canada, 2022f). Interviews with SaskPower (2022) revealed that in 2022 (n=0), the value of the CCM generation assets are \$73,936. The depreciation expense in each future year is a rolling estimate where

$$(A_i)_{(n)} = (A_i)_{(n-1)} - \alpha_{iu(n)}, n = 0, 1, \dots, N. \tag{4.8}$$

4.3.2 Community Investment: Solar PV

For the community investment scenario, a market-based approach is used to estimate the costs of production and profit benefit. A qualitative approach is used to describe the social costs and benefits incurred by both the electric utility operator and the community. The net social benefit (NSB) of this scenario is the summation of the utility revenue reaped minus the market costs sustained by the electric utility operator and the community over the term of the analysis (see Equation 4.9).

$$\text{NSB} = \sum_{n=0}^{N} \Big[\big[R_{iu} = E_{i(n)}\, \pi_{i(n)}\big] - \Big[[P_{ju} + \delta_{iu} + \eta_{iu} + C_{iu} + OM_{iu} + \alpha_{iu}] + \big[P_{jt} + C_{jt} + OM_{jt} + \alpha_{jt}\big]\Big]\Big] \tag{4.9}$$

Where:

Revenue (R_{iu}) is estimated using the same methodology outlined in "4.3.1 Without Project: No Community Investment". Given that a 20% reduction in the electric power demanded from diesel is expected, I assume that the value of the revenue parameter (R_{iu}) will decrease by 20%. Given the 20% power generation offset from solar PV integration, the fuel costs (δ_i) are estimated using the same methodology as in "4.3.1 Without Project: No Community Investment", with a 20% reduction in fuel use starting in 2024 (n=2). The federal carbon tax expense (η_i) is estimated using the same methodology as in "4.3.1 Without Project: No Community Investment", with a 20% reduction in fuel use and therefore, a 20% reduction in the federal carbon tax expense is estimated starting in 2024 (n=2). In this scenario it is assumed that the electric utility operator will continue to invest in capital assets (C_{iu}), operation and maintenance expense (OM_{iu}), and yearly depreciation using the same methods and valued as described in "4.3.1 Without Project: No Community Investment".

The estimate for pre-project planning (P_j) echoes values reported by Wilber et. al. (2019), where solar PV contractors stated that logistics and planning attributed to 30% of a project's total budget, where labour and capital expenditures total the other 70%. In this model application, I assume that the logistics and planning accounting for P_j includes human resource costs only and does not include transport or specialty engineering and design. To predict this pre-planning cost, an estimate for the solar PV capital expenditure (C_j) is used using Equation 4.10. This expense is included in the years 2022 (n=0) and 2023 (n=1) only for both the utility corporation and the community.

$$P_{jut} = \left(\frac{3}{7}\right) C_j, n = 0, 1 \tag{4.10}$$

The cost category specific to the depreciable capital infrastructure assets that generate solar power as integrated into the CCM are represented by (C_j). This estimate is reported in one year, 2024, and does not include the cost of transport or specialty electrical or engineering work. An estimate for capital expenditures was initially obtained through participatory interviews with PBCN (2022) at $2.75/Watt (CAD) and was confirmed by FNPA (2022) to reflect current Saskatchewan-based community scale solar PV costs. This estimate is low compared to the costs for installed community scale solar PV projects in Alaska reported by Wilbur et. al. (2019), which ranged from $3.19 - $13.33/Watt (2016 USD). Given the 30 kW (30,000 watt) generating capacity of the modeled solar scenario, the capital expense borne onto the community in 2024 is $82,500.

The depreciation expense (α_j) reflects the loss in value that occurs each year from the use of the renewable energy generating asset or, the future costs that will inevitably occur for the replacement of that asset. This expense begins the year after installation, in 2025. The method for calculating the depreciation expense mirrors the method used for depreciating the diesel generation assets defined in “4.3.1 Without Project: No Community Investment”, where α_j is a function of the asset value (A_j) and the depreciation rate (β). In this case, A_j is the cost of the infrastructure assets reported as part of the solar PV technology capital expenditures expense, absent of transport/delivery or costs attributed to specialty engineering. The depreciation rate of the solar PV generation assets belongs to the Class 43 rate, where infrastructure assets are depreciated by 30% per year (Government of Canada, 2022f).

$$\alpha_{jt} = (A_{jt})(\beta), n = 4, 5, \dots, N \tag{4.11}$$

Wilber et. al. (2019) affirm that the operations and maintenance of remote solar arrays in Alaska are a fixed `cost including cleaning, part replacements and unscheduled maintenance. A community’s level of remoteness can influence the costs of solar PV operation and maintenance. Given the remoteness of the case study community, this model application uses the $100/kWh per year (2016 USD) estimate provided in work by Wilber et. al. (2019). After adjusting the value to 2022 Canadian dollars, the annual operations and maintenance (OM_{jt}) cost borne by the community from 2024 to 2047 is $151.00/kWh/year, or $4350.00 per year.

4.4 Demand Side Scenario Analysis

The scenario analysis aims to identify a project constraint, management, environmental or timeline impact that is important to the study community and model the net welfare effect of its’ hypothetical actualization. The scenario analysis in this thesis investigates and reports potential benefits of community investment into demand side management (DSM) by estimating and applying a demand side management efficiency factor to community-led home retrofit investments in Kinoosao. The costs and benefits of DSM home retrofit upgrades are estimated using secondary data conveyed in Arnold's (2021) "*The benefits of retrofits – Canadian Climate Institute – blog*," which describes the Mi'kmaw Home Energy Efficiency Project in Nova Scotia (see Section 2.1.3 Canadian Energy Policy, page 9).

Arnold (2021) reports that the cost of the retrofits for the Mi'kmaw First Nation in Nova Scotia was $7000 per household, and the corresponding power bill cost savings totaled $750 CAD per household per year. Given that the Mi'kmaw project was slated to start in 2020 (Province of Nova Scotia, 2019) and that the power bill cost saving benefit was reported in 2021, I assume that the $750 saved per household was for electricity billed at the 2021 residential rate. In 2021, the residential electricity rate in Nova Scotia was $0.16 per kWh (Canada Energy Regulator, 2021b).

Using this data, the corresponding electricity saved per household per year (in kWh) can be estimated by dividing the electricity cost savings per household per year by the power rate (see Equation 4.12). The resulting electricity savings reaped from the Mi'kmaw DSM project is estimated to be 4,688 kWh per household per year.

$$Electricity\ Savings\ (kWh/HH/Year)\ = \frac{Power\ Bill\ Cost\ Saving\ (\$/HH/Year)}{Power\ Rate\ (\$/kWh)} \tag{4.12}$$

The efficiency factor provides a unitless measure, similar to the benefit cost ratio, to which the benefits (electricity cost savings) of investments into DSM housing retrofit projects in Indigenous communities may be applied. The DSM efficiency factor can be calculated by dividing the cost of the project by the electricity saving per household (see Equation 4.13). The DSM efficiency factor of the Mi'kmaw home retrofit project is estimated to be 0.67. This means that for every $1.00 invested in DSM home retrofit, 0.67 kWh of electricity is estimated to be saved per year through a reduction in demand.

$$DSM\ Effeciency\ Factor\ = \frac{Electricity\ Savings\ (kWh/HH/Year)}{Cost\ of\ DSM\ Home\ Retrofit\ (per\ HH)} \tag{4.13}$$

Assuming that all 16 households in Kinoosao receive a $7,000 DSM home retrofit, the community-led DSM scenario for Kinoosao will have a total cost of $112,000 CAD in 2022 (n=0). Applying the DSM efficiency factor, this equates to a 75,000-kWh reduction in electricity demanded in Kinoosao per year as a result of the retrofits. As the modeled retrofit is assumed to decrease the quantity of electricity demanded, the only modeled changes on the supply side are the corresponding adjustments to the fuel, operations and maintenance and carbon tax expenses. The capital expenditures and depreciation are assumed to stay the same.

4.5 Discounting

For this analysis, the future costs and benefits are reported in real dollars. This means that the costs and benefits are expressed in today's prices and are not inflated. The interviews revealed that SaskPower (2021b) uses a 5.5% discount rate and that the First Nations Power Authority (2022) uses a 4 or 5% discount rate on community and utility scale projects. The First Nations Power Authority stated that because of the strict regulatory requirements of RE projects, they are seen as being fairly low risk. Given the direct market and social impacts that RE integration may have in CCMs, a 3% discount is applied, as advised by the Treasury Board of Canada (2007), in all scenarios.

$$NPV_{i,j} = \sum_{n=0}^{N} \frac{B_n - C_n}{(1+.03)^n}, n = 0, 1, \ldots, N \quad (4.14)$$

4.6 Conclusion

The application of the cost benefit framework used a participatory modeling approach to gather data. Local geographic and economic constraints were uncovered and the feasible set of modeled investment paths specific to the CCM in Kinoosao, Saskatchewan, were described, over a defined timeline. The costs and benefits of the feasible set of modeled scenarios were identified via interviews with representatives of the study community, Kinoosao and the electric utility operator, SaskPower. The costs and benefits of the scenarios were quantified, valued and/or qualified using data from participatory primary interviews and secondary scholarly and industry-related resources. The scenario analysis presented a contrasting investment alternative, based on demand side management. Finally, selecting and applying the discount rate in a spreadsheet model enabled the net present value of alternatives to be expressed. Chapter 5 presents the results of the application of the cost benefit framework for cold climate microgrids and the scenario analysis to provide further depth of understanding for energy-related investments aimed to improve welfare in northern, remote and Indigenous communities.

5.0 Results

The cost benefit framework for cold climate microgrids estimates the net welfare effects of alternative energy investment paths in northern, remote and Indigenous communities. Chapter five of this thesis presents the results of the CBA, focusing on a comparison of the net present value and benefit cost ratio of investment alternatives as detailed in chapter four. Three scenarios are presented (i) the baseline scenario, with no community investment; (ii) the first ‘with project’ scenario, reporting the results of community investment into solar PV integration (see Table 5-1); (iii) and an additional ‘with project’ scenario, reporting the results of community investment into demand side management. The first section of this chapter presents the results of the three CBA scenarios. Subsequent sections provide a broader discussion of the direct effects and welfare implications of the results, including sensitivity analysis of select parameters and criteria for community evaluation.

5.1 Results for Baseline and Alternative Scenarios

The final step of the framework compares the net present value of the baseline scenario (diesel generation alone) to the community investment scenarios, where (i) a solar PV array is integrated to augment the diesel generation in 2024 (n=2) and maintained over the term of the analysis and (ii) demand side management home retrofits begin to reduce the demand for electricity in 2022 (n=0). The results of the CBA are summarized in Table 5-1, expressed in Canadian 2022 dollars, discounted at 3%, assuming a 25-year planning horizon. The revenue benefit and costs presented below are alternative market impacts, quantified via participatory interviews and literature review; nonmarket values were not estimated are not included in the calculations.

Table 5-1: Net present value and benefit cost ratio of modeled energy investment paths for Kinoosao, Saskatchewan

	Baseline	*Solar PV*	*DSM*
PROJECT BENEFITS:			
Utility:			
Revenue	$1,703,668.15	$1,440,744.82	$1,290,773.23
Total Benefits	$1,703,668.15	$1,440,744.82	$1,290,773.23
PROJECT COSTS:			
Utility:			
Pre-project planning	-	$70,694.39	-
Fuel	$4,719,224.45	$3,839,555.64	$3,337,792.11
Capital expenditures	$331,273.80	$331,273.80	$331,273.80
Operations & Maintenance	$2,183,281.95	$1,963,364.75	$1,861,491.98
Depreciation	$350,118.22	$350,118.22	$350,118.22
Federal Carbon Tax	$978,559.57	$789,440.54	$694,793.87
Community:			
Pre-project planning	-	$70,694.39	-
Capital expenditures	-	$77,764.16	-
Depreciation	-	$70,684.89	-
Operations & Maintenance	-	$74,483.50	-
Building Retrofits	-	-	$112,000.00
Total Costs	$8,562,457.99	$7,638,074.27	$6,687,469.98
NET COST	**-$6,858,789.84**	**-$6,197,329.45**	**-$5,396,696.75**
BENEFIT COST RATIO	**0.20**	**0.19**	**0.19**

The baseline scenario reflects the status quo, where all of the electricity generated and consumed in Kinoosao, Saskatchewan comes from the combustion of diesel fuel. The net cost (revenue minus costs) of operating the baseline scenario is estimated to be $6,858,789.84 (see Table 5-1). As the community incurs no costs in the baseline scenario, the net cost of $6,858,789.84 represents the loss in producer surplus, or profit, that SaskPower undertakes by owning and operating the CCM over the 25-year analysis horizon. The community-led solar PV integration scenario reports a net cost of $6,197,329.45, indicating that welfare is improved with community investment into solar PV in Kinoosao. The difference in the net cost of operations from the baseline to the solar PV scenario, $661,460.40 over the term of the analysis (see Table 5-2).

The BCR of the baseline (0.20) and with solar PV (0.19) scenarios are calculated using the revenue and costs reported in Table 5-1. Both ratios are below one; this is expected given that both projects impose net costs, or the net benefits of both scenarios are negative. The BCR measure indicates that for every $1.00 invested in diesel generation, the utility reaps $0.20 in revenue and that for every $1.00 invested in diesel generation with solar PV integration, the utility reaps $0.19 in revenues. The utility reaps the benefits in this application of the framework because the revenue reaped from electricity sales is the only monetized benefit stream.

Table 5-2: Comparison of net present value (2022 CAD) and benefit cost ratios

	Baseline	***Solar PV***	***DSM***
Total PV Revenue	$1,703,668.15	$1,440,744.82	$1,290,773.23
Total PV Costs	$8,562,457.99	$7,638,074.27	$6,687,469.98
Net Cost	-$6,858,789.84	-$6,197,329.45	-$5,396,696.75
Cost Savings*	-	$661,460.40	$1,462,093.09
Benefit Cost Ratio	0.20	0.19	0.19

*Cost savings (in 2022 CAD) are relative to the baseline scenario.

The net cost of the DSM scenario is $5,396,696.75. The DSM project results in a $1,462,093.09 reduction in net costs when compared to the baseline (see Table 5-2). The cost saving from DSM is 121% higher than the solar PV scenario, implying that demand side management, on its own, may have the potential to improve community welfare at a greater scale than supply-side investments, strictly from a market standpoint. The BCR of the DSM scenario was calculated using the revenue and costs reported in Table 5-1. The BCR for the demand side management is 0.19, which is lower than the baseline BCR (0.20) based on diesel generation with no community investment. This indicates that for every $1.00 invested in diesel generation with community-led home retrofits, the utility reaps $0.19 revenue.

5.2 Discussion

This section of the results chapter expands the theoretical paradigms of cost benefit analysis, where the monetary market and nonmarket values of investments into CCM management, solar PV integration and DSM are explored at greater depth. The first subsection focuses on financial analysis and the impacts of variations in market behaviour, from both the utility and community perspectives. This is followed by discussion on directing, evaluating, focusing the nonmarket valuation scholarship and techniques specific to Indigenous values and REA integration in northern, remote and Indigenous communities.

5.2.1 Market Costs and Benefits: Financial Analysis

Financial analysis informs business decision making based on pricing and the efficiency and/or profitability of the inputs of electricity generation and distribution. This is where indictors related to various forms of risk can be examined. The broad financial component makes cost benefit analysis a data-intensive economic method with many sources of information. The primary data sources for estimating the market costs and revenues of CCM management and REA integration came from SaskPower and representatives from PBCN (see Appendix B). This subsection of the results investigates and reports the financial (market) implications of the three modeled scenarios from the utility and community perspectives.

5.2.1.1 Electric Utility Operator Costs

The following analysis focuses on the effects that CCM management and REA integration has on the projected variable costs of production: diesel fuel, operation and maintenance and the federal carbon tax. As capital expenditures and depreciation are fixed costs throughout the analysis, they are excluded. The total cost to SaskPower for the baseline, solar PV and DSM scenarios, total $8,562,457.99, $7,344,447.33 and $6,575,469.98 respectively. In the modeled solar PV scenario, this is a 14% reduction in costs for SaskPower compared to the baseline. For the DSM scenario, SaskPower is estimated to see a 23% reduction in costs compared to the baseline.

i. Fuel

In electricity generation, a primary energy source is converted and distributed as consumable power. In Kinoosao, the primary energy source is diesel fuel. It is the largest operating cost to CCM management representing 55%, 52% and 51% of the total costs in the baseline, solar PV and DSM scenarios, respectively (see Table 5-3). Over the duration of the baseline scenario (N=25), an estimated 3,732,660 liters of diesel would be required to power Kinoosao.

Table 5-3: Utility expenses in three modeled scenarios reported as a % of total utility costs

Scenario	Fuel Expense	Operation and Maintenance Expense	Federal Carbon Tax Expense
Baseline: No Project	55%	25%	11%
Solar PV	52%	27%	11%
DSM	51%	28%	11%

As an economic method, CBA estimates the NPV of project alternatives at a single point in time, in this application the costs and benefits are reported in 2022 CAD. In contrast, the variability of the fuel expense represents a high level of price risk year over year (see Figure 5-1). As an essential input of production in CCM management, comprising more than 50% of estimated total costs for the electric utility operator, the price of fuel at the time of purchase can have a potentially dramatic effect on the net cost of operations. An analysis of the diesel fuel price (per liter) in Saskatchewan over the past 25 years (see Appendix D) shows that it can be highly erratic, changing as much as 33% year over year.

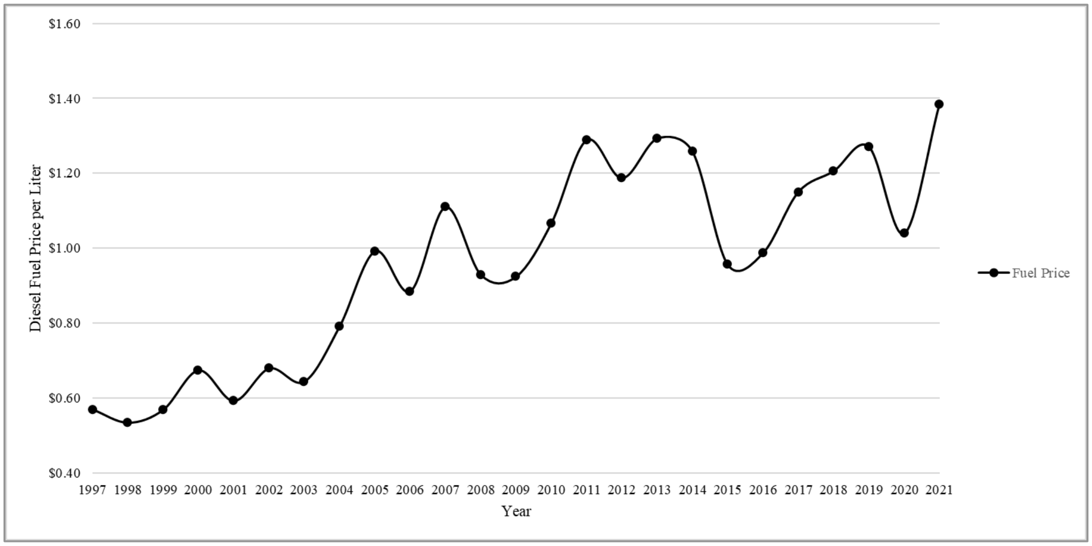

Figure 5-1: Diesel fuel price per litre in Saskatchewan 1997-2021

As modeled, the integrated solar PV technology acts as a renewable energy substitute for electricity generation in Kinoosao, meaning that it may have potential to mitigate the market impacts of the diesel fuel price risk. The solar PV scenario, modeled over 23 years, is estimated to provide SaskPower with diesel fuel cost savings totalling $879,668.81. I conducted sensitivity analysis to calculate the cost savings generated by the solar PV scenario if the price of fuel increased by 5%, as opposed to the conservative 2% increase used in the model. The corresponding cost savings from the integrated solar PV offset, under the 5% modeled assumption, would total $1,345,741.79, representing a 53% increase in fuel cost savings. This highlights the effectiveness that solar PV integration in Kinoosao may have to mitigate the price risk from diesel fuel in the long run.

ii. Operations and Maintenance

The second largest expense incurred by the utility is the operation and maintenance of the CCM. It is the cost required to keep the CCM operational and includes salaries, corporate administration, and billing. The operation and maintenance expense for SaskPower is modeled to have both a fixed cost component (labour and travel) and variable cost component, representing a percentage of fuel and capital expenditures (see Equation 4.8). The results show that the OM costs are $2,183,281.95, $1,963,364.75 and $1,861,491.98 representing a 25, 27 and 28 percent share of the present value of total costs in the baseline, solar PV and DSM scenarios, respectively (see Table 5-3). Similar to the fuel expense, the OM expense is stable, when the quantity of electricity demanded decreases by 20% from solar PV integration, the OM costs to the utility decrease by 2%. The OM costs in the DSM scenario show that a 38% reduction in demand in year zero would reduce OM costs by 3% over 25 years.

iii. Federal Carbon Tax

The federal carbon tax expense is $978,559.57, $789,440.54 and $694,793.87 in the baseline, solar PV and DSM scenarios (see Table 5-1), equating to 11% of the NPV of total costs for SaskPower. The greenhouse gas emissions savings achieved from the community investment scenarios are presented in tonnes CO_2e in Table 5-4. The emissions savings are an estimate of the emissions avoided from (i) the 20% reduction in diesel generated power from the solar PV technology beginning in n=2 and (ii) the 38% reduction in electricity demanded in the DSM scenario beginning in n=0. The emission savings were calculated by subtracting the total emissions in the solar PV and DSM scenarios from the total emissions in the baseline scenario (see Appendix E). This corresponds to an estimated 1825 tonnes of CO_2e emissions saved in the solar PV scenario and an estimated 2810 tonnes of CO_2e emissions savings from DSM over the term of the analysis. The estimates in Table 5-4 are based only on decreased diesel consumption and does not include a full life-cycle assessment of carbon emissions from solar PV construction, transportation or installation and DSM embodied emissions.

Table 5-4: Greenhouse gas emissions savings 2022 – 2047 (Tonnes CO_2e)

Community Investment Scenario	Emissions Savings*
Solar PV	1825
DSM	2810

*Calculated using data presented in Appendix E.

5.2.1.2 Electric Utility Operator Benefits

The total present value of the revenue in the baseline, solar PV and DSM scenarios is $1,703,668.15, $1,440,744.82 and $1,290,773.23 respectively. The BCR showed that the modeled cost of supplying diesel generated electricity in Kinoosao is roughly five times higher than benefits. This means that in order to for SaskPower to break-even in providing diesel generated electricity to Kinoosao, they would need to charge consumers $1.27/kWh.

5.2.1.3 The Discount Rate

The discount rate commonly used by SaskPower (5.5%) was studied to evaluate cost savings of the solar PV and DSM scenarios, reflecting the utility's preferential representation of the time value of money, positive time preference and perceived project risk. For the baseline scenario, the estimated net cost of operations is 25% less than the estimated net cost of operations at the modeled 3% social discount rate (see Table 5-2). Table 5-5 illustrates the estimated net cost of CCM operations (2022 CAD) over 25 years at the 5.5% industry discount rate for comparison.

Table 5-5: Estimated net cost of CCM operations over 25 years at 5.5% discount rate

	Baseline	***Solar PV***	***DSM***
Total PV Revenue	$1,271,555.30	$1,080,924.74	$956,561.33
Total PV Costs	$6,439,128.14	$5,837,662.65	$5,033,816.56
Net Cost	-$5,167,572.84	-$4,756,737.91	-$4,077,255.24
Cost Savings*	-	$410,834.93	$1,090,317.60

*Cost savings (in 2022 CAD) are relative to the baseline scenario.

5.2.1.4 Community Costs

The following analysis focuses on the market effects that REA integration in Kinoosao has on the costs borne by the community. I assume that all costs of solar PV planning, infrastructure and operation and maintenance are directly paid by the community over the analysis horizon with no financing or government transfers. For the solar PV scenario, pre-project planning, capital expenditures, operations and maintenance and depreciation are the quantified market costs paid by the community. For the DSM scenario, the sole quantified cost to the community is the home retrofits which is assumed to include materials and labour only.

i. Solar PV

The present value of costs borne by the community in the solar PV scenario totals $293,626.94. This includes pre-project planning, capital expenditures, operations and maintenance and depreciation expense categories. The 30-kW solar array is modeled to be integrated with the diesel generation for 23 years of PV based electricity generation, in which time the power bill cost savings to PBCN and the residents of Kinoosao totals $262,923.32 (see Table 5-6). This value equates to the loss in revenue realized to SaskPower from the duopolistic electricity delivery scheme where two agents now exist in the marketplace. The change in revenue/power bill cost savings simply shifts the surplus away from SaskPower, the producer, and transfers it to Kinoosao, the consumer. Data from SaskPower (2021b) shows that 30% of all billing for electricity in Kinoosao goes to private residents and the remaining 70% of charges are paid by PBCN. Over the 23 years that the solar technology is modeled to offset diesel generation, assuming the same billing distribution, I estimate that private residents will save $78,877.00 on their electricity bills and that PBCN will save $184,046.33 (see Table 5-6).

Table 5-6: Power bill cost savings relative to baseline scenario (2022 CAD)

Community Investment Scenario	**Solar PV**	**DSM**
Power Bill Cost Savings (Total Charges)	$262,923.32	$412,894.92
Power Bill Cost Savings (Private Accounts[1])	$78,877.00	$123,868.48
Power Bill Cost Savings (PBCN Account[2])	$184,046.32	$289,026.44

[1]Private accounts are billed for 30% of all electricity charges in Kinoosao.
[2]PBCN is billed for 70% of all electricity charges in Kinoosao.

Considering that the community pays $293,626.94 to own and operate the solar infrastructure and achieves $262,923.32 in power bill cost savings (see Table 5-6), overall, the community realizes a net loss of $30,703.61 by investing in and maintaining a 30-kW solar array in Kinoosao strictly from a market standpoint. Given that the community solar PV scenario results in a net loss in surplus to the community totalling $30,703.61, I assume that the $661,460.40 in overall cost savings from the solar PV scenario (see Table 5-2) is an improvement in producer surplus actualized by SaskPower.

ii. DSM

The electricity savings from the modeled DSM investment totals 75,000 kWh per year (see Appendix E), representing a 38% reduction in the demand for diesel-generated electricity in 2022 (n=0). The DSM efficiency factor is static, meaning that the electricity savings are modeled to remain consistent over the term of the analysis. So, as the demand for electricity grows over time, the corresponding DSM offset will gradually decline (see Appendix E). The present value of costs borne by the community in the demand side management scenario totals $112,000, a one-time cost in 2022 (n=0). There are no annual expenses needed to actualize the market benefits of the modeled demand side management in Kinoosao. It is estimated that the community will achieve $412,894.92 in power bill cost savings (see Table 5-6) over the term of the analysis, realizing a net gain of $300,894.92, strictly from a market standpoint for its investment into DSM in Kinoosao, Saskatchewan. I assume, therefore, that the $1,462,093.09 cost savings achieved in this scenario (see Table 5-2) provides a gain in both consumer surplus ($300,894.92) and producer surplus ($1,161,198.17).

The DSM scenario is not modeled to include a pre-project planning expense, although coordinating accommodations for labourers and the transport and storage of equipment and tools will increase the project costs for the community. To help understand the pricing effects of remoteness on demand-side management investments a sensitivity analysis of the retrofit costs was conducted. If the community sees a 100% increase in the cost of the building retrofit expense for expenses related to remoteness (extra labour, travel, accommodations) and that the DSM electricity savings (75,000 kWh per year) remains the same, the net present value of cost savings ($1,350,093.09) is still 104% higher than the supply side solar PV investment scenario ($661,460.40). With the 100% increase in DSM costs, the BCR stays at 0.19.

5.2.1.5 Community Benefits

While PBCN is not modeled to reap any revenue from the solar PV or the DSM scenarios, the power bill cost savings are a quantifiable benefit achieved with both investment alternatives. Considering only the market costs and benefits of each scenario assigned to the community, a benefit cost ratio can be calculated. The benefit cost ratio for the community uses the present value of power bill cost savings as the sole benefit in the numerator and the total present value of community costs in the denominator. Using this criterion, the BCR for the solar PV scenario is 0.90 and the BCR for the DSM scenario is 3.69.

5.2.2 Nonmarket Costs and Benefits: Qualitative Analysis

As the only two stakeholders to have standing in the CBA, this research identifies the impacts of REA investments from the utility and community perspectives. This means that one impact results in two separate welfare implications and requires two separate valuation approaches. While outside of the scope of this research, the impacts could be valued using either stated preference or revealed preference approaches (see Table 5-7). This discussion, therefore, provides greater depth of the theory and practices that are appropriate for qualifying and valuing the nonmarket impacts related to REA investments. The nonmarket impacts are described to detail the possible net gain or loss in social surplus due to CCM management and community investment into REAs in northern, remote and Indigenous communities.

Table 5-7: CBA impacts and nonmarket valuation approaches

Nonmarket Impact	***Stated Preference***	***Revealed Preference***
Utility		
Fuel Spill Risk		●
Environmental Catastrophe Risk		●
Reconciliation		●
Reduced Administrative and Legal Costs		●
Knowledge Building		●
Community		
Fuel Spill Risk	●	●
Environmental Catastrophe Risk	●	●
Noise Pollution	●	●
Energy Literacy	●	●
Energy Security	●	●
Pride	●	
Knowledge Building and Sharing	●	
Local Air Quality Improvement	●	●
Power Bill Cost Savings		●
Reconciliation	●	

5.2.2.1 Nonmarket Costs

SaskPower is expected to incur two nonmarket costs, the fuel spill risk and environmental catastrophe risk. The nonmarket costs are production externalities of diesel generated electricity stemming from the baseline scenario and are expected to remain consistent in all scenarios. Fuel spill risk, environmental catastrophe risk and noise pollution are nonmarket costs identified by PBCN and are described specifically to consider the effects borne onto the residents of Kinoosao from the CCM. The fuel spill risk, environmental catastrophe and noise pollution risks are not anticipated to change for the interim of the analysis as they are production externalities attributable to diesel-generated power.

i. Fuel Spill Risk

Diesel fuel is a refined petroleum product derived from crude oil, the chemical composition of which makes it especially toxic for plant life in pristine natural environments (Behr-Andres et.

al., 2001). Oil products in soils have the potential to completely suppress water uptake at the root-level (Bykova et. al., 2021). In Kinoosao, a storage tank (see Figure 4-2) holds approximately 70,000 litres of diesel fuel. The age and current condition of the storage tank are not reported in this work. However, leaks are common in fuel storage tanks located in remote, northern communities (Behr-Andres et. al., 2001). With the fuel tank's location directly adjacent to the tree line, a spill could impact the local vegetation, wildlife (Mercer et. al., 2020) and/or increase the likelihood of an environmental catastrophe.

While it is out of the scope of this analysis to determine how much it would cost to remediate a fuel spill in Kinoosao, in a related anecdotal example, a northern airline paid roughly $1,636 per litre of diesel fuel spilled at an airport in Old Crow, Northwest Territories, Canada (CBC News, 2017). This spill occurred when a storage tank was overfilled. The total cost paid by the airline ($180,000 CAD) was allocated to cover expenses incurred for soil remediation and disposal of contaminated material with any additional resources to be saved by Gwich'in First Nation as part of an environmental damage fund.

In their survey of 75 residents living in remote, diesel-powered communities in Labrador, Mercer et. al. (2020) report that fuel spills and leaks were given a mean concern rating of 3.3/5. Bykova et. al. (2021) examined data for oil spills in Russian forests and state that localized ecosystem damage from fuel storage tanks is a high risk, as many leaks go unreported or are ignored. Remediation tactics for northern diesel fuel spills can include laying absorption pads, using fertilizer, removing soil with heavy equipment and hand tools or laying containment booms in wet regions (Behr-Andres et. al., 2001). Given the traditional subsistence lifestyle of the residents of Kinoosao, any leaks or spills are expected to impose a social cost to the community.

ii. Environmental Catastrophe Risk

Due to its remote location, Kinoosao, may be at risk of being directly impacted by wildfires. Kinoosao's neighbouring village, Southend is also located in Saskatchewan's Boreal Forest region. It was evacuated in 2021 as a safety measure in response to local wildfires, with residents being displaced and transported via helicopter to city centers in southern Saskatchewan (Pearce, 2021). PBCN (2022) reported that within the last ten years, a wildfire has come within ten kilometers of Kinoosao. In the event of a wildfire, it is possible that residents may have to drive to the closest city-center, which is Lynn Lake, Manitoba, located 100 kilometers away, or be lifted out via helicopter.

The location of the 70,000-liter diesel fuel tank within the community may present a significant environmental catastrophe risk, where a wildfire could increase the likelihood of a localized explosion. Such a catastrophe may destroy the electricity generation and distribution assets, community infrastructure and could put human lives at risk. In the case of an environmental catastrophe occurring, the residents of Kinoosao may be put at risk of injury or fatality. Economists often examine such risk using stated or revealed preference methodology (Roman et. al., 2012) to estimate the value of a statistical life (VSL) (Boardman et. al., 2018, page 408). In the stated preference context, individuals may be asked to assign a value to the compensation required to accept a fatality risk (Roman et. al., 2012). Studies that analyze occupational risk and wages are in the revealed preference category of nonmarket valuation. For applications in the United States, Boardman et. al. (2018) suggest using an estimate of $5 million (2008 USD) as the VSL. The Government of Canada's Policy on Cost Benefit Analysis (2018) suggests using a similar value of $6.1 million (2004 CAD) as the VSL and adjusting the value for inflation.

iii. Noise Pollution

The CCM has one Cummins Power Generation commercial-grade diesel generator running 24 hours per day. The generator, if unhoused, emits 86.3 dBa, or a-weighted decibels (see Appendix F). A-weighted decibels are the sound scale used to describe air noise by humans. It is not clear how audible the noise from a generator operating 24 hours per day is generally in the community or how many households in proximity are impacted by the noise. Mercer et. al. (2020) report that the noise pollution from diesel generated power in northern regions may be substantial, particularly in remote communities. Hedonic methods are often used to value the impacts of noise pollution on welfare by estimating the effects that industrial noise has on residential housing markets (Boardman et. al., 2018, page 428).

In addition to the impacts on direct human wellbeing, noise pollution can affect the surrounding environment, including wildlife species. Shannon et. al. (2016) report that shifts in terrestrial wildlife behaviour have been observed with anthropogenic noise levels of 40 dBa. Specifically, songbirds, terrestrial mammals and bats are sensitive to negative impacts of noise in the wild

(Shannon et. al., 2016). Given the traditional subsistence values of the community members, it is possible that any impacts from noise pollution on local wildlife could also affect the welfare of the residents.

5.2.2.1 Nonmarket Benefits

The anticipated nonmarket benefits of solar PV integration reaped by SaskPower over the term of the analysis are reduced legal and administrative costs, reconciliation and knowledge building. Theoretically, these benefits provide a correction to market failure stemming from information asymmetry, where a lack of knowledge, communication and/or relationship building results in extra costs to one or more agents in a market. In this case, I assume that, on the supply side, the improvement in social welfare, by reducing information asymmetry, is a transfer away from deadweight loss to the producer, SaskPower. These nonmarket benefits may be quantified using market models and/or revealed preference methods.

The qualified benefits reaped by the community for the solar PV scenario include energy literacy, energy security, pride, knowledge building and sharing, local air quality improvement, power bill cost savings and reconciliation. The nonmarket benefits of REA integration that are not quantifiable using revealed preference methods hold ancient Indigenous spiritually and culturally meaningful value (Manero et. al., 2022) that improve community welfare. In this research these include knowledge sharing and building, reconciliation and pride. Using classical nonmarket valuation approaches, original stated preference studies may be appropriate techniques used to value these benefits.

i. Reduced Legal and Administration Costs

The benefit of reduced legal or administrative costs are unique to this case study, as PBCN and SaskPower have been in a lawsuit stemming from 2004 related to infringement on Indigenous land rights (see Taylor, 2021). The case is based on the development of the Whitesand Dam located adjacent to Reindeer Lake, near Southend, in 1942. It is possible that successful RE integration in Kinoosao could ease future relations or negotiations between the two groups, resulting in a correction of information asymmetry. To estimate the benefit, legal specialists or accountants could estimate the hours of labour saved from eased negotiations between the two groups. Reduced legal and administration costs was not identified by PBCN as a benefit of solar

PV integration in Kinoosao; if administrative and legal costs for the First Nation were also expected to be reduced due to relationship-building, these cost savings could be estimated as a nonmarket benefit using an appropriate valuation method.

ii. Knowledge Building

Interviews with SaskPower (2022a) revealed that the utility operator sees organizational knowledge building as a benefit of RE integration in Kinoosao. Organizational knowledge is unique information that serves to advance the mandate or goals of a business. SaskPower (2022a) stated that in the future the company is considering taking some 'end of line' communities in the north off the grid. This research has shown that at minimum, 12 different departments in SaskPower will be coordinating to transition northern communities to low or no carbon systems. The departments are distribution planning, customer strategy & solutions, standards, inventory control, procurement, indigenous customer care, grid modernization, field operations, field technicians, information technology, logistics and finance. Furthermore, cooperation and knowledge sharing between communities and utility companies in Canada have been shown to enhance the benefits for utilities companies including improved reputation in the community, learning new opinions/worldviews, enhanced employee loyalty and enthusiasm (McDonald, 2005). There may also be opportunities, through the application of this framework, for utility companies to benefit from the traditional knowledge held and shared by residents of the community.

As a large First Nation with eight communities and roughly 4550 residents, PBCN stands to benefit from improving its capacity to meaningfully participate in Canada's rapid energy transition. In 2019, PBGOC joined the USask's CASES Partnership, demonstrating a formal commitment to facilitating renewable energy research and capacity building for remote and Indigenous communities throughout the circumpolar north. Improved business capacity in the electricity sector impact individual welfare at the community level through improved access to skill development and training leading to increased employment opportunities in the north and elsewhere. Enhanced business capacity, specific to successful RE integration in Kinoosao, may also enable PBCN to be more competitive in future bids for federally or provincially funded energy development projects. If PBCN articulated the successes and challenges of integrating RE in Kinoosao through research platforms and formal and informal Indigenous knowledge sharing networks, it may support other northern, remote and Indigenous communities achieve culturally sustainable energy transitions both now and in the future. In nonmarket valuation, such altruistic actions that have the potential to enrich the lives of current and future generations are known to provide bequest value (Boardman et.al., 2018, page 227). Estimation of the bequest value could begin by surveying PBCN and/or CASES project partner FNPA.

iii. Energy Literacy

Energy literacy has various behavioral components. It relates to building the foundation of knowledge around energy choices and improvements to energy literacy, which has been shown to change how people consume power (Dewaters & Powers, 2011). Eisler (2016) asserts that positive externalities resulting from one's level of energy literacy can impact the harmony in a community. Research also shows that increased energy literacy among school-aged children can positively impact energy conservation at the household level and in school (Craig et. al., 2015). Opportunities for hands on learning, such as the installation of solar technology, has been found to be particularly effective for developing energy literacy (Dewaters & Powers, 2011; Cervetti et. al., 2012). This is related to the option value of having new technology in a community. Estimating the value of increased energy literacy from REAs could be based on a meta-analysis of relevant nonmarket scholarship describing enhanced opportunities for learning in northern, remote and Indigenous communities (Boardman et. al., 2018, page 278). In a more direct approach, the residents of Kinoosao could be surveyed prior to project commencement of the project and after, as a means to gauge changes to energy literacy in the community.

iv. Energy Security

Energy security is defined by the International Energy Agency (2020) as "the obtainability of the energy sources uninterruptedly and at affordable prices". Given this definition, it is possible that residents of Kinoosao may experience enhanced energy security through community investment into solar PV integration as service interruptions may be reduced. Discussion with the Northwest Territories Power Corporation (2022) revealed that their 2016 integration of solar PV technology into a CCM resulted in an 80% reduction in power outages in the remote, northern, Indigenous community of Colville Lake. Unlike this case study, the Colville Lake project included the installation of all new diesel generation infrastructure and power line upgrades. Many stated preference studies estimated the marginal value of energy security to households. Motz (2021) provides a summary of estimates for the economic value to Scandinavian households to avoid a one hour-long unannounced power outage, which ranged from $0.79 to $2.34 USD (2015).

Given the remoteness and traditional subsistence lifestyle of residents in Kinoosao, one quantifiable method to estimate the benefits of reduced power outages employ surveys to estimate the costs incurred to avoid the loss in welfare experienced from power interruptions (Kjølle et. al., 2008). This avoided loss in welfare could be provided through the purchase of generators or alternative energy systems by HHs, PBCN and/or SaskPower. There is currently no data available reporting the duration or frequency of power outages in Kinoosao.

v. Pride

McMaster (2022) identified local energy champions as an important socio-technical component for sustainable energy transitions in northern, remote and Indigenous communities. Local energy champions are those individuals or a collective who take responsibility for the conception and completion of community energy projects (McMaster, 2022). Interviews with PBCN (2022) and PBGOC (2022) confirmed the sense of pride attained by championing the development of solar PV technology in Kinoosao. Boardman et. al. (2018, page 226) characterizes this nonmarket value to exhibit *individualistic altruism*, where the REA's ability to improve the general utility level of the community, as a whole, creates unique value reaped by the local energy champion(s). Estimation of individualistic altruism in this context may require qualitative survey work and an original stated preference study (Boardman et. al., 2018, page 226). In this case, a survey could be administered to energy champions with the assistance of Indigenous energy organizations, like the First Nations Power Authority and the valuation could be given a higher weighting to reflect its inherent importance in building capacity in remote, northern and Indigenous communities.

vi. Local Air Quality Improvement

The effects of reducing GHG emissions is recognized to have impacts at a global scale, and this is represented, at least partially, in the Canadian electric utility market through various carbon pricing mechanisms. However, the scope of this study limits the qualitative discussion to only include the effects at the local, community scale. One effect of reducing diesel fuel use may be articulated by understanding and valuing the impacts that reduced emissions have on local air quality in Kinoosao. Air pollution can have negative effects on both people (human health, local aesthetics) and terrestrial and aquatic habitats (Gwich'in Council International, 2015; Boardman et. al., 2018, page 429). A common approach used to estimate the social cost of air pollution applies a damage function that essentially captures the perceived values of the residents to avoid respiratory illness or increased mortality (Boardman et. al., 2018, page 429). For example, the social cost of specific air pollutants in the continental US were estimated by Matthews and Lave (2000) and updated by Boardman et. al., (2018, page 430) The mean cost (2008 USD) per ton of air emissions for carbon monoxide, nitrogen oxides, sulfur dioxide, particulate matter and volatile organic compounds were $796, $4,284, $3,060, $6,579, and $2,448 respectively (Boardman et. al., 2018, page 430). However, costs of these air pollutants in northern, remote and Indigenous communities may be significantly different and would require more site-specific estimates.

The analysis in the solar PV scenario shows that 1,266,036 kWh of electricity savings leads to approximately 1,825 tonnes of avoided CO_2 emissions over 23 years. A study released by Gwich'in Council International (2015) stated that no work has been completed to estimate the social costs of diesel generation in northern, remote and Indigenous communities, but research for other jurisdictions has estimated the social cost of air emissions derived from fossil fuels to range between 0.25 – 55.15 cents/kWh. Gwich'in Council International (2015) went further to state that given their unique socio-cultural environment these values were not applicable to describe the costs borne by northern, remote and Indigenous communities experiencing energy transitions. Valuing the local air quality improvement could be completed by estimating the social cost of air emissions derived from fossil fuels using values provided by Gwich'in Council International (2015) or a social cost of air pollution estimate from previous research.

vii. Power Bill Cost Savings

Transitioning to renewable energy sources may reduce some of the high-stakes trade-offs experienced by residents in remote, northern communities; trade-offs like having to choose between purchasing essential goods or heating a residence. Interviews with SaskPower (2021b) revealed that 70% of all electric billing in Kinoosao goes to the First Nation, while 30% goes to private residents. The results (Table 5-1) show that overall the community and residents may save $262,923.32 on their power bills with solar PV integration over the term of the analysis (see Table 5-6). In the winter of 2021, a PBCN community member employed by the CASES research project interviewed two individuals from Deschambault Lake, Saskatchewan who indicated that any household cost savings from reduced electricity bills would go towards supporting their children, hunting, fishing and purchasing food. This implies that power bill savings could have positive welfare effects beyond the community and that they may also increase opportunities for residents to practice traditional subsistence activities.

viii. Reconciliation

Community investment into REAs can produce a mechanism for reconciliation between PBCN and government agencies. By using the Truth and Reconciliation Commission's (2015) definition which explains reconciliation to mean "establishing and maintaining a mutually respectful relationship between Aboriginal and non-Aboriginal peoples in Canada," SaskPower may be now aligning their policy framework to improve welfare in Indigenous communities. Reconciliation is a potential social, or nonmarket benefit, on the supply side. Interviews with SaskPower (2022b) revealed that the corporation is currently drafting corporate reporting in relation to electricity generation and reconciliation in Saskatchewan.

The British Columbia Utility Commission's *Indigenous Utilities Regulation Inquiry: Final Report* (2020) reports the results of engagement with Indigenous stakeholders specifically as it relates to achieving reconciliation through energy development in Canada. In total, members of over 50 First Nations provided feedback (BCUC, 2020). Working harmoniously over time to facilitate capacity building (energy literacy), protect sacred territory, develop mechanisms that enable Indigenous stakeholders to receive the economic benefits of current regulatory structures and create rhetoric that strengthens the Crown's dedication to acknowledge and grow Indigenous people's rights to self-government were all identified as having potential to facilitate reconciliation (BCUC, 2020). In the context of community energy development in Kinoosao, the energy literacy, energy security, pride, knowledge sharing and building, local air quality improvement and power bill cost savings benefits in combination may establish some contribution to reconciliation.

Long-term success of the community investment into solar PV in Kinoosao will require sustained cooperation, communication, and engagement between the solar operator, PBCN, and SaskPower, thus providing a possible mechanism to reconcile historical relations between government agencies and Indigenous communities. In recent work, Hoicka et. al. (2021) examined if and how Canadian renewable energy projects contribute to reconciliation between Indigenous peoples and both private companies and government institutions. The authors state that policies that support 100% project ownership, equity ownership, improved access to capital and capacity building have the most potential to provide opportunities for reconciliation in the energy sector.

5.2.2.2 Nonmarket Impacts of DSM

The literature review revealed that DSM provides benefits to households through improved living conditions and various cost savings in the short and long run. While the only social impact of community-led investment into DSM identified in this work was power bill cost savings, inference can be made about potential nonmarket costs and benefits of this scenario. For this scenario, I assume that a 38% reduction in electricity demanded from DSM may provide a local air quality improvement, offer a sense of pride for local energy champions and provide opportunities for communal knowledge building and sharing. It is rational to assume that the social costs to the community identified in the solar PV scenario (fuel spill risk, environmental catastrophe risk, noise pollution) would persist with the DSM project. The persistence of the social costs borne from diesel power generation are assumed as SaskPower is not modeled to change any management aspects of the CCM over the course of this scenario.

5.3 Criteria for Community Evaluation

The preceding analysis articulates a spectrum of welfare outcomes that could be achieved from community investment into solar PV technology, as an electricity generation substitute in Kinoosao, Saskatchewan. The scenario analysis describes how DSM projects augment the energy landscape by reducing the household demand for electricity and potentially improving living conditions in remote, northern and Indigenous communities. The financial and social implications of the investment alternatives imply that in each scenario, PBCN will be faced with distinct project timelines and management commitments. Table 5-8 below summarizes the social benefits of the investment alternatives as identified via participatory interviews with PBCN for the solar PV scenario and assumed for the DSM scenario. Given PBCN's high level of business capacity, if the First Nation seeks to provide more social benefits to the community (and improve welfare) in the long run, it appears that the solar PV investment path may provide more value, overall. The benefits can only be reaped however, if the community agrees to the financial, temporal and management caveats present in the selected alternative.

Table 5-8: Criteria for community investment evaluation in Kinoosao, Saskatchewan

Community Benefit	***Solar PV***	***DSM***
Energy Literacy	●	
Energy Security	●	
Reconciliation	●	
Pride	●	●
Knowledge Building and Sharing	●	●
Local Air Quality Improvement	●	●
Power Bill Cost Savings	●	●

To successfully execute the solar PV integration project, PBCN needs a high level of business capacity and experience planning and managing community-scale energy projects, which it has. Two years of project planning are allotted for the solar PV scenario, but it is unclear exactly how many years of relationship building would be required between PBCN and SaskPower to bring the legal, administrative and financial components of the project together. The timeline of the CBA is 25 years, a long-term commitment from PBCN for operating and managing the solar PV infrastructure. Conversely, the DSM scenario could be planned and executed independent of the utility. This means that while addressing DSM does not require any legal, administrative, or financial discourse with SaskPower, successful implementation will require sophisticated project management skills within PBCN, related to housing. As modeled, the DSM scenario requires a one-year commitment and after the project is implemented requires negligible ongoing management.

Rezaei & Dowlatabadi (2016, page 795) list self sufficiency, employment, improved reliably, revenue, environment and reduced diesel dependence as community motivators for REA development in diesel-powered communities in British Columbia, Canada (see Table 5-9). Table 5-9 below summarizes Rezaei & Dowlatabadi's (2016) findings and validates them based on the impacts identified in this thesis. Solar PV integration in Kinoosao allows for communal decision making about the local energy environment where self sufficiency is signified by PBCN's financial investment in the infrastructure and dedicated ongoing socio-technical presence. While the REA integration is unlikely to create permanent employment in Kinoosao, it will provide ongoing job security in Peter Ballantyne Cree Nation. As modeled, neither the solar PV or DSM scenarios are expected to improve system reliability or generate local revenue. There are environmental benefits attributed to the community reducing its demand for diesel-generated electricity, namely an air quality improvement. Lastly, the introduction of solar PV technology does reduce diesel-dependence in Kinoosao and the energy literacy, energy security, pride and knowledge building and sharing benefits stem from having the physical infrastructure present.

Table 5-9: Criteria for community evaluation from the literature

Community Goal	***Solar PV***	***DSM***
Self Sufficiency	●	
Employment	●	
Improved Infrastructure/Reliability		
Local Revenue Generation		
Environmental Benefits	●	●
Reduced Diesel Dependence	●	

5.4 Conclusion

The results of the cost benefit framework for cold climate microgrids include a comparison of the alternative investment paths and presentation of criteria for community evaluation. The results reveal that the community-led solar PV and DSM scenarios improve efficiency by providing a lower net cost to society compared to the baseline scenario, based on diesel generation alone. The social costs of CCM management are all generated in the baseline scenario and are linked to the primary power generation source, diesel fuel. Over the term of the analysis, the solar PV scenario lowers the net costs of operating the CCM for SaskPower and both the community of Kinoosao and SaskPower are expected to gain from a substantial number of nonmarket benefits. The scenario analysis demonstrated that demand side management can significantly reduce power bills for northern, remote and Indigenous households. The one-time DSM cost, borne by the community, is expected to provide fewer social benefits in remote, northern and Indigenous locales, overall. The following chapter concludes the thesis by describing the overarching policy and scholarly implications of the results.

6.0 Conclusion

Previous research (see Gjorgievski, 2021; Cook et. al., 2016; Miller et. al., 2015) asserts that an economic approach is needed to understand the comprehensive effects that REA development has in northern, remote and Indigenous communities. In this work, the principal theories of market and nonmarket valuation were presented to quantify, value and qualify the impacts of electricity generated from diesel fuel with solar PV integration in Kinoosao, Saskatchewan. The applied CBA framework presents a preliminary and exploratory understanding of the market and nonmarket impacts of prevailing northern energy transitions. The estimation of the net present value of alternative investments provides a preliminary quantifiable economic indicator of culturally sustainable energy transition alternatives. For socially or environmentally sensitive projects, this can be helpful to justify decision making that goes against the status quo. The results contribute to the fields of energy finance and investment and nonmarket valuation specific to community investment in REAs in northern, remote and Indigenous communities. This conclusion includes five sections. First, is an overview of the approach used to achieve the research objectives of the thesis. This is followed by key observations, findings and contributions from the research reported in this thesis. Next is a discussion of the policy implications of this work followed by the limitations of the research. Lastly, I describe the potential avenues for future research in this emerging field.

6.1 Project Summary

This thesis demonstrates how the characteristics of remote, northern and Indigenous communities' presents unique challenges for both the supply and demand of diesel-generated electricity. The research adopts a case-study approach for CCM management based on the characteristics of the boreal community of Kinoosao, Saskatchewan located adjacent to Reindeer Lake, in Treaty 10 territory. The characterization of the Peter Ballantyne Cree Nation community was part of the first step in the CBA framework, scoping. During the scoping section the case-study community and the electric utility operator, SaskPower, were engaged using a participatory modeling approach to help identify project specific variables and quantify values. Qualitative and quantitative data were collected to address the project goals, demand, potential supply alternatives and the constraints specific to renewable energy integration into the diesel microgrid (see Table 4-2). Secondary data was collected through literature and document review to support the development of the framework and its application. I limited the analysis to only consider the costs and benefits borne by each stakeholder at the community scale.

Three alternative scenarios were modeled, (i) the baseline, where diesel generation continues as usual (ii) a community-led solar PV integration scenario and (iii) a community-led DSM was estimated using secondary data from relevant literature. All scenarios are modeled over 25 years, starting in 2022. For the baseline scenario, I assumed that neither the community nor the utility will invest in renewable energy integration. For the solar PV integration scenario, I was limited by a technical constraint (see Equation 4.1) to model a 20% offset from renewable energy into the microgrid.

I then identified the range of costs and benefits of each scenario first through literature review and discussions with academic project leaders and where then confirmed based on information gathered through participatory interviews with PBCN and SaskPower. The interviews also revealed costs and benefits that were not identified in the literature review phase. For the baseline scenario, fuel, federal carbon tax, capital expenditures, operations and maintenance and depreciation are recognized as quantifiable costs for SaskPower and revenue is the quantifiable benefit. For the baseline scenario, all of the market costs and benefits are estimated using market models. To further detail the range of scenario effects the nonmarket costs, including fuel spill risk and environmental catastrophe risk are qualified based on relevant literature.

For the solar PV scenario, project planning was confirmed as an additional quantifiable cost in the first two years of the modeling for both SaskPower and community. For the community, who will pay for the solar infrastructure and manage it over time, I included quantifiable capital expenditures, operations and maintenance and depreciation expenses into the model. Significantly more social benefits were qualified for the solar PV scenario. Reduced legal or administrative costs, knowledge building and reconciliation are nonmarket benefits potentially recognized by SaskPower. On the community side, improvements to energy literacy, energy security, reconciliation, pride, knowledge sharing and building, local air quality improvement and power bill cost savings are qualifiable benefits. When qualifying the nonmarket benefits, it was my approach to provide as much data as possible relating to each, especially socio-demographic and technical details.

To represent the costs and benefits that occur over a multi-year planning horizon, as characterized in the energy scenarios estimated here, I applied discounting within a spreadsheet based model to develop present value estimates. The application of discounting allows the costs and benefits to be analyzed using their equivalent, present value, over the term of the analysis, in this case, 25 years. The First Nations Power Authority (2022) stated that because of the strict regulatory requirements of renewable energy projects, they are low risk investments, and so, a 3% discount rate was applied, as advised by the Treasury Board of Canada. When considering the alternatives on behalf of the community, I examined the net present values and benefit cost ratios. By comparing alternatives based on their net present value, which is a measurement of net social benefit, we see which investment imposes the smallest net cost over the term of the analysis. The benefit cost ratio expresses the magnitude of benefits reaped in relation to the amount of costs paid over the 25-year timeline.

6.2 Key Findings

Considering the complexities of energy development imposed by community remoteness, sociotechnical capacity and honoring the sacredness of Indigenous culture, beliefs, territorial and human rights creates a unique blend of elements that challenge electric utility management in remote, northern and Indigenous communities. Both the supply of electricity by the utility and the demand of electricity by the community are influenced by outside forces such as relevant federal policy directing long-term investment decision making and simultaneously considering reliability, renewable generation technologies, fuel costs, environmental factors, system operations and maintenance, and legal and ethical obligations. Currently, federal programs that transfer financial capacity to investigate the feasibility and implementation of renewable energy alternatives in cold climate microgrids are enabling communities to express their demand for new technologies and DSM.

When investigating feasible technologies for integration in Kinoosao, it was revealed that a diesel generator’s ability to operate efficiently after integration hinged on a technical constraint that limits the offset of power generated from solar PV to one-fifth of the electricity demanded. This assumption was not investigated at depth but infers that eliminating diesel-generated power in CCM communities may only be possible if energy transitions include comprehensive microgrid planning including innovative energy storage and perhaps the development of an entirely new heat and power system. For the market impacts identified, data was available through participatory interviews and secondary sources. When scoping the project and evaluating appropriate nonmarket valuation approaches it became clear that access to the knowledge of the community residents is important for gathering relevant environmental, social and technical data. The residents have traditional ancestral knowledge of the regional environment and localized knowledge of the energy landscape.

In the application stage of the CBA framework the incorporation of participatory modeling was effective. Both PBCN and SaskPower are partners of the University of Saskatchewan's CASES project, which enabled ease of communication between the analyst and community leaders and utility personnel. In essence, the successful application of the participatory modeling approach in economics signifies a contribution to reconciliation. If a stakeholder was unwilling to participate in a CBA for a community-led project, the reconciliation benefit on both sides would likely cease to exist, the local impacts of energy transitions may be omitted, and the net present value estimates may be invalid. Moreover, a participatory modeling approach that enables unique variables to be identified and included aligns with appropriate techniques for conducting nonmarket valuation in northern, remote and Indigenous communities.

The diesel fuel input accounts for the largest share (>50%) of market costs in all scenarios of the model application. Diesel fuel provides energy security because it can be stored and used for power generation continuously, on demand. The nature of the fuel itself and its storage proximity to households and the treeline increases risk to human and environmental well being, creating nonmarket costs for the community and broader society. Transitioning away from diesel fuel as a power source in northern, remote communities would curtail the production externalities borne from its utilization. As the owner operators of CCM infrastructure, government electric utility corporations stand to benefit immensely from REA integration. The financial analysis affirms Boute's (2016) notion that in the absence of transmission infrastructure, microgrids in northern, remote locations mitigate some of the classic high-cost characteristics of grid-connected electric utility systems; and so, if one or more renewable generation sources can eliminate diesel, the NPV and BCR of the CCM would theoretically, dramatically improve. The results revealed that simply reducing the amount of fuel combusted, with the physical adoption of a supply-side REA, specifically solar PV technology, provides significant potential to improve social surplus, in this case through a $661,460.40 reduction in net costs.

Communities with high levels of capacity for technical investments and management and long-term vision, like PBCN, can theoretically realize the benefits of investment into REA integration or DSM. It is difficult to comprehend if REA integration can be successful if the transfer of CCM ownership, and as a result the transfer of energy generation risks, away from the electric utility to the community is not the long-term goal for both stakeholders. This implies that maintaining the monopolistic market structure, where only one stakeholder is responsible for supplying electricity, may be ideal. The choice as to which organization is best suited to manage power systems in northern, remote and Indigenous communities is a decision that can only be made by the First Nation or community itself based on its own goals and internal capacity.

As modeled, the DSM investment reduced the net costs of operating the CCM by $1,462,093.09 over 25 years. The results revealed that DSM investments may provide northern, remote and Indigenous communities with almost four times more financial benefits than solar PV integration. The fixed nature of the DSM investment means that making households in northern, remote and Indigenous communities more energy efficient in the short run can improve welfare into the future. Given that the installed capacity of new REAs or community energy systems are based on the demand for power, perhaps REAs ought to be investigated after DSM projects are implemented. If the electric utility corporation plans to invest in REA integration (or a combination of power generation and storage technologies) to satisfy GHG-related policies, the community can potentially increase local benefits from reaping the local air quality improvement and opportunities for energy literacy and security while diverting their spending to demand-side investments.

6.3 Policy Implications

A cause of market failure in the electricity market are multi-pricing systems as characterized by natural monopolies. Electricity consumers in northern, remote and Indigenous communities face extraordinary circumstances (limited energy sources, aging infrastructure) that impact their welfare. Choosing a power rate for CCM households (northern, remote and Indigenous communities) equal to that of grid-tied households (southern communities) would improve welfare in communities and represent a more equitable pricing scheme. The potential benefits borne by DSM investments are noteworthy and may be particularly important for communities with low financial and sociotechnical capacity. The timeframe of implementing DSM projects is aligned with the timeframe of current federal energy transition policies (five years) meaning that the benefits of federal investments into DSM in northern, remote and Indigenous communities may have the potential to be actualized more readily than long-term REA investments.

In regions where eliminating diesel fuel combustion is not an option, new policies at the federal, provincial, and territorial levels that regulate the quality and maintenance of diesel tanks may reduce or even eliminate some CCM production externalities. Given the high net cost of CCM management, electric utility operators stand to benefit from working with communities to move the burden of service from government corporations to Indigenous communities. Spiegel-Feld et al. (2016) conclude that funding policy designed to alleviate the risks of integration and maintenance borne by utilities (or infrastructure investors) may allow consumers to benefit from lower power bills and this work supports that assertion. Federal government policies could ease the risk by incentivizing utility corporations in successful energy transitions. Moreover, policies that invest in partnership building in the electricity sector implicitly correct information asymmetry and improve social surplus, as both communities and utility companies recognize the benefit of knowledge transmission between stakeholder groups.

6.4 Research Limitations

The assumptions made in the development of the thesis are clearly articulated and where data was available, also referenced (see Appendix G). Notably excluded from the model are quantifiable costs and benefits related to legal and financing implications, insurance, the impacts of certain geotechnical and biophysical risks (ex. climate change), human resource or sociotechnical capacity building, land clearing, feasibility analysis, transport, energy storage, in-kind contributions and federal or provincial government funding and support. Assumptions made by the author (see Appendix G) are subject to forecasting errors. In this application of the cost benefit framework for cold climate microgrids, omission errors representing unvalued social surplus and loss are present, as all ten of the nonmarket costs and benefits are unvalued. Some of the nonmarket impacts, such as the risks stemming from diesel fuel use and storage are quantifiable using survey techniques and market models. Other nonmarket impacts such as noise pollution, pride and reconciliation require further theorizing before they can be valued.

While the remoteness of Kinoosao is a physical geographic barrier to data collection, other barriers such as unforeseen climatic, geo-political and socio-cultural circumstances were also prevalent to challenge this research. Scoping the CBA commenced at the height of the Covid-19 pandemic and so, travel to PBCN communities was not possible. The interpretation of the results was limited by my inability to survey the household residents in Kinoosao. This research did not investigate how REA integration could impact the local subsistence economy in Kinoosao. Baseline data about the satisfaction of the residents with the status quo, based on diesel generated power, was not collected from the community to enable a better understanding of community perceptions.

This thesis does not include scenario development where SaskPower invests in REA integration at the community scale. The decision to model the baseline as diesel generation only was chosen to explicitly represent and articulate the welfare effects of investments into solar PV integration and DSM by the community. This scenario development in the spreadsheet model and analysis was limited to a desktop review of relevant literature, and so the demand side management efficiency factor was not scaled for regional climatic differences and the increased costs of remoteness. While the results show that solar PV and DSM can reduce CO_2e by 1825 and 2810 tonnes respectively over the term of the analysis, emissions savings estimates for other air pollutants were not considered. The solar PV technology was not modeled to decrease in generating capacity (efficiency) over time. Similarly, the electricity savings from DSM are not modeled to decrease over time.

6.5 Future Research

The recent emergence of this field of research means that currently, transferable market and nonmarket valuation literature, especially relating to the benefits of REA integration are scarce. The existing body of scholarship, across various disciplines, identifies various externalities of electricity generation from diesel and renewable resources but research is needed surrounding the potential for REA integration in northern, remote communities to reduce externalities or correct information asymmetry. Investments into Canadian CCMs are happening now, and the time is ideal to estimate the value the nonmarket impacts of energy transitions.

Future research could investigate how REA integration and DSM impacts local subsistence economies, as it may deepen the scholarship’s ideology of the spiritual and cultural significance of community energy systems. Understanding the dynamics of the subsistence economy in this context could help researchers to develop survey instruments that use appropriate trade-offs for valuation using stated preference and revealed preference studies that incorporate traditional knowledge. For the electric utility operator, the nonmarket benefits of REA integration identified are in the realm of information economics and can be quantified using survey techniques and market models. Given the immense size of the electric utility supply industry, identifying, and quantifying the nonmarket impacts experienced by electric utility operators during energy transitions could be prioritized.

The cost benefit framework for cold climate microgrids can be scaled to analyze the welfare implications of alternative investments into new community-scale heat and power systems. This is particularly important if the goal of a community or utility corporation is to eliminate diesel fuel use in a remote, northern location. Today, technologies like biomass district heating are a substitute for electric heat and provide their own unique suite of market and nonmarket costs and benefits to a community. It is possible, therefore, that diesel generated electricity could be reduced, over time, using a combination of renewable power, heat and storage technologies.

If northern energy transitions are going to transfer the risk of supply away from utilities to communities, the legal implications ought to be investigated and quantified. This is applicable to cases where communities plan to invest in supply side technologies. This area of research could start by undertaking qualitative survey work with Indigenous energy organizations, like First Nations Power Authority, or First Nations and project financiers who have completed RE projects that involve a shared burden of electricity supply. In the case of monopolistic markets serviced by government corporations, the legal implications of culturally sustainable energy transitions are funded by taxpayers. Research could be done to quantify these legal costs and evaluate them against the benefits they provide to society at large. The breadth of the framework can also be expanded to include the federal government as a project stakeholder and the tax burdens could be explored. This would contribute to the totality of market and nonmarket impacts of REA investment into CCMs to be potentially monetized at nationwide or international scales.

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Appendix A: Interview Schedule

Table A-1: Dates, times and modes of delivery for primary data collection

Interviewee/Organization	Method of Communication	Date/Time	Topic
PBCN Solar Developer	In person	June 2, 2021 – 2:00 PM	Model Discussion
SaskPower	WebEx (Web)	June 24, 2021 – 1:00PM	General Discussion – Feasibility Analysis
PBCN Solar Developer	Teams (Web)	Sept. 24, 2021, 3:00 PM	Data Collection - Solar modeling & Community
SaskPower	Teams (Web)	Nov 24, 2021, 12:00 PM	Model Discussion
SaskPower	Teams (Web)	Dec 10, 2021, 9:00 AM	Data Collection – Utility Costs and Benefits
SaskPower	Teams (Web)	Feb 1, 2022, 330-430PM	Questions - Data Collection - Utility Costs and Benefits
PBGOC	Teams (Web)	Feb 1, 2022, 230-300PM	Questions - Data Collection - Community Costs and Benefits
PBGOC	Teams (Web)	Feb 3, 2022, 10-1030AM	Follow Up Questions Community Goals and Finance
SaskPower	Teams (Web)	Feb 16, 2022, 330-4PM	SPC Plans for Kinoosao
NTPC	Teams (Web)	Feb 18 - 11-1130AM	Informal discussion - Colville Lake Solar Case Study
FNPA	Teams (Web)	March 1st, 2022 – 1PM	Electricity modelling discussion
PBCN Solar Developer	Teams (Web)	Mar 7, 2022, 10:30 AM	Community Data
PBCN Solar Developer	Teams (Web)	March 8, 2022, 10:30AM	Mapped out community

Appendix B: Sample Survey Questions

Survey Questions for the Utility

1. In what year was the original diesel generation system installed in Kinoosao?
2. For the year ended March 31st, 2021, how much did SaskPower spend on fuel for Kinoosao?
3. What is the value (current and/or historical) of SaskPower's generation assets in Kinoosao?
    a. What technologies are included in these assets?
4. What is the value (current and/or historical) of SaskPower's distribution assets in Kinoosao?
5. How many meters of lines are included in the distribution system?
    a. In what year were they last replaced?
    b. What is the average replacement cost per meter?
6. How many poles are included in the distribution system?
    a. In what year were they last replaced?
    b. What is the average cost of replacing each pole?
7. Can you describe the categories/types of human resources allocated to planning SaskPower's renewable energy projects?
8. Commonly, what percentage of a renewable energy projects' total cost are used for pre-planning?
9. What temporal planning horizon does SPC usually use for modeling power projects?
10. What decision-making criteria may SaskPower use to determine how much generation capacity is feasible for integration in an off-grid community?
11. What do you estimate the capacity factor of solar technology to be in northern SK communities?
12. Do you anticipate that decommissioned diesel generators operating in the north have any salvage value?

Survey Questions for Community Leaders

1. Can you describe the average amount of time (in years) PBCN and/or PBGOC spends from initial feasibility planning to installation of technologies for community RE projects?
2. Can you describe the amount of resources (human (time) and financial) used annually by PBCN and/or PBGOC for community RE integration planning?
3. At what rate are PBCN communities growing?
    a. Is this growth rate the same in Kinoosao?
4. Are you aware of any factors, other than population growth, that may affect the amount of electricity demanded by households in Kinoosao?
5. Can you provide any technical specifications/details of current energy system in Kinoosao?

6. Can you provide details about the current social and economic status of residents in Kinoosao including community energy management, permanent and seasonal employment, local culture, access to healthcare and governance?
7. Can you describe the results of feasibility analysis or business analysis/planning already completed for developing renewable energy alternatives in Kinoosao?
8. Can you explain to me, as simply as possible, how the diesel generation system in Kinoosao works?

Appendix C: Solar Output Saskatchewan

Table C-1: Southern and northern solar output in Saskatchewan

	South	North
January	100%	61%
February	100%	83%
March	100%	98%
April	100%	101%
May	100%	94%
June	100%	92%
July	100%	82%
August	100%	81%
September	100%	72%
October	100%	71%
November	100%	61%
December	100%	54%
Total	100%	84%

Reference: SaskPower (2022a)

Appendix D: Historical Diesel Fuel Price in Saskatchewan (per liter)

Table D-1: Point estimate of diesel fuel prices in Saskatchewan from December 1997-2021

Year	Fuel Price
1997	$0.57
1998	$0.53
1999	$0.57
2000	$0.67
2001	$0.59
2002	$0.68
2003	$0.64
2004	$0.79
2005	$0.99
2006	$0.89
2007	$1.11
2008	$0.93
2009	$0.92
2010	$1.07
2011	$1.29
2012	$1.19
2013	$1.29
2014	$1.26
2015	$0.96
2016	$0.99
2017	$1.15
2018	$1.21
2019	$1.27
2020	$1.04
2021	$1.38

Source: Statistics Canada, 2022. Monthly prices for diesel fuel in Saskatchewan – December 1997 – 2021.

Appendix E: Data Charts

Table E-1: Excel data

		No Project	Solar	DSM		No Project	Solar	DSM		No Project	Solar	DSM	DSM	No Project	Solar	DSM
	n	Fuel Used (L)	Fuel Used (L)	Fuel Used (L)	Fuel Cost ($/L)	Fuel Savings (L/Year)	Fuel Savings (L/Year)	Fuel Savings (L/Year)	Carbon Tax ($/tonne CO2e)	Emissions (tonnes CO2e)	Emissions (tonnes CO2e)	Emissions (tonnes CO2e)	Electricity Savings (kWh/Year)	Emissions Savings	Emissions Savings	Emissions Savings
2022	0	110857	110857	69286	1.44	0.00	0	41571	50.00	288	288	180	75000.00	0.00	0	108
2023	1	113074	113074	71503	1.47	0.00	0	41571	65.00	294	294	186	75000.00	0.00	0	108
2024	2	115336	92269	73764	1.50	0.00	23067	41571	80.00	300	240	192	75000.00	0.00	60	108
2025	3	117642	94114	76071	1.53	0.00	23528	41571	95.00	306	245	198	75000.00	0.00	61	108
2026	4	119995	95996	78424	1.56	0.00	23999	41571	110.00	312	250	204	75000.00	0.00	62	108
2027	5	122395	97916	80824	1.59	0.00	24479	41571	125.00	318	255	210	75000.00	0.00	64	108
2028	6	124843	99875	83272	1.62	0.00	24969	41571	140.00	325	260	217	75000.00	0.00	65	108
2029	7	127340	101872	85769	1.65	0.00	25468	41571	155.00	331	265	223	75000.00	0.00	66	108
2030	8	129887	103909	88315	1.69	0.00	25977	41571	170.00	338	270	230	75000.00	0.00	68	108
2031	9	132485	105988	90913	1.72	0.00	26497	41571	170.00	344	276	236	75000.00	0.00	69	108
2032	10	135134	108107	93563	1.76	0.00	27027	41571	170.00	351	281	243	75000.00	0.00	70	108
2033	11	137837	110270	96265	1.79	0.00	27567	41571	170.00	358	287	250	75000.00	0.00	72	108
2034	12	140594	112475	99022	1.83	0.00	28119	41571	170.00	366	292	257	75000.00	0.00	73	108
2035	13	143406	114724	101834	1.86	0.00	28681	41571	170.00	373	298	265	75000.00	0.00	75	108
2036	14	146274	117019	104702	1.90	0.00	29255	41571	170.00	380	304	272	75000.00	0.00	76	108
2037	15	149199	119359	107628	1.94	0.00	29840	41571	170.00	388	310	280	75000.00	0.00	78	108
2038	16	152183	121746	110612	1.98	0.00	30437	41571	170.00	396	317	288	75000.00	0.00	79	108
2039	17	155227	124181	113655	2.02	0.00	31045	41571	170.00	404	323	296	75000.00	0.00	81	108
2040	18	158331	126665	116760	2.06	0.00	31666	41571	170.00	412	329	304	75000.00	0.00	82	108
2041	19	161498	129198	119926	2.10	0.00	32300	41571	170.00	420	336	312	75000.00	0.00	84	108
2042	20	164728	131782	123156	2.14	0.00	32946	41571	170.00	428	343	320	75000.00	0.00	86	108
2043	21	168022	134418	126451	2.18	0.00	33604	41571	170.00	437	349	329	75000.00	0.00	87	108
2044	22	171383	137106	129811	2.23	0.00	34277	41571	170.00	446	356	338	75000.00	0.00	89	108
2045	23	174811	139848	133239	2.27	0.00	34962	41571	170.00	455	364	346	75000.00	0.00	91	108
2046	24	178307	142645	136735	2.32	0.00	35661	41571	170.00	464	371	356	75000.00	0.00	93	108
2047	25	181873	145498	140301	2.36	0.00	36375	41571	170.00	473	378	365	75000.00	0.00	95	108

Table E-2: Excel data

			No Project			Solar			DSM			No Project		Solar	
	n	Annual Billing	Revenue ($CAD)	Community Demand (kWh)	Blended Power Rate ($/kWh)	Revenue ($CAD)	CommunityDemand (kW/HH)	Blended Power Rate ($/kWh)	Revenue ($CAD)	Community Demand (kWh)	Blended Power Rate ($/kWh)	Asset Values	Depreciation	Asset Values	Depreciation
2022	0	12703.07	60416.00	200000	0.24	60416.00	200000	0.24	42523.65	125000	0.24	73936.00	22180.80	0.00	0.00
2023	1	12957.13	62597.66	204000	0.24	62597.66	204000	0.24	44347.47	129000	0.24	51755.20	15526.56	0.00	0.00
2024	2	13216.27	64862.28	208080	0.25	54533.08	166464	0.25	46247.08	133080	0.25	86228.64	25868.59	82500.00	0.00
2025	3	13480.60	67213.11	212242	0.25	56466.61	169793	0.25	48225.61	137242	0.25	110360.05	33108.01	82500.00	24750.00
2026	4	13750.21	69653.51	216486	0.26	58472.85	173189	0.26	50286.26	141486	0.26	127252.03	38175.61	57750.00	17325.00
2027	5	14025.22	72187.01	220816	0.26	60554.65	176653	0.26	52432.41	145816	0.26	89076.42	26722.93	40425.00	12127.50
2028	6	14305.72	74817.25	225232	0.27	62714.95	180186	0.27	54667.56	150232	0.27	62353.50	18706.05	28297.50	8489.25
2029	7	14591.83	77548.03	229737	0.27	64956.79	183790	0.27	56995.35	154737	0.27	43647.45	13094.23	19808.25	5942.48
2030	8	14883.67	80383.30	234332	0.28	67283.37	187466	0.28	59419.56	159332	0.28	30553.21	9165.96	13865.78	4159.73
2031	9	15181.34	83327.16	239019	0.29	69698.00	191215	0.29	61944.15	164019	0.29	21387.25	6416.17	9706.04	2911.81
2032	10	15484.97	86383.88	243799	0.29	72204.10	195039	0.29	64573.20	168799	0.29	64971.07	19491.32	6794.23	2038.27
2033	11	15794.67	89557.89	248675	0.30	74805.25	198940	0.30	67311.00	173675	0.30	95479.75	28643.93	4755.96	1426.79
2034	12	16110.56	92853.82	253648	0.30	77505.17	202919	0.30	70161.99	178648	0.30	116835.83	35050.75	3329.17	998.75
2035	13	16432.78	96276.46	258721	0.31	80307.72	206977	0.31	73130.80	183721	0.31	81785.08	24535.52	2330.42	699.13
2036	14	16761.43	99830.80	263896	0.31	83216.93	211117	0.31	76222.22	188896	0.31	57249.55	17174.87	1631.29	489.39
2037	15	17096.66	103522.03	269174	0.32	86236.96	215339	0.32	79441.28	194174	0.32	40074.69	12022.41	1141.91	342.57
2038	16	17438.59	107355.55	274557	0.33	89372.16	219646	0.33	82793.19	199557	0.33	28052.28	8415.68	799.33	239.80
2039	17	17787.36	111336.96	280048	0.33	92627.04	224039	0.33	86283.36	205048	0.33	19636.60	5890.98	559.53	167.86
2040	18	18143.11	115472.12	285649	0.34	96006.32	228519	0.34	89917.44	210649	0.34	63745.62	19123.69	391.67	117.50
2041	19	18505.97	119767.07	291362	0.35	99514.85	233090	0.35	93701.30	216362	0.35	94621.93	28386.58	274.17	82.25
2042	20	18876.09	124228.14	297189	0.35	103157.73	237752	0.35	97641.05	222189	0.35	66235.35	19870.61	191.92	57.58
2043	21	19253.62	128861.88	303133	0.36	106940.23	242507	0.36	101743.05	228133	0.36	46364.75	13909.42	134.34	40.30
2044	22	19638.69	133675.13	309196	0.37	110867.84	247357	0.37	106013.92	234196	0.37	32455.32	9736.60	94.04	28.21
2045	23	20031.46	138674.97	315380	0.38	114946.27	252304	0.38	110460.54	240380	0.38	22718.73	6815.62	65.83	19.75
2046	24	20432.09	143868.80	321687	0.38	119181.46	257350	0.38	115090.08	246687	0.38	15903.11	4770.93	46.08	13.82
2047	25	20840.73	149264.29	328121	0.39	123579.58	262497	0.39	119909.99	253121	0.39	11132.18	3339.65	32.26	9.68

Appendix F: Diesel Generator Specifications

Power Generation

Specification sheet

Diesel generator set 100 kW standby

EPA emissions

Description

Cummins Power Generation commercial generator sets are fully integrated power generation systems providing optimum performance, reliability and versatility for stationary applications. Pre-configured diesel generator sets come in either an open configuration or with a combination of a sound attenuated enclosure and an under-skid fuel tank.

ISO 9001	This generator set is designed in facilities certified to ISO 9001 and manufactured in facilities certified to ISO 9001 or ISO 9002.
PTS	The Prototype Test Support (PTS) program verifies the performance integrity of the generator set design. Cummins Power Generation products bearing the PTS symbol meet the prototype test requirements of NFPA 110 for Level 1 systems.
CSA	All low voltage models are certified to CSA C22.2 No.100 and CSA C22.2 No.14.
UL2200	The generator set is available listed to UL2200.
U.S. EPA	Engine certified to Stationary Emergency U.S. EPA New Source Performance Standards, 40CFR 60 subpart IIII Tier 3 exhaust emission levels. U.S. applications must be applied per this EPA regulation.
International Building Code	The generator set package is available certified for seismic application in accordance with the following International Building Code: IBC2000, IBC2003, IBC2006 and IBC2009.

Features

Cummins® heavy-duty engine - Rugged 4-cycle industrial diesel engine delivers reliable power, low emissions and fast response to load changes. 1800 rpm operation offers quiet performance and superior durability.

Alternator - 12 lead reconnectible alternators offer superior motor starting capability with low reactance 2/3 pitch windings, low waveform distortion with non linear loads and fault clearing short-circuit capability. Pre-wired from the factory for single phase output.

Control system - The PowerCommand 1.1 is standard equipment that provides integrated generator set control system. Major features include:

- Alpha-numeric display with push button access for viewing engine and alternator data and providing set up, controls and adjustments (English or international symbols)
- LED lamps indicating various genset status
- AC protection including warning and/or shutdown for over current, over and under voltage, over and under frequency, over excitation, field overload, etc.
- Full engine protection including warning and/or shutdown for overspeed, low coolant, high temperature, low battery voltage, over crank, low oil level, etc.
- Standard PCCNet interface to devices such as remote annunciator for NFPA 110 applications
- Inpower PC-based service tool for detailed diagnostics such as data logging and fault simulation
- Remote start/stop
- 2 configurable inputs/outputs
- Control boards potted for environmental protection
- Control suitable for -40 °C to +70 °C (-40 °F to 158 °F) and altitude to 5000 meters (13,000 feet)

Cooling system - Standard integral set-mounted radiator system, designed and tested for ambient temperatures up to 55 °C (131 °F), simplifies facility design requirements for rejected heat.

Fuel tank - 309 gallon (1171 liters) dual wall sub-base fuel tank is offered as standard equipment for enclosed unit. Fuel tank is UL / ULC listed and built in compliance with NFPA 30, 37, 110.

NFPA - The genset accepts full rated load in a single step in accordance with NFPA 110 for Level 1 systems.

Warranty and service - Two year standard warranty for standby applications and backed up by worldwide distributor network. Extended warranty options available.

Cold weather package – Genset equipped with coolant heater as a standard feature.

				Standby rating		
Model	**Phase**	**Voltage**	**Hz**	**kW**	**kVA**	**Amps**
DSGAA	1	120/240	60	100	125	417

Other optional voltages may be available

Ratings definitions

Emergency standby power (ESP): Applicable for supplying power to varying electrical load for the duration of power interruption of a reliable utility source. Emergency Standby Power (ESP) is in accordance with ISO 8528.
Derate factor: Engine power available up to 3048 m (10,000 ft) at ambient temperature up to 50° C (122° F).

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Generator set specifications

Governor regulation class	ISO 8528 Part 1 Class G3
Voltage regulation, no load to full load	± 1%
Random voltage variation	± 0.5%
Frequency regulation	Isochronous
Random frequency variation	± 0.25%

Engine specifications

Displacement	6.69 L (408 in^3)
Configuration	Cast iron, in-line, 6 cylinder
Battery charging alternator	100 amps
Starting voltage	12 volt, negative ground
Fuel system	Direct injection: number 2 diesel fuel, fuel filter, automatic electric fuel shutoff
Fuel filter	Single element, 10 micron filtration, spin-on fuel filter with water separator
Air cleaner type	Dry replaceable element
Lube oil filter type(s)	Spin-on, full flow

Alternator data

Alternator design	Brushless, 4 pole, drip proof, revolving field, 1800 rpm
Alternator rotor	Single bearing, flexible discs
Alternator insulation system	Class H
Alternator standard temperature rise	125 °C standby at 40 °C ambient
AC waveform total harmonic distortion	< 5% no load to full load; 3% for any single harmonic

Three Phase Table		125 °C	Single Phase Table		125 °C
Feature Code		B267-2	Feature Code		B267-2
Alternator Data Sheet Number		209	Alternator Data Sheet Number		209
Voltage Ranges		277/480 120/208 120/240	Voltage Ranges		120/240
Surge kW		156	Surge kW		152
Motor Starting kVA (at 90% sustained voltage)	Shunt	516	Motor Starting kVA (at 90% sustained voltage)	Shunt	305

Sound levels

Standard-unhoused – infinite exhaust	86.3 dB(A) at 7 meters (23 ft) at full rated load
F173 – Quiet Site II second stage – mounted muffler	71.9 dB(A) at 7 meters (23 ft) at full rated load

Dimensions and weights

	Package Dimensions			Footprint Dimensions		
	Length mm (in)	Width mm (in)	Height mm (in)	Length mm (in)	Width mm (in)	Set wet weight Kg (lbs)
Open unit without fuel tank	2656 (104.6)	1100 (43.3)	1548 (61)	2656 (104.6)	1100 (43.3)	1263 (2784)
Enclosed unit with fuel tank	3678.8 (145)	1100 (43.3)	2455.9 (96.7)	3015 (118.7)	1100 (43.3)	2599 (5738)

Generator set accessories

Engine
- ☐ 120 V 150 W lube oil heater

Control
- ☐ Auxiliary output relays
- ☐ 120V, 100W anti-condensation heater
- ☐ Remote annunciator
- ☐ PowerCommand iWatch web server for remote monitoring and email notification
- ☐ AC output analog meters display (bargraph)
- ☐ Remote operator/display panel

Generator set
- ☐ AC entrance box
- ☐ Battery
- ☐ Battery charger
- ☐ Spring isolators

Fuel tank
- ☐ Accessory kits for U.S. regional codes

Generator set
- ☐ Standby comprehensive 2 year/1500 hour
- ☐ Standby basic extended 5 year/1500 hour
- ☐ Standby comprehensive extended 5 year/1500 hour

Warning: Back feed to a utility system can cause electrocution and/or property damage. Do not connect to any building's electrical system except through an approved device or after building main switch is open.

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Appendix G: Assumptions

Table G-1: Summary of modeled assumptions

Variable	Value	Reference
Financial assumptions		
Discount rate	3%	Treasury Board of Canada Secretariat (2007)
Modeled timeline (years, N)	25	Made by author
Consumer Power Rate ($/kWh) in 2022 (n=0)	$0.24	SaskPower (2015)
Modeled annual increase in Consumer Power Rate starting in 2023 (n=1)	2%	Made by author
Annual Billing ($/Community) in 2022 (n=0)	$12703.07	SaskPower (2015)
Modeled annual increase in Annual Billing starting in 2023 (n=1)	2%	Made by author
Diesel generation and distribution asset values in 2022 (n=0)	$73,936	SaskPower (2021b)
Solar PV generation asset values in 2024 (n=2)	$82,500	Calculated using data from PBCN (2022)
Depreciation (Diesel and solar assets)	30%	Government of Canada (2022f)
Power bill cost savings (HH/year) from DSM	$750	Arnold (2021)
System operations assumptions		
Electricity demanded (MWh/year, n=0)	200	Adapted from SaskPower (2021b)
Number of households	16	PBCN (2022)
Increase in consumer demand for electricity, starting in 2023 (n=1)	2%	SaskPower (2021c)
Emissions from diesel combustion (tonnes CO_2e/litre)	.0026	University of Calgary (2015)
Cost assumptions		
Solar technology capital cost (per watt)	$2.75	PBCN (2022), FNPA (2022)
Generator	$50,000	SaskPower (2022a)
Diesel fuel ($/litre) starting in n=0	$1.44	SaskPower (2021b)
Diesel fuel price increase starting in n=1	2%	Made by author
Carbon tax rate (per tonne CO_2e) n=0 to n=8	Varies	Government of Canada (2022f)
Carbon tax rate (per tonne CO_2e) n=9 to n=25	$170	Made by author
Annual CCM OM expense (as a proportion of annual fuel and capital expenditures)	25%	Adapted from SaskPower (2021b)
Annual travel for SaskPower staff	$50,000	SaskPower (2022a)
Annual Solar PV OM expense ($/kW)	$151.00	Adapted from Wilber et. al. (2019)
DSM cost per HH	$7000	Arnold (2021)
Technical assumptions		
Solar capacity factor	16%	Adapted from SaskPower (2021b)
Power offset from solar in n=2	40 MWh	Adapted from Ross (2022)
Litres of diesel used per MWh of electricity generated	554	SaskPower (2021b)
DSM efficiency factor	0.67	Adapted from Arnold (2021)

Chart adapted from Sidhu et. al. (2018).