TD 103-19(2) TABLED ON MAY 27, 2020

Alternatives North

Climate Emergency: Getting the NWT off Diesel

Cost effective investments to reduce NWT GHG emissions by 50% within 5 years.

April 22, 2020

For Public Release

Wood Pellet Heating

Renewable Diesel

Carbon Offsets

Gold Standard

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Icons from Freepik, flaticons.com

Contents

Executive Summary

An increasing number of “Climate Emergencies” are being declared by governments in Canada and around the world. This report examines a strategy for quickly reducing greenhouse gas emissions in the NWT by 50% by 2030 or sooner. A 50% reduction is estimated to be 600kt of annual avoided CO2eq emissions.

This report shows that it is not necessary to wait until 2030 to reduce the NWT’s emissions by 50% and further, that doing so could cost substantially less than the actions proposed in the current GNWT 2030 Energy Strategy.

This report looks at the total investment required to fund, build and operate the following “emission reduction pathways” over 20 years:

- Carbon offsets
- Renewable Diesel
- Biomass District Heating
- Diesel Co-generation (CHP)
- Biomass Co-generation (15 MW Steam Power Plant)
- Transmission line from existing Taltson Hydro to future North Slave mines
- Transmission line from expanded Taltson Hydro to Ekati plus future mines plus Fort Providence plus electric vehicles in Yellowknife
- Wind and Solar PV (partial analysis based on existing studies)

Purchasing Carbon Offsets is the most immediate and affordable way of reducing emissions by 600kt/yr at an estimated cost of $15M per year. However, Biomass District Heating and Diesel co-generation could be combined to produce 68kt/yr of reductions and have potential net income of $80 million over a 20-year operating life. Renewable diesel is more expensive than Carbon Offsets, requiring a subsidy of ~$70M per year to cost-effectively replace 600kt/yr of emissions from fossil diesel. Despite analyzing two of the best possible business cases, neither Taltson hydro-based pathways could achieve 600kt/yr of emissions reductions and are by far the most expensive ways of reducing emissions. Generating electricity from biomass was also among the highest cost pathways.

This leads to the following recommendations:

1. The GNWT revise the current Energy Strategy towards more immediate and cost effective ways of reducing emissions – as outlined below
2. The GNWT commit to purchasing 600 kt of Gold Standard Carbon Offsets (about $15M/yr), starting in 2020 and continue to purchase offsets each year as required to maintain a total reduction of 600kt as other actions take effect
3. The GNWT directly invest over the next 5 years in the construction of biomass and co-generation district heating systems in NWT communities (~$145M). This should be done over the next five years with financial support from the Government of Canada. The GNWT should also operate these systems and sell heat recovered from diesel generators and centralized biomass boilers at 80% of the price of fossil heating oil. This is estimated to reduce emissions by 68kt/yr
4. Beginning with its own internal operations, The GNWT should immediately begin a transition from fossil diesel to renewable diesel. The GNWT can begin with its own internal operations, and show how renewable diesel can be used in its own boilers, vehicles, and generators. The GNWT should

also work with fuel suppliers to purchase approximately 200M litres of renewable diesel per year within 5 years and provide a subsidy to reduce the price to be the same as fossil diesel (about $65M/yr). Combining renewable diesel use with the district heating systems in recommendation three would result in at least 600kt of annual reductions within 5 years and eliminate the need to purchase carbon offsets

5. The GNWT commission a study, similar to this one to examine the most cost effective way of becoming carbon neutral within 15 years. While this study uses tail-pipe emissions, life cycle analysis of each fuel source would be better. However, lack of life-cycle analysis is not an excuse for delaying action. As NWT moves toward climate neutrality a method for life cycle carbon accounting similar to what is used for California's renewable fuel standards or Canada's Clean Fuel Standard should be adopted.

Introduction

In June, 2019, the Canadian House of Commons passed a motion declaring a climate emergency[1] and, as of December 18th, 2019, 1,260 jurisdictions around the world had also declared climate emergencies[2]. In fact, global warming has been globally recognised as a crisis, requiring urgent action for decades[3]. Recent school strikes inspired by Greta Thunberg and many others around the world are demanding that all governments recognize that global warming is an emergency requiring an urgent and effective response.

This report looks at Greenhouse Gas (GHG) emissions from the Northwest Territories (NWT), assuming that the Government of Canada (GC) and the Government of the NWT (GNWT) will take action based on the understanding that global warming is an emergency (i.e. rapid, direct and effective). These emergency actions are based on the following principles:

- "Be the change you want to see in the world". Global warming is a planet-wide issue that requires collective action in all countries and regions. Although the NWT's emissions are a small part of the over-all problem, we have a moral obligation to achieve net zero emissions.
- We are far wealthier than most other jurisdictions in the world.
- Inaction is not an option.
- Resources must be allocated to the actions that have the fastest and highest impact. By definition, emergencies require "triage". Triage is a screening process that directs finite resources towards actions that will have the most immediate and effective impacts.

Action on Climate Change in the NWT so far has not followed these principles. Recent NWT Premier Bob McLeod often publicly stated that the NWT was only a small source of emissions and therefore did not need to take action and further that there were no viable alternatives to fossil fuels in the NWT[4]. Over the last two decades, the GNWT has published a series of greenhouse gas plans and energy strategies that the Auditor General of Canada found showed a lack of leadership on reducing emissions, saying the strategies "*lacked meaningful targets and did not include concrete actions for major emitters.*"[5] The current energy strategy is a slight improvement, but this report will show that it still does not prioritise actions that will result in the most immediate, cost-effective and largest greenhouse gas reductions.

The GNWT is certainly not alone in putting other priorities above immediate, cost-effective greenhouse gas reductions but as with any other emergency, we will only be able to take the rapid action at the scale required if people put aside competing priorities and work together.

This report is a continuation of the conversation that started with Alternatives North's technical overview titled "100% Renewable Energy in the NWT", published in October 2016[6] that outlined a vision for a 100% renewable energy powered NWT by 2050 using existing technologies. This report goes into more detail, costing out options for achieving a minimum 50% reduction in current NWT GHG emissions by 2030. The solutions presented here are ***not necessarily intended for the rest of Canada*** – the North features relatively small energy loads separated by vast distances, making transmission lines and pipelines very costly. Solutions that may work very well in the rest of Canada, therefore, may not be the best solutions for the North.

These are also interim solutions, valued because they are immediately viable, effective and affordable, but recognizing that over time further solutions to replace these interim actions will be required to reach the ultimate targets of zero emissions, particularly is there is not effective management of energy demand.

While this is a technical report, we try to use terminology that most people are familiar with. Detailed calculations are included as appendices.

Assumptions and Limitations

Addressing the energy use of all sectors of NWT society within the confines of a small project budget requires some constraints and assumptions on the scope of the study. Therefore, this study:

- Assumes that failure is not an option and that the Government of Canada / GNWT are committed to achieving a 50% reduction in NWT GHG emissions by 2030 and 100% reduction by 2050. Lowest cost option(s) are to be identified, though the cost may be higher than the status quo
- Bases a 50% reduction on the most current (2017) NWT emissions levels of 1,200 ktCO_{2eq} per year, which works out to a goal of 600kt/yr. 2017 appears to have been a low year for emissions so our target is not that much higher than the GNWT 2030 Energy Strategy target (30% over 2005 levels, or 517kt/yr, also by 2030). "ktCO_{2eq} per year" means kilo tonnes of carbon dioxide equivalent per year and is a measure of how much greenhouse gas is produced by an activity. Greenhouse gas pollution by human activity is the cause of the climate emergency we see today. 1 tonne CO_{2eq} = 1,000 kg CO_{2eq}, which is produced by burning 370 litres of diesel or taking 2 return, economy flights from Yellowknife to Vancouver. For the rest of the report "ktCO_{2eq} per year" will be shortened to "kt/yr"
- Estimates investment required, operating costs and incomes, assuming that all projects are implemented by 2030 and operate for 20 years. While project development costs are included, it is assumed that existing GNWT staff could administer the funds
- Assumes that NWT society stays roughly the same as it is now over the next 20 to 30 years:
    - The overall population and the distribution of population between smaller and larger communities remains the same,
    - Given the boom and bust nature of commodity markets and mining activity, and the relatively long outlook of this analysis, it is very difficult to ensure the accuracy of any assumptions of mining activity. While there will be reductions in emissions from the end of oil production in Norman Wells and the closing of some diamond mines, this report will focus on active efforts to reduce emissions from the resource extraction sector. This report assumes that, for the 20 year study period, the Ekati diamond mine will continue to operate and new mines, such as the proposed NICO, Yellowknife Gold or Nechalacho mines will begin operations as the other diamond mines reach the end of their lives. In other words,

the electricity demand from the resource extraction sector is assumed to remain steady at 36 MW

- Seeks to achieve a Class 5 cost estimate (+/-50%) using financial information from completed projects in Canada's north, industry estimation, and the experience of the authors, in that order
- Assumes that the NWT's GHG profile is accurately represented by the GHG inventory data collected by Environment and Climate Change Canada[13]
- Does not include the impact of reduced government revenue from fossil fuel taxes. In 2014/15 the GNWT collected $19M in fuel tax on all fuels except wood, wood pellets, heating fuel, natural gas and propane, which are not taxed[7]. By 2022 a $50/t NWT Carbon Tax is expected to generate $54.5M per year[8], with the same fuels and aviation fuel exemptions. With the exception of Carbon Offsets and heating fuels, reducing NWT net emissions by 50% would substantially reduce these revenues
- Focuses on energy use and the resulting greenhouse gas production within the boundaries of the NWT – it does not include "upstream" emissions such as those from fossil or renewable fuel production and refining, and it does not include food production as a source of emissions. In other words, this report looks at "tail-pipe emissions" only
- GHG emissions factors are based on the values used in RETScreen software. RETScreen is a clean energy management software system for energy efficiency, renewable energy and cogeneration feasibility analysis[9]. This means that the CO_2 portion of emissions from burning biofuels like wood pellets or renewable diesel are assumed to be carbon-neutral. There are small amounts of methane and N_2O emitted when burning any fuel and these are included.

Methodology

In order to determine the cost effectiveness of the examined technologies, they will be modelled as "pathways". A pathway combines a technology with NWT-specific information such as the number of communities, mines or buildings to be served by a technology. To determine each pathway's potential to reduce overall GNWT GHG emissions, the following will be estimated:

- Capital cost (cost of design, construction and commissioning),
- Annual operations and maintenance (O&M) cost,
- Revenue from energy sales, assuming that the GNWT builds & operates the assets
- Expected life of the asset
- Annual GHG emissions (kt/yr)

The above estimates will be used to calculate:

- The total pathway investment required or income generated over 20 years. This is calculated as the total capital cost plus operations and maintenance, minus revenues, assuming that all assets will operate over a period of 20 years. In economics, this is known as the Net Present Value (NPV). All costs are in constant 2020 dollars, with a discount rate of 0%. A negative NPV will be called an investment; a positive value will be called an income.)
- The average annual $/t cost of pathway GHG reductions (investment over 20 years divided by emissions reduction over 20 years)
- In most cases, the calculations will be done using RETScreen

In addition, the report will look at each pathway and provide:

- A summary of perceived barriers to implementing the pathway
- A brief summary of additional considerations for the pathway:
  - Impact on human health
  - Impact on NWT employment
  - Impact on NWT self-sufficiency

This analysis is from the perspective that the Governments of Canada and the NWT will fund and build the projects and collect any revenues. This keeps the analysis simple and also ensures that real-world reductions occur. The current approach of providing financial incentives to the private sector and municipal governments does not guarantee that there will be enough projects to accomplish the required reductions.

All pathways are based on the following cost assumptions:

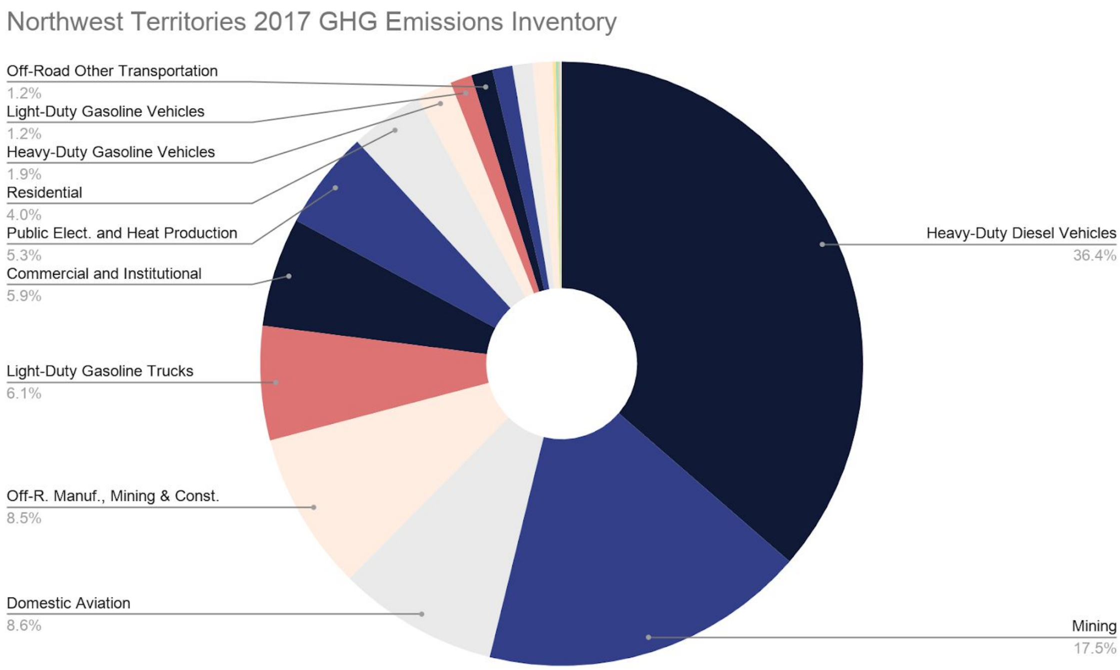
- Fossil fuel prices:
  - Diesel fuel for power generation and transportation at mines: $1.28 per litre, including the $50/t carbon tax that is planned for 2022. [10] [11]
  - Heating oil: $1.20 per litre at mines or community prices based on the Arctic Energy Alliance's *Fuel Cost Library.*[12] The GNWT currently rebates heating fuel carbon taxes at the point of purchase so a carbon tax is not added to heating fuel costs in this study
- Renewable heat and power will be sold to industry and building owners at a 20% discount over comparable fossil fuel alternatives to ensure uptake. In the case of renewable diesel however, it is assumed that the GNWT will make up the cost difference with fossil diesel only.

Some pathways will not result in 600kt/yr of reductions on their own. Pathways will be combined into several scenarios that each add up to a combined reduction of 600kt/yr. The total investment and average annual $/t will be used to compare scenarios.

The Current GHG Picture

Before discussing the pathways to GHG reductions in the NWT it is valuable to review the current sources of emissions. Every year Environment Canada and Climate Change collects information on GHG emission sources throughout Canada and compiles a GHG Inventory by region. The figure below takes the ECCC data for the NWT from 2017[13] and plots it so that the largest contributors and their relative contribution to overall emissions easily compared. In the case of the NWT, the top eight sectors that account for 92% of GHG emissions are:

- Heavy Duty Diesel Vehicles (36%) – mining equipment such as Excavators, Haul Trucks, Loaders, etc. –;
- Mining (17%);
- Domestic Aviation (9%);
- Off-Road Manufacturing, Mining, and Construction (8%);
- Light Duty Gasoline Trucks (6%);
- Commercial and Institutional (6%) – heating buildings in Yellowknife & the communities –;
- Public electricity and heat generation (5%);
- and Residential (4%) – heating.



To date much time and discussion by both government[14] and advocacy groups has been focused on reducing diesel used for electricity generation in NWT communities, yet this sector is 7th on the list and represents just over 5% of total NWT emissions. Total community-based emissions from power generation, heating and transportation are approximately 25% of the total, while resource extraction and transportation outside community boundaries makes up 75%.

An emergency response to the climate crisis requires that policy focus on cost effective and immediate reductions from primarily the largest sources of emissions. In the NWT, this means the resource extraction sector must be a priority.

GHG Reduction Pathways

Carbon Offsets

carbon offsets

Overview

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
600+	N/A	-$300M/600kt	-$25/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
existing large-scale market	neutral	indirectly negative	indirectly negative

The NWT is a challenging environment. Long distances, few roads, extreme weather and the relatively small scale of enterprises make the cost to build and operate assets more expensive than industry standard in most of the country. It is therefore no surprise that renewable energy alternatives are also more expensive to implement in the NWT than elsewhere. However, as climate change is a global issue, GHG reductions that happen elsewhere in the world are just as effective. For these reasons the NWT may be able to have a greater immediate impact, per dollar spent, in fighting climate change by investing in reduction activities outside of the NWT.

Carbon Offsets are a set of financial mechanisms and contracts that allow parties to invest in and take credit for GHG reductions anywhere in the world by providing assurance that the money invested results in real, additional, and permanent reductions of GHG emissions. As the reductions that Carbon Offsets would provide are independent of the technology or industry that produces GHG emissions they are applicable to 100% of the NWT GHG profile and have the potential to be used to make the NWT carbon neutral.

Carbon Offsets markets are either compliance (regulated within certain political boundaries, such as the Alberta Emission Offset System[15]) or voluntary (unregulated by government). The NWT could participate in an existing compliance market but these are typically designed for jurisdictions with much higher emissions than the NWT and may be therefore too complicated and expensive for the NWT to participate in. The NWT could pursue offsets through voluntary markets, which offer offsets at a more appropriate scale. The voluntary carbon offset market in 2018 was estimated to represent 94,000kt/yr[16], while the NWT's 2017 emissions were 1,200kt/yr. This means there are almost 100 times more voluntary carbon offsets available than would be required for the entire NWT to become carbon neutral.

Being unregulated, there are a wide variety of voluntary carbon offsets available and some come under more criticism than others in terms of whether they offer actual reductions in emissions. The David Suzuki Foundation and the Pembina Institute reviewed these concerns in 2009 and produced a purchasing guide[17]. The guide recommends purchasing offsets that "*meet relatively strong, independent standards, such as [...] the Gold Standard*' and that priority be placed on offsets from Renewable Energy and Energy Efficiency projects. The Gold Standard is a non-profit Swiss foundation, created in 2003 by environmental and human rights organizations that were concerned that the lack of regulation in voluntary carbon offset markets was creating a "race to the bottom". According to its' website, the Gold Standard is "*Now endorsed by 80+*

international NGOs and with more than 1,400 projects in 80 countries undergoing certification. The Gold Standard has become the global benchmark for the highest integrity and greatest impact in climate and development initiatives." [18] Gold Standard carbon offsets are available in Canada through the Montreal based non-profit Planetair[19].

There are several perceived barriers when considering the use of voluntary Carbon Offsets:

- People do not understand how offsets work
- People do not know how to calculate their emissions and therefore do not know how many offsets to purchase (this is an issue on the individual level, but also applies to businesses, communities and even the entire NWT)
- People are concerned that unregulated voluntary markets do not always provide offsets that actually reduce emissions - as discussed above
- People prefer to invest in reducing emissions locally, even if that means less over-all emissions reductions

Despite any barriers, Carbon Offsets provide a measure of cost-effectiveness against which potential local investments can be measured. They also provide the ability to fill in the gap if not enough affordable, local projects can be found to achieve 600kt/yr of reductions. This makes accomplishing the necessary reductions more a question of finance than technical feasibility. The cost to achieve a 600kt/yr reduction in emissions through purchasing offsets creates a baseline against which other local projects can be compared.

Carbon Offsets on the Gold Standard website are available in a range from $17-$25/tCO2e. It is difficult to project the future cost of voluntary carbon offsets – if demand increases faster than availability of projects seeking funding, the price could increase, but on the other hand, if the supply of projects seeking funding increases, the price could drop. Uncertainty in the price of offsets make them better suited as a short-term strategy. This report assumes a relatively high price of $25/t. This means that to offset 600kt/yr would cost $15M per year, with a total investment over 20 years of $300M.

Since this pathway involves investment outside the NWT, it could be argued that, while not directly reducing NWT employment in the energy sector or changing the NWT's self sufficiency in energy production, it would divert funds that would otherwise be spent in the NWT.

Renewable Diesel

renewable diesel

Overview

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
600+	N/A	-$1,394M/600kt	-$116/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven cold climate outside NWT	neutral	indirectly negative	indirectly negative

Renewable Diesel, also known as Hydrogenation-Derived Renewable Diesel (HDRD), is a fuel that can be generated from the same feedstock as Biodiesel (Fatty Acid Methyl Ester, FAME).The different processing methods result in a fuel that is nearly chemically identical to diesel and does not suffer the same technical challenges as biodiesel. Renewable Diesel is considered "carbon neutral" because it is made from vegetable oils and fats that are part of natural carbon cycles, rather than fossilized carbon. This report assumes a Renewable Diesel carbon intensity of 70g CO_2e/L compared to 2,825 gCO_2e/L for conventional diesel (RETScreen), resulting in a 98% reduction in tailpipe GHG emissions. Renewable Diesel has been tested as a drop-in replacement (both for refining and use) for diesel in a variety of countries and climates including a 3-year cold weather test in public transportation in Helsinki, Finland[20] and a cold weather test in Alberta, during which it was transported by truck and pipe at 100% concentration without issue[21].

Renewable Diesel is currently available at gas stations in California in 100% concentration as part of their state-wide low carbon fuel standards[22]. Co-op has announced it will make Renewable Diesel available at its pumping stations in Quesnel and Vanderhoof, British Columbia, by the end of 2019, expanding to five more locations by 2021[23]. Several municipalities in the US have begun switching their entire fleets to Renewable Diesel to achieve GHG emissions reductions with Vancouver, Canada, being the first Canadian municipality to take this step.[24]

As Renewable Diesel is a proven drop-in alternative to conventional diesel, it can be used in power generation, mobile transportation, and space heating, making it applicable to approximately 76% of the current NWT GHG profile. In addition, the use of Renewable Diesel does not require the costly early replacement of infrastructure, involves minimal modification to equipment, and relies on training and skillsets that are already in place in the workforce. Adopting Renewable Diesel in all current conventional diesel applications would result in a total annual GHG emission reduction of 906 ktCO2e, 306 kt more than the proposed target. In addition, jet aircraft are already capable of operating on 50% Renewable Kerosene (similar to Renewable Diesel)[25]. Gasoline vehicles could be replaced with diesel equivalents, which would, combined, cover roughly 95% of NWT emissions. However, this report only looks at the potential of directly replacing fossil diesel in existing equipment.

One of the key barriers to adopting Renewable Diesel is, until recently, few in the NWT had heard of it. This is related to the other barriers; cost and availability in the NWT. Renewable Diesel is more expensive than fossil diesel and is therefore currently only readily available in regions like California and British Columbia where renewable fuel standards require fuel suppliers to gradually increase the renewable content of the fuel they sell. The Government of Canada announced in 2016 that it is developing a Clean Fuel Standard (CFS) with the first regulations coming into force in 2022. The objective of the CFS is to reduce GHG emissions by 30 Mt by 2030, in part through the use of low-carbon fuels[26]. A Canada-wide clean fuel standard should mean that Renewable Diesel will be more widely available across the country.

To achieve a 600kt reduction utilizing only Renewable Diesel would require 218M liters. Current global production of Renewable Diesel is estimated to be 20B litres per year and is projected to increase to 80B litres by 2030[27]; making the NWT's requirements a "drop in the bucket" in comparison. However, Renewable Diesel is not manufactured in Canada in large quantities. This means that bulk quantities of pure Renewable Diesel in western Canada come from refineries in Singapore or the southern USA, increasing retail costs due to additional transportation.

In California and British Columbia, the retail price of renewable diesel is the same as fossil diesel because low-carbon fuel standards require fuel companies to sell specific volumes of renewable fuel.[28] [29] The fuel retailers buy renewable diesel in bulk and that market price is higher than fossil diesel. Market prices of up to $1.80/L[30] have been reported in Western Canada, but due to relatively low production volumes, there is no regularly updated price index for renewable diesel in Canada. A 2013 study for Natural Resources Canada estimated that renewable diesel would cost 20% more than biodiesel, which worked out to $1.40/litre[31]. A study for the City of Toronto in 2019, estimated a price in California of $1.60/litre and suggests that there would be an undefined premium for a winter renewable diesel[32]. California is the largest market for renewable diesel in North America at the moment, so market prices there will largely determine prices in Alberta. Since the NWT is roughly the same distance from Alberta, this report assumes that the market price in the NWT will also be $1.60/litre. While current Renewable Diesel production in Canada is minimal, there are plans to expand. Parkland Fuel Corporation is planning production at its BC refinery by 2023 [33], and Cielo Waste Solutions sold its first 5,000 litres of renewable diesel from a plant in Aldersyde Alberta in April 2019[34], with additional plants planned for Brooks, Calgary, Medicine Hat, and Grand Prairie in 2020[35]. Assuming sufficient quantities become available in Alberta this report estimates that Canadian sourced Renewable Diesel would cost $1.60/litre, $0.32/L more than fossil diesel at $1.28/litre (which includes a $50/t carbon price). At a premium of $0.32/L purchasing Renewable Diesel would be equivalent to purchasing Carbon Offsets at $116/t.

As there are minimal operational differences between fossil diesel and Renewable Diesel, we assume that the NWT could switch all diesel to be 100% Renewable Diesel and the GNWT could choose to offset any increase in the cost of living and doing business by subsidizing Renewable Diesel at $0.32/litre. Note that this is a different approach than used when looking at a model where the GNWT builds and owns renewable energy infrastructure and sells the energy at a discount (used in Hydro expansion, district heating, & biomass CHP). To achieve a 600kt reduction utilizing only Renewable Diesel would require 218M liters at a subsidy of $70M per year, resulting in a total investment over 20 years of $1,394M.

Another barrier to adoption is concern over using land capable of producing food, for producing fuel, and the potential climate impact of land use change to grow feedstock. As of 2014 just 55% of the world's crops were directly eaten by people, while 36% were used to feed livestock and 9% were used for biofuels and other industrial uses[36]. In the context of a climate emergency, reducing meat consumption would provide more resources for biofuels without causing humans to go hungry.

In addition, Renewable Diesel is often refined from existing waste streams such as used cooking oil and animal fats from meat-processing plants. Making Renewable Diesel requires approximately 1kg of feedstock to create 1 L of Renewable Diesel. Achieving 50% GHG reduction in the NWT through the use of Renewable Diesel alone would require 218M liters annually or 218kt of feedstock. Cielo Waste Solutions uses a combination of household, commercial, and construction waste as feedstock. West Coast Reduction supplies renewable feedstock for fuel refinement, collecting animal and vegetable waste oils from BC, Alberta, and Saskatchewan.[37] West Coast Reduction currently processes 250kt a year. Cielo's planned capacity would produce roughly 2,000L per hour per production plant, or 70M Liters assuming five plants at 80% utilization, which infers 70kt of available feedstock. Collecting waste streams for processing into fuel is just beginning in Western Canada but, combined, these two companies can already access more feedstock than what is required to achieve a 50% GHG reduction in the NWT.

This report does not look at the impact of using Renewable Diesel in the rest of Canada, where higher population densities and extensive transmission lines make electrification of heating and transportation and the interconnection of wind, solar and hydro power facilities an economically viable option. In contrast, the NWT, due to its challenges of low energy and population density, remote communities and mines, and limited infrastructure, creates a scenario in which the high energy density, transportability, ease of long term storage, and familiarity with fossil diesel makes Renewable Diesel an ideal solution, at a volume which can still be sustainably sourced.

Since this pathway involves investment outside the NWT, it could be argued that, while not directly reducing NWT employment in the energy sector or changing the NWT's self sufficiency in energy production, it would divert funds that would otherwise be spent in the NWT.

Biomass District Heating

biomass district energy

Overview

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
64	$126M	$79M/64kt	$62/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven	neutral	positive	neutral

Biomass District Heating centralizes the creation of heat using large boilers that burn biomass, such as wood pellets, and then piping the heat to nearby buildings. Pellets or other sources of biomass are delivered by truck, and stored on site in bins or silos until burned. Biomass District Heating is common in Northern Europe and seeing growing investment in recent years in Canada. The NWT has been an early adopter of these systems with smaller operating districts in Hay River, Behchoko, and Yellowknife.

By centralizing heat creation, it is possible to obtain high reliability and low operation cost, offsetting the cost of piping and leading to cheaper heating on a per kWh basis than distributed fuel oil heating. With District Heating it is also possible to size the central boilers less than peak capacity, allowing existing boilers in connected buildings to handle peak loads. Peak heating load occurs on only a small numbers of days in a year meaning a boiler sized at 50% of peak load can deliver roughly 90% of a building's annual heating load. Installing District Heating Systems sized for base load requires less money while still almost completely eliminating GHG emissions. For this reason, Biomass District Heating was evaluated assuming base load design rather than a full redundant design.

The feasibility of Biomass District Heating Systems in the NWT saw significant detailed study in 2010 with Arctic Energy Alliance (AEA) evaluating non-tax-based communities,[38] and FVB Energy Inc. evaluating a system for downtown Yellowknife.[39] AEA's analysis was completed using a baseload design and is therefore directly transferrable to this analysis with capital costs corrected for inflation using a cost factor of 17%.[40] A key component of payback is fuel pricing, both of pellets and fuel oil. To avoid completely recreating AEA's work it was assumed that the price of pellets remained unchanged since 2010 and that only fuel prices changed according to AEA's fuel cost database.[41] The AEA used high and low fuel cost scenarios and current fuel prices fall between them so this report adjusted the results proportionally. The updated results are in the appendices.

The scope of FVB's downtown Yellowknife study included the use of geothermal heat from nearby Con Mine, supplemented by Biomass Boiler, and backed up to full redundancy by oil boilers. Financial returns were not calculated in this report; however detailed heat load, capital costing, and operational costing were given. This allowed costs to be modified to represent a District Heating System that ran only on biomass. All construction costs given in the report were corrected for inflation using a cost factor of 17%. An updated pellet price of $188/t was obtained from La Crete Pellet. O&M costs were set to $120/kW based on GNWT information regarding actual O&M costs of various sized pellet boilers currently operating in the NWT.[42] These numbers were then entered into RETScreen to provide Annual GHG reduction, Simple Payback, and Investment/income estimates.

Beyond the opportunities discussed by these studies there is additional potential for implementing Biomass District Heating Systems both in other tax-based communities, as well as in Yellowknife, or at operating or future mines. Using information from both studies, RETScreen models were made for 1MW and 4MW systems. A 1MW system could provide heat to the downtown of a regional centre, such as Hay River, Inuvik, or Fort Simpson, while a 4MW system could provide heat to a larger area such as the hangers at the Yellowknife airport, or supplement diesel generator derived heat at a 100-person mining camp. As the price of pellets can vary based on where the project is implemented these systems were evaluated using a pellet cost of $250/t. It is assumed that five of the smaller systems and three of the medium systems could be implemented.

In order to ensure customers connect to the District Heating Systems there needs to be a clear financial incentive. A 20% savings on annual heating cost was decided to be adequate to convince customers to connect. This was accounted for in the payback and financial calculations for all models by discounting the cost of the diesel by 20%.

Implementing a system in each of the communities in AEA's study, as well as downtown Yellowknife, and an additional five 1MW and three 4MW districts would result in an overall capital cost of roughly $126M, an annual GHG reduction of 64kt/yr, and a net income of $79M over 20 years.

System	Total Systems	Capital Cost	Annual GHG Reduction (kt)	Simple Payback	Investment/ Income
Non-Tax Communities	23	$42,800,000	16	16 year avg.	$32,400,000
Downtown Yellowknife	1	$34,215,000	18	13	$20,300,000
Additional 4MW Instal.	3	$32,700,000	21	12	$22,700,000
Additional 1MW Instal.	5	$16,125,000	9	6	$4,000,000
	Total	$125,840,000	64		$79,400,000

There are relatively few barriers to adopting Biomass District Heating. The systems are known to work and have been installed in some communities with operational data confirming their potential for long-term savings, and it is possible to provide customers with cheaper heat while still returning an income overall. The largest barrier is coordinating the various buildings, people, and groups involved to build, operate, and connect to the system. This has been a significant barrier in implementing these systems in the past. There are also perceptions from installed systems that the capital cost is too high, however more recent installations have found cost savings such as using insulated PEX lines instead of steel.[43] Another perceived barrier is that there may not be a consistent supply of pellets at necessary volume and cost. However the current wood pellet production capacity in Alberta and British Columbia already vastly exceeds the total required for the NWT with the majority of wood pellets being exported to Europe and Asia. A wood pellet production plant in Enterprise, NWT has been in the planning stages for many years, but it is not clear that these pellets will be economically competitive with pellets imported from Alberta or British Columbia. Another perceived barrier is that trucking wood pellets requires double the number of trucks compared to diesel resulting in higher transportation related emissions. However the scale of this increase is negligible compared to the reductions achieved and the option exists to fuel trucks with renewable diesel, mitigating this impact.

Diesel Co-Generation

heat & power

Overview

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
● 4	$16.3M	● $7.8M/4kt	● $98/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
● proven	● positive	● positive	● positive

Co-generation is also known as Combined Heat and Power (CHP), waste heat recovery, or residual heat recovery. Diesel Generators convert roughly 33% of the input energy available into electricity; the rest is lost mostly as heat. Heat is collected by the engine and oil cooling systems and rejected to the surrounding air using fans and radiators; it is also rejected as part of the exhaust gas. In a co-generation system, instead of rejecting heat, it is captured with heat exchangers and piped to a nearby heating load. This reduces the amount of fuel used for space heating. Every operating mine in the NWT utilizes these systems to reduce their operating cost. There are also systems operating in Fort Liard and Fort MacPherson.[44] Heat is available as long as power is being produced, and can be salvaged at roughly 40% thermal energy per kWh of electricity produced.[45]

Depending on the size, type and distance from the generator to the heating load, different amounts of the salvaged heat can be utilized. Serving the domestic hot water and space heating demands of a larger network could allow all available heat to be used year-round, but at much greater piping and connection expense. Alternatively, a smaller load can be serviced at a lower cost while not utilizing all the available heat. Given the cost of piping and connections this study analyses the second case because it is more likely to generate income over 20 years.

For this small-sized scenario, the estimated total utilization of annual available heat is 16% of the electricity produced. This estimation can then be applied to known annual power production in thermal communities to determine the amount of heating fuel that can be displaced. As the heating fuel displaced is diesel (except Inuvik where it is natural gas), we can estimate the GHG reduction achieved. This method was checked using the published annual fuel displacement from the operating Fort Liard and Fort McPherson systems and was found to be sufficiently accurate for the purposes of this analysis.

The capital cost of retrofitting existing generators to act as co-generation systems are estimated to be $100/kW for larger systems[46] to $260/kW for smaller systems (not including piping).[47] For reference, the Fort Liard system cost about $1700/kW (piping included), but this project utilized steel piping when much less expensive PEX piping could have been used. The generating plants in NWT communities are relatively small so a cost of $260/kW was assumed. With only servicing nearby heating loads it is assumed 500m of piping would be required for less than 1 GWh available heat, 1000m for 1-2 GWh, and 1500m for greater than 2GWh. Piping is assumed to have an installed cost of $500/m.

In order to ensure customers connect to the District Heating Systems that would be needed for co-generation heating to happen, there needs to be a clear monetary incentive. A 20% savings on heating bills was decided to be adequate to convince customers to connect. This was accounted for in the payback and financial calculations for all models by discounting the cost of the diesel by 20%. As Co-generation systems are essentially automated once set-up, and there are few moving parts outside of the engine itself, the O&M costs for the system are considered negligible.

The results of applying these assumptions to the values obtained for the thermal communities[48], [49] is shown in the table in the appendices. Total cost to implement in all communities except Fort Liard, Fort McPherson, and Norman Wells (data unavailable) is approximately $16.3M, with a total GHG reduction of roughly 4kt/yr.

Total investment was calculated for each community utilizing the 2018 cost of fuel. As co-generation obtains heat from fuel already being burned for power production, the simple payback and income result from dividing the capital cost by annual fuel savings. Simple payback ranges from 10-50 years and collectively the income from operating these systems until 2050 is $7.8M.

The barriers to implementing this technology are coordination, profitability, and retail cost of heat. Similar to Biomass District Heating, coordinating the various buildings, people, and groups involved to build, operate, and connect to the system has been a significant barrier in implementing these systems in the past. Outside of mining (i.e. in communities), where the heating loads are located next to the generators, co-generation projects are perceived as not being good financial investments. However, in comparison to other pathways, co-generation does have the potential to generate some net income over 20 years. It should also be noted that the profitability improves slightly when existing generators are reaching their end of life. At this time the new generators could come equipped with heat recovery systems cheaper than retrofitting. The third barrier (see first sentence), the retail selling price of the recovered heat (or heat rate), arises when it comes time to market heat to surrounding buildings. As the heat is salvaged from fuel that was already bought and paid for as part for the electricity rate, customers perceive that the heat should be free. However there must be a cost to heat in order to pay for the capital cost of implementing the system, as well as to encourage conservation and efficiency so that the heat produced can have maximum impact.

Biomass Co-Generation (15MW)

cogeneration

Overview

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
73+	$135M	-$589M/73kt	-$403/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven	neutral	positive	neutral

In the NWT, biomass is currently used for heating, in the form of firewood and wood pellets. However Biomass can also be used to produce electricity or both electricity and heat with Combined Heat and Power (CHP) steam plants. According to Natural Resources Canada; "As of 2014, Canada had approximately 70 biomass generating power plants with total installed capacity of 2,408 MW" with facilities located in seven provinces. The typical application uses biomass in a boiler to create steam, which is then used to drive a turbine generator, with the remaining heat in the steam then being used for either process or space heating. This is a renewable version of a process that has existed for decades, but traditionally one that used coal, oil, or gas to create steam. For steam plants in Canada, larger facilities are required due to greater safety requirements, costs and efficiencies - with the minimum size being around 10MW (in Europe it is not uncommon to find 2.5 MW and up[50]). Mine sites present an ideal application for Biomass CHP because they have both large electrical and heating requirements in close proximity. Looking at existing and proposed mine power draws, a 15MW system is the most likely to be utilized.

Construction costs for biomass fired CHP units are significantly higher compared to fossil fuel plants, averaging $9,000/kW (RETScreen). This puts the capital cost of a 15MW plant at $135M, compared to the cost of an equivalent diesel engine co-gen system of $18M. O&M costs were set at $315/kW (RETScreen). Facilities built in Canada between 1993 and 1995 are just now requiring large scale retrofit, so the asset life is considered to be 25 years.

15MW CHP plants using both diesel engines and biomass steam turbines were modeled in RETScreen to compare emissions. The diesel system resulted in annual emissions of 80kt, while biomass CHP resulted in annual emissions of 7kt, a reduction of 73kt/yr. Biomass CHP plants could be constructed at both existing and new mines but the economic viability would be determined by the number of years that the mines operate. CHP could also supplement power production on the North or South Slave electrical grids if demand increased beyond the current hydro-electric capacity. However, for this report, only one facility of this size is modeled; a hypothetical mine with a 15 MW power requirement, located near Yellowknife, but accessed with a 100km ice road.

Revenue calculations for biomass CHP are highly sensitive to the cost of fuel. The rate for pellets delivered in bulk from La Crete to Yellowknife is currently $188/t. During winter road season pellets would be trucked an equivalent distance directly to the mine but with the ice road portion increasing travel time. The estimated cost is $223/t.[51] Also, given that the carbon tax applies to power generation in the NWT, and federal announcements have targeted the carbon tax to be at least $50/t by 2030, the cost of diesel fuel is assumed to be $1.28/L by 2030. To simplify the analysis, the savings achieved by salvaging heat in a diesel CHP plant were incorporated into the electricity rate, yielding an electricity cost of $0.25/kWh. This means a biomass CHP facility operated by the government would have to sell power at less than this for it to make economic sense to the mining business. Assuming 20% savings as an incentive, the rate becomes $0.20/kWh. The result of these assumptions is that the facility's combined fuel and O&M costs exceed the revenue from sales, causing annual negative earnings and a total investment by 2050 of $589M.

There are many barriers to adopting this technology: profitability, fuel supply, familiarity with the technology, and requirements of steam plants. As this analysis has shown this option would have to operate at a loss, requiring constant subsidy using public money. Secondly, should the nearest supplier not be able to meet demand, the cost premium to ship the extra distance to the next nearest supplier would further impact profitability, and depending on the amount of notice may result in supply shortfall. This could possibly be addressed through supply contracts, though these are not currently supported by the nearest pellet provider. The last two barriers, unfamiliarity and requirements are related. There is only one operating steam plant in the NWT, in Fort Simpson, so there is little familiarity with this technology in the NWT. Steam plants operate at high pressures and, while modern controls and technology have made explosions a thing of the past, these facilities require certified steam plant operators. This skill set is highly specialized, adding to the O&M cost of operating a plant and potential difficulty in sourcing trained personnel.

Transmission Line – From Existing Taltson across Great Slave Lake to Future North Slave Mines

transmission line

Overview

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
89	$900M	-$1,226M/89kt	-$689/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven	positive	positive	positive

The North Slave hydro capacity requires on average only 2% of annual generation to be serviced by diesel generators during winter peak loads[52] (in low water years diesel use is substantially higher). Outside of low water years (which occur every 8 to 10 years) there can be up to 30% surplus energy available. While this report assumes that the South Slave grid has 8MW of surplus capacity year-round[53], some of that electricity is probably currently sold at low, interruptible rates to customers with electric heat. However, using the entire surplus capacity to offset diesel power generation could generate more emission reductions and income. New transmission lines could be used to connect mines or communities to these grids, thereby offsetting diesel use for power generation. The communities within 150km of the existing grid are Whati, Gameti, Kakisa, and Fort Providence. Currently there are no operating mines within 150km of the existing grid, however there are three potential projects that meet this criterium: Pine Point – Osisko Metals, NICO – Fortune Minerals, and Nechalacho – Avalon Advanced Materials. The estimated loads of these mines and communities are given below. Combined, these loads exceed the available grid capacity.

However, the best case (i.e. most cost-effective) scenario for reducing emissions using existing Taltson hydro capacity comes in utilizing the surplus electrical load with minimal powerline connections, which could be accomplished by connecting a single mining project with at least a 20 year lifespan. This report assumes that the most likely mine to be developed in the near future is NICO (near Whati). The proposed NICO mine is nearest to the North Slave grid, which does not have extra capacity so a grid connection between North and South Slave grids would be required. Many possible routes have been examined with the latest being an underwater line across the East Arm of Great Slave Lake estimated at 270km long.[54] [55] A second transmission line from the Snare Hydro facility running to NICO would connect this project. This combines to 300km total distance.

This report assumes that total installed costs for over-land transmission lines in the NWT are $1M/km, but underwater cables are much more expensive than over land. This capital cost of connecting the grids via underwater cable is currently estimated at $800M. Accounting for 30km of overland transmission line brings the estimated total capital cost to $830M. Given that the NICO mine is expected to be exhausted 10 years after opening, this report assumes that, in a best-case scenario, another similar sized mine opens for at least another 10 years. This mine will require its own transmission line which this report assumes will be 70km long. These added assumptions bring the lifetime capital cost to $900M.

Transmission lines also require annual operations and maintenance costs (O&M) for line inspections, repairs, substation maintenance, etc. O&M costs are estimated as a percentage of capital cost, typically ranging from 1-4%,[56] but can be as high as 10% in the NWT.[57] Assuming 5% of the initial capital cost of $830M results in an annual O&M cost of $41.5M.

As mines will have to retain their own form of power generation as a back-up in the event of transmission outages, the power to be transmitted has to be sold at a competitive rate versus self-generation. In the case of mines, onsite power generation has the additional bonus of providing residual heat through co-generation which can be used to offset space heating costs. By connecting to the grid this residual heat is no longer available and must be generated by something else. This means that the power rate for mines must not only be set to consider bulk use, but also the heat savings that come from co-generation. For this reason, it is assumed the mine rate will be $0.20/kWh.

Assuming transmitted power is offsetting emissions from large diesel generators (emitting roughly 0.7 kg CO_2e/kWh) and assuming 8MW available year-round from the South Slave grid, with an additional 56GWh from the North Slave grid summer surplus results in an annual available energy of roughly 126GWh (84% of the mine's estimated total energy requirements) which is equivalent to a GHG reduction of 89 kt/yr.

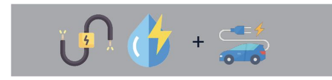
Based on these assumptions the costs to maintain the new infrastructure exceeds the revenue of electrical sales, causing annual negative earnings and a total investment by 2050 of $1,166M. These poor economic indicators suggest that it might be more economically feasible to use the excess Taltson capacity in the South Slave region for powering electric vehicles and heating homes and buildings.

Potential Community/Mine Transmission Line Connections

Community/Mine	Connection Length (km)	Max Load (MW)	Annual Power Demand (MWh)
Whatì	35	1	1,760
Gamèti	70	0.6	1,180
Kakisa	100	0.3	360
Fort Providence	50 (from Kakisa)	1.5	2,950
Nechalacho	70	8	70,000
NICO	30 (from Snare)	17	150,000
Pine Point	25	15	132,000
Yellowknife Gold	25		88,000

The perceived barriers in building additional power lines are cost and permitting. For permitting, in some areas transmission lines would cut through undisturbed regions. Depending on the impact communities may suggest longer line routes to avoid certain areas, or may not want transmission lines in these areas at all.

Taltson Hydro Expansion & Transmission lines across Great Slave Lake to Ekati, Future Mines, & Fort Providence, plus Electric Cars in Yellowknife



transmission line & expansion +EV

Overview

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
227	$2,120M	-$2,782M	-$613/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven	positive	positive	neutral

Overview, with electric vehicles

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
244	$2,223M	-$2,779M	-$569/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven	positive	positive	neutral

It would be possible to electrify current operating mines, meet the full demand of potential new mines, and allow for uptake of large numbers of electric vehicles if existing hydro facilities were expanded. The best studied expansion is of the Taltson Dam, on the South Slave grid. The Taltson facility has a current capacity of 18MW which is currently proposed to be expanded by 60MW to 78MW without additional flooding. As the available capacity is on the South Slave grid, and the existing and potential load is largely on the North Slave region, expansion would require a grid connection to be effective. Expanding Taltson by 60MW would make roughly 520GWh of energy available, in addition to current surpluses.

Both communities and mines will have to retain some form of power generation as a back-up in the event of transmission outages. The power to be transmitted has to be sold to mines at a rate that is competitive with the avoided cost of fossil diesel. This report assumes that the avoided cost of diesel in communities is $0.37/kWh. As discussed in the previous section the discounted mine rate is assumed to be $0.20/kWh

The current estimated cost of the Taltson expansion is $600M. In general, hydro facilities are long lived assets, and the expansion can be considered to have a base life of 60 years, which can be extended with proper management. However, as this report is looking at rapid and effective methods of reducing GHG emissions, it only considers the first 20 years of hydro facility operations.

Connecting the two grids and the NICO project would require 300km of transmission line (discussed in the previous section), connecting Ekati (this report assumes that other diamond mines will shut down before they can be connected) to the existing grid would require roughly 400km of transmission line. Connecting Kakisa and Fort Providence would require roughly 140km of transmission line. This results in an initial capital cost for transmission lines of $1,370M and initial capital cost for the pathway of $1,970M. Connecting Kakisa and Fort Providence may happen prior to the proposed timeline as a standalone project, however they are included in this analysis as they are part of the larger proposed electrification picture and their costs and revenues should be included. This report assumes that NICO and Ekati mines are operational for the first 10 years of the hydro expansion project and then two similar sized loads are assumed to come on-line, requiring an additional 150km of transmission lines. This brings the lifetime capital cost for transmission lines to $1,520M and a total lifetime capital cost of the pathway to $2,120M.

Assuming annual O&M costs are 5% of initial capital costs results in an annual O&M cost of $98M.

Assuming 36 MW year-round demand, 315GWh would be utilized to offset mine diesel power generation (0.7kg CO_2e/kWh) and assuming 5GWh year-round to offset community diesel power generation (0.8kg CO_2e/kWh)[58], results in an overall annual GHG reduction of 227kt/yr, with approximately 200 GWh energy surplus remaining.

Based on these assumptions the costs to maintain the new infrastructure exceeds the revenue of electrical sales, causing annual negative earnings and a total investment by 2050 of $2,782M.

Sub-case – Electric vehicles in Yellowknife

Electric vehicles have been drawing a lot of attention as a means of reducing GHG emissions in the transportation sector. Although the largest impact to be realized from electrification is by offsetting mine related emissions, having surplus grid capacity raises the possibility of utilizing this surplus to power electric vehicles to accomplish further offsets. The viability of Electric Vehicles in the NWT was studied in detail in 2018 in a report commissioned by the City of Yellowknife.[59] The report examines three cases of which the electrification of 6,000 cars (equivalent to every car, but not including the 10,000 pick-up trucks in Yellowknife) is the one we will examine here. The expected annual energy requirement of this many vehicles would be 35.5GWh, which is less than the 56GWh of excess summer capacity on the North Slave grid, but would peak in the winter when there is no excess capacity. This report looks at the additional revenue that could be generated from importing electricity from the South Slave grid to power 6,000 electric vehicles.

The report highlights that the peak load of electric cars depends on how many cars are charging at once, with 6,000 cars being able to draw up to 43MW if all charged at the same time. The current Yellowknife electrical infrastructure couldn't handle this load, so it is assumed that some form of "smart" charging can be utilized to stagger load. In addition, grid load can be managed by offering lower power rates at night when grid load is lower. We will assume this is the case for our analysis, utilizing $0.15/kWh as the charging rate for vehicles. This would add an additional $5.3M of revenue per year from energy sales.

For electric vehicles, the necessary incentive for individuals to purchase electric vehicles in large enough quantities is considered to be a 5-year payback. Given that the current premium for electric vehicles and a home charging station is roughly $22,000 even the assumption of a lower rate of $0.15/kWh and including savings from reduced maintenance, and a gasoline price of $1.24/litre (including a $50/t carbon tax) charging requires an additional subsidy of $17,100 per vehicle. For 6,000 electric cars this makes the capital cost $103M and would result in a GHG reduction of 17kt/yr per year.

Adding this to the previous cost of building the power line across Great Slave Lake and expanding Taltson results in a capital cost of $2,223M, annual GHG reduction of 244kt/yr, and total investment over 20 years of $2,892M.

Solar PV

solar photovoltaic

Overview

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
2.1	$32.7M	-$24.4M	-$580/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven	positive	positive	positive

The initial scope of this study did not include photovoltaic panels (Solar PV). However, the GNWT has published cost estimates for ten community solar PV projects, four of the projects include batteries and six include variable speed generators[60]. The total subsidy required for these projects is $24.4M with an annual emissions reduction of 2.1kt/yr. This works out to an average of $580/t over 20 years.

The cost of solar PV panels has come down a lot in the last decade and continues to decline. Adding solar PV generation to diesel generation, without batteries or variable speed generators (also known as “low penetration solar PV”) would be cheaper than the above figures, but there is a limit to how much solar PV can be added to diesel generators without causing problems. Assuming low penetration solar PV systems could displace 10% of emissions from diesel power generation results in a potential 6kt/yr reduction from NWT communities and up to 30kt/yr from mining power generation[61]. More research would be required to estimate the costs of low penetration solar PV in all the NWT communities and mines but the total potential of 36kt/yr is relatively low in any case.

Wind

4 community Wind Power projects

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
6	$35.5M	-$17.8M	-$147/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven	positive	positive	positive

Diavik 9.2 MW Wind Power

Potential Impact (kt)	Capital Cost	Total 20 yr Investment	Average Annual $/t
12	$33M	$67M	$280/t
Technical Viability	**NWT Human Health**	**NWT Employment**	**NWT Self-Sufficiency**
proven	positive	positive	positive

The initial scope of this study did not include wind power. However, the GNWT has published cost estimates for four community wind power projects, one of which is a larger project in Inuvik[62]. The total subsidy required for these projects is $17.8M with an annual emissions reduction of 6kt. This works out to an average of $147/t over 20 years.

In 2012, the Diavik Diamond mine installed 9.2 MW of Wind Turbines at a cost of $33M. A case study by the Canadian Wind Energy Association shows that the project saves 12kt of emissions per year and an average of $5.5M in avoided fuel costs[63]. The study does not mention the cost of maintaining the turbines, but assuming $500K per year in maintenance costs would still leave $5M per year in savings, for a net income of $67M over 20 years or an average income of $280/t. It should be noted that the Diavik mine is not expected to be open for the full 20 years since the wind turbines were installed, but we use a lifespan of 20 years because that is what has been used in this report for all other pathways.

The cost of wind turbines has come down a lot in the last decades and continues to decline. The above projects add wind turbines to diesel generators, without batteries or variable speed generators which also known as “low penetration Wind Power”. Wind speeds vary from site to site, so the four community wind projects plus Diavik (which is expected to close in the next few years) probably represent a reasonable estimate of the total potential of low penetration wind power in all the NWT communities and mines.

Summary of Pathways

The following table summarizes all technical, economic, and social factors of the examined pathways.

Option	Potential Impact (kt)	Technical Viability	Capital Cost	20 year Investment/ Income	NWT Human Health	NWT Employment	NWT Self-Sufficiency	Average Annual $/t over 20 years
Carbon Offsets	● 600+	● [1]	-	● -$300M	-	● [3]	● [3]	● -$25/t
Renewable Diesel	● 600+	● [2]	-	● -$1,394M	-	● [3]	● [3]	● -$116/t
Biomass District Heating	● 64	●	$126M	● $79M	-	●	-	● $62/t
Diesel Co-Generation	● 4	●	$16.3M	● $7.8M	●	●	●	● $98/t
15MW Biomass CHP	● 73+	●	$135M	● -$589M	-	●	-	● -$403/t
Transmission line – existing Taltson across Lake to future North Slave Mines	● 89	●	$900M	● -$1,226M	●	●	-	● -$689/t
Taltson Hydro expansion, Transmission across lake and on to Ekati, Future Mines and Fort Providence	● 227	●	$2,120M	● -$2,782M	●	●	-	● -$613/t
As above w/ Electric Vehicles	● 244	●	$2,223M	● -$2,779M	●	-	-	● -$569/t
10 Community Solar PV projects w. Batteries or variable speed generators	● 2.1	●	$33M	● -$24.4M	●	●	●	● -$580/t
4 community Wind Power projects	● 6	●	$35.5M	● -$17.8M	●	●	●	● -$147/t
Diavik 9.2 MW Wind Power	● 12	●	$33M	● $67M	●	●	●	● $280/t

[1] existing large-scale market
[2] proven in cold climate outside NWT
[3] indirectly

Legend

● The project is in the public interest as it creates revenues compared to status quo.
● The project represents the first two lowest cost options (initial, or annual) to cumulatively achieve 50% GHG reduction (600kt).
● The project does not represent the lowest cost option.

20-Year Scenario Comparison

Each of the pathways discussed has its own challenges, cost, and potential impacts that affect the likelihood of implementation and overall investment. The purpose of this report is to identify the lowest cost combination of pathways to determine where the most resources should be invested in order to achieve a 600kt GHG emission reduction and maintain that reduction for 20 years. Rather than exhaustively comparing all possible combinations of pathways, the four most relevant scenarios are summarized.

Carbon Offsets Only

At $25/t achieving a 600kt reduction with offsets will cost $15M a year and require a total investment over 20 years of $300M, an average annual $/t of $25/t. As offsets are currently available to purchase, these reductions could take effect within a few months.

Taltson Hydro Expansion + Transmission Lines + Offsets

Even this report's "best case scenario" for using expanded Taltson Hydro to provide electricity to the Ekati and NICO mines plus 2 other future mines would only result in a 227kt reduction. While proponents of the Taltson Hydro expansion project suggest that hydro power would be cheaper, this report found that the cost of operations and maintenance would require an annual subsidy to be competitive with diesel power. The cheapest way to get from 227kt to 600kt would be to purchase carbon offsets at an additional cost of $9.3M per year over 20 years. Together this results in a scenario with a capital cost of $2,120M, and total investment by 2050 of $2,968M, resulting in an average annual $/t of $247/t. Planning and building a hydro and transmission project of this scale will take at least 10 years. However, carbon offsets are currently available so reductions under this scenario could begin within a few months.

Lowest Cost Investment

The lowest investment scenario is a combination of Biomass District Heating, Diesel Co-generation, and Carbon Offsets. Biomass District Heating and Co-generation are the only two pathways to reducing emissions that generate a net income, but they only add up to a reduction of 68kt. After that, the lowest cost option is to purchase Carbon Offsets The income from the heat sales partly subsidizes the cost of Offsets, resulting in a total investment of $178M over 20 years, resulting in an average annual $/t of $15/t. Planning and building the full network of Biomass and Co-generation district heating networks would likely also take about 10 years. However, Carbon Offsets are currently available so reductions under this scenario could begin within a few months.

Maximizes Canadian Factors

This scenario looks to find the lowest investment without utilizing offsets. This comes with a combination of Biomass District Heating, Diesel Co-generation, and Renewable Diesel (assuming Canadian supply). As in the previous scenario, income from heat sales could offset the cost of subsidizing renewable diesel. This results in a total investment of $1,148M over 20 years, resulting in an average annual cost of $96/t. As above, planning and building the full network of Biomass and Co-generation district heating networks would likely also take about 10 years. However, Renewable Diesel is currently available so reductions under this scenario could begin within a few months.

It should be noted that scenarios that combine Biomass District Heating and Diesel Co-generation would likely result in better performance than is reflected in this report. All pathways were analyzed as stand-alone options, with diesel co-gen utilizing a smaller District Heating System and less heat as a result. Combined with a larger pipe network, paid for by the Biomass pathway, there would be greater heat utilization from the Diesel co-generation pathway leading to reduced costs per kt of emission reductions.

Energy & Climate Policy Implications

The current GNWT energy strategy is focused on directly investing billions of dollars in transmission lines and hydro expansion to mines that may or may not be developed and some that have not even been discovered yet. Tens of millions of dollars are allocated to wind and solar development in some communities[64]. A few million dollars are allocated to private sector projects such as financial incentives for biomass heating[65] and programs run by the Arctic Energy Alliance (AEA). The AEA recently announced that in 2018/19 it had provided incentives valued at $600,000 that resulted in 6kt of emissions reductions, which works out to $1,000/t[66].

This report shows that, with the exception of wind power in some communities, the current GNWT Energy Strategy is focusing most of its effort and resources towards the <u>least effective and most expensive options</u> for reducing emissions. While claiming to be about reducing emissions, it is clear that other priorities, such as subsidizing the NWT Power Corporation and providing a supportive environment to future potential mining developments (through a multi-billion dollar, publicly funded hydro-electric expansion) take precedence.

While the GNWT and GC obviously have to balance many priorities, in the context of a Climate Emergency, other priorities need to be temporarily set aside so that NWT society can immediately address the problem at hand. The GNWT energy strategy should be revised to ensure absolute priority be given to rapid, direct, and cost effective emissions reductions.

The concept of a "Green New Deal" has been proposed for both Canada and the USA. In part, the proposal is that government invest directly in building infrastructure and other actions that would rapidly reduce emissions while ensuring a just transition of fossil fuel jobs to a renewable energy-based economy[67] Direct government investment in renewable energy projects in the NWT could very well be an opportunity for faster and more effective results than offering financial incentives, particularly in NWT communities where the GNWT has more technical expertise and capacity than either the private sector or local governments. Co-generation and biomass fired district heating systems are particularly suited to GNWT investment as the GNWT already owns or occupies most of the diesel power plants, schools, health centres, and office and other buildings (garages, water plants, maintenance centres) that would be heated by these systems. This report shows that such investments would generate revenue for the GNWT as well as employment in the communities.

Renewable Diesel, however is a relatively affordable option that could reduce NWT emissions rapidly and economy-wide without substantial government spending on new infrastructure in the NWT. Instead, the GNWT could mandate the adoption of renewable fuels in the NWT, while providing subsidies to offset increases in the cost of living/doing business. Reducing emissions by 600kt would require roughly double the amount of renewable diesel currently sold in California[68], which would make the NWT a relatively large North American market for renewable diesel and could help develop the renewable fuel sector in Western Canada.

Finally, the climate does not care where in the world emissions are reduced and carbon offsets provide an immediate and cost effective way to reduce emissions in the short term. Continuing to burn fossil fuels without at the very minimum offsetting the resulting carbon emissions is simply not an acceptable response to the climate emergency.

Conclusions

This report started out with the objective of finding the means to achieve a 50% reduction in greenhouse gas emissions in the NWT by 2030. The analysis demonstrates that it is not necessary to wait ten years to make these reductions as carbon offsets could achieve the required 600kt of reductions within a matter of months. In addition, two other pathways, biomass district heating and diesel co-generation, accounting for roughly 10% of the required 600kt were found to have positive net income over a 20-year operating life. Combining these with carbon offsets creates the lowest overall investment scenario requiring $178M over 20 years and costing on average $15/t/year CO_2e reduction.

Renewable diesel manufactured in Canada could also be combined with biomass district heating and cogeneration. This scenario results in a cost of $1,148M over 20 years and an average of $96/t CO_2e reduction, but with the added benefit that all money would be spent within Canada.

Other technologies such as biomass CHP and hydro and transmission expansion promise comparatively large CO_2e reductions, but at much higher cost, ranging from three to over ten times the costs of the other technologies examined.

Recommendations

This report assumes that the Government of Canada and GNWT agree that climate change is an emergency and are therefore prepared to take immediate actions to reduce greenhouse gases by at least 50% by 2030 as their highest priority. This leads to the following recommendations:

1. The GNWT revise the current Energy Strategy towards more immediate and cost effective ways of reducing emissions – as outlined below
2. The GNWT commit to purchasing 600 kt of Gold Standard Carbon Offsets (about $15M/yr), starting in 2020 and continue to purchase offsets each year as required to maintain a total reduction of 600kt as other actions take effect
3. The GNWT directly invest over the next 5 years in the construction of biomass and co-generation district heating systems in NWT communities (~$145M). This should be done over the next five years with financial support from the Government of Canada. The GNWT should also operate these systems and sell heat recovered from diesel generators and centralized biomass boilers at 80% of the price of fossil heating oil. This is estimated to reduce emissions by 68kt/yr
4. Beginning with its own internal operations, the GNWT should immediately begin a transition from fossil diesel to renewable diesel. The GNWT can begin with its own internal operations, and show how renewable diesel can be used in its own boilers, vehicles, and generators. The GNWT should also work with fuel suppliers to purchase approximately 200M litres of renewable diesel per year within 5 years and provide a subsidy to reduce the price to be the same as fossil diesel (about $65M/yr). Combining renewable diesel use with the district heating systems in recommendation three, this would result in at least 600kt of annual reductions within 5 years and eliminate the need to purchase carbon offsets
5. The GNWT commission a study, similar to this one to examine the most cost effective way of becoming carbon neutral within 15 years. While this study uses tail-pipe emissions, life cycle analysis of each fuel source would be better. However, lack of life-cycle analysis is not an excuse for delaying action. As NWT moves toward climate neutrality a method for life cycle carbon accounting similar to what is used for California's renewable fuel standards or Canada's Clean Fuel Standard should be adopted.

Appendices

- Biomass district heating calculations – communities
- Generator Heat recovery calculations

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