Small Modular Reactor (SMR) Economic Feasibility and Cost-Benefit Study for Remote Mining in the Canadian North: A Case Study

Prepared by:

François Caron and Luckny Zephyr, for MIRARCO

Megan Moore and Pronnapa Sanongboon, for CNL

Ashlea Colton on behalf of Megan Moore

David Zekveld, for OPG

Reviewed by:

Jennifer Abols, MIRARCO

Ali Siddiqui, CNL

Chris Deir, OPG

April 14, 2021

Table of Contents

List of Figures

List of Tables

Summary of the Terms of Reference

The Canadian mining industry is well suited for deployment of very Small Modular Reactors (vSMRs) as a cost effective means for electricity and heat production while meeting climate change objectives. Typical energy demand (heat and electricity) for Canadian mineral mines are well aligned with the capacity of vSMRs. This research project identifies the specific electrical and thermal requirements of a representative mine site to evaluate the economic competitiveness of vSMR deployment under four scenarios: 1) diesel generators only; 2) vSMRs only; 3) vSMRs and diesel generators; and 4) vSMRs, diesel generators, wind turbines and battery energy storage.

The goal of this project is to determine vSMR requirements (e.g., electricity and heat demand curves / seasonality, life of mine) from the perspective of a mining company that operates in the far North (Arctic climate).

The analysis has been performed by a team of nuclear and mining industry experts, including:

- **MIRARCO** – Prepared and analyzed an economic model of the four energy scenarios at the mine site leveraging knowledge of the Canadian mining and nuclear industries;
- **Canadian Nuclear Laboratories (CNL)** – Provided vSMR technical expertise and analyzed the four energy scenarios using the CNL proprietary Hybrid Energy System Optimization model to determine optimum mix of energy assets on site based on hourly energy demand and technology specifications/operating limits;
- **Ontario Power Generation** – Provided nuclear operator insights, vendor cost data and weather corrected hourly thermal and electricity load data from the mine site, and reviewed analysis results; and,
- **Mining Partner** – Provided mine operator insight and thermal and electricity data from the representative arctic mine site.

All data in this study is protected under the terms of the “Collaborative Research Agreement Regarding Mining and Small Modular Reactors Agreement no. CRA20200116” executed by July 15, 2020 by all four parties.

Executive Summary

This report is a conceptual economic analysis of Small Modular Reactors for both electricity and heat demand at a representative mine site in the far North. The team has reviewed the operational data and analyzed the costs to produce electricity and heat, on a unit basis, for the life of mine. The chosen metric of the industry standard is the levelized cost of electricity (LCOE, $/kW·h) – recognizing that some heat is also produced and utilized. The team calculated the economic competitiveness of vSMR deployment under four scenarios: 1) diesel generators only; 2) vSMRs only; 3) vSMRs and diesel generators; and 4) vSMRs, diesel generators, wind turbines and battery energy storage.

Table 1 – Key Results

Scenario	LCOE $ per kW·h	Total CO_2 from Energy Production
	($CDN)	(Million tonnes)
(1) Diesel Only (benchmark case)	$0.281	1.56
(2) vSMR Only	$0.387	0.00
(3) vSMR and diesel	$0.266	0.24
(4) vSMR, diesel, wind and storage	$0.279	0.16

Based on the results shown in Table 1, the energy system with vSMR and diesel generators (scenario (3)) was found to be the most economic. In this scenario, the vSMR provided baseload electricity to the mine site (approximately 90% of annual demand), while the diesel generators covered peak loads (approximately 10% of annual demand). The heat demand was met through a combination of diesel cogeneration (capturing waste heat) and nuclear heat; no diesel-fuelled burners were required to meet heat demand. This scenario resulted in an 85% reduction in CO_2 equivalent emissions compared to diesel only.

Although the vSMR only scenario (2) eliminated all CO_2 equivalent emissions from energy production, it also resulted in a relatively high LCOE. This was expected in part due to the high CAPEX of the SMRs, the highly seasonal demand and the ramp up of production over several years, which resulted in unused capacity of the reactor during periods of low demand.

Initially both solar panels and wind turbines were considered as potential sources of variable renewable energy. It was quickly determined that available solar energy in the region was a poor fit for energy demand at the mine site, since peak generation is expected to occur during seasons of low demand (i.e. summer). Therefore, only wind energy was considered. The addition of wind turbines in scenario (4) did reduce the CO_2 equivalent emissions from energy generation compared to scenario (3). Scenario (4), however required additional infrastructure (battery, reserve diesel capacity) to manage the variability of supply, which came at an additional cost. The final result from scenario (4) had a slightly higher LCOE than scenario (1), the diesel generator benchmark, as well as higher cost than the vSMRs and diesel generators scenario.

Through a series of sensitivity analyses, additional potential advantages were identified if a set of vSMRs were deployed at the mine site.

- The LCOE for vSMRs is not sensitive to fuel costs and carbon tax, increasing confidence in the long-term cost of energy.
- For Scenario (3), vSMR and diesel, increasing the life of mine from 14 years to 20 years results in LCOE of $0.220/kW·h, a 17% reduction.
- vSMR can accommodate a variety of demand profiles, and could be used to support a northern energy hub with an operating life of up to 60 years without major refurbishment (except for refuelling). For example, in Scenario (2), vSMR-only, increasing the life of mine (or energy hub requirements) from 14 years to 20 years results in LCOE of $0.300 /kWh (a 23% reduction). Likewise, increases to 40, and 60 years yield LCOE values of $0.237 /kWh (a 39% reduction) and $0.222/kWh (a 43% reduction), respectively. This demonstrates the increased economic benefits of using vSMR to meet longer term energy needs.
- Excess electricity could be distributed to nearby communities generating goodwill and creating a potential revenue source.
- Many vSMRs are capable of providing high temperature heat that can be used to support industrial process beyond district heating.

Note that this study evaluates the relative economic viability of vSMR deployment at a mine site but does not propose the business model or ownership structure for the vSMR. It is anticipated that the mine owners would establish a power purchase agreement (PPA) with a nuclear owner / operator for provision of electricity but is outside the scope of this assessment.

This report has used the best available data from a representative mine site, various sources from the open literature, actual vSMR vendor costing data, and best expert judgment (with assumptions documented).

Table of Acronyms, Definitions and Units

SMR	Small Modular Reactors
vSMR	very Small Modular Reactors
kW·h	Kilowatt-hour
MW·h	Megawatt-hour
MW_e	Megawatt of electricity
MW_{th}	Megawatt of thermal energy (heat)
$MW{\cdot}h_e$	Megawatt-hour of electricity
$MW{\cdot}h_{th}$	Megawatt-hour of thermal energy (heat)
GHG	Greenhouse Gases, equivalent to the CO_2 warming potential
CO_2e	Carbon dioxide equivalent. Since not all GHG have the same warming potential, greenhouse gases are normalized to CO_2 units as a warming potential equivalent
Tonne, t	Metric tonne (1000 kg)
Ton	US ton (907.2 kg)
Genset	Generator set, applies to the main set of diesel generators for electricity and heat
LCOE	Levelized Cost of Electricity
CAPEX	Capital Expenditures
OPEX	Operating Expenditures

1. Introduction

The potential to use small modular reactors (SMRs) for electricity and heat production in remote mining operations has been considered for some time (Hatch, 2016); (EFWG, 2018); (Wojtaszek, 2017); (WNA, 2020b). Unlike large nuclear reactors, SMRs produce electricity in the range of 300 MW_e or less and are considered for a variety of markets: on-grid, industrial and off-grid applications, including remote mines. This report focuses on a subcategory of SMRs called very small modular reactors (vSMRs) which generally produce <10 MW_e and offer numerous advantages for remote locations. The small size and architecture of vSMRs simplifies transport to remote communities and installation, and better matches local energy demands. It is anticipated that the construction period of vSMRs would be shorter due to increased efficiency gained from modular construction and factory fabrication. Additional advantages include a smaller inventory of fuel at the location, the potential for multiple units in a fleet that would service multiple sites, and potentially easier commissioning/decommissioning. All these features together are thought to constitute an attractive option with potential cost savings, particularly for industrial applications such as off-grid mine sites.

1.1 The general context of vSMRs in this study

There are 10 off-grid operating mines in Canada, most are served by diesel generators, which offer reliable, fast acting, easy to vary output but are greenhouse gas (GHG) emitting. Due to the remoteness of these mines, there is a need for self-sufficiency and power generation without interruption, extra diesel generator capacity is added beyond the peak load needed to account for on-line load variations, off-line maintenance and unplanned system failures. This results in installed diesel capacity that is almost twice the peak requirement.

A vSMR put in place of, or coupled with, a diesel generator would need to recognize the capacity needed, the variation in that capacity, and be a fully reliable and safe power supply at a competitive price. The diesel generator would likely remain in place as back-up for the mine when a vSMR is installed.

The collaboration between Canadian Nuclear Laboratories (CNL), Ontario Power Generation (OPG) and Mining Innovation, Rehabilitation, and Applied Research Corporation (MIRARCO), a research arm of Laurentian University, is reviewing the economic feasibility of deploying a vSMR on a remote mine site. This study uses detailed engineering data and projections from a mining company, and builds on the public-domain reports by Hatch Ltd (Hatch, 2016), the Natural Resources Canada (NRCan) SMR Roadmap (SMR Roadmap, 2018) and the associated report from the Economic and Finance Working Group (EFWG) of the SMR Roadmap (EFWG, 2018). Different scenarios of incorporating a vSMR in a mixed nuclear-renewable hybrid energy system/microgrid at a remote location are possible; several of which are evaluated in this report.

1.2 The representative mine

The representative mine is located in Canada's far North. It is anticipated that mining will be carried out over a period of 14 years through underground and open pit mining operations. This defines the life of mine (LoM) in this document. The energy demand for the site includes the mining operations, some post-processing, and staff camp facilities.

1.3 Overview of the energy needs for the site

A simplified power and heat distribution network of the representative mine is shown in Figure 1.1. The network is organized as a generation centre, a distribution network, and the demand centres. Losses for all centres are shown for the sake of completeness; losses are not explicitly quantified, and are accounted for in assuming different system efficiencies, based on past experiences and expert judgment.

1.3.1 Generation (power and heat)

Table 1.1 gives a snapshot of the power and heat generation for the representative mine site. The main power plant (genset) consists of five (5) main generators of 5.56 MW_e each, four smaller generators (3 x 1.825 MW_e each and 1 x 0.91 MW_e), plus one diesel burner. The system has a heat recovery capacity from the main generators that is used to support a district heating network. An emergency system consists of two small generators (1 x 1.825 MW_e and 1 x 2 MW_e) and two boilers for the camp. The total electricity generation capacity is 38 MW_e that includes the 3.825 MW_e on standby.

The main genset has a heat recovery capacity of 10.8 MW_{th}. The recovery efficiency is calculated at 39% of the electricity nameplate; the efficiency varies as a function of temperature (recovery is higher above -20 °C). The burners for the mine air has a capacity of 13 MW_{th}, plus the hot boilers (4.9 MW_{th}) for the camp (emergency) for a total heat producing capability for the site of 33.4 MWth. The smaller generators are not equipped with heat recovery.

1.3.2 Demand Centres

The camp, plant and the mine are the main demand centres. The camp itself comprises living quarters (camp, recreation hall, kitchen, utilities), whereas the plant hosts the milling and other process operations. The mine has two portals: an underground feeder and ventilation.

The heat demand is correlated with the outside temperature: higher demands are expected for the colder months. Most of the heat is required for the mine, whereas the camp buildings and process plant consume heat for hot water.

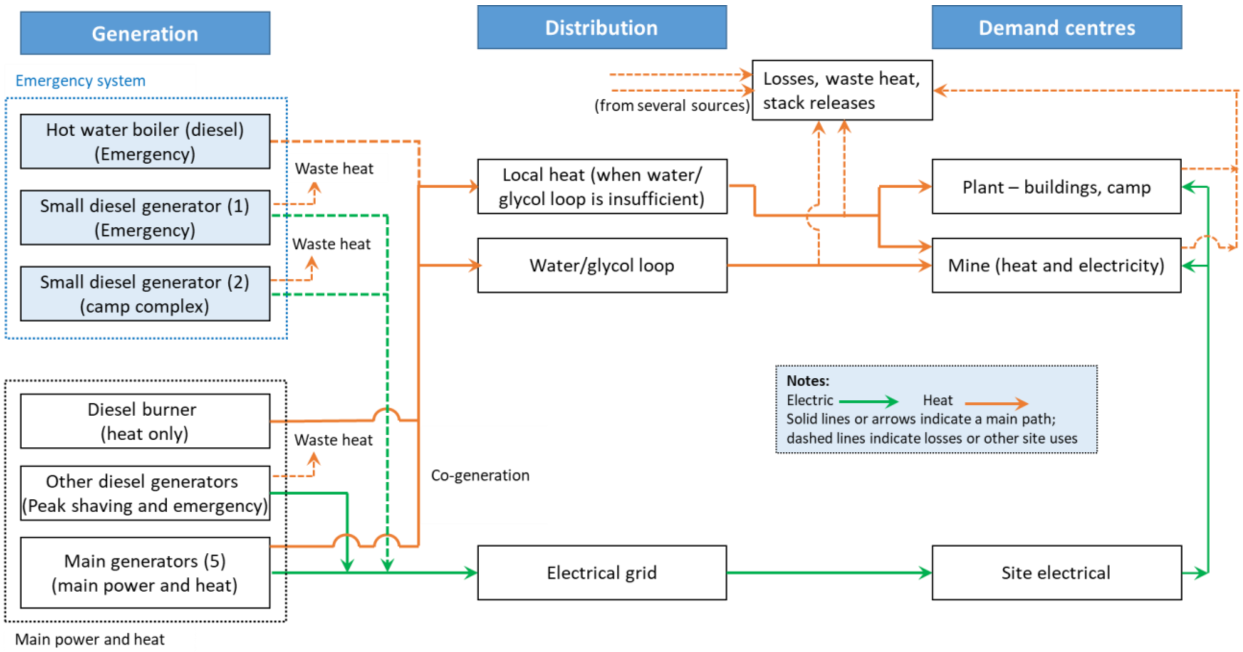

Figure 1.1: Overview of the energy system for the representative mine.

Table 1.1: Total electricity and heat generation for the representative mine site.

Electricity generation	Number x Capacity	Description	Functions/other
Main generators (5)	5 x 5.564 MW_e	Main genset	Primary power source
Other diesel generators	3 x 1.825 MW_e	Mine portal	Peak shaving and emergency
	1 x 0.91 MW_e	Mine portal	Peak shaving and emergency
Small generator (1)	1 x 1.825 MW_e	Process plant	Peak shaving and emergency
Small generator (2)	1 x 2 MW_e	Camp complex	Emergency (standby)
Total Electricity	**38.03 MW_e**		
Heat generation	**Number x Capacity**	**Description**	**Functions/other**
Diesel burner	1 x 13 MW_{th}	Boiler	Underground heat
Co-generation	10.8 MW_{th} *	Heat recovered from main genset	Varies with genset capacity factor*
Hot water boiler (diesel)	2 x 2.45 MW_{th}	Emergency system	Hot water network (emergency)
Total heat	**28.7 MW_{th}**		

*nameplate of genset times an average heat recovery factor of 0.39 MW_{th} / MW_e at the mine.

2. Objectives of the work

The vSMRs considered in this report represent a future technology with first deployments anticipated in the latter half of this decade. Several studies have identified vSMRs as an attractive source of energy, with increasing market potential for mining (on- or off-grid) (SMR Roadmap, 2018). A Canadian mining company has collaborated with OPG, CNL and MIRARCO to complete a conceptual economic analysis based on actual detailed energy production and consumption plans for an operating mine. The study has the following objectives:

(1) Establish realistic energy requirements (electricity and heat) based on the representative mine;
(2) Determine how a vSMR can be used to meet these requirements;
(3) Calculate the costs of production (electricity and heat) of pre-determined energy mixes in different scenarios (incl. diesel only, vSMR only, vSMR + diesel, vSMR + renewables + diesel);
(4) Identify the different economies that the mining company could benefit from, including cogeneration, carbon tax, or others as determined from the analysis, and calculate the magnitude of the benefit where possible.

The primary purpose of this study is to determine relative cost of energy production under various energy mix scenarios. The approach is open and interactive to enable mining companies to make informed decisions on the best cost structure when engaging with a provider. We believe the level of confidence is for a feasibility study – particularly, the reactor vendor indicated a Class 4 level estimate from the AACE recommended practice 18R-97 (AACE, 2021).

3. Methodology

The general approach is to replace the main power system at the mine (inside black dashed lines on Figure 1.1) with a suite of different technologies according to four scenarios to meet expected electricity and heat demand throughout the LoM. The scenarios are:

(1) Benchmark the current system with diesel generators;
(2) A fleet of vSMRs only;
(3) A hybrid mix of vSMRs (baseload electricity and heat) and diesel generators (peak shaving and cogeneration); and
(4) A hybrid mix of vSMRs (baseload electricity and heat), wind turbines and batteries (electricity generation and short-term storage), plus diesel generators (peak shaving and cogeneration).

The emergency system (inside the blue dashed lines on Figure 1.1) would remain unchanged for all scenarios.

3.1 Overview of the methodology

Figure 3.1 gives an overview of the methodology used in this work. The OPG, MIRARCO and CNL team created and shared a questionnaire with the mining company. The questions were grouped into four general categories: (1) mine site characteristics and access; (2) current electricity and heat production capacity; (3) energy demands for the site (electrical, heat, distribution grid); and (4) other, such as transportation (fuel, mobile equipment), environmental (carbon footprint, climate), other opportunities (new processes, regional).

Upon receipt of the completed questionnaire, the team has curated the data interactively with the mining company to create a database. Among the efforts, the team extracted annual data on energy and heat needs of the mine site over the anticipated operating life of the mine. From that point, hourly electricity and heat demands were estimated, based on one year of hourly temperature data, using the correlation between heat/electricity requirement and temperature.

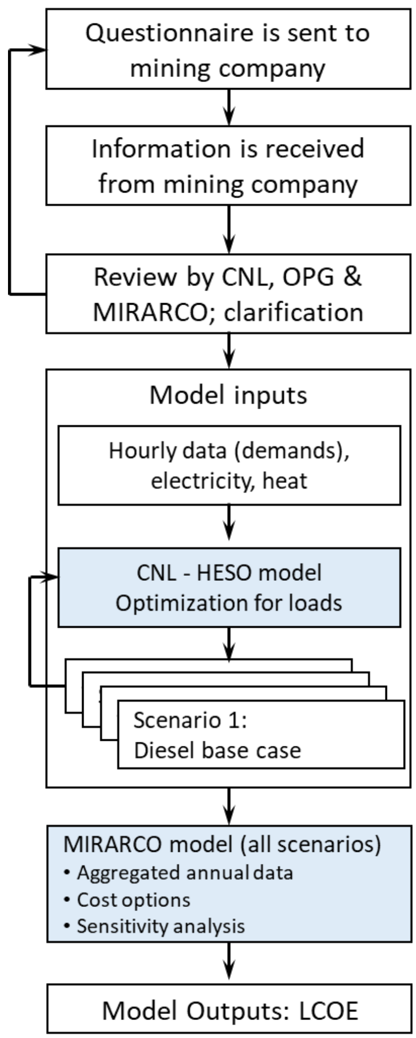

Figure 3.1: Simplified flowchart of the process used in this work.

3.2 Input data from the mining company

Electricity and heat requirements are based on actual data from the representative mine site, supplemented by data from another nearby mine site as required. It is understood that the two mine operations are different, however the mine experiences and climate data are reasonably similar to one another and therefore can be used for projections.

The aggregated annual demand projections (electricity and heat) for the expected LoM (14 years) are shown in Table 3.1.

Table 3.1: Electricity & heat consumption for the representative site.

Year	Projected Electricity Consumption $MW{\cdot}h_e$	Projected Heat Consumption $MW{\cdot}h_{th}$
1	106,243	0
2	127,463	73,577
3	146,423	73,577
4	138,242	73,577
5	167,631	75,562
6	182,042	75,669
7	184,757	75,669
8	199,807	75,669
9	210,818	75,669
10	189,339	72,081
11	192,773	70,261
12	189,234	69,779
13	183,881	62,550
14	167,079	60,890

3.3 Conceptual description of input models

OPG's analytics team created hourly patterns for the annual forecasts of the loads provided by Hatch (data not shown). This analysis determined the increase in demand due to possible extreme weather impacts using the last 20 years of historical weather data from a neighbouring community. The weather-related loading contributions to the Camp and Portal loads were estimated using OPG's weather-normalization methodology. Combined with OPG's forecasting tools, hourly weather-normal load patterns were generated depicting a normal movement in weather and variations due to calendar effects (season, month, weekday, holidays, daylight savings and hours of sunlight).

The Hybrid Energy System Optimization model (HESO; see Figure 3.2), developed by CNL to study feasibility and benefits of nuclear energy systems, is formulated as a large-scale mixed-integer linear programming (MILP) and solved using the IBM ILOG CPLEX Optimizer. The model offers integration of multiple technologies and system optimization to determine the best energy mix to minimize cost. Solutions obtained by this model always meet 100% of energy demand and the assigned GHG emission reduction target. The current version of the HESO model can be customized to solve for up to thirteen generating technologies and four storage technologies. Available technologies include conventional hydroelectric, run-of-the-river hydroelectric, wind turbines, solar photovoltaic (PV), electricity imports from the grid, concentrated solar, biomass, nuclear, natural gas, coal, diesel, biofuel, burner (gas or oil), battery energy storage (BES), pumped hydroelectric storage (PHS), hydrogen production and energy storage (HES), and thermal energy storage (TES), as illustrated in in Figure 3.2. For each generating technology, there can be multiple stations to resemble real-world problems more closely. With each given set of technologies, the model can minimize annual cost or GHG emissions over a one-year time horizon to meet hourly demand for electricity, heat, and/or hydrogen.

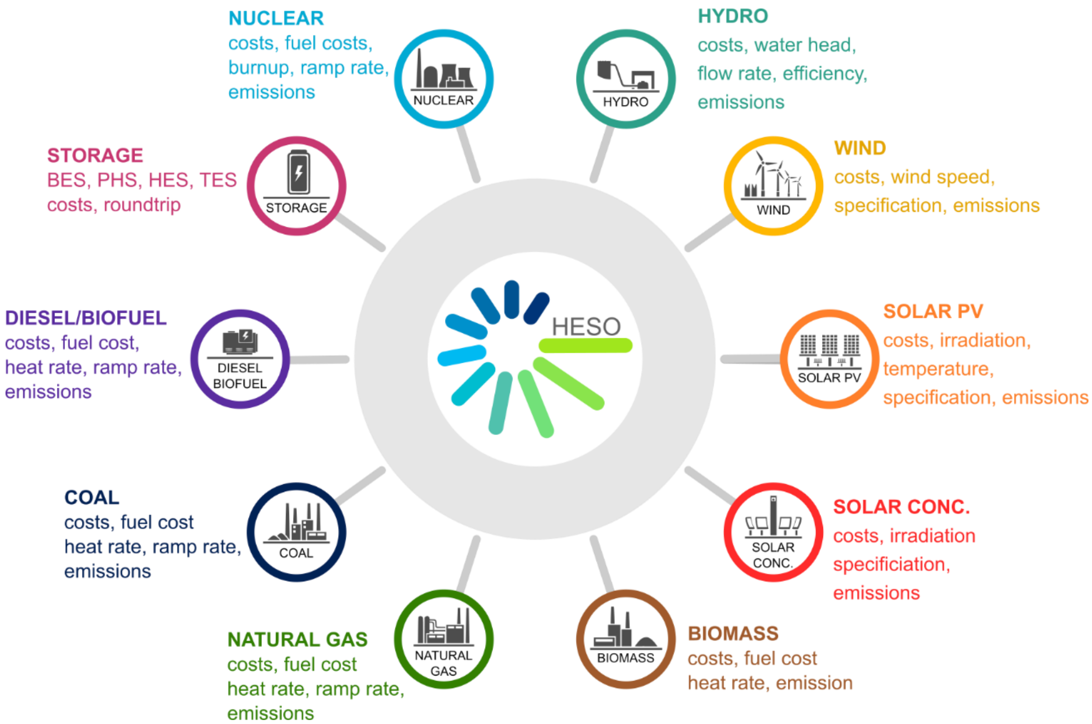

Figure 3.2: Schematic overview of the HESO model and its capabilities

3.4 Conceptual description of economic model (MIRARCO)

The MIRARCO model uses the optimum mix of energy sources (e.g. vSMRs, diesel generators, wind turbines, battery storage) in a set of deterministic scenarios. It uses the HESO model output as its input of energy sources. The model uses the cost items of capital expenditures (CAPEX), other one-time expenditures (e.g., removal or decommissioning), and the operational expenditures (OPEX), on an annual basis. The model output is Levelized Cost of Electricity (LCOE). LCOE is a metric used most often by utilities or clients to determine the cost of producing electricity. It is useful in comparing different sources of electricity on a similar basis, returning a cost per unit (e.g., dollars per kW·h or MW·h) over the lifetime of a plant. The equation of the LCOE is (Hatch, 2016), (*Energy Education*, 2020):

$$\text{LCOE} = \text{PV of Costs to Produce Electricity / PV of Electricity Produced} \tag{1}$$

Where: PV = Present value

The detailed equation is:

$$\text{LCOE} = \frac{\sum [(\text{CAPEX})*(1+\text{i})^{\text{n}}/(1+\text{d})^{\text{n}}] + \sum [(\text{OPEX})*(1+\text{i})^{\text{n}}/(1+\text{d})^{\text{n}}]}{\sum [\text{Electricity produced}/(1+\text{d})^{\text{n}}]} \tag{2}$$

Where:

	CAPEX =	capital expenditures in period "n", usually in years. This is for the one-time costs associated with the engineering, procurement and construction (EPC) of the equipment (e.g., diesel generators).
	OPEX =	operating expenditures in period "n", usually in years. This item is for the recurring costs associated with operation of the equipment or resources utilized in the same period spending occurs. (e.g., for diesel generation, Operating and Maintenance, diesel fuel, lubricants).
	Electricity Produced =	average electricity produced in period "n", in kW·h or MW·h.
	n =	period of time, usually set as annual
	i =	annual compound rate of inflation
	d =	annual discount rate, to reflect the time value of money and a premium for risk associated with the uncertainty of longer term projections.

The LCOE, CAPEX and OPEX are expressed in 2019 $ CDN in this work. As written, the CAPEX and OPEX in the formula would be constant over time, which is not the case. In addition, the formula should index the CAPEX and OPEX by the time period; this is accommodated in our spreadsheets. The inflation rate (i) can be set at zero for "real" or constant dollars, or a specific numeric rate, e.g., 2 % per annum for "as spent" or current dollars, similar to the Consumer Price Index (CPI). Both "i" and "d" are expressed as a fraction in the equation, e.g., 2 % is 0.02.

Equation (2) above can be customized as required. For example, CAPEX can be incurred over multiple years and may be expensed over a time span different from that of the full project. Likewise, values for "i" and "d" may be defined separately, depending upon the assumptions of the scenario under examination. In some cases, such as the Economic and Finance Working Group of the SMR Roadmap (EFWG, 2018), different values of "d" were used (e.g., 6 and 9%). Hatch (Hatch, 2016) performed sensitivity calculations over a wide range of discount rates, from zero to 10%. When the discount rate is zero, there is no discounting and LCOE collapses to a simple ratio of unit cost, with no provision for cost of capital. As the discount rate "d" is increased, LCOE rises to reflect the provision for cost of capital.

3.4.1 Cost items

The initial capital cost, operating cost, fuel and maintenance costs, and any fuel inventory costs are required for each energy source (e.g. diesel generators, vSMRs, wind turbines). Other costs specific to a project could also be included, such as regulatory, commissioning, decommissioning, remediation, and re-deployment costs of equipment to another site.

Input parameters for Scenario (1) (benchmark case, diesel generators only) were provided by the mine owner, focusing on the electricity and heat demand projections. The required input data includes potential electrical power and heat generating options and the corresponding costs to meet these requirements (CAPEX, OPEX, other items). Using diesel generation as the historical baseline production, the cost of the generator, fuel handling, and storage infrastructure items (CAPEX) are added to the model. Fuel cost, maintenance and other operational aspects (OPEX) are then included in a separate set of inputs. Equivalent input data for the vSMR was provided from a reactor vendor who is expected to deploy a vSMR within the decade. Wind energy and battery storage input data was taken from publically available sources. The cost calculations are done over the lifetime of the mine, and represent the general cost of producing energy (electricity and heat).

3.4.2 Cost of heat

In addition to electricity, the mine requires low-temperature heat for district heating and ventilation in the underground mine. This is generated in two ways. First, co-generation, which uses the waste heat from electricity generation, is used. This heat is essentially free, because no additional generation capacity or fuel is required to produce it. The second method is direct generation, which is currently produced using a diesel burner, but could also be produced by a vSMR. For direct generation, additional generation capacity must be installed and additional fuel may be required, which comes at a cost to the mine.

Attributing CAPEX and OPEX costs to electricity generation and heat generation is complex, especially for assets such as a vSMR that provide both electricity and heat with very little variable costs. To simplify this analysis, all costs were included in the “PV of Costs to Produce Electricity” (numerator of equation 1). This results in increased cost of electricity (LCOE) since it also includes the costs for heat generation, and makes heat generation essentially free. This method was used for all scenarios to ensure results within this study are comparable, however caution should be taken when comparing with electricity only estimates from other studies that do not include the additional costs associated with heat production.

3.4.3 Carbon tax

Concerns about the environmental impacts of greenhouse gases (GHG) emissions have motivated advocacy to reduce emissions. The Kyoto Protocol, adopted on December 11, 1997, committed industrialized countries to reducing GHG according to individual targets agreed upon, and required the signatory parties to adopt GHG mitigation policies (UNFCCC, 1998). In order to reduce Canada’s GHG from the industrial sector, the federal government has developed a carbon price, “beginning at $20 per tonne of carbon dioxide equivalent emissions (t CO_2e) in 2019 and rising to $50 per tonne"[1,2] (Canada, 2020b). This is implemented under the *Greenhouse Gas Pollution Pricing Act*, which came into force on June 21, 2018. The federal carbon pricing system has two components, namely (i) "a pollution price on fuel, known as the fuel charge;" and, (ii) a pollution price for industry, known as the Output-Based Pricing System (OBPS) (Canada, 2020b).

To prevent stiff competition from industrial facilities in jurisdictions that haven't priced pollution yet, the OBPS prices GHG of 50,000 tonnes or more per year, though industrial facilities that emit 10,000 tonnes or more may voluntarily participate. Industrial facilities with emission below the standard get credit that they may sell or save for the future. The carbon price was set at $20 per tonne exceeding the limit in 2019, rising by $10 annually to $50 per tonne in 2022 (Canada, 2020b).

The GHG taxes are treated in the models as follows: the OBPS threshold is set at 550 t GHG/GWh for generation of electricity using liquid fuels (Canada, 2020b). The portion of GHG emissions above this limit are taxed. The approximate GHG emissions of diesel fuel usage is 2.79 kg/L (Hatch, 2016); thus, the total GHG emissions (in kg) is equal to the total litres of diesel fuel used multiplied by 2.79 (kg GHG emissions per litre). The *GHG emissions per gigawatt-hour (GWh)* is the *total GHG emissions* divided by the *total generated electricity* (in GWh). As a result, the *portion of GHG emissions above the limit* is:

$$\text{Portion of GHG emission above the limit (in percent)} = \\ (\textit{GHG emissions per GWh} - 550)/\ \textit{GHG emissions per GWh} \qquad (3)$$

Thus, the taxed GHG emissions are:

$$\text{Taxed GHG emissions (in tonnes)} = \\ \text{Portion of GHG emissions above the limit (in percent)} * \text{Total GHG emissions} \qquad (4)$$

For example, suppose the Company has produced 652.9 tonnes GHG /GWh based on its operations in a given year. The *portion of GHG emission above the limit* is (652.9 – 550 t/GWh)/ 652.9 t/GWh = 0.16 or 16%. The total GHG emissions that year were 0.07 M tonnes, where the taxable amount is 16% of this value, or 0.011 M tonne GHG. At a tax rate of $20 per tonne GHG, the Carbon tax on this amount is $0.22 M.

At the end of 2020, Canada announced a proposal that would increase carbon tax to $170 per tonne by 2030 (Canada, 2020a). When or if this is implemented, it will increase the costs related to GHG emissions at the mine. Therefore, the results shown here are considered a lower bounding case, and should be revised when changes to the carbon tax pricing system are implemented.

---

[1] Carbon dioxide equivalent (CO_2e) is the model substance for greenhouse gas (GHG). The GHG term is often used interchangeably with CO_2e in the literature.

[2] The metric tonne is used throughout this document, not to be confused with the US ton (1 tonne is 1000 kg or 1.102 US ton).

4. Analysis and modeling

Modeling evaluates how different technologies can be used to meet the main power and heat demand at the mine. Modeling is conceptual and focuses on electricity and heat generation. Hardware upgrades or other integration technologies are outside the scope of this work.

4.1 Technologies

4.1.1 Diesel generation (benchmark system)

The main generators has a diesel conversion efficiency of 0.230 to 0.265 litre of diesel fuel per kW·h_e (L/kW·h_e), based on the information from the mining company. The conversion efficiency depends upon the load factor and the outside temperature. Knowing that the sole combustion of diesel fuel releases between 42 to 46 MJ of energy per kg (WNA, 2020a), the fully efficient combustion of diesel fuel would use 0.092 to 0.101 L per kW·h of thermal energy. This suggests that the efficiency of combustion to electricity is about 35-44% efficient[3], compared to the fully efficient combustion of diesel fuel. The value of 38% efficiency and 0.234 L/kW·h_e, based on the expected annual capacity factor and the experience at the mine (Table 4.1). The other diesel generators are less efficient, at 0.290 L/kW·h_e. Given that these generators are sparsely used, if at all, the same efficiency value of 38% was used in our calculations.

Table 4.1: Diesel burning efficiencies for Scenario (1).

Electricity	**Burning efficiency (L/kW·h_e)**	**Nominal capacity** (MW_e)	**Efficiency value used**
Main generators	0.234	27.5	38%
Other diesel generators	0.290	5.475	38%
	0.290	0.91	38%
Thermal	**Burning efficiency (L/kW-h_{th})**	**Capacity (MW_{th})**	
Main genset (co-generation)	N/A	10.8	39%
Diesel burners	0.116	13	85%
Items not included in the study (emergency system)			
Hot water boiler	Camp complex		
Small generator (1)	Process plant		
Small generator (2)	Emergency (standby) for camp complex		

[3] Example: 0.092 L/kW·h_e / 0.265 L/kW·h_e = 34.7% (or 0.35 in fractional form).

The rest of the heat produced from the combustion of the diesel fuel, if not utilized, would be released as waste heat (system losses, friction, exhaust or other inefficiencies). The heat recovery system on the main genset captures some of this heat as co-generation (cogen). The heat capacity of 10.8 MW_{th} was taken from the ratio of heat recovered per unit of electrical capacity (0.39 MW_{th} / MW_e, based on the data from the mining company) times the nominal capacity of the main genset. The burning efficiencies of the diesel burner and the emergency hot water boiler are also based on data provided by the mining company (i.e. 1 L of diesel provide 8.600 $kW \cdot h_{th}$ from the boilers, or 0.116 $L/kW \cdot h_{th}$). A burner efficiency of 85% was picked, based on the range of theoretical values of 0.092-0.101 $L/kW \cdot h_{th}$.

4.1.2 The MMR vSMR

All nuclear reactors, including SMRs, are a source of low carbon energy as they do not generate or emit any GHG during operations. The Micro Modular Reactor (MMR) is the vSMR technology of the Ultra-Safe Nuclear Corporation (GFP, 2019) and was selected for this analysis. The MMR consists of two plants: (1) the nuclear plant, which consists of a reactor core contained in a reactor vessel and connected to an intermediate heat exchanger, which transfers heat from the helium coolant to a molten salt loop (Figure 4.1). The adjacent power plant (2) transfers heat from the molten salt loop to a steam loop for direct use as process heat or for electrical conversion as required.

Inside the nuclear plant, heat from the reactor core is transferred to a helium gas coolant, which then passes through the intermediate heat exchanger. The cooled helium is returned to the core and is then re-circulated in the loop. The heat generated is transferred to a molten salt system. The reactor design allows for passive removal of heat from the reactor core.

The molten salt carries heat to the adjacent power plant through a closed loop (Figure 4.2). The molten salt loop consists of molten salt tanks for intermediate heat storage, heat exchangers, a recirculating pump and a gas heater. The heat from the salt loop is transferred to a closed steam loop. This loop incorporates a steam turbine and a generator for electricity production. Some of this steam can be diverted to a secondary loop with another heat exchanger for other thermal uses, such as district heating. The cooled water is recirculated to the molten salt heat exchanger. Another important feature of the salt loop is the capability to operate with load variations on a daily, seasonal or lifetime demand. These demand variations can be somewhat offset by increasing the molten salt capacity for the MMR configuration.

The reactor fuel contains civilian-grade low-enriched uranium (<19.75% ^{235}U-enriched) into TRi-structural ISOtropic (TRISO) ceramic particles. This technology, originally developed in the 1960's, has been adapted for high temperature operations in the 1980's and beyond. The particles are extremely resistant to high temperatures, allowing them to retain fission products and to provide environmental protection. They can be bonded into graphite or silicon carbide pellets, some of the most heat-resistant and inert substances known – in this case, the TRISO particles are further encapsulated into walnut-sized pellets to form a USNC proprietary assembly, called Fully Ceramic Microencapsulated fuel (FCM). The FCM is stacked and assembled into graphite blocks to constitute the reactor core. The core assembly is built to allow sufficient flow path for heat removal by the helium coolant. In addition to physical support, the core also acts as a moderator and neutron reflector. This full assembly brings an additional inherent safety to the reactor operation.

The MMR design life and power output can be optimized to meet specific user requirements, which was done in this assessment based on operating life and energy requirements of the mine. The reactor is designed for a nominal 20-year operating life without refueling. Based on user demands, the MMR can be designed for a thermal output of either 15 MW_{th} or 30 MW_{th} per reactor unit by changing design requirements. This can be achieved by setting the operating helium gas pressure at different settings for the same reactor design (Unpublished vendor information). The lower output option (15 MW_{th}) allows lighter pressure vessels for easier deployment in remote locations such as in Northern Canada. As well, the power output of this reactor can be increased slightly to achieve user performance requirements, resulting in a reduced core life. Based on the mine site requirements used in this analysis, a 20 MW_{th} output is used with a reduced operating life of 14 years (Unpublished vendor information). Up to four of these reactor units can be built to feed into a single turbine for electricity generation. These parameters (higher output, number of units feeding into a single turbine) must be specified and costed at the time of planning for the power plant.

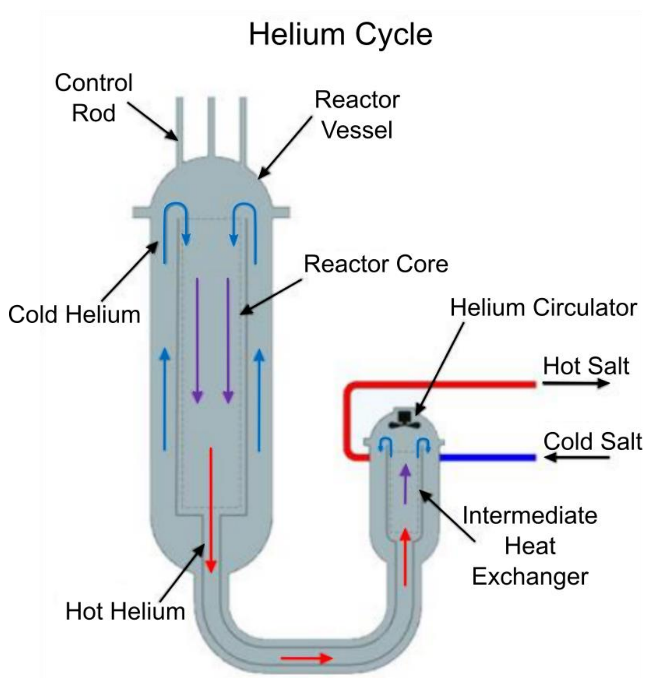

Figure 4.1: Simplified schematics of the MMR reactor vessel (GFP, 2019).

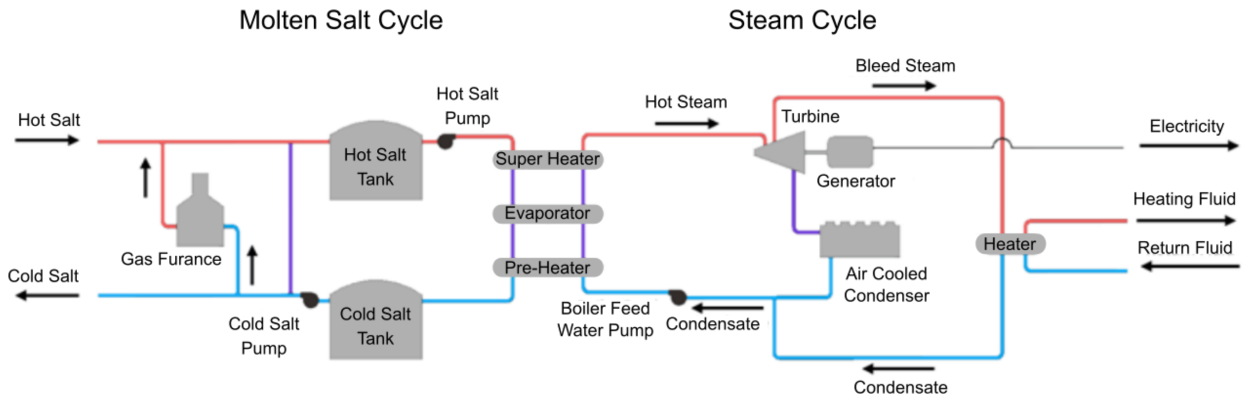

Figure 4.2: Simplified diagram of the non-nuclear molten salt and steam loops of the MMR (GFP, 2019)

4.1.3 Wind turbines

Wind turbines are a source of carbon-free electricity and therefore considered in many GHG reduction plans. This study assumes a set of three Enercon E 70 turbines (Pinard, 2016). The rated capacity of each tower is 2.3 MW. Those towers were recommended because of their proven track record at two mine sites in the Canadian North. Turbines have a 15+ year operating life before major maintenance is required. This same study recommended wind integration with battery storage. Batteries have an average life of 12 years (ibid), with actual life varying based on the operating parameters (e.g. number of charge/discharge cycles). This study assumes no major maintenance/replacement will be needed for the mine or the batteries during the 14 year operating life of the mine.

4.2 Energy generation and projections

Both electricity and heat production have to match the demand. The demand varies as a function of the mine operation, the outside temperature and the mine evolution. Figure 4.3 shows the projected annual energy variations for the mine. Electricity consumption projections gradually increase to a maximum of 210,818 $MW{\cdot}h_e$ in year 9, then decrease to 167,079 $MW{\cdot}h_e$ at the end of the LoM (also see Table 3.1). The projections for heat demand begin in year 2 at 73,577 $MW{\cdot}h_{th}$, increase to 75,669 $MW{\cdot}h_{th}$ by year 6, remain steady until year 9, and then decrease gradually to the end of the LoM.

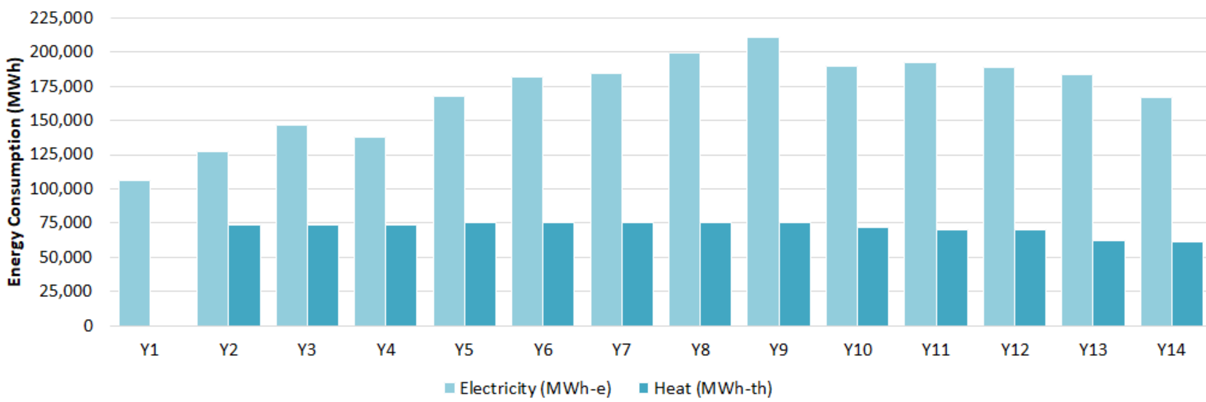

Figure 4.3: Projected annual energy consumption over 14 year LoM (data from Table 3.1).

4.3 Scenarios

The HESO model developed by CNL requires hourly electricity and heat demand inputs for estimating load variations. The behaviour for short-term spikes of electricity and heat was analyzed at the hourly level to better understand the system behaviour. This was necessary to ensure the demand at any one hour does not exceed the nominal power plant capacities installed.

One year of hourly electricity demand variation was provided by the mining company. This pattern was assumed constant over the 14 year operating life, with hourly demand scaled to match the annual demand projections in Table 3.1 (Figure 4.4).

Heat, on the other hand, has its own challenges. Its demand is strongly temperature dependent, especially if the outside temperature is below 0 degrees C. Historical ambient temperature data and the correlation between temperature and heat demand were used to estimate the hourly heat demand curve, which was then scaled to annual demand projections (Table 3.1) for each year of operation (Figure 4.5).

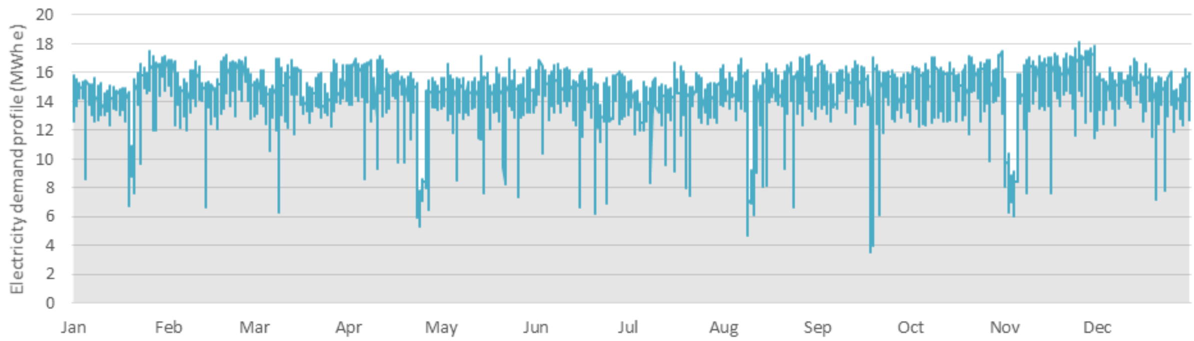

Figure 4.4: Hourly electricity consumption, used as a typical year for the duration of the simulations.

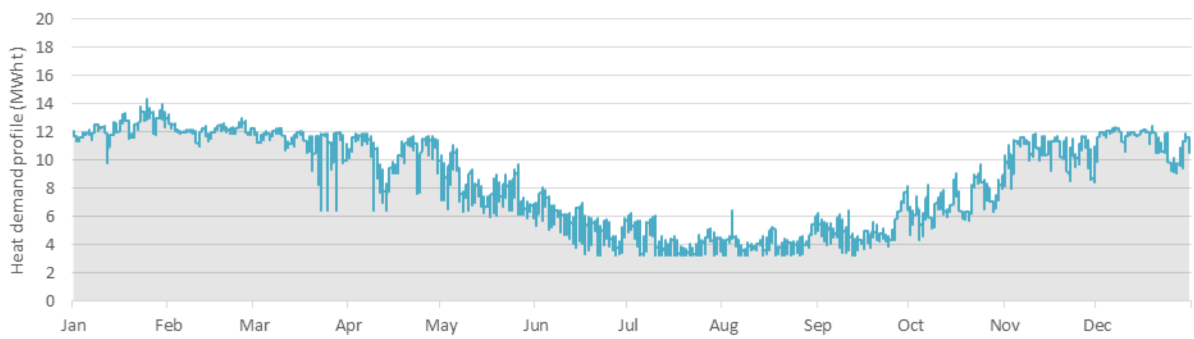

Figure 4.5: Hourly heat consumption, used as a typical year for the duration of the simulations

There were four scenarios considered in this study: (1) diesel only benchmark; (2) vSMRs only; (3) vSMRs and diesel generators; and (4) vSMRs, wind turbines with battery, and diesel generators. For each scenario, the HESO model used the hourly data (short-term demands) and energy projections (long-term demands) over the 14-year LoM. The HESO model then provided an optimal mix of technologies for each scenario, along with capacities and utilization rates of each technology. The long-term optimal capacities are summarized in Table 4.2.

In Scenario (1), both electricity and heat are provided by a set of diesel generators and burners. This is the actual case at the representative mine, and is used for benchmarking the output economic model. In Scenario (2), a set of three vSMRs are built and operated at an early stage of the project. The steam produced by the vSMRs is directed to a single turbine. Another set of two vSMRs would be built and operated two years into the project, with steam from these two units directed to a second turbine. Scenario (3) is a diesel and vSMR mixed model. A fleet of three vSMRs is the main source of electricity and thermal energy, whereas diesel generators will take the peak electricity loads and only provide heat through cogeneration. Finally, Scenario (4) is similar to Scenario (3) except three wind turbines and battery storage are added to provide additional electricity when possible to further reduce diesel generator usage.

Table 4.2: Summary of the long-term optimal capacities of the technologies

Scenario	Technologies	Diesel MW_e | MW_{th}	Wind MW_e	vSMR20 x2 [1] MW_e | MW_{th}	vSMR20 x3 [2] MW_e | MW_{th}	Total Capacity MW_e
Scenario (1)	Diesel	30.0 | 78.9	-	-	-	30.0
Scenario (2)	vSMR	-	-	13.6 | 40	21.0 | 60	34.6
Scenario (3)	Diesel, vSMR	10.5 | 27.6	-	-	21.0 | 60	31.5
Scenario (4)	Diesel, vSMR, Wind	9.0 | 23.7	6.0	-	21.0 | 60	36.0

Note: [1] vSMR20 x2 describes two 20MW_{th} vSMRs with a single turbine, efficiency 34%
[2] vSMR20 x3 describes three 20 MW_{th} vSMRs with a single turbine, efficiency 35%

The HESO model provides an optimal output for a hybrid energy system. Given that year-to-year electricity and heat demands are variable, and that there are seasonal variations in the demands (especially for heat), the annual output per technology in terms of energy, peak power, and capacity factor will vary.

The output from the HESO model provides the number of units of each technology and their respective capacity factors, which are aggregated on an annual basis. The MIRARCO model takes the aggregated annual capacity factors and estimates the costs of the technologies to meet the electricity and heat demands for the duration of the project (14 years). This model calculates the LCOE (calculated costs of electricity and heat production, levelized per unit of electricity production), the metric of choice used in the industry.

The MIRARCO model assumes capital expenditures (CAPEX) of the diesel generators, vSMRs, wind turbines, and battery are incurred in year 1 of the simulation, and the cost is recovered over the operating life of the equipment. The CAPEX includes costs associated with transportation of equipment to the mine site and all installation costs, where dismantling costs are assumed to take place at the end of life of the mine. The operating expenses (OPEX) have fixed and variable components. The OPEX associated with the diesel generators had substantial variable components, such as fuel handling and the price of the diesel fuel itself. The OPEX for both the vSMR and wind turbines were predominantly fixed. Refueling of the vSMRs was the main OPEX item, but this did not apply in the main scenario (14 years), as the fuel was part of the initial CAPEX of the vSMRs and did not need to be replaced in that time period. Both the vSMRs and the wind turbines had a minimum of 20-year service life.

A summary of the LCOE estimates is given in Table 4.3 below for a discount rate of 5% for the LoM (14 years). The summary indicates that the LCOE for Scenarios (1) and (3) are fairly close to one another, whereas the vSMR-only scenario (2) is the most expensive.

Table 4.3: Summary of the LCOE calculations for the four scenarios.

Scenario	LCOE ($CDN per kW·h$_e$)	GHG emissions
	5% discount rate	M tonnes of CO_2e
(1) Diesel	0.281	1.56
(2) vSMRs only	0.387	0
(3) vSMR and diesel	0.266	0.24
(4) Wind + battery, vSMR, diesel	0.279	0.16

*Note that these figures include an estimate for the carbon tax (based on an increase to $50/tonne).

For the Scenario (1), diesel only, the total GHG for energy production is 1.56 M tonnes over the LoM, of which 0.25 M tonne is taxable (see Eq. (3) and (4) above), for a total of $11.53 M in Carbon tax. Likewise, the carbon tax for Scenarios (3) and (4) is $1.17 M and $0.54 M, respectively.

4.3.1 Scenario (1): diesel generation (benchmark case)

Scenario (1) is the benchmark case using the data provided by the mining company. It considers diesel electricity generation with cogeneration that produces both electricity and heat, as well as diesel burners for additional heat. The long-term projected generations (14 years) are shown in Figures 4.6 (a) and (b).

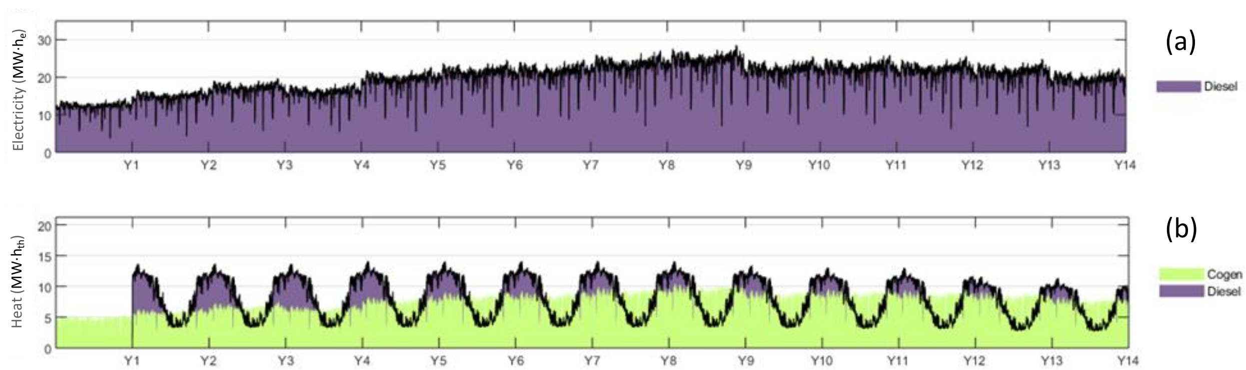

Figure 4.6: Scenario (1): Long-term optimal result: (a) electricity from diesel generators; (b) heat (purple is from heat burners, the dull green is from cogeneration.

The calculated minimum installed capacity needed to meet demand, which includes extra capacity for peak shaving (bars)[4], and capacity factors based on this minimum capacity (line) are shown in Figure 4.7. The system reaches its nominal capacity with the demand in year 9. Past year 9, the capacity factor reaches its maximum of ~82% and gradually decreases to ~65% in year 14.

[4] Note: Capacity is added as required but not removed when demand decreases.

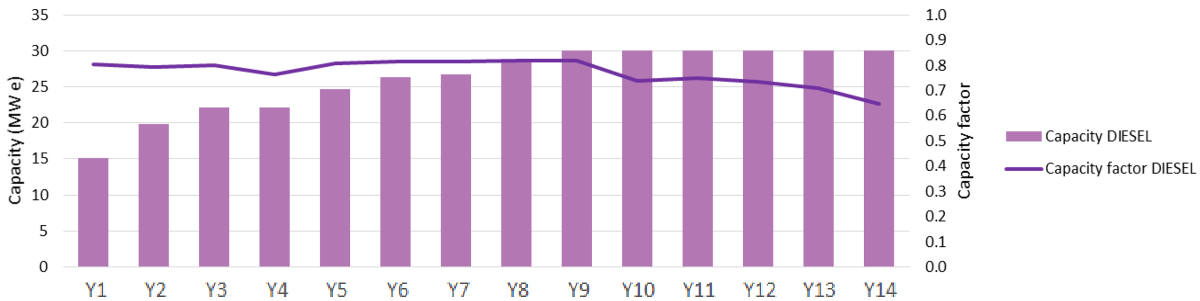

Figure 4.7: Scenario (1): Installed capacity and capacity factor.

Table 4.4 gives a summary of the technology input to the MIRARCO model for the main diesel generator, the smaller generators (peak shaving) and the burners. Only the main genset is equipped with a heat recovery system for co-generation, whereas the burners were used for heat only. The smaller generators are not equipped with heat recovery and are therefore not part of the heat modelling. The CAPEX of this system is $94.9 M and the OPEX was treated as variable for all three items. The wholesale diesel fuel cost was $0.80/L for years 1 and 2, then it was increased to $0.84/L thereafter. The closure cost of the main genset was included at the end of the LoM, year 14. The closure cost of the smaller generators is sunk as a part of the mine decommissioning.

Table 4.4: Scenario (1): Cost data.

	Main Gensets (electric and heat)	**Smaller generators (electric - peak shaving)**	**Diesel Burners (heat only)**
Installed capacity (MW_e or th)	27.85	6.3	13
CAPEX ($M)	82	7	5.9
OPEX ($/kW-h)	0.015	0.015	<0.015
Fuel Cost ($/L)	0.80 – 0.84	0.80 – 0.84	0.80 – 0.84
Burning efficiency (L/kW-h_e)	0.234	0.290	0.116
Thermal Efficiency (%)	39	N/A	85
Closure Costs ($M)	1.145	-	-

The MIRARCO model output summary for Scenario (1) is shown in Table 4.5 (discount rate 5%). The LCOE calculated for this scenario was $0.281 /kW·h (Table 4.3). Table 4.5 also shows the calculated amount of CO_2 produced and the applicable carbon tax. It should be noted that the heat recovered via co-generation is not monetized in the LCOE. Rather, it is calculated in a separate line as an example of the cost of heat that would need to be produced in the absence of this co-generation source. We have calculated that $99.6 M are saved through a combination of fuel and OPEX. In other words, if diesel fuel were burned for heat instead of being recovered from the generators, the cost would increase by $99.6 M in addition to the $616.7 M (from Table 4.5).

The largest portion of the undiscounted cost was related to OPEX (fuel at ~75%, variables ~6%), followed by CAPEX (~16%). Carbon tax was a small portion of the cost, and only accounted for approximately 2% of overall cost.

Table 4.5: Scenario (1): Cost estimate from the MIRARCO model.

Scenario 1: Diesel only

C $	2019 $				
	Life of mine		**Unit**		**Total (lifetime)**
Demand	Electricity	Site	Million kwh-e		2,385.39
	Heat	Site	Million kwh-th		934.53
Supply	Genset Electricity		Million kwh-e		2,385.39
	Genset Co-gen		Million kwh-th		879.57
	Mine Air Burners		Million kwh-th		54.96
Genset	Capex		$ Million		94.90
	Opex		$ / kwh-e		-
	Opex		$ Million		35.78
	Fuel	Efficiency	L/kwh-e		-
	Fuel		Million Litres		558.18
	Fuel		$ / Litre		-
	Fuel		$ Million		471.72
	Heat - Diesel		$ / KWh-th		-
	Heat - Burner		$ / KWh th		-
	Heat		$ Million		13.21
	Closure		$ Million	$	1.15
	Total Gen Cost		**$ Million**	**$**	**616.75**
Carbon			kg CO2 eq/ Litre diesel	$	-
	Emissions		Million t CO2		1.56
			t CO2/Gwh		-
	Emissions Cap		t CO2/Gwh		-
	Emissions Portion above Cap				-
	Emissions taxable		Million t CO2 eq		0.25
	Carbon Tax		$/ t CO2 eq		-
			$ Million	**$**	**11.53**
	Total Cost		**$ Million**	**$**	**628.28**
	02.09.21-LZ.xlsx				

4.3.2 Scenario (2): vSMR only

In Scenario (2), the model considers only vSMRs with cogeneration to produce both electricity and heat for the mine. Heat comes from cogeneration (waste heat from electricity generation) or directly from the vSMR steam cycle before going through the turbine. The combined long-term generation profiles are shown in Figures 4.8 (a) and (b).

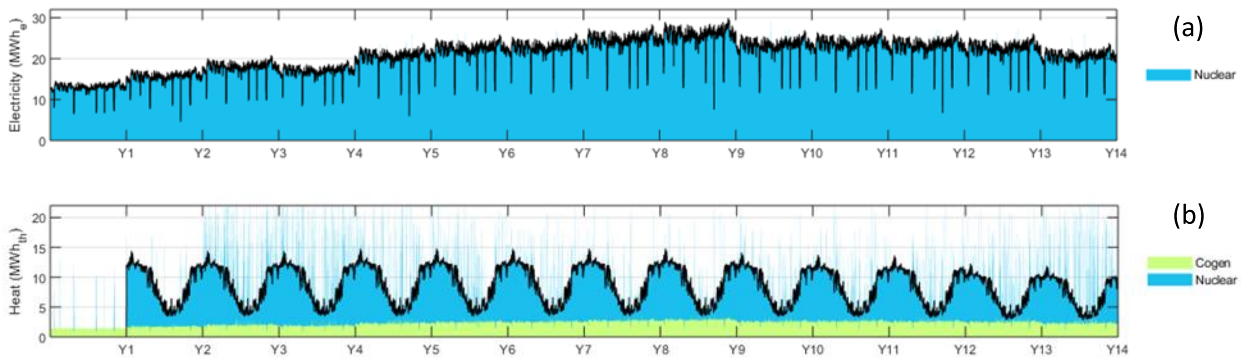

Figure 4.8: Scenario (2): Long-term optimal result: (a) electricity; (b) heat.

Optimization indicated that three vSMRs would be sufficient to meet the demand in years 1 and 2 (vSMR20x3), feeding a single turbine. This is followed with the addition of two more vSMRs in year 3 (vSMR20x2), feeding a second turbine. The optimization results are shown in Figure 4.9. Two of the first three vSMRs have a capacity factor of about 50% while the third one had a capacity factor of about 75% in year 1. All three vSMRs have a higher capacity factor in year 2, that is one increased to almost 70% and the other two at almost 90%. The average annual capacity factors decrease in year 3 with the addition of two units, and increase to 70-90% with the anticipated consumption throughout the LoM to year 14.

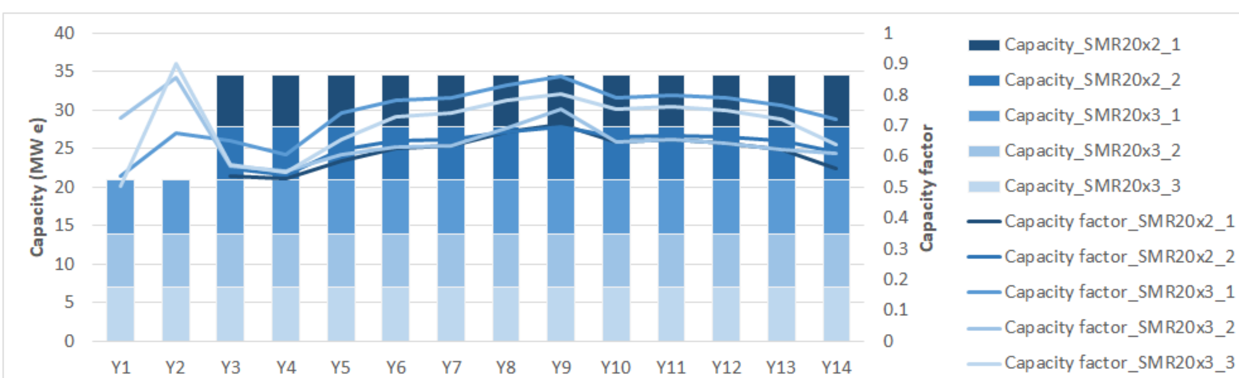

Figure 4.9: Scenario (2): HESO model results: installed capacity (bars) and capacity factor (lines) for the technologies.

Table 4.6 gives a summary of the technology input to the MIRARCO model for the vSMR-only scenario. Note that the peak shaving diesel generators and the diesel burners are not part of this scenario, therefore the vSMRs have both sufficient electrical and heat producing capacity. The CAPEX of the first three vSMRs (including turbine and fuel) is $285 M, whereas it is smaller at $222 M for the other two (unpublished vendor data). The cost per unit is smaller for the first fleet of three, as only one turbine needs to be built to accommodate the steam from the vSMRs. The CAPEX otherwise includes project development, licensing and owner's costs. The closure costs are a separate one-time item, spent at the end of the LoM.

The OPEX items comprise a regional service centre and on-site staff (including lodging expenses), insurance, licensing and decommissioning. The OPEX are largely fixed costs and do not depend upon electricity and heat production. Spare parts are the only variable cost, and represent 0.4% of the direct capital cost (~2.2% of OPEX).

Table 4.6: Scenario (2): Cost data

	3 vSMRs @ 20 MW_{th} /6.7 MW_e (added at year 1)	**2 vSMRs @ 20 MW_{th} /6.7 MW_e (added at year 3)**
CAPEX ($M)	285	222
OPEX ($M/year)	6.91	5.77
Fuel cost ($/kW-h)	0[a]	0[a]
Closure cost ($M)	38.8	29.9
Thermal Efficiency (%)	35	34
Lifetime (years)	14	14

a: no refueling is required over the 14-year LoM; the cost of the fuel is included in the vSMRs initial cost.

The output summary for Scenario (2) is shown in Table 4.7 (discount rate 5%). The costs are dominated by CAPEX (~68% of the total), followed by OPEX (23%) and closure/decommissioning (9%). Since the OPEX are mostly fixed cost, the LCOE is not very sensitive to electricity and heat production. The LCOE calculated for this scenario was $0.387/kW-h$_e$ (Table 4.3), which was the most costly of all four scenarios. This is not a surprise, since the vSMRs are not utilized to full capacity, and that the costs are spread over only 14 years. It is well known that vSMRs are more cost competitive when run at high capacity factors over their design life (EFWG, 2018).

Table 4.7: Scenario (2): Cost Estimate.

Scenario 2: SMRs only

C$	2019$			
	Life of mine		**Unit**	**Total (lifetime)**
Demand	Electricity	Site	Million kwh-e	2,385.39
	Heat	Site	Million kwh-th	934.53
Supply	Electricity-SMR		Million kwh-e	2,396.41
	Electricity-Diesel		Million kwh-e	-
	Total Electricity		Million kwh-e	2,396.41
	Heat-SMR		Million kwh-th	1,153.09
	Heat-Diesel		Million kwh-th	0.00
GENSET	Capex-SMR		$ Million	$ 507.21
	Capex-Diesel		$ Million	$ -
	Opex-SMR		$ Million	$ 171.80
	Refueling- SMR		$ Million	$ -
	Opex-Diesel		$ Million	$ -
	Fuel		$ Million	$ -
	Heat-Diesel		$ Million	$ -
	Closure-SMR		$ Million	$ 68.67
	Closure-Diesel		$ Million	$ -
	TOTAL GEN COST		**$ Million**	**$ 747.67**
	12.07.20-LZ			

4.3.3 Scenario (3): vSMRs and diesel generators

In Scenario (3), the model considers that diesel generators and vSMRs produce both electricity and heat for the mine. Electricity comes primarily from the vSMRs (~90%), with diesel providing additional electricity during periods of peak demand (~10%). Heat is cogenerated from vSMRs and diesel generators or directly from the vSMR steam cycle before going through the turbine. No diesel is burned for direct heat production. The generator efficiencies are 35% and 38% for vSMRs and diesel, respectively. The power-to-heat ratios for the two technologies are significantly different, where 0.11 MW_{th}/MW_e is the vSMR ratio and 0.39 MW_{th}/MW_e is the diesel ratio.

The long-term optimal generations are presented in Figure 4.10 (a) and (b). Figure 4.11 shows the installed capacities and the capacity factors for the technologies.

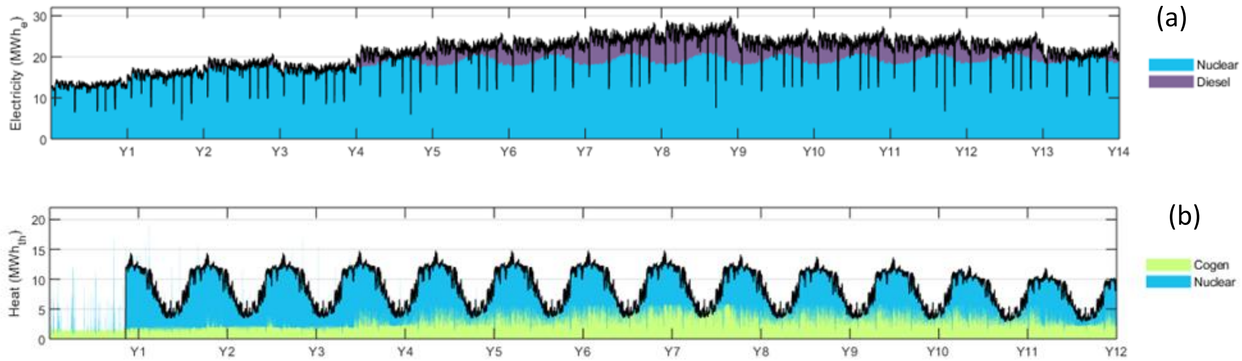

Figure 4.10: Scenario (3) long-term optimal result: (a) electricity from vSMRs and diesel; (b) heat from vSMRs and diesel co-generation.

In this scenario, the diesel generators would be used occasionally to meet peak demands in the first four years, shown by the purple bars. Diesel use would increase to year 9, and it would necessitate two diesel generators (as opposed to five in the current scenario). The capacity factor of the diesel generators would peak at just below 0.50 at year 9, decreasing afterwards in response to the reduction in demand. The vSMRs would be significantly underutilized in the first two years (<80% capacity factor), with their use increasing steadily in years 3 and 4. The vSMRs would be used at or near nominal capacity thereafter (~94% to near 100%).

The vSMR CAPEX is now approximately 57% of the total cost. The diesel generator CAPEX was adjusted to 40% of the cost of the 5 generators from Scenario (1) (Table 4.4), which is $32 M. It is also noted that the calculated volume (and cost) of the diesel fuel required decreased by a factor of about 12, compared to Scenario (1). Since diesel generation OPEX is treated as variable cost, its decrease parallels that of the fuel cost.

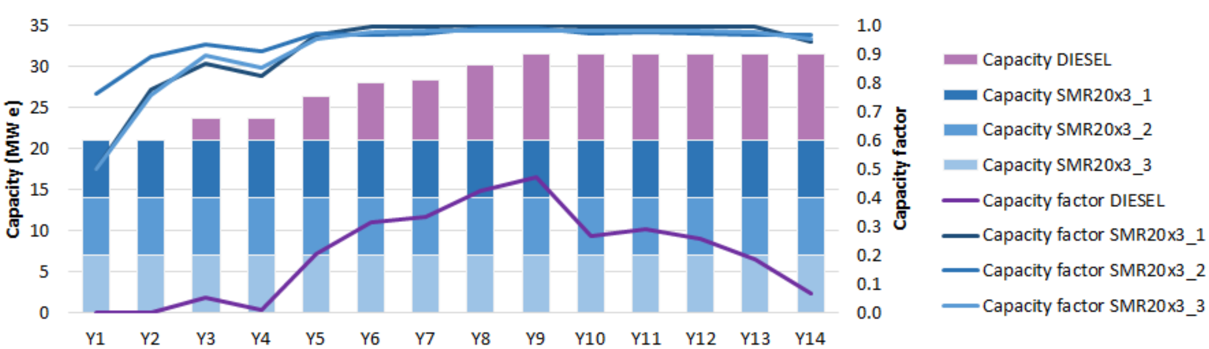

Figure 4.11: Scenario (3) HESO model results: installed capacity (bars) and capacity factor (lines) for the technologies.

Table 4.8: Scenario (3): Cost data.

	3 vSMRs @ 20 MW_{th} /6.7 MW_e (added at year 1)	2 diesel generators (added at year 1)
CAPEX ($M)	285	32
OPEX ($M/year)	6.91	0.243[b]
Fuel cost ($/L for diesel)	0[a]	0.80-0.85
Closure cost ($M)	38.81	1.15
Thermal Efficiency (%)	35	39
Lifetime (years)	14	14

a: no refueling is required over the 14-year LoM; the cost of the fuel is included in the vSMRs initial cost.

b: OPEX is $3.4 M for the 14-y LoM, at a rate of 0.015/kW·h (from Table 4.4).

Table 4.9: Scenario (3): Cost estimate.

Scenario 3: vSMR and diesel

	Life of mine		**Unit**		**Total (lifetime)**
Demand	Electricity	Site	Million kwh-e		2,385.39
	Heat	Site	Million kwh-th		934.53
Supply	Electricity-SMR		Million kwh-e		2,160.61
	Electricity-Diesel		Million kwh-e		226.98
	Total Electricity		Million kwh-e		2,387.59
	Heat-SMR		Million kwh-th		960.31
	Heat-Diesel		Million kwh-th		-
GENSET	Capex-SMR		$ Million	$	284.95
	Capex-Diesel		$ Million	$	32.80
	Opex-SMR		$ Million	$	96.73
	Refueling-SMR		$ Million	$	-
	Opex-Diesel		$ Million	$	3.40
	Fuel		$ Million	$	45.15
	Heat-Diesel		$ Million	$	-
	Closure-SMR		$ Million	$	38.81
	Closure-Diesel		$ Million	$	1.15
	TOTAL GEN COST		**$ Million**	**$**	**502.99**
Carbon	Emissions		Million t CO2		0.15
	Emissions Taxable		Million t CO2		0.02
	Carbon Tax		**$ Million**	**$**	**1.17**
	TOTAL COST		**$ Million**	**$**	**504.15**
	02.01.21-LZ				

4.3.4 Scenario (4): vSMR, diesel, and wind turbines

This scenario is very similar to Scenario (3) except wind turbines (+ battery) are introduced as a way to further reduce the use of diesel at the mine site. As per the previous scenario, heat comes directly from the vSMR steam cycle or from cogeneration from the vSMRs or diesel generators. The electric generator efficiencies are 35% and 38% for vSMRs and diesel generators, respectively, and wind turbine module efficiency is 43%, based on historic wind data collected near the mine site. The power-to-heat ratios are 0.11 and 0.39 MW_{th} / MW_e for vSMRs and diesel, respectively. Battery storage has been included to smooth the variability of wind energy.

The long-term optimal generations are presented in Figure 4.12 (a) and (b). The installed capacities and capacity factors for the technologies are given in Figure 4.13.

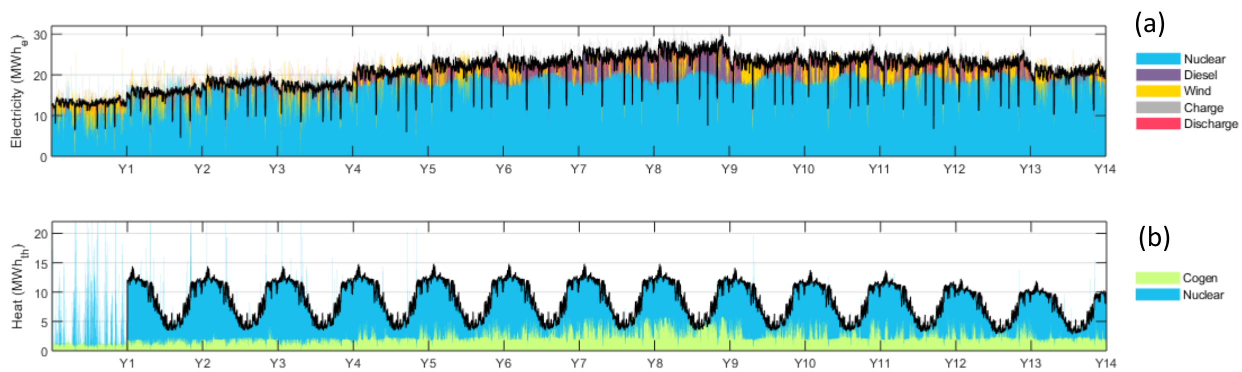

Figure 4.12: Scenario (4), long-term (14-years) optimization result

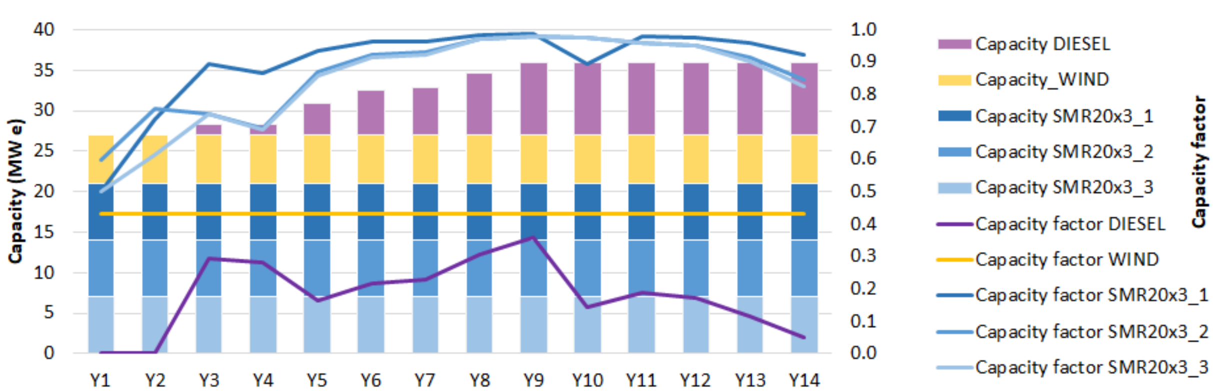

Figure 4.13: Scenario (4): HESO model results: installed capacity (bars) and capacity factor (lines) for the technologies.

The optimal solution from the HESO model suggested a wind turbine capacity of 6 MW_e, and the same number of units for the vSMRs (3 x 7 MW_e) and diesel generators (2 x 5.5 MW_e) as in the previous scenario. The wind capacity was estimated based on one year of historic wind data from the area. Since this one year of data was used for all 14 years, the average annual capacity factor for wind appears constant, however the hourly variation in wind energy production was accounted for. The vSMRs are operated at low capacity factors during the first two years (<70%). The capacity factor increases with demand, reaching near full capacity in year 5 and thereafter (86-98%). Similarly to Scenario 3, diesel generators would be used sparingly, with no operating hours in the first two years, and used only occasionally to meet peak demands thereafter. Only two diesel generators would be needed, and their capacity factor peaks at approximately 36% in year 9.

It is noted that the model predicted slightly lower capacity factors for the diesel generators (average of 21% vs 24%) and the vSMRs (average of 87 vs 93%) for this scenario, compared to Scenario (3). This is expected, as the wind turbines provide new capacity to the system that is non-dispatchable. Since the same number of vSMRs and diesel generators are needed compared to Scenario (3) (to account for days that are not windy), it is not surprising that the LCOE of this scenario is higher than in the previous scenario.

The wind turbine costs are based on the work of (Pinard, 2016) which was commissioned for an energy corporation operating in the far North. This work was adapted for 3 Enercon towers (2.3 MW each) and a 1 MW battery storage system. The wind turbine (and battery) is a net add-on to the CAPEX, plus a small OPEX. The cost was $32.9M (all-in, road construction omitted), plus the annual O&M of $0.923M for the wind turbine and battery, annually. Decommissioning cost assumes no salvage value for the towers. A value of $0.22 M per tower was used, based on (Ortegon et al., 2013) and (Stripling, 2015), adjusted to year 2019. A lifetime of 15 to 25 years is generally assumed for the wind turbines, so it is assumed that no significant rebuild will be needed for the 14-year LoM.

Similarly to Scenario (3), the capital cost was adjusted for two generators instead of the five required for Scenario (1). The OPEX, fuel and carbon tax are less than in the previous scenario due to reduced runtime. Both CAPEX and OPEX of the vSMR remain the same as for Scenario (3), despite a slightly lower capacity factor. The input cost data are shown in Table 4.10, and the aggregated outputs are in Table 4.11.

Table 4.10: Scenario (4): Cost data.

	3 vSMRs @ 20 MW_{th} /6.7 MW_e (added at year 1)	3 Wind Turbines + Battery	2 diesel generators (added at year 1)
CAPEX ($M)	285	32.9	32
OPEX ($M/year)	6.91	0.96	0.112[b]
Fuel ($/L for diesel)	0[a]	0	0.80-0.85
Closure ($M)	38.81	0.660	1.15
Thermal Efficiency (%)	35	N/A	39
Lifetime (years)	14	15-25	14

a: no refueling is required over the 14-year LoM; the cost of fuel is included in the vSMRs initial cost.

b: OPEX is $1.57 M for the 14-y LoM, at a rate of 0.015/kW·h (from Table 4.4).

Table 4.11: Scenario (4): Cost estimate.

Scenario 4: vSMR, wind (+ battery) and diesel

	Life of mine		**Unit**		**Total (lifetime)**
Demand	Electricity	Site	Million kwh-e		2,385.39
	Heat	Site	Million kwh-th		934.53
Supply	Electricity-SMR		Million kwh-e		1,982.70
	Electricity-Wind		Million kwh-e		316.79
	Electricity-Diesel		Million kwh-e		104.41
	Total Electricity		Million kwh-e		2,403.90
	Heat-SMR		Million kwh-th		983.06
	Heat-Diesel		Million kwh-th		-
GENSET	Capex-SMR		$ Million	$	284.95
	Capex-Diesel		$ Million	$	32.80
	Capex Wind + Battery		$ Million	$	32.94
	Opex-SMR		$ Million	$	96.73
	Opex Wind + Battery		$ Million	$	13.44
	Opex-Diesel		$ Million	$	1.57
	Fuel		$ Million	$	20.77
	Heat-Diesel		$ Million	$	-
	Closure-SMR		$ Million	$	38.81
	Closure Wind		$ Million	$	0.66
	Closure-Diesel		$ Million	$	1.15
	TOTAL GEN COST		**$ Million**	**$**	**523.80**
Carbon	Emissions		Million t CO2		0.07
	Emissions Taxable		Million t CO2		0.01
	Carbon Tax		**$ Million**		0.54
	TOTAL COST		**$ Million**	**$**	**524.34**
	02.01.21-LZ				

4.4 Sensitivity cases: alternate demand developments

Two alternate demand developments constitute realistic situations that could take place at the mine, without necessarily anticipating major changes for the power and heat generation. Both these alternate developments were modeled over the 14-year period, similarly to the base case scenarios. These two hypothetical developments are:

- Extending the mine by opening a new mining area; and
- Providing electricity to a neighbouring community.

Extending the mine by opening a new mining area was estimated by adding 2 MW_e installed electrical capacity, based on the company operation site profile. This new mining area is expected to start operating in year 10 (Figure 4.15) and will continue for 5 years, closing the same time as the main site.

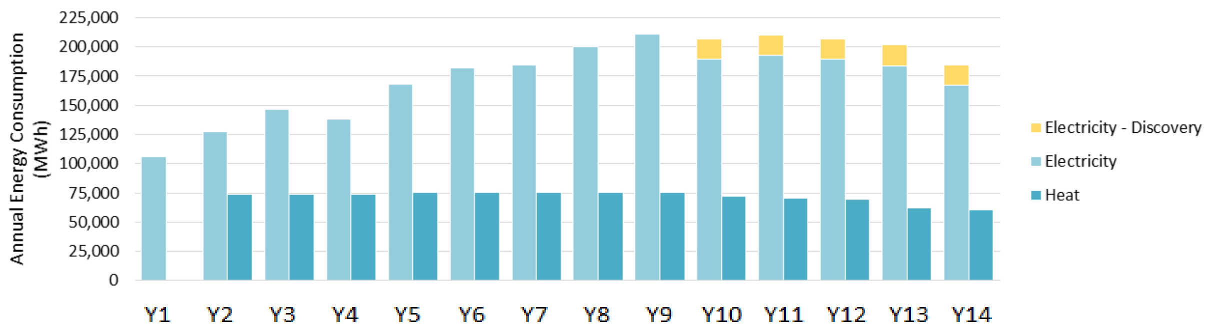

Figure 4.14: Conceptual demands (electricity, heat) for opening a new mining area of the mine.

The new mining area includes electricity-only demand, based on the data provided from the mining company. We did not include heat projections in this development: heating the new mining area would likely be impractical, as the extension is expected to be several kilometres away making transportation of heat difficult, especially in an arctic climate.

The LCOE changes (Table 4.12) are very small but beneficial (i.e. a decrease of 0.6% (diesel-only) to 2.8% (vSMR only)) compared to the respective base cases. These are a result of higher utilization rate of the technologies for producing electricity and additional opportunities for co-generation of heat. It is important to note that the additional demand comes online after the peak demand at the main site (year 9). If the new mining area were to begin operations a year earlier, additional system capacity may be required, which could potentially increase costs slightly depending on how much of the cost could be offset with co-generation savings.

Table 4.12: Summary of the sensitivity for the alternate case developments.

	LCOE ($CDN/kW·h$_e$) (DR = 5%, 14 years)		
Scenario / sensitivity case	**Base case**	**New mining area**	**Neighbouring community**
Scenario (1) – Diesel only	0.281	0.279 (-0.6%)	0.275 (-2.2%)
Scenario (2) – vSMRs only	0.387	0.377 (-2.8%)	0.351 (-9.3%)
Scenario (3) – vSMR and diesel	0.266	0.247 (-1.8%)	0.252 (-5.3%)
Scenario (4) – vSMR, diesel, wind + battery	0.279	0.276 (-1.1%)	0.266 (-4.9%)

* The percent change compared to the base case is in brackets, next to the LCOE.

Providing electricity to a neighbouring community considers exporting excess electricity generated to a neighbouring community as a way to generate good will by offering clean electricity at a competitive rate, as well as creating another revenue source for the mine. A maximum export value was set to match the existing community demand. The average additional demand amounts to an increase of 17.59 MW·h annually for the 14 years of the mine operation (Figure 4.16). The increase is based on the annual demand of a model community near the representative mine site. This scenario considers only electricity export to the community, and does not include other factors, such as supplying heat or distribution system upgrades.

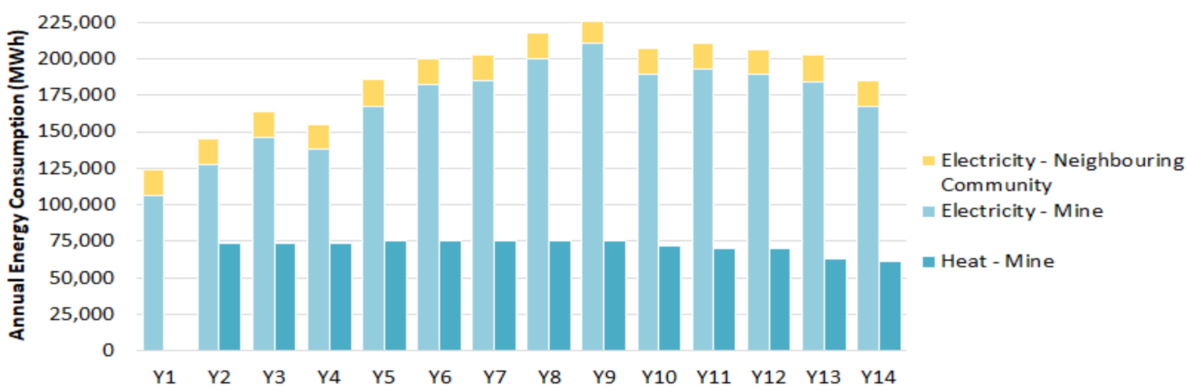

Figure 4.15: Conceptual demands (electricity, heat) to include power for neighbouring Community.

This simulation (shown in Table 4.12) gave lower LCOE values by a factor of 2.2% (diesel) to 9.3% (vSMR-only). It was expected that the vSMR-only scenario would perform well in this scenario, because there was significant excess capacity built in the system that could be exported to the community at a minimal cost to the mine since OPEX costs are fixed. On the other hand, diesel benefits are much less because of the additional OPEX costs (primarily fuel) that would be needed to generate the additional electricity.

Still, some benefits are gained by utilizing excess capacity which would increase co-generation and reduce direct heating cost.

In summary, the LCOE of all four Scenarios would decrease for these two alternate demand developments, from 0.6% (diesel-only) to 9.3% (vSMRs-only). This is expected, as the technologies are utilized at a higher capacity with no new CAPEX. Since the CAPEX of diesel generators is relatively small and its OPEX is relatively large, the benefits are small. The benefits are higher for the capital-intensive vSMRs and wind turbines.

4.5 Sensitivity cases: demands for shorter or longer periods

These demands were simulated for these time periods:

- A shorter period of 10 years;
- Extending the life of mine from 14 to 20 years
- Creating an energy hub that operates for 40 and 60 years

A shorter LoM (assumed 10 years) considers an unexpected closure or extended shutdown of the mine. The shorter LoM was simulated by taking the first 10 years of mine production, and abruptly stopping its operation at the end of year 10. The CAPEX and OPEX are spread over that shorter period of time. Closure or decommissioning costs are included in this analysis.

Extending the life of mine from 14 to 20 years can be more complex for two reasons. Firstly, we are simply adjusting the number of years the mine and the power plant would operate, for the purpose of our simulations. An actual adjustment would need to be part of bigger plan from a mining company to support the change. This is outside the scope of the current work. Secondly, the vSMRs, in reality, would need to operate with the lower output option (Section 4.1.2) assuming the 20-year LoM. The vSMR with the high output option, which has a shorter design life of 14 years, would not be realistically operated for 20 years.

In our simulations, extending the life of the mine and the vSMRs follows the low-output option, i.e., a 20-year normal operation, with no refueling. For the other technologies, the timeframe is reasonable for wind turbines under these climate conditions (Pinard, 2016) but not necessarily for the batteries. Likewise, our simulations assume that the main diesel generators continue to produce electricity and heat for 20 years with no replacement, and that maintenance and the OPEX other than diesel do not increase with age of the generators.

This 20-year demand sensitivity case was simulated by extending the peak demand of Year 9 by six years, to Year 15, then decreasing gradually to Year 20 as per the base demand (see Figure 4.14).

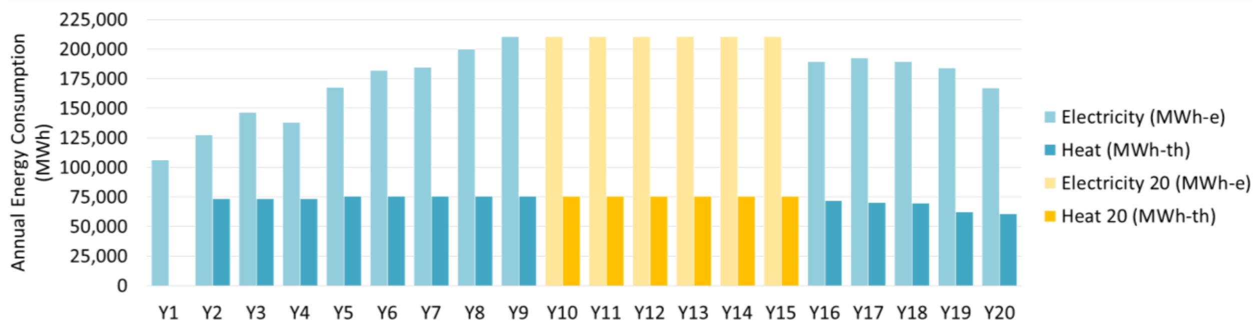

Figure 4.16: Conceptual demands (electricity, heat) for the extended LoM simulations.

The sensitivity case of the diesel-only Scenario (1) assumes that the current set of generators will continue to have the same OPEX. We have assumed that these generators have a 20-year design life, for simplicity. The same fuel cost is being used ($0.85/L), and the carbon tax remains constant at $50/tonne.

The simulation for Scenario (2) (vSMRs only) utilizes five reactors with the low output option of 15 MW_{th} (5 MW_e). Three vSMRs are installed at the onset, followed by two vSMRs starting on the third year. The choice with respect to power and design life trade-off (15 MW_{th} /5 MW_e for 20 years) does not increase the capital cost of the reactors (Unpubl.), whereas the OPEX is extended at the same rate for the extra years. No other costs are involved for this vSMR-only scenario.

The sensitivity case of Scenario (3) involving vSMR and diesel generators utilizes three vSMRs (15 MW_{th} / 5 MW_e) and diesel generators. As per the previous sensitivity case, there is no additional CAPEX associated with the vSMR, only the OPEX would be extended. The simulation does not call for replacing the diesel generators, as they have a reduced capacity (we have calculated about 40%), for a 20-year service life. The fuel for the extra 6 years is the major OPEX addition, with no new CAPEX for the diesel generators.

The sensitivity case of Scenario (4) with vSMRs, wind/battery and diesel involves three vSMRs (15 MW_{th} / 5 MW_e), three wind turbines, and two diesel generators. Wind turbines are designed for a minimum of 20 years, therefore this is compatible with most scenarios involving wind power (Ortegon et al., 2013; Pinard, 2016). We picked a constant OPEX for wind, consistently with (Pinard, 2016). As per the previous sensitivity case, the diesel generators were extended to 20 years with the extra fuel as additional OPEX.

The creation of an energy hub that operates for 40 or 60 years entails adjusting the operating life of the energy system by extending the middle portion of the electricity and heat demand after Year 9 similarly to Figure 4.14, except that the extension was by 26 years (40-y LoM) and 46 years (60-y LoM). The results are shown in Table 4.13.

Table 4.13: Sensitivity cases illustrating the LCOE changes for different LoM.

Scenario / sensitivity case	LCOE ($CDN/kW·h$_e$) (DR = 5%)				
	Base case	Shorter LoM	Longer life of the energy system / Energy Hub		
	14 years	10 years	(20 years)	40 years	60 years
Scenario (1) – Diesel only	0.281	0.299 (+6.5%)	0.266 (-5.1%)	0.253 (-9.9%)	0.250 (-11%)
Scenario (2) – vSMRs only	0.387	0.496 (+27.9%)	0.300 (-22.6%)	0.237 (-38.8%)	0.222 (-42.6%)
Scenario (3) – vSMR and diesel	0.266	0.372 (+39.7%)	0.220 (-17.2%)	0.190 (-28.7%)	0.183 (-31.4%)
Scenario (4) – vSMR/Wind/battery/	0.279	0.356 (+27.3%)	0.225 (-19.5%)	0.187 (-32.9%)	0.179 (-36.1)

The LCOE increases for all scenarios if the LoM were decreased to 10 years. The relative increase is smaller for the diesel-only scenario, whereas the relative increases would be larger for the scenarios that have vSMRs. This is expected as the capital costs of the technologies are spread over a shorter amount of time, compared to the base scenario. The vSMR-based scenarios (2-4) are capital-intensive, therefore the shorter LoM has a greater impact on LCOE, compared to the diesel-only scenario.

The creation of an energy hub that operates for 40 and 60 years shows significantly lower LCOE figures with longer LoM for the vSMR only scenario. The decrease of LCOEs generally reflect the CAPEX being spread over longer periods (cost of the vSMRs and decommissioning – which would occur once at the end of the respective periods). These sub-scenarios include refuelling at 20 and 40 years (the latter only for the 60-year scenario); disposal of the previous core is built into the cost. Core replacement is treated as OPEX, which is a relatively small cost, compared to cost of the CAPEX.

The LCOE estimates for all scenarios increase with a shorter LoM (10 years), and decrease with longer operating times (increase in the LoM, or the creation of an energy hub in the region). Similarly to the 20-year LoM extension and other demand cases (Table 4.12), the sensitivity cases involving the vSMRs show the most significant LCOE changes with shorter or longer lifetimes, compared to the diesel-only Scenario (1). This is expected, particularly for Scenario (2) (vSMRs only) and is indicative of the longer design life of vSMRs. The benefits are comparatively limited for the diesel-only Scenario (1), because of the fuel requirements varying proportionally with site consumption.

These calculations involving diesel generators (Scenarios 1, 3 and 4) are included for illustrative purposes only, to compare the LCOEs relative to the vSMR-only Scenario (2). Diesel generators and wind turbines were assumed to be replaced every 20 years, on the same schedule as SMR refuelling. As well, the price of diesel fuel and the carbon tax might increase significantly, which is not accounted for in these calculations. In low carbon future projections, the vSMR scenario is likely to be advantageous.

4.6 Sensitivity cases: economics

These sensitivity cases are of high interest to a mine client:

- Increase of CAPEX for the technologies
- Cost of diesel fuel
- Price of carbon, carbon emissions savings;
- Change in discount rate

These sensitivity cases are compared to the base case (5% discount rate, LoM 14 years), see the summary in Table 4.14. In the first sensitivity case, the CAPEX was increased by 25% at installation (Year 1), regardless of what constitutes capital, installation costs, etc. In the second sensitivity case, the diesel fuel cost was increased from \$0.80 to \$0.85/L to Year 4 as per the base scenario, followed by an increase to \$1.20 at Year 5 and beyond. Similarly, the sensitivity case involving the carbon tax used \$20 per tonne of CO_2 in Year 1, it was incrementally increased to \$50 per tonne to Year 4, and kept at \$80 per tonne starting Year 5. Finally, in the last sensitivity case, the discount rate (DR) was increased to 9% in equation (Eq. 2).

Table 4.14: Sensitivities cases of LCOEs for the economic parameters.

	LCOE (\$CDN/kW·h_e)				
Scenario/sensitivity case	**Base case**	**Increased CAPEX**	**Increased diesel fuel cost**	**Increased CO_2 tax**	**Higher discount rate**
Sensitivity parameter	DR 5%	+25%	\$1.20 (+50%)	To \$170/t CO_2	DR 9%
Scenario (1) – Diesel only	\$0.281	\$0.295 (+5.2%)	\$0.352 (+25.3%)	\$0.286 (+2.0%)	\$0.298 (+6.0%)
Scenario (2) – vSMRs only	\$0.387	\$0.461 (+19.0%)	\$0.387 (0%)	\$0.387 (0%)	\$0.460 (+18.7%)
Scenario (3) – vSMR and diesel	\$0.266	\$0.314 (+18.2%)	\$0.273 (+2.7%)	\$0.267 (+0.2%)	\$0.320 (+20.5%)
Scenario (4) – vSMR/ Wind/ battery/diesel	\$0.279	\$0.332 (+18.9%)	\$0.283 (+1.2%)	\$0.280 (+0.1%)	\$0.340 (+21.7%)

Table 4.14 indicates that the scenarios can be categorized into two groups: the diesel-only case (Scenario (1)), and the vSMR-based Scenarios (2-4). Scenario (1) is not very sensitive to the increased CAPEX and the higher discount rate. This is expected, since the CAPEX of the diesel generators makes a small contribution to the LCOE. On the other hand, the LCOE is very sensitive to the price of fuel. We have arbitrarily increased it to \$1.20/L, which increased the LCOE by 25%. The price of diesel would need to rise only to 1.375/L (14 y sensitivity case) or \$1.01/L (20 y sensitivity case) to yield the same

LCOE as the corresponding vSMR-only scenario. The diesel fuel prices are realistic, based on the pump price.

The carbon tax increase to \$80/t CO_2e to year 2023, in the current tax and OBPS regime, yield an LCOE increase of a little less than 1% for the LoM. This equates to an increase in the cost of carbon tax from \$11.53 M (constant tax at \$50/tonne) to \$17.20 M over 14 years. This sensitivity to the Carbon tax is based on the current OBPS regime (Canada, 2020b). An increase to \$170/t CO_2 to year 2030 was recently announced by the Government of Canada (Canada, 2020a; NRF, 2020). If made into law, applying this new carbon tax value to Scenario (1) results in a calculated LCOE of \$0.286 /kW-h (increase of 2% compared to the base case). This represents an LCOE increase of \$26.6M in tax.

The vSMR-based Scenario (2) indicates a high sensitivity to capital costs and discount rates. Since no diesel fuel is consumed in this scenario, nor are there CO_2 gas emissions when producing electricity and heat, the LCOE is not affected when considering diesel fuel cost or carbon tax increases.

The other two Scenarios (3, 4) follow a trend similar to that of Scenario (2). In both these scenarios, the economic model indicates that the diesel generators are used at a low capacity. The sensitivity for CAPEX is dominated by the vSMRs. With the introduction of wind energy, the utilization rate of the diesel generators is lower in Scenario (4). Similarly to vSMRs, wind turbines are capital-intensive and do not consume diesel fuel nor do they produce CO_2 during operation. Therefore, the LCOE calculated for Scenario (4) is more sensitive to CAPEX and discount rate compared to Scenario (3). Since the utilization rate of the diesel generators is low, the sensitivity to the price of diesel fuel and carbon tax is also low, compared to Scenario (1).

5. Discussion

5.1 The base scenarios

This study examined four base scenarios for supplying electricity and heat to a representative mine in Northern Canada. The cost of producing electricity and heat was estimated and compared for the four scenarios described therein using the Levelized Cost of Electricity (LCOE) as the main metric.

The benchmark case, Scenario (1) was based on the current situation at the mine, with diesel generators providing the electricity and heat to the site, supplemented by diesel burners. Scenario (1) (5% discount rate, LoM 14 years) gave an LCOE of \$0.281/kW-h. The SMR-only scenario had the highest LCOE from the four scenarios (\$0.387/kW·h), whereas the scenarios with mixed electricity generation (vSMR with diesel generation, and vSMR with wind turbine and diesel generation) showed LCOE which were cost competitive with Scenario (1), at \$0.266/kW·h and \$0.279/kW·h, respectively.

Scenario (1) with diesel generators was sensitive to the price of diesel fuel. Low fuel prices were assumed in this modeling, increasing only slightly from \$0.80/L up to \$0.85/L over the LoM. The amount of diesel fuel burned for the 14 year LoM was estimated at 558 Million litres, for a cost of \$471.7 M. In comparison, the CAPEX for the diesel generation system was \$92 M. The carbon tax was calculated at \$11.5 M for the LoM, assuming the OBPS carbon tax regime is implemented (above the allowance of 550 t CO_2/GWh), and that the carbon tax, if applicable, increases from \$50/t to \$80/t. Without this allowance, the carbon tax would increase to \$73 M and the LCOE to \$0.306, a 9.0% increase over the base case LCOE. The proposed increases in carbon tax to \$170/t, changes in the OBPS regime and/or diesel price increases would greatly affect this cost. Therefore, Scenario (1) is seen to have a high degree of uncertainty in the long-term cost of energy.

Scenarios (2-4) were dominated by the comparatively high CAPEX of the vSMRs. As per all capital-intensive generation technologies, the LCOE was sensitive to changes in the cost of the technology itself and the discount rate. These scenarios were advantageous on the viewpoints of decreases in diesel fuel consumption and lower carbon taxes. Since the capital cost and discount rate are generally fixed before operations begin, these scenarios were seen to have much less uncertainty in the long-term cost of energy.

Scenario (2) (vSMR only) had the highest LCOE. The vSMRs are underutilized due to the excess capacity installed to ensure sufficient energy during periods of peak demand. Since there is little economic incentive to operate a reactor below capacity (ex. no fuel savings) this underutilization resulted in high a LCOE estimate. However, this scenario also had the lowest carbon emissions of all scenarios included in this study. Nuclear reactors do no emit any GHG's during operation, therefore if Scenario (2) were deployed the mine would not produce any GHG emissions for energy production. In addition, life-cycle emissions (which consider emissions incurred off-site such as emissions during uranium mining, or construction of the SMR) are competitive with renewable energy sources such as wind and solar (Warner & Heath, 2012).

Scenario (3) (vSMRs + diesel generators) had the lowest LCOE. In addition, diesel fuel consumption decreased by about ten-fold compared to Scenario (1), for a calculated savings of \$45 M. The cost of carbon emitted above the cap amounts to \$1.17M, which is another savings compared to Scenario (1).

The LCOE of Scenario (4) with wind was slightly higher than for Scenario (1). The introduction of wind turbines results in a lower utilization rate of the diesel generators. Accordingly, the cost of diesel fuel for the LoM is reduced to \$20.8 M and the calculated cost of the carbon tax is \$0.54 M. Even though this scenario uses less diesel fuel (and produces less CO_2 emissions), it is more capital-intensive than Scenario (3) and this is reflected in the LCOE.

The analysis of the benchmark case (Scenario (1)) with diesel-only suggested that the co-generation capacity would not suffice to produce heat to the mine, the processing plant and the living quarters, and additional heat from burners was needed especially for the cold winter months. This was easy to quantify in Scenario (1) by including the CAPEX, and OPEX of the diesel burner in the PV of Costs to Produce Electricity (equation 1). For Scenarios (2-4), the heat from the steam cycle of the vSMRs was sufficient to meet all heat demand, based on the vendor information (unpubl.). Excess heat (beyond what was required to support mining operations) was not utilized and is assumed to be released to the surroundings.

5.2 Other sensitivities

5.2.1 Additional loads (mine extension, neighbouring community)

The increases of electricity load due to mine extension and providing electricity to the neighbouring community would increase the electricity demand by 3.7% and 10.3%, respectively. Despite these additional loads, all the LCOE values decreased for all four scenarios. This is because these scenarios take advantage of excess capacity that was built to meet peak demand at the main mine site, leading to a lower unit production cost. It is noted that, even if the LCOE values of the four scenarios are lower for both the mine extension and the neighbouring community, additional costs would be incurred due to increased diesel use.

Scenario (1) would necessitate the same increases (3.7% and 10.3%) in fuel consumption to meet the additional demands. The fuel costs would be $489M and $520 M for the two cases, respectively, compared to the original fuel cost of $471M.

Scenario (2) would not incur additional expenses for this additional demand, as the vSMRs have excess capacity, and the OPEX are mostly fixed costs.

In Scenario (3) (vSMRs and diesel generators), fuel costs would increase to $58.7 M and $73.9M for these additional loads, respectively, compared to $45M in the base case.

Fuel costs for Scenario (4) (vSMRs, wind turbines and diesel generators) would increase to $33.2M and $47.4 M, for the two scenarios, compared to $20.8 M in the base case.

5.2.2 Different LoM and energy hub scenarios

10 years (shorter LoM)

This scenario could be caused by an unexpected closure, or an extended shutdown of the mine. The consequence is much higher LCOE values since the energy generation assets are not used for their full operating life. If such an event were to occur, it may benefit the mine to identify another local energy consumer (i.e. a local community) that would purchase the excess energy for the remaining life of the asset. This could allow the mine to maximize the benefit from their investment in energy generation equipment.

20 years (longer LoM)

All four scenarios exhibit a lower calculated LCOE if the mine had a longer operating life. This 20-y timeframe is well within the design life of an SMR and therefore no refuelling or major maintenance is expected. Diesel generators, on the other hands, necessitate periodic maintenance and rebuilds. As engines become older, maintenance costs are expected to increase to the point that the mine owner might decide to replace the generators. It is not unusual for a mine owner to replace generators before the 20y timeframe. This cost is not reflected in the analysis, as it assumed the same CAPEX and OPEX for 20 years. Likewise, wind technologies have a design life of 20-30 years (Pinard, 2016), but the lifetime of the batteries can be much shorter, in the range of 12 years in Northern climates (ibid). As well, efficiency losses over time have been documented for wind farms, however a decrease of life expectancy for the turbines in cold climates is not well documented.

These other factors were out of the scope of this study. It is expected, if included, these factors would negatively affect the LCOE for diesel generators and wind turbines, leading to outcomes that may favor vSMRs, which may offer more certainty in capital cost and performance over the 20 year operating life.

40 and 60 years (regional energy hub)

The LCOE figures decrease significantly with time for the vSMR. In Scenario (2), reductions of 22.6% over 20 years, 38.8% over 40 years, and 42.6% over 60 years are estimated. Based on the vSMR design used for this study, refuelling is required once every 20 years. One core replacement would be necessary for the 40-year scenario, and two core replacements would be needed in the 60-year scenario.

For comparison purposes, diesel fuel use for Scenario (1) amounts to $471M for the 14-y LoM, $723M for the 20-y sensitivity case, $1,562 M for 40 years, and $2,400 M for 60 years, assuming the same price of diesel. In the same 60-y time span for Scenario (2), the cores would be swapped twice for all five vSMRs, at a combined cost of $332M. The carbon emissions during operation from the vSMRs would be zero, averting 7.8 M tonnes of CO_2e that would be released from diesel generators.

5.3 Our results vs other Canadian benchmarks

This report focuses on the needs of an off-grid remote mine. This type of application was investigated as a part of the scope of the Ontario Ministry of Energy SMR deployment feasibility study (Hatch, 2016) and NRCan's Economic and Finance Working Group (EFWG) of the SMR Roadmap (EFWG, 2018). These two reports constituted the authoritative works on SMRs in the Canadian context at the time. These reports had a wide scope and addressed the state of the SMR development in Canada at the time, particularly for technical, financial and socio-economic aspects. A comparison of the LCOE calculated from our study with those from Hatch and EFWG is given in Table 5.1. The comparison should be made with caution as assumptions and cost data are different, as were the objectives of these works.

The Hatch report calculated an LCOE of $0.345/kW·h for diesel generation for remote mines, while they indicated LCOE values between $0.193 - $0.288/kW·h for nine SMR technologies. Their simulations assumed an economic life of 20 years. Scenarios were hypothetical, and some of the methodologies to calculate the LCOE were not detailed. Nevertheless, this study laid the ground work for refinement in the industry.

Table 5.1: Illustrative examples of the LCOEs from our study with those of the Hatch report and the EFWG of the SMR Roadmap.

Scenarios	**LCOE - 20 years (DR 6%) $CDN/kW·h**		
	This work	**Hatch (2016)**	**EFWG (2018) mining**
Scenario (1) – Diesel only	0.271	0.345	0.271 - 0.324 (0.300 median)
Scenario (2) – vSMRs only	0.318	0.193 - 0.288	0.179 - 0.250 (0.211 median)
Scenario (3) – vSMR and diesel	0.233	-	-
Scenario (4) – vSMR, diesel, wind + battery	0.241	-	-

NRCan's roadmap also had a wide scope. Working groups produced topical reports, one of which was the EFWG document, where the work focused on four applications or markets: on-grid, off-grid communities, mining and oil sands. The median LCOEs (6% DR) of $0.246/kW·h was calculated for a 10 MW$_e$ vSMR that could be used by an off-grid remote community (project life 30 years; range $0.190 - $0.311, depending upon assumptions).

For mining, the EFWG report suggested a hypothetical 20 MW$_e$ vSMR and a 20-year project life; the median LCOE (6% DR) was $0.211/kW·h (range $0.179 - $0.250). The benchmark was diesel generation, delivered by barge: the median LCOE (6% DR) was $0.300/kW·h (range $0.271 - $0.324).

Both these works provided a generic benchmark that lacked specific data from a mine and a reactor vendor. The current report provides more refined LCOE estimates for a specific case, using data from a mine and from an SMR vendor (Class 4 estimate; unpubl.). The LCOE estimates of the current work have been adjusted as shown in Table 5.1 for a closer comparison with both the Hatch and EFWG works.

The "diesel only" case, Scenario (1), is somewhat lower than for the previous works. The "vSMR only" case, Scenario (2) values are higher that the LCOEs reported in the other studies, but not drastically higher. The mixed Scenarios (3 and 4) represent the most favorable LCOEs.

5.4 Other factors affecting costs and future work

The work presented in this report has provided LCOE estimates for an off-grid mine in Northern Canada. Many factors have been included, but more detailed analysis is required to understand and quantify the effects of variations in long-term costs. For instance, long term price projections of diesel fuel, the effect of significantly less diesel fuel consumption on diesel price per litre ($/L paid is expected to increase as total amount of fuel purchased is decreased) and the federal carbon tax regime could negatively impact the cost of diesel generation, thus favoring vSMRs.

Externalities such as social acceptance of all technologies presented by local Indigenous Peoples, from mining companies and even society in general would need to be evaluated and costed. This is outside the scope of the current work.

Synergies between SMRs and future technologies such as hydrogen generation are well known (WNA, 2021). Hydrogen gas is a potential source of energy (electricity and heat). It can be produced from water by electrolysis through electrolyzers, stored on-site, and energy can be recovered through fuel cells (Moore & Gnanapragasam, 2018); (WNA, 2021). Some SMR designs can also produce hydrogen directly (WNA, 2021). In most cases, the excess capacity from vSMRs could be used as a clean source of electricity for powering electrolyzers. Hydrogen can be stored on-site for point-of-use, for example, directly at a mine, or in mobile equipment in future mines.

A remote mine has already adopted hydrogen generation in a renewable pilot demonstration (Tugliq, 2016); (Stickler et al., 2017). Since this is a demonstration, the full benefits of the economics are limited, given the secondary uses of hydrogen fuel, low round-trip efficiency and the significant investments (Stickler et al., 2017). Nevertheless, hydrogen production from vSMRs and future uses at a mine are promising; this was outside the scope of the current work.

6. Conclusions

This report provides realistic scenarios of energy production (electricity and heat) for an off-grid mine in Northern Canada. The Scenarios are: (1) diesel generators (benchmark case); (2) vSMR-only; (3) vSMRs and diesel generators; (4) vSMRs, wind turbines and battery, plus diesel generators. Under the base assumptions of a 14-y LoM (including a 5% Discount Rate), Scenario (3) gave the lowest levelized cost of electricity (LCOE), while the SMR-only Scenario (2) had the highest. Sensitivity analyses indicated the following:

- The LCOE of diesel generators was very sensitive to the price of fuel, making long-term costs unpredictable.
- The LCOE of diesel generators was less sensitive than expected to a modest increase in the carbon tax. However, a more significant increase, such as the $170/tonne currently proposed, or a change to OBPS carbon tax regime have the potential to significantly increase costs associated with energy from diesel generators.
- vSMRs are capital-intensive and therefore scenarios that include vSMRs were sensitive to capital costs, discount rate and life of mine (the longer the LoM, the lower the cost per unit energy).
- Additional demand sources (a new mining area of the mine; providing electricity to a neighbouring community) decreased the unit cost of energy (as indicated by the LCOE); this was attributed to a higher utilization rate of the technologies.
- The LCOE of the vSMR-only scenario decreased significantly with longer operation. For illustration purposes, our calculations indicated a ~39% LCOE decrease for 40 years of operation, and a ~43% decrease for 60 years of operation, compared to the 14-year base case (5% DR).

This was due in large part to the long operating life of a vSMR, with no major maintenance or refurbishment needed over the 60 year operating life. This might not be the case for the other technologies (diesel generator, wind turbine), which are expected to require frequent replacements (every 20 years or maybe less).

This study offers a methodology that allows various remote mining scenarios to be assessed and used as a basis to initiate discussions with a vSMR operator for a potential power purchase agreement (PPA). The initial scenario studied here demonstrated vSMRs are economically competitive with diesel generators, and are best utilized in conjunction with other technologies that can complement the vSMRs by providing small amounts of additional energy during periods of peak demand. Furthermore, this work illustrated the potential of an energy hub that could support several mines and local communities in a remote community for many years. Due to the long operating life of a vSMR, it is able to provide reliable power to a region for many years to come. This would not only decrease energy costs (by maximizing the value of the vSMR) but also bring energy price stability to the region which is expected to support economic development.

7. Acknowledgements

The Team gratefully acknowledges the contribution from the Anonymous mining company, both for financial support, for providing valuable knowledge of the mine site operations and energy requirements that were supported by detailed data. M.J. Martin (consultant and MIRARCO Associate, Kingston, ON) helped with the data review with the mining company and the team to June 30, 2020. L. Chee (OPG) also helped interpret the energy profile, and interacted with M.J.M. and the mining company. Direct funding for the project was provided by the mining company and OPG. The team members were also supported by their organizations (in-kind), that is M. Moore and P. Sanongboon (CNL), D. Zekveld (OPG), L. Zephyr (Laurentian University and MIRARCO), and F. Caron (Bruce Power, Laurentian University and MIRARCO). The authors also wish to thank the reviewers (Travis Pettigrew) for their comments.

8. References

AACE. (2021). *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries*. http://library.aacei.org/pgd01/pgd01.shtml

Canada. (2020a). *Pricing carbon pollution*. https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/climate-plan/annex_pricing_carbon_pollution.pdf

Canada. (2020b). *Output-Based Pricing System Regulations* (SOR/2019-266). Government of Canada. http://laws-lois.justice.gc.ca

EFWG. (2018). *Economic and Finance Working Group of the SMR Roadmap*. https://smrroadmap.ca/wp-content/uploads/2018/12/Economics-Finance-WG.pdf

Energy Education. (2020). https://energyeducation.ca/encyclopedia/Levelized_cost_of_energy

GFP. (2019). *Project Description for the Micro Modular Reactor™ Project at Chalk River* (CRP-LIC-01-001). Global First Power. https://iaac-aeic.gc.ca/050/documents/p80182/130911E.pdf

Hatch. (2016). *Feasibility of the Potential Deployment of Small Modular Reactors (SMRs) in Ontario*. Ontario Ministry of Energy. http://ontarioenergyreport.ca/pdfs/MOE%20-%20Feasibility%20Study_SMRs%20-%20June%202016.pdf

Moore, M. A., & Gnanapragasam, N. (2018). Energy storage coupled with vSMR for remote communities. *Pacific Basin Nuclear Conference*, San Francisco, 2018 Sept 30-Oct 5, CW-120200-CONF-026 (R0).

NRF. (2020). *Canada to increase carbon taxes by 566%*. https://www.nortonrosefulbright.com/-/media/files/nrf/nrfweb/knowledge-pdfs/canada-to-increase-carbon-taxes-by-566.pdf?la=en&revision=450e7624-d6bb-487d-abdc-0f5680ce7efa

Ortegon, K., Nies, L. F., & Sutherland, J. W. (2013). Preparing for end of service life of wind turbines. *Journal of Cleaner Production*, *39*, 191–199. https://doi.org/10.1016/j.jclepro.2012.08.022

Pinard, J. P. (2016). *Potential for Wind Energy in Nunavut Communities, prepared for Qulliq Energy Corporation*. https://www.qec.nu.ca/sites/default/files/potential_for_wind_energy_in_nunavut_communities_2016_report_0.pdf

SMR Roadmap. (2018). *A call to action: A Canadian roadmap for small modular reactors*. Canadian Small Modular Reactor Roadmap Steering Committee. https://smrroadmap.ca/

Stickler, A., McKenna, K., Carreau, M., & Delves, D. (2017). *Energy storage*. Hatch. https://www.hatch.com/en/About-Us/Publications/Technical-Papers/2017/10/Energy-Storage

Stripling, W. S. (2015). Wind energy's dirty word: Decommissioning. *Texas Law Review*, *95*, 123.

Tugliq. (2016). *Completion Report Glencore RAGLAN Mine Renewable Electricity Smart-Grid Pilot Demonstration* (ecoEII GC 128296). https://tugliq.com/wp-content/uploads/2019/09/2016-11-11-tugliq-raglan-public-report-en.pdf

UNFCCC. (1998). *Kyoto protocol to the United Nations Framework Convention on Climate Change*. https://unfccc.int/resource/docs/convkp/kpeng.pdf

Warner, E. S., & Heath, G. A. (2012). Life Cycle Greenhouse Gas Emissions of Nuclear Electricity Generation. *Journal of Industrial Ecology*, *16*(s1), S73–S92. https://doi.org/10.1111/j.1530-9290.2012.00472.x

WNA. (2020a). *Heat values of various fuels*. https://www.world-nuclear.org/information-library/facts-and-figures/heat-values-of-various-fuels.aspx

WNA. (2020b). *Small Nuclear Power Reactors*. https://www.world-nuclear.org/information-library/nuclear-fuel-cycle/nuclear-power-reactors/small-nuclear-power-reactors.aspx

WNA. (2021). *Hydrogen production and uses*. https://www.world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses.aspx

Wojtaszek, D. T. (2017). Potential off-grid markets for SMRs in Canada. *CNL Nuclear Review*. https://doi.org/10.12943/CNR.2017.00007.