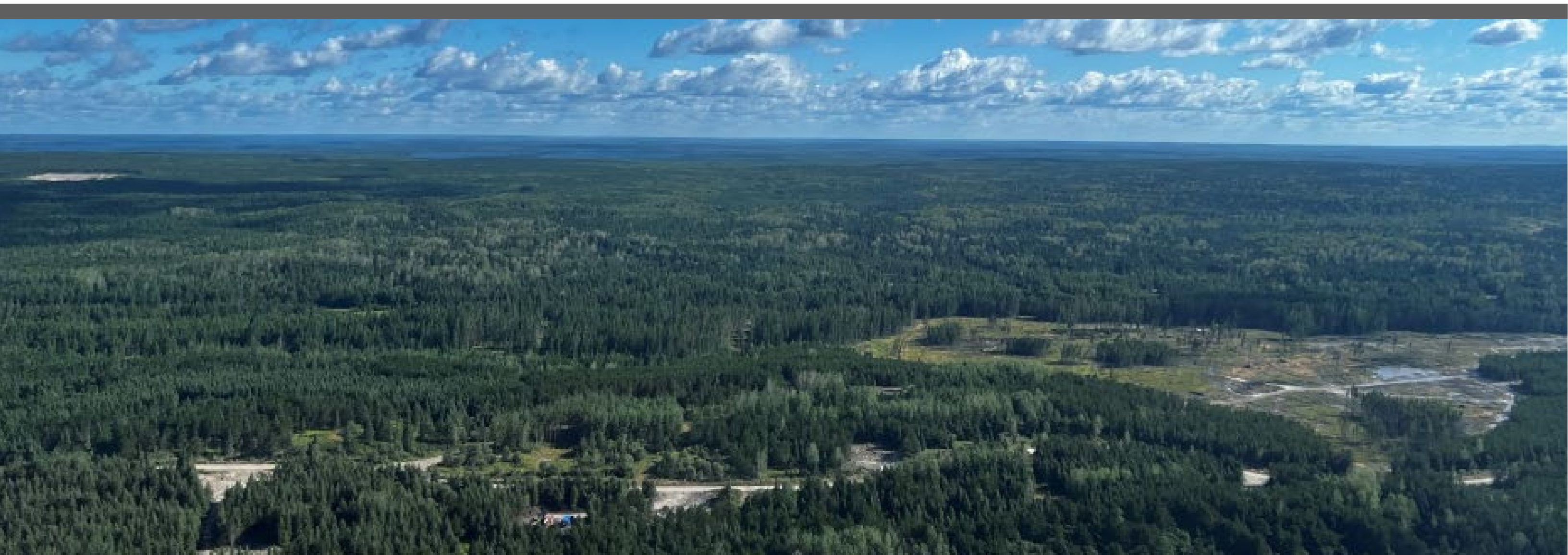
KINROSS Great Bear

Great Bear Gold Project Impact Statement

Appendix W-2:

Best Available Technologies / Best Environmental Practices Determination



GREAT BEAR RESOURCES LTD.

GREAT BEAR PROJECT

BEST AVAILABLE TECHNOLOGIES / BEST ENVIRONMENTAL PRACTICES DETERMINATION

SEPTEMBER 2025

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GREAT BEAR RESOURCES

PROJECT NO.: OMEMA2303
SEPTEMBER 2025

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ABBREVIATIONS

BAT / BEP	best available technologies / best environmental practices
CO_2e	carbon dioxide equivalent
CCUS	carbon capture utilization and storage
EPS	Emissions Performance Standards
ESG	environmental, social and corporate governance
GHG	greenhouse gas
Great Bear Resources	Great Bear Resources Ltd.
ITC	investment tax credit
kg	kilogram
km	kilometres
kt-CO_2e	kilotonnes of carbon dioxide equivalent
kW	kilowatt
kWh	kilowatt-hour
Mt	million tonnes (metric)
Mt-CO_2e	million tonnes of carbon dioxide equivalent
MW	megawatt
MWh	megawatt-hour
Project	Great Bear Project
SACC	Strategic Assessment of Climate Change, 2020
SACC Technical Guide	Draft Technical Guide Related to The Strategic Assessment of Climate Change, 2021
SMR / MMR	small modular reactor / micro modular reactor
tpd	tonnes per day
TISG	Tailored Impact Statement Guidelines
WSP	WSP Canada Inc.

GLOSSARY OF TERMS

Avoided Domestic Greenhouse Gas (GHG) Emissions	GHG emissions that are reduced or eliminated in Canada as a result of the Project. The avoided GHG emissions only apply to the Project's net GHG emissions.
Best Available Technologies / Best Environmental Practices (BAT / BEP)	The most effective measures for reducing GHG emissions during the lifetime of a project. They encompass techniques, practices, technologies (including emerging technologies) that are both technically and economically feasible.
Carbon Dioxide Equivalent (CO_2e)	A unit of measure used to allow the addition of, or the comparison between, gases that have different global warming potentials (GWPs). Since many GHGs exist and their GWPs vary, the emissions are added in a common unit, CO_2e. To express GHG emissions in units of CO_2e, the quantity of a given GHG (expressed in units of mass) is multiplied by its global warming potential.
Great Bear Project or the Project	The Great Bear Project is a proposed mine with supporting facilities that includes construction, operations, and closure and decommissioning phases.
Net-Zero	Project net GHG emissions will equal 0 tonnes of carbon dioxide equivalents. Net GHG Emissions = Direct GHG emissions + Acquired energy GHG emissions – Avoided domestic GHG emissions – Offset measures.
Net-Zero Plan	A credible plan for the Project to achieve Net-Zero by 2050. A Net-Zero Plan does not need to describe every technology or practice the Project will implement over time to achieve net-zero emissions, nor is it a commitment to implement the specific measures identified in the Plan. It is a process to follow in order to make the decisions and investments needed to achieve net-zero emissions by 2050.
Tailored Impact Statement Guidelines	Guidelines for the Preparation of an Impact Statement pursuant to the *Impact Assessment Act*, 2019 for the Great Bear Project, dated August 1, 2024.

TABLE OF CONTENTS

TABLES

FIGURES

APPENDICES

1 INTRODUCTION

1.1 OVERVIEW

Great Bear Resources Ltd. (Great Bear Resources), a wholly owned subsidiary of Kinross Gold Corporation is planning to develop, operate, and reclaim a gold mine (the Great Bear Project or Project) on the Great Bear Property (the Property) located approximately 25 kilometres (km) southeast of the Municipality of Red Lake (Figure 1-1) in northwestern Ontario. The Project will consist of two open pits, underground mining activities, an onsite ore processing facility, and auxiliary operations and administrative activities.

An Impact Assessment pursuant to the *Impact Assessment Act* is required to be completed for the Project. This Best Available Technologies / Best Environmental Practices (BAT / BEP) Determination has been prepared to help describe the predicted environmental impact of the Project. Assessment of climate change and climate action are needed to support the impact assessment process and require a GHG assessment as well as a determination of BAT / BEP and the development of a credible path to achieving net-zero by 2050. The GHG Assessment and Net-Zero Plan are provided under separate cover.

1.2 OBJECTIVE

As a part of Canada’s efforts to avert the impacts of climate change, the federal government enacted the *Canadian Net-Zero Emissions Accountability Act* in June 2021. This legislation outlines the Canadian commitment to achieve net-zero GHG emissions by 2050 and aligns with Great Bear Resources’ senior management strategy, as outlined in their 2023 sustainability and climate reports (Kinross 2023).

This BAT / BEP Determination describes the process of determining the mitigation measures that will be taken to minimize GHG emissions throughout all phases of the Project, including an assessment of current and emerging technologies, and their feasibility for reducing GHG emissions.

This assessment is conducted through six steps, as defined by the Strategic Assessment of Climate Change (SACC) and outlined in Table 1-1 at the end of Section 1 (ECCC 2020).

1.3 PROPOSED PROJECT

Great Bear Resources is planning to develop, operate, and eventually reclaim a gold mine comprised of underground workings and two open pits (LP Central pit and Viggo pit) with associated stockpiles, ore processing facilities and infrastructure. To allow for the development and safe operation of the mine, onsite roads will be constructed with accompanying utilities and a water management and treatment system will be established to facilitate controlled dewatering of the mining area. Ore from the open pit will be processed in an onsite ore processing plant up to a maximum of 15,000 tonnes per day (tpd) and tailings resulting from the processing of ore will be stored in a tailings management facility and a re-purposed open pit (the Viggo management facility).

The main components of the Project include:

- LP Central pit and Viggo pit
- Underground mine accessed via portals, ramps and shaft
- Flood protection berm
- Tailings management facility
- Viggo management facility
- Run of mine stockpile

- Low grade ore stockpile
- Mine rock stockpile
- Overburden stockpile
- Process plant or process plant complex
- Buildings and supporting infrastructure
- Water management and treatment facilities
- Construction camp and permanent camp
- Quarries, and sand and gravel pits.

1.4 ASSESSMENT BOUNDARIES

The assessment boundary defines the scope of direct and indirect emissions for the Project, as well as carbon sink impacts. The Project boundary encompasses the activities within the Property where Great Bear Resources has operational control.

The assessment boundary excludes any upstream and downstream emissions such as transportation of product (doré) offsite, raw materials to site, employees to site, and offsite waste disposal.

This operational boundary defines which GHG emissions sources and carbon dioxide (CO_2) removals are part of the net GHG determination, and which would be considered upstream or downstream (indirect scope 3), avoided emissions, or carbon offsets. The BAT / BEP is specific to the evaluation of technologies and practices to reduce the direct (scope 1) GHG emissions.

The temporal boundaries for this assessment span the construction, operations, and decommissioning and closure phases of the Project. The expected duration of the Project phases are:

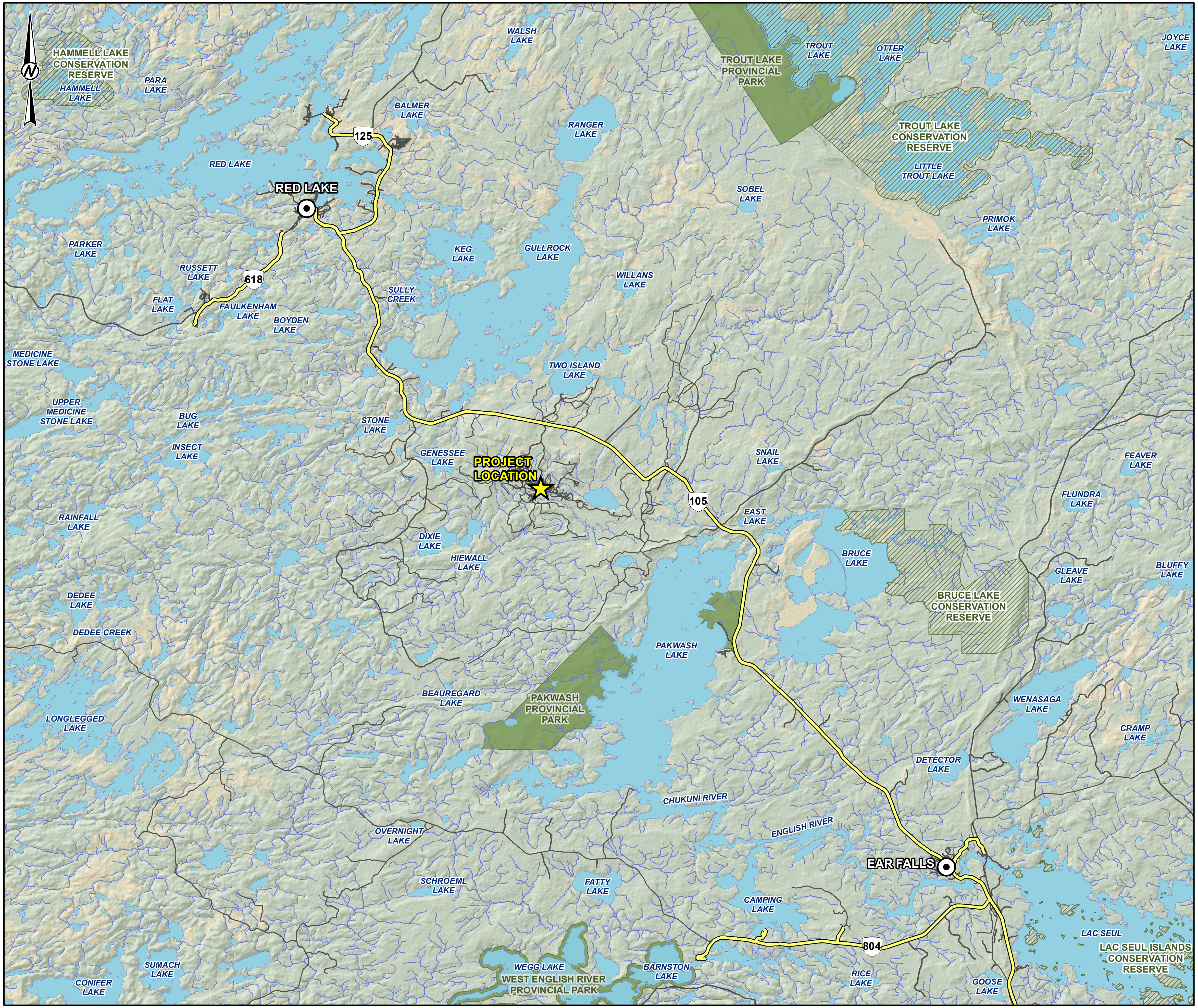
The expected duration of Project phases is approximately:

- Construction (Year -3 to Year -1: three years in length)
- Operations (Year 1 to Year 26: twenty-six years in length)
- Decommissioning and Closure (starting in Year 27 with a three year period of active closure).

After active decommissioning of the site a period of passive closure and environmental monitoring will follow while mine workings fill with water. Minor decommissioning will occur after that period. GHG emissions associated with the passive closure and final closure periods will be limited and not material. As such, only GHG emissions from the construction phase, operations phase, and active period of the closure phase were assessed in this BAT / BEP Determination.

Table 1-1: Steps of the BAT / BEP Determination

No.	Process Step	Description
1	Listing	Develop a list of all technologies and practices, including existing and emerging technologies, based on the identified sources of emissions for the Project during its lifetime.
2	Technical Feasibility Assessment	Identify whether the listed technologies and practices are feasible for implementation based on the specific circumstances of the Project.
3	GHG Reduction Potential Assessment	Identify the GHG reduction potential of each assessed technology and practice assessed on their corresponding sources of emissions.
4	Economic Feasibility Assessment	Evaluate the economic impact of the technologies and practices and determine whether they are feasible or not within the constraints of the Project.
5	Selection of BAT / BEP	Determine which of the technologies and practices are optimal for the Project and provide justifications for the options that are not a BAT / BEP.
6	Review	Impact Assessment Agency of Canada or the relevant lifecycle regulator, with support from expert federal authorities, reviews the BAT / BEP Determination and requests additional information if required.



KEY MAP

SCALE 1:30,000,000

LEGEND

- ★ PROJECT LOCATION
- ⊙ TOWN
- ▨ CONSERVATION RESERVE
- 🟩 PROVINCIAL PARK
- HIGHWAY
- LOCAL ROAD
- RESOURCE/ RECREATION ROAD
- WATERCOURSE
- WATERBODY

0 2.5 5 10
1:250,000 KILOMETRES

NOTE(S)
1. ALL LOCATIONS ARE APPROXIMATE

REFERENCE(S)
1. CONTAINS INFORMATION LICENSED UNDER THE OPEN GOVERNMENT LICENCE - ONTARIO
2. WATERCOURSES AND WATERBODY ACQUIRED FROM LAND INFORMATION ONTARIO (MNRF) AND MODIFIED TO MATCH AERIAL IMAGERY AND LIDAR.
3. ROADS INFORMATION PROVIDED BY KINROSS, AUGUST 2022.
4. COORDINATE SYSTEM: NAD 1983 UTM ZONE 15N

CLIENT
GREAT BEAR RESOURCES

PROJECT
GREAT BEAR GOLD PROJECT

TITLE
PROJECT LOCATION

CONSULTANT

YYYY-MM-DD	2024-10-28
DESIGNED	----
PREPARED	MD
REVIEWED	----
APPROVED	----

PROJECT NO.	CONTROL	REV.	FIGURE
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2 GHG ASSESSMENT

A GHG inventory was prepared for the Project which outlines the GHG emissions associated with the Project. Emission sources considered in the assessment include those that produce GHG, namely carbon dioxide, methane, and nitrous oxide. Project GHG emissions are predominantly the result of fuel combustion onsite, with carbon dioxide making up the majority of the overall GHG emissions. As such, the GHG emissions are expressed in total equivalent GHGs (i.e., carbon dioxide equivalent; CO_2e) (WSP 2024a).

The following emission types were considered in the assessment:

- Direct GHG emissions – scope 1
- Acquired energy GHG emissions – scope 2
- Indirect upstream and downstream GHG emissions – scope 3.

However, only scope 1 and 2 GHG emissions were included in the assessment, as they are owned and within the control of by Great Bear Resources.

Direct GHG Emissions – Scope 1

As per Section 3.0 of the SACC, direct GHG emissions includes carbon emissions occurring from sources that are owned or controlled by Great Bear Resources at the Project. They are generated by activities that are within the defined scope of the Project (ECCC 2020). Examples of these GHG emissions include:

- Mobile combustion (e.g., diesel fuel combustion in haul trucks)
- Stationary combustion (e.g., onsite blasting, camp heating)
- Land use changes (e.g., land clearing deforestation and biomass decay)
- Industrial processes (e.g., ore processing, gold refining)
- Flaring, venting, and fugitive emissions.

These direct GHG emissions are also referred to as scope 1 emissions as per the GHG Protocol (WRI / WBCSD 2004).

Acquired Energy GHG Emissions – Scope 2

As per Section 3.0 of the SACC, acquired energy GHG emissions include emissions from the generation of electricity, heat, steam, or cooling, purchased from a third party by Great Bear Resources for the Project (ECCC 2020). The acquired energy GHG emissions are referred to as scope 2 emissions as per the GHG Protocol.

The BAT / BEP Determination and Net-Zero Plan does not include reduction in the GHG intensity of the electricity supply but includes reductions in electricity demand and substitution of electricity from the grid with renewable generation and the option of purchasing renewable energy credits for the electricity use (WSP 2024b). In other words, as the grid CO_2 intensity improves over time, the scope 2 GHG emissions from the Project will decrease.

Indirect Upstream and Downstream GHG Emissions – Scope 3

Indirect upstream and downstream GHG emissions or carbon removals are those which are a consequence of the Project but occur at GHG sources or sinks not owned or controlled by Great Bear Resources. Indirect emissions are not part of the GHG Assessment nor the BAT / BEP Determination and are also not included in the calculation of net GHG emissions (WSP 2024a).

Although scope 3 emissions are not included in the development of a BAT / BEP Determination, Great Bear Resources will implement measures to identify and reduce upstream and downstream GHG emissions, as stated as an environmental, social, and governance (ESG) Strategic Priority (Kinross 2024).

2.1 GHG EMISSIONS SUMMARY

A summary of the Project's GHG sources and emissions is presented in Table 2-1. This summary shows that the majority of GHG emissions are a result of the natural gas electricity generation to support the grid power limitations at the Project. Diesel consumption for the mobile vehicles and equipment used for mining and material movements at the Project are the second and third highest contributors, at a combined 36% of the total GHG emissions.

The BAT / BEP Determination will take into consideration the grid power limitations to the site when evaluating the technologies / practices available for GHG mitigation. If further electrical power is required as the Project progresses that cannot be provided through the grid, the CO_2 intensity (e.g., tonne of CO_2 per megawatt-hour (MWh)) of each option will be considered in any selection, with priority given to lower CO_2 intensity technologies.

Other considerations taken in this assessment relate to the Project's mining operations. The initial phase of the mine (from Years +1 to +10) will account for emissions from both the open pit and underground mining, however from Year +11 onward the open pit operations will cease, and underground mining will continue until the end of the operations phase. Therefore, emissions associated with the open pit operations will phase out and, after Year +11, GHG reduction measures will address GHG emissions from the underground operations, surface material handling, ore processing, and auxiliary sources.

The abovementioned trends and GHG emissions are summarized on a year-over-year basis as shown in Figure 2-1. It can be noted that GHG emissions from biomass removal will be incurred equally over the first three years of operation. Further, the maximum annual Project GHG emissions occur in Year +4 when there is activity in both the underground mine and open pit. Further information on the quantification of the GHG emissions can be found in the GHG Assessment documented under separate cover.

2.2 BASELINE GHG EMISSIONS SCENARIO

The scenario presented in the GHG Assessment, and captured in Table 2-1, represents the baseline GHG emission that serve as starting point for this BAT/BEP (WSP 2024a). All references to the project baseline scenario used in the BAT / BEP Determination will not include the decarbonization measures already incorporated into the design.

The baseline GHG emissions for each year and for the lifetime of the Project were used in calculating the GHG Reduction Potential of the technologies and practices identified as technically feasible. This GHG reduction potential allowed for the ranking of the BAT / BEP in terms of the impact it may have on achieving net-zero emissions by 2050 and the interim targets established in Net-Zero Plan (WSP 2024b). The interim targets were based upon the baseline GHG emissions scenario as a means to track progress towards net-zero achievement, and to incorporate agility to review and modify the decarbonization efforts if these targets are at risk of not being met.

Table 2-1: Project GHG Emissions by Phase

Category	Phases			Total [1] (kt-CO_2e)	Percent of Total (%)
	Construction (kt-CO_2e)	Operations (kt-CO_2e)	Decommissioning and Closure (kt-CO_2e)		
Direct - Open Pit - Diesel Fuel	140.0	694.4	17.2	851.6	17%
Direct - Underground Mine Fleet - Diesel Fuel	11.5	956.6	2.9	971.0	19%
Direct - Quarry, Borrow and Tailings - Diesel Fuel	24.3	210.6	24.3	259.2	5%
Direct - Explosives	2.2	25.9	0.0	28.1	<1%
Direct - Heating - Natural Gas	40.4	613.0	18.9	672.3	13%
Direct - Electricity Generation - Natural Gas	0.2	1,796.2	0.0	1,796.4	36%
Direct - Construction Electricity Generation - Diesel Fuel	56.2	0.0	0.0	56.2	1%
Direct – Operations Electricity Generation - Diesel Fuel	13.2	114.4	13.2	140.8	3%
Direct – Domestic Waste Landfill [2]	0.2	14.3	2.5	17.0	<1%
Direct - Land Use Changes from Biomass Removal	146.2	0.0	0.0	146.2	3%
Indirect - Acquired Energy [3]	7.6	69.4	0.4	77.4	2%
Net GHG Emissions	**442.1**	**4,496.2**	**79.6**	**5,017.9**	**—**

Notes:

1 *Subtotals may not add to totals due to rounding.*

2 *A domestic landfill is not proposed for the Project. The potential associated emissions from a landfill and potential mitigation measures, are considered in this document as a contingency should a landfill be required in the future.*

3 *GHG emissions associated with the removal of biomass during site clearing and GHG emissions associated with the indirect acquired energy are not part of a BAT / BEP Determination as per the SACC Technical Guide (ECCC 2021).*

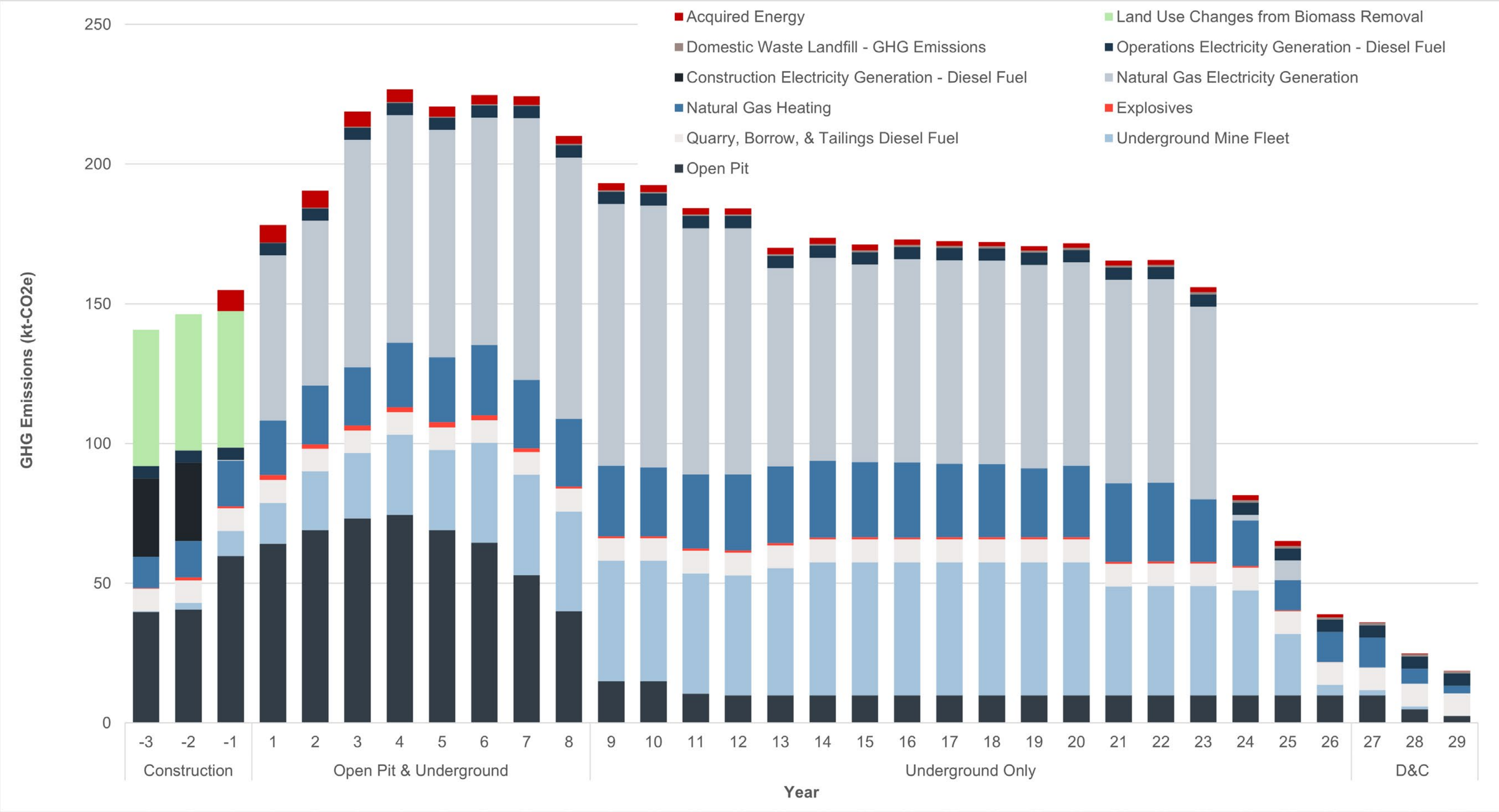

Figure 2-1: Annual Breakdown of GHG Emissions

3 FRAMEWORK AND METHODOLOGY

The *Canadian Net-Zero Emissions Accountability Act* is a legislation that the federal government has enacted as part of their commitment to achieve net-zero GHG emissions by 2050. The Act establishes a legally binding process to set five-year national emissions-reduction targets as well as develop credible, science-based emissions-reduction plans to achieve each target; the 2030 GHG emissions target is set at 40 to 45% below 2005 levels by 2050 (Government of Canada 2022).

The 2030 Emissions Reduction Plan details a roadmap of how this 2030 target will be achieved. The economy-wide target for 2030 is a reduction of 40% to 443 million tonnes (Mt)-CO_2e; to achieve this, the target reduction for the heavy industry sector is 39% (to 52 Mt-CO_2e). Decarbonizing the heavy industry sector is essential for meeting Canada's 2030 climate target, and especially net-zero emissions by 2050 (Government of Canada 2022).

3.1 STRATEGIC ASSESSMENT OF CLIMATE CHANGE

The SACC was developed by Environment and Climate Change Canada (ECCC) to enable consistent, predictable, efficient, and transparent consideration of climate changes throughout the impact assessment process for designated projects under the *Impact Assessment Act*. The Draft Technical Guide Related to the SACC (SACC Technical Guide) was also published to be used as a more comprehensive basis for this GHG Assessment (ECCC 2021).

The BAT / BEP Determination has been prepared following the SACC and SACC Technical Guide. It is based upon the GHG Assessment for the Project where the GHG emissions associated with all phases of the Project are quantified to present the net GHG position for each year of the Project and the cumulative lifetime net GHG emissions. The net GHG emissions consider the relevant and significant direct GHG emissions, acquired electricity, and the effect of land use changes on GHGs (WSP 2024a).

In addition to achieving net-zero annual emissions by 2050, Great Bear Resources will be implementing measures to reach their target of a corporate average emission intensity reduction of 30% by 2030, as outlined in their corporate climate and sustainability reports (Kinross 2024).

3.2 TAILORED IMPACT STATEMENT GUIDELINES

The Tailored Impact Statement Guidelines (TISG) require that Great Bear Resources complete a BAT / BEP Determination that will assess potential GHG mitigation measures throughout all phases of the Project, as described in Section 5.1.4 of the SACC. Additional guidance is provided in Section 3.2 of the SACC Technical Guide.

3.3 BAT / BEP DETERMINATION PROCESS

As per Section 3.2 of the SACC Technical Guide, the BAT / BEP Determination is a tool to support the goal of achieving Net-Zero and its goal is to help identify GHG mitigation measures and minimize GHG emissions through these principles outlined below (ECCC 2021).

- Emphasize the reduction of the net GHG emissions of the Project as early as practical during the Project lifetime;
- Reduce energy and resource consumption at the source, therefore prioritizing the reduction of direct and acquired energy GHG emissions; and
- BAT / BEP Determination is an ongoing process, which should be performed iteratively over the lifetime of the Project to include any emerging technologies and practices that may become technically and/or economically feasible.

The BAT / BEP selection process involves a structured analysis developed into six steps to identify and select the most effective technologies, techniques and practices that are technically and economically feasible to minimize GHG emissions associated with the Project. These steps are included in Table 2 of the SACC. Each of the steps is further described below, with a description on how these were applied to the BAT / BEP for the Project.

3.3.1 LISTING OF TECHNOLOGIES AND PRACTICES

The first step of the BAT / BEP Determination is to identify the sources of emissions in efforts to establish project-wide solutions that would minimize GHG emissions, as outlined in Table 2 of the SACC (ECCC 2021). These are sources that generally contribute 1% or more of the total direct GHG emissions of the Project (ECCC 2021).

The emission sources groupings evaluated in this assessment are those that contribute more than 1% of the total direct GHG emissions of the Project, and include:

- Open pit mine and surface fleet
- Underground mine fleet
- Onsite power generation
- Heat for the underground mine, ore processing, and comfort heating of buildings
- Supplemental power generation (backup power)
- Explosives use.

A full list of the technologies and practices pertaining to these sources and source grouping is provided in Section 4.0, as well as a description of each and considerations that may influence the BAT / BEP Determination.

3.3.2 TECHNICAL FEASIBILITY ASSESSMENT

The second step of the BAT / BEP Determination is the technical feasibility assessment, as outlined in Section 3.2 of the SACC Technical Guide.

Each technology and practice was evaluated based on their technical feasibility keeping in mind the constraints of the Project. The technical feasibility was completed following the guiding questions outlined in Table 10 of the SACC Technical Guide. All technologies and practices were assigned a Technology Readiness Level (TRL) from 1 to 9 to characterize the maturity of the technology and, where practical, an estimation of the time to maturity for the technologies. Each practice and technology was classified as one of the four categories presented in Table 3-1. The TRL scale was used to identify the technologies demonstrated effective in the mining sector and generally aligns with the scale published by Innovation Canada (Innovation Canada 2018).

Technologies and practices deemed technically feasible will be carried forward to the BAT / BEP Determination, where other factors will be introduced to allow for detailed evaluation and identification of the technologies deemed BAT / BEP and those carried forward to the Net-Zero Plan at this time (WSP 2024b).

3.3.3 GHG REDUCTION POTENTIAL ASSESSMENT

The third step of the BAT / BEP Determination is the GHG reduction potential assessment, as outlined in Section 3.2 of the SACC Technical Guide. Each technology and / or practice deemed as technically feasible was assessed by its GHG reduction potential. This reduction potential was justified and calculated through references from other examples of implementation and current literature. This exercise provided further refinement of the list of practical BAT / BEP.

The GHG reduction potential is presented in terms of a total GHG reduction, in tonnes CO_2e, and as a percentage of the total lifetime baseline emissions. The supporting analysis and calculations are provided in Appendix A.

3.3.4 ECONOMIC FEASIBILITY ASSESSMENT

The economic feasibility assessment is the first part of the fourth step of the BAT / BEP Determination, as outlined in Section 3.2 of the SACC Technical Guide.

In this part the remaining technologies and practices were evaluated against their economic feasibility. Which considers current capital expenditures and operating costs, as well as forecasts, where applicable.

3.3.5 ADDITIONAL CONSIDERATIONS

Additional considerations are included as the second part of the fourth step of the BAT / BEP Determination, as outlined in Section 3.2 of the SACC Technical Guide. The remaining technologies and practices that were not otherwise excluded due to technical feasibility, GHG reduction potential, or economic feasibility, were subjected to additional considerations (ECCC 2021).

The additional considerations were determined by the guiding questions in Table 12 of the SACC Technical Guide and consider Project-specific characteristics such as the reliance on an upgrade of electricity supply from the Ontario grid, potential co-benefits, consequential environmental or social effects, and upstream and downstream considerations (e.g., supply chain constraints and scope 3 emissions).

3.3.6 SELECTION OF BAT / BEP

The selection of the BAT / BEP is the fifth step of the BAT / BEP Determination, as outlined in Section 3.2 of the SACC Technical Guide. The selection of the BAT / BEP combines the technologies and practices that were not eliminated in the previous steps. Scenarios in which GHG emissions are minimized are developed by considering all emission sources and potential trade-offs and interactions between the various practices and technologies. The selection of BAT / BEP prioritizes reducing emissions permanently early in the Project and targeting the largest sources of emissions of the Project (ECCC 2021). This results in the largest reduction in the net GHG emissions over the Project lifetime.

Various scenarios were considered where it was feasible to implement the technologies and practices, and combinations thereof, including emerging technologies that may become technically and economically feasible during the Project lifetime. The selection of BAT / BEP is included in Section 5.0 of this report for the various sources of emissions.

Table 3-1: Categorization of Technical Feasibility used in BAT / BEP Determination

Category	Technology Readiness Level (TRL)	Description
Technically Feasible	9	Commercially available and wide adoption in the mining sector
Technically Feasible, Project Specific Barriers	9	Commercially available Limited adoption in the mining sector Implementation barriers (zero-carbon electricity, supply chain)
Technically Feasible, Emerging	7 - 8	Not in wide commercial use, pilot projects
Technically Infeasible	1 - 6	Demonstration of concept, research and development, planning stages of pilot projects

Table 3-2: Categorization of Economic Feasibility used in BAT / BEP Determination

Category	Description
Low	Limited capital expenditures or design modifications required for implementation. Operating expenses associated with adoption lower than, equal to, or slightly higher than baseline.
Medium	Capital expenditures and / or design modifications required for implementation. Capital and operating expenses are not expected to have a net present cost that is substantially higher than baseline. Additional costs are balanced by certainty in achieving GHG reductions with implementation.
High	High capital and operating costs result in a net present cost that is substantially higher than baseline and may affect the economic viability of the Project. Uncertainty of achieving GHG reductions do not warrant the investment.

4 IDENTIFICATION OF TECHNOLOGIES AND ENVIRONMENTAL PRACTICES

The SACC Technical Guide defines BAT / BEP as the most effective technologies, techniques, or practices, including emerging technologies, that are technically and economically feasible for reducing GHG emissions over the lifetime of the Project. In alignment with Step 2 of the BAT / BEP Determination process, as outlined in Section 3.2 of the SACC Technical Guide, a listing of potential GHG reduction technologies and practices was developed. The technologies and practices include both available and emerging technologies that may be suitable for an open pit and underground mine.

The technologies and practices have been categorized by the main sources or source groupings for the Project which align with the categories established in the GHG Assessment. The seven categories were established based upon the energy source or the nature of the activity that generates the GHG emissions.

For each technology and practice, a brief description is provided along with information on the technology. The additional considerations fulfil Step 4B of the BAT / BEP Determination process and were used to evaluate whether a technology or practice may have secondary or collateral effects or notable constraints that would influence the decision-making.

The list of technologies and practices reflect the options available at the time of this report. It is anticipated that additional options will emerge as the Net-Zero Plan is implemented, as there are substantial resources working on progressing technologies to facilitate the energy transition and decarbonization (WSP 2024b).

The technology and practices considered for the BAT / BEP are presented in Appendix A Tables A-1 to A-21, as outlined below:

- Table A-1: Fuel Switching to Renewable Diesel
- Table A-2: Fuel Switching to Biodiesel
- Table A-3: Electrification with Tethered Equipment
- Table A-4: Fleet Optimization
- Table A-5: Trolley Assist
- Table A-6: In Pit Crushing and Conveyance
- Table A-7: Battery Electric Vehicles and Equipment – Underground Mining Fleet
- Table A-8: Underground Shaft and Hoist
- Table A-9: Ventilation on Demand
- Table A-10: Renewable Electricity Microgrid
- Table A-11: Co-generation
- Table A-12: Battery Energy Storage Systems
- Table A-13: Explosives Use
- Table A-14: Natural Gas Power Generation
- Table A-15: Renewable Natural Gas
- Table A-16: Carbon Capture, Utilization and Storage
- Table A-17: Heat Recovery and Heat Exchangers
- Table A-18: Air Source Heat Pumps

- Table A-19: Geothermal and Ground Source Heat Pumps
- Table A-20: Hydrogen Fuel Cells
- Table A-21: Hydrogen Internal Combustion Engines
- Table A-22: Hydrogen Boilers and Furnaces
- Table A-23: Nuclear Small Modular Reactors (SMR) and Micro Modular Reactors (MMR).

Each table includes a brief description of the technology or practice and its respective TRL rating. As per Step 3 listed in Section 3.2 of the SACC Technical Guide, the table describes several other considerations relating to the GHG reduction potential in terms of functional or environmental impacts of the BAT / BEP. This includes the technology’s reliance on power, potential secondary environmental effects of implementing the BAT / BEP, and effects on scope 3 emissions through upstream and downstream considerations.

Following Step 4A listed in Section 3.2 of the SACC Technical Guide, the BAT / BEP details the economic feasibility in terms of the capital expenditures, operating and maintenance costs, opportunities for government incentives, subsidies or grants, and potential impacts on the carbon pricing program.

As per Step 4B listed in Section 3.2 of the SACC Technical Guide, there were additional considerations made in the selection of potential BAT / BEP. These additional considerations involve Project-specific conditions, including the operations at the Project, the restrictions of Ontario’s grid capacity at the Project, the climate in the region, and the location of the Property. These constraints were considered when evaluating potential BAT / BEP.

5 BAT / BEP DETERMINATION

Based upon the approach presented in the SACC for the BAT/ BEP Determination, the technologies and practices were evaluated to determine which are BAT / BEP in that they are technically feasible, widely demonstrated at comparable sites, and are not economically infeasible relative to the costs of the technologies and practices considered in the mine planning and for the baseline GHG inventory.

The BAT / BEP Determination process is intended to establish an organized mechanism to rank and evaluate feasible technologies and practices to reduce energy consumption and mitigate GHG emissions. This process will provide additional certainty in decision-making that the measures to be implemented will achieve the GHG reductions needed and will provide awareness of the anticipated costs, potential risks, and secondary effects that may result from implementation.

There are a number of constraints and barriers associated with the Project that influenced the selection of BAT / BEP, notably that the regional electrical grid cannot currently supply the full power needs of the Project, the regional natural gas pipeline system within the existing Enbridge distribution network cannot supply the full power needs of the Project, climate, and the lifetime of the open pit mining. Great Bear Resources is actively working to minimize these barriers, particularly in regard to investigating the ability to secure sufficient electricity supply from the regional grid.

This BAT / BEP Determination is considered to be preliminary at this early stage of planning and design. Great Bear Resources has also been undertaking feasibility studies for a number of the technologies, with the findings of these studies taken into consideration in the evaluation of the GHG reduction technologies and practices.

The BAT / BEP Determination considers only direct GHG emissions (scope 1). It is noted that the Net-Zero Plan includes indirect, acquired electricity to be reduced to achieve net-zero GHG emissions per the SACC definition (WSP 2024b). There are also interdependences to be accounted for, as the reduction of direct emissions through electrification and the use of grid supplied electricity will increase acquired energy emissions and/or on-site power generation.

The evaluation of each technology and practice is summarized in Tables 5-1 to 5-6, categorized by source grouping:

- Table 5-1: Open Pit Operations and Surface Fleet
- Table 5-2: Underground Vehicles and Equipment BAT / BEP Evaluation
- Table 5-3: Onsite Power Generation
- Table 5-4: Underground, Process, and Comfort Heating
- Table 5-5: Supplemental Power Generation (Diesel Backup)
- Table 5-6: Explosive Usage.

The categories presented in Tables 5-1 through 5-6 include the technical feasibility, economic feasibility, and GHG reduction potential, which were the basis for the BAT / BEP Determination. In addition to these criteria, other site-specific factors described in Section 4.0 were taken into consideration.

With respect to the GHG reduction potential, the technologies and practices with high potential for reducing lifetime GHG emissions were the electrification of surface and underground diesel-powered equipment and vehicles, fuel substitution to hydrogen or low-carbon alternatives, and ventilation-on-demand.

A quantitative analysis of the GHG reduction potential was completed for each technically feasible technology, with the reduction potential determined as a percentage of the total lifetime GHG baseline. For the purposes of this assessment, the GHG baseline scenario was defined as the GHG inventory presented in the GHG Assessment.

Using these criteria, the following are the outcomes of the BAT / BEP Determination:

- Open pit electrification of haul trucks was deemed not technically feasible
- Trolley assist, in-pit crushing and conveyance, cogeneration and CCUS were deemed not economically feasible at this time
- Electrification, biodiesel substitution, autonomous mining and geothermal energy use were deemed not feasible due to Project constraints
- Hydrogen as a fuel, nuclear and green explosives were deemed not feasible due to technology readiness for this application.

In accordance with Step 5 listed in Section 3.2 of the SACC Technical Guide, two scenarios for decarbonization based upon the information available at this time was selected and carried forward to the Net-Zero Plan, with the selection of BAT / BEP for different Project phases.

The emission intensities (excluding carbon sink impacts) were determined in the GHG Assessment, as follows:

- Average Annual Operations: 13.8 t-CO_2e/kg-gold (Year +1 to +26)
- Maximum Annual Year of Operations: 19.5 t-CO_2e/kg-gold (Year +3).

As the GHG intensity of a mine will vary based on factors including the energy sources, the GHG intensity of the electricity grid and grid capacity, deposit grade, location of the processing facility and the type of mine, it is difficult to find projects that are directly comparable for benchmarking. For this reason, two sources of potential benchmarking information were considered:

- The global average carbon intensity for on-grid gold production, estimated at 27.7 t-CO_2e/kg-gold, and for gold mines in Canada an intensity of 8.6 t-CO_2e/kg-gold is reported (Ulrich et al. 2022).

  Publicly availably intensities via corporate ESG reporting for the larger Canadian and global mining companies. Emission intensities were reported for 15 gold mining operations (12 in Canada, 4 in the United States) with a range of 3.2 to 50.8 t-CO_2e per kg-gold and an average of 17.6 t-CO_2e/kg-gold. The highest GHG intensities were for the four sites in the United States and two mines in Nunavut that do not have access to the electrical grid. The ten Canadian mines that are powered from the electrical grid had GHG emission intensities of 3.2 to 16.5 t-CO_2e/kg-gold, and the average intensity of these mines was 7.5 t-CO_2e/kg-gold.

Based upon the review of corporate ESG reporting, in general high-performing gold mining operations are those with access to low-carbon intensity electricity grids. Ulrich et al. (2022) support this finding noting that Canada’s low carbon electricity supply is a contributing factor to lower GHG intensities relative to the global average.

With the implementation of the GHG reduction technologies and practices, the Project emission intensity will decrease notably as electricity supply from the Ontario grid increases, noting that the Independent Electricity System Operator is examining pathways to decarbonize the grid by 2035 (IESO 2022).

Table 5-1: Open Pit Operations and Surface Fleet BAT / BEP Evaluation

Source of Emission	Technology / Practice	Technical Feasibility	GHG Reduction Potential	Economic Feasibility	Notes
Open Pit Fleet	Diesel to Renewable Diesel	Technically Feasible, Project Specific Barriers	Moderate	Low / Medium	Constraints on renewable content in cold weather, supply chain limitations and economic feasibility.
Open Pit Fleet	Diesel to Biodiesel	Technically Feasible, Project Specific Barriers	Moderate	Low / Medium	Constraints on renewable content in cold weather and supply chain limitations.
Open Pit Fleet	Tethered Equipment: Electric Shovels and Drills	Technically Feasible, Project Specific Barriers	High	Medium / High	Electricity grid power supply constraints Additional 4-5 MW to power equipment (2.4 MW for electric shovels only). Shown 94% reduction in GHG emissions with use of electric shovels and drills in place of diesels (10.5 kt).
Open Pit Fleet	Fuel Tracking / Optimization	Technically Feasible	Low	Low	Average 3% reduction shown on fuel optimization alternatives.
Open Pit Fleet	Anti-idling	Technically Feasible	Low	Low	Average 3% reduction shown on fuel optimization alternatives.
Open Pit Fleet	Trolley Assist	Technically Feasible, Project Specific Barriers	High	Medium / High	Electricity and life of mine constraints.
Open Pit Fleet	Electrification – Battery Electric Vehicles	Not Feasible	Not Assessed	Not Assessed	Not applicable
Open Pit Crushing	In-pit Crushing and Conveyance	Technically Feasible, Project Specific Barriers	Medium	Medium	Constraints on electricity supply for Phase 1, Short lifespan of open pit (minimum 10 years recommended for in-pit crushing and conveyance) Throughput insufficient to justify in pit crushing / conveyance infrastructure)
Open Pit Fleet	Hydrogen Fuel Cell	Technically Feasible, Emerging	High	Low	Technology still in early development, another 5-10 years expected for maturity.
Open Pit Fleet	Hydrogen Internal Combustion Engines	Technically Feasible, Emerging	Moderate	Low	Technology still in early development, another 5-10 years expected for maturity.
Open Pit Fleet	Autonomous vehicles	Technically Feasible, Project Specific Barriers	Low	Medium / High	Not applicable

Table 5-2: Underground Vehicles and Equipment BAT / BEP Evaluation

Source of Emission	Technology / Practice	Technical Feasibility	GHG Reduction Potential	Economic Feasibility	Notes
Underground Fleet	Diesel to Renewable Diesel	Technically Feasible, Project Specific Barriers	Moderate	Low / Medium	Constraints on renewable content in cold weather, supply chain limitations and economic feasibility
Underground Fleet	Diesel to Biodiesel	Technically Feasible, Project Specific Barriers	Moderate	Low / Medium	Constraints on renewable content in cold weather and supply chain limitations
Underground Fleet	Fuel Tracking and Optimization	Technically Feasible	Low	Low	Average 3% reduction shown on fuel optimization alternatives
Underground Fleet	Anti-idling	Technically Feasible	Low	Low	Average 3% reduction shown on fuel optimization alternatives
Underground Fleet	Electrification – Battery Electric Vehicles	Technically Feasible, Project Specific Barriers	High	High	Electrification may be carried out in two phases. Phase 1: Load Haul Dump Only +1 MW additional electricity Underground Trucks Electrification +1 MW Other Equipment + 1 MW Electricity demand increase of 3-4 MW Phase 2: Underground fleet to battery electric vehicles increases electricity demand by 5-6 MW
Underground Fleet	Hoist	Technically Feasible, Project Specific Barriers	High	Medium / High	Constraints on Electrification 2,575 kW installed power, 13,130 kg payload
Ventilation	Optimized Ventilation-on-Demand	Technically Feasible	High	Medium	Not applicable
Underground Fleet	Trolley Assist	Technically Feasible with Constraints	High	Medium / High	Constraints on grid electricity supply
Underground Fleet	Hydrogen Fuel Cell	Technically Feasible, Emerging	High	Low	Technology in development, 5 to 10 years expected for maturity
Underground Fleet	Hydrogen Internal Combustion Engines	Technically Feasible, Emerging	Moderate	Low	Technology in development, 5 to 10 years expected for maturity
Underground Fleet	Autonomous vehicles	Technically Feasible, Project Specific Barriers	Low	High	Not applicable

Table 5-3: Onsite Power Generation Best Available Technologies / Best Environmental Practices Evaluation

Source of Emission	Technology / Practice	Technical Feasibility	GHG Reduction Potential	Economic Feasibility	Notes
Electricity Generation	Transmission Line Upgrade to Access Electricity from Ontario Grid	Technically Feasible	High	High	Focused priority to decarbonize. Engaging with Regional grid operator but not in the Project's control
Electricity Generation	Natural Gas for Internal Combustion	Technically Feasible, Project Specific Barriers	Medium	Medium	Natural gas pipeline supply constraints
Electricity Generation	Renewable Natural Gas	Technically Feasible, Project Specific Barriers	High	Medium	Supply chain constraints
Electricity Generation	Hydrogen	Technically Feasible, Emerging	Not Assessed	Not Assessed	Implementation in 5 to 10 years for power generation. research and development stage, limited deployment
Electricity Generation	Cogeneration	Technically Feasible	Medium	High	Pending location and layout of facilities
Electricity Generation	Hybrid, introducing renewable solar, wind, biomass	Technically Feasible	High	High	Not applicable
Electricity Generation	Nuclear (SMR / MMR)	Technically Feasible, Emerging	High	High	Technology in development, 10 years expected for maturity
Electricity Generation	Carbon Capture	Technically Feasible, Emerging	Not Assessed	Not Assessed	Not applicable

Table 5-4: Natural Gas Heating BAT / BEP Evaluation

Source of Emission	Technology / Practice	Technical Feasibility	GHG Reduction Potential	Economic Feasibility	Notes
Underground Heating	Heat recovery and heat exchangers	Technically Feasible	Medium	Medium	Not applicable
Underground / Building Heating	Air to air heat pumps / air source heat pump	Technically Feasible, Project Specific Barriers	Medium	Medium	Technology has not been implemented in northern Ontario regions due to climate and geological constraints
Underground / Building Heating	Ground source heat pump	Technically Feasible, Project Specific Barriers	Medium	Medium	No noted current uses in project region
Underground / Building Heating	Renewable Natural Gas	Technically Feasible, Project Specific Barriers	High	Medium	Supply chain constraints
Building Heating	Hydrogen boilers	Technically Feasible, Emerging	High	Low	Technology in development, 5 to 10 years expected for maturity

Table 5-5: Supplementary Electricity Generation (Diesel Generators) BAT / BEP Evaluation

Source of Emission	Technology / Practice	Technical Feasibility	GHG Reduction Potential	Economic Feasibility	Notes
Diesel Generators	Natural Gas Generators	Technically Feasible, Project Specific Barriers	Moderate	Low / Medium	Limitations in natural gas supply
Diesel Generators	Diesel to Renewable Diesel	Technically Feasible, Project Specific Barriers	Moderate	Low / Medium	Constraints on renewable content in cold weather
Diesel Generators	Diesel to Biodiesel	Technically Feasible, Project Specific Barriers	Moderate	Low / Medium	Constraints on renewable content in cold weather and supply chain limitations
Diesel Generators	Battery Electric Storage System	Technically Feasible, Project Specific Barriers	Moderate	High	High capital and operating costs

Table 5-6: Explosive Use BAT / BEP Evaluation

Source of Emission	Technology / Practice	Technical Feasibility	GHG Reduction Potential	Economic Feasibility	Notes
Blasting	Green bulk explosives or reformulations to reduce GHGs	Technically Feasible, Emerging	High	Medium	Supply chain constraints
Blasting	Optimizing blasts	Technically Feasible	Low	Low	Not applicable

6 SUMMARY OF FINDINGS

The Project will emit greenhouse gases primarily from the energy demands that include:

- Electricity for the processing of ore, underground ventilation and other requirements
- Natural gas for heating of surface structures and the underground mine
- Diesel fuel for the surface and underground fleets and auxiliary vehicles.

A range of options for reducing GHG emissions were identified. Key considerations and constraints associated with the Project were described, which included: (i) the availability of sufficient electricity from the Ontario grid to support baseline demand as well as additional demand from the electrification of equipment as a decarbonization option, (ii) the availability of natural gas to support heat demand and electricity production as a lower carbon alternative to diesel generation, (iii) local climate conditions and cold winters, and lack of a robust supply chain for low- and zero- carbon alternatives.

After reviewing the technical and economically feasible technologies and practices available for different sources of emissions, the measures deemed technically feasible are presented in Table 6-1 with the conclusions of the BAT / BEP Determination. There are two outcomes of the BAT / BEP determination presented in this table: those categorized as technically feasible and implemented and those deemed technically feasible but are either still emerging or are subject to project-specific constraints. Those deemed not feasible for the Project are not presented in Table 6-1. Supporting calculations are provided in Appendix A.

Implementation of the BAT / BEP refers to advancing the technology or practice to detailed feasibility studies and including the technology or practice in the Net-Zero Plan to achieve the interim reduction targets and net-zero by 2050. Technologies and practices which are technically feasible and either emerging or subject to project-specific constraints will be reconsidered each year with the review of the Net-Zero Plan. Technical considerations, economic considerations, and the GHG reduction potential of the measures are included in Table 6-1 to justify selection of the BAT / BEP to be implemented (WSP 2024b).

Credible paths to achieving net-zero emissions by 2050 have been developed and are presented in the Net-Zero Plan (under separate cover). The paths demonstrates that net-zero is achievable, and will form the basis of target setting, advanced feasibility studies, and decision-making related to the decarbonization strategy for the Project. The technologies and practices selected by Great Bear Resources, and the schedule of implementation, will be developed as the Project design is advanced.

Table 6-1: BAT / BEP Selection Summary

Source of Emission	Technology / Practice	BAT / BEP Selection	General Considerations
Surface Fleet	Diesel to Renewable Diesel	Feasible	Not applicable
Surface Fleet	Diesel to Biodiesel	Future consideration (feasible with Project constraints)	Not applicable
Surface Fleet	Tethered Equipment: Electric Shovels and Drills	Feasible	Not applicable
Surface Fleet	Electrification (expanded grid connection)	Feasible with Project constraints	Considers improvements to the regional transmission line to increase grid electricity.
Surface Fleet	Fuel Tracking and Fleet Optimization	Feasible	Reduction potential considers various optimization tools (fuel tracking, anti-idling, preventive maintenance).
Surface Fleet	Anti-Idling	Feasible	Reduction potential considers various optimization tools (fuel tracking, anti-idling, preventive maintenance).
Surface Fleet	Autonomous vehicles	Feasible, subject to feasibility study	Not applicable
Surface Fleet	Trolley Assist	Future consideration (feasible with Project constraints)	Not applicable
Underground Fleet	Diesel to Renewable Diesel	Feasible	Not applicable
Underground Fleet	Diesel to Biodiesel	Future consideration (feasible with Project constraints)	Not applicable
Underground Fleet	Fuel Tracking / Fleet Optimization	Feasible	Reduction potential considers various optimization tools (fuel tracking, anti-idling, preventive maintenance).
Underground Fleet	Anti-Idling	Feasible	Reduction potential considers various optimization tools (fuel tracking, anti-idling, preventive maintenance).
Underground Fleet	Electrification – Battery Electric Vehicles	Feasible	Not applicable
Underground Fleet	Electrification (expanded grid connection)	Feasible with Project constraints	Considers improvements to the regional transmission line to increase grid electricity.
Underground Fleet	Hoist	Feasible with future implementation	Not applicable
Underground Heating and Ventilation	Optimized Ventilation-on-Demand	Feasible	Not applicable
Underground Fleet	Trolley Assist	Future consideration (feasible with Project constraints)	Not applicable

Source of Emission	Technology / Practice	BAT / BEP Selection	General Considerations
Underground Fleet	Autonomous vehicles	Future consideration (feasible with Project constraints)	Not applicable
Underground Heating	Heat recovery and heat exchangers	Feasible, subject to feasibility study	Not applicable
Underground and Building Heating	Air to air heat pumps and air source heat pump	Feasible, subject to feasibility study	Not applicable
Underground and Building Heating	Renewable Natural Gas	Feasible and implemented	Reduction potential based on all sources of natural gas usage.
Natural Gas Electricity Generation	Renewable Natural Gas	Feasible and implemented	Not applicable
Natural Gas Electricity Generation	Electrification (expanded grid connection)	Feasible with Project constraints	Considers improvements to the regional transmission line to increase grid electricity.
Diesel Generators	Diesel to Renewable Diesel	Feasible and implemented	Reduction potential based on all sources of diesel usage.
Diesel Generators	Electrification (expanded grid connection)	Feasible with Project constraints	Considers improvements to the regional transmission line to increase grid electricity.
Diesel Generators	Diesel to Biodiesel	Future consideration (feasible with Project constraints)	Not applicable
Diesel Generators	Battery Electric Storage System	Future consideration (feasible with Project constraints)	Not applicable
Blasting	Optimizing Blasts	Feasible and implemented	Not applicable
Electricity Usage	Hybrid power generation: Implementing renewable electricity generation sources such as solar, wind and biomass	Feasible	Not applicable

Table 6-2: BAT / BEP Scenario 1 for Achieving Interim Targets

GHG Source Grouping	BAT / BEP	Estimated GHG Reduction Potential for Scenario 1 (t-CO_2e)
Underground Fleet	Full electrification of diesel-powered underground fleet	696,600 t-CO_2e, 14% reduction from baseline scenario
Surface Fleet	Full electrification of diesel-powered surface fleet	441,800 t-CO_2e, 9% reduction from baseline scenario
Natural Gas Electricity Generation	Electricity from natural gas power generation electricity to be replaced by power from the grid	1,702,200 t-CO_2e, 34% reduction from baseline scenario
Diesel Generators	Electricity from diesel power generation electricity to be replaced by power from the grid	58,200 t-CO_2e, 1% reduction from baseline scenario
Underground Heating and Ventilation	Ventilation-on-Demand	47,800 t-CO_2e, 1% reduction from baseline scenario
Electric Heating	Heating from natural gas to be replaced by electric heating	243,000 t-CO_2e, 5% reduction from baseline scenario

Notes:
Scenario 1 assumes a regional transmission line upgrade to improve site access to electricity from Ontario grid, which is outside of the Great Bear Gold Project's scope. This would allow full electrification of onsite fleets and the displacement of natural gas and diesel for onsite power generation with grid electricity.

Table 6-3: BAT / BEP Scenario 2 for Achieving Interim Targets

GHG Source Grouping	BAT / BEP	Estimated GHG Reduction Potential for Scenario 2 (t-CO_2e)
Underground Fleet	Electrification of underground fleet (battery electric vehicles)	695,600 t-CO_2e, 14% reduction from baseline scenario
Surface Fleet	Electrification of surface fleet (battery electric vehicles, tethered equipment)	240,800 t-CO_2e, 5% reduction from baseline scenario
Underground and Surface Fleet	Optimization of fleet operations (Anti idling, fuel tracking, preventative maintenance)	91,500 t-CO_2e, 1% reduction from baseline scenario
Diesel Fuel Consumption	Renewable Diesel	59,300 t-CO_2e, 2% reduction from baseline scenario
Natural Gas Usage (Heating and Electricity)	Renewable Natural Gas	65,800 t-CO_2e, 2% reduction from baseline scenario
Underground Heating and Ventilation	Ventilation-on-Demand	293,700 t-CO_2e, 6% reduction from baseline scenario
Natural Gas Electricity Generation	Hybrid of renewables (solar, wind)	261,100 t-CO_2e, 6% reduction from baseline scenario

Notes:
Scenario 2 assumes an alternative approach to achieving net-zero by employing a combination of efforts.

7 REFERENCES

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- World Business Council for Sustainable Development / World Resources Institute (WRI/WBCSD). 2004. Greenhouse Gas Protocol for Project Accounting. ISBN 1-56973-598-0. March 2004.
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Appendix A

BAT / BEP Determination

Table A-1: Description of Technologies and Practices (Fuel Substitution - Renewable Diesel)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Diesel to Renewable Diesel	Renewable diesel is a synthetic diesel manufactured from organic sources such as animal fats and vegetable oils (e.g., canola, sunflower, soy). It is also known as hydrogenation-derived renewable diesel (HDRD) or Hydrotreated Vegetable Oil (HVO) and is produced from the same raw materials as biodiesel, but its production process and properties are different. Renewable diesel is produced using a hydrogenation process like the process used for desulphurization of petroleum diesel. It is chemically similar compared to conventional diesel and can be transported and used like conventional diesel. Renewable diesel that meets ASTM D975 specification for petroleum diesel is considered a drop-in fuel, directly substituting petroleum diesel without blending (i.e., 100% replacement is practical), and performs better than biodiesel in winter conditions. Presents potential supply chain constraints due to lack of availability of sufficient renewable diesel. TRL – 9 Commercially available and used in the mining sector at low blends (R3, R7, R20), higher blends in warm ambient conditions (to R100).	Potential Barriers or Risks: R100 demonstrated during warm months for off-road and on-road equipment (4Refuel 2024); high renewable diesel blends may not be feasible in colder climates.	Capital Expenditures: No appreciable requirements for implementation.
		Reliance on Supply of Zero Carbon Electricity: No additional electricity demand.	Operations and Maintenance Expenses: High variability in cost of renewable diesel. Costs range from equivalent to conventional diesel (with subsidies considered) to approximately a 30% premium (Mika 2021).
		Potential Secondary Environmental Effects: Criteria air contaminant emissions releases from combustion of fuel.	
		Upstream and Downstream Considerations: Potential supply chain constraints / availability of sufficient renewable diesel. Potential increase in scope 3 emissions with increased transportation distances from suppliers.	Potential Incentives or Grants: Government programs to facilitate growth in renewable diesel and biodiesel market adoption: National Renewable Diesel Demonstration Initiative (NRDDI), ecoEnergy for Biofuels, and Next-Generation Biofuels Fund.
		Examples of Implementation: Rio Tinto Borax, California fully transitioned fleet of approximately 35 vehicles including 14 haul trucks, three loaders, dozers, graders, water carts and drills to renewable diesel (Rolfe 2023). Kennecott copper operations in Salt Lake City, Utah will replace fleet of 90 haul trucks and all heavy machinery to renewable diesel starting in 2024 (Rio Tinto 2023). Cummins has approved their entire line of industrial high-horsepower engines for use with unblended RD100 (Cummins 2023). Majority of key equipment and engine manufacturers have approved varying levels of biodiesel blends, with several OEMs approving RD100 and / or biodiesel (B100) in their engines. Chevron Renewable Energy Group has worked with Union Pacific and Canadian National Railways to deploy renewable diesel / biodiesel (Chevron 2023).	Carbon Disclosures and Carbon Pricing Obligations: Biogenic CO_2 emissions are considered separately in carbon accounting and not included in the total carbon emissions considered under the Provincial Emissions Performance Standards (EPS).

Table A-2: Description of Technologies and Practices (Fuel Substitution - Biodiesel)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Diesel to Biodiesel	Biodiesel is manufactured by transesterification of vegetable oils and mineral fats and meets ASTM D6751 and is approved for blending with petroleum diesel. It can only be used as a blend in limited concentrations due to its tendency to congeal (i.e., gel) at low temperatures and remove existing deposits in fuel tanks and lines, with potential filter plugging. Biodiesel may be better suited for underground work or seasonal switching. TRL – 9 Commercially available and widely used at low blends in warm ambient conditions (to B100).	<u>Potential Barriers or Risks</u>: Cold weather use of biodiesel is limited due to the tendency to gel; a biodiesel blend up to B7 (7% biodiesel) can be used for up to 5 months per year. Biodiesel may also remove existing deposits in fuel tanks and lines, leading to occasional filter plugging (Canada Energy Regulator 2024). Older engines may require retrofits to switch to biodiesel, with potential invalidation of warranties.	<u>Capital Expenditures</u>: No appreciable requirements for implementation.
		<u>Reliance on Supply of Zero Carbon Electricity</u>: No additional electricity demand.	<u>Operations and Maintenance Expenses</u>: In the US, the cost of B100 was reportedly 12% higher than fossil diesel but B20 was lower in cost per litre (US DOE 2024). Biodiesel has a lower energy content per litre, estimated in one study at 9% lower than fossil diesel (Navius 2023), requiring more fuel per km travelled or per hour of operation. Combined this could reflect in an overall increase in cost of up to 20%
		<u>Potential Secondary Environmental Effects</u>: Criteria air contaminant emissions releases from combustion of fuel. Reduced benefit of Ventilation-on-Demand with diesel exhaust.	
		<u>Upstream and Downstream Considerations:</u> Potential increase in scope 3 emissions with increased transportation distances from suppliers. Potential supply chain constraints / availability of sufficient biodiesel.	<u>Potential Incentives or Grants</u>: Government programs to facilitate growth in market adoption: National Renewable Diesel Demonstration Initiative (NRDDI), ecoEnergy for Biofuels, and Next-Generation Biofuels Fund.
		<u>Examples of Implementation</u>: Biodiesel blended at high levels has been common in the underground mining sector for nearly 20 years. Majority of key equipment and engine manufacturers have already approved varying levels of biodiesel blends. In several cases, OEMs approve the use of 100% biodiesel (B100) in their engines. Chevron Renewable Energy Group has worked with Union Pacific and Canadian National Railways to deploy renewable diesel / biodiesel. The use of B5 in power generators in remote northern Canadian locations was demonstrated in both warm and cold seasons in the NRDDI Manitoba Hydro project without any issues or requiring additional maintenance (NRCan 2024).	<u>Carbon Disclosures and Carbon Pricing Obligations:</u> Biogenic CO_2 emissions are considered separately in carbon accounting and not included in the total carbon emissions considered under Provincial EPS.

Table A-3: Description of Technologies and Practices (Tethered Equipment)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Tethered Equipment: Electric Shovels and Drills	Open pit tethered equipment have a hybrid diesel / electric powertrain. The diesel power allows for movement around the mine site. When the equipment is stationary and in operation, the equipment tethers to an electrical source. In some cases, the equipment may be permanently tethered. Tethered drills and shovels are commonly employed at mines. TRL – 9 Technically Feasible, Project Specific Barriers	Potential Barriers or Risks: Access to low carbon electricity. Limited spatial range when operating on electricity. Accommodations needed for the cable.	Capital Expenditures: Notably higher for electrical due to infrastructure and purchase price.
		Reliance on Supply of Zero Carbon Electricity: Additional 4-5 megawatts (MW) to power equipment, with electric shovels accounting for approximately 2.4 MW of this total.	Operations and Maintenance Expenses: Net savings each year with switch from diesel fuel. Electric powertrain has lower time to repair than diesel, but Tethered equipment may have lower productivity / require more downtime compared with diesel engines, possibly lower tonnage than diesel equipment for haulage (Nieto et al. 2020).
		Potential Secondary Environmental Effects: Less heat, noise and vibration levels compared with operating a diesel engine. Air emissions associated with diesel engine.	
		Upstream and Downstream Considerations: Developed technology with robust supply chain for replacement parts.	Potential Incentives or Grants: To be determined if selected for implementation. Potential eligibility for rebate from federal government for low carbon technology.
		Examples of Implementation: Agnico Eagle Detour Lake, ON use both electric and diesel drill rigs and will deploy two electric hydraulic shovels (International Mining 2023). Zielitz Potash Mine is testing tethered electric load haul dump with onboard battery electric vehicle capability (Moore 2021).	Carbon Disclosures and Carbon Pricing Obligations: Lower scope 1 emissions with electrification if power supplied by the grid or natural gas generators.

Table A-4: Description of Technologies and Practices (Fleet Optimization)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Fleet Optimization Fuel Tracking, Anti-Idling, Haulage cycle Routing	Fleet Management Tools Computer-based dispatching tools which optimize haulage cycle and reduce truck idling time. Fleet management tools are computer-based dispatching tools which optimize haulage cycle and reduce truck idling time. These systems are often used in municipal waste management and collection vehicles to manage load and optimize routing to improve fleet efficiency. Internet of Things (IoT) devices in particular can help by generating the vast amounts of data needed for advanced asset management. Additionally, performing proper equipment maintenance and recording these maintenance activities via tracking tools can improve safety, prevent failures, optimize process performance and lower overall operational costs. Discrete event simulations to optimize haulage and energy consumption. Anti-Idling Avoid or minimize engine use when vehicles are not undertaking useful work. A study by the National Research Council (Zhang 2021) indicated that up to a 4% reduction could be achieved in construction equipment equipped with a 1-minute shutoff timer. TRL – 9	Potential Barriers or Risks: Idling in winter may be necessary for worker safety and diesel engine warm-up.	Capital Expenditures: Potential need for WIFI network to track vehicle movements.
		Reliance on Supply of Zero Carbon Electricity: No additional electricity demand.	Operations and Maintenance Expenses: Reduction in diesel fuel usage.
		Potential Secondary Environmental Effects: Less onsite diesel fuel storage and handling.	
		Upstream and Downstream Considerations: Reduced scope 3 emissions associated with fuel transportation.	Potential Incentives or Grants: None identified.
		Examples of Implementation: VERIDAPT platform monitors, controls and authorizes the use of over 30 billion litres of fuel annually, across 150+ large global mining, rail and terminal operations. Their clients include top tier commodity producers BHP, Rio Tinto, Glencore, Vale, Teck, Syncrude and major rail companies (Veridapt 2024). Myra Falls Nystar, BC, implemented underground fleet management system in 2020, increasing production by 15% (Outlier Mining Solutions, n.d.). Kinross, Fort Knox, Alaska, implemented IntelliMine, a fleet management tool that has an optimization algorithm to improve productivity that provides automatic haul truck assignments and monitors and controls shovels and loaders.	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations.

Table A-5: Description of Technologies and Practices (Trolley Assist)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Trolley Assist	Hybrid diesel / electric powertrain, onboard pantographs to connect a mining truck's drive system to overhead power lines on uphill haulage segments. When connected to the overhead power lines in trolley mode, the full power capacity of the electric wheel motors can be translated into speed on grade while the diesel engine idles. For mining operations with uphill haulage, the trolley assist system can supply the electric power needed to support effective and efficient travel on steep grades. With reduced fuel consumption and less strain on the engine during uphill haulage, can prolong equipment's uptime and extend maintenance requirements. TRL – 9 Trolley assist systems have been available for 40 years (BBA 2024a). Technically Feasible, Project Specific Barriers	Potential Barriers or Risks: Short open pit life, pit size and location of the open pit ramp, and quantities hauled may not make trolley assist feasible in terms of payback period. Requires installation of overhead infrastructure (cables, supports) and substations.	Capital Expenditures: High capital cost associated with trolley assist. Open pit operations limited to 10-years, which is a short life for trolley installations.
		Reliance on Supply of Zero Carbon Electricity: The use of trolley assist has a large power demand, one estimate of 2.2 MW for typical haul truck payload on a steeper grade is reported in literature (Mazumdar 2011).	Operations and Maintenance Expenses: The uphill speed of haul trucks can increase up to two times faster than without trolley assistance and they rely less on their diesel engine. Reduced fuel consumption by up to 70%; in one example, at the engine's top speed, the fuel rate is 450 L/h, but with trolley assist, the engine idles and the fuel rate drops to 40 L/h (Mazumdar 2011).
		Potential Secondary Environmental Effects: Increased fugitive dust as road widths may need to be wider for an additional lane (BBA 2014).	
		Upstream and Downstream Considerations: No effects that will influence BAT / BEP determination.	Potential Incentives or Grants: To be determined if selected for implementation. Potential eligibility for rebate from federal government for low carbon technology.
		Examples of Implementation: In Australia, seven major mining companies have financially backed BluVein and its "next generation trolley-charging technology" for heavy mining vehicles, with the industry collaboration project now moving forward with final system development and construction of a technology demonstration pilot site in Brisbane, Australia (International Mining 2021). One copper mine in British Columbia reports a fully implemented trolley assist infrastructure for haul trucks resulting in a 90% reduction in carbon emissions (Hudbay Minerals 2024). One gold mine in Ontario is in the planning stages of implementing trolley assist (Agnico Eagle 2022). Boliden is expanding trolley assist at Aitik copper and adding it at Kevitsa nickel mines (Gleeson 2019).	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations.

Table A-6: Description of Technologies and Practices (In-pit Crushing and Conveyance)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
In-pit Crushing and Conveyance	In-pit Crushing and Conveyance / Underground Conveyance is presented as an alternative to conventional haul trucks. The goal is to minimize transport of ore and mine rock due to the shorter distance conveyance to the in-pit crusher, conveyance of crushed material to mill. Options for in-pit crushing and conveyance include fully mobile, permanent, and semi-mobile. TRL – 9	Potential Barriers or Risks: Additional requirements for mine planning and operational management. In-pit infrastructure can be large (McEwing 2019). System downtime results in complete loss in production (McEwing 2019). May not be suitable where lifespan of the open pit is 10 years or lower or small open pits where pit is constantly changing	Capital Expenditures: High capital expenditure for installation.
		Reliance on Supply of Zero Carbon Electricity: Additional electricity demand to operate conveyor and in-pit crusher.	Operations and Maintenance Expenses: Increased productivity. Savings on diesel fuel, lower carbon emissions will result in EPS savings.
		Potential Secondary Environmental Effects: Source of dust within pit, as a result of crushing, to be approved and managed. No effects that will influence BAT / BEP determination.	
		Upstream and Downstream Considerations: No effects that will influence BAT / BEP determination.	Potential Incentives or Grants: To be determined if selected for implementation.
		Examples of Implementation: Rio Tinto (Guinea) Germany-based Takraf has secured a contract to deliver an integrated in-pit crushing and conveyance and material handling system for the Simandou iron ore complex in Guinea. Vale (Brazil) USD 6.4 billion investment to develop the S11D Eliezer Batista iron ore complex, Vale installed a truckless mining system based on continuous in-pit crushing and conveyance technology. The result is 67% lower energy consumption relative to comparable truck-and-shovel systems, reducing both CO_2e emissions and the operating cost of mining. Cost: $6.4 billion USD (FLSmidth 2022).	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations.

Table A-7: Description of Technologies and Practices (Electrification – Battery Electric Vehicles)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Electrification – Battery Electric Vehicles	Battery Electric Drivetrain Specific equipment to be battery electric vehicles include load haul dump, Underground Truck, and CRF Truck. May also include forklifts, excavators, loaders, graders and haul trucks. Comparable mobility to conventional diesel equipment. Advancements and cost reductions are expected as many OEMs are piloting battery-powered systems on larger equipment. Charging infrastructure, sufficient low-carbon electricity supply and skilled mechanics to maintain and repair EV are required. Long charge times may require purchase or use of additional, redundant equipment. Battery supply chain and end of life disposal may introduce substantial scope 3 emissions. Additional savings in ventilation requirements (10-15%, estimated). TRL – 7-9	<u>Potential Barriers or Risks</u>: Charging schedule management. Electricity constraints. Phasing in battery electric vehicles requires maintenance of infrastructure for both diesel and battery electric trucks. Potential for battery fires to be addressed. Range anxiety may affect truck utilization. A variety of development stages across the different construction equipment types.	<u>Capital Expenditures</u>: Battery as a service BaaS reduces capital for the trucks by managing the cost of batteries separately as an operating expense. Reduction in ventilation-on-demand operation requirements (minimum 30%), and removal of the associated surface infrastructure representing economic savings, and reduction in footprint.
		<u>Reliance on Supply of Zero Carbon Electricity</u>: Constrains in additional electricity demand for battery electric vehicle charging, due to lack of availability of onsite power supply.	<u>Operations and Maintenance Expenses</u>: Operating cost estimates range from 30% lower to 20% higher than diesel.
		<u>Potential Secondary Environmental Effects</u>: No tailpipe emissions from battery electric vehicles, which minimize ventilation requirements and benefits employees' health and safety.	
		<u>Upstream and Downstream Considerations:</u> Scope 3 emissions associated with lithium-ion batteries both upstream (mining and production) and battery end-of-life disposal.	<u>Potential Incentives or Grants</u>: To be determined if selected for implementation. Potential eligibility for rebate from federal government for low carbon technology.
		<u>Examples of Implementation</u>: Newcrest Brucejack Mine: Replacing 12 diesel trucks with 8 electric haul trucks at their gold and silver mine in northwestern BC, fully implemented in 2022 (Yakub 2022). Newmont: In collaboration with Caterpillar created a successful battery electric prototype underground mining truck. Planning and investment phase (Newmont 2023). Rio Tinto, Australia: Rio Tinto and BHP will collaborate on the testing of large battery electric haul truck technology in the Pilbara, Western Borden Gold, ON using tethered equipment, including load haul dump (Hiyatel, 2019). Volvo Trucks North America's Deployment: Supported by a $22-million USD grant from the U.S. EPA, deployment of 70 Class 8 VNR Electric trucks in Southern California (Volvo 2020).	<u>Carbon Disclosures and Carbon Pricing Obligations</u>: Lower carbon emissions and savings on EPS obligations.

Table A-8: Description of Technologies and Practices (Underground Hoist)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Underground Hoist	For underground material handling and transport to surface facilities. Life of mine material handling system will include a production shaft with a skip hoist system and personnel/supplies cage. The system will be fed by horizontal conveyors installed on dedicated transfer levels, often with a crusher on each haulage level. Quickest access to bottom resource during Phase 2 of underground mining with infrastructure readily expanded as the mine deepens. Accelerates delivery of materials to the surface. Reduces reliance on haul trucks. TRL – 9	Potential Barriers or Risks: System downtime results in complete loss in production.	Capital Expenditures: High CAPEX for shaft and skip hoist construction.
		Reliance on Supply of Zero Carbon Electricity: Additional electricity demand for hoist operation.	Operations and Maintenance Expenses: Savings on diesel fuel. Higher productivity - accelerates delivery of materials to surface. Less underground haul trucks needed
		Potential Secondary Environmental Effects: Reduced air emissions with fewer diesel haul trucks.	
		Upstream and Downstream Considerations: No effects that will influence BAT / BEP determination.	Potential Incentives or Grants: To be determined during design stage.
		Examples of Implementation: Newmont Éléonore: Production shaft movements of 8,500 tpd combined ore and waste (Mining Technology 2021). Newmont Musselwhite conveyor system and the material handling systems, the underground shaft hoists ore from the underground crushers, reducing haulage distances and ventilation costs (Newmont 2020). Alamos Young Davidson: Scooptrams load, haul and transfer stope production to the ore pass system from where it is hoisted to the surface with minimal ore and waste re-handling. 2020 expansion with highly automated lower mine infrastructure 8,000 tonnes per day (Alamos Gold Inc. 2024). Brucejack Mine (BC): Ore is trucked from working areas to the centrally located underground crusher at the 1300 m elevation level and subsequently transferred to surface via the two conveyors (Newcrest 2024).	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations.

Table A-9: Description of Technologies and Practices (Optimized Ventilation on Demand)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Optimized Ventilation-on-Demand	Ventilation-on-demand or ventilation control systems dynamically manages air supply in underground facilities, like mines. A system of sensors and control software monitors air quality and personnel location, adjust the volume flow and fan power in real-time to direct airflow precisely where and when it's needed. This reduces the overall airflow and heat required within underground facilities. The equipment also reduces the labour required to calibrate and test sensors throughout the underground facility. Robust network connectivity and accurate sensors are needed to monitor air quality and airflow rates effectively with timely transmission of data and control signals that the ventilation-on-demand system can respond quickly to changing conditions. A ventilation control systems or ventilation-on-demand control system will be necessary to monitor and control the overall ventilation system at the Project. The ventilation control systems and ventilation-on-demand system provides the air flow setpoint for each controlled regulator station, including the main fan stations speed (controls RPM). The regulator dampers are usually driven by a Proportional-Integral-Derivative flow controller that opens/closes the variable positions louvers so that the actual flow through the regulator remains at the setpoint value. Occupancy sensors allow for ventilation to be automatically shut off when not required. TRL – 9	<u>Potential Barriers or Risks</u>: New expertise required onsite. Risks posed by air sensor failure. Ensuring robust and reliable communication networks for the operation of ventilation-on-demand systems in underground settings.	<u>Capital Expenditures</u>: CAPEX 1% of total mining and milling costs (Howden Group Limited 2022).
		<u>Reliance on Supply of Zero Carbon Electricity</u>: Reduces electricity demand for ventilation. <u>Potential Secondary Environmental Effects</u>: Air quality improvements due to reduced natural gas or propane combustion.	<u>Operations and Maintenance Expenses</u>: OPEX 50% reduction in electrical, 21% reduction in heating costs.
		<u>Upstream and Downstream Considerations:</u> No effects that will influence BAT / BEP determination.	<u>Potential Incentives or Grants</u>: To be determined during design stage.
		<u>Examples of Implementation</u>: Newmont Éléonore (QC) ventilation-on-demand system from Howden VentSim™ CONTROL was implemented. The benefits of this solution are the energy efficiency and air treatment fully implemented with a 43% reduction in mine heating, 56% reduction in electricity and 73% reduction in surface ventilation electricity (Howden Group Limited 2018). Boliden Kankberg Gold Mine (Sweden) ABB Ability™ Ventilation Optimizer provides fresh air for workers while delivering ventilation energy savings of 54% and air heating energy savings of 21% during first year of use (ABB 2021). Glencore Nickel Rim South mine in Sudbury incorporated ventilation-on-demand for more than 10 years now (McLaren 2019). EastLink twin tunnels in Melbourne, where the tunnel ventilation system was upgraded to a variable speed, self-regulating operation. This system is controlled by software that responds to air quality and airflow sensors within the tunnels, automatically adjusting the operation of the ventilation fans (Infrastructure Magazine 2017).	<u>Carbon Disclosures and Carbon Pricing Obligations</u>: Lower carbon emissions and savings on EPS obligations.

Table A-10: Description of Technologies and Practices (Renewable Electricity Microgrid)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Hybrid, Introducing Renewable Solar, Wind, Biomass	Project specific electricity supply lower carbon microgrid enabling local power generation from renewables and storing the energy (National Renewable Energy Laboratory). Can be used to replace all or part of the electricity demand. The installation of a microgrid increases resilience via the capture of local renewable energy including micro-dams, geothermal, solar, and wind. The microgrid can be culminated by a cogeneration power plant. This can reduce GHG emissions from scope 2 activities and scope 3 upstream activities such as transportation of fuel. Hybridization, with the combining of more than one source of energy in a power supply system, commonly the augmentation of renewable energy with thermal power generation. It becomes complex due to the variable nature of renewables and their increasing volume compared with a thermal plant. A hybrid system may incorporate a battery to smooth out the variability and employ a specialized control system – a microgrid controller – to manage the dispatch of each of the sources of energy, ensuring the power supply is reliable and the use of renewable energy is always maximized. TRL – 9	Potential Barriers or Risks: Significant area required for installation. Additional federal and provincial permitting and approvals requirements may apply. Market for renewable electricity upon mine closure. Further site-specific feasibility work required, including of Battery energy storage would enhance microgrid by mitigating variability in electricity generation. Reliance on Supply of Zero Carbon Electricity: Not dependent upon grid electricity, rather it displaces the use of grid electricity and/or natural gas power generation. Potential Secondary Environmental Effects: Depends upon the renewable energy technology selected. Upstream and Downstream Considerations: Reduced scope 3 emissions associated with fuel production, refining, and transport to site. Examples of Implementation: Glencore Raglan I – Hybrid Wind, Diesel and Storage Energy Generation in Arctic Canada (Tugliq 2018); first of its kind autonomous industry scale microgrid project in arctic Canada, commissioned 2014. 3 MW arctic rated wind turbine, 200-kilowatt (kW) flywheel, 200kW Li-Ion Battery Energy Storage BES, 200 kW hydrogen cylinder/ hydrogen loop with electrolyser and fuel cells long term storage. TUGLIQ Energy is the owner and operator of the asset and has signed a 20-year Power Purchase Agreement with Glencore RAGLAN Mine (Tugliq 2018). Diavik Mine NWT installed 4 x 2.3 MW E70 Enercon turbines that have been operational since 2012 (Canadian Mining & Energy 2024). Agnico Eagle Meliadine Mine is pursuing a wind farm. Gold Fields – Granny Smith Mine (Australia): over 20,000 solar panel microgrid implemented as of 2019 to supply 2 MW of battery storage and 27 MW of gas power (Aggreko, n.d.). Gold Fields – Agnew Gold Mine (Australia): mine powered by a wind, solar, battery and gas microgrid at a cost of $111.6M (ARENA 2019)	Capital Expenditures: Depends upon mix of renewable energy. Estimated $79.6M for wind and $69.2M for solar (WSP 2024), excluding investment tax credit (ITC). Operations and Maintenance Expenses: Estimated $1.5M/y for wind and $1.2M for solar (WSP 2024). Levelized cost of electricity LCOE, 20-year project: $81.5M / MWh for wind and $142.1M for solar (WSP 2024). Costs do not consider the ITC. Potential Incentives or Grants: Potential for ITC. Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations. Lower scope 2 emissions if grid electricity is displaced.

Table A-11: Description of Technologies and Practices (Renewable Electricity Generation)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Cogeneration	A cogeneration power plant generates both electrical energy and thermal energy (heat), increasing the efficiency substantially. Also referred to as combined heat and power systems. TRL – 9	Potential Barriers or Risks: With planned connection to the grid within 10 years, the costs associated with installing cogeneration and the required infrastructure for short term use may not be economically feasible.	Capital Expenditures: High capital cost for cogeneration plants and infrastructure to distribute electricity and heat.
		Reliance on Supply of Zero Carbon Electricity: Limited electricity requirements to operate.	Operations and Maintenance Expenses: To be determined if feasibility assessment is undertaken.
		Potential Secondary Environmental Effects: Glycol may be used in thermal systems, although waster is a feasible alternative. To be determined if feasibility assessment is undertaken.	
		Upstream and Downstream Considerations: To be determined if feasibility assessment is undertaken.	Potential Incentives or Grants: To be determined during design stage.
		Examples of Implementation: Agnico Eagle Meadowbank Mine, NU: six 4,400kW diesel generators and a heat recovery system (BBA 2016). Agnico Eagle Meliadine Mine, NU: 28 MW plant, with energy efficiency above 80%, incorporated potential for conversion from diesel to natural gas in the future (BBA 2024b). Nutrien Cory Cogeneration Station, SK: A 50/50 joint venture with ATCO power. 2 natural gas-fuelled combustion turbines and generators for total of 234 MW (SaskPower 2024a).	Carbon Disclosures and Carbon Pricing Obligations: Reduced CO_2 emissions and lower EPS obligations.

Table A-12: Description of Technologies and Practices (Renewable Electricity Generation)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Battery Energy Storage System	Batteries receive electricity from the power grid, directly from the power station, or from a renewable energy source like solar panels, and subsequently store it as current to then release it when it is needed. Battery energy storage systems can adapt to dips and peaks in demand and supply, and has several applications for commercial and industrial users such as: peak shaving, manage energy demand, load shifting by tapping the battery when energy costs more, flexibility, whereby customers can reduce their site's grid demand at critical times – without changing their electricity consumption to facilitate participation in Demand Response program Behind-the-Meter systems are installed on the user's premises to improve the stability of its owner's energy supply and cut costs, but if the local regulatory framework allows for it, the batteries can also supply energy back into the grid and thereby become an additional revenue stream. Front-of-the-Meter systems are larger and directly connected to the power grid and usually therefore belong to a utility, helping it solve network congestion issues or as an alternative to building new power lines. TRL – 9	Potential Barriers or Risks: Risk of battery fires. Significant area required for installation. Lengthy periods without electricity generation will drain Battery energy storage systems, backup generation required (secondary power source).	Capital Expenditures: High cost, to be determined if feasibility assessment is undertaken. Battery energy storage systems CAPEX and OPEX 4.3-times that of diesel and 2.5-times that of natural gas (assuming 300h runtime) (Worley 2024).
		Reliance on Supply of Zero Carbon Electricity: No additional electricity demand.	Operations and Maintenance Expenses: To be determined if feasibility assessment is undertaken. Battery replacement is required approximately every 10 years.
		Potential Secondary Environmental Effects: To be determined during feasibility assessment. Reduction in noise emissions compared with diesel or natural gas generators.	
		Upstream and Downstream Considerations: Notable upstream GHG emissions from production of lithium-ion batteries. Battery end of life disposal.	Potential Incentives or Grants: To be determined during feasibility assessment.
		Examples of Implementation: Gold Fields $112 million microgrid at its Agnew mine in Western Australia includes Li-ion energy storage in the form of a Saft Intensium®Max+ 20M ESS in six 20-foot containers, plus a power conversion system (PCS), transformer and medium voltage switchgear in three 40-foot containers (Thonney 2021). Sardinia Mine (Italy) Energy Vault Holdings Inc, a leader in sustainable grid-scale energy storage solutions, and Carbosulcis S.p.A., a coal mining company owned by the Autonomous Region of Sardinia, have announced their plans to develop a 100 MW hybrid gravity energy storage system, a solution designed by Energy Vault for underground mines, pairing modular gravity storage and batteries (Gleeson 2024). Sandvik, Glencore have initiated a pilot project to deploy a second-life battery energy storage system at to-be-determined Glencore assets (Sandvik 2024).	Carbon Disclosures and Carbon Pricing Obligations: Displaces fossil fuel generation, with reduced CO_2 emissions (scope 1 and/or scope 2) and lower EPS obligations.

Table A-13: Description of Technologies and Practices (Explosives Use)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Green Bulk Explosives or Reformulations to Reduce GHGs Optimizing Blasts	Emulsion explosive (Hypex Bio) based on hydrogen peroxide that can be used in a similar operational manner to conventional bulk explosives (Swedish Mining Innovation 2024). Artificial intelligence and advanced optimization tools to minimize the explosive required to blast ore and mine rock for transport from open pit or underground. TRL – 7-9	Potential Barriers or Risks: Availability of green explosives. Limited field data to evaluate efficacy compared with emulsion or ANFO.	Capital Expenditures: No notable additional infrastructure required.
		Reliance on Supply of Zero Carbon Electricity: No additional electricity demand.	Operations and Maintenance Expenses: Surcharge unknown for procurement of green explosives.
		Potential Secondary Environmental Effects: Other air emissions released during blast.	
		Upstream and Downstream Considerations: Limited information available at this time.	Potential Incentives or Grants: To be determined during design stage.
		Examples of Implementation: Demonstration projects underway. Requires manufacturers (Orica, Dyno Noble as examples) to produce green explosives in sufficient quantities to displace conventional ANFO or emulsion.	Carbon Disclosures and Carbon Pricing Obligations: Reduce or eliminate CO_2 emissions with green or reformulated explosives. Reduce CO_2 emissions by optimizing traditional explosive use.

Table A-14: Description of Technologies and Practices (Natural Gas Power Generation)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Natural Gas for Internal Combustion	A reciprocating, or internal combustion (IC), engine converts the energy contained in a fuel into mechanical power. This mechanical power is used to turn a shaft in the engine with a generator to convert the rotational motion into power. Consider compressed natural gas or liquified natural gas with onsite storage to supplement natural gas supplied by Enbridge's gas pipeline. TRL – 9	Potential Barriers or Risks: Constraints on the supply of natural gas to the Project via the Enbridge pipeline.	Capital Expenditures: Comparable to diesel generators.
		Reliance on Supply of Zero Carbon Electricity: No electricity demand associated with the technology.	Operations and Maintenance Expenses: Comparable to diesel generators.
		Potential Secondary Environmental Effects: Air emissions released as by-produce of natural gas combustion, predominantly criteria air contaminants.	
		Upstream and Downstream Considerations: Upstream (scope 1) emissions associated with production and distribution of natural gas.	Potential Incentives or Grants: Undetermined.
		Examples of Implementation: The Wärtsilä 34SG features a wide power output range from 5.6 to 9.8 MW, as it is available in 12V, 16V and 20V cylinder configurations. Wartsila has delivered more than 1000 natural gas engines. Cat industrial and commercial gas generator sets, at ratings from 100 to 4,500 ekW (100 to 4,500 kVA), operate on natural gas and a wide range of other gaseous fuels including biogas, landfill gas, coal gas and propane (Wartsila 2024). Werner Enterprises and Cummins announce collaboration to integrate Cummins' new 15-liter natural gas and 15-liter hydrogen internal combustion engines (Cummins 2022).	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions than diesel power generation, lower EPS obligations for fossil fuel use.

Table A-15: Description of Technologies and Practices (Renewable Natural Gas)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Renewable Natural Gas	Renewable natural gas / biomethane (RNG). Its production is associated with landfill biogas capture, agriculture and/or food waste processing, wastewater processing, and wood waste processing. Both are low carbon alternatives to fossil natural gas. RNG may be used as a drop-in fuel to displace conventional natural gas once upgraded/purified. Biogas, in contrast, is unpurified and can be utilized locally for heating and electricity and cannot be injection into natural gas distribution networks. Number of RNG projects operating in Canada are expected to more than double between 2021 and 2025, however in Ontario the two projects are in southern Ontario. There is also a mechanism through Enbridge to purchase renewable natural gas at a surcharge and incorporate this zero-carbon option into the Net-Zero Plan, regardless of where the RNG is physically used; if there is no local opportunity to develop an RNG project, this is an option to address the natural gas demands to satisfy Project power and heat requirements. TRL – 9	Potential Barriers or Risks: Capacity of pipeline supply to project. Enbridge program to select RNG not fully rolled out. Safety considerations for storage of methane, particularly if liquified or compressed natural gas is used rather than supplied by pipeline. Availability / sourcing of enough renewable natural gas for project	Capital Expenditures: Storage and distribution facilities if RNG to be purchased for use onsite.
		Reliance on Supply of Zero Carbon Electricity: No additional electricity demand. Potential Secondary Environmental Effects: May reduce upstream methane emissions depending upon source.	Operations and Maintenance Expenses: Premium per cubic metre of RNG. Enbridge has a REC program to consider paying to support RNG in Ontario without requiring RNG use at the Project. RNG can be produced, cleaned and put into the natural gas distribution system at a cost of between $10-25 per gigajoule (GJ), or equivalent to between 4-9 cents per kilowatt hour (kWh) (CGA 2016).
		Upstream and Downstream Considerations: Methane leaks to atmosphere along the pipeline or from storage facilities.	Potential Incentives or Grants: Undetermined.
		Examples of Implementation: Argonaut's Magino Gold Mine to be powered by Wärtsilä Gas-fired Engines at Ontario site, with 22 MW onsite power plant. The engines that can combust 100% synthetic carbon neutral methane (Walton 2022).	Carbon Disclosures and Carbon Pricing Obligations: Biogenic CO_2 emissions are considered separately in carbon accounting and not included in the total carbon emissions considered under Provincial EPS.

Table A-16: Description of Technologies and Practices (Carbon Capture, Utilization, and Storage)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Carbon Capture, Utilization, and Storage (Natural Gas and Diesel Generator CO_2 Emissions)	Carbon Capture, Usage, and Storage (CCUS) is a key technology for mitigating CO_2 emissions, particularly from major sources such as power plants and industrial facilities. This process involves capturing CO_2 from flue gases post-combustion using chemical solvents, or pre-combustion by transforming fuel into a hydrogen-CO_2 mix. Beyond storage in geological formations, captured CO_2 is also utilized in commercial applications, such as producing building materials and plastics. The CO_2 is typically compressed and dehydrated prior to injection into a pipeline for transportation to a permanent sequestration reservoir (Shell Quest and Boundary Dam) or enhanced oil recovery reservoir (Enhance Energy's ACTL and Estevan). Western Canada has largest storage resource potential for CO_2 storage sedimentary basins, while Canada as a whole has great storage capacity. Most CCS pilot projects are within Western Canada (NRCan 2013). TRL – 6-9 Flue gas CO_2 capture is commercially available, but not widespread; no examples identified at comparable mining projects.	Potential Barriers or Risks: Carbon capture and storage is location specific because it requires a pipeline and storage capacity. If no end use identified, permanent sequestration is not considered a viable option at this time due to economics and regulatory approvals risk.	Capital Expenditures: High cost supporting infrastructure, costs are also location-specific (i.e., proximity to existing pipeline infrastructure and/or storage capacity).
		Reliance on Supply of Zero Carbon Electricity: Electricity required to capture and store.	Operations and Maintenance Expenses: Undetermined.
		Potential Secondary Environmental Effects: CCUS technologies are energy intensive.	
		Upstream and Downstream Considerations: CO_2 Leakage Risks from storage (non-permanent).	Potential Incentives or Grants: To be determined when technology has matured to TRL-9 and demonstrated at mining projects.
		Examples of Implementation: As of now, CCUS deployment has been slower than anticipated. However, there is growing momentum, with plans for more than 30 new integrated CCUS facilities announced since 2017, primarily in the United States and Europe (IEA 2020). By 2030, approximately 110 million tons per annum of CO_2 are expected to be captured annually based on the current CCUS project pipeline (Biniek et al. 2022). Petra Nova CCS Facility, Texas: Captures CO_2 from a coal-fired power plant and stores it underground in a depleted oil reservoir. It can capture up to 1.6 million tons of carbon dioxide annually (Paulson Institute 2015). Boundary Dam CCS Project, SK: Captures CO_2 from a coal-fired power plant and stores it underground in a saline aquifer. It has a capacity to capture one million tons of CO_2 annually (SaskPower 2024b). Decatur Project, Illinois US: Captures carbon dioxide from an ethanol plant and stores it underground in a saline aquifer. It can capture up to one million tons of CO_2 annually (US DOE 2017).	Carbon Disclosures and Carbon Pricing Obligations: Captured CO_2 may be exempt from determining EPS obligations based upon tonnes of CO_2 released.

Table A-17: Description of Technologies and Practices (Heat Recovery and Heat Exchangers)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Heat Recovery / Heat Exchangers	Energy efficiency opportunity through the capture of waste heat from underground ventilation, process water, processing exhausts, compressors. Underground mining operations rely on ventilation systems to confirm adequate heating and cooling throughout varying seasonal conditions. seasonal thermal energy storage (Se-TES) heat in summer is stored underground to be used for winter heat, and cold energy stored over winter. Heat exchangers at mine ventilation exhaust. Capture waste heat from natural gas heating facility via a preheater / heat exchanger. High efficiency heat exchangers will recapture a portion of the heat from the exhaust system and use this heat to preheat incoming fresh air. Most heat exchangers have an efficiency of 50%-80%. Mine Exhaust Heat Recovery (MEHR) systems can be viable for some mines (not for shallow mines in warmer regions with a low air volume flow rate). TRL – 9	Potential Barriers or Risks: To be determined if feasibility study is undertaken.	Capital Expenditures: Heat exchange/recovery infrastructure needed. May require modifications to mine design to accommodate heat recovery equipment.
		Reliance on Supply of Zero Carbon Electricity: Electricity required to operate heat exchangers. Potential Secondary Environmental Effects: Use of refrigeration / thermal fluids for heat exchange.	Operations and Maintenance Expenses: Unknown.
		Upstream and Downstream Considerations: No effects that will influence BAT / BEP determination.	Potential Incentives or Grants: To be determined if feasibility study undertaken.
		Examples of Implementation: Rio Tinto: Seeking solutions to capture and reuse the heat from underground, contributing towards powering the equipment needed to cool the operations (TNMG 2020). Vale Creighton (ON) used ice cavern system (OMA, n.d.). Zinkgruvan Mine (Lundin) installed plate heat exchanger for mine ventilation heating, using heat to preheat air to underground fresh air raise. (Holmund 2015). Teck Line Creek Coal Mine installed heat exchanger between exhaust and intake air (Gov BC 2024) Lockerby, Strathcona and Kidd Creek mines, ON: Heat exchange system recovering heat of air compressors (Kalantari & Ghoreishi-Madiseh 2023). Macassa mine, Ontario: A collective heat recovery system of both air compressor cooling loop and mine discharge water and delivering the recovered energy to the intake air (Kalantari & Ghoreishi-Madiseh 2023). Teck Red Dog Lead Zinc, US: Waste heat from cooling diesel gensets is used to heat the mill, an efficient means of engine cooling when demand for heat is low (Teck Resources Ltd 2017). Barrick Hemlo (Williams) Mine, ON: Combined exhaust air, compressor and water discharge heat recovery system which showed that an investment of $1.7M resulted in $500k of annual savings (Sbarba 2012) .	Carbon Disclosures and Carbon Pricing Obligations: Energy efficiency to reduce fossil natural gas use for heat, resulting in a reduction in CO_2 emissions and lower EPS obligations.

Table A-18: Description of Technologies and Practices (Air Source Heat Pumps)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Air To Air Heat Pumps / Air Source Heat Pump Ammonia Heat Pumps	Heat transfer from ambient air via heat exchanger, which is then brought up to design temperature through a heat pump. These systems are typically integrated into HVAC systems. Heat pumps do not generate heat but are heat transfer units that provide heating in cold conditions and cooling in hot conditions. For each kWh of electricity heat pumps use to operate, they can produce two to five kWh of heat (2 to 5 times the efficiency of even the most modern and efficient gas furnaces) Heat pumps can also convert low and high temperature waste heat to useful high-quality process heat or steam. When supplementing heat with emissions-intensive electricity or fossil fuels, heat pumps emit between 20 and 30 % less carbon emissions than gas furnaces because of their high efficiency. Heat pumps use up to 65 per cent less energy than standard electric resistance heating. Standard heat pumps can now perform well at temperatures as low as -8 to -10 degrees Celsius. Cold climate heat pumps, which have become more prevalent in the marketplace over the last five to ten years, are designed to maximize heating capacity at colder temperatures and can perform well at temperatures as low as -25 degrees Celsius. TRL – 9	Potential Barriers or Risks: Low CO_2 reduction potential, suitable for smaller structures.	Capital Expenditures: No change to mine design required. Cold climate heat pumps have higher upfront costs but reduce the need for backup systems because of effectiveness in cold temperatures.
		Reliance on Supply of Zero Carbon Electricity: Electricity required to operate heat pump.	Operations and Maintenance Expenses: Routine maintenance similar to that of a heat exchanger or make-up air unit.
		Potential Secondary Environmental Effects: Use of refrigeration / thermal fluids for heat exchange.	
		Upstream and Downstream Considerations: No effects that will influence this BAT / BEP determination.	Potential Incentives or Grants: To be determined if feasibility study undertaken.
		Examples of Implementation: Installations in residential, commercial and industrial buildings. Cold-climate air-source heat pumps (ASHP) are increasingly being installed (Energy Solutions Centre 2013). MAN Energy Solutions The power output ranges from 10 megawatts thermal (MWth) to above 90 MWth per heat pump unit. Higher outputs can be achieved with several heat pumps in parallel operation (MAN Energy Solutions 2024).	Carbon Disclosures and Carbon Pricing Obligations: Energy efficiency to reduce fossil natural gas use for heat, resulting in a reduction in CO_2 emissions and lower EPS obligations.

Table A-19: Description of Technologies and Practices (Geothermal and Ground Source Heat Pumps)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Ground Source Heat Pump Geothermal Heat	A geothermal heat pump utilizes the constant temperature below the earth's surface to provide heating, cooling, and hot water. Ground source heat pumps absorb the sun's energy stored in relatively shallow ground (up to 200 m) and upgrade it for heating and cooling. Roughly 15 metres below ground, the earth sustains a consistent temperature all year round which is near to the average annual air temperature. Trenches or boreholes are drilled and heat transfer fluid passes through heat exchanger(s). TRL – 9	Potential Barriers or Risks: Geothermal - not demonstrated in northwestern Ontario near Project.	Capital Expenditures: Costs associated with drilling / installation of infrastructure.
		Reliance on Supply of Zero Carbon Electricity: Electricity required to operate GSHP or geothermal.	Operations and Maintenance Expenses: Limited information available at this time.
		Potential Secondary Environmental Effects: Decommissioning wells may not fully remove subsurface infrastructure.	
		Upstream and Downstream Considerations: Limited information available at this time.	Potential Incentives or Grants: To be determined if feasibility study is undertaken.
		Examples of Implementation: Limited information available at this time.	Carbon Disclosures and Carbon Pricing Obligations: Energy efficiency to reduce reliance on fossil natural gas for heat, resulting in a reduction in CO_2 emissions and lower EPS obligations.

Table A-20: Description of Technologies and Practices (Hydrogen Fuel Cells)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Hydrogen Fuel Cell	Hydrogen fuel cell technology generates electricity via chemical reaction between hydrogen and oxygen with water as the sole by-product. The clean energy potential, combined with the ability to refuel quickly and provide high power for demanding tasks, positions hydrogen fuel cells as a promising power source for the next generation of construction equipment with the technology readiness progressing (TRL: 7-8), maturity in 5-10 years. When integrated into construction vehicles like loaders, excavators, and haul trucks, fuel cell technology can potentially surpass the efficiency of diesel counterparts. May be more suitable for northern climates than batteries which have limitations due to distance and temperature.	Potential Barriers or Risks: Advanced Safety Protocols need to be considered due to the danger of explosion from hydrogen release – ignition energy for hydrogen is less than 10% of the energy required for natural gas, propane or gasoline vapor.	Capital Expenditures: Undetermined.
		Reliance on Supply of Zero Carbon Electricity: Appreciable electricity demand if green hydrogen is produced onsite (electrolysis).	Operations and Maintenance Expenses: Cost of green hydrogen expected to be $12-$70 per GJ by 2030 (NRC Hydrogen Strategy for Canada 2020) May reduce underground ventilation requirements in mines which can contribute 30-40% of a mine's total operating costs (Hydrogen Strategy for Canada 2020).
		Potential Secondary Environmental Effects: No effects that will influence BAT / BEP determination at this time. Eliminates diesel exhaust.	
		Upstream and Downstream Considerations: Supply of low carbon hydrogen needs to be secure. Lifecycle emissions depend upon the method of hydrogen production. Green or blue hydrogen is required to avoid notable scope 3 emissions from steam methane reforming.	Potential Incentives or Grants: To be determined when technology has matured to TRL-9 and demonstrated at mining projects.
		Examples of Implementation: Volvo Construction Equipment: Developed the HX04, the first prototype hydrogen fuel cell articulated hauler, as part of a research initiative aiming to contribute to a net-zero future in construction. The HX04 can be refueled in approximately 7.5 minutes for about four hours of operation (Volvo 2022). AngloAmerican: Prototype hydrogen fuel cell / battery electric hybrid haul truck at its Mogalakwena PGMs mine in South Africa since May 2022. Hydrogen for the truck is produced from solar energy at an onsite hydrogen production, storage and refueling complex. Plan to retrofit 40 diesel haul trucks at Mogalakwena and eventually roll out the technology across the global feet of 400 trucks (AngloAmerican 2022).	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations.

Table A-21: Description of Technologies and Practices (Hydrogen Internal Combustion Engines)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Hydrogen Internal Combustion Engine	Hydrogen can be used as a fuel in gasoline internal combustion engines with modifications mainly to the fuel storage and fuel injection system. Hydrogen in conjunction with diesel in internal combustion engine trucks is referred to as co-combustion technology; co-combustion offers lower entry cost for end-users, as existing diesel engines can be retrofit. However, these engines do not provide the efficiency advantages of fuel. A traditional diesel engine can accommodate a hydrogen-diesel blend of up to 90% hydrogen pending a retrofit of the injection system. With co-combustion, the equipment is familiar for maintenance and repair teams. Hydrogen combustion is less efficient than using hydrogen in a fuel cell with conversion to mechanical energy. Combusting hydrogen can lead to increased NO_X emissions (Hydrogen Strategy for Canada 2020). Total life-cycle emissions, however, are dependent on the production pathway of the hydrogen. TRL – 7-8 Technology proven in passenger vehicles and companies are testing the H_2 internal combustion engine prototypes for heavy duty applications.	Potential Barriers or Risks: Key technical challenges include achieving an efficient air and hydrogen mix, managing steam output, and optimizing ignition systems for hydrogen combustion (SAE, 2023). Advanced Safety Protocols need to be considered due to the danger of explosion from hydrogen release – ignition energy for hydrogen is <10% of the energy required for natural gas, propane or gasoline vapor.	Capital Expenditures: Additional infrastructure required for hydrogen storage and dispensing at onsite fueling stations. Hydrogen internal combustion engine trucks are forecast to cost 50% more than an equivalent diesel truck by 2027 (Randall, 2022).
		Reliance on Supply of Zero Carbon Electricity: Appreciable electricity demand if green hydrogen produced onsite (electrolysis). Potential Secondary Environmental Effects: No effects that will influence BAT / BEP determination at this time. Eliminates diesel exhaust, but NO_X emissions may be generated.	Operations and Maintenance Expenses: Cost of green hydrogen expected to be \$12-\$70 per GJ by 2030 (NRC Hydrogen Strategy for Canada 2020)
		Upstream and Downstream Considerations: Supply of low carbon hydrogen needs to be secure. Lifecycle emissions depend upon the method of hydrogen production. Green or blue hydrogen is required to avoid notable scope 3 emissions from steam methane reforming.	Potential Incentives or Grants: To be determined when technology has matured to TRL-9 and demonstrated at mining projects.
		Examples of Implementation: 5-10 years to maturity. Liebherr: developed a hydrogen-powered crawler excavator prototype, the R 9XX H2, equipped with a zero-emission 6-cylinder engine, H966. The R 9XX H2 was even presented at Bauma 2022, indicating a step towards commercial availability (Schultz 2022). JCB: Unveiled a new hydrogen combustion engine, the 448 ABH2, which is currently being used to power a backhoe loader and Loadall telescopic handler machines. Over 50 prototypes of this engine have been manufactured and are in use (SAE 2023). Werner (American transportation and logistics company): Letter of intent signed for 500 hydrogen-fueled internal combustion engines from Cummins Inc. to use in their truck fleet (Adler 2022).	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations.

Table A-22: Description of Technologies and Practices (Hydrogen Boilers and Furnaces)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Hydrogen Boilers and Furnaces	Combustion of hydrogen to heat water with flue gases. Differences in hydrogen properties and combustion conditions (higher flame speed, lower ignition energy) require different design when compared with conventional boiler design. TRL – 7-8 The technology is in the development phase.	Potential Barriers or Risks: Hydrogen has different combustion properties compared to natural gas. It has a higher flame speed and a lower ignition energy. This means the design of burners and combustion controls must be adjusted to handle these characteristics safely and efficiently. Hydrogen can cause embrittlement in certain metals, leading to material failure.	Capital Expenditures: The anticipated costs for hydrogen boilers are expected to be similar to natural gas boilers. Ideal, Baxi, Worcester Bosch, and Vaillant have agreed that a new generation of boilers that can be converted to run on hydrogen will cost no more than the equivalent natural gas systems (Hydrogen Central 2021).
		Reliance on Supply of Zero Carbon Electricity: Appreciable electricity demand if green hydrogen produced onsite (electrolysis).	Operations and Maintenance Expenses: Cost of green hydrogen expected to be \$12-\$70 per GJ by 2030 (NRC Hydrogen Strategy for Canada 2020)
		Potential Secondary Environmental Effects: No effects that will influence BAT / BEP determination at this time. Eliminates diesel exhaust, but NO_X emissions may be generated.	
		Upstream and Downstream Considerations: Supply of low carbon hydrogen needs to be secure. Lifecycle emissions depend upon the method of hydrogen production. Green or blue hydrogen is required to avoid notable scope 3 emissions from steam methane reforming.	Potential Incentives or Grants: To be determined when technology has matured to TRL – 9 and demonstrated at mining projects.
		Examples of Implementation: H2GO Power and Baxi Partnership: Baxi provides hydrogen boilers, and H2GO Power engineers the necessary systems, integrating hydrogen storage and production. Initial application uses hydrogen to pre-heat natural gas with plans for an industrial-scale demonstration (Mundell 2023). BDR Thermea Group in the Netherlands: Installed world's first hydrogen-powered domestic boiler, goal to replace over 400 conventional gas boilers with hydrogen boilers in the UK (Contractor 2020). Viessmann's Hydrogen Solutions: Developing "H_2-ready" condensing boilers that can operate with 100% hydrogen. Prototypes that can run on natural gas, or on a natural gas/hydrogen mixture, are being tested. SmartQuart pilot project in Kaisersesch with a complete hydrogen infrastructure, a hydrogen-fired steam boiler in Jordan, and a hydrogen heating project at the Mercure Hotel MOA Berlin (Viessmann 2024).	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations.

Table A-23: Description of Technologies and Practices (Small Modular Nuclear Reactors)

Technology / Practice	Technology Description	Technical Considerations	Economic Considerations
Nuclear Small Modular Reactor (SMR / MMR)	Small Modular Reactors (SMR) are nuclear fission reactors that are smaller than traditional nuclear power plants with a generation capacity of 300 MW or less (approximately 1/3 of traditional nuclear power reactors), are less expensive and faster to build, can be scaled in size, and have more flexible site requirements. Micro SMRs (MMRs) are designed to generate up to 10 MW. SMRs and MMRs can be prefabricated and installed into an existing grid or remotely off-grid to provide low carbon power for industry. SMRs require less frequent refueling compared to conventional plants (3-7 years vs. 1-2 years), some not for 30 years. The technologies differ from traditional power plants, with inherent safety features and modular design. TRL – 7-8	Potential Barriers or Risks: Public and stakeholder acceptance. Regulatory licensing (federal and provincial). Safety and Security, the foremost consideration for SMRs, as with any nuclear technology - the prevention of nuclear accidents, containment of radioactive materials, and protection against external threats such as natural disasters or malicious attacks. Initial capital investment, along with operational and decommissioning costs may be prohibitive.	Capital Expenditures: Undetermined. Small Modular Reactor under construction in Argentina is experiencing increasing costs as it develops. 2014 estimate: $446 million USD for a 25 MW reactor. 2017: $700 million USD for a 25-32 MW reactor (Green 2019). $270 million dollars CAD for 20 MWe system (NRCan 2021).
		Reliance on Supply of Zero Carbon Electricity: No additional electricity demand. Potential Secondary Environmental Effects: Waste Management: Radioactive waste requires long-term storage solutions. Cooling System: once-through cooling systems can harm aquatic life, while closed-loop systems require large amounts of water.	Operations and Maintenance Expenses: Fuel cost $64 million CAD dollars for fuel replacement every 10 years - $6,400,000 CAD per year (NRCan 2021). Compared to the existing grid, Small Modular Reactors could be competitive on a $ / MWh basis (EFWG 2018).
		Upstream and Downstream Considerations: Lifecycle Emissions - Nuclear power is low in GHG emissions during operation. However, the construction, mining, fuel processing, and decommissioning of nuclear plants, including SMRs, involve emissions.	Potential Incentives or Grants: To be determined when technology has matured to TRL – 9 and demonstrated at mining projects.
		Examples of Implementation: Implementation timeline >10 years. Global First Power micro modular reactor at Chalk River Laboratories in Ontario (Government of Canada 2024). Currently undergoing environmental assessment and has started the licensing process for Canadian Nuclear Safety Commission's License to Prepare Site. Pilot Project could be operational at Ontario Power Generation's Darlington site by 2028, but commercialization could take longer (CANDU 2021).	Carbon Disclosures and Carbon Pricing Obligations: Lower carbon emissions and savings on EPS obligations.

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Appendix B

GHG Reduction Potential Evaluation

B1-a. Electrification of Underground Fleet (Scenario 1)

Key Parameters

Parameter	Value	Unit	Comments
Equipment Baseline Fuel	358,300	kL	LOM, Diesel-Powered Fleet (Underground)
Equipment Baseline GHGs	970,800	tCO_2e	LOM, Diesel-Powered Fleet (Underground)
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions
Utilization Factor	-	-	Electrification of surface fleet ranges from 0% to 100% throughout the life of mine.

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Electrification of Underground Fleet			
Avoided Fossil Diesel Fuel	275,500	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	746,300	tCO_2e	
Additional GHGs	50,700	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of the electrified fleet.
Net Avoided GHGs	695,600	tCO_2e	
Equipment % GHG Reduction	72%	-	
Project % GHG Reduction	14%	-	

B1-b. Electrification of Surface Fleet (Scenario 1)

Key Parameters

Parameter	Value	Unit	Comments
Equipment Baseline Fuel	392,200	kL	LOM, Diesel-Powered Fleet (Open Pit, Quarry, Borrow, Tailings)
Equipment Baseline GHGs	1,063,000	tCO_2e	LOM, Diesel-Powered Fleet (Open Pit, Quarry, Borrow, Tailings)
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions
Utilization Factor	-	-	Electrification of surface fleet ranges from 25% in 2030 to 100% in 2040.

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Electrification of Open Pit Fleet			
Avoided Fossil Diesel Fuel	114,200	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	309,300	tCO_2e	
Additional GHGs	31,200	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of the electrified fleet.
Net Avoided GHGs	278,100	tCO_2e	
Equipment % GHG Reduction	26%	-	
Project % GHG Reduction	6%	-	
Electrification of Quarry, Borrow, and Tailings Fleet			
Avoided Fossil Diesel Fuel	64,600	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	174,900	tCO_2e	
Additional GHGs	13,300	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of the electrified fleet.
Net Avoided GHGs	161,600	tCO_2e	
Equipment % GHG Reduction	15%	-	
Project % GHG Reduction	3%	-	
Total			
Net Avoided GHGs	439,700	tCO_2e	

B1-c. Grid Electricity for Onsite Power (Scenario 1)

Key Parameters

Parameter	Value	Unit	Comments
Baseline Fuel	929,742,500	m^3	LOM, Natural Gas Electricity Generation
Baseline GHGs	1,796,200	tCO_2e	LOM, Natural Gas Electricity Generation
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Grid Electricity for Onsite Power			
Avoided Natural Gas Usage	929,742,500	m^3	Value approximated based on the combined CO_2e emission factor for natural gas from the National Inventory Report (2024).
Gross Avoided GHGs	1,796,200	tCO_2e	
Additional GHGs	95,200	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of site.
Net Avoided GHGs	1,701,000	tCO_2e	
Equipment % GHG Reduction	95%	-	
Project % GHG Reduction	34%	-	

B1-d. Electrification of Diesel Generators (Scenario 1)

Key Parameters

Parameter	Value	Unit	Comments
Baseline Fuel	49,953	kL	LOM, Operational Diesel Generators
Baseline GHGs	136,400	tCO_2e	LOM, Operational Diesel Generators
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Electrification of Operational Diesel Generators			
Avoided Fossil Diesel Fuel	22,600	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	61,600	tCO_2e	
Additional GHGs	3,900	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of site.
Net Avoided GHGs	57,700	tCO_2e	
Equipment % GHG Reduction	42%	-	
Project % GHG Reduction	1%	-	

B1-e. Ventilation-on-Demand in Underground (Scenario 1)

Key Parameters

	Value	Unit	Comments
Equipment Baseline Fuel	700,898,600	m^3	LOM, Natural Gas Electricity Generation in Underground Mine
Equipment Baseline GHGs	1,353,300	tCO_2e	LOM, Natural Gas Electricity Generation in Underground Mine
Equipment Baseline Fuel	347,450,900	m^3	LOM, Natural Gas for Heating at Mine
Equipment Baseline GHGs	672,300	tCO_2e	LOM, Natural Gas for Heating at Mine
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions
Utilization Factor	20%	-	Assumes 20% reduction in electricity and heating demand from start of underground operations.

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Ventilation-on-Demand Electricity Reduction			
Avoided Electricity Usage	423,822,800	kWh	Assumes 20% reduction in electricity demand from start of underground operations. Avoided scope 2 emissions.
Gross Avoided GHGs	8,400	tCO_2e	
Additional GHGs	0	tCO_2e	
Net Avoided GHGs	8,400	tCO_2e	
Equipment % GHG Reduction	1%	-	
Project % GHG Reduction	0%	-	
Ventilation-on-Demand Natural Gas Heating Reduction			
Avoided Natural Gas Usage	20,422,868	m^3	Assumes 20% reduction in heating demand from start of underground operations. Avoided natural gas usage for heating.
Gross Avoided GHGs	39,400	tCO_2e	
Additional GHGs	0	tCO_2e	
Net Avoided GHGs	39,400	tCO_2e	
Equipment % GHG Reduction	6%	-	
Project % GHG Reduction	1%	-	
Total			
Net Avoided GHGs	47,800	tCO_2e	

Implementation Examples

Site (Location)	Description	Project Stage
1. Teck Red Dog Lead Zinc	Waste heat from cooling diesel gensets is used to heat the mill, an efficient means of engine cooling when demand for heat is low	Implemented
2. Newmont Eleonore (Quebec)	VOD system from Howden VentSimTM CONTROL was implemented in the Newmont Goldcorp – Eleonore mine. The benefits of this solution are the energy efficiency and air treatment - 43% reduction in mine heating, 56% reduction in electricity and 73% reduction in surface ventilation electricity.	Implemented
3. Boliden Kankberg Gold Mine (Sweden)	ABB Ability™ Ventilation Optimizer provides fresh air for workers while delivering ventilation energy savings of 54% and air heating energy savings of 21% during first year of use	Implemented
4. Glencore	Glencore Nickel Rim South mine in Sudbury incorporated VOD for more than 10 years now	Implemented

B1-f. Electrification of Natural Gas Heating (Scenario 1)

Key Parameters

Parameter	Value	Unit	Comments
Baseline Fuel	347,450,900	m^3	LOM, Natural Gas for Heating at Mine
Baseline GHGs	672,300	tCO_2e	LOM, Natural Gas for Heating at Mine
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Electrification of Natural Gas Heating			
Avoided Natural Gas Usage	136,902,800	m^3	Value approximated based on the combined CO_2e emission factor for natural gas from the National Inventory Report (2024).
Gross Avoided GHGs	264,900	tCO_2e	
Additional GHGs	21,900	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of site.
Net Avoided GHGs	243,000	tCO_2e	
Equipment % GHG Reduction	36%	-	
Project % GHG Reduction	5%	-	

B2-a. Electrification of Underground Fleet (Scenario 2)

Key Parameters

Parameter	Value	Unit	Comments
Equipment Baseline Fuel	358,300	kL	LOM, Diesel-Powered Fleet (Underground)
Equipment Baseline GHGs	970,800	tCO_2e	LOM, Diesel-Powered Fleet (Underground)
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions
Utilization Factor	-	-	Electrification of underground fleet ranges from 50% in 2035 to 100% in 2040.

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Electrification of Underground Fleet			
Avoided Fossil Diesel Fuel	275,500	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	746,300	tCO_2e	
Additional GHGs	50,700	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of the electrified fleet.
Net Avoided GHGs	695,600	tCO_2e	
Equipment % GHG Reduction	72%	-	
Project % GHG Reduction	14%	-	

B2-b. Electrification of Surface Fleet (Scenario 2)

Key Parameters

Parameter	Value	Unit	Comments
Equipment Baseline Fuel	392,200	kL	LOM, Diesel-Powered Fleet (Open Pit, Quarry, Borrow, Tailings)
Equipment Baseline GHGs	1,063,000	tCO_2e	LOM, Diesel-Powered Fleet (Open Pit, Quarry, Borrow, Tailings)
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions
Utilization Factor	-	-	Electrification of open pit fleet ranges from 35% in 2040 to 100% in 2045. Electrification of quarry, borrow, and tailing sources ranges from 0% to 100% in 2045

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Electrification of Open Pit Fleet			
Avoided Fossil Diesel Fuel	52,700	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	142,700	tCO_2e	
Additional GHGs	8,700	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of the electrified fleet.
Net Avoided GHGs	134,000	tCO_2e	
Equipment % GHG Reduction	13%	-	
Project % GHG Reduction	3%	-	
Electrification of Quarry, Borrow, and Tailings Fleet			
Avoided Fossil Diesel Fuel	41,900	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	113,400	tCO_2e	
Additional GHGs	6,600	tCO_2e	Acquired energy emissions anticipated to increase due to the power demand of the electrified fleet.
Net Avoided GHGs	106,800	tCO_2e	
Equipment % GHG Reduction	10%	-	
Project % GHG Reduction	2%	-	
Total			
Net Avoided GHGs	240,800	tCO_2e	

Implementation Examples

Site (Location)	Description	Project Stage
1. Newmont	Newmont and Caterpillar created a successful battery electric prototype underground mining truck	Planning / Investment
2. Newcrest	Replacing 12 diesel trucks with 8 electric haul trucks at their gold and silver mine in northwestern BC	Implemented
3. Anglo American	Anglo American announces the launch of a research and development project in collaboration with GEM, one of China’s largest battery and battery material recyclers, to explore new and more efficient technologies for the use of existing and alternative raw materials to be used in batteries for electric vehicles (EVs)	Planning / Investment
4. Rio Tinto	Rio Tinto and BHP will collaborate on the testing of large battery-electric haul truck technology in the Pilbara, Western Australia, to accelerate the potential for its future deployment	Planning / Investment

B2-c Optimization of Fleet Operations (Scenario 2)

Key Parameters

Parameter	Value	Unit	Comments
Equipment Baseline Fuel	392,200	kL	LOM, Diesel-Powered Fleet (Open Pit, Quarry, Borrow, Tailings)
Equipment Baseline GHGs	1,063,000	tCO_2e	LOM, Diesel-Powered Fleet (Open Pit, Quarry, Borrow, Tailings)
Equipment Baseline Fuel	358,300	kL	LOM, Diesel-Powered Fleet (Underground)
Equipment Baseline GHGs	970,800	tCO_2e	LOM, Diesel-Powered Fleet (Underground)
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions
Utilization Factor	-	-	Combined optimization measures can ranges from 4% up to 10% reduction of GHG emissions from underground and surface fleet throughout life of mine.

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Optimization of Diesel-Powered Surface Fleet			
Avoided Fossil Diesel Fuel	25,800	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	69,900	tCO_2e	
Additional GHGs	0	tCO_2e	
Net Avoided GHGs	69,900	tCO_2e	
Equipment % GHG Reduction	3%	-	
Project % GHG Reduction	1%	-	
Optimization of Diesel-Powered Underground Fleet			
Avoided Fossil Diesel Fuel	8,000	kL	Value approximated based on the combined CO_2e emission factor for diesel from the National Inventory Report (2024).
Gross Avoided GHGs	21,600	tCO_2e	
Additional GHGs	0	tCO_2e	
Net Avoided GHGs	21,600	tCO_2e	
Equipment % GHG Reduction	1%	-	
Project % GHG Reduction	0%	-	

B2-d. Renewable Drop-in Fuels in Stationary and Mobile Sources (Scenario 2)

Key Parameters

Parameter	Value	Unit	Comments
Equipment Baseline Fuel	750,400	kL	LOM, Diesel-Powered Mobile Sources (Underground, Open Pit, Quarry, Borrow, Tailings Fleet)
Equipment Baseline GHGs	2,033,800	tCO$_2$e	LOM, Diesel-Powered Mobile Sources (Underground, Open Pit, Quarry, Borrow, Tailings Fleet)
Equipment Baseline Fuel	60,372	kL	LOM, Diesel-Powered Stationary Sources (Operational and Construction Diesel Generators)
Equipment Baseline GHGs	164,500	tCO$_2$e	LOM, Diesel-Powered Stationary Sources (Operational and Construction Diesel Generators)
Equipment Baseline Fuel	929,742,500	m^3	LOM, Natural Gas Electricity Generation
Equipment Baseline GHGs	1,796,400	tCO$_2$e	LOM, Natural Gas Electricity Generation
Equipment Baseline Fuel	347,450,900	m^3	LOM, Natural Gas for Heating at Mine
Equipment Baseline GHGs	672,300	tCO$_2$e	LOM, Natural Gas for Heating at Mine
Project Baseline GHGs	5,017,900	tCO$_2$e	LOM, Direct and Acquired GHG Emissions
Utilization Factor - Natural Gas	20%	-	Assumes 20% blend of renewable natural gas (RNG) starting in 2045.
Utilization Factor - Diesel	3%	-	Assumes 100% renewable diesel blend for 5 months per year and 3% renewable diesel blend for 7 months per year starting in 2045.

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Renewable Diesel - Diesel-Powered Mobiles Sources (Underground, Open Pit, Quarry, Borrow, Tailings Fleet)			
Avoided Fossil Fuel	10,500	kL	
Gross Avoided GHGs	28,400	tCO$_2$e	
Additional GHGs	700	tCO$_2$e	Emission factor for renewable diesel from GHGenius (2023).
Net Avoided GHGs	27,700	tCO$_2$e	
Equipment % GHG Reduction	1%	-	
Project % GHG Reduction	1%	-	
Renewable Diesel - Diesel Generators			
Avoided Fossil Fuel	12,200	kL	
Gross Avoided GHGs	33,000	tCO$_2$e	
Additional GHGs	700	tCO$_2$e	Emission factor for renewable diesel from GHGenius (2023).
Net Avoided GHGs	32,300	tCO$_2$e	
Equipment % GHG Reduction	1%	-	
Project % GHG Reduction	1%	-	
Total - Diesel			
Net Avoided GHGs	60,000	tCO$_2$e	
Renewable Natural Gas - Natural Gas Electricity Generation			
Avoided Fossil Fuel	19,926,100	m^3	
Gross Avoided GHGs	38,500	tCO$_2$e	
Additional GHGs	3,600	tCO$_2$e	Emission factor for renewable natural gas from GHGenius (2023).
Net Avoided GHGs	34,900	tCO$_2$e	
Equipment % GHG Reduction	1%	-	
Project % GHG Reduction	1%	-	
Renewable Natural Gas - Natural Gas Heating			
Avoided Fossil Fuel	17,726,600	m^3	
Gross Avoided GHGs	34,300	tCO$_2$e	
Additional GHGs	3,400	tCO$_2$e	Emission factor for renewable natural gas from GHGenius (2023).
Net Avoided GHGs	30,900	tCO$_2$e	
Equipment % GHG Reduction	1%	-	
Project % GHG Reduction	1%	-	
Total - Natural Gas			

B2-e. Ventilation-on-Demand in Underground (Scenario 2)

Key Parameters

	Value	Unit	Comments
Equipment Baseline Fuel	700,898,600	m^3	LOM, Natural Gas Electricity Generation in Underground Mine
Equipment Baseline GHGs	1,353,300	tCO_2e	LOM, Natural Gas Electricity Generation in Underground Mine
Equipment Baseline Fuel	347,450,900	m^3	LOM, Natural Gas for Heating at Mine
Equipment Baseline GHGs	672,300	tCO_2e	LOM, Natural Gas for Heating at Mine
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions
Utilization Factor	20%	-	Assumes 20% reduction in electricity and heating demand from start of underground operations.

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Ventilation-on-Demand Electricity Reduction			
Avoided Natural Gas Usage	102,651,400	m^3	Assumes 20% reduction in electricity demand from start of underground operations. Avoided natural gas usage for electricity.
Gross Avoided GHGs	198,200	tCO_2e	
Additional GHGs	0	tCO_2e	
Net Avoided GHGs	198,200	tCO_2e	
Equipment % GHG Reduction	15%	-	
Project % GHG Reduction	4%	-	
Ventilation-on-Demand Natural Gas Heating Reduction			
Avoided Natural Gas Usage	49,355,300	m^3	Assumes 20% reduction in heating demand from start of underground operations. Avoided natural gas usage for heating.
Gross Avoided GHGs	95,500	tCO_2e	
Additional GHGs	0	tCO_2e	
Net Avoided GHGs	95,500	tCO_2e	
Equipment % GHG Reduction	14%	-	
Project % GHG Reduction	2%	-	
Total			
Net Avoided GHGs	293,700	tCO_2e	

Implementation Examples

Site (Location)	Description	Project Stage
1. Teck Red Dog Lead Zinc	Waste heat from cooling diesel gensets is used to heat the mill, an efficient means of engine cooling when demand for heat is low	Implemented
2. Newmont Eleonore (Quebec)	VOD system from Howden VentSimTM CONTROL was implemented in the Newmont Goldcorp – Eleonore mine. The benefits of this solution are the energy efficiency and air treatment - 43% reduction in mine heating, 56% reduction in electricity and 73% reduction in surface ventilation electricity.	Implemented
3. Boliden Kankberg Gold Mine (Sweden)	ABB Ability™ Ventilation Optimizer provides fresh air for workers while delivering ventilation energy savings of 54% and air heating energy savings of 21% during first year of use	Implemented
4. Glencore	Glencore Nickel Rim South mine in Sudbury incorporated VOD for more than 10 years now	Implemented

B2-f. Onsite Renewable Energy Generation (Scenario 2)

Key Parameters

Parameter	Value	Unit	Comments
Baseline Fuel	929,742,500	m^3	LOM, Natural Gas Electricity Generation
Baseline GHGs	1,796,400	tCO_2e	LOM, Natural Gas Electricity Generation
Project Baseline GHGs	5,017,900	tCO_2e	LOM, Direct and Acquired GHG Emissions

GHG Reduction Potential Analysis

The following table summarizes the estimates of net avoided GHG emissions

Parameter	Value	Unit	Data Source / Assumptions
Renewable Energy Generation - Solar			
Avoided Natural Gas Usage	40,576,700	m^3	Solar power assumed to provide up to 24 GWh of onsite electricity starting in 2045.
Gross Avoided GHGs	78,400	tCO_2e	
Additional GHGs	0	tCO_2e	
Net Avoided GHGs	78,400	tCO_2e	
Equipment % GHG Reduction	4%	-	
Project % GHG Reduction	2%	-	
Renewable Energy Generation - Wind			
Avoided Natural Gas Usage	94,558,000	m^3	Wind power assumed to provide up to 55 GWh of onsite electricity starting in 2045.
Gross Avoided GHGs	182,700	tCO_2e	
Additional GHGs	0	tCO_2e	
Net Avoided GHGs	182,700	tCO_2e	
Equipment % GHG Reduction	10%	-	
Project % GHG Reduction	4%	-	
Total			
Net Avoided GHGs	261,100	tCO_2e	