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"Capacity Facility for Greenland - support to administrative capacity and Arctic processes"

ANALYSIS OF THE POTENTIAL FOR CLEAN ENERGY MICRO GRIDS IN THE MINING INDUSTRY IN GREENLAND,

implemented by RAMBOLL

in cooperation with

MINISTRY OF BUSINESS, MINERAL RESOURCES, ENERGY, JUSTICE AND GENDER EQUALITY, GOVERNMENT OF GREENLAND



Solar PV, Wind Turbines, Tidal Energy, Hydropower, Regenerative Braking, E-fuels and Storage Technologies.

Project funded by EU

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Prepared by	**Per Jørgensen, Frida Kloster, Enrica Raheli, Carlos Martin Nieto**
From	**Ramboll**

Report description

This report was commissioned by the Ministry of Business, Mineral Resources, Energy, Justice and Gender Equality, Government of Greenland and has been funded by the European Union via Agriconsulting Europe S.A, where Ramboll has acted as sub-consultant.

The reader of this report can use the report as a source of inspiration and should therefore not rely upon or use directly any parts of this project without an independent check and analysis being carried out. The reader of the report will work on its own risk if using any elements from the present report.

This report has been prepared by Ramboll in its professional capacity as an engineering consultant. The report therefore does not intend to include any legal advice or opinion. It has been prepared on an independent basis based on Ramboll's knowledge of the current market and with reference to various third party published reports and studies, information provided by third party and Ramboll's in-house analysis.

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1. Executive Summary

The study presented in the following pages of this report was commissioned by the Ministry of Business, Mineral Resources, Energy, Justice and Gender Equality of Greenland to assess the integration of clean energy (renewable energy, regenerative braking, etc.) solutions into microgrids within the mining industry. The initiative aims to align with Greenland's commitment to sustainable mineral resource development and the broader objectives of EU-Greenland cooperation to foster environmentally responsible economic growth. Today, Greenland hosts 25 of the 34 raw materials identified by the European Commission in 2023 as critical for the EU's green and digital transition, many of which are associated with high supply risks. Both the EU and Greenland share a mutual interest in sustainable mining practices and seek to establish responsible mineral value chains from Greenland's mines to the EU's industrial ecosystems.

The primary objective of this report is to conduct a detailed analysis of the technical feasibility and cost-effectiveness of various clean energy technologies for remote mining sites in Greenland. Specifically, the report evaluates the potential benefits and limitations of incorporating clean energy technologies into microgrids serving these remote locations, in comparison to traditional fossil fuel-based systems. To achieve the stated objectives, this study evaluates a range of clean energy technologies, including solar, wind, hydropower, tidal energy, regenerative braking, e-fuels, and battery energy storage systems (BESS). These are compared with fossil fuel-based technologies such as diesel generators and diesel storage to provide a comprehensive assessment.

Due to Greenland's vast geographic diversity, the potential for clean energy resources varies significantly across regions, necessitating region-specific analyses. For this purpose, the study focuses on four representative geographical regions —East, South, West, and North— each encompassing current or potential mining operations:

1. East: Greenland Resources A/S
2. South: GreenRoc Graphite Limited and TANBREEZ Mining Greenland A/S
3. West: Lumina Sustainable Materials A/S and Qaatsuitsup Ulloriaa (Neo North Star Resources Inc)
4. North: Ironbark A/S

These regions and the grouping were selected in collaboration with the Ministry, mining facilities, and publicly available data from organizations such as Nukissiorfiit.

For each region, different scenarios encompassing a mix of clean energy technologies used to satisfy the mine´s electricity and transport demand are considered and assessed in the techno-economic analysis. Table 1-1 summarizes the scenarios considered for the electricity and transport demand, respectively. The electricity demand category includes five overall scenarios: Diesel Generator (Business-as-Usual), Mix of Solar photovoltaic (PV) and Wind, Hydropower, E-fuel, and Tidal Energy. The transport category includes two scenarios: Diesel Trucks (Business-as-Usual) and Regenerative Braking.

Category	Scenarios
Electricity demand	Diesel Generator (Business-as-Usual)
	Mix of Solar PV and Wind
	Hydropower
	E-fuel
	Tidal Energy
Transport demand	Diesel Trucks (Business-as-Usual)
	Regenerative braking

Table 1-1: Scenario overview.

Ramboll's Energy System Modelling tool was used to optimize the sizes and operation of the technologies included in each scenario to minimize total system costs, i.e., both capital expenditures (CAPEX) and operational expenditures (OPEX), while meeting all technical and operational limitations of the components. The tool has been customized to address the specific requirements of this analysis and functions as an energy hub model for the microgrids in Greenland's mining industry. For Solar PV and Wind, it takes as input the hourly electricity production for a specific location in a reference year (based on publicly available data from Renewables.ninja [48]).

For each scenario, the primary outputs of the model include the sizes of the technologies and their corresponding hourly operation (i.e., the hourly energy flows within the system). These outputs are then used in the techno-economic analysis to calculate CAPEX, OPEX, discounted cash flows, and key performance metrics, such as the levelized cost of electricity (LCOE) in EUR/MWh, the Clean Electricity Share (CES), and the Clean Electricity and Transport Share (CETS).

Key outputs of the modelling analysis include:

- **Capacity of clean energy technologies**: installed capacity of technologies needed to meet the mine´s electricity demand.
- **Levelized cost of electricity (LCOE)**: average cost per unit of electricity consumed from the mix of energy-generating technologies that supply its demand.
- **Clean Electricity Share**: share of the total yearly electricity demand of the mine that is met by clean energy technologies.
- **Clean Electricity and Transport Share**: share of the total yearly energy demand of the mine that is met by clean energy technologies, including both electricity and transport demand.

Figure 1-1 provides an overview of the LCOE and Clean Electricity Share of the various electricity-producing technologies analysed in this study. These technologies include diesel generator (business-as-usual), a mix of solar PV, wind and potentially diesel generator (lowest LCOE, same LCOE as Diesel Generator, and 100% solar PV and wind), hydropower (new hydropower plant with 100 km or with 1035 km electrical lines, upgraded hydropower plant + 100 km electrical line and different combinations of an upgraded hydropower plant with solar PV, wind turbines and diesel generator), green hydrogen, e-methanol, and tidal energy. The South location is used as a reference, but similar conclusions can be drawn for the other locations.

The scenario with the lowest LCOE involves upgrading an existing hydropower facility with additional production capacity close to the mine (approximately 100 km distance), achieving an LCOE of 60 EUR/MWh with a Clean Electricity Share of 100%. If upgrading an existing hydropower facility is not feasible, constructing a new hydropower facility also presents a competitive LCOE. For instance, if a new facility is built with a 1035 km electrical line, the LCOE would still be comparable to that of the Diesel Generator (Business-as-Usual) scenario, while achieving a Clean Electricity Share of 100%. Shorter distances between the hydropower facility and the mine could significantly reduce the LCOE compared to the Diesel Generator (Business-as-Usual) scenario.

Hydropower, whether through upgrading an existing facility or building a new one, emerges as the most economically feasible technology to fully decarbonize the electricity demand of the mines. It can also be deemed competitive to implement a combination of an upgraded hydropower plant, solar PV, wind turbines and diesel generator, though the Clean Electricity Share is only at 68%. There will be cases where the production from the hydropower plant will not fulfil both the peak and total energy demand. In these cases, it is relevant to consider options where hydropower is accompanied by solar PV, wind turbines and/or a diesel generator. As wind and solar are fluctuating

resources it will in most cases (where the hydropower can't fulfil the peak demand) be relevant to also include a diesel generator to ensure the demand is covered in all hours.

Achieving a 100% Clean Electricity Share using only solar PV, wind, and Battery Energy Storage Systems (BESS) is not economically viable due to the need for significant oversizing of solar PV and onshore wind plants, along with large BESS requirements. Similarly, importing e-fuels from Europe or producing it in Greenland led to significantly higher costs compared to fossil fuel alternatives.

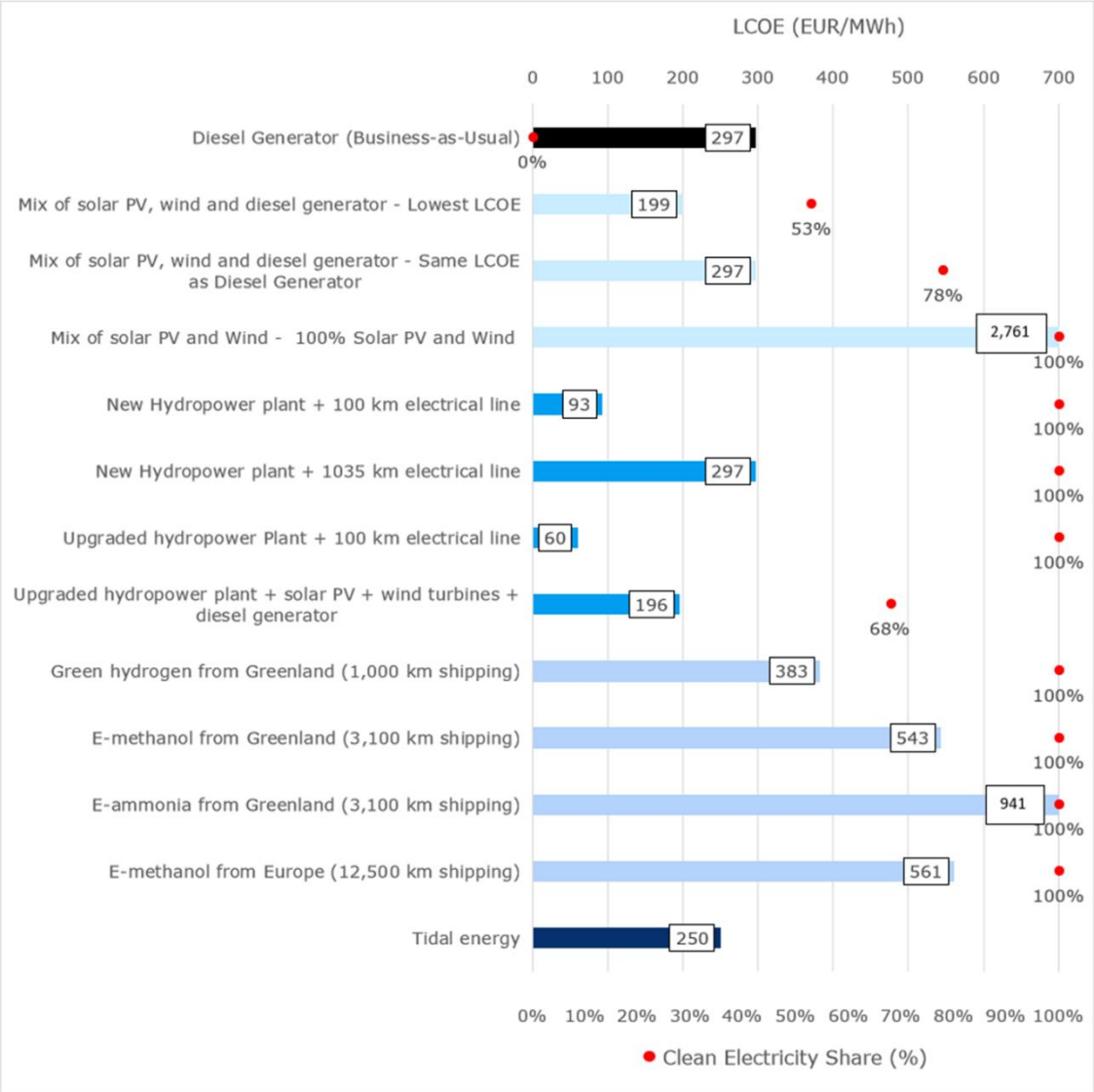


Figure 1-1: Scenario comparison of the clean energy solutions that can be used to decarbonize a mine´s electricity demand.

Tidal energy potential is highly site-specific and requires on-site measurement of high and low tide heights. The LCOE shown in Figure 1-1 for tidal energy represents an average sourced from various references. To fully meet the mine's electricity demand, tidal turbines would need to be combined with a Battery Energy Storage System (BESS) or a diesel generator, which would further increase the total LCOE of the energy mix. Tidal energy is a promising technology for Greenland, particularly due to its numerous large fjords. However, its application is currently hindered by high capital expenditure (CAPEX) due to the low maturity of this technology and environmental impact barriers.

Finally, Figure 1-1 shows that supplying the mine with a mix of solar PV, wind, and diesel generators (Lowest LCOE and Same LCOE as Diesel Generator scenarios) can achieve an LCOE lower than or similar to the business-as-usual scenario (199-297 EUR/MWh) while reducing dependence on fossil fuels by more than half (Clean Electricity Share of 53-78% for the South location). This indicates that decarbonization can be achieved at no additional cost compared to the business-as-usual scenario.

Figure 1-2 and Figure 1-3 illustrate the dynamic interplay and complementarity of solar PV, onshore wind, and diesel generator in meeting the mine's electricity demand. Figure 1-2 shows the monthly contributions of each energy source, while Figure 1-3 provides an hourly view for a representative week. The East location is used as an illustrative example. Figure 1-2 shows the significant variability in solar resources, with solar PV production almost nonexistent during the winter months. Wind production is more stable during the year and slightly increases during winter months when solar PV production is minimal. Figure 1-3 shows an illustrative week of operation during the summer, where solar PV plays a significant role, with wind generation compensating during cloudy days and nights. The diesel generator serves as a backup during periods of low renewable energy availability.

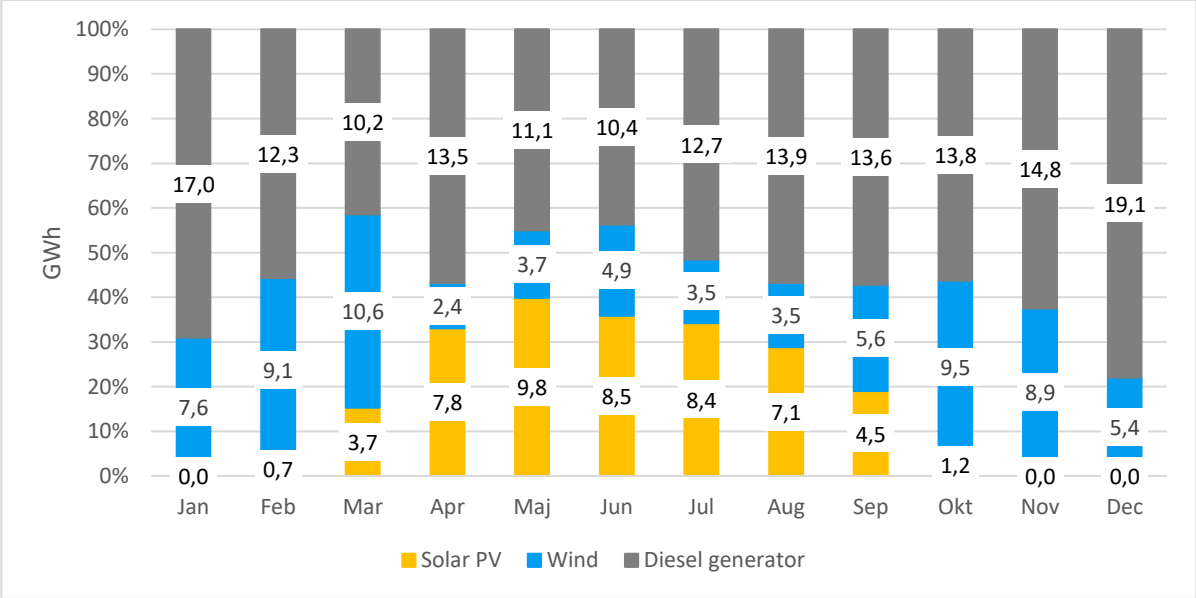


Figure 1-2: Monthly electricity production (Lowest LCOE scenario for East location).

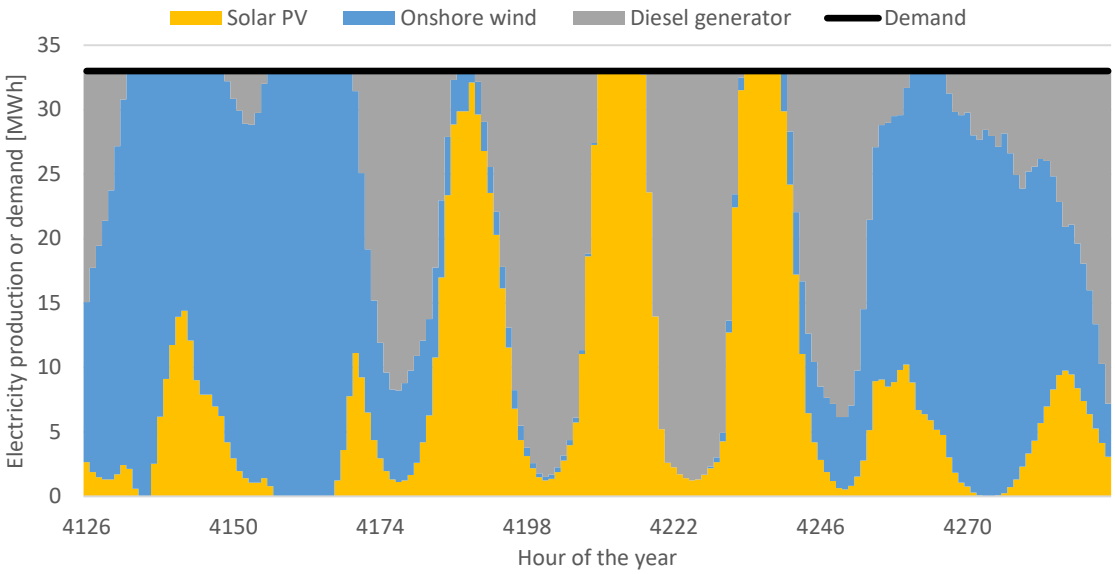


Figure 1-3: Hourly electricity production and demand for one representative week in summer (Lowest LCOE scenario for East location).

Transport fuel demand constitutes approximately 60% of the total energy demand of the mine. This study explored the potential of regenerative braking for conveyor belts and electric or hybrid trucks. Results indicate that, under the right conditions of slope and transport capacity, regenerative braking can significantly reduce transport energy demand. Conveyor belts are a good technology for using regenerative braking as they through the regenerative braking technology can be energy-reducing, energy-neutral or even energy-positive, where more energy is created through the braking system than of the consumption of the conveyor belt. This could effectively eliminate the transport energy demand while recovering extra energy from the braking system. This recovered energy can be repurposed for other mining operations. In the case of electric or hybrid vehicles, a high-level assessment demonstrated that with a 5% slope, diesel consumption can be reduced by approximately 20% using regenerative braking technology. Studies show that trolley systems using overhead electricity lines have the ability to reduce the fuel consumption with up to 50-60% compared to conventional diesel-powered haul trucks. There are also cases where electric trucks have been implemented successfully and, in some cases, eliminate the need to charge or refuel, by only using the regenerative braking systems for energy.

2. Introduction

This report aims to provide a comprehensive assessment of the potential of incorporating clean energy into the power supply infrastructure of mining operations in Greenland. Commissioned by the Ministry of Business, Mineral Resources, Energy Justice and Gender Equality, the project seeks to evaluate the technical feasibility, economic competitiveness, and long-term viability of clean energy technologies tailored to the unique demands and challenges of Greenland's mining sector.

Greenland is characterized by its remote and rugged terrain, extreme arctic climate, and lack of a centralized electrical grid. Mining operations in the region are currently reliant on stand-alone fossil-fueled power solutions, which provide scalable and reliable power but come with environmental impacts and operational costs. Given the global transition towards cleaner energy and the urgent need to reduce greenhouse gas (GHG) emissions, this project aims to explore how clean energy technologies can be leveraged to reduce the carbon footprint and improve the sustainability of Greenland's mining industry.

Mining could play a critical role in Greenland's economic development and its global importance in securing critical raw materials. Greenland hosts deposits of 25 of the 34 critical raw materials defined by the European Commission in 2023 as having high importance for the EU's green and digital transitions. These resources include rare earth elements, highlighting Greenland's potential to contribute significantly to the global green energy shift. As this report is intended for an audience already familiar with the importance of mining for Greenland, a dedicated chapter on the topic is not included in the main report. However, *Appendix 1* provides a detailed description of Greenland's mineral occurrences, its mining history, and future mining plans, offering valuable context for understanding the opportunities and challenges addressed in this report.

The study assesses a range of clean energy technologies. These include solar photovoltaic systems, onshore and nearshore wind turbines, hydropower reservoirs, and tidal energy systems. Energy storage solutions are also evaluated (battery energy storage solutions), considering their potential for providing consistent power to remote, off-grid mining sites. The report further examines emerging technologies, such as regenerative braking systems for mining vehicles, and e-fuels based on clean energy sources through PtX technologies.

In assessing these technologies, the analysis considers not only the short-term but also the long-term perspectives, recognizing that while some technologies may not currently be cost-competitive with traditional hydrocarbon-based systems, future innovations and economies of scale could significantly improve their viability.

2.1 Chapter Guide

The report is structured as follows:

- Chapter 3 includes an assessment and mapping of clean energy resources in Greenland – including solar PV, wind, hydropower, regenerative braking, tidal resources, e-fuels, energy storage (battery energy storage, diesel tanks, and e-fuel storage), and fossil fuel-based technologies.
- Chapter 4 gives an overview of the mines in Greenland including future mining facilities, selects the mines to be included in this study, and groups the mines into geographical regions.

- Chapter 5 presents the methodology for the techno-economic assessment, including component sizing, definition of metrics, scenarios definition, and assumptions behind the economic model.
- Chapter 6 presents the results of the decarbonization of the mine´s electricity demand based on different technology configurations (Diesel Generator – Business-as-usual, Mix of Solar PV and Wind, Hydropower, E-fuel, and Tidal Energy), including a comparison of the different scenarios.
- Chapter 7 presents the results for the decarbonization of the mine´s transport demand (Diesel Tucks – Business-as-usual, Regenerative breaking from conveyor belts, e-fuels for transport and electric trucks).
- Chapter 8 presents the conclusions of the study.
- Chapter 9 presents the references of the study.
- Chapter 10 presents the appendixes of the study.

2.2 Abbreviations

Following is an overview of the abbreviations of this study.

- **BESS** – Battery Energy Storage Solutions.
- **CAPEX** – Capital Expenditures.
- **CCS** – Carbon Capture and Storage
- **CES** – Clean Electricity Share
- **CETS** – Clean Electricity and Transport Share
- **CHP** – Combined Heat and Power.
- **GHG** – Greenhouse Gas.
- **LCOE** - Levelized Cost of Electricity.
- **LOHC** – Liquid Organic Hydrogen Carriers.
- **OPEX** – Operational Expenditures.
- **PtX** – Power-to-X.
- **PV** – Photovoltaic.

3. Clean Energy Resources in Greenland

This assignment focuses on assessing various clean energy technologies and their potential in Greenland. Each technology is evaluated in terms of its technical advantages and disadvantages, as well as its profitability compared to traditional hydrocarbon-based energy sources, considering Greenland's unique regional and local conditions. The clean energy technology potentials being assessed in depth are:

- **Solar Photovoltaic (solar PV)**
- **Onshore and Nearshore Wind Turbines**
- **Hydropower**
- **Tidal Energy**
- **E-fuels**
- **Energy storage**
- **Regenerative Braking**

A more in-depth technological description of the above-mentioned technologies and several other technologies is included in *Appendix 3*. The additional technologies presented in *Appendix 3* include battery energy storage systems, large- and small-scale hot water tanks, hydrogen storage, biomass and electric boilers, waste and biomass combined heat and power (CHP) plants, compression and absorption heat pumps, diesel generators and the utilization of their excess heat, carbon capture, hydrogen pipeline distribution, and Power-to-X (PtX) technologies. Furthermore, *Appendix 3* also includes a description of microgrids and considerations that must be made when operating in Greenland.

As previously mentioned, this study evaluates not only the technical viability but also the potential profitability of these technologies. If clean energy technology is deemed technically feasible but not currently profitable compared to hydrocarbon-based alternatives, the assessment tries to project the future potential for cost parity, considering technological advancements and economies of scale.

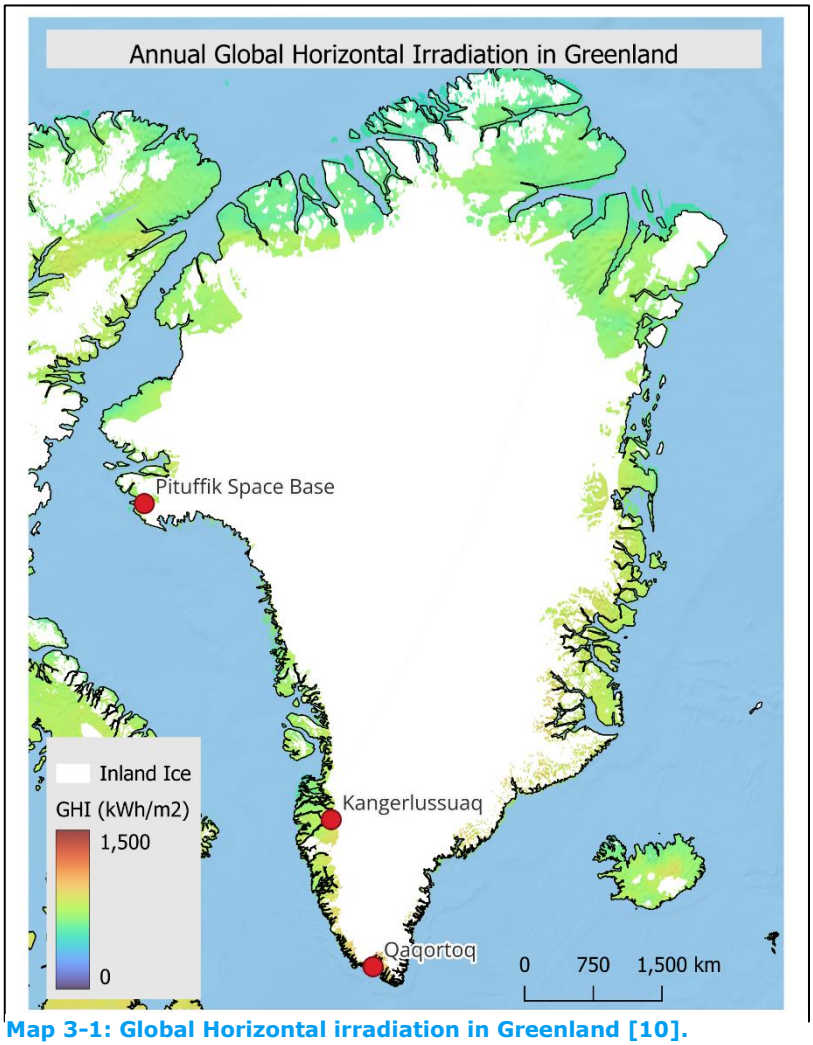
Since the focus of the study is technical and financial feasibility, environmental challenges, such as subsea noise from tidal turbines, may be acknowledged but are outside the scope of this project. Likewise, clean energy projects combined with carbon capture and storage (CCS) are beyond the project’s scope.

Lastly, it must be noted that for all the energy potentials described in the following pages installing infrastructure (such as wind turbines and solar PV) on the inland ice has not been considered in this study. This is due to the safety risks that come with installing and maintaining technologies on ice that is moving, and the high costs of transporting the electricity to the mines through long electrical lines.

3.1 Solar Resources

In 2023, Nukissiorfiit installed 620 kW of solar panels, all of which are now active. An additional 105 kW of solar panels were purchased in 2023 and are scheduled to be connected in 2024. With the currently connected capacity, the expected annual production from these solar panels is approximately 558 MWh [5].

Solar irradiance is one of the most critical and variable factors for determining the suitability and potential energy production from solar installations (Map 3-1). Greenland's high latitude presents extreme seasonal variations in solar irradiance. While 24-hour daylight in the summer above the Arctic Circle (increasing with latitude), offers excellent opportunities for solar energy generation, the polar night (extended periods of darkness) in winter poses challenges. Seasonality challenges for solar energy are more severe in northern Greenland due to its higher latitude. Northern regions can experience up to two months of polar night during winter, making solar power generation impossible during that time. In contrast, southern Greenland has shorter periods of darkness and more daylight during the spring and autumn. However, both regions benefit from many hours of sunlight in the summer, offering strong solar potential during those months despite winter limitations in the north. Solar PV facilities have the highest capacity factor when there is direct sunlight but can also produce electricity through indirect sunlight.



Map 3-1: Global Horizontal irradiation in Greenland [10].

Figure 3-1 shows the monthly solar PV production from a 10 MW plant in Kangerlussuaq, Qaqortoq and Pituffik Space Base. It shows that the production from solar PVs is highest in the summer months, where there are more hours of daylight. The three locations are chosen in order to have one in the North of Greenland (Pituffik Space Base), one near the Artic Circle (Kangerlussuaq) and one in the south of Greenland (Qaqortoq). The location of the three are visualized on the above Map 3-1, while the coordinates and capacity factor of the solar PV plant at the three different locations are shown in the below Table 3-1.

Location	Coordinates	Capacity factor
Pituffik Space Base	60.7349; -46.1774	11 %
Kangerlussuaq	67.0302; -50-6745	12 %
Qaqortoq	76.5294; -68.7176	13 %

Table 3-1: Coordinates and Capacity factors for solar PV for Kangerlussuaq, Qaqortoq and Pituffik Space Base. [48]

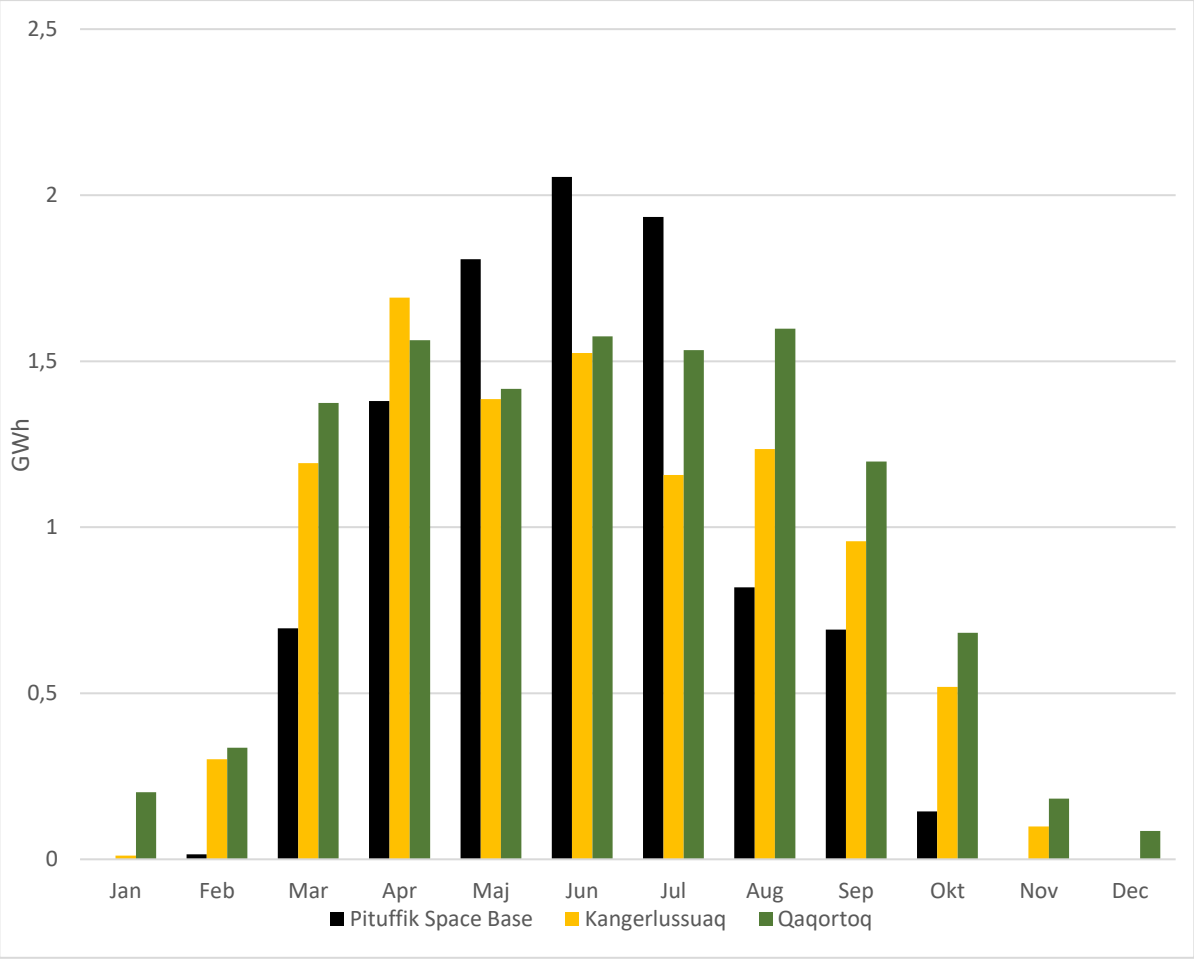


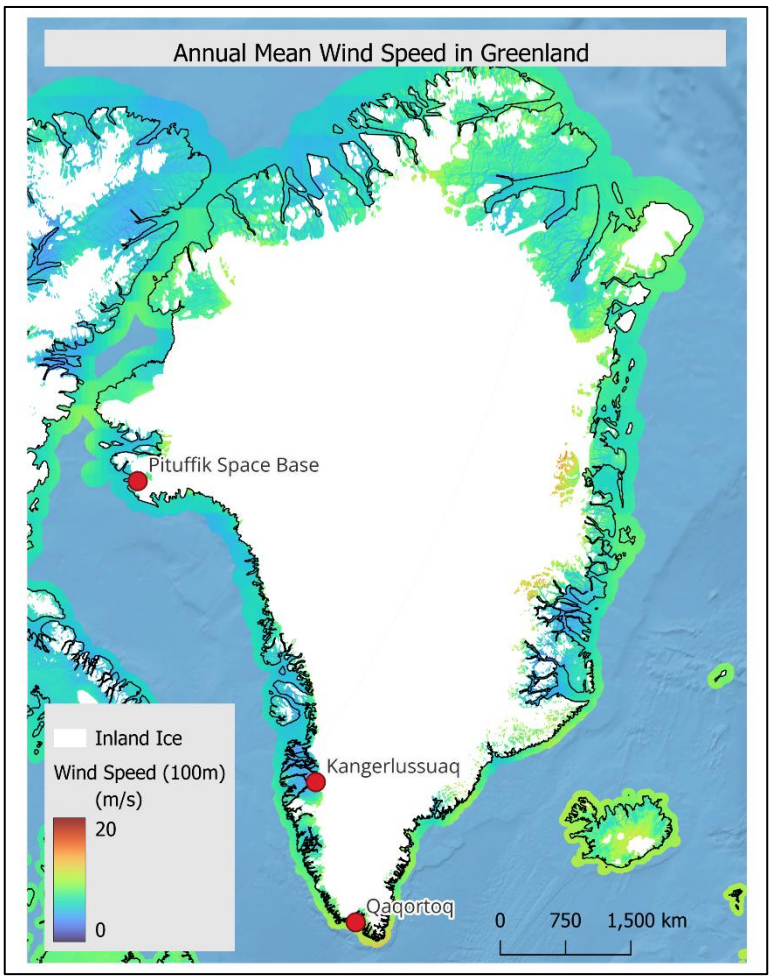
Figure 3-1: Monthly solar PV production at Kangerlussuaq, Qaqortoq and Pituffik Space Base. [48]

In some areas, water, snow and ice can increase the efficiency of solar panels by reflecting sunlight back onto the panels (a phenomenon known as the albedo effect).

The landscape can also play an important role in determining where and how solar panels can be installed. The conditions of the terrain, including subsurface freezing, influence foundation types while the accessibility of equipment and technicians for operation and maintenance (O&M) affects site selection and ongoing maintenance costs. These are all factors that must be taken into account when selecting a specific site for the installation of solar panels.

3.2 Wind Resources

Currently, Greenland operates only three wind turbines with a total capacity of 56 kW [5], but several sites have shown significant promise for future development and new wind turbines are already planned to be installed [5]. Greenland's wind energy potential presents both opportunities and technical challenges, particularly due to the Arctic conditions. Greenland possesses some of the highest annual mean wind speeds in the world, with some sites reaching over 15m/s and most coastal areas averaging between 4 and 8 m/s [8]. Some of the highest wind speeds in Greenland can be found in the interior of the country, this is due to Katabatic winds that typically originate from the ice sheet and flow down the slopes towards the coast. These winds are driven by the cooling of dense air over the ice sheet, which then descends due to gravity. The southern tip of Greenland also shows very high mean wind speeds. Too high wind speeds could potentially damage wind turbines and many turbine models operate by a cut-out wind speed around 25-30 m/s to prevent damages [26].



Map 3-2: Annual average wind speed at 100m height [7]

Onshore wind turbines benefit from higher air density in cold climates, which increases efficiency. However, they can face issues during winter months, including ice accumulation on turbine blades, which reduces aerodynamic efficiency and can lead to mechanical failures. To mitigate these challenges, advanced turbine designs incorporate blade heating systems and ice-resistant coatings, which are critical for maintaining operational integrity in Arctic environments. These measures help ensure consistent energy output despite freezing conditions, while turbine control systems can automatically shut down or adjust to prevent damage from ice formation. Map 3-2 shows the annual average wind speed at 100 m height, and also the three locations of Kangerlussuaq, Qaqortoq and Pituffik Space Base. The three locations are chosen in order to have one in the North of Greenland (Pituffik Space Base), one near the Artic Circle (Kangerlussuaq) and one in the south of Greenland (Qaqortoq). The coordinates and capacity factor for the three locations for a wind turbine of 4.2 MW are shown in Table 3-2. Figure 3-2 gives an overview of the monthly production from a wind turbine of 4.2 MW in the three locations, while Figure 3-3 shows a duration curve for the same wind turbine production in the three locations.

Location	Coordinates	Capacity factor
Pituffik Space Base	60.7349; -46.1774	27 %
Kangerlussuaq	67.0302; -50-6745	24 %
Qaqortoq	76.5294; -68.7176	41 %

Table 3-2: Coordinates and Capacity factors for wind for Kangerlussuaq, Qaqortoq and Pituffik Space Base. [48]

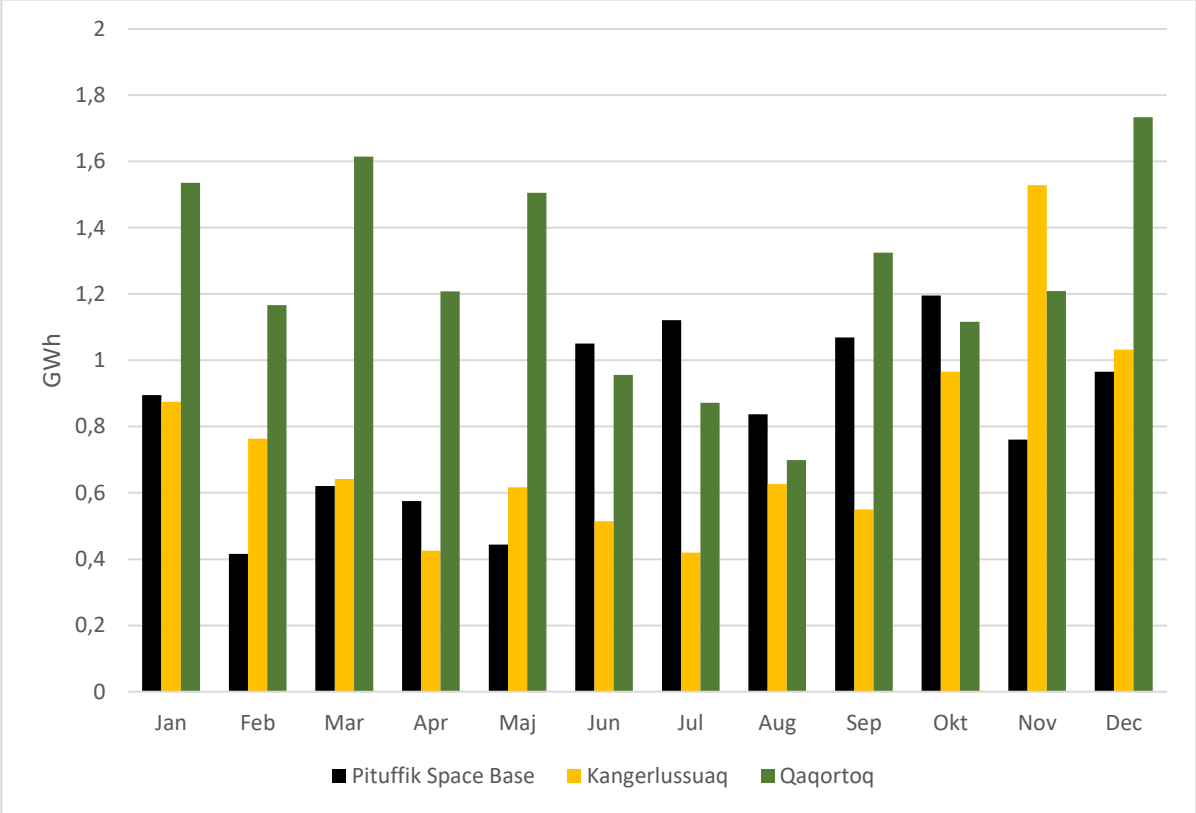


Figure 3-2: Monthly production for an onshore wind turbine in Kangerlussuaq, Qaqoortoq and Pituffik Space Base. [48]

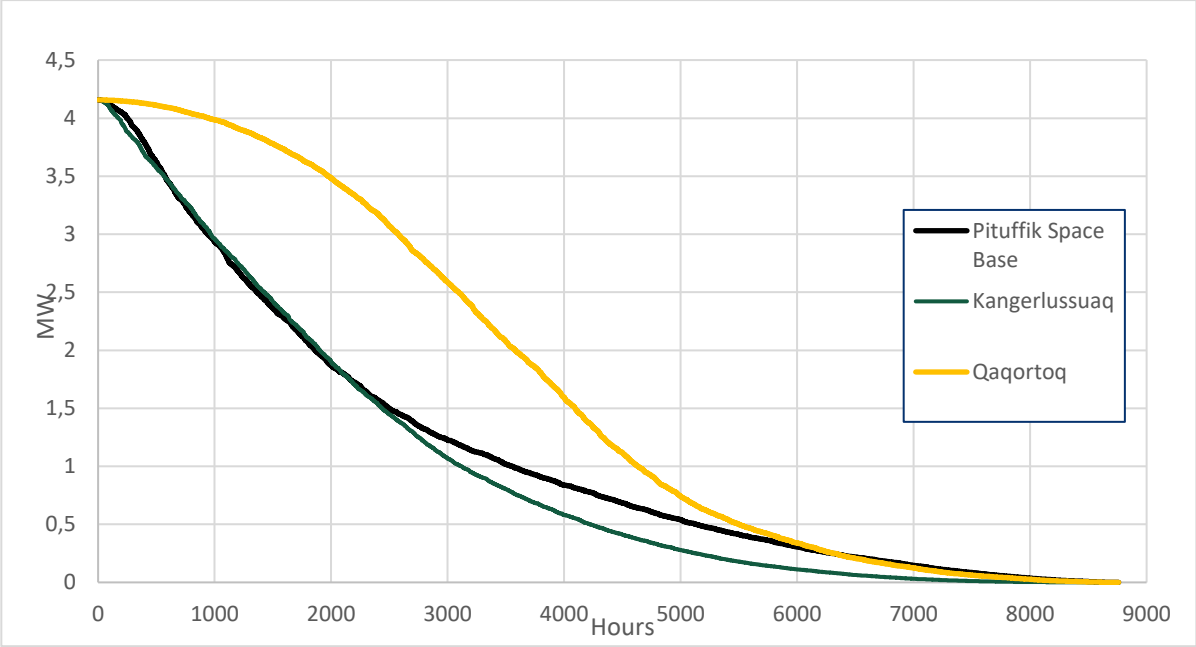


Figure 3-3: Power duration curve for an onshore wind turbine (4.2 MW) in Kangerlussuaq, Qaqoortoq and Pituffik Space Base. [48]

It is not deemed feasible to install offshore wind turbines, due to float ice in the waters that would damage such turbines. On the contrary, it is viewed that nearshore and onshore wind turbines would be feasible in Greenland, as they are placed onshore or in shallow waters e.g. in fjords where icebergs and drift ice (under the right conditions) cannot reach.

Nearshore turbines are a feasible technology for the mining industry in Greenland to consider, as the turbine capacities are higher than for onshore turbines which leads to higher efficiencies. Nearshore wind turbines could be connected through array cables to onshore transformer stations. Due to the more simplified grid compared to offshore wind farms, no offshore substation, more shallow waters, and shorter distances to service hubs, nearshore wind turbine farms have a lower cost level for both investment and O&M. [26]

For onshore wind turbines (dependent on the specific turbine size and model) the cut-in wind speed is around 3-4 m/s, the rated power generation wind speed is at 10-12 m/s (where the power output reaches 100 % for the turbine), and the cut-out wind speed is around 25 m/s. [26]

Due to the lack of infrastructure (roads etc.) at remote mining facilities it can be difficult to install the onshore and nearshore turbines, and thereby make it more expensive to implement wind turbines compared to places with a high density of infrastructure.

This report does not include a detailed planning of wind turbine placement in connecting to specific wind speeds. This kind of detailed study would require a comprehensive analysis including site visits and measurements of specific wind speeds.

3.3 Tidal Resources

Tidal power generation utilizes the natural rise and fall of ocean tides or tidal energy current, which are caused by the gravitational forces exerted by the moon and the sun on the Earth's oceans. Tidal technologies can be divided into two main groups: tidal stream and tidal range.

Tidal stream (or tidal current) generators capture the kinetic energy of moving water caused by tidal currents. This method often uses underwater turbines, similar to wind turbines, to generate electricity. Due to the density of water, tidal stream turbines can generate more power at slower speeds compared to wind turbines. The most common and mature type of tidal stream turbines is the horizontal axis design, which can be either fixed to the seafloor or floating with moorings attached to the seafloor. Other designs, including lower Technology Readiness Level (TRL) technologies, include vertical axis turbines, tidal kites, and oscillating hydrofoils [57].

Tidal range energy harnesses the potential energy from the height difference between high and low tides using structures like tidal barrages or tidal lagoons. A tidal barrage is a dam-like structure built across a tidal estuary or coastal basin, equipped with turbines that generate power as water flows through during tidal movements. These turbines extract power from tidal flows similar to how river dams generate power from river flows. Tidal barrages can operate in various modes such as ebb generation (energy generation during the outgoing tide), flood generation (energy generation during the incoming tide), or both (also called double-mode generation). Tidal lagoons are similar to tidal barrages, but they create an artificially constrained body of water along a natural coastline. An example of a tidal barrage and a tidal lagoon are shown in Figure 3-4.

Currently, only a few tidal power stations are operational. The largest include:

- Sihwa Lake Tidal Power Station in South Korea (254 MW capacity)
- Rance Tidal Power Station in France (240 MW capacity)

Both stations are barrage-type. Additionally, the MeyGen project in Scotland is the largest planned tidal stream project, with the first 6 MW already operational. Several other tidal projects are under construction or at the proposal stage [63].



Figure 3-4: Example of tidal barrage (on the left) [58], and tidal lagoon (on the right) [59].

Tidal energy is a highly predictable renewable energy source with limited impact from weather conditions, compared to, for example, wind and solar energy. The lifespan of tidal power plants is generally long (e.g., Rance Tidal Power Station has been operating since 1966) [60]. However, tidal energy faces several challenges. The main barrier associated with tidal energy is the relatively high initial capital expenditure (CAPEX) for construction and significant maintenance costs. Additionally, limited suitable locations with the required tidal range exist in the world. Producing tidal energy economically requires an average tidal range (i.e., the difference between high tide and low tide) of at least 3-5 meters [60, 61]. Finally, tidal energy poses environmental challenges related to protecting ocean resources and existing uses like fishing and navigation [12]. Environmental impacts include potential harm to marine life, disruption of sediment transport, underwater noise, electromagnetic fields (EMFs) affecting animal behavior, and changes in local ecosystems [62].

Greenland's numerous fjords present an interesting potential for tidal energy. The irregular coastlines with narrow bodies of water and sizable tidal ranges suggest potentially promising sites for tidal energy extraction. The tidal energy potential in the fjords of Greenland could be a suitable technology for decarbonizing remote mines in Greenland since the mines tend to be located close to fjords, for easy shipment of minerals [21, 22]. A tidal barrage could be particularly of interest. A damn with turbines could be built across the fjord to create a water basin that experiences tidal ranges. Alternatively, tidal lagoon could also be relevant for the larger fjords.

The potential for tidal energy in Greenland depends significantly on the geographical location. Entities like the Danish Meteorological Institute [24] (and other public websites [23, 25]) provide tide tables for several harbours in Greenland (around 100 locations), but accurate predictions at other sites would require on-site measurements. Figure 3-5 shows the tidal level at the Nakasuk station in West Greenland (around 70 km northeast of Nuuk), taken as an illustrative example. For this location, the difference between high and low tides ranges between 1 and 5 meters, with a yearly average of 2.6 meters.

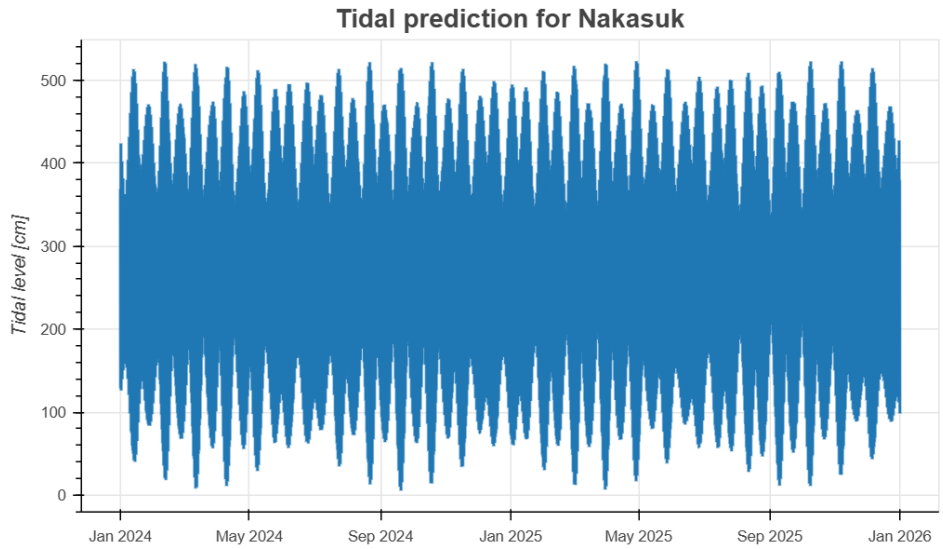


Figure 3-5: Tidal level at Nakasuk station (64.639900, -50.784900) in the West of Greenland. [24])

An estimation of the maximum potential energy that can be extracted by tidal barrage and lagoon technologies and its dependence on the surface area of the basin and tide range will be discussed in Section 6.4.

3.4 Hydropower Resources

Greenland is endowed with vast, largely untapped hydropower resources, exceeding domestic energy needs. The stable and environmentally sustainable nature of hydropower reservoirs makes it a key component of Greenland's energy transition.

Greenland's energy transition has seen significant progress in recent decades. As of 2023, hydropower covers more than 80% of Greenland's electricity demand [41]. This shift has been driven by the development of five hydropower plants, which have significantly reduced the country's dependence on imported fossil fuels, contributing to a cleaner, more sustainable energy system [5]. The public utility, Nukissiorfiit, has been utilizing hydropower for over 30 years in public energy production.

Global warming has increased glacial meltwater, in a way enhancing Greenland's reservoir capacities. Discharge rates have been monitored over the years, ensuring that these hydropower sources remain viable long-term, despite the environmental challenges posed by climate change. The Greenlandic government is committed to reducing reliance on fossil fuels and advancing clean energy technologies to mitigate the effects of climate change, which threatens Greenland's unique biodiversity.

Map 3-3 presents the currently operational 5 hydropower reservoirs plants in Greenland:

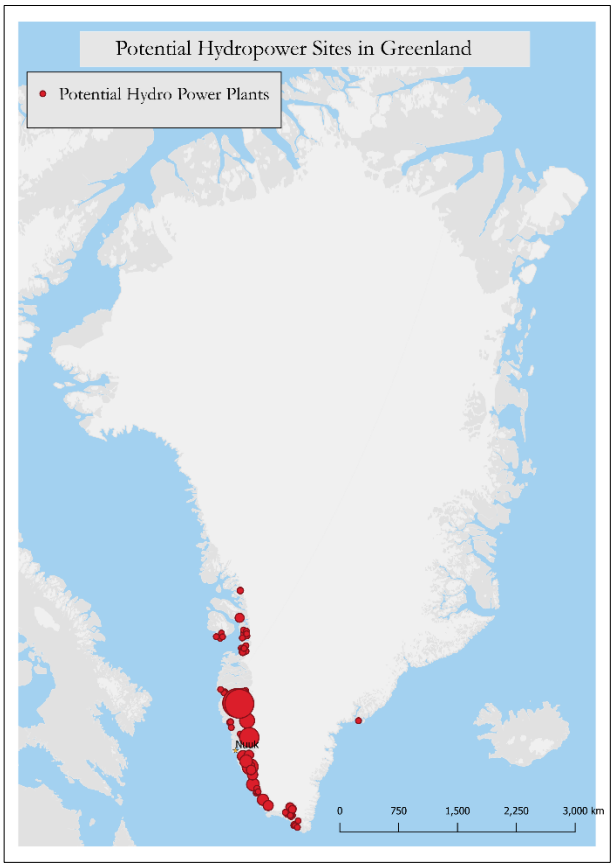
- **Qorlortorsuaq**: Completed in 2007, this plant has a capacity of 7.2 MW and supplies electricity to both Qaqortoq and Narsaq. It was the first hydropower plant in Greenland to provide energy to more than one town, replacing diesel generators that previously powered these communities. In 2023 it produced 35.5 GWh. [5].
- **Buksefjord (Nuuk)**: Greenland's first and largest hydropower plant, commissioned in 1993, with a total capacity of 45 MW. Today, there are plans to increase the plant's capacity to meet Nuuk's growing demand. The plant produced 293.5 GWh in 2023 [5].

- **Sisimiut**: Operational since 2009, this plant has a capacity of 15 MW and uses water from Lake Tasersuaq. It supplies electricity and heating to Sisimiut, Greenland's second-largest town. A very wet summer in 2023 led to record production of 59.5 GWh [5].
- **Paakitsoq**: This plant was developed to serve Ilulissat, Greenland's third-largest town, and has a total capacity of 22.5 MW. Set a record in 2023 with a production of 81.2 GWh, despite some outages leading to diesel backup usage [5].
- **Tasiilaq**: Inaugurated in 2005, this small hydropower plant has a capacity of 1.2 MW. Recorded a record production of 6.7 GWh in 2023 [5].

Additionally, the Government of Greenland has performed numerous studies to expand the hydropower reservoir capacity of the country and has selected over 60 sites with hydropower reservoir potential [6]. Map 3-4 presents the potential hydropower reservoir plants that have been studied.



Map 3-3: Existing Hydropower plants in Greenland (scaled by production capacity) [6]



Map 3-4: Potential Hydropower plants in Greenland (scaled by projected capacity) [6]

As Map 3-3 and Map 3-4 show, the southwest region of Greenland holds the majority of the country's hydropower reservoir resource potential due to its unique geographic and climatic conditions. The relatively milder climate in the southwest, compared to the northern regions, ensuring year-round hydropower operation with fewer interruptions. The area features mountainous terrain and deep fjords, creating ideal conditions for hydropower generation. The steep elevation gradients in this region also enhance the gravitational force needed for effective power generation.

Hydropower can also be categorized as a run-of-river technology and can be utilized in the fjords or rivers of Greenland. The run-of river hydropower technology is a facility that channels flowing

water from a river or fjord and energy would be harnessed through turbines when water is running through.

A detailed description of various hydropower technologies can be found under 'Pumped Hydro Storage' and 'Hydro Reservoir Storage' in *Appendix 3*. The investment cost of installing electrical lines from a hydropower plant to a mine is covered under 'Electric Transmission and Distribution Networks' in *Appendix 3.* The cost of connecting a mine to a hydropower plant varies depending on the specific scenario. If the hydropower plant has excess capacity, it may be sufficient to invest solely in electrical lines from the plant to the mine. However, if the plant is operating at full capacity, it may be necessary to increase the reservoir's water volume by constructing tunnels to nearby lakes and expand the plant by adding additional turbines, in addition to installing the connecting electrical lines. Another option is to build a new hydropower plant specifically to supply electricity to a single mine or a group of mines in the area.

3.5 Regenerative Braking

Regenerative braking represents an innovative approach to harnessing energy during downhill transport operations at mining sites. By capturing the kinetic energy generated during braking, this technology can significantly reduce the energy demand and carbon footprint associated with mining activities. Today there are different ways to implement regenerative braking. The primary application of regenerative braking in mining is conveyor systems, although alternative systems like trolley trucks, (modified) electric haul trucks, (e-)trains, and material ropeways also exist for specific scenarios.

Regenerative braking is one of the most efficient methods to reduce diesel consumption. Diesel fuel consumption typically accounts for 40-60% of the total energy demand in a mine and the entirety of the energy demand in the ore transportation process [15] [50]. The most effective implementation of regenerative braking for open pit mines involves conveyor systems equipped with energy recovery mechanisms [15]. These systems have the potential to completely eliminate energy consumption during material transport, thereby achieving energy neutrality in the transportation phase. Some systems have also shown the ability to not only cover but also generate extra energy. The efficiency of these regenerative conveyor systems is dependent on factors such as the inclination of the route and the capacity of the conveyor (tons/hour). A study for a Polish open-pit mine has shown that under optimal conditions a slope steeper than 2 degrees and a transport capacity exceeding 280 tons per hour could allow conveyor systems to start recovering part of their breaking energy and lower the operational costs associated with diesel usage (Figure 3-6). An example of this is the proposed rope conveyor in the Greenland Resources Malmbjerg project, with an average inclination angle of 2.05 degrees and an estimated capacity of 35,000

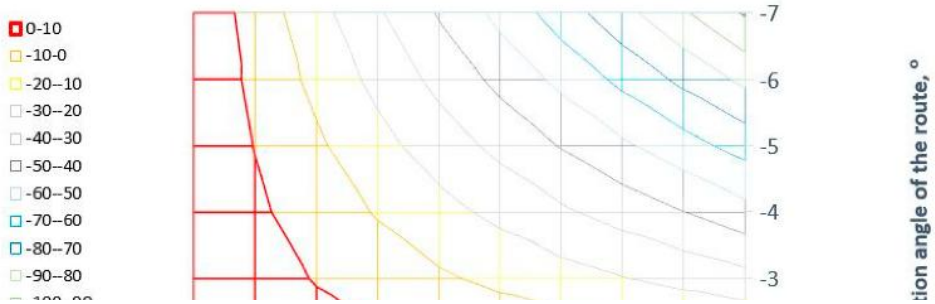


Figure 3-6: Potential energy recovery for a downhill conveyor; power contours every 10 kW (ranging from 0 to 110kW recovered in different coloured lines), red grid—no energy recovery area, negative values represent recovered power. The more negative the power contour the more power is being saved [15].

tons/day, allowing for no input energy required to operate the rope aerial conveyor and no CO2 generation [16] [17]. However, a steeper slope is recommended in order to make sure that regenerative braking is possible [15].

In cases where conveyor systems are impractical due to site-specific constraints or preferences, a trolley truck system offers a viable alternative. Trolley systems, which utilize overhead electrical lines for power, have demonstrated the ability to reduce fuel consumption by 50–60% compared to conventional diesel-powered haul trucks [15]. In a trolley truck regenerative braking system, the truck is connected to an overhead trolley line via pantographs or similar devices. When the truck is on a downhill slope, the braking system captures the kinetic energy and converts it to electricity, which is then fed back through the trolley line to the power grid. These systems can also significantly decrease CO2 emissions and improve the efficiency of material transport in mining operations.

Another option that has become increasingly interesting to consider in the last years are fully electric trucks. Some fully electric trucks have started to be used in different mines, an example of this is *Elektro Dumper,* a dumper that has shown that it is possible for an electric truck to completely eliminate the need to charge or refuel only by using regenerative braking and has even shown to be energy positive [42].

For mining sites where neither conveyors nor trolley systems are feasible, regenerative braking can still be used by electric drive mining trucks or applied to conventional haul trucks through system modifications [43]. While this approach does not achieve the same energy recovery levels as conveyors or trolley systems, it provides a partial solution by covering a small percentage of the truck's fuel consumption [18]. Such modifications may include the integration of energy recovery systems that store excess energy in small batteries for later use. Following Figures 3-7 to 3-10 show examples of mining transport solutions that could include regenerative braking.



Figure 3-9: Rope conveyor system [51]



Figure 3-10: Trolley truck system [52]



Figure 3-8: Electric mining truck [43]



Figure 3-7: battery powered train. [46]

To determine the most suitable regenerative braking technology for a specific mining site, it is also crucial to assess the transport demand and the site's physical characteristics, other than slope steepness and ore transport capacity. In this study, if the requirements are met for a regenerative braking conveyor system this will be the proposed solution, as research has proven it to be the best solution for energy savings. If the requirements are not met, trolley or battery system will be explored.

In addition to regenerative braking systems, green hydrogen-powered dumper trucks represent another innovative solution for reducing the carbon footprint of ore-transport in mining operations. These trucks are equipped with hydrogen fuel cells that generate electricity through a chemical reaction between green hydrogen and oxygen, producing only water vapor as a byproduct. This zero-emission technology could replace conventional diesel engines in the future. Although still in early stages of adoption, these trucks have shown promise in pilot projects, and companies like Komatsu have begun developing specific models [20].

3.6 E-fuels

E-fuels present a viable option for decarbonizing mining operations, both their transport and electricity demand, particularly in regions with limited potential for other clean energy resources. These e-fuels can either be produced on-site at the mine (using surplus electricity from e.g. solar PV or wind turbines) or imported by ship from other parts of Greenland or other countries. Production requires significant amounts of clean electricity to power the Power-to-X (PtX) synthesis process. Potential e-fuels for implementation include green hydrogen, e-methanol, and e-ammonia. To realize the decarbonization of a mine’s electricity demand through e-fuels an e-fuel generator is essential to convert the fuel to electricity. Whereas for decarbonizing the transport demand of a mine specialized vehicles who run on e-fuels must be present. Additionally, a storage facility onsite of the location of the mine is essential as the import of e-fuels is infrequent as the ship will only come by with deliveries a few times a year.

When looking at the option of importing e-fuels to the mine, the costs consist of both the production cost of the e-fuel and the transportation cost of transporting the e-fuel by ship. There are several factors to consider when deciding which e-fuel to use at the mines in terms of transportation costs, technical feasibility and practical aspects.

The main means of transporting e-fuels is through pipelines, trucks and by ship. Transporting green hydrogen through ships instead of pipelines can be a less expensive option over longer distances up to 1,500 km, depending on the terrain, where it becomes more economically and technically feasible to transport green hydrogen through hydrogen carriers as methanol, ammonia or liquid organic hydrogen carriers (LOHC). For shipping transportation hydrogen must be liquified prior to transport. The process and technology maturity of transporting ammonia and methanol by ship is higher than transporting liquid hydrogen. There are currently no commercially available tankers for shipping liquified hydrogen, whereas there are tankers available for methanol and ammonia. Transporting green hydrogen and hydrogen-based fuels requires the use of specialized port infrastructure. This includes deep-water facilities for the handling of liquefied gases such as green hydrogen and ammonia, as well as conversion plants for the transformation of green hydrogen into hydrogen carriers at the exporting port. Additionally, reconversion facilities may be necessary at the importing port for the processing of these carriers back into pure hydrogen. [73, 74]

3.7 Energy Storage

Several energy storage solutions hold significant potential for application in Greenland's remote mining industry.

An energy storage solution that plays a critical role is the use of steel tanks for storing diesel fuel. Given the possible geographical remoteness of mines, supply ships may often arrive only a few times a year. This makes it essential for mining operations to have adequate storage capacity to ensure a continuous supply of diesel between shipments. These storage tanks will enable mines to maintain uninterrupted operations despite irregular fuel deliveries. Detailed specifications and investment costs for diesel storage tanks are provided in *Appendix 3*.

For mines aiming to transition to clean energy sources, the installation of battery energy storage systems (BESS) represents an effective energy storage solution. Batteries can address the variability of clean energy production by supplying electricity during hours when generation from e.g. solar PV and wind turbines is insufficient to meet demand. However, this depends on having surplus electricity production during other periods to charge the batteries. In Artic climates it is shown that batteries have performance limitations in terms of reduced charge and discharge performance, accelerated degradation and aging, thermal management challenges (maintaining the optimal battery temperature for charging and discharging) and reduced charge acceptance (the battery's ability to absorb and utilize current is impeded significantly below 0° C). On top of the technical challenges, the batteries also face environmental challenges such as snow, icing etc. These challenges can be addressed through adapted system design and operation strategies such as thermal control systems and phase change materials. [49]
A comprehensive description of different BESS technologies, along with an overview of their investment costs, is included in *Appendix 3.*

E-fuel storage is another essential energy storage solution for remote mining operations relying on e-fuels. With infrequent fuel deliveries, adequate storage capacity is crucial. This ensures a consistent fuel supply to the power generators (e.g., an e-methanol generator) enabling the mine to operate continuously throughout the year. Other e-fuel storage facilities are available if different e-fuels, such as green hydrogen or e-ammonia, are to be used. Specific details on e-fuel storage options are further discussed in *Appendix 3*.

3.8 Fossil Fuel-based Technologies

Diesel generators are currently the most widely used fossil fuel-based technology in mining industries around the world. Their dominance is due to their reliability, ease of deployment, and ability to provide consistent power in a variety of conditions. In remote mining sites, i.e., those with limited or no access to centralized power grids, diesel generators often serve as the sole source of energy, powering mining operations, equipment, and infrastructure.

Diesel generators are also being used widely to provide standby power for sites and industries that cannot afford to lose power in events of shutdown or interruptions of the main electrical supply network. An advantage of diesel generators is their capability to start and reach full load very quickly, which minimizes the time with no power generation in times of interruptions. Another advantage of using a diesel generator is the possibility of harnessing the surplus heat produced during its operation [26]. This excess heat can be captured and utilized for various purposes, such as heating facilities, providing hot water, or supporting other thermal energy needs at the site.

In networks with clean energy, where the electricity production can fluctuate, it is very common to have backup generation from a diesel generator. In these instances, the diesel generator capacity installed should be able to supply the full peak demand to accommodate the demand where production from clean energy is not present [26].

In *Appendix 3* financial data is presented for diesel generators.

3.9 Additional Technologies

Added to the previously described technology potentials, other technologies (presented in the below Table 3-3) are further explained in *Appendix 3*. This appendix also includes different financial and investment data for the technologies.

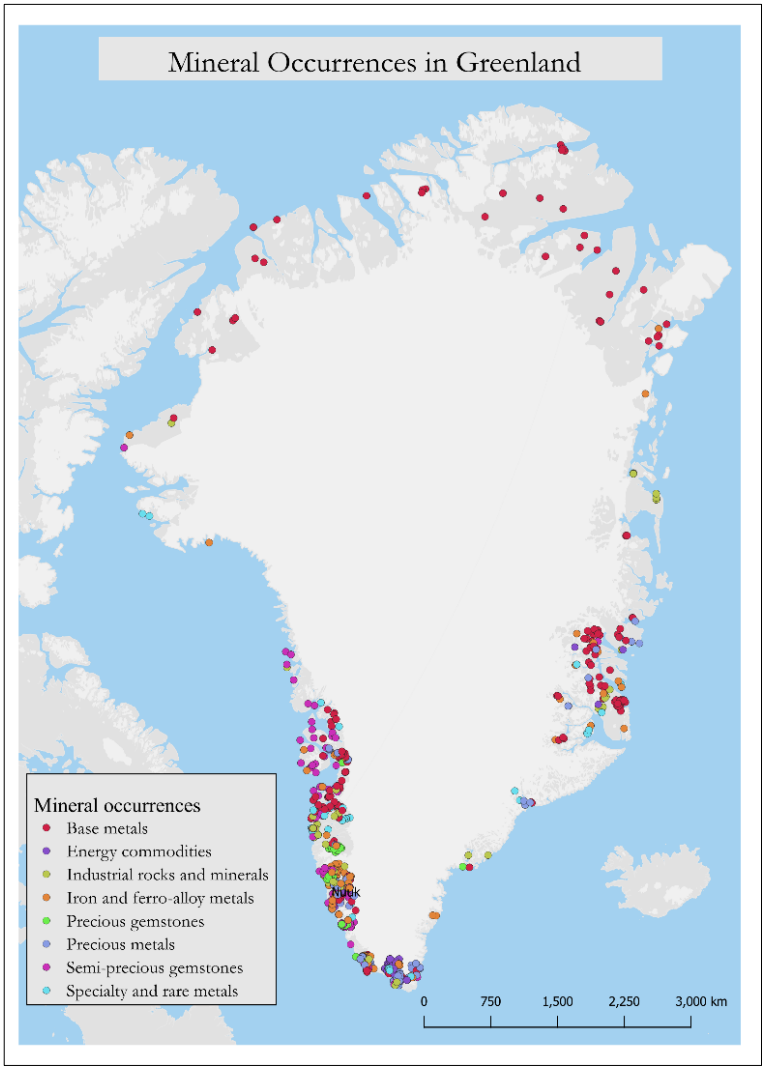
Technologies	
Clean energy (Renewable energy)	Solar PV
	Onshore wind
	Nearshore wind
	Hydropower
	Tidal and wave energy
Clean energy (Power-to-X)	Green hydrogen
	E-methanol
	E-ammonia
	E-methane
Clean Energy (Transport)	Regenerative braking
Carbon Capture Utilization and Storage	Carbon Capture Utilization and Storage
Other electricity producing technologies	Biomass boiler
	Biomass Combined Heat and Power (Biomass CHP)
	Waste Combined Heat and Power (Waste CHP)
	Compression heat pump
	Absorption heat pump
	Diesel generator
Energy storage	Large-scale hot water tanks
	Small-scale hot water tanks
	Electric batteries
	E-fuel storage
	Hydro reservoir storage
	Diesel tank
Microgrids	District heating transmission and distribution networks
	Electricity transmission and distribution networks

Table 3-3: Summary of technologies presented in Appendix 3.

4. Mines in Greenland

4.1 Mines Selected in This Study

There are currently over 80 distinct Mineral Exploration and Exploitation Licenses issued in Greenland. Given the large number of actual and potential mining sites, this study focuses on a representative sample of actual and potential mining operations to conduct the techno-economic assessment. The following Map 4-1 gives an overview of where in Greenland the 80 Mineral Exploration and Exploration Licenses are located. More information about mining in Greenland and the list of Exploration and Exploration Licenses are provided in Appendix 1 and 2, respectively.



Map 4-1: Mineral occurrences in Greenland. [1]

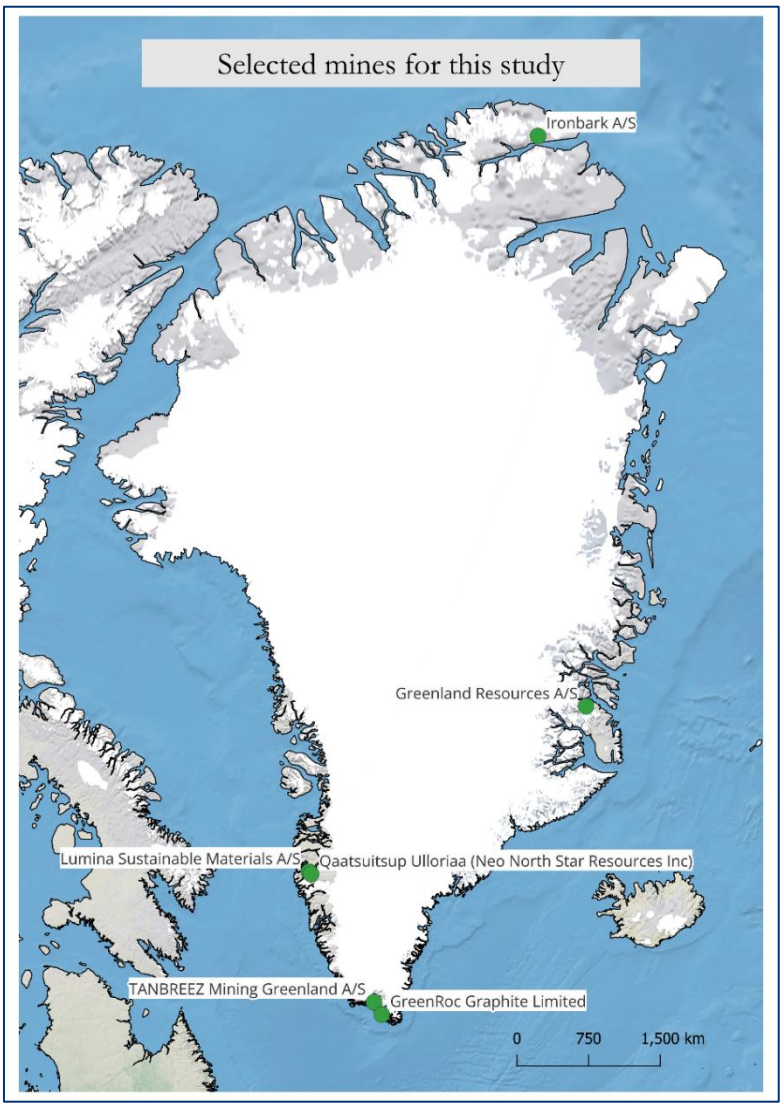
A selection process for choosing which mines and potential future mines should be included in this study was initiated. The selection process was conducted in close collaboration with the Ministry and involved frequent and detailed consultations. The primary objective was to identify approximately 6-8 actual or potential mines that would best represent the diversity and scope of

mining activities across Greenland. The selection criteria were carefully defined and included the following key considerations:

1. **Geographical region**: Given Greenland's vast size and its diverse environmental conditions from north to south, the study aimed to include projects from all major regions of the country. To achieve this, Greenland was divided into four zones: north, south, east, and west, with at least one mine selected from each zone to ensure comprehensive geographical representation.
2. **Mineral Extracted**: Projects focusing on the extraction of critical raw materials were given preference. These materials are of significant economic and strategic importance, aligning with the broader objectives of the study.
3. **Type of License**: Projects holding active exploitation licenses were prioritized over those with exploration licenses. This approach aimed at accessing more detailed and relevant data, from the most advanced projects.

This thorough and collaborative selection process was essential in establishing a robust foundation for the techno-economic assessment, ensuring the study's findings would be both representative and relevant.

The selection process of the actual and potential mines resulted in choosing six representative projects. The location of the six selected projects can be seen in the following Map 4-2.



Map 4-2: Location of selected actual and potential mines for this study.

All six selected actual and potential mines were contacted and provided with a standardized questionnaire. The questionnaire included a range of questions related to the mine's energy and electricity demands, current and projected costs, technologies in use, and other technical details. The output of the questionnaire varied; as not all the projects responded, some are not yet in operation and could therefore not answer all questions, and some of the information received are confidential and can therefore not be included in this study.

Following Table 4-1 gives an overview of the six actual and potential mines that are included in this study. The table includes the location and coordinates of each of the projects, the type of mineral extracted, the peak electricity consumption and the electricity consumption profile, whether the technology of regenerative braking is applicable at the mine and finally a list of the renewable energy sources that are available at each of the mines. This information is based on the questionnaire sent to the mining companies, public available data and the mapping of the renewable resource potential in the previous Chapter 3.

Mine	Coordinate and location	Mineral	Peak electricity consump-tion	Electricity consump-tion profile	Regen-erative braking	Renewable energy resources assessed
Greenland Resources A/S	East 71.9833° N, 24.3167° W	Molybdenum and Magnesium	33 MW	All hours of the year	Applicable	Solar PV, hydropower, wind turbines, tidal energy, e-fuels, battery energy storage system
GreenRoc Graphite Limited	South 60.2850° N, 45.1258° W	Graphite	11 MW	All hours of the year	Not applicable	Solar PV, hydropower, wind turbines, tidal energy, e-fuels, battery energy storage system
TANBREEZ Mining Greenland A/S	South 60.9000° N, 45.8667° W	REE, Zr, Nb, Ta, Hf	4.5 MW	Uncertain	Applicable	Solar PV, hydropower, wind turbines, tidal energy, e-fuels, battery energy storage system
Qaatsuitsup Ulloriaa (Neo North Star Resources Inc)	West 66.7024° N, 51.3907° W	REE	No data	No data	No data	Solar PV, hydropower, wind turbines, tidal energy, e-fuels, battery energy storage system
Lumina Sustainable Materials A/S	West 66.5500° N, 52.0999°W	Anorthosite	Confiden-tial	Confiden-tial	Confiden-tial	Solar PV, hydropower, wind turbines, tidal energy, e-fuels, battery energy storage system
Ironbark A/S	North 83.1667° N, 29.0000° W	Zinc, Lead	No data	No data	No data	Solar PV, hydropower, wind turbines, tidal energy, e-fuels, battery energy storage system

Table 4-1: Overview of the six mines that are included in this study.

4.2 Mine Grouping into Geographical Regions

The six actual and potential mines selected are grouped into four different geographical regions, where each region is characterized by similar clean energy potential:

1. East: Greenland Resources A/S
2. South: GreenRoc Graphite Limited and TANBREEZ Mining Greenland A/S
3. West: Lumina Sustainable Materials A/S and Qaatsuitsup Ulloriaa (Neo North Star Resources Inc)
4. North: Ironbark A/S

Table 4-2 shows the peak electricity consumption for each location. For the East location, the peak electricity demand is 33 MW, which is the demand provided by the mining company (Greenland Resources A/S). The peak electricity demand for the South, West, and North locations has been

generalised to be 10 MW. The reason for this choice is that there was either no data on the peak electricity demand, the data was confidential, or there were two different peak electricity demands for the same location (South). The selected 10-MW value is in the range of electricity demands provided by the interviewed mines. For all locations, it is assumed that the mines operate all hours of the year.

The peak electricity demand only includes the electricity demand and does not therefore include any transport demand. In this study, we assume that the transport fuel demand covers approximately 60% of the total energy demand, while the electricity demand covers approximately the remaining 40%.

Geographical region	Mines	Peak electricity consumption
East	Greenland Resources A/S	33 MW
South	GreenRoc Graphite Limited TANBREEZ Mining Greenland A/S	10 MW
West	Lumina Sustainable Materials A/S Qaatsuitsup Ulloriaa (Neo North Star Resources Inc)	10 MW
North	Ironbark A/S	10 MW

Table 4-2: Mines divided by geographical region with corresponding peak electricity consumption.

5. Methodology For the Techno-Economic Assessment

In Chapter 3, the technical feasibility of the different clean energy technologies was established based on resource potential. To provide a comprehensive assessment that combines both technical and economic feasibility, a techno-economic analysis was developed in this study. This analysis aims to offer insights into the viability of transitioning from conventional fossil fuel-based systems to clean energy alternatives.

Sections 5.1 and 5.2 outline, respectively, the methodology and key metrics used to compare the different scenarios. Firstly, the component sizes required to meet the energy demand of the mine are determined. Based on these sizes, the capital expenditures (CAPEX) and operational expenditures (OPEX) for each scenario are calculated. Secondly, a discounted cash flow analysis is performed, including all annual costs incurred during the plant's development, construction, operation, and decommissioning phases. Finally, the levelized cost of electricity (LCOE) is calculated, along with other relevant metrics, to facilitate comparison among the various scenarios.

Section 5.3 introduces the different scenarios considered in the techno-economic analysis. These scenarios are differentiated based on the mix of clean energy technologies used to satisfy the mine´s electricity and transport demand.

Section 5.4 lists the main assumptions behind the discounted cash flow analysis (i.e., the financial model) used to calculate the LCOE.

5.1 Component Sizing: Ramboll's Energy System Modelling Tool

To capture the financial aspects, such as CAPEX and OPEX, the sizing of the components in each location and scenario must be done as a first step. For dispatchable electricity generators that can produce power when needed by the mine, such as diesel generators, the sizing process is relatively straightforward. For instance, in a case where the mine is fully powered by a diesel generator (i.e., the business-as-usual case), the diesel generator will be sized to match the peak electricity demand of the mine or slightly oversized to account for maintenance periods or unexpected outages.

However, optimal sizing is more complex for clean energy technologies that generate power based on the availability of primary resources, such as solar PV and wind. These sources produce electricity when the sun is shining or the wind is blowing, while the mine´s electricity demand remains constant each hour. This challenge is schematically illustrated in Figure 5-1 which depicts a mine supplied by a mix of PV and wind, along with a diesel generator and battery storage to meet the constant electricity demand when solar and wind resources are unavailable.

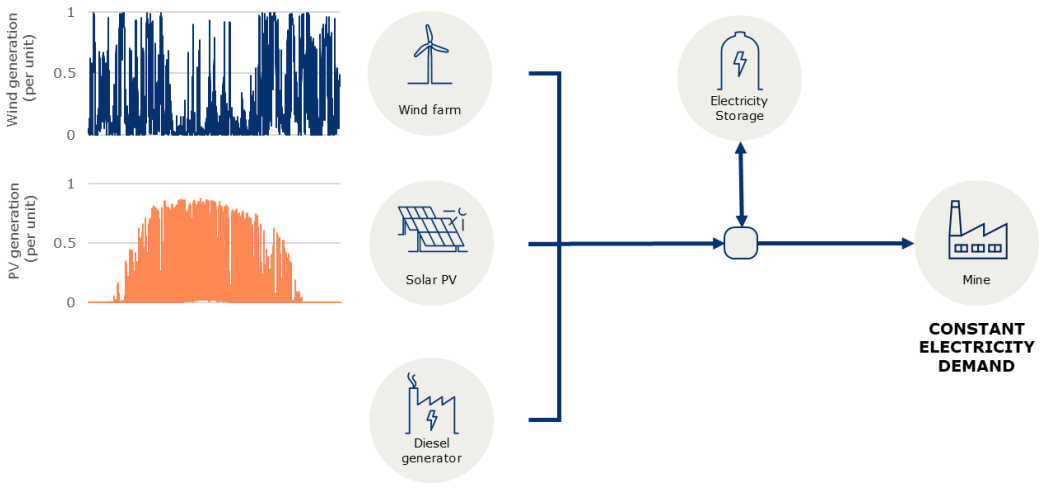


Figure 5-1: Schematic representation of the mine's constant electricity demand and the variable production from renewable energy technologies. The variable production from solar PV and wind is represented with the hourly production plots (blue and orange), during a reference year, for a specific location in Greenland (East location). The renewable production is expressed in per unit, i.e., it represents the production normalized by the technology installed capacity.

To address the variability of clean energy technologies, a more comprehensive approach to component sizing is necessary, which combines hourly production potential with financial aspects (i.e., CAPEX and OPEX). For instance, in the illustrative example in Figure 5-1 oversizing the solar PV and wind components compared to the peak electricity demand may lead to an overall cost reduction, as it increases the share of demand met by PV and wind and reduces reliance on the diesel generator. Although oversizing the components results in higher CAPEX, it can potentially lead to significant savings by reducing the fuel consumption and operational costs associated with the diesel generator. Renewable energy technologies such as solar PV and wind require substantial capital expenditures at the beginning of the project, but they have low operational expenditures due to the absence of fuel costs throughout the project's lifetime. This is the opposite of conventional fossil-based generators, such as diesel generators, which have low initial CAPEX but high OPEX due to ongoing fuel costs. To capture all these aspects and trade-offs in component sizing, Ramboll's Energy System Modeling tool was used.

Ramboll's Energy System Modelling tool optimizes the sizes and operation of the technologies included in the scenarios to minimize total system costs, i.e., both CAPEX and OPEX, while meeting all technical and operational limitations of the components. The tool has been customized to address the specific requirements of this analysis and functions as an energy hub model for the microgrids in Greenland's mining industry. For Solar PV and Wind, it takes as an input the hourly electricity production for a specific location in a reference year (based on publicly available data from [48]).

For each scenario, the primary outputs of the model include the sizes of the technologies and their corresponding hourly operation (i.e., the hourly energy flows within the system). These outputs are then used in the techno-economic analysis to calculate CAPEX, OPEX, discounted cash flows and key performance metrics, such as the levelized cost of electricity (LCOE) in EUR/MWh, the Clean Electricity Share, and the Clean Electricity and Transport Share, which are defined in Section 5.2.

5.2 Definitions of Key Comparison Metrics

5.2.1 Levelized Cost of Electricity (LCOE)

The main metric used for comparison among scenarios is the Levelized Cost of Electricity (LCOE). The LCOE is a widely recognized and industry-standard measure for evaluating energy technologies in techno-economic feasibility studies, as it allows the comparison of technologies with unequal lifespan, scale, efficiency, capital and operating costs, and associated risks. This comprehensive indicator allows for consistent comparisons across different methods of electricity generation.

The LCOE of an energy-generating asset is the average total cost of building and operating the asset per unit of total electricity generated over an assumed lifetime. Alternatively, LCOE can be considered the average minimum price at which the electricity generated by the asset must be sold to offset the total production costs over its lifetime. From an energy consumer's perspective (e.g., the mine), the LCOE represents the average cost per unit of electricity consumed from the mix of energy-generating technologies that supply its demand.

The LCOE accounts for all costs incurred over the project's lifetime (i.e., CAPEX, OPEX and fuel costs), and the total electricity produced over the project's lifetime. The LCOE is calculated based on a discounted cash flow analysis, wherein all costs and generated electricity are discounted to their present value.

The LCOE is defined as follows:

$$LCOE = \frac{Sum\ of\ discounted\ costs\ over\ lifetime}{Sum\ of\ discounted\ electricity\ produced\ over\ lifetime} = \frac{\sum_{y=1}^{N} \frac{I_y + M_y + F_y}{(1+r)^y}}{\sum_{y=1}^{N} \frac{E_t}{(1+r)^y}}$$

where the input values are as follows:

- y: index for year in the range (1,..,N)
- N: expected project lifetime in years
- I_y: CAPEX expenditures in year *y* (EUR)
- M_y: OPEX expenditures (maintenance) in year *y* (EUR)
- F_y: fuel expenditures in year *y* (EUR)
- E_y: electricity produced in year *y* (MWh)
- r: discount rate (%)

The LCOE is expressed in EUR/MWh of electricity produced within each scenario. It reflects the production cost of one MWh of electricity over the project's lifetime, incorporating all electricity-producing units and storage technologies considered in the scenario. Note that E_y includes only the energy produced by the electricity-generating technologies that is used by the mine. This distinction is relevant in cases where oversizing of PV and wind is necessary compared to the mine's peak electricity demand. Due to the remote location of these mines, it is assumed that any electricity generated above the mine's peak consumption will be curtailed, thus not taken into account in the LCOE calculation.

5.2.2 Clean Electricity Share

For each scenario, the Clean Electricity Share (CES) represents the share of the total yearly electricity demand of the mine that is met by clean energy technologies.

It is expressed as a percentage and defined as:

$$CES = \frac{Electricity\ demand\ covered\ by\ clean\ energy\ technologies}{Total\ yearly\ electricity\ demand}$$

For example, in the case where a mine is fully powered by a diesel generator, the Clean Electricity Share is equal to 0%, as the total electricity demand is met by fossil fuel. Conversely, if the mine´s electricity demand is fully covered by hydropower, the Clean Electricity Share is equal to 100%. Scenarios that include a mix of solar PV and wind will have varying Clean Electricity Shares, depending on the specific details of the scenario, as will be discussed in Section 6.2.

5.2.3 Clean Electricity and Transport Share

For each scenario, the Clean Electricity and Transport Share measures the share of the total yearly energy demand of the mine that is met by clean energy technologies, including both electricity and transport demand.

It is expressed as a percentage and defined as:

$$CETS = \frac{Electricity\ and\ transport\ demand\ covered\ by\ clean\ energy\ technologies}{Total\ yearly\ electricity\ and\ transport\ demand}$$

For example, if the electricity demand is fully decarbonized (e.g., by hydropower), but diesel trucks are still used in the mine, the Clean Electricity and Transport Share will be significantly lower than the Clean Electricity Share. This discrepancy is due to the substantial role of transport demand in mine operations, with transport accounting for approximately 60% of the total mine energy demand. If regenerative braking technology can be fully utilized to decarbonize the transport demand, the CES and CETS indicators will be the same (CES = CETS). If regenerative braking is energy-positive (producing more energy than needed), the CETS can potentially be higher than the CES.

5.3 Scenarios Definition

For each geographical region defined in Section 4.2, different scenarios in terms of mix of clean energy technologies used to satisfy the mine´s electricity and transport demand are considered and assessed in the techno-economic analysis. Table 5-1 summarizes the scenarios considered for the electricity and transport demand, respectively. The electricity demand category includes five overall scenarios: Diesel Generator (Business-as-Usual), Mix of Solar PV and Wind, Hydropower, E-fuel, and Tidal Energy. The transport category includes two scenarios one for Diesel – Business-as-Usual scenario and one in which Regenerative Braking is assessed.

Category	**Scenarios**
Electricity demand	Diesel Generator (Business-as-Usual)
	Mix of Solar PV and Wind (with and without diesel generator or BESS)
	Hydropower
	E-fuel

	Tidal Energy
Transport demand	Diesel Trucks (Business-as-Usual)
	Regenerative braking

Table 5-1: Scenario overview.

A short description of each scenario for the electricity demand is provided as follows:

- Diesel Generator (Business-as-Usual): This scenario represents the business-as-usual case for mines in Greenland, where the entire electricity demand of the mine is covered by diesel generators.
- Mix of Solar PV and Wind: For this scenario, three different versions have been investigated with different objectives. As it is not feasible to meet the constant electricity demand of the mine with solar PV and wind alone, due to the variability of these energy sources, different combinations of solar PV, wind, diesel generator, and battery energy storage systems (BESS) are considered. The three versions are:
    - **Lowest LCOE:** The objective is to find the combination of solar PV, wind, and diesel generators that achieves the lowest possible LCOE while meeting the mine's electricity demand.
    - **Same LCOE as diesel generator:** The objective is to find a combination of solar PV, wind and diesel generators that reaches the same LCOE as the Diesel Generator scenario, while meeting the electricity demand of the mine.
    - **100% solar PV and wind:** The objective is to find the combination of solar PV and wind that fully satisfies the mine's electricity demand (i.e., Clean Electricity Share = 100%). To reach this objective and compensate for the intermittent nature of PV and wind generation, BESS is needed in this scenario.
- Hydropower: For this scenario three different versions have been analysed:
    - **New hydropower plant:** This considers building a new hydropower plant and the associated electricity transmission lines connecting the plant to the mine.
    - **Upgrading an existing hydropower plant:** This includes upgrading an existing hydropower facility to add additional capacity to meet the electricity demands of the mining operation, along with the associated electricity transmission lines.
    - **Upgraded hydropower combined with solar PV and/or wind and diesel generator:** This includes 8 scenarios with different combinations of demand profiles, included technologies and production capacities (upgraded hydropower plant, solar PV, wind turbines, diesel generator).
- E-fuel: This scenario involves supplying the mine's energy demand with e-fuels. The e-fuel is used to produce electricity in an e-fuel generator, similar to the Diesel Generator scenario.
    - Scenario where the e-fuel is **produced in Greenland** and shipped to the mine.
    - Scenario where the e-fuel is **produced in Europe** and shipped to the mine in Greenland.
- Tidal Energy: This scenario considers utilizing tidal energy to meet the mine's electricity demand. The scenario provides a high-level assessment of the tidal barrage potential and the maximum theoretical tidal energy potential at each mine of this study.

A short description of each scenario for transport demand is provided as follows:

- Diesel Trucks (Business-as-Usual): In this scenario, the entire transport demand is covered by diesel trucks.
- Regenerative Braking: For this scenario, two variants are considered:
    - **Conveyor belt:** The transport demand is fully or partially covered by utilizing the regenerative braking potential of a conveyor belt. This scenario includes a high-level assessment of the potential for regenerative breaking at the selected mines based on transport capacity and the slope of the transport route.
    - **Electric haul trucks:** The transport demand is fully or partially covered by using the regenerative braking potential of electric haul trucks. This scenario provides a high-level approach to estimate the theoretical maximum recoverable energy that an electric or hybrid haul truck could achieve under ideal conditions through regenerative braking.
- Alternative fuels for mining transport: An analysis of the market for e-fuel and electric mining vehicles.

It is important to note that the scenarios defined in Table 5-1 and considered in this study are representative but not exhaustive to what could be feasible for mining operations in Greenland.

The results for the electricity demand scenarios are presented in Chapter 6, following the techno-economic assessment methodology described in Chapter 5. For the transport demand scenarios, a high-level methodology to estimate the potential for regenerative breaking for conveyor belts and electric haul trucks is described in Chapter 7, discussing the potential to reduce or eliminate diesel use compared to the business-as-usual scenario.

5.4 Assumptions Behind the Economic Model

The expected operation of a mine can vary significantly depending on several factors such as the mineral resource availability and licence duration. In the pool of mines interviewed in this study, the shortest project operation was 10 years, and the longest 30 years. For the techno-economic analysis, a project lifetime of 20 years is assumed for comparison purposes among scenarios. However, it is important to notice that the lifespan of the included clean energy technologies is likely to exceed 20 years (for example, solar PV and onshore wind have a lifetime of 30+ years). As the project lifetime has a significant impact on the business case, this aspect will be discussed in Section 6.2.2.

Year 2030 is used as a reference for the techno-economic analysis. A two-year construction period from 2030 to 2032 is assumed for all scenarios, and the project is assumed to start operation in 2032. During the two-year construction period, project management, development, design, and engineering costs are assumed to be 10% of the total CAPEX for each scenario. Additionally, decommissioning costs are included as 10% of the total CAPEX for each scenario, with the decommissioning process assumed to take one year.

A discount rate of 8% has been applied in the techno-economic calculation for all scenarios. Similar discount rates have been used by mining companies analysing the economics of mining operations in Greenland (Greenland Resources A/S [76] and GreenRoc Strategic Materials [77]). The discount rate depends significantly on the parties involved in the project and providing the financing, and on the risk associated with different technologies. These aspects are not considered in this analysis,

which has the aim to be a high-level comparative assessment and should therefore be further investigated in future studies. A sensitivity analysis of the results according to different discount rates is provided in Section 6.6.1.

The investment costs (CAPEX) for this study are based on projections for the year 2030.

Due to Greenland's arctic climate, a winterization factor of +20% has been applied to the CAPEX and OPEX of all technologies included in the scenarios, this percentage is based on previous studies performed in arctic regions. This adjustment accounts for the additional insulation some technologies may require, the challenges of installation in extreme conditions, the need for specialized equipment, and the increased complexity and cost of maintenance.

Table 5-2 provides an overview of the CAPEX and OPEX for the various technologies considered in the scenarios, with the +20% winterization factor included.

Technology	CAPEX/OPEX	Cost (2030)	Unit	Sources
Diesel generator	CAPEX	0.43	MEUR/MW	[28]
	OPEX	7.2	% of CAPEX/year	[28]
Onshore wind farm	CAPEX	1.33	MEUR/MW	[28]
	OPEX	2.0	% of CAPEX/year	[28]
Solar PV	CAPEX	0.46	MEUR/MW	[28]
	OPEX	2.5	% of CAPEX/year	[28]
BESS	CAPEX	0.79	MEUR/MW	[28]
	OPEX	2.2	% of CAPEX/year	[28]
E-methanol generator	CAPEX	0.52	MEUR/MW	[28]
	OPEX	8.5	% of CAPEX/year	[28]
E-methanol Storage	CAPEX	0.0002	MEUR/ton	[28]
	OPEX	6.0	% of CAPEX/year	[28]
Hydropower	CAPEX	2.6	MEUR/MW	[37, 38]
	OPEX	2	% of CAPEX/year	[37, 38]
Tidal	CAPEX	6.54	MEUR/MW	[55, 56]
	OPEX	4.1	% of CAPEX/year	[55, 56]

Table 5-2: CAPEX and OPEX overview.

It should be noted that no direct market consultations were conducted to validate or refine the CAPEX and OPEX estimates. The analysis conducted is a comparative analysis, not a site-specific evaluation. Due to the high-level assessment of this study, a 35% contingency of the total CAPEX and OPEX was included to account for incomplete project definition and specific project. Contingency typically covers, for instance, estimate adjustments, bias, omissions, and normal market price variations. For example, the CAPEX and OPEX related to building and operating the microgrid infrastructure have not been explicitly considered in this study.

To estimate the investment required for supplying a mine with electricity from a hydropower facility, the distance between the mine and the hydropower plant should be considered. The investment

and operational costs associated with electricity transmission lines in rural locations are detailed in Table 5-3 [27]. A more detailed description of investment costs for electricity transmission lines is included in Appendix 3.

Investment cost	Value
Single line 100 kW - 250 kW (EUR/m)	36
Single line 250 kW – 1 MW (EUR/m)	36
Single line 1 MW – 5 MW (EUR/m)	41
Single line 5 MW - 25 MW (EUR/m)	88
Type 1 station (EUR/MW)	67,500
Fixed O&M (EUR/MW/year)	1,605

Table 5-3: Investment cost of electricity transmission lines in rural areas. [27]

A fuel cost for diesel at 96 EUR/MWh (7.17 kr./l) is used, and an e-methanol fuel cost of 1.23 EUR/t [53]. The diesel cost includes an environmental tax and the difference in price of winter and summer months, additionally the diesel price is benchmarked against current industry prices in Greenland. For the e-methanol, a transportation cost is also used at 12 EUR/t [54] for an approximate transportation distance of 12,500 km, representing an average import distance from Europe. Greenland does not have a CO2 tax; therefore, no CO2 tax is included in the techno-economic analysis of the scenarios.

Greenland Resources A/S has previously conducted a pre-feasibility study of renewable energy generation at their sight at Malmbjerget. This report has been shared with Ramboll and, where relevant, findings have been included in the analysis of this study. [78, 79]

6. Results: Clean Energy Solutions for Mine Electricity Demand

This chapter presents the results for the electricity demand scenarios described in Section 5.3.

Each scenario explores different clean energy technologies or combinations thereof to decarbonize the electricity demand of mining operations in Greenland. The technologies considered include solar PV and wind, hydropower, e-fuel, and tidal energy. These scenarios are compared against a Business-as-Usual scenario, where the mine is fully supplied by a diesel generator, providing a reference point for comparison. The methodology and assumptions outlined in Chapter 5 is used to assess the techno-economic feasibility of each technology.

The results for each technology are detailed in Sections 6.1 to 6.4. Finally, Section 6.6 provides a comparative analysis of the technologies.

6.1 Diesel Generator (Business-as-Usual)

The Diesel Generator (Business-as-Usual) scenario represents the current practice in the mining industry, where a diesel generator is used to fully supply the peak electricity demand of the mine. This scenario serves as a reference point for comparison against other scenarios with different technology configurations. It portrays a situation where no changes are made, and the entire electricity demand is met solely by fossil fuels.

Since this scenario depends entirely on diesel fuel, it is not influenced by specific resource availability at geographical locations. Therefore, it is applicable to all four geographical regions: East, South, West, and North. Minor differences may be due to the accessibility of the mine and the related transport cost of the diesel to the mine, but these are not accounted for in this study.

It is assumed that the diesel generator has an average electrical efficiency of 35%, and the energy density of the diesel is 10.9 kWh/litre. The utilization of surplus heat produced during the operation of the diesel generator is not considered in this analysis.

The capacity of the diesel generator is sized according to the peak electricity demand with an additional 33% capacity added to account for maintenance periods or unexpected outages.

For example, for a peak electricity demand of 10 MW (i.e., the peak electricity demand for locations South, West, and North as shown in Table 4-2), the capacity of the diesel generator is set at 13 MW. Table 6-1 shows the diesel generator capacity and the comparison metrics defined in Section 5.2, i.e. the Levelized Cost of Electricity (LCOE), the Clean Electricity Share and Clean Electricity and Transport Share. The LCOE calculated for this scenario is 297 EUR/MWh. Both the Clean Electricity Share and Clean Electricity and Transport Share are 0%, as the entire energy demand is met by fossil fuels.

Diesel Generator (Business-as-Usual)	
Installed capacity by technology	
Diesel generator (MW)	13
Metrics	
LCOE (EUR/MWh)	297
Clean Electricity Share (%)	0%
Clean Electricity and Transport Share (%)	0%

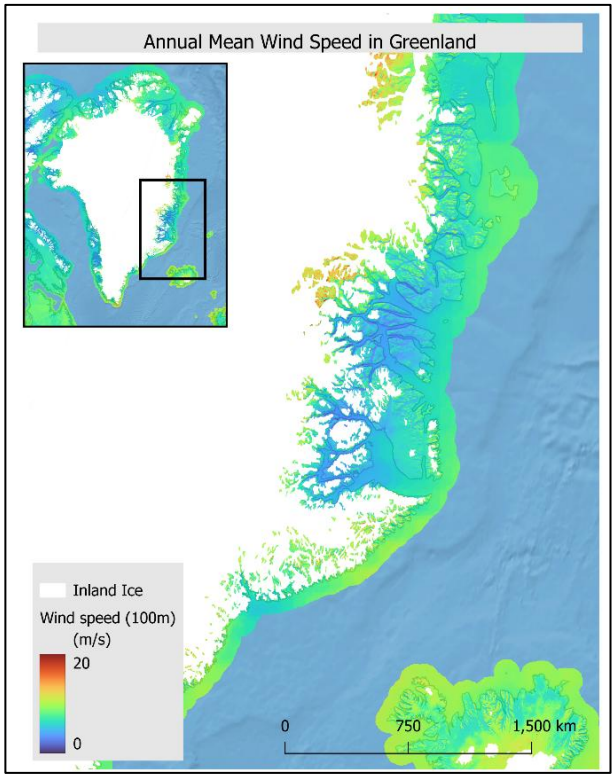
Table 6-1: Results for the Diesel Generator (Business-as-Usual) scenario.

6.2 Mix of Solar PV and Wind

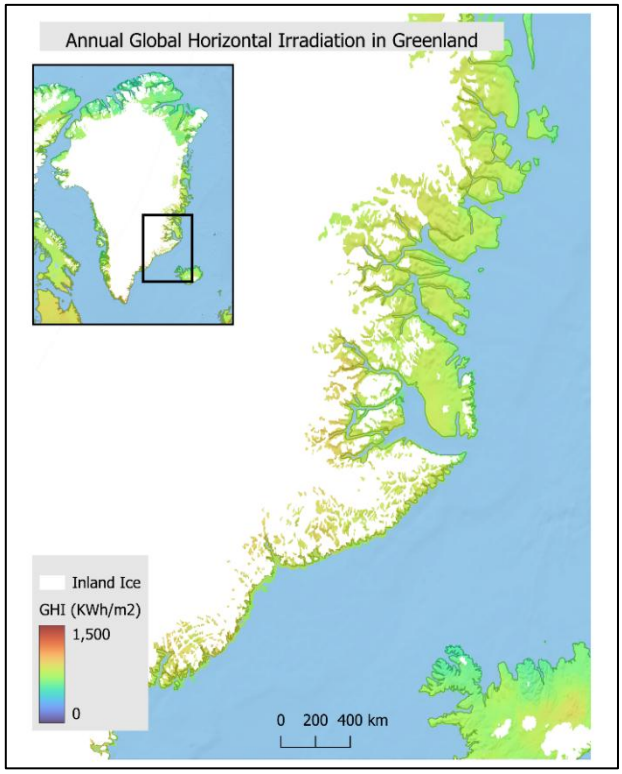
This scenario explores the decarbonization of the mine's electricity demand using a mix of solar PV and onshore wind. Due to the variability and intermittency of solar and wind resources, it is not possible to fulfil the mine's constant electricity demand with solar PV and wind alone. Therefore, additional clean energy technologies are required to ensure a constant electricity supply. A diesel generator can serve as a backup, operating during periods when production from solar PV and wind turbines is insufficient. Alternatively, a Battery Energy Storage System (BESS) can be included to store surplus electricity generated by solar PV and wind, which can then be utilized to meet demand during periods of low generation.

Decarbonizing the mine's electricity demand with a mix of these technologies is potentially applicable to all four geographical regions defined in this study (East, South, West, and North). However, the results, such as the Levelized Cost of Electricity (LCOE) and Clean Electricity Share, are significantly influenced by the specific wind and solar resources at the exact mine location.

Map 6-1 and Map 6-2 give a closer look into the wind and solar resources on the East coast of Greenland. There can be several safety risks concerning the installation of wind turbines or solar panels on the inland ice, which is why the wind and solar resources on the inland ice is excluded.

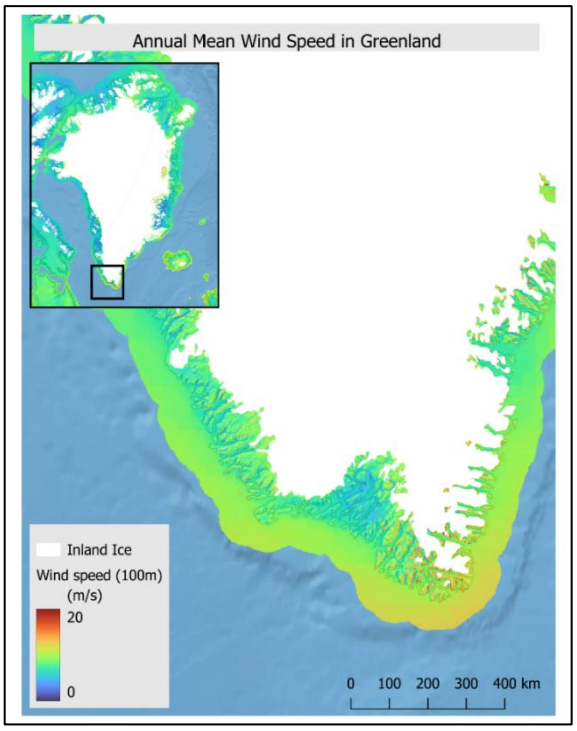


Map 6-2: Wind resources in East of Greenland.

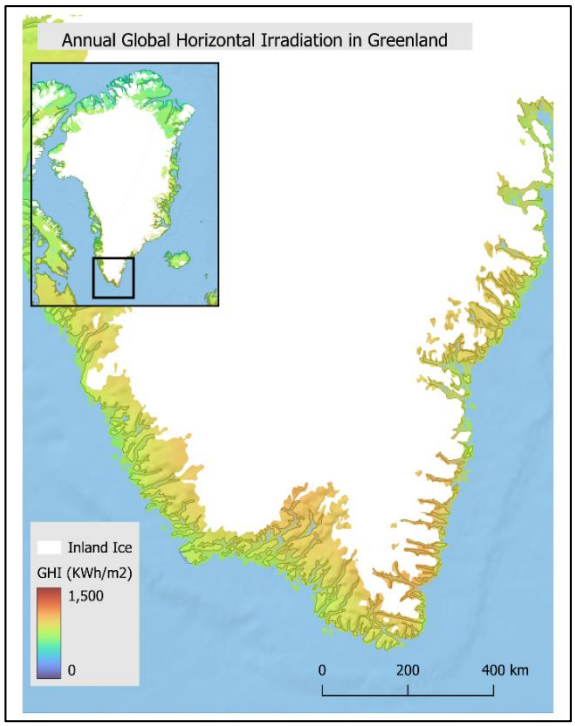


Map 6-1: Solar PV resources in East of Greenland.

Map 6-3 and Map 6-4 give a closer look into the wind and solar resources in the South of Greenland.

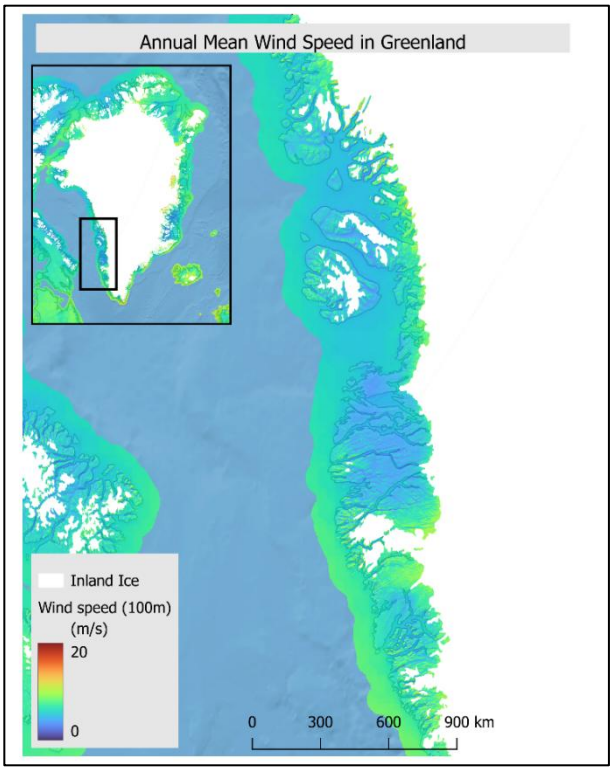


Map 6-4: Wind resources in South of Greenland.

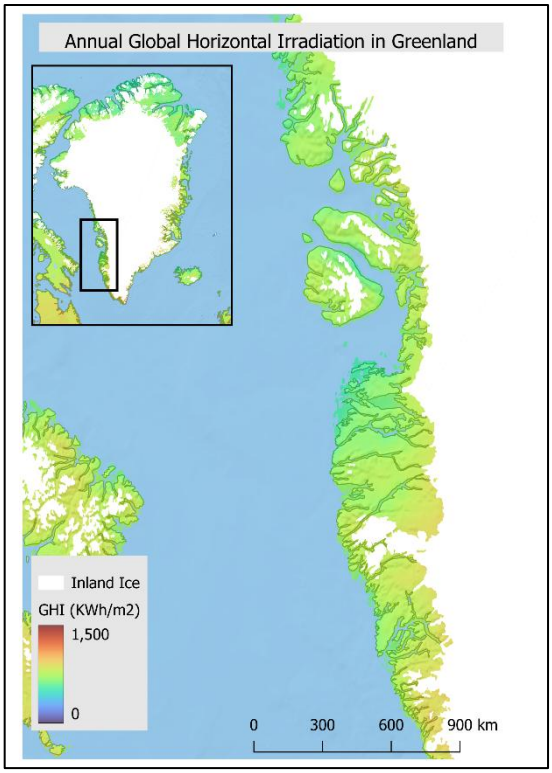


Map 6-3: Solar PV resources in South of Greenland.

Map 6-5 and Map 6-6 give a closer look into the wind and solar resources in the West of Greenland.

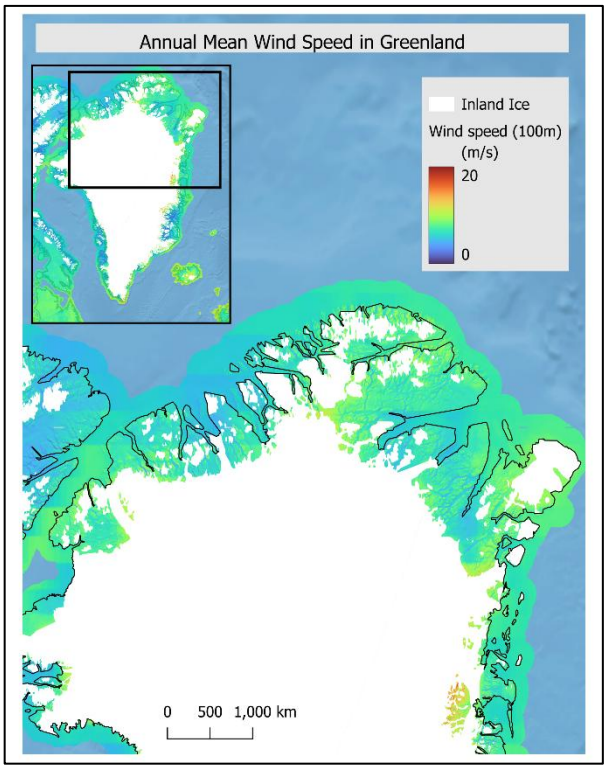


Map 6-6: Wind resources in West of Greenland.

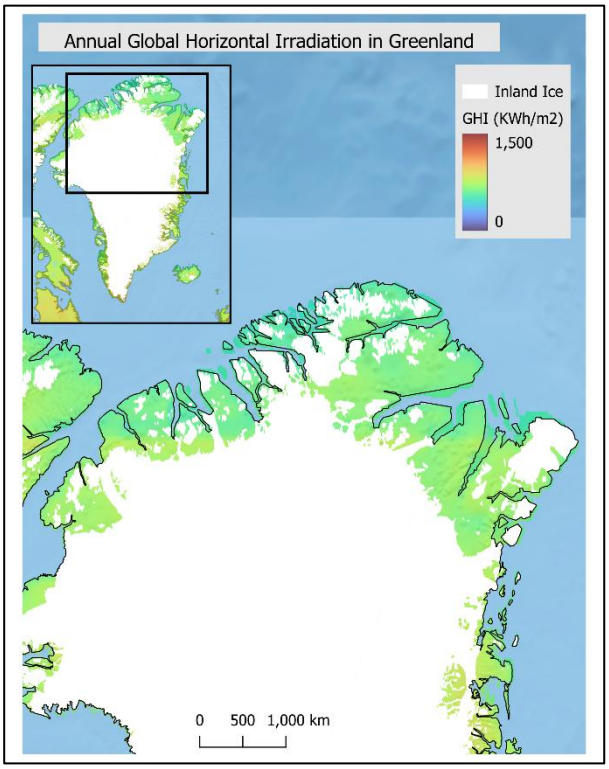


Map 6-5: Solar PV resources in West of Greenland.

Finally, Map 6-7 and Map 6-8 give a closer look into the wind and solar resources in the North of Greenland.



Map 6-7: Wind resources in North of Greenland.



Map 6-8: Solar PV resources in North of Greenland.

These maps illustrate the significant variability in solar and wind resources based on geographical location. Table 6-2 shows the capacity factors for wind turbines and solar PV at three specific sites in the East, South, and West regions. The capacity factor is the ratio of the actual yearly electricity produced by a generator to the maximum possible electricity that could have been produced if the generator operated continuously at full capacity. Points close to the selected mines in each geographical region were chosen for analysis. However, wind and solar potential can vary significantly due to local conditions and terrain, making site-specific assessments necessary. The wind and solar potential in the North of Greenland also exists, but hourly resolution data was unavailable, preventing capacity factor calculation for that region.

Solar PV and wind resource data with hourly resolution were obtained through publicly available platforms (Renewables.ninja [48]). Weather data from the year 2022 was selected for both solar PV and wind to ensure consistency and capture the correlation between wind and solar resource availability.

Capacity factor	East (71.8246, -22.8502)	South (60.2392; -45.1051)	West (66.5636; -51.4162)
Solar PV	11.9 %	11.5 %	11.8 %
Onshore Wind farm	22.3 %	34.3 %	19.5 %

Table 6-2: Capacity factor solar PV and onshore wind [48].

Three versions of the Mix of Solar PV and Wind scenario have been developed with different objectives, as discussed in Section 5.3:

- **Lowest LCOE:** The objective is to find the combination of solar PV, wind, and diesel generators that achieves the lowest possible LCOE while meeting the mine's electricity demand.
- **Same LCOE as diesel generator:** The objective is to find a combination of solar PV, wind, and diesel generators that reaches the same LCOE as the Diesel Generator scenario, while meeting the electricity demand of the mine.
- **100% solar PV and wind:** The objective is to find the combination of solar PV and wind that fully satisfies the mine's electricity demand (i.e., Clean Electricity Share = 100%). To reach this objective and compensate for the intermittent nature of PV and wind generation, BESS is needed in this scenario.

For each variation of the mix of solar PV and Wind scenarios, Table 6-3 shows the results in terms of installed capacity by technology and comparison metrics (i.e., LCOE, Clean Electricity Share, and Clean Electricity and Transport Share) for the South, West and East locations. Since the same economic assumptions are applied for all locations, the main differences in the results arise from variations in solar and wind resources, which lead to different optimal installed capacities and metrics. Additionally, the peak electricity consumption of the mine at the East geographical location is 33 MW, while the mines in the West and South regions have a peak electricity consumption of 10 MW. This difference impacts the optimal installed capacities of technologies.

Results for Mix of Solar PV, Wind and Diesel Generator									
	East			South			West		
	Lowest LCOE	Same LCOE as diesel generator	100% solar PV and wind	Lowest LCOE	Same LCOE as diesel generator	100% solar PV and wind	Lowest LCOE	Same LCOE as diesel generator	100% solar PV and wind
Installed Capacity by Technology									
Onshore wind farm (MW)	40	191	802	13	62	893	11	51	2551
Solar PV (MW)	59	162	103	16	53	50	18	49	0
Diesel generator (MW)	44	44	0	13	13	0	13	13	0
BESS (MWh)	0 (not economic ally feasible)	0 (not economic ally feasible)	1572	0 (not economic ally feasible)	0 (not economic ally feasible)	351	0 (not economic ally feasible)	0 (not economic ally feasible)	688
Share of Clean Energy Technologies									
Clean Electricity Share (%)	44%	73%	100%	53%	78%	100%	39%	66%	100%
Clean Electricity and Trans-port Share (%)	18%	29%	40%	21%	32%	40%	15%	26%	40%
Levelized Cost of Electricity									
LCOE (EUR/MWh)	225	297	1,045	199	297	2,761	237	297	7,503

Table 6-3: Results of scenarios for Mix of Solar PV and Wind.

For all locations, the lowest LCOE (199/237 EUR/MWh, depending on the location) scenarios are achieved with a combination of onshore wind, solar PV, and diesel generator. The diesel generator is sized to fully cover the peak electricity demand with an additional 33% capacity to account for

maintenance periods and unexpected outages. Solar PV and onshore wind capacities are slightly oversized compared to the peak demand to account for capacity factors. In the Lowest LCOE scenarios, the BESS is never preferred over the diesel generator due to the high CAPEX ("not economically feasible" in Table 6-3). The lowest LCOE scenarios achieve a Clean Electricity Share of around 39-53%, depending on the location.

The Lowest LCOE scenarios achieve a lower LCOE than the Diesel Generator (Business-as-Usual) scenario, which has an LCOE of 297 EUR/MWh. This means that the mine's decarbonization (i.e., the Clean Electricity Share) can be further improved by maintaining the diesel generator size and further oversizing the solar PV and wind capacities until the LCOE matches that of the Diesel Generator scenario. This Same LCOE as Diesel Generator scenario allows for a higher Clean Electricity Share compared to the Lowest LCOE scenarios, at no additional cost compared to the business as usual.

To achieve a fully decarbonized electricity demand, it is necessary to eliminate the diesel generator and rely on a BESS. However, the 100% Solar PV and Wind scenarios require significant oversizing of installed PV and wind capacities combined with a very large BESS, resulting in an LCOE that is significantly higher than the Business-as-Usual scenario. This setup does not represent a realistic scenario and demonstrates that decarbonizing the mine's electricity demand using only PV and wind is not an economically viable option.

In all scenarios, the Clean Electricity and Transport Share is smaller than the Clean Electricity Share, highlighting the impact of the transport sector, which covers 60% of the total energy demand.

Focusing on the South location as an exemplary case:

- **Lowest LCOE Scenario**: Combining onshore wind (13 MW), solar PV (16 MW) and diesel generator (13 MW) achieves an LCOE of 199 EUR/MWh, with a Clean Electricity Share of 53% and a Clean Electricity and Transport Share of 21%. This shows that it is possible to incorporate clean energy technologies in the electricity production of a mine and achieve a lower LCOE compared to the fully diesel generator scenario (which has an LCOE of 297 EUR/MW).
- **Same LCOE as Diesel Generator Scenario**: A combination of onshore wind (62 MW), solar PV (53 MW), and diesel generator (13 MW) results in an LCOE of 297 EUR/MWh, the same as the Business-as-Usual scenario. However, this configuration achieves a Clean Electricity Share of 78% and a Clean Electricity and Transport Share of 32%.
- **100% Solar PV and Wind Scenario**: This includes an onshore wind farm of 893 MW, a solar PV facility of 50 MW, and a BESS with a capacity of 351 MWh, resulting in an LCOE of 2,761 EUR/MWh, a Clean Electricity Share of 100%, and a Clean Electricity and Transport Share of 40%. The high LCOE is driven by the significant capacity of the BESS and onshore wind farm, making this scenario economically unrealistic due to high investment costs. Furthermore, the optimal sizes are based on one average weather year. To ensure the mine's electricity demand is met in worst-case scenarios, such as prolonged periods with limited renewable potential or years with lower-than-average renewable production, it may be necessary to further oversize the installed capacity of renewables and BESS, which would further impact economic feasibility.

Figure 6-1 illustrates the relationship between the LCOE and the Clean Electricity Share (CES) for the East, South, and West locations. Variations in this relationship across the different locations are due to the different capacity factors and hourly availability of solar PV and onshore wind at each site. The 0% CES represents the Diesel Generator (Business-as-Usual) scenario, while the 100% CES represents the fully decarbonized 100% Solar PV and Wind scenarios. Between these extremes, the points representing the Lowest LCOE and Same LCOE as Diesel Generator scenarios are

depicted. This figure, alongside Table 6-3, shows that incorporating clean energy technologies can achieve a lower LCOE compared to the business-as-usual scenario up to a certain CES. However, achieving a 100% CES with a mix of solar PV and onshore wind is economically unfeasible, as LCOE increases exponentially when attempting to decarbonize the last percentages of the mine's electricity demand. This is due to the need for significant oversizing of solar PV and wind capacities coupled with large BESS installations.

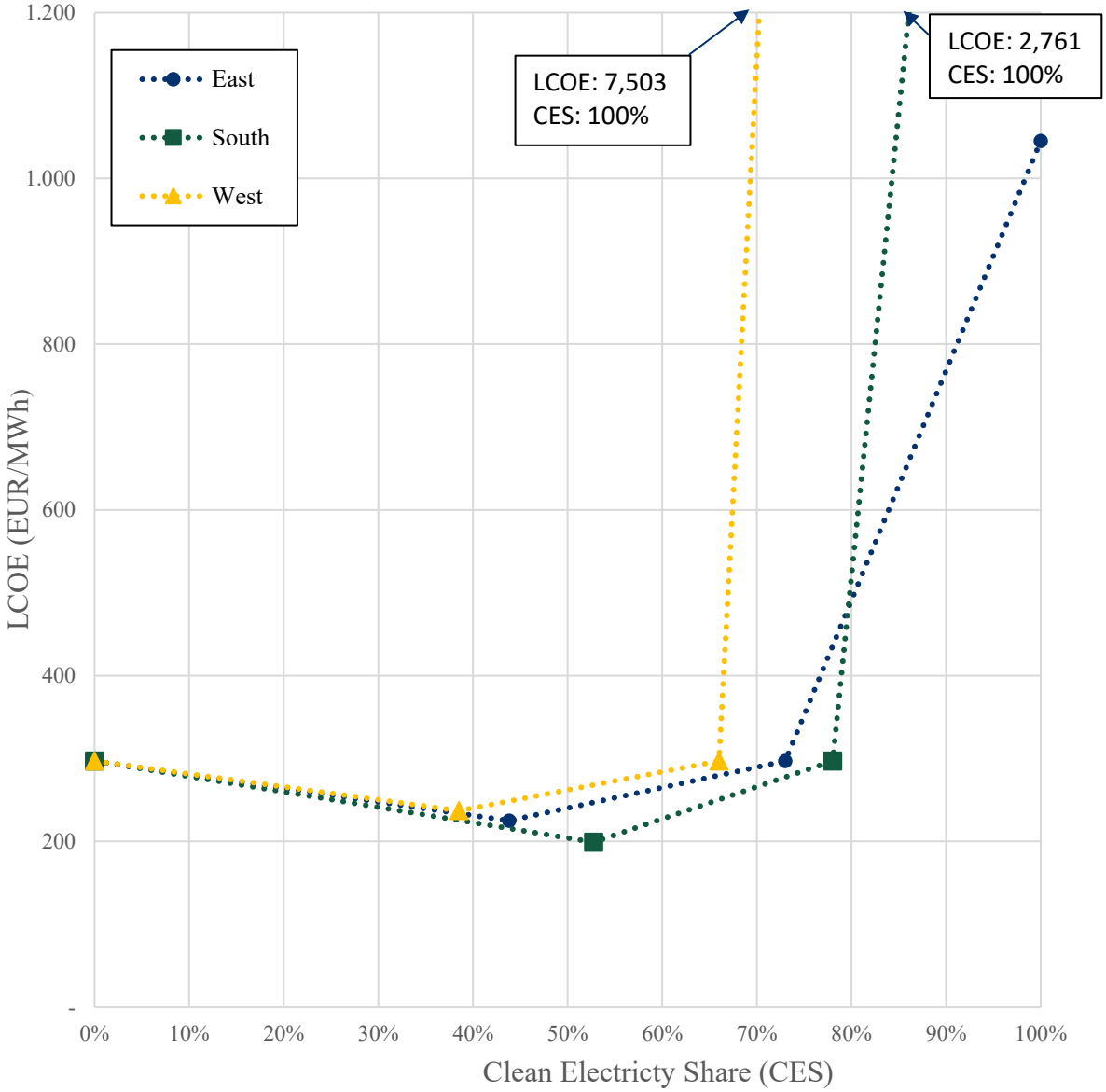


Figure 6-1: LCOE as a function of the Clean Electricity Share for the East, South, and West locations.

6.2.1 Seasonal and Hourly Variations

Figure 6-2, Figure 6-3, and Figure 6-4 show the share of monthly electricity demand that is covered by solar PV, onshore wind, and diesel generator for the South, West and East locations (Lowest LCOE scenarios), illustrating how much each technology contributes to meeting the mine´s demand each month. The graphs show that solar PV production is highest from March to October, while it is almost non-existent in November, December, and January due to minimal sunlight during those months.

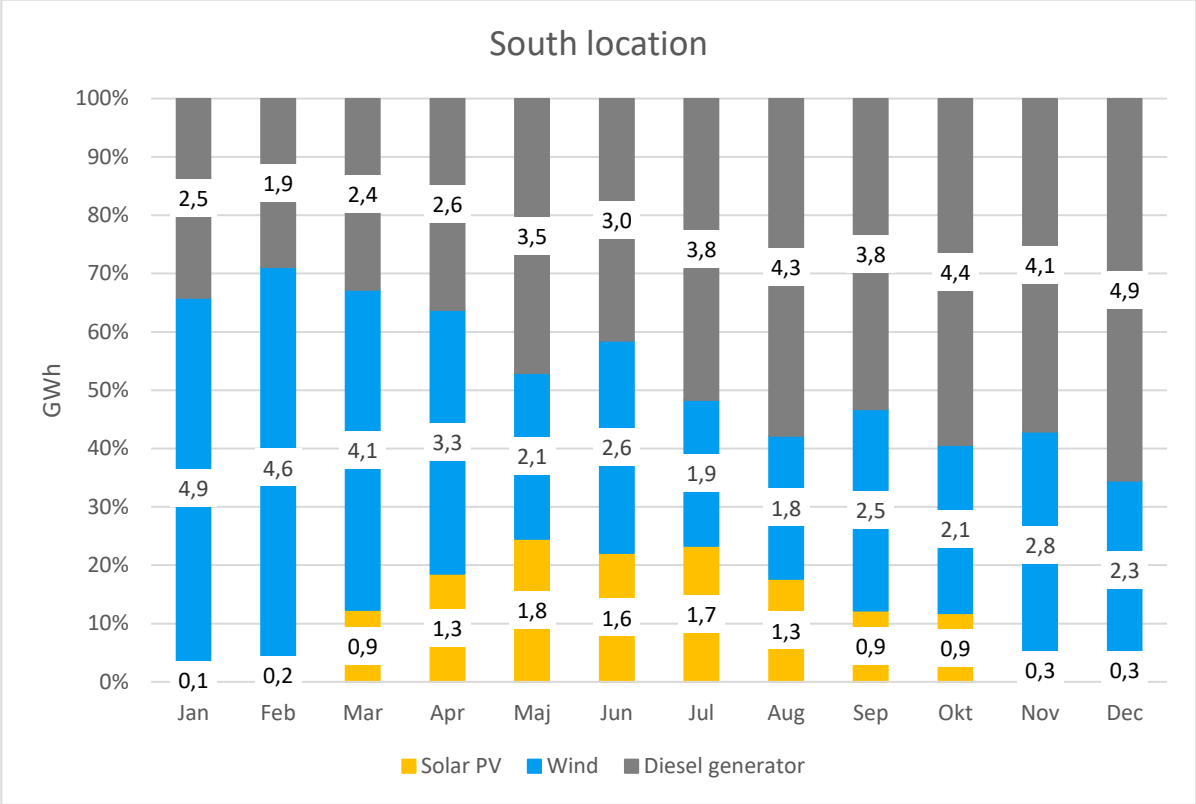


Figure 6-2: Monthly electricity production for the South location.

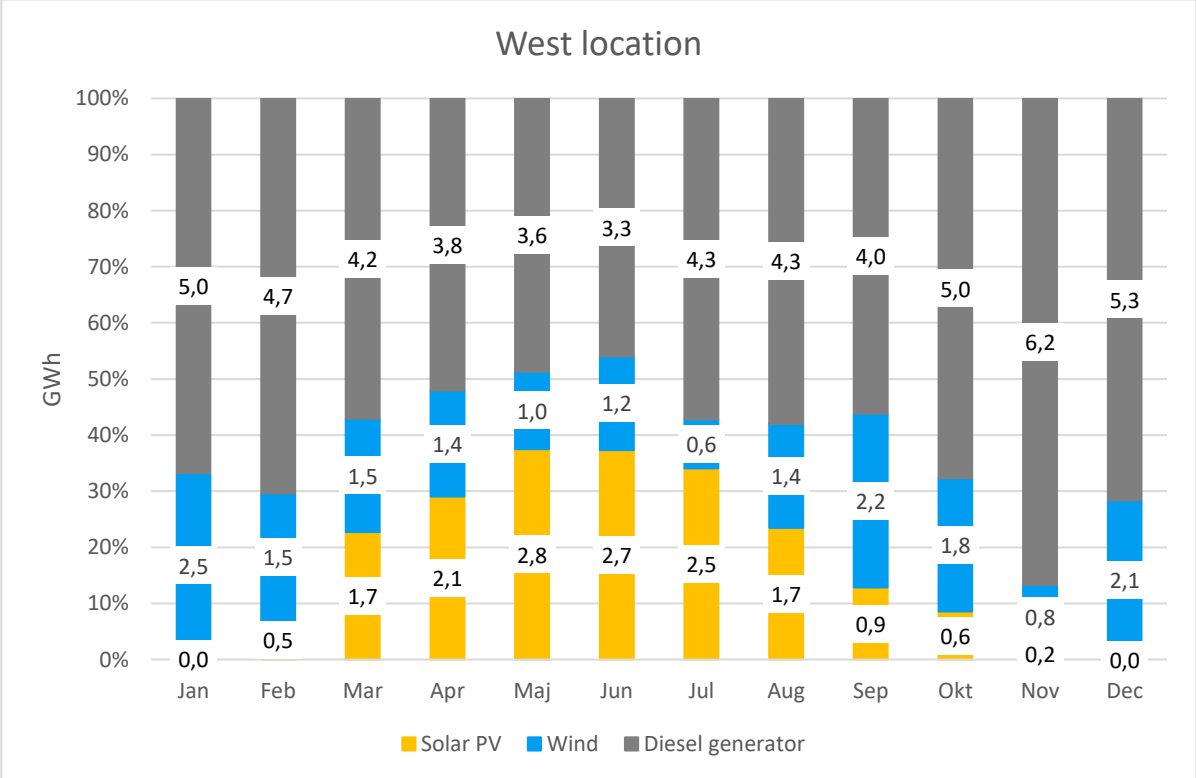


Figure 6-3: Monthly electricity production for the West location.

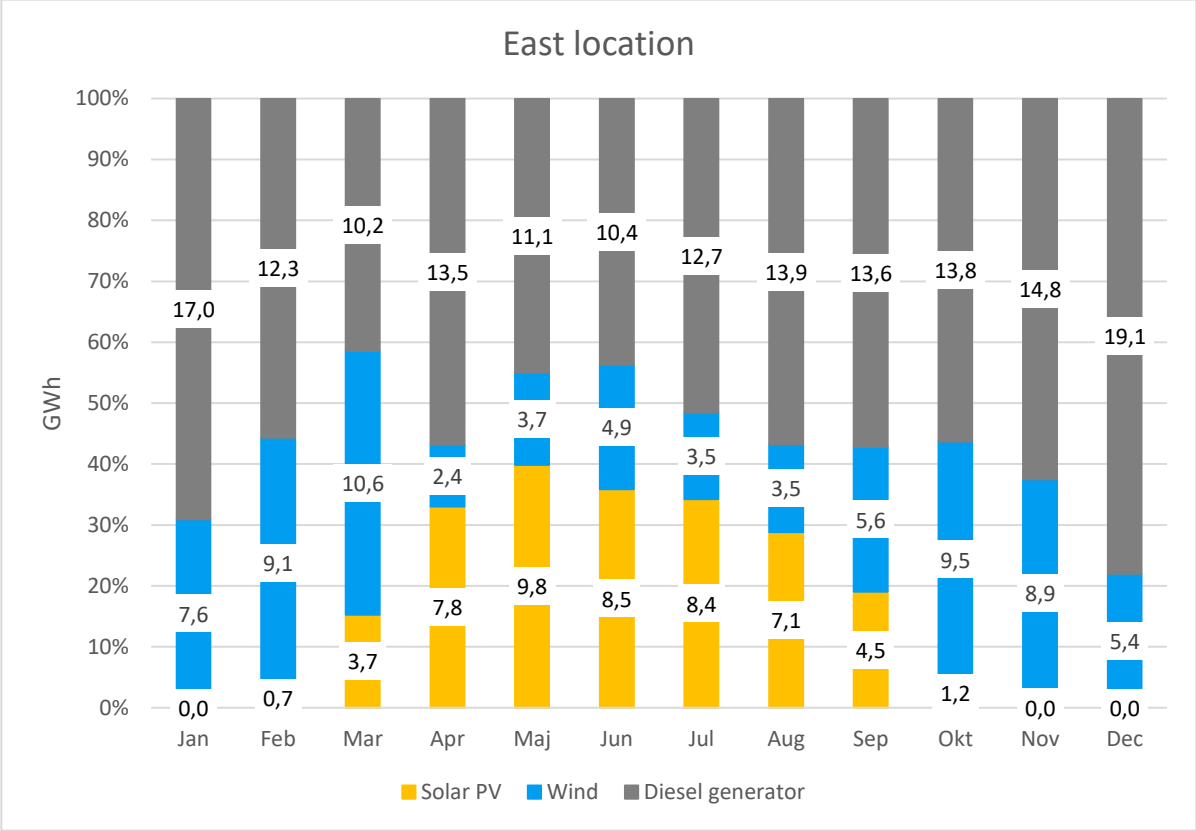


Figure 6-4: Monthly electricity production for a point on the East location.

In Figure 6-5 and Figure 6-6, the Lowest LCOE scenario for the East location is used as an illustrative case to show how the electricity demand of the mine is satisfied, each hour, by the mix of technologies (i.e., solar PV, onshore wind, and diesel generator). To highlight the seasonal variations in the energy mix, we show a representative week in both winter (Figure 6-5) and summer (Figure 6-6).

During winter, solar PV's contribution is minimal, with electricity demand mainly being covered by onshore wind production. Diesel generators serve as a backup source when wind production dips. Conversely, in summer, solar PV plays a significant role, even contributing a small amount of power during the night thanks to the midnight sun. Figure 6-6 highlights the complementary nature of solar PV and onshore wind production, with high wind generation during periods of low sunlight (cloudy days and nighttime). This case study illustrates the dynamic interplay between different energy sources and their complementarity throughout the year in meeting the mine’s electricity demand.

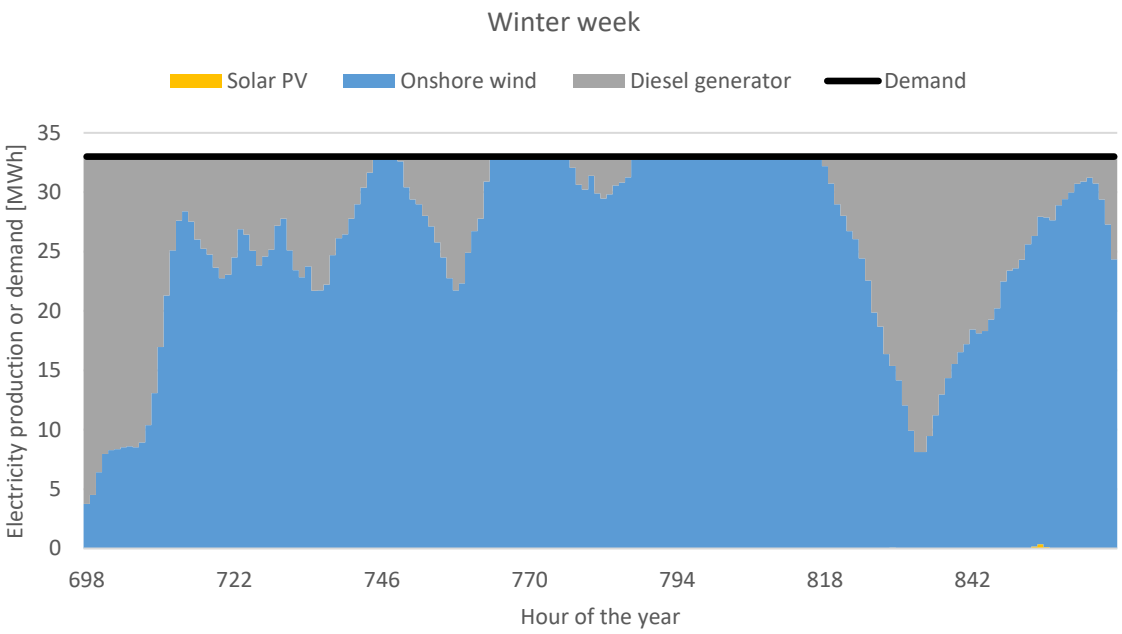


Figure 6-5: Hourly electricity production and demand for one representative week in winter (Lowest LCOE scenario for East location).

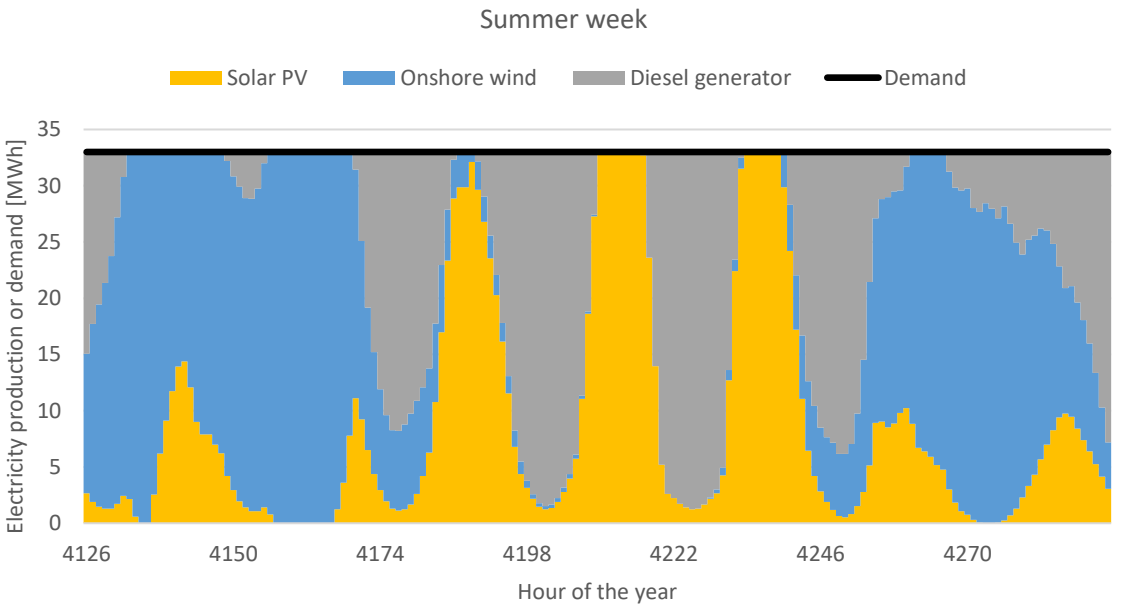


Figure 6-6: Hourly electricity production and demand for one representative week in summer (Lowest LCOE scenario for East location).

6.2.2 Sensitivity

Two sensitivity analyses of the Mix of Solar PV and Wind scenarios have been conducted. The first analysis uses 2040 CAPEX and OPEX projections instead of 2030 projections. The second analysis explores the impact of varying the project lifetime, setting it to either 10 years or 30 years instead of the default 20 years.

6.2.2.1 Year 2040 CAPEX Projections

As this project aims to evaluate the techno-economic feasibility of various clean technologies for future applications, it is essential to consider scenarios extending beyond 2030. Specifically, projections for the year 2040 have been analyzed. Sensitivity analysis has been conducted for the Lowest LCOE scenario with the solar PV, wind, and diesel generator configuration for the East geographical region, which has a peak electricity demand of 33 MW.

It is assumed that the 2040 CAPEX for onshore wind will be reduced by 3% compared to 2030, and the solar PV CAPEX will be reduced by 13%. These reductions are based on projections from the Danish Energy Agency [28]. The CAPEX for diesel generators is assumed to remain unchanged between 2030 and 2040.

Table 6-4 presents the results of the CAPEX sensitivity analysis. The results indicate that incorporating the projected learning rates for solar PV and onshore wind can potentially reduce the LCOE slightly with a minor increase the Clean Electricity Share for the Lowest LCOE scenario.

2030 vs. 2040 CAPEX projections		
Scenarios	**Lowest LCOE - 2030**	**Lowest LCOE - 2040**
Capacity of technologies		
Onshore wind farm (MW)	40	41
Solar PV (MW)	59	65
Diesel generator (MW)	44	44
BESS (MWh)	0	0
Metrics		
LCOE (EUR/MWh)	225	224
Clean Electricity Share (%)	44%	45%

Table 6-4: Sensitivity: 2030 or 2040 CAPEX and OPEX projections.

6.2.2.2 10- and 30-Year Lifetime

In this study, it was deemed relevant to examine how the results of the scenarios would change if the project lifetime were adjusted to 10 or 30 years, compared to the 20-year lifetime used as the reference case. This consideration stems from the fact that mining operations may have a shorter or longer operational window, depending on the availability of extractable minerals. Additionally, it is important to note that the lifespan of the included clean energy technologies is likely to exceed 20 years (for example, solar PV and onshore wind typically have lifetimes of 30+ years).

For this sensitivity analysis, two scenarios were chosen: the Diesel Generator (Business-as-Usual) scenario and the Mix of Solar PV and Wind scenario with the Lowest LCOE for the East geographical region. The results are presented in Table 6-5 and Table 6-6.

Diesel Generator – Business-as-usual			
Project lifetime (years)	**10**	**20**	**30**
LCOE (EUR/MWh)	298	297	293
Clean Electricity Share	0%	0%	0%
LCOE variation compared to 20-year lifetime	0.2%	-	-1.4%

Table 6-5: Diesel Generator (Business-as-Usual scenario): 10- vs. 30-year lifetime.

Mix of Solar PV, Wind Turbines and Diesel (Lowest LCOE – East)			
Project lifetime (years)	**10**	**20**	**30**
LCOE (EUR/MWh)	250	225	213
Clean Electricity Share	39%	44%	46%
LCOE variation compared to 20-year lifetime	11.1%	-	-5.5%

Table 6-6: Mix of Solar PV, Wind Turbines and Diesel (Lowest LCOE – East): 10- vs. 30-year lifetime.

The LCOE figures presented in the tables above indicate that both scenarios see a decrease in LCOE if a longer project lifetime is assumed, as there are more years to recover the initial CAPEX investments. The results also show that the Mix of Solar PV and Wind scenario (Lowest LCOE – East) is more significantly affected by the length of the project lifetime compared to the Diesel Generator scenario. This difference is due to the differing cost structures of the two scenarios: the Diesel Generator scenario involves a low initial investment (CAPEX) but incurs higher operational costs (OPEX), whereas the Mix of Solar PV and Wind scenario (Lowest LCOE – East) has a higher CAPEX and lower OPEX. The business case for the Mix of Solar PV and Wind is challenged for mining operations that have a short operational window. For 30-year projects, there is potential for reaching even higher decarbonization rates at the same LCOE as the Diesel Generator option.

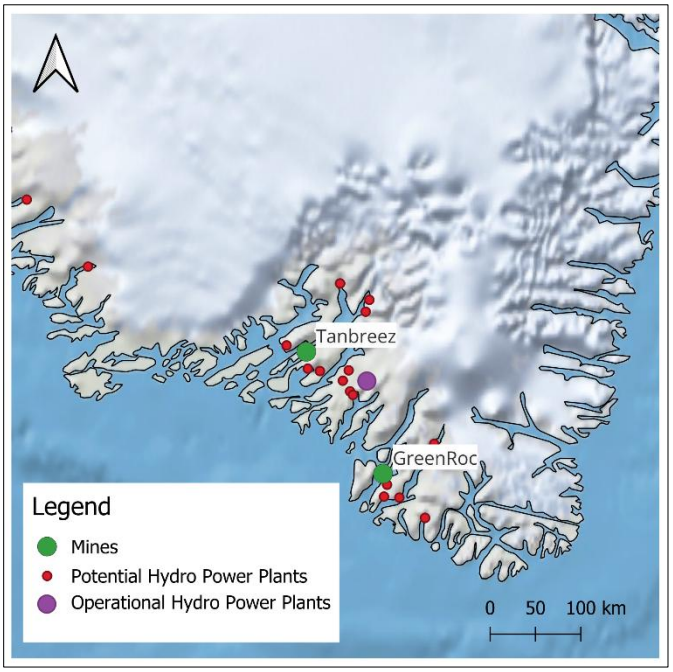
6.3 Hydropower

This scenario assesses the decarbonization of a mine´s electricity demand using electricity generated from hydropower plants. For this scenario, two different versions have been analysed:

- **New hydropower plant:** This considers building a new hydropower plant and the associated electricity transmission lines connecting the plant to the mine.
- **Upgrading an existing hydropower plant:** This includes upgrading an existing hydropower facility to add additional capacity to meet the electricity demands of the mining operation, along with the associated electricity transmission lines.

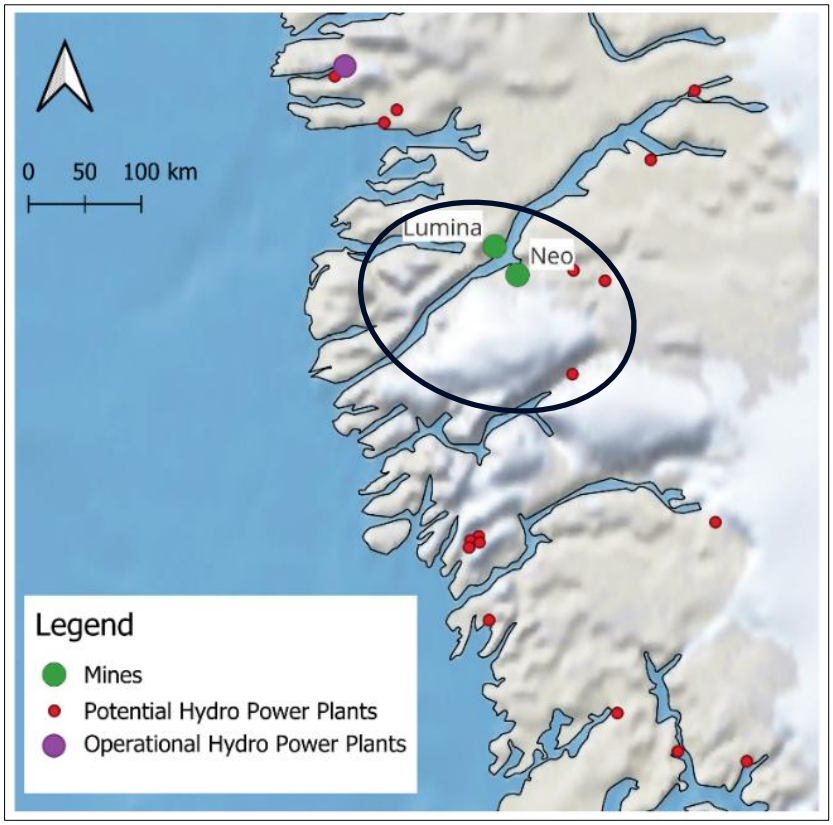
Hydropower potential exists across Greenland. However, it is more thoroughly mapped in the West and South regions (see Map 3-3 and Map 3-4 in Section 3.4). Therefore, this analysis focuses on the South and West of Greenland.

In the South of Greenland, there is significant potential for utilizing hydropower to supply energy to mines due to the high density of prospective hydropower plant sites in the region. Most of these sites are currently classified as potential projects, meaning their actual implementation remains uncertain. However, there is one operational hydropower plant, Qorlortorsuaq, located near both TANBREEZ Mining Greenland A/S and GreenRoc Graphite Limited. Map 6-9 provides a geographical overview of the locations of the two mines in relation to potential and operational hydropower plants.



Map 6-9: Hydropower potential South of Greenland.

The West geographical region in Greenland also shows strong potential for utilizing hydropower as an energy source for mines, given its high density of prospective hydropower plant sites. These sites are classified as potential projects, and their actual implementation is uncertain. Currently, there is one operational hydropower plant in this region (Sisimut/Tasersuaq hydroplant). Map 6-10 provides a geographical overview of the Lumina Sustainable Materials A/S and Qaatsuitsup Ulloriaa (Neo North Star Resources Inc) mines in relation to both potential and operational hydropower plants. The three potential hydropower plants in the black circle are the three plants with the highest potential to be implemented in the area. The three potential hydropower plants are all connected to the Tasersiaq lake, and only one of them will be implemented.



Map 6-10: Hydropower potential West Geographical region. The three potential hydropower plants in the black circle are the three plants with the highest potential in this area (only one of them will be implemented).

To estimate the investment required for supplying a mine with electricity from a hydropower facility, several factors must be considered. These include the distance between the mine and the hydropower plant, the available capacity at the plant, and whether upgrades are necessary.

6.3.1 New hydropower plant

For the "New hydropower plant scenario", a high-level assessment of the LCOE has been conducted for implementing a new 10 MW hydropower facility and the associated electricity transmission lines. The size is chosen to supply the peak electricity demand of the South and West locations (see Table 4-2). It is assumed that the hydropower plant can provide a constant electricity supply during the year. Since the exact location of a potential hydropower plant is unknown, a sensitivity analysis was performed to account for variations in the length of the electricity lines, ranging from 20 to 1100 km. The investment cost of the transmission lines includes the cost per meter of line, a transformer station (per MW), and operation and maintenance (O&M) costs (per MW), as listed in Table 5-3. Figure 6-8 and Figure 6-7 illustrates the relationship between the LCOE of a 10 MW hydropower plant and the length of the electricity lines (i.e., the distance from the mine). The sensitivity is shown in two different graphs to better visualise the variations in LCOE in the shorter distances. The figures shows that the scenario with a 1035 km electrical line (LCOE of 297 EUR/MWh) is competitive with the LCOE of the diesel generator (Business-as-usual) scenario (LCOE 297

EUR/MWh). In this scenario, the Clean Electricity Share is 100%, while the Clean Electricity and Transport Share is 40%.

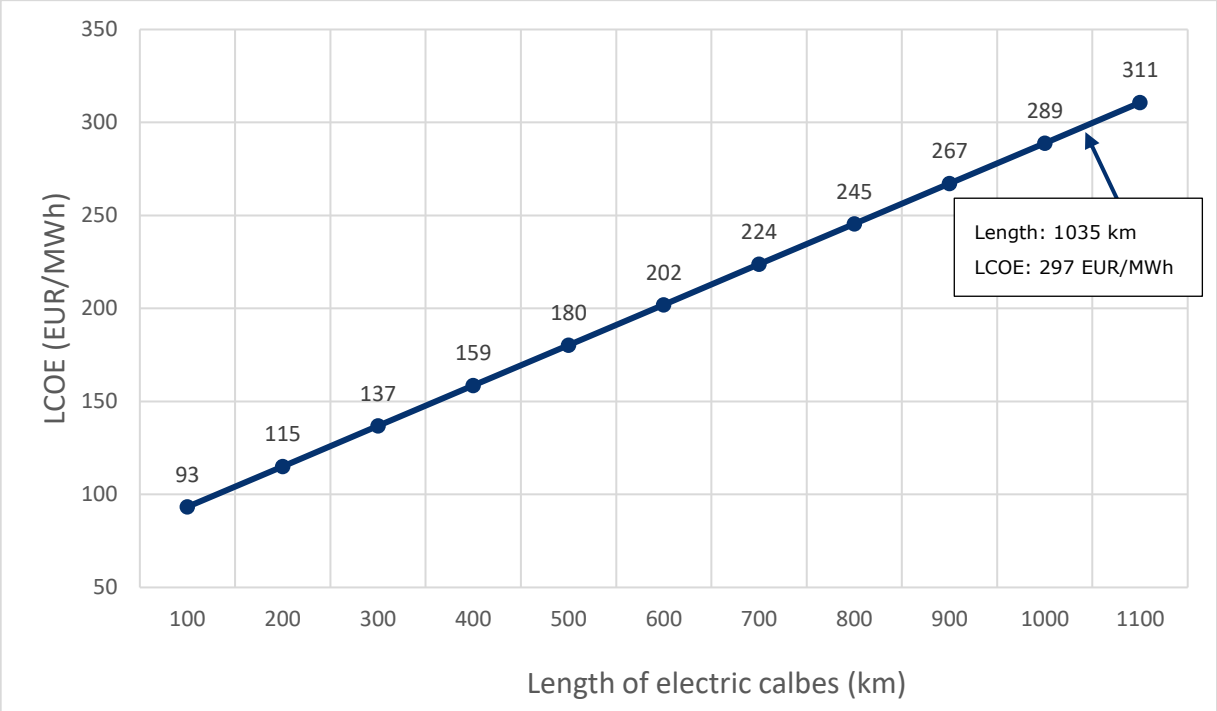


Figure 6-8: Estimated LCOE of a hydropower plant as a function of the length of the electric cables 100 km – 1100 km.

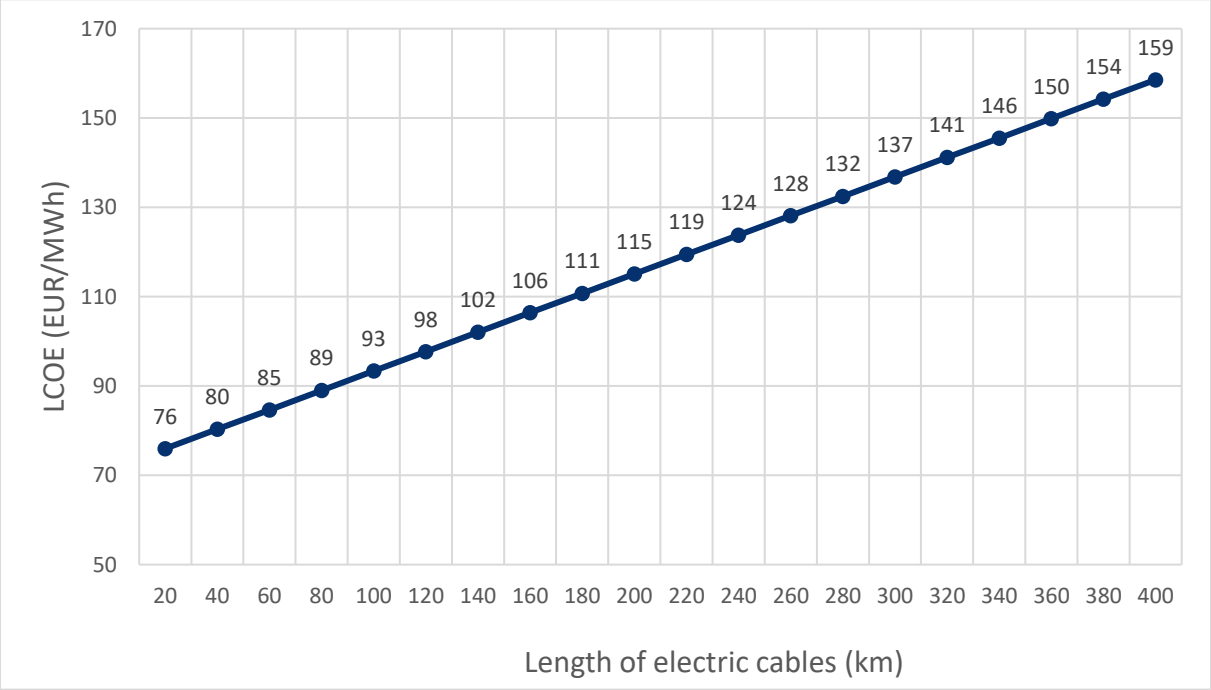


Figure 6-7: Estimated LCOE of a hydropower plant as a function of the length of the electric cables. 20 km – 400 km.

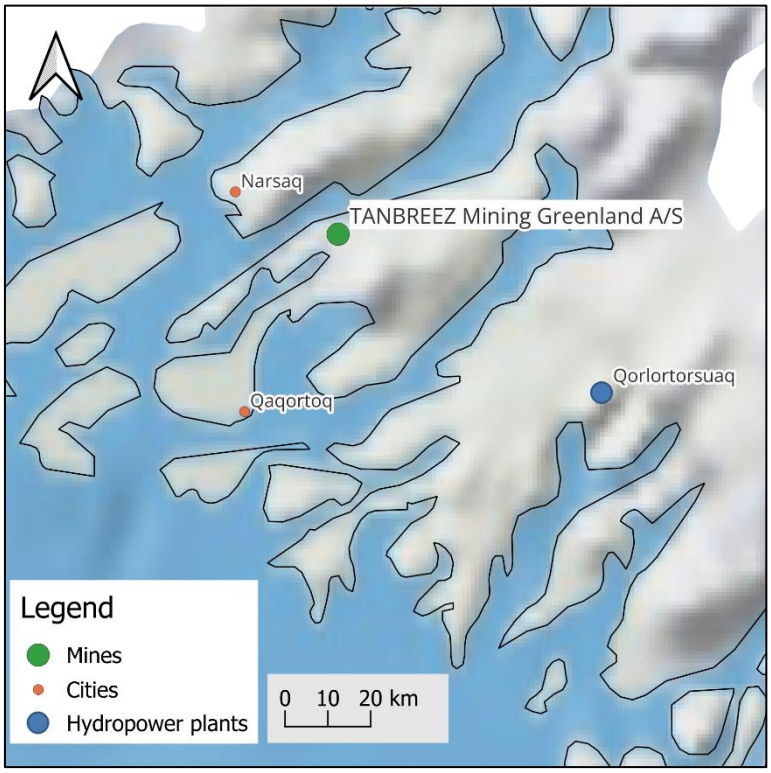
Note that if multiple mines are located in the same area, a larger hydropower plant could be built to supply multiple electricity demands. This may provide advantages in terms of economies of scale, which has not been considered in this study.

6.3.2 Upgrading an existing hydropower plant

For the "Upgrading an existing hydropower plant" scenario, we estimated the LCOE in case of upgrading an existing hydropower plant with an additional capacity of 10 MW to meet the energy demands of a mining operation. For this calculation, it was assumed that the powerhouse, shaft, and electro-mechanical equipment constitute 30% of the total CAPEX of the hydropower plant. The cost of the upgrade, aimed at increasing the plant's capacity, is estimated to be 75% of the investment required for the powerhouse, shaft, and electro-mechanical equipment [38]. This reflects the significant expense involved in refurbishing and enhancing these critical components to improve the plant's output. In addition to the upgrade costs, the calculation incorporates the investment required for 100 km of electricity transmission lines to connect the hydropower plant to the mining site. These costs are based on the same parameters used in the analysis of a new hydropower facility, which include the cost per meter of line, transformer stations (per MW), and operational and maintenance (O&M) expenses. Under these assumptions, the LCOE for the upgraded hydropower plant is calculated to be 60EUR/MWh.

6.3.3 Hydropower combined with solar PV and wind

This section analyses the combination of hydropower, solar PV and or wind turbines and a diesel generator. The section will be situated in the South of Greenland, as there is an operating hydropower facility, Qorlortorsuaq, and the TANBREEZ Mining Greenland A/S is located in a short distance (see Map 6-11). The Qorlortorsuaq hydropower facility uses a conventional dam-tunnel-penstock-turbine system and has an existing capacity of 7.6 MW coming from two turbines (Francis turbines with horizontal axes). Both turbines have a theoretical maximum capacity of 4.1 MWe and a rated capacity of 3.8 MW (normal operating capacity). The yearly average inflow of water to the existing reservoir is 128 hm3. The facility has a yearly average electricity production of 28.5 GWh. In the hydropower facility there is additional room for a third turbine, which presents the possibility that the facility can be upgraded. An additional turbine of 3.8 MW can be added, which will present the facility with a peak capacity of 11.4 MW. To upgrade the existing hydropower facility additional inflow of water is necessary. This can come from the nearby glacier Sermeq Kangilleq. The glacier has an estimated water volume of 336 hm3, where approximately 61% (200 hm3) can be transferred to the existing reservoir. This means that the new total inflow of water to the reservoir is 328 hm3. [75]



Map 6-11: South of Greenland – TANBREEZ mine in relation to the cities Narsaq and Qaqortoq and the existing hydropower facility Qorlortorsuaq.

The total yearly electricity demand of the system is 70.7 GWh and consists of the following sources:

- Electric demand to the Qaqortoq city (26.3 GWh)
- Electric demand to the Narsaq city (9.1 GWh)
- Electric demand to the TANBREEZ mine (32.41 or 87.6 GWh)
- Interruptible electric heating demand for Qaqortoq and Narsaq cities (2.8 GWh)

The yearly electricity demand of the TANBEREEZ mine will vary in the scenarios of this section. In the source from Nukissiorfiit [75] the yearly electricity demand of the mine is set to 32.41 GWh, while in this report a general electricity demand of the mine is set to 87.6 GWh. The future demand of the system is uncertain, which gives incentive to assess scenarios with different demands.

Following are the scenarios of this section:

1. Upgrade of inflow to the hydropower reservoir + mine yearly electricity demand of 32.42 GWh.
2. Upgrade of inflow to the hydropower reservoir + adding a new turbine + mine yearly electricity demand of 32.42 GWh.
3. Upgrade of inflow to the hydropower reservoir + adding a new turbine + mine yearly electricity demand of 87.6 GWh.

4. Upgrade of inflow to the hydropower reservoir + adding a new turbine + mine yearly electricity demand of 87.6 GWh + solar PV + diesel generator.
5. Upgrade of inflow to the hydropower reservoir + adding a new turbine + mine yearly electricity demand of 87.6 GWh + wind turbines + diesel generator.
6. Upgrade of inflow to the hydropower reservoir + adding a new turbine + mine yearly electricity demand of 87.6 GWh + solar PV + wind turbines + diesel generator.
7. Upgrade of inflow to the hydropower reservoir + adding a new turbine + mine yearly electricity demand of 87.6 GWh + diesel generator.
8. Same configuration as scenario 6 but the priority of the technologies is reversed. The demand is firstly met by solar PV and wind, then the hydropower and finally the diesel generator.

It is decided to analyse the combination of hydropower and wind or solar PV in separate scenarios to understand how they operate in combination with hydropower. There are substantial differences in the production profiles of wind and solar PV over a year which influences how they interact with the production profile of the hydropower plant.

The diesel generator will be included in the scenarios to be used as a backup electricity generating unit to be used in hours where there is not sufficient electricity production from the hydropower plant or the solar PV/wind turbine units. The diesel generator is sized to fully cover the peak electricity demand with an additional 33% capacity to account for maintenance periods and unexpected outages. The capacity of the diesel generator will for all relevant scenarios be 21 MW.

The electricity production from the hydropower facility will be prioritized in hours where it is available. Secondly the electricity from the solar PV or wind will be prioritized, and finally, the electricity from the diesel generator will be utilized. This is not the case for scenario 8 where the demand is firstly met by solar PV and wind, then hydropower and finally the diesel generator.

All scenarios will include an electrical line of 100 km located from the hydropower facility to the TANBREEZ mine. Figure 6-8 and Figure 6-7 presents a sensitivity over the length of the electrical line and the LCOE.

The electricity consumption of the two cities follows the profile of the following Figure 6-9.

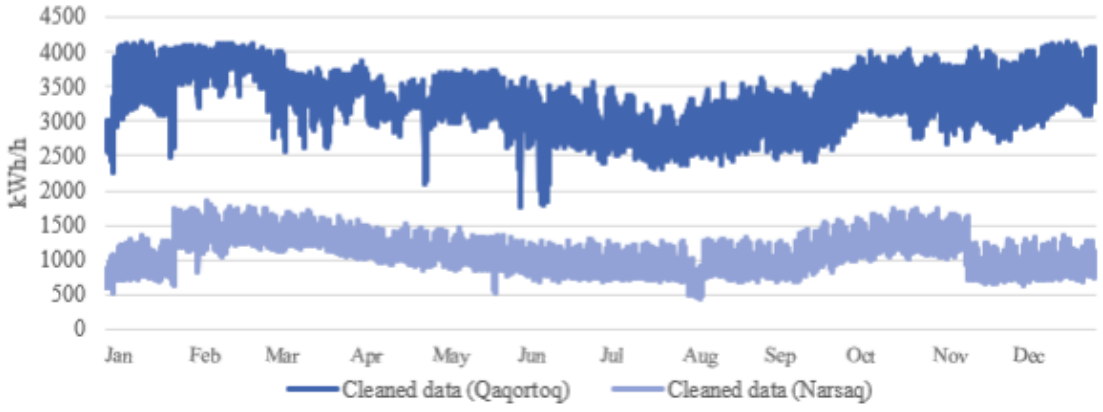


Figure 6-9: Hourly electricity consumption [75]

The interruptible heating demand follows the yellow profile of the individual interruptible electric heating of the following Figure 6-10.

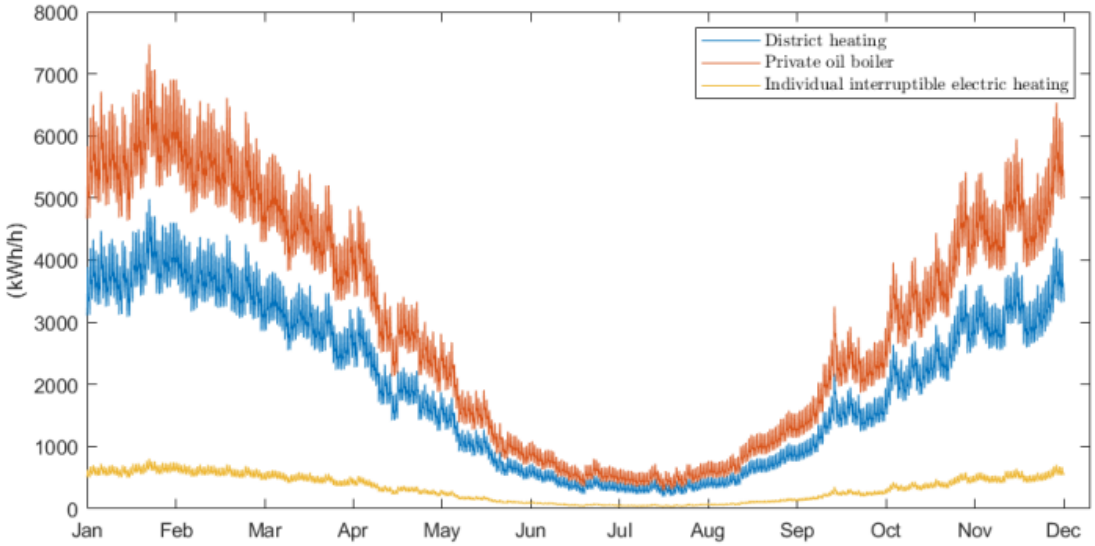


Figure 6-10: Hourly heating profiles [75]

The inflow of water to the hydropower reservoir follows the following profile in Figure 6-11.

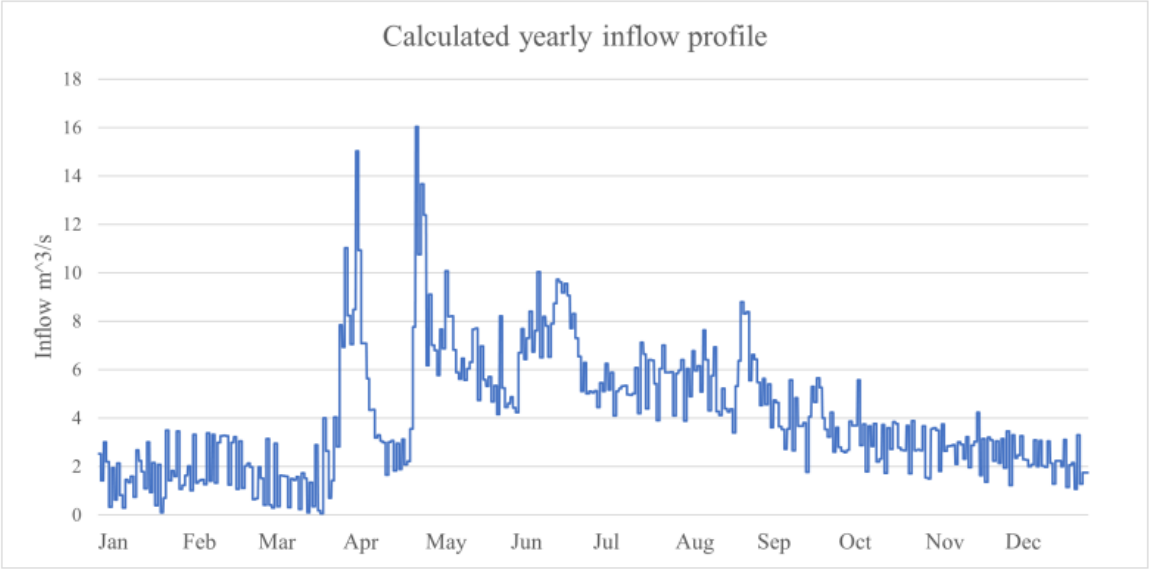


Figure 6-11: Hourly inflow profile of water to the hydropower profile [75]

For the techno-economic assessment the same CAPEX and OPEX values will be used as in the previous scenarios. The CAPEX and OPEX values are presented in Table 5-2 in Section 5.4. For this calculation, it was assumed that the powerhouse, shaft, and electro-mechanical equipment constitute 30% of the total CAPEX of the hydropower plant. The cost of the upgrade, aimed at increasing the plant's capacity by installing an additional turbine, is estimated to be 75% of the investment required for the powerhouse, shaft, and electro-mechanical equipment [38]. This reflects the significant expense involved in refurbishing and enhancing these critical components to

improve the plant's output. For these scenarios an additional inflow of water to the reservoir will be present, which means that a tunnel and dam construction is to be implemented. The CAPEX of constructing a tunnel constitutes 14 % of the total CAPEX of building a new hydropower plant. The CAPEX of constructing a new reservoir constitutes 26 % of the total CAPEX of building a new hydropower plant. The construction of a dam can approximately be compared to building a new reservoir, which means that building a dam constitutes approximately 26 % of the total CAPEX of building a new hydropower plant. [38]

Results of the scenarios' capacities, production, energy flows and techno-economic assessment:

It is not relevant to include scenario 1-3 in the techno-economic assessment as the choice to only include the hydropower facility does not fulfil the total electricity demand, which makes the scenarios unrealistic.

The available energy production from the upgraded inflow to the hydropower reservoir is 73 GWh.

The following Table 6-7 shows the results of the scenarios:

Table 6-7: Results of hydropower combined with solar PV wind and diesel generator scenarios (installed capacity).

		Sc. 1	Sc. 2	Sc. 3	Sc. 4	Sc. 5	Sc. 6	Sc. 7	Sc. 8
Energy flows, production and capacities									
Turbine capacity	MW	7.6	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Hydropower production	GWh	66	69.5	73	73	73	73	73	73
Mine electricity demand	GWh	32.41	32.41	87.6	87.6	87.6	87.6	87.6	87.6
Total electricity demand	GWh	70.7	70.7	125.9	125.9	125.9	125.9	125.9	125.9
Residual demand after hydropower production	GWh	4.6	1.1	52.9	52.9	52.9	52.9	52.9	83.5 (after solar PV and wind production)
Solar PV	GWh	-	-	-	4.3 (4 MW)	-	4.3 (4 MW)	-	15 (14 MW)
Wind turbines	GWh	-	-	-	-	7.8 (4 MW)	7.8 (4 MW)	-	27.4 (14 MW)
Diesel generator	GWh	-	-	-	48.6 (21 MW)	45.1 (21 MW)	40.8 (21 MW)	52.9 (21 MW)	10.5 (21 MW)
Techno-economic assessment									
LCOE	EUR/ MWh	-	-	-	207	203	196	214	149
Clean Electricity Share	%	-	-	-	61 %	64 %	68 %	58 %	92 %
Clean Electricity and Transport Share	%	-	-	-	25 %	26 %	27 %	23 %	37 %

The results of **scenario 1** shows that the hydropower production of 66 GWh is lower than the available energy production from the upgraded inflow to the hydropower reservoir of 73 GWh. This shows that the system cannot utilize the full energy potential of the upgraded inflow with the existing turbine capacity of 7.6 MW. The system also shows a residual demand that is not fulfilled by the production of electricity of the hydropower plant.

The results of **scenario 2** show that the additional third turbine increases the hydropower production to 69.5 GWh and reduces the residual demand to 1.1 compared to scenario 1. There is, however, still a residual demand which is not met by the hydropower production, which indicates that additional production capacity is needed. It is evident that the total yearly demand of electricity of 70.7 GWh is not met in this scenario even though additional turbine capacity is included. This is because the electricity production from the hydropower facility is limited to the energy content of the inflow of water, which is 5000 kW, which means that in hours where the electricity demand is higher than 5000 kW the demand cannot be met by the production from the hydropower facility. This limitation of the system is also present in the following scenarios.

The results of **scenario 3** show that when the demand of the TANBREEZ mine is increased to be 87.6 GWh the total demand increases, which means that the residual demand that is not met by the hydropower also increases. This scenario includes the increased turbine capacity. The residual demand of 52.9 GWh gives strong incentives to implement additional production capacity e.g. in the form of renewables.

The results of **scenario 4** show that the residual demand that is not met by the hydropower in the past scenarios can be met by a combination of solar PV and diesel generator. A capacity of 4 MW for the solar PV is chosen to minimize curtailment and investment cost, which results in a production of 4.3 GWh. The diesel generator, with a capacity of 21 MW, has a production of 48.6 GWh and contributes to the total demand being met. This scenario has a LCOE of 207 EUR/MWh, Clean Electricity Share of 61 % and a Clean Electricity and Transport Share of 25 %.

The results of **scenario 5** shows that when introducing the same capacity wind turbines (4 MW) instead of solar PVs the production of the diesel generator decreases. This is due to the higher capacity factor of the wind turbines in the South of Greenland. This means that to meet the total electricity demand the wind turbines produces 7.8 GWh and the diesel generator produces 45.1 MWh. This scenario has a LCOE of 203 EUR/MWh, Clean Electricity Share of 64 % and a Clean Electricity and Transport Share of 26 %.

The results from **scenario 6** show that when including both a solar PV and wind turbine facility of respectively 4 MW the production of the diesel generator decreases to 40.8 GWh. The upside to this scenario is that the diesel generator produces less which equals to a higher Clean Electricity Share, but the downside is that investments and technology experts for both solar PV and wind turbines are required. This scenario has a LCOE of 196 EUR/MWh, Clean Electricity Share of 68 % and a Clean Electricity and Transport Share of 27 %.

The results of **scenario 7** shows that the residual demand after the production from the hydropower facility can also be solely met by a diesel generator. At this example the diesel generator will have a production of 52.9 GWh. This scenario has a LCOE of 214 EUR/MWh, Clean Electricity Share of 58 % and a Clean Electricity and Transport Share of 23 %.

For **scenario 8** the capacity of solar PV and wind is increased and set to be prioritized to fulfill the electricity demand first. The capacities are both set to 14 MW and the combined production is 42.4 GWh. Following, the hydropower facility is the second technology to fulfill the electricity demand and has the same production of 73 GWh as in the other scenarios. For this scenario there are hours where there is an over production of electricity from the hydropower plant at a total of 14.5 GWh of overproduced electricity. The operation of the hydropower plant could in this case be adjusted to fit the demand. There are still hours where the solar PV, wind turbines and hydropower is insufficient

in covering the peak electricity demand, in these hours the diesel generator will supply with electricity. The diesel generator has in this scenario a production of 10.5 GWh. This scenario has a LCOE of 149 EUR/MWh, Clean Electricity Share of 92 % and a Clean Electricity and Transport Share of 37 %.

Scenario 8 has the lowest LCOE and the highest Clean Electricity Share of the scenarios in this section. This can be explained by the lower production from the diesel generator as the capacities of the solar PV and wind turbines are increased in this scenario. The low production from the diesel generators means a lower import of diesel for the generators, which has a cost of 96 EUR/MWh (7.17 kr./l). Scenario 6 also has a lower LCOE of the scenarios of this section. This can be explained by the introduction of both solar PVs and wind turbines, which gives a higher production of renewables with low operational costs, compared to the diesel generator with higher operational costs. Including higher capacities of solar PV and wind turbines, with higher CAPEX costs compared to diesel generators, does not result in higher LCOE as their OPEX costs are lower than of the diesel generator. The OPEX (without the price of diesel) of the diesel generator is approximately 7.2% of its CAPEX, while the OPEX of the solar PV and wind turbines are respectively 2.5 % and 2 % of their respective CAPEX.

It is difficult to conclude if solar PV or wind turbines are the better renewable source to implement in the system in combination with hydropower. Scenarios 4 and 5 result in almost the same LCOE, while scenario 5 has a slightly higher Clean Electricity Share of 64 % compared to 61 % of scenario 4. It can though be concluded that the wind turbines have a higher capacity factor, as they have a higher production than the solar PVs, even though the installed capacity is the same. For that reason, it might be more feasible to choose to invest in wind turbines and thereby have a lower production form the diesel generator and thus have a more renewable system.

Following figures (Figure 6-12 and Figure 6-13) show the production of wind turbines and solar PV systems with a capacity of 4 MW over the course of a year. The figures show that the wind turbines have a more consistent production over the year, while the production from the solar PVs is more concentrated in the spring and summer months.

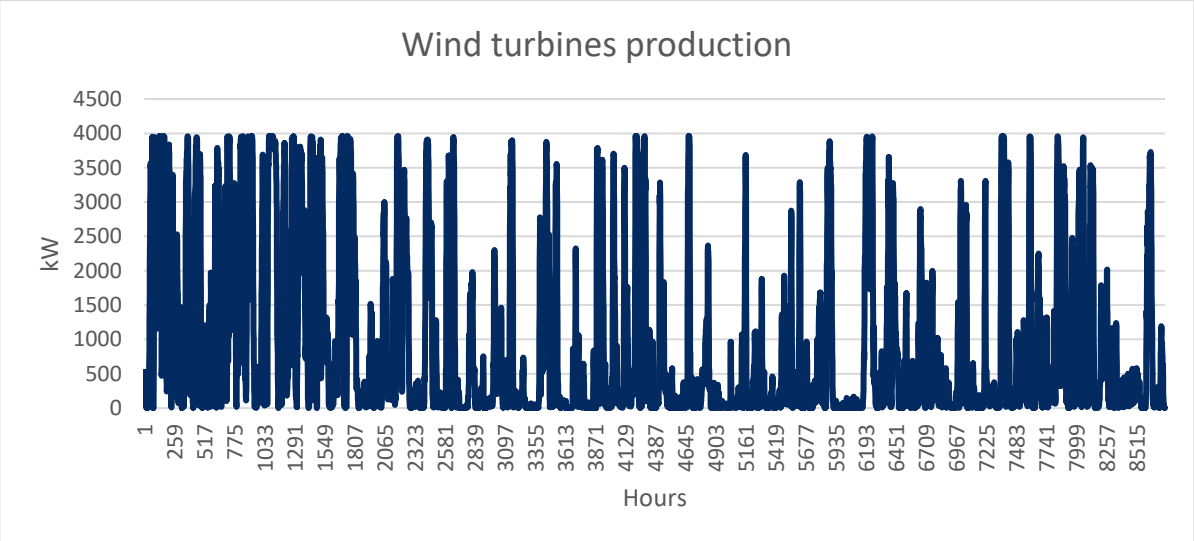


Figure 6-12: Wind turbines production.

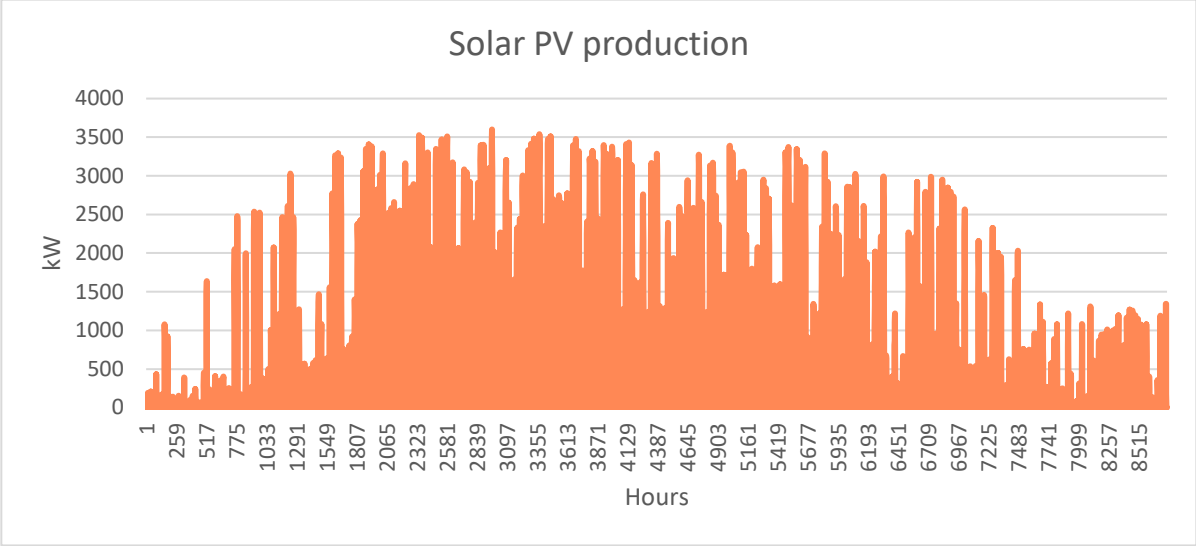


Figure 6-13: Solar PV production.

For future studies it could also be worth exploring the option of pumped hydro storage as a source of electricity. Pumped hydro storage can be seen as a good option for parring with solar PV and wind turbines, as it can store excess electricity (curtailment) and provide backup when there is no/not enough production from the solar PV and wind turbines to secure reliable and stable electricity supply. [72]

6.4 Tidal Energy

Tidal energy potential is highly dependent on the geographical location. On-site measurements of tide elevations should be performed to assess the techno-economic feasibility of tidal projects at specific sites. As discussed in Section 3.3, tidal barrages are particularly interesting for Greenland due to the numerous fjords and irregular coastline. A dam-like structure can be built across a fjord, equipped with turbines that generate power as water flows through during tidal movements. Alternatively, tidal lagoon could also be built in the larger fjords. These technologies exploit the energy potential from the height difference between high and low tides.

This section provides a high-level assessment of the tidal range (barrage or lagoon) potential near the selected mines for this study. The same methodology can be used as an initial assessment for other mines outside the scope of this study.

The maximum theoretical potential energy available from a head difference (i.e., an elevation difference) in Joules can be expressed as:

$$E_{max} = \frac{1}{2}\rho g A H^2$$

where ρ is the density of the water (kg/m3), g is the gravitational acceleration (m/s2), A is the basin area (m2), and H is the tidal range (m, the difference between the high and low tides) [62].

First, tide tables provided by the Danish Meteorological Institute (DMI) [24] for around 100 locations in Greenland were investigated to find the closest available dataset to each mine. Where possible, a DMI station in the same fjord as the mine was selected. The selected mines and their closest DMI stations for analysis are listed in Table 6-8, along with maximum and average tide ranges. The maximum theoretical tidal energy potential at each location is then calculated per unit area of the basin using the formula above. It is assumed that the turbines operate in double generation mode,

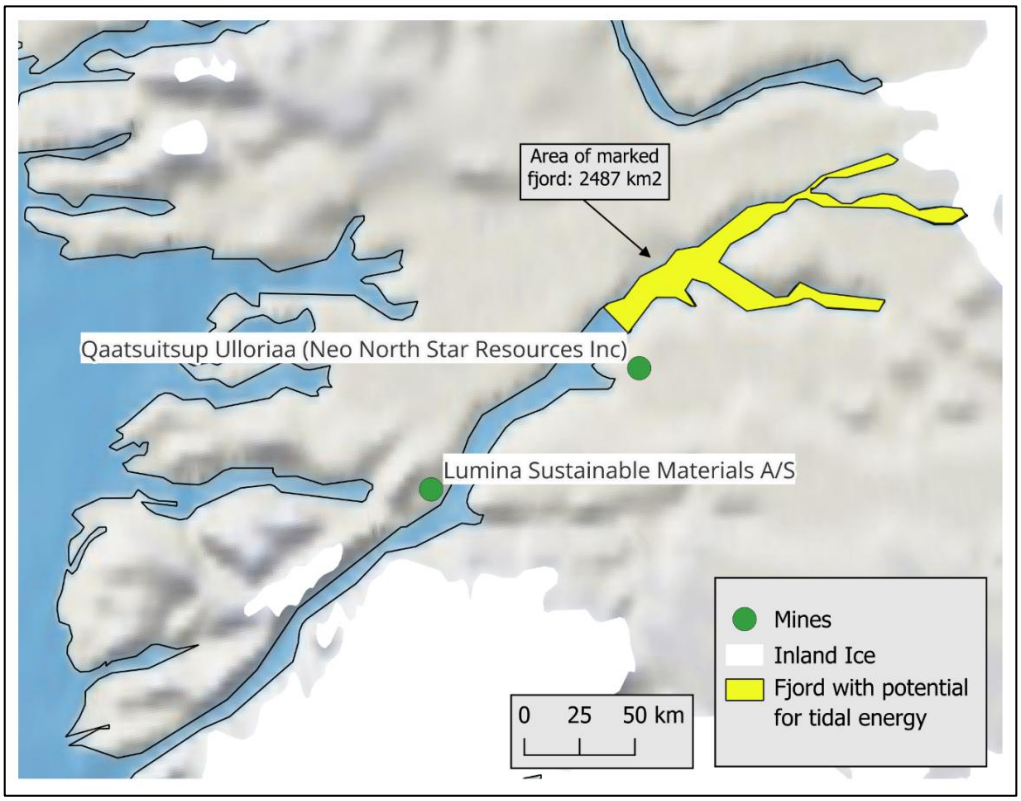
producing electricity during both the outgoing and incoming tides. For each tidal range, the formula is applied with a seawater density of 1025 kg/m³ and a gravity constant of 9.81 m/s². The maximum yearly theoretical potential in MWh per km² of the water basin is reported in Table 6-8. Assuming a tidal barrage efficiency of 20% [64], the actual yearly electricity production per km² can be estimated, as shown in Table 6-8.

Mine	Region	DMI Station (Ref: [24])	Max tide range (m)	Average tide range (m)	Maximum yearly theoretical potential (MWh/km2)	Actual yearly potential (MWh/km2)
Greenland Resources A/S	East	Mestersvig	1.7	0.9	1,901	380
GreenRoc Graphite Limited	South	Nanortalik	3.2	1.6	7,134	1,427
TANBREEZ Mining Greenland A/S	South	Narsaq	3.4	1.7	7,703	1,541
Lumina Sustainable Materials A/S	West	Kangerlussuaq Kuussuaq	3.4	1.6	10,974	2,195
Qaatsuitsup Ulloriaa (Neo North Star Resources Inc)	West	Camp Lloyd	3.6	1.7	12,189	2,438
Ironbark A/S	North	ThankGodHavn	3.1	0.7	2,899	580

Table 6-8: Potential tidal energy close to the selected mines.

Note that as mentioned in Section 3.3, producing tidal energy economically requires an average tidal range of at least 3-5 meters [60, 61]. Among the analysed locations, the highest average tidal range is at Camp Lloyd near the Qaatsuitsup Ulloriaa (Neo North Star Resources Inc) mine on the west coast of Greenland, at 1.7 meters. The tidal potential energy formula shows that the head difference is crucial, as potential energy is proportional to the square of the tidal range. Furthermore, the tidal potential is also proportional to the basin surface area; therefore, tidal energy could still be feasible if a large water basin is available due to the geographical shape of the fjord.

For example, assuming a peak electricity consumption of 10 MW for the Qaatsuitsup Ulloriaa (Neo North Star Resources Inc) mine and a 24/7 mine operation according to Table 4-2, around 87,600 MWh of electricity are needed annually. Based on the actual yearly potential in MWh/km² reported in Table 6-8, the basin area needed to supply the mine with tidal energy would be approximately 36 km². For reference, the basin area available in the fjord where Qaatsuitsup Ulloriaa (Neo North Star Resources Inc) and Lumina Sustainable Materials A/S are located exceeds 2000 km², as shown in Map 6-12.



Map 6-12: Fjord with potential for tidal energy with an approximate area of 2487 km2.

Apart from environmental impacts, the main barrier associated with tidal energy is the relatively high initial capital expenditure (CAPEX) for construction and significant maintenance costs. This results in a levelized cost of electricity (LCOE) around 250 EUR/MWh, based on averages from commercial-scale projects [55, 56].

Although tidal energy is highly predictable, it still experiences daily and seasonal variations. To meet the constant demand of the mine solely with tidal energy and achieve full decarbonization, it is necessary to oversize the turbines compared to the mine's peak electricity demand and couple the tidal project with a Battery Energy Storage System (BESS), which would additionally increase the LCOE hindering the economic feasibility of the projects. Alternatively, it could be more viable to size the tidal system to match peak consumption and cover only part of the electricity demand with tidal energy, while the remaining could be supplied by other sources (e.g., diesel, hydropower).

To fully assess the techno-economic feasibility of tidal energy, site-specific assessments should be developed, including on-site measurements of tidal range, assessment of the feasibility of building a dam-like structure in the fjord, and environmental considerations.

6.5 E-fuel

This section presents two overall scenarios; one where the e-fuel is produced in Greenland and one where the e-fuel is imported from Europe.

6.5.1 E-fuel production in Greenland

This section assesses the potential for supplying a mine's electricity demand with e-fuels. Three e-fuels have been selected for this analysis: green hydrogen, e-methanol and e-ammonia. It is assumed that all e-fuels will be produced at a PtX-facility at the Tasersiaq lake on the West coast of Greenland. The assumption is that the PtX-facility will be supplied with renewable electricity from a hydropower plant in connection to the Tasersiaq lake. Green hydrogen is to be used to supply mines that are within a close distance of the PtX-facility through ship transport, while e-methanol and e-ammonia are to be used to supply mines further away using long distance transport through ship. The technological limitations for shipping green hydrogen over longer distances can be seen in Section 3.6. It is assumed that the mining company does not own the PtX-facility itself, the mining companies will instead have an offtake agreement with the PtX-facility to ensure a reliant supply of fuel.

The use of e-fuels would be applicable for remote mines that do not have access to electricity from anywhere else, and therefore need to import e-fuels from either Greenland or from Europe to use in a generator to produce electricity.

This section includes three scenarios:

1. Green hydrogen short distance from the Tasersiaq lake to the South of Greenland
2. E-methanol long distance from the Tasersiaq lake to the East of Greenland
3. E-ammonia long distance from the Tasersiaq lake to the East of Greenland

The distance from the Tasersiaq lake to the mines in the South of Greenland is approximately 1,000 km, while the distance to the mines on the East coast of Greenland is approximately 3.100 km.

An onsite e-fuel storage is also included in this scenario, assuming that e-methanol is delivered to the mines at least every 6 months. As economic data for e-fuel generators was not available, the CAPEX and OPEX values of a diesel generator were used as a baseline, with a 20% adjustment added to account for the innovative nature and potential additional costs associated with the e-fuel generators as an emerging technology. Like the diesel generator in the Diesel Generator scenario, the e-fuel generator is oversized by 33% compared to the peak electricity demand to account for maintenance periods or unexpected outages.

Other assumptions and data included in the three scenarios can be seen in following Table 6-9:

Assumptions e-fuels production in Greenland			
	Value	**Unit**	**Source**
Fuel cost			
Green hydrogen (2030)	3,300	EUR/t	Ramboll
E-methanol (2030)	990	EUR/t	Ramboll
E-ammonia (2030)	1,640	EUR/t	Ramboll
Transportation cost			
Green hydrogen (from the Tasersiaq lake to mines on the South of Greenland) 1,000 km	960	EUR/t	[73]
E-methanol (from the Tasersiaq lake to mines on the East coast of Greenland) 3,100 km	2.5	EUR/t	[19]
E-ammonia (from the Tasersiaq lake to mines on the East coast of Greenland) 3,100 km	32	EUR/t	[73]

Table 6-9: Assumptions e-fuel production in Greenland.

The results of the e-fuel production in Greenland can be seen in the following Table 6-10. The scenario where green hydrogen is produced and transported to mines in the South of Greenland the LCOE is 383 EUR/MWh. For the scenario where e-methanol is produced and transported to the mines at the East coast of Greenland the LCOE is 543 EUR/MWh, while the LCOE is 941 EUR/MWH for the scenario where e-ammonia is produced and also transported to the mines at the East coast of Greenland. All three scenarios have a Clean Electricity Share of 100% and a Clean Electricity and Transport Share of 40%, which means all three scenarios are 100% renewable when assessing the electricity demand.

The lower LCOE value of the green hydrogen scenario can be explained by the difference in calorific value of green hydrogen, e-methanol and e-ammonia. The calorific value of green hydrogen is approximately 6 times higher than e-methanol and e-ammonia, which means a smaller amount of green hydrogen is needed to fulfil the demand compared to the other two fuels. This calorific value influences both the fuel cost and the transportation cost as they are both measured in tonnes of the respective fuel. Another reason for the green hydrogen scenario having a lower LCOE is the shorter shipping distance.

The difference in LCOE of the e-methanol and e-ammonia scenarios can be explained by the e-ammonia scenario having both higher fuel- and transport costs compared to the e-methanol scenario.

Note that the e-fuels could potentially be used also to decarbonize the transport demand, which would improve the Clean Electricity and Transport Share. This would require increasing the e-fuel import and storage facilities to meet both the electricity and transport demands of the mine and investing in e-fuel-powered mining vehicles.

Results e-fuels production in Greenland			
	Green hydrogen	**E-methanol**	**E-ammonia**
Installed capacity by technology			
E-fuel generator (MW)	13	13	13
E-fuel storage (ton)	3755	22642	23837
Metrics			
LCOE (EUR/MWh)	383	543	941
Clean Electricity Share	100%	100%	100%
Clean Electricity and Transport Share	40%	40%	40%

Table 6-10: Results e-fuel production in Greenland.

The necessary infrastructure for shipping e-fuels, including storage tanks, liquefaction and regasification plants, and conversion and reconversion plants, to be built at the loading and receiving terminals as appropriate has not been included in the scenarios, and will therefore add extra CAPEX and OPEX costs and therefore result in a higher LCOE.

6.5.2 Import from Europe

This scenario assesses the potential for supplying the mine´s electricity demand with e-fuels imported from Europe. The e-fuel selected for the analysis is e-methanol, which is used in an e-methanol generator to produce electricity. An onsite e-methanol storage is also included in this scenario, assuming that e-methanol is delivered to the mines at least every 6 months. For this scenario, the import of e-methanol from Europe is considered with a shipping distance of 12,500 km. The cost of importing e-methanol includes both fuel cost and transportation expenses. This scenario assumes that the mine's electricity demand will be covered 100% by e-methanol.

As for the previous section, economic data for e-methanol generators was not available, therefore the CAPEX and OPEX values of a diesel generator were used as a baseline, with a 20% adjustment added to account for the innovative nature and potential additional costs associated with the e-methanol generator as an emerging technology. Similar to the diesel generator in the Diesel Generator scenario, the e-methanol generator is oversized by 33% compared to the peak electricity demand to account for maintenance periods or unexpected outages.

The results for the e-fuel scenario are presented in Table 6-11. The LCOE is 561 EUR/MWh, which is higher than the Diesel Generator scenario (LCOE = 297 EUR/MWh). This difference is due to the high fuel and transport costs of e-methanol. This scenario achieves a Clean Electricity Share of 100% and a Clean Electricity and Transport Share of 40%. Note that e-methanol could potentially be used also to decarbonize the transport demand, which would improve the Clean Electricity and Transport Share. This would require increasing the e-fuel storage and import of e-methanol to meet both the electricity and transport demands of the mine and investing in methanol-powered mining trucks. The economic viability of this option is hindered by the high fuel and transport costs, and it is not further investigated in this study.

Results e-methanol	
Installed capacity by technology	
E-methanol generator (MW)	13
E-fuel storage (ton)	22642
Metrics	
LCOE (EUR/MWh)	561
Clean Electricity Share	100%
Clean Electricity and Transport Share	40%

Table 6-11: Results of the e-methanol scenario.

When comparing this scenario with the previous e-methanol scenario where the e-fuel is produced in Greenland, the difference in LCOE is 18 EUR/MWh, where the locally produced e-methanol in Greenland has the lowest LCOE. The reason for the higher LCOE for the scenario where the e-methanol is produced in Europe is the longer shipping distance (3,100 km to 12,500 km).

This scenario also portraits a scenario of e-fuel production from the Tasersiaq lake on the West coast of Greenland to mines in the North of Greenland. The distance from the West to the North of Greenland sailing south of Greenland would be approximately 14,000 km, which only changes the transport cost from 12 EUR/t to 13 EUR/ton. As the transport cost is only approximately 1% of the total cost of the import of e-fuels, the extra 1,500 km does not change the perception of the scenario.

6.6 Scenario Comparison

Figure 6-14 provides an overview of the LCOE and Clean Electricity Share of the various electricity-producing technologies discussed in Chapter 6. These technologies include diesel generator (business-as-usual), a mix of solar PV, wind and where relevant diesel generators (lowest LCOE, same LCOE as Diesel Generator, and 100% solar PV and wind), hydropower (new hydropower plant with 100 km or with 1035 km electrical lines, upgraded hydropower plant + 100 km electrical line and an upgraded hydropower plant in combination with solar PV, wind turbines and diesel generator), green hydrogen, e-methanol, and tidal energy. The South location is used as a reference, but similar conclusions can be drawn for the other locations.

The LCOE and Clean Electricity Share for all technologies, except tidal energy, are derived using Ramboll's Energy System Modelling Tool and the techno-economic assessment methodology described in Chapter 5. Conversely, for tidal energy, the LCOE represents an average sourced from different references and it does not represent a facility capable of meeting the constant electricity demand of the mine due to the daily and seasonal variations in tidal turbine production, as discussed in Section 6.4. Due to the different methodology used for tidal energy compared to the other technologies, the Clean Electricity Share is not represented in Figure 6-14. The provided LCOE can be used as an initial reference, but in practice, tidal energy would be paired with a diesel generator or an energy storage solution like BESS to ensure a constant electricity supply to the mine and compensate for periods when tidal turbines do not produce sufficient electricity. Including a diesel generator or BESS would increase investments and subsequently raise the LCOE compared to what is shown in Figure 6-14.

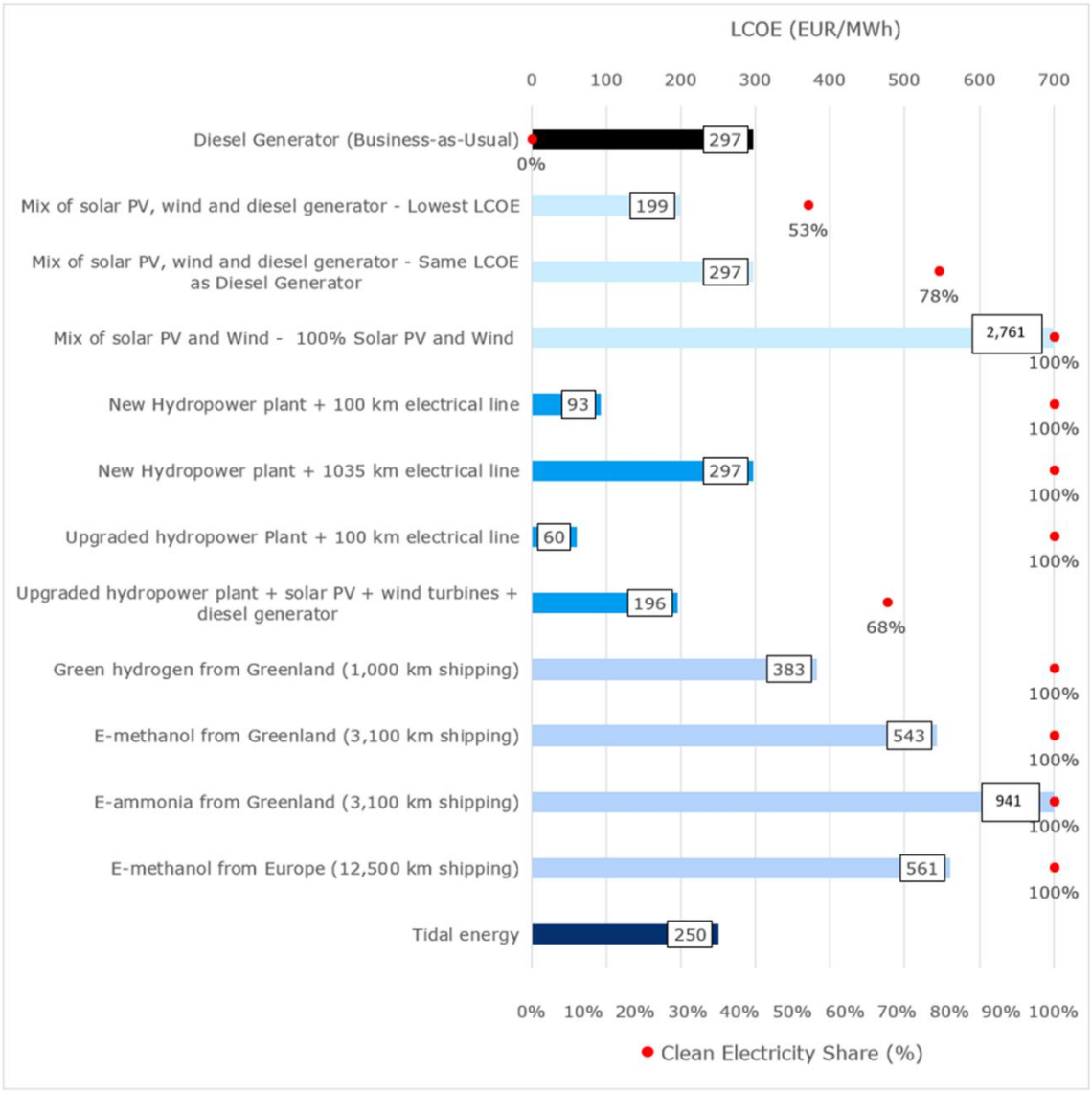


Figure 6-14: Scenario comparison of the clean energy solutions that can be used to decarbonize a mine´s electricity demand.

For each mix of technologies, Figure 6-14 shows the LCOE and the corresponding Clean Electricity Share (red dot). The scenario with the lowest LCOE involves the upgrading of a hydropower facility close to the mine (e.g., 100 km distance), achieving an LCOE of 60 EUR/MWh with a Clean Electricity Share of 100%. This scenario requires that an existing hydropower facility is nearby, with the possibility for expansion, i.e., installing additional turbines to cover the mine´s electricity demand. Even if upgrading an existing hydropower facility is not an option, building a new hydropower facility shows competitive LCOE. If a new hydropower facility were built with a 1035 km electrical line, the LCOE would be comparable to the Diesel Generator (Business-as-Usual) scenario while achieving a Clean Electricity Share of 100%. Shorter distances between the hydropower facility and the mine could significantly reduce the LCOE compared to the Diesel Generator (Business-as-Usual) scenario.

The upgraded hydropower plant + solar PV + wind turbines + diesel generator also have a competitive LCOE of 196 EUR/MWh. This shows that it is possible to combine hydropower, solar PV, wind turbines and a diesel generator to meet the electricity demand of a mine.

Hydropower (either a new facility or upgrading an existing facility) appears to be the most economically feasible technology to fully decarbonize the electricity demand of the mines (i.e., Clean Electricity Share = 100%). Achieving a 100% Clean Electricity Share with only solar PV, wind, and BESS (100% Solar PV and Wind scenario) is not economically feasible due to the need for significantly oversizing the solar PV and onshore wind plants, and the need for large BESS.

Similarly, importing e-methanol to the mine from Europe results in an LCOE higher than the fossil fuel alternative. Alternative e-fuel scenarios with a production in Greenland have also been assessed for green hydrogen, e-methanol and e-ammonia, but neither of them have a competitive LCOE.

Figure 6-14 shows that supplying the mine with a mix of solar PV, wind, and diesel generators (Lowest LCOE and Same LCOE as Diesel Generator scenarios) can achieve an LCOE similar to or even slightly lower than the business-as-usual scenario (199-297 EUR/MWh) while reducing dependence on fossil fuels by more than half (Clean Electricity Share of 53-78% for the South location). This indicates that decarbonization can be achieved at no additional cost compared to the business-as-usual scenario.

Another technology configuration that has not been explored in this study but may be interesting for future investigations is the establishment of an electrolyzer facility in combination with a hydropower plant. Hydropower electricity could supply both the mine's electricity demand and an on-site electrolyzer, converting clean electricity into green hydrogen. The green hydrogen could then be used to fuel hydrogen dumpers for mining operations. This would require oversizing the hydro plant and electrical lines compared to the mine's electricity demand but would support the decarbonization of the transport demand, which accounts for around 60% of the total electricity demand.

A technology configuration that could have been explored is regenerative braking as an energy positive technology. Regenerative braking, covered in more detail in Chapter 7, has the potential to be energy positive. For instance, braking energy from a conveyor belt could be recovered into a BESS and used to decarbonize not only the mine's transport demand but also its electricity demand. Analysing a mix of regenerative braking together with solar PV and/or wind could be interesting, as energy-positive regenerative braking could reduce the capacity of solar PV and/or wind required, potentially improving the economic feasibility of these technologies.

6.6.1 Sensitivity discount rate

A sensitivity analysis on the discount rate has been conducted to illustrate how the LCOE changes corresponding to the difference in the discount rate. The differences in the discount rate illustrates the possible different risk profiles in local projects. Tidal energy is not included in this sensitivity analysis as it’s LCOE value is based on averages from commercial-scale projects and not on in-house calculations. The sensitivity analysis of the discounts rate is shown in the below Table 6-12.

Scenario	LCOE [EUR/MWh]			
	6%	8%	10%	12%
Diesel Generator (Business-as-Usual)	296	297	299	301
Mix of solar PV, wind and diesel generator - Lowest LCOE	191	199	208	217
Mix of solar PV, wind and diesel generator - Same LCOE as Diesel Generator	267	297	330	365
Mix of solar PV and Wind - 100% Solar PV and Wind	2.406	2761	3.153	3.571

New Hydropower plant + 100 km electrical line	81	93	106	120
New Hydropower plant + 1035 km electrical line	258	297	338	383
Upgraded hydropower Plant + 100 km electrical line	52	60	69	79
Upgraded hydropower plant + solar PV + wind turbines + diesel generator	182	196	211	227
Green hydrogen from Greenland (1,000 km shipping)	381	383	385	388
E-methanol from Greenland (3,100 km shipping)	540	543	547	551
E-ammonia from Greenland (3,100 km shipping)	937	941	944	948
E-methanol from Europe (12,500 km shipping)	557	561	564	568

Table 6-12: Sensitivity analysis on the discount rate.

7. Results: Clean Energy Solutions for Mine Transport Demand

This chapter analyses possibilities of decarbonising the transport demand of mining operations. First, a business-as-usual case with diesel trucks is present, following an investigation of regenerative braking for conveyor belts and electric haul trucks, and finally an analysis of the option of e-fuels for mining transport.

7.1 Diesel Trucks (Business-as-Usual)

This scenario represents a business-as-usual case where the energy transport demand of a mine is fully supplied by diesel. The transport vehicles are presumed to be diesel haul trucks, conveyor belts, or other transport technologies that are fuelled by diesel. The transport demand constitutes around 60% of the total energy demand of a mine. This means that for a mine with a yearly electricity demand of 88 GWh (10 MW peak electricity demand), the yearly transport demand is 132 GWh. The price of diesel that is used for this study is 96 EUR/MWh (7.17 kr./l). This results in an annual total cost for diesel to cover the transport demand of 12.7 MEUR/year.

7.2 Regenerative Braking

This section considers the technology of regenerative braking as a method of reducing the energy consumption of the transport demand of mining operations. The section will first explain the regenerative braking potential for a conveyor belt, then explain the approach of assessing the regenerative braking potential for electric or hybrid haul trucks, followed by a high-level approach to estimate the theoretical maximum recoverable energy that an electric or hybrid haul truck could achieve under ideal conditions through regenerative braking.

It is worth mentioning that the application of regenerative braking in mining can be applied to conveyor systems, trolley trucks, (modified) electric haul trucks, (e-)trains, and material ropeways.

7.2.1 Regenerative Braking - Conveyor Belts

The potential for conveyor belt regenerative braking can be assessed by taking into account the ore transport capacity and transport route slope, as explained in Section 3.5 (see Figure 3-6). The mines considered in this study show different potentials for the viability of a conveyor system with the ability to partially or fully recover its energy demand, as described in Table 7-1.

When examining the potential for using conveyor belts in arctic climates, it is essential to consider the minimum temperature allowance for lubricants, as low temperatures can cause the lubricants to congeal and will limit the flow, which can result in both material and performance degradation of machine components. A possible accommodation is to understand at which temperatures this occurs and then insulate the conveyor belts. [65]

For example, Greenland Resources A/S mine has already investigated the potential for regenerative braking using rope conveyors, and it expects not only to achieve energy neutrality but also to become energy positive by generating approximately 1.3 MW of electricity from the braking system. TANBREEZ Mining Greenland A/S shows great potential for an energy-neutral conveyor, as it both has sufficiently large transport capacity and steep slopes (around 7%) suitable for the installation of conveyor systems that require minimal to no energy consumption. On the other hand, GreenRoc Graphite Limited shows no potential for an energy-efficient conveyor system due to the lack of slope between the ore and the processing site. There is not enough data to assess the regenerative

braking conveyor potential for Qaatsuitsup Ulloriaa (Neo North Star Resources Inc) and Ironbark A/S. Moreover, the data regarding Lumina Sustainable Materials A/S remains confidential.

Mine	Regenerative Braking Conveyor Potential
Greenland Resources A/S	Great potential for an energy-neutral or even energy-positive conveyor system.
GreenRoc Graphite Limited	No potential for an energy-efficient conveyor system due to lack of slope between the ore and the processing site.
TANBREEZ Mining Greenland A/S	Great potential for an energy-neutral conveyor system.
Qaatsuitsup Ulloriaa (Neo North Star Resources Inc)	Not enough data to assess
Lumina Sustainable Materials A/S	Confidential
Ironbark A/S	Not enough data to assess

Table 7-1: Regenerative braking conveyor belt potential for the assessed mines in the study.

Regenerative braking from conveyor belts has the potential to significantly improve the Clean Electricity and Transport Share and facilitate the decarbonization of the mine's transport energy demand. In energy-positive regenerative braking systems (such as Greenland Resources A/S), if the extra energy can be stored and utilized for other purposes within the mine, the Clean Electricity Share can also be improved thanks to the additional electricity generated by the braking system.

The analysis does not provide CAPEX and OPEX estimates for conveyor belts with regenerative braking systems for mining industries in arctic climates, as these values are highly dependent on the specific case (manufacturer, type of conveyor belt, length of conveyor belt, regenerative braking system etc.).

7.2.2 Regenerative Braking - Electric Haul Trucks

7.2.2.1 Regenerative Braking Potential for Electric Haul Trucks

A fundamental method for assessing regenerative braking potential for vehicles is based on the rate of change of gravitational potential energy as a vehicle descends a slope. This approach assumes that as the vehicle moves downhill, gravitational potential energy is continuously converted into kinetic energy. When regenerative braking is applied, a portion of this energy can be captured and converted into electrical energy rather than being dissipated as heat through traditional braking systems.

For the purposes of this analysis, it is assumed that the vehicle maintains a constant velocity during descent. Under this condition, the kinetic energy remains unchanged, and only the change in potential energy contributes to the regenerative braking power. This simplifies the calculation while providing an upper bound on the possible energy recovery.

Potential energy is defined as:

$$\boldsymbol{Potential\ Energy\ =\ mass * gravity * h} \quad \textbf{(1)}$$

Since power is the rate of energy change per unit of time (power = energy/time), the instantaneous power available for regeneration is given by:

$$\boldsymbol{P = m \cdot g \cdot \left(\frac{dt}{dh}\right)} \quad \textbf{(2)}$$

Since we need power in Watts, we must convert speed from km/h to m/s:

$$\mathbf{1}\ \boldsymbol{km/h} = \mathbf{3600}\ \boldsymbol{s}/\mathbf{1000}\ \boldsymbol{m} = \mathbf{3.6}\ \boldsymbol{m/s}$$

The total theoretical recoverable power is then:

$$\boldsymbol{P} = \frac{\boldsymbol{mass} \cdot \boldsymbol{gravity} \cdot \boldsymbol{velocity} \cdot \boldsymbol{sin}(\boldsymbol{\theta})}{\mathbf{3.6}} \quad \textbf{(3)}$$

Finally, the efficiency of the regenerative braking system, which represents the % of recoverable energy the regenerative braking system can capture, must be considered:

$$\boldsymbol{P} = \boldsymbol{efficency} * \frac{\boldsymbol{mass} \cdot \boldsymbol{gravity} \cdot \boldsymbol{velocity} \cdot \boldsymbol{sin}(\boldsymbol{\theta})}{\mathbf{3.6}} \quad \textbf{(4)}$$

This approach provides an upper bound on the regenerative braking power that could theoretically be recovered in an ideal system. In practice, however, not all the potential energy can be fully converted into usable electrical energy due to various efficiency losses inherent in the drivetrain and energy storage components. These losses primarily occur in the electric motor, which converts mechanical energy into electrical energy, the inverter, which manages power conversion and distribution, and the battery system, which stores the recovered energy. Each of these components introduces conversion inefficiencies, meaning that a portion of the available energy is inevitably lost as heat or other non-recoverable forms. Regenerative braking systems have shown an overall efficiency of around 60% [36].

Furthermore, if the calculated regenerative power exceeds the vehicle's rated regenerative braking capacity, the system will not be able to capture and store all the available energy. When this happens, any excess energy that cannot be stored or utilized effectively must be dissipated, often through mechanical braking or other resistive methods, leading to additional energy losses. This practical limitation underscores the importance of properly sizing regenerative braking systems to ensure that energy recovery remains within feasible operational limits.

There are relatively few references or established industry guidelines specifically addressing regenerative braking in large-scale mining operations, particularly in remote and extreme environments like Greenland. The calculations presented here are grounded in basic gravitational potential energy theory and mechanical power conversion principles, providing a first-order estimate of energy recovery potential. While more detailed modeling, including real-world efficiency factors, operational constraints, and system-specific limitations, would be required for precise system design, this approach offers a preliminary assessment of regenerative braking feasibility in mining applications. Examples of the calculation of the regenerative braking potential will be assessed in the following section 7.2.2.2.

7.2.2.2 Regenerative Braking Assessment in Mining Operation

Utilizing the methodology outlined in Section 7.2.2.1, a representative scenario is proposed to assess the potential of regenerative braking in mining operations. Estimating the exact amount of energy that can be recovered through regenerative braking in the chosen mining operations is challenging due to the lack of specific data from the mines included in this study. Many of these mines have yet to finalize the physical parameters of their future facilities or define their primary ore transportation methods. As previously explained in Section 3.5, the best technology to capture and recover energy from regenerative braking is conveyor systems equipped with energy recovery mechanisms [15]. However, if a conveyor system is not possible or preferred there are also opportunities to employ hybrid or electric dumpers equipped with regenerative braking technologies. As a result of the lack of data, this report adopts a high-level approach to estimate

the theoretical maximum recoverable energy that an electric or hybrid haul truck could achieve under ideal conditions.

This example scenario considers a 100-ton haul truck, including its load, descending from an excavation site to a processing facility. For this scenario, key assumptions include a 5-degree slope, a constant descent speed of 20 km/h, and a regenerative braking system efficiency of 60% [36].

Employing equation (4) from the previous section:

$$\boldsymbol{P = efficency * \frac{mass \cdot gravity \cdot velocity \cdot sin(\theta)}{3.6} = 0.6 * \frac{100,000 \cdot 9.81 \cdot 20 \cdot sin(5)}{3.6} = 285\ kW}$$

PIn the proposed scenario, the maximum theoretical regenerative power is estimated to be 285 kW. To further refine the analysis, an additional assumption regarding the duration of braking during the descent can be introduced. By incorporating this factor, it becomes possible to calculate the total recoverable energy, providing a more comprehensive assessment of the regenerative braking potential in this case study. If it is then assumed that the truck travels downhill, loaded, a total of 2 hours per day, the total recoverable energy can be calculated as:

$$\boldsymbol{Energy = 285kW * 2h = 570\ kWh}$$

For the proposed case study, the total recoverable energy through regenerative braking is estimated at 570 kWh. To evaluate the potential fuel savings, we consider a diesel-powered haul truck with an engine efficiency of 35% and a diesel energy content of 10 kWh per liter. The equivalent fuel consumption reduction can be calculated as follows:

$$\boldsymbol{Fuel\ consumption\ reduction = \frac{570\ kWh}{0.35 * 10kWh/liter} = 163\ liters\ of\ diesel}$$

In this representative scenario, regenerative braking could potentially reduce diesel consumption by 163 liters per day, highlighting its significant impact on fuel efficiency and operational cost savings in mining applications.

Figure 7-1 and Figure 7-2 present the maximum recoverable power for a regenerative braking system with an assumed 60% efficiency as a function of mass, slope, and speed:

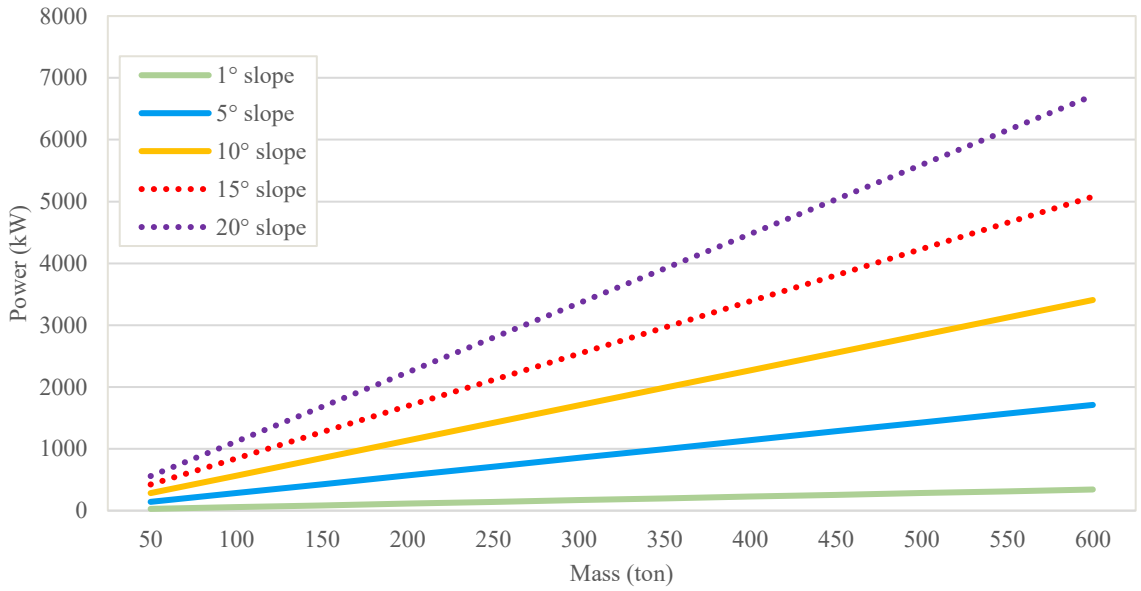


Figure 7-1: Power recovered as a function of mass and slope (constant speed of 20 km/h). Slopes of 15 and 20 degrees are deemed unrealistic due to safety risks.

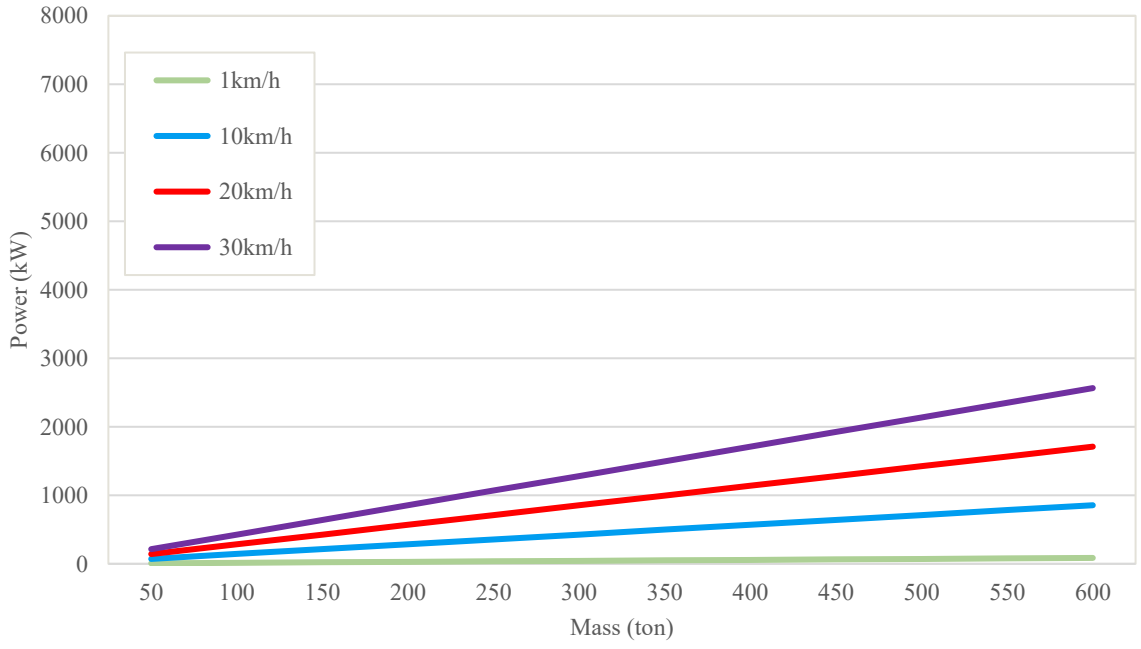


Figure 7-2: Power recovered as a function of mass and speed (constant 5° slope).

Building on the previous assumptions regarding system efficiency, operational time, and physical parameters, and incorporating real-world data from existing haul trucks on the market, we can develop a high-level assessment of the potential energy savings achievable through regenerative braking. By assuming that haul trucks operate continuously throughout the day and utilize diesel engines with an efficiency of 35%, we can estimate their fuel consumption based on their technical

specifications. To illustrate this concept, four Caterpillar trucks of varying sizes and weights have been selected for analysis [44] [45]. In this assessment, it is assumed that these trucks engage their regenerative braking systems for approximately two hours per day.

The results, presented in Figure 7-1, demonstrate that while regenerative braking alone would not completely eliminate diesel consumption, it has the potential to significantly reduce fuel use and corresponding CO_2 emissions. Although a 20% slope is considered highly unrealistic due to the impracticality and safety risks of such a steep incline, the findings suggest that on a 10% slope, regenerative braking could reduce fuel consumption by approximately one-third for all trucks considered. A 5% slope, which is more representative of typical mining road conditions, could still lead to a reduction in diesel consumption of approximately 20% across all vehicles. These insights underscore the potential role of regenerative braking in improving fuel efficiency and lowering the environmental impact of heavy-duty mining operations.

It is worth noting that while the trucks may be operating 24h a day, they may not be driving all this time (due to load and unload periods), this would make the energy needed for these trucks lower, and regenerative braking would be able to cover more of it. It is however also important to understand that Figure 7-3 represents the maximum recoverable power, as previously explained, due to component losses and factors not included in the analysis the actual recovered energy is lower.

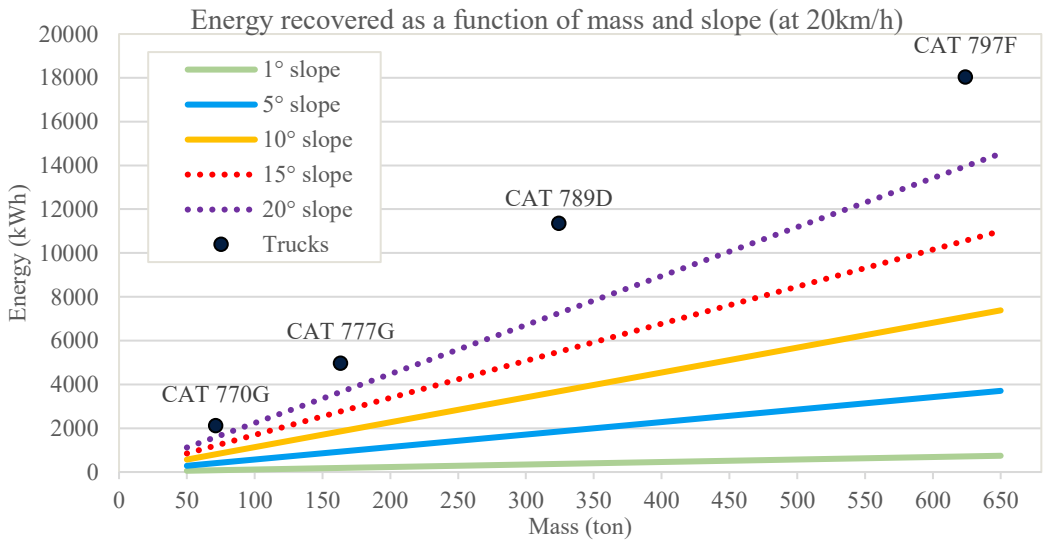


Figure 7-3: Energy recovered as a function of mass and slope. Slopes of 15 and 20 degrees are deemed unrealistic due to safety risks.

As previously stated, while the proposed approach provides a high-level estimation of the regenerative braking potential and its impact on fuel savings, it is important to recognize its inherent limitations. This analysis is based on simplified assumptions regarding vehicle operation, slope conditions, and braking efficiency, and does not account for several real-world factors that could influence actual energy recovery. For instance, variable terrain, uneven road surfaces, braking patterns, and operational constraints such as load variations and traffic conditions can significantly affect the performance of regenerative braking systems. Additionally, energy losses in power electronics, mechanical components, and battery storage systems further reduce the theoretical recoverable energy. The efficiency of the energy transfer process, including the conversion of mechanical energy into electrical energy and subsequent storage or utilization, is also highly dependent on the specific design and state of the vehicle's drivetrain and energy storage system.

Therefore, while this calculation provides a useful upper-bound estimate, it should be interpreted as an approximate benchmark rather than a precise representation of actual regenerative energy recovery in a mining environment.

Due to the still early nature of regenerative braking systems for mining vehicles no reliable CAPEX and OPEX estimates were found. It is relevant to state that regenerative braking systems might not be the most cost-effective option for minimizing the CO2 emissions from the transport sector of mining facilities, which is why further studies must be done to determine the optimal approach.

7.3 Alternative fuels for mining transport

This section investigates the option for decarbonizing the mining transport demand through e-fuels and electrification of vehicles.

The e-fuels for decarbonizing the mining transport sector could be produced in Greenland at a Power-to-X facility close to a hydropower facility, as the hydropower facility supplies a reliant supply of electricity. Another option is to import the e-fuels from outside of Greenland, this could be from Europe, Canada or USA. The mining company could either own the PtX-facility itself and thereby own the produced e-fuel, or the mining company could initiate an offtake agreement with the PtX-facility, to ensure sufficient e-fuels for their transport demand.

E-fuels for mining transport is a new field, which means that available vehicles are limited. There are through several realistic options for e-fuel land transport for mining operations. One of these options are Komatsu, which is a global manufacturer of mining and construction equipment, who is developing a hydrogen fuel cell module for their electric mining truck (930E electric drive mining truck). They argue that hydrogen fuel cells are ideal for electrifying applications which are traditionally powered by diesel engines. Green hydrogen provides an effective method to package large quantities of energy in the vehicle without compromising the carrying capacity of the truck. [67]

Some early-stage studies analyse the option of on-board green hydrogen production through an electrolysis process in the engine. Also, the option of hydrogen-enhanced combustion is present, where green hydrogen is added to the fuel (diesel) mixture to improve the combustion efficiency and thereby reduce the emissions of the already present engines. The co-combustion of green hydrogen and diesel increases the fuel savings by 15-25 % and reduces emissions by 40-50 %. [68]

The technologies for on-board green hydrogen production and regenerative braking in mining transport vehicles can be combined. The created electricity from the regenerative braking system can be exploited using electrolyzers to produce green hydrogen. Though, this option is unstable with varying production. The production of green hydrogen must have a more stable electricity supply. An option here could be to use batteries to stabilize the electricity supply. With an electrolyser efficiency of 40-70 % it is possible to obtain between 35-62 kWh of green hydrogen, which approximately account for 2.3-4.1 % of the energy input to the engine of a mining truck. [68]

Studies have also been made for the electrification of mining trucks through new battery technology. When implementing an electric fleet there are high upfront costs, but the overall cost could be reduced by 15-20 % due to lower maintenance and fuel costs. [69]

The International Council on Mining and Metals have stablished an initiative to find ways to reduce emissions from mining trucks and are estimating to have zero-emission vehicles in scale by 2030. There is no ‘one size fits all’ solutions for decarbonizing mining vehicles as mining facilities are different, and the pace of decarbonization is highly uneven across the industry and countries. [70, 71]

8. Conclusion

This study evaluated the techno-economic feasibility of various clean energy technologies for application in the mining industry of Greenland.

First, the potential and resource availability for clean energy resources in Greenland were assessed. Given the geographical diversity of Greenland, the potential of these clean energy resources was evaluated individually for each region. The clean energy resources analysed included solar, wind, tidal, hydropower, regenerative braking, e-fuels, and energy storage.

Greenland possesses significant renewable energy potential. Solar energy potential (solar PV) is primarily limited to central and southern Greenland, as the high latitudes and extreme seasonal variations in solar irradiance significantly restrict its viability in Northern Greenland. Greenland possesses substantial wind energy potential, with some of the highest annual mean wind speeds globally. While the inland ice exhibits strong wind potential, installing turbines in such terrain is impractical. Onshore and nearshore wind turbines, which are protected from floating ice like pack ice, icebergs, and growlers, are considered the most feasible technologies for harnessing wind energy. Offshore wind is not considered feasible due to the risk of floating ice. Hydropower represents one of the most prominent and widely used energy resources in Greenland. Most hydropower potential is concentrated in the Southwest, where most lakes are located and where the potential is mapped, but opportunities for hydropower development exist across the country. Tidal energy potential is present throughout Greenland, particularly in fjords, and is assessed by the difference in height between low- and high-tides. Regenerative braking, a clean energy technology that captures energy from downhill transport operations, is particularly relevant for vehicles and conveyor belts. For this technology to be feasible, the site must meet specific criteria, including a steep enough slope and a large transport capacity. Different options exist today to recover braking energy such as regenerative braking conveyors, trolley truck systems, or electric trucks. To address the variable electricity output from clean energy sources, energy storage technologies such as battery energy storage solutions were also evaluated. E-fuels, which can be produced onsite through Power-to-X (PtX) technology or imported, were assessed as useful for areas with low potential for other clean energy resources.

Secondly, this study investigated the techno-economic feasibility of these technologies in various configurations, discussing the benefits and limitations of integrating clean energy technologies into the microgrids of remote mining operations in Greenland, compared to traditional fossil fuel-based systems. For each configuration, the Levelized Cost of Electricity (LCOE) was calculated and used as a comparison metric. Additionally, the Clean Electricity Share metric was used to compare the decarbonization level achieved by different technology configurations, indicating the share of the mine's electricity demand met by clean energy sources. A business-as-usual scenario where the mine's electricity and transport demand are met with diesel fuel was used as a reference.

The study examined the feasibility of these technologies in various configurations, including a mix of solar PV and wind (in combination with BESS or diesel generator for backup), upgraded and newly constructed hydropower plants (with some scenarios in combination with solar PV and wind turbines), e-methanol imports, and tidal energy. Key findings indicated that hydropower is the most economically feasible technology for fully decarbonizing the electricity demand of the mines, achieving the lowest LCOE with a Clean Electricity Share of 100%. Upgrading an existing hydropower facility or building a new plant in the vicinity of the mine showed competitive costs compared to business-as-usual for distances up to 1035 km from the mine. It can also be deemed economically competitive to implement a combination of an upgraded hydropower plant, solar PV, wind turbines and diesel generator, though the Clean Electricity Share is only at 68%. It could potentially also be an option to achieve a Clean Electricity Share of 100% combining hydropower and solar PV and wind turbines, if the production meets the electricity demand in all hours,

eliminating the need of a backup diesel generator, though this scenario is not analysed in this report.

Achieving a Clean Electricity Share of 100% with solar PV, wind, and BESS was deemed economically unfeasible due to the need for substantial oversizing of plants and large battery storage systems, resulting in high costs. Similarly, importing e-fuels from Europe or producing it in Greenland led to significantly higher costs compared to fossil fuel alternatives.

A mixed technology approach involving solar PV, wind, and diesel generators proved viable for reducing reliance on fossil fuels, achieving an LCOE similar to the business-as-usual scenario while reducing reliance on fossil fuels. This suggests that partial decarbonization can be achieved without additional costs compared to business-as-usual.

The study highlighted the potential of regenerative braking systems, particularly for conveyor belts, to significantly reduce the mine's transport demand or even be energy-neutral, given appropriate conditions for slope and transport capacity. In some cases, regenerative braking can be energy-positive, meaning transport demand can be fully decarbonized and extra energy potentially used for other mine operations. Incorporating regenerative braking with solar PV and/or wind could reduce the required installed capacity for these technologies, improving economic feasibility and supporting decarbonization efforts.

In conclusion, hydropower stands out as the most viable solution for achieving complete decarbonization of the mining sector's electricity demand in Greenland. Exploring combinations of renewable technologies, energy storage solutions, and regenerative braking further enhances the prospects of creating a sustainable and economically feasible future for mining operations in the region. Future investigations should focus on specific site assessments to understand the exact potential and complementarity between clean energy resources, specific challenges, geographical limitations, and opportunities.

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10. Appendix

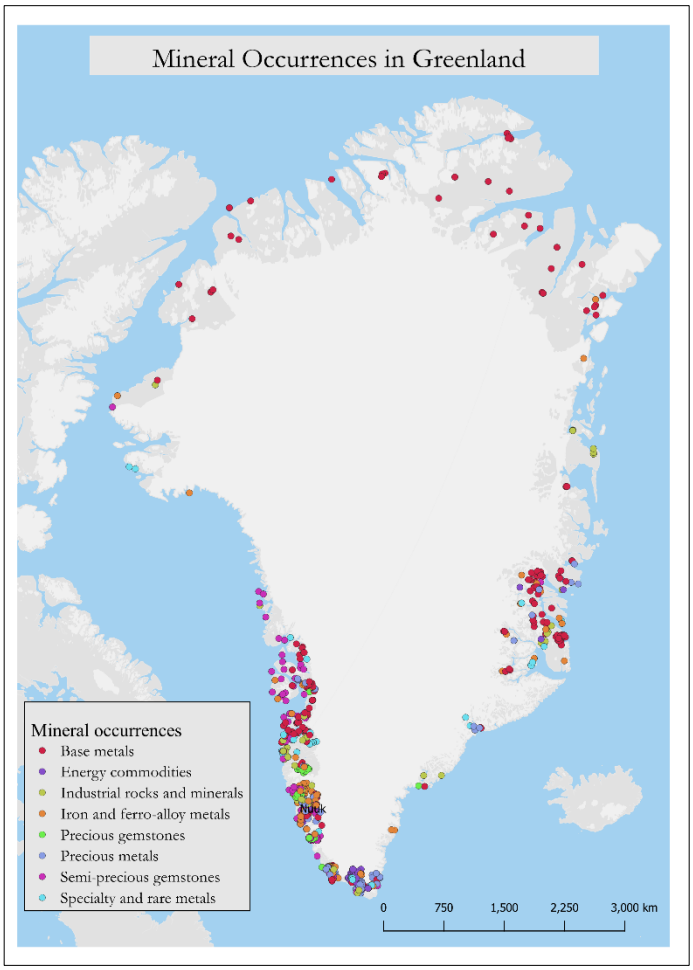
10.1 *Appendix 1:* Mining in Greenland

Mineral Occurrences

Greenland is home to a diverse array of valuable mineral resources, which have increasingly drawn attention from the global mining industry. The unique geological makeup of the country offers a rich variety of materials, many of which are essential for modern technologies and industries. The mineral occurrences in Greenland are shown on Map 10-1.

One of the most abundant resources in Greenland is base metals, including copper, zinc, and lead. These materials are essential for numerous industries, from construction and manufacturing to electronics. The prevalence of base metals all around the coast of Greenland makes these resources a central focus for future mining efforts. Their utility in energy infrastructure and electronics manufacturing positions them as crucial for global industries, especially as demand for these metals grows with advancements in green technologies, such as electric vehicles and clean energy infrastructure.

Greenland is not granting new licenses for oil and gas, and exploration for and mining of uranium is prohibited.



Map 10-1: Mineral occurrences in Greenland [1]

Industrial rocks and minerals, such as anorthosite and marble, are widely distributed across Greenland, particularly in the southern regions. These materials can be essential for construction and manufacturing industries. The presence of these industrial minerals positions Greenland as a potential supplier of construction materials, both domestically and internationally.

Precious metals, such as gold and platinum, also feature prominently across Greenland, particularly along the southern and western coasts. These metals are highly sought after for both industrial applications and as investment commodities. Gold in particular remains a cornerstone of the global financial system and jewelry industry, while platinum is critical in automotive catalysts and electronics.

Beyond metals, Greenland's deposits of specialty and rare metals (like niobium, tantalum, and rare earth elements) and industrial rocks and minerals are of significant importance. Rare earth elements are particularly vital for high-tech industries, including the production of electronics, wind turbines, and defense technologies. Given the increasing demand for these materials in the global market,

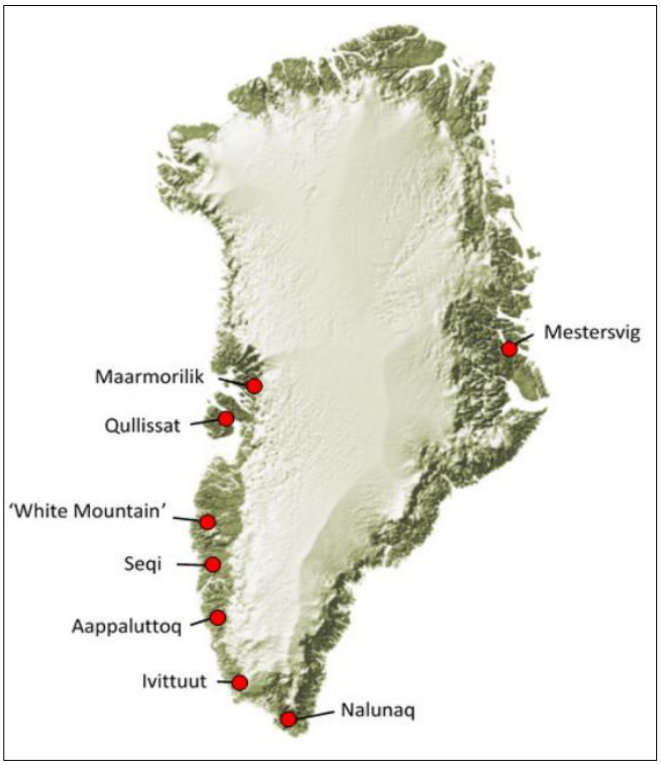
Greenland’s vast reserves could play a key role in meeting future demands, especially as supply chains diversify away from traditional suppliers like China.

Furthermore, precious gemstones such as rubies and sapphires add another dimension to Greenland’s mining potential. These stones have not only commercial value but also cultural significance, and Greenland's gem-quality stones have already garnered interest in global markets.

History of Mining in Greenland

Mining in Greenland has a long and varied history, with eight major mines operating at different points since the 18th century. The first instance of mining began in 1782, with small-scale coal mining on Qeqertarsuaq, located in the western part of Greenland. This marked the beginning of Greenland's mining industry, which would expand significantly over the next two centuries. The major former and present mines are presented on Map 10-2.

One of the most important mines in Greenland’s history is the Ivittuut cryolite mine, located in the Arsuk Fjord in the southwestern part of the country. Ivittuut was the world’s only significant source of cryolite, a mineral critical to aluminum production, and operated from 1854 to 1987. In addition to cryolite, the mine’s waste rock contained valuable amounts of lead and zinc, which were also transported for processing.



Map 10-2: Major former and present mine sites [2].

Other significant mining ventures include the only mine on Greenland's east coast, an underground lead-zinc mine near Mestersvig, which operated from 1956 to 1963. This mine also highlighted the challenges of mining in Greenland’s remote and harsh environments, where transporting materials and maintaining operations posed considerable logistical difficulties.

At the beginning of 2025, two mines are in operation, Lumina Sustainable Materials A/S' White Mountain anorthosite mine and Nalunaq A/S' gold and silver mine.

Future mining plans

Greenland's future in mining is critical for its economic prospects. The country’s vast mineral resources have attracted significant international interest, particularly as these minerals become more important in the context of global competition and the transition to greener energy.

Today, there are over 80 different Mineral Exploration and Exploitation Licenses in Greenland. A complete table of all Active Licenses can be found in Appendix 2. These proposed mining operations (Map 10-3) are mostly concentrated along the southern coast, while mining exploitation licenses (green) are also present in isolated regions, such as northeastern Greenland. Meanwhile, the majority of exploration licenses (blue) stretch across the southwest and southeast, indicating the future potential of the area for the mining sector. The extensive presence of exploration licenses demonstrates Greenland's vast untapped mineral potential, ranging from precious metals like gold and silver to specialty minerals and rare earth elements that are crucial for clean technologies, batteries, and electronics.



Map 10-3: Mining Licenses in Greenland [3]

As global industries shift towards greener energy solutions, Greenland's mining industry is expected to play a key role. The push for clean energy development—such as wind turbines, electric vehicles, and solar panels—requires significant amounts of minerals like cobalt, nickel, and rare earth elements, all of which are present in Greenland. In fact, as nations strive to reduce their dependence on fossil fuels, the demand for these materials is only projected to grow.

Unlike in the past, where mines were heavily dependent on fossil fuels and contributed to environmental degradation, today's mining operations are increasingly looking to reduce their environmental footprint. Clean energy, such as wind, hydroelectric, and solar power, is seen as a viable alternative for powering mining operations worldwide, which could dramatically reduce carbon emissions and pollution associated with these activities.

10.2 *Appendix 2*: Active Mineral Exploitation and Exploration Licences in Greenland

Source [3]

Owner	Type	Status	Minerals	Regions
Arcticulture ApS	Mineral Exploration Licence (MEL)	Active License		Qeqqata Region
Xploration Services Greenland A/S	Mineral Exploration Licence (MEL)	Active License	Zinc, Tin, Gold, Copper, Tantalum, Silver, Molybdenum, Cerium, Lead, Lithium	Qeqqata Region Sermersooq Region
Xploration Services Greenland A/S	Mineral Exploration Licence (MEL)	Active License	Lithium, Copper, Gold, Molybdenum, Zinc, Tin, Lead, Tantalum, Silver	Sermersooq Region
Arcticulture ApS	Mineral Exploration Licence (MEL)	Active License		Sermersooq Region
Nikkeli Greenland A/S	Mineral Exploration Licence (MEL)	Active License	Platinum Group Minerals, Nickel, Copper, Cobalt	Qeqertalik Region
Zawar Greenland ApS	Mineral Exploration Licence (MEL)	Active License	Magnesium, Iron, Manganese, Copper, Silver, vanadium, Lithium, Chromium, Cobalt, Gold, Tin, Rare Earth Elements, Molybdenum, Zinc, Nickel, Platinum Group Minerals, Lead	Avannaata Region
Navella AB	Mineral Exploration Licence (MEL)	Active License	Aggregate for concrete	Sermersooq Region
Itinnera Solutions ApS	Mineral Exploration Licence (MEL)	Active License	Sand	Sermersooq Region Qeqqata Region
Gardaq A/S	Mineral Exploration Licence (MEL)	Active License	Rare Earth Elements, Gold, Copper	Kujalleq Region
Gardaq A/S	Mineral Exploration Licence (MEL)	Active License	Zirconium, Niobium, Tantalum, Rare Earth Elements	Kujalleq Region
Greenfields Exploration Pty Ltd	Mineral Exploration Licence (MEL)	Active License	Gold, Copper, Antimony	Sermersooq Region
Nalunaq A/S	Mineral Exploration Licence (MEL)	Active License	Copper, Gold	Kujalleq Region
Ox Resources Pty Ltd Greenland	Mineral Exploration Licence (MEL)	Active License	Feldspar, Titanium, Zirconium, Tantalum, Rare Earth Elements, Niobium, Quartz (gold), Hafnium	Kujalleq Region
Greenland Gold s.r.o	Mineral Exploration Licence (MEL)	Active License	Copper	Sermersooq Region
Greenroc Graphite Limited	Mineral Exploration Licence (MEL)	Active License	Graphite	Kujalleq Region
Gardaq A/S	Mineral Exploration Licence (MEL)	Active License	Copper, Gold	Kujalleq Region Sermersooq Region
Hudson Resources Inc.	Mineral Exploration Licence (MEL)	Active License	Anorthosite	Sermersooq Region

GEFIB s.r.o.	Mineral Exploration Licence (MEL)	Active License	Gold, Rare Earth Elements, Niobium, Tantalum	Sermersooq Region
Halmares Resources s.r.o	Mineral Exploration Licence (MEL)	Active License	Tantalum, Rare Earth Elements, Molybdenum, Niobium	Sermersooq Region
Gardaq A/S	Mineral Exploration Licence (MEL)	Active License	Copper, Gold, Molybdenum, Uranium, Zinc	Kujalleq Region
Gardaq A/S	Mineral Exploration Licence (MEL)	Active License	Copper, Gold, Silver, Molybdenum, Uranium	Kujalleq Region
Bright Star Resources Limited	Mineral Exploration Licence (MEL)	Active License	Cobalt, Copper, Platinum Group Minerals, Nickel	Qeqertalik Region
Stallion Resources Limited	Mineral Exploration Licence (MEL)	Active License	Rare Earth Elements, Niobium, Tantalum	Kujalleq Region
Greenroc Graphite Limited	Mineral Exploration Licence (MEL)	Active License	Gold, vanadium, Nickel	Sermersooq Region
Dundas Titanium A/S	Mining Exploitation Licence (MIN)	Active License	Titanium	Avannaata Region
Copenhagen Minerals Inc.	Mineral Exploration Licence (MEL)	Active License	Copper, Gold, Rare Earth Elements, Lead, Tungsten, Silver, Zinc	Sermersooq Region
Gardaq A/S	Mineral Exploration Licence (MEL)	Active License	Gold	Kujalleq Region
Longland Resources Limited	Mineral Exploration Licence (MEL)	Active License	Iron, Gold, Lead, Silver, Zinc	Sermersooq Region
TANBREEZ Mining Greenland A/S	Mining Exploitation Licence (MIN)	Active License	Niobium, Europium, Rare Earth Elements, Zirconium, Yttrium, Terbium, Samarium, Holmium, Dysprosium, Gadolinium, Hafnium, Praseodym, Lanthan, Lutetium, Tantalum, Cerium, Neodym	Kujalleq Region
Nalunaq A/S	Mineral Exploration Licence (MEL)	Active License	Gold	Kujalleq Region
Black Angel Mining A/S	Mineral Exploration Licence (MEL)	Active License	Lead, Zinc	Avannaata Region
Gardaq A/S	Mineral Exploration Licence (MEL)	Active License	Gold	Kujalleq Region
NAIP West Exploration A/S	Mineral Exploration Licence (MEL)	Active License	Platinum Group Minerals, Nickel, Copper	Qeqertalik Region
Disko Exploration Ltd.	Mineral Exploration Licence (MEL)	Active License	Tin, Zinc	Kujalleq Region
Qaatsuitsup Ulloriaa	Mineral Exploration Licence (MEL)	Active License	Cadmium, Tantalum, Rare Earth Elements, Niobium	Qeqqata Region
Disko Exploration Ltd.	Mineral Exploration Licence (MEL)	Active License	Silver, Zinc, Lead	Avannaata Region
Nikkeli Greenland A/S	Mineral Exploration Licence (MEL)	Active License	Copper, Cobalt, Platinum Group Minerals, Nickel	Sermersooq Region Qeqertalik Region

NAIP West Exploration A/S	Mineral Exploration Licence (MEL)	Active License	Cobalt, Nickel, Platinum Group Minerals, Copper, PGE Rhodium, PGE Osmium	West Region Qeqertalik Region Avannaata Region
Nalunaq A/S	Mineral Exploration Licence (MEL)	Active License	Gold, Graphite	Kujalleq Region
Anglo American Exploration Overseas Holdings Limited	Mineral Exploration Licence (MEL)	Active License	Copper, PGE Palladium, PGE Platinum, Drilling, Nickel	Qeqertalik Region
Nikkeli Greenland A/S	Mineral Exploration Licence (MEL)	Active License	Copper, Cobalt, Nickel	Qeqertalik Region Avannaata Region
Dundas Titanium A/S	Mineral Exploration Licence (MEL)	Active License	Titanium, Ilmenite	North Region
Anglo American Exploration Overseas Holdings Limited	Mineral Exploration Licence (MEL)	Active License	Copper, PGE Palladium, Nickel, PGE Platinum, Drilling	Avannaata Region
Anglo American Exploration Overseas Holdings Limited	Mineral Exploration Licence (MEL)	Active License	Nickel, PGE Platinum, Copper, Drilling	Avannaata Region
Northground Ltd.	Mineral Exploration Licence (MEL)	Active License	Tantalum, Zirconium, Drilling, Rare Earth Elements, Niobium	Kujalleq Region
Stallion Resources Limited	Mineral Exploration Licence (MEL)	Active License	Tantalum, Zirconium, Rare Earth Elements, Niobium	Kujalleq Region
21st NORTH ApS	Mineral Exploration Licence (MEL)	Active License	Copper, Zinc	East Region
White Eagle Resources Limited	Mineral Exploration Licence (MEL)	Active License	Cobalt, Lead, Gold, Iron, Nickel, Zinc	
Greenland Resources A/S	Mineral Exploitation Licence (MIN)	Active License	Molybdenum and Magnesium	East Region
Nikkeli Greenland A/S	Mineral Exploration Licence (MEL)	Active License	Copper, Platinum Group Minerals, Nickel	Qeqertalik Region Avannaata Region
Premium Nickel Resources Ltd.	Mineral Exploration Licence (MEL)	Active License	Gold, Drilling, Diamonds, Rare Earth Elements, Platinum Group Minerals, Cobalt, PGE Palladium, Nickel, Copper	
Greenfields Exploration Pty Ltd	Mineral Exploration Licence (MEL)	Active License	Antimony, Tungsten, Copper, Gold	Northeast Greenland National Park Region East Region
Zawar Greenland ApS	Mineral Exploration Licence (MEL)	Active License	Gold	Avannaata Region
White Eagle Resources Limited	Mineral Exploration Licence (MEL)	Active License	Magnetite, Ilmenite	Avannaata Region
Resource 500 FeVTi Ltd.	Mineral Exploration Licence (MEL)	Active License	vanadium, Iron, Titanium, Spinel, Ilmenite	Kujalleq Region

Nikkeli Greenland A/S	Mineral Exploration Licence (MEL)	Active License	Zinc, Lead, Nickel	Qeqertalik Region
Longland Resources Limited	Mineral Exploration Licence (MEL)	Active License	PGE Palladium, Platinum Group Minerals, Iron, Titanium, Feldspar, Gold, Copper, Nickel	East Region
Ironbark A/S	Mining Exploitation Licence (MIN)	Active License		
Greenland Gold s.r.o	Mineral Exploration Licence (MEL)	Active License	Gold	Kujalleq Region
Greenland Gold s.r.o	Mineral Exploration Licence (MEL)	Active License	Gold	Sermersooq Region
Lumina Sustainable Materials A/S	Mining Exploitation Licence (MIN)	Active License		
Dundas Titanium A/S	Mineral Exploration Licence (MEL)	Active License	Ilmenite, Drilling	Avannaata Region
Nalunaq A/S	Mineral Exploration Licence (MEL)	Active License	Gold	Sermersooq Region
Greenland Ruby A/S	Mining Exploitation Licence (MIN)	Active License		
Copenhagen Minerals Inc.	Mineral Exploration Licence (MEL)	Active License	Gold	Sermersooq Region
Greenland Silver Moly Resources ApS	Mineral Exploration Licence (MEL)	Active License	Gold, Molybdenum, Copper, Silver, Zinc, Lead	Sermersooq Region
Graphite Fields Resources Ltd.	Mineral Exploration Licence (MEL)	Active License	Graphite	Qeqertalik Region
Greenroc Graphite Limited	Mineral Exploration Licence (MEL)	Active License	Silver, Gold, Nickel, Graphite	Kujalleq Region
Major Precious Greenland	Mineral Exploration Licence (MEL)	Active License	Drilling	East Region
Premium Nickel Resources Ltd.	Mineral Exploration Licence (MEL)	Active License	Diamonds, Platinum Group Minerals, Rare Earth Elements, Drilling, Nickel, Olivine, Copper	Qeqqata Region
Nikkeli Greenland A/S	Mineral Exploration Licence (MEL)	Active License	Cobalt, Platinum Group Minerals, Nickel, Drilling, Copper	Avannaata Region Qeqertalik Region
Disko Exploration Ltd.	Mineral Exploration Licence (MEL)	Active License	Copper, PGE Platinum, Nickel, Drilling	Avannaata Region
Premium Nickel Resources Ltd.	Mineral Exploration Licence (MEL)	Active License	Drilling, Rare Earth Elements, Nickel, Iron	Qeqqata Region
Greenland Anorthosite Mining A/S	Mineral Exploration Licence (MEL)	Active License	Anorthosite	Sermersooq Region
Greenland Feldspar Aluminium Resources ApS	Mineral Exploration Licence (MEL)	Active License	Platinum Group Minerals, Nickel, Copper	Qeqqata Region

Greenland Ruby A/S	Mineral Exploration Licence (MEL)	Active License	Corundum (containing ruby)	Sermersooq Region
Major Precious Greenland	Mineral Exploration Licence (MEL)	Active License	Titanium, vanadium, Iron, Gold, PGE Palladium	Sermersooq Region
Eclipse Metals Limited Greenland	Mineral Exploration Licence (MEL)	Active License	Quartz (gold)	Sermersooq Region
Nalunaq A/S	Mineral Exploration Licence (MEL)	Active License	Gold	Kujalleq Region
Greenland Minerals A/S	Mineral Exploration Licence (MEL)	Active License	Rare Earth Elements, Uranium, Fluorite, Zinc	Kujalleq Region
Rimbal Pty. Ltd.	Mineral Exploration Licence (MEL)	Active License	Drilling, Rare Earth Elements	Kujalleq Region
FBC Mining (BA) Limited	Mineral Exploration Licence (MEL)	Active License	Lead, Zinc	Avannaata Region
Nalunaq A/S	Mining Exploitation Licence (MIN)	Active License		Kujalleq Region
Greenland Ruby A/S	Mineral Exploration Licence (MEL)	Active License	Corundum (containing ruby), Gold, Aluminium, Nickel, Chromite, Sand, Gravel, Copper	Sermersooq Region

10.3 *Appendix 3:* Technology Catalogue

The Technology Catalogue is an appendix to this report and can be seen in the following pages.

The technology catalogue presented has been meticulously compiled based on the latest information from a variety of reliable sources. These include advanced tools and databases, such as the Danish Energy Agency Technology Catalogue, the Greenlandic Environmental Agency's Technology Database, IEA, IRENA, etc.

This catalogue features a comprehensive array of technologies (both clean energy and fossil fuel technologies) tailored for the conditions of Greenland and potential resources. The catalogue includes detailed technical specifications, capital and operational cost analyses. Furthermore, it illustrates the scalability of different technological solutions and how they can be integrated to optimize microgrid operations in Greenland.

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    - 1.2 Energy Landscape – Greenland
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1. Greenland Considerations



Establishing energy systems in Greenland's arctic climate poses unique challenges. The extreme cold, with temperatures dropping as low as -40°C, necessitates highly reliable and protected infrastructure.

One of the primary considerations is these extreme temperatures. Infrastructure must withstand harsh conditions and sub-zero temperatures. Materials and technologies used must be resilient and capable of operating efficiently in these conditions. Secondly, many settlements in Greenland are remote and far from renewable energy sources and the nearest power grid. This isolation requires self-sustaining power systems that can operate independently. Logistical challenges are significant, as the transport of equipment and supplies may be limited to specific times of the year (summer months) due to weather conditions. Strategic planning is essential to ensure that all necessary components are available and operational year-round.
Efficient energy systems in these areas often rely on a mix of sources. For instance, light oil can be used initially, with plans for integrating wind energy and heat from waste incineration. Above-ground district heating networks can connect buildings, combining water, waste water, power, and telecommunication cables in a single resilient infrastructure.
There are several barriers and challenges to implementing large-scale Variable Renewable Energy Sources (VRES) in arctic areas. Firstly, the pricing of electricity and heat is often politically influenced, providing little economic incentive for private adoption of district heating over individual systems. The lack of transparency in pricing complicates policy decisions aimed at achieving energy objectives.

Additionally, resources like water for hydropower and waste heat should be assigned economic value, reflected in energy pricing structures to incentivize efficient use. There is often a lack of systematic evaluation and follow-up on energy operations in various towns, hindering the optimization of residual heat utilization and energy efficiency measures.

Implementing large-scale VRES increases system complexity, necessitating advanced computer-based measurement, management, control, and monitoring systems. Before making major investments in VRES, thorough evaluation and validation of the technology under arctic conditions are crucial. This includes learning from existing research and practical experiences, such as those from the Arctic Technology Center (ARTEK).

By considering these factors, energy systems in the Artic Circle can be designed to be robust, efficient, and capable of meeting the unique demands of the environment.

1.1 Weather Conditions

Greenland, the world's largest island, is located between the Arctic and Atlantic Oceans, east of the Canadian Arctic Archipelago. It is an autonomous territory within the Kingdom of Denmark. Covering an area of over 2.16 million square kilometers while roughly 80% of Greenland is covered by the Greenland Ice Sheet, the second largest body of ice in the world. The island's geography is marked by a rugged coastline, deep fjords, and towering glaciers. As of 2024, the population of Greenland is estimated to be around 56,789 people. This small population is spread over the vast expanse of the island, resulting in an extremely low population density, with most inhabitants residing in coastal areas, particularly in the southwestern part of the country. The capital city, Nuuk, is the largest urban center, housing a significant portion of the population.



Figure 1-1: Nuuk, Capital of Greenland

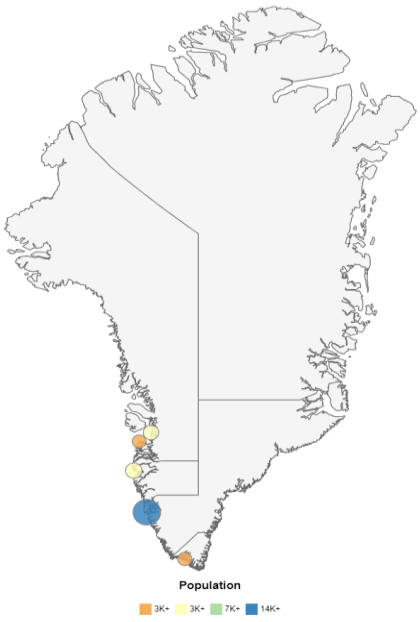


Figure 1-2: Greenland Population Density [30]

Temperature

Greenland experiences a polar climate with significant temperature variations across regions and seasons. Coastal areas, particularly in the south, generally have milder temperatures compared to the interior ice sheet.

Coastal Areas
Southern Coastal Areas: In summer (June to August), temperatures range from 5°C to 15°C (41°F to 59°F), while winter temperatures (December to February) range from -8°C to -20°C (17.6°F to -4°F). Western coastal areas, including Nuuk, experience summer temperatures from 3°C to 10°C (37.4°F to 50°F) and winter temperatures between -10°C and -20°C (14°F to -4°F).

Interior Ice Sheet
The interior of Greenland is extremely cold year-round. Winter temperatures can drop to -30°C (-22°F) or lower, with some areas reaching -60°C (-76°F) during extreme cold spells. Summer temperatures in the interior rarely rise above freezing, generally staying between -12°C to 0°C (10°F to 32°F).

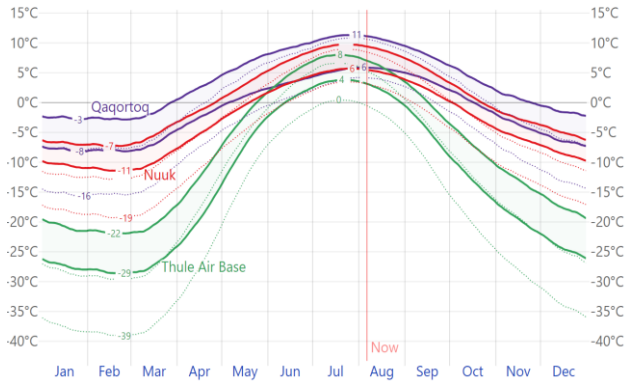


Figure 1-3: Average Temperatures during the year in Nuuk, Qaqortoq and Thule Air Base [31]

Seasonal Variations
- Spring (March to May): Coastal temperatures rise above freezing, reaching around 0°C to 5°C (32°F to 41°F) by May. The interior remains below freezing.
- Summer (June to August): Coastal areas see the mildest temperatures, ranging from 5°C to 15°C (41°F to 59°F), while the interior stays around -12°C to 0°C (10°F to 32°F).
- Autumn (September to November): Temperatures drop rapidly, with coastal areas decreasing to -5°C to 5°C (23°F to 41°F) and the interior returning to sub-zero conditions.

- Winter (December to February): Coastal areas experience temperatures from -8°C to -20°C (17.6°F to -4°F), and the interior frequently drops below -30°C (-22°F).

Precipitation

Greenland experiences relatively low precipitation overall, especially in the central ice sheet regions, which receive less than 250 mm (10 inches) of precipitation annually, classifying them as polar deserts. The majority of Greenland's precipitation falls in the form of snow, which is a crucial factor in maintaining the extensive ice cover that defines the island's geography.

Southern and Southeastern Coasts: These regions are the wettest in Greenland. Annual precipitation ranges from 800 mm to over 2,000 mm (31.5 to 78.7 inches). The southern coast, influenced by the North Atlantic weather systems, receives substantial precipitation, particularly during the autumn and early winter months. This is when the region experiences frequent storms that bring heavy snowfall. The southeastern coast, facing the open Atlantic, also receives significant precipitation, driven by moist air masses from the ocean.

Western and Northern Coasts: The western coastal areas, including the capital Nuuk, receive moderate precipitation. Annual precipitation in Nuuk averages around 750 mm (29.5 inches). Precipitation here is relatively evenly distributed throughout the year, though it is slightly higher in autumn and early winter. The northern coastal areas, being closer to the Arctic Circle, receive less precipitation, typically around 200 mm to 400 mm (7.9 to 15.7 inches) annually, with most falling as snow during the colder months.

Central Ice Sheet: The interior of Greenland, dominated by the vast ice sheet, is extremely dry. Annual precipitation in these central regions is less than 250 mm (10 inches), primarily occurring as snow. The cold temperatures ensure that the precipitation accumulates as part of the ice sheet rather than melting. This low level of precipitation is characteristic of polar deserts and contributes to the ice sheet's stability.

Seasonal Variations
Most of Greenland's precipitation occurs during the autumn and early winter months. During this period, the southern and southeastern coasts experience frequent storms that bring substantial snowfall. Spring and summer months see less precipitation, but the melting snow contributes to runoff and glacier movement.
These precipitation patterns play a crucial role in shaping Greenland's climate and its unique polar environment. Understanding these patterns is essential for predicting changes in the ice sheet and the broader implications for global sea levels.

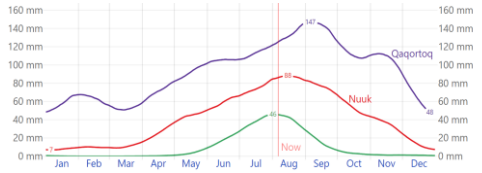


Figure 1-4: Average monthly rainfall during the year in Nuuk, Qaqortoq and Thule Air Base [31]

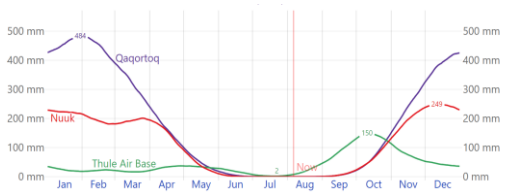


Figure 1-5: Average monthly snowfall during the year in Nuuk, Qaqortoq and Thule Air Base [31]

Sunlight

Due to its high latitude, Greenland experiences extreme variations in daylight throughout the year, profoundly influencing daily life and the environment.

Summer Months

During the summer months, especially within the Arctic Circle, Greenland experiences the phenomenon of the midnight sun. From late May to late July, the sun does not set, remaining above the horizon for 24 hours a day. This period of continuous daylight allows for extended outdoor activities and significantly affects the local ecosystem, promoting rapid plant growth and abundant wildlife activity.

Winter Months

Conversely, the winter months bring prolonged darkness, known as the polar night. In regions above the Arctic Circle, such as Qaanaaq, the sun does not rise for several weeks or even months. This period typically lasts from late November to mid-January, creating a challenging environment for residents. The southern regions experience shorter periods of darkness, with daylight limited to a few hours each day.

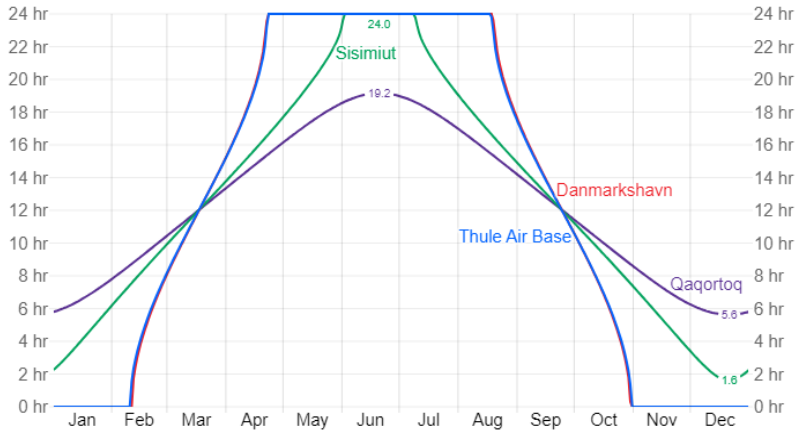


Figure 1-6: Average monthly sunlight hours during the year in Nuuk, Qaqortoq and Thule Air Base [31]

Wind and Storms

Greenland is known for its strong and persistent winds, which significantly influence its weather conditions. These winds are particularly notable in coastal areas and over the ice sheet.

Katabatic Winds

Katabatic winds are a defining feature of Greenland's wind patterns. These winds are gravity-driven, flowing down the slopes of the ice sheet and reaching high speeds. As they descend, they compress and heat up, but the overall effect is a significant lowering of temperatures where they reach the ground. Katabatic winds can be particularly fierce. They create extremely cold conditions, especially during the winter months, and pose substantial challenges for both residents and wildlife

Coastal Winds

Coastal regions also experience strong winds, which can be more persistent and severe during certain seasons. The interaction between the cold Arctic air and the relatively warmer air over the ocean generates frequent and powerful winds along the coast. These winds can affect sea ice conditions, making navigation difficult and impacting local fisheries.

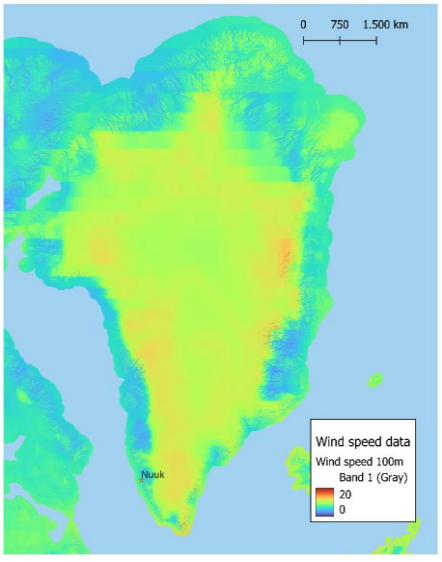


Figure 1-7: Wind Speed Map of Greenland

Storms
Greenland's coastal areas are susceptible to storms, especially during the winter months. These storms often bring heavy snowfall, high winds, and blizzard conditions, creating challenging and sometimes hazardous situations for the inhabitants. Winter storms can disrupt transportation, hinder outdoor activities, and increase the risk of avalanches in mountainous regions. The southern and southeastern coasts are particularly vulnerable to these storms due to their exposure to moist air masses from the Atlantic.

Environmental Impact
The strong winds and frequent storms play a crucial role in shaping Greenland's environment. They contribute to the distribution of snow and ice, affecting glacier dynamics and the overall ice sheet stability. The winds also influence the local climate by impacting temperature patterns and precipitation distribution.

1.2 Energy Landscape - Greenland

Greenland's energy landscape has evolved significantly over the years, shaped by its unique geography and the challenges of remote, isolated communities. Historically, Greenland relied heavily on imported fossil fuels due to the lack of connectivity between urban settlements, absence of indigenous resources, and technical challenges of developing alternative energy sources in the harsh Arctic environment. The earliest energy infrastructure consisted of small, localized diesel power plants, supplying electricity to sparse population centers, primarily along the coast. Until the late 20th century, there was minimal use of renewable energy sources, as the focus was on ensuring reliable energy supply rather than exploring alternatives.

In recent decades, Greenland has made substantial progress in transitioning to renewable energy. The cornerstone of this shift has been the development of five hydroelectric power plants, harnessing abundant glacial meltwater and precipitation. These plants have significantly reduced the dependence on imported fuels, providing a more sustainable energy source for the country.
Greenland has also explored other renewable solutions. Waste-to-energy initiatives in municipalities, where heat from waste incineration is used for district heating, have contributed to the energy mix in several towns. Innovative local projects, such as converting fish residues into energy in Sisimiut and utilizing renewable energy to revitalize small settlements like Saarloq, demonstrate Greenland's commitment to diversifying its energy sources. Wind and solar power are still in the nascent stages, but pilot projects have been launched.

Nukissiorfiit, Greenland's state-owned utility, manages energy production, distribution, water supply, and operating microgrids in isolated communities. These microgrids, are crucial in Greenland's harsh environment to provide reliable energy to settlements not connected by a national grid. This decentralized approach is essential due to the dispersed population and challenging geography, aligning with sustainability goals.
Despite advancements, Greenland faces ongoing challenges due to the lack of a coherent energy transmission system. The isolation of each settlement means that surplus energy from one area cannot easily be transferred to another, requiring backup capacity in every community. This fragmentation poses difficulties, particularly when integrating variable renewable energy sources like wind and solar.

Nevertheless, Greenland is making strides in addressing these issues. Since 2014, policies have been implemented to encourage renewable energy development, with subsidies available to renewable energy generators based on the cost of equivalent non-renewable production. This has provided an additional impetus for the continued growth of renewable energy in the region, paving the way for a more sustainable and self-sufficient energy future for Greenland.

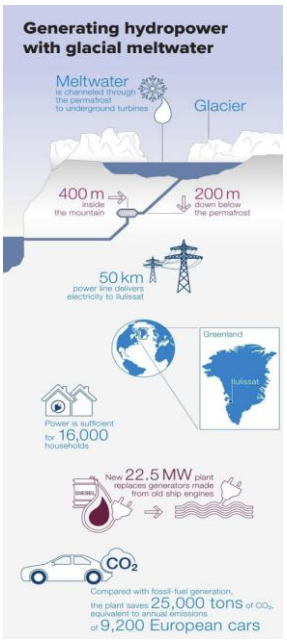


Figure 1-8: Ilulissat hydropower plant in Greenland [32]

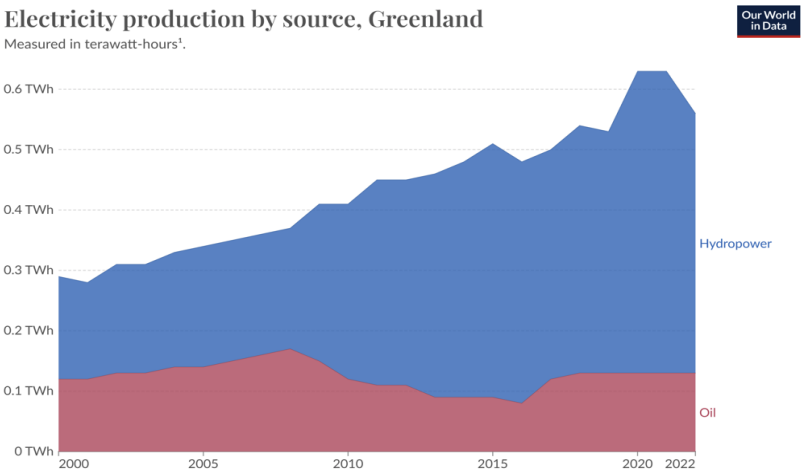


Figure 1-9: Electricicty production by source in Greenland [33]

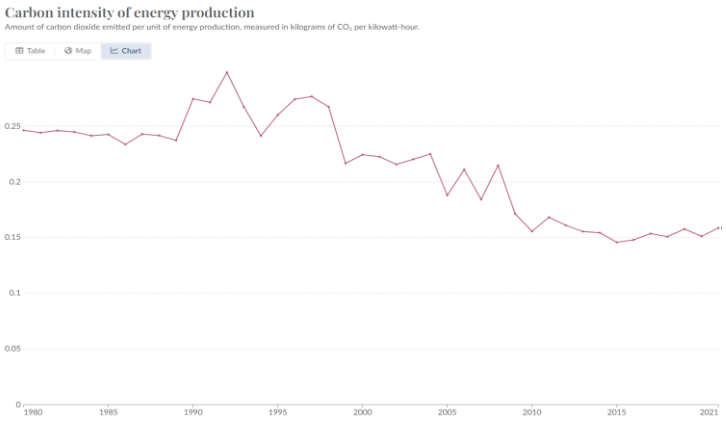


Figure 1-10: Carbon intensity of Energy production in Greenland [33]

2. Processes of Mining, Machinery and Vehicles

There are different processes of operating a mine, which is dependent on the geographical location of the mine and the extracted minerals. There are different types of mines, there are surface mines, underground mines, placer mines and in-situ mines.

The process of extracting minerals in a mine can consist of breaking and crushing of ore, an additional exploration processing of the broken ore and then disposal of waste product. The minerals are then often broken into smaller particles and then shipped from the mine. The process of extracting minerals in in-situ mines is a little different, as here chemicals are injected into an ore body to dissolve the metal an allow it to flow to the surface. At placer mines the process of obtaning minerals is through loose river sediments along the beds of the stream.

Even though the processes of the mines can vary, there are several internal processes that are the same, this includes the process of moving material around the mine site. For moving materials around the mine site a heavy-duty truck can be used. These are large trucks with extra large tires to support the heavy loads and the ueven terrain, so they can withstand extreme conditions like cold, dust, high altitudes, steep slopes and heavy loads. There are different vehicles for surface mines compared to underground mines, as underground mining trucks and loaders require specific qualifications to operate in confined spaces. A mining machine that is used in many mines is a crusher, which is a machine designed to break down rocks into smaller pieces. Similar to a crusher, is a drilling rig which creates holes through the rocks or soil.

In addition to the processes and energy consumption of the activities in the mines, comes the energy consumptioin of processing the extracted materials in industrial buildings above ground. These are buildings which require both electricity and heat. Furthermore, there will also be accommodation areas at the mines for the emplyees working at the mines. These accommodation areas also require both electricity and heat.



Figure 2-1: Mining processes [29]



Figure 2-2: Mining processes [29]

2.1 Transitioning of Mining Vehicles

Dump trucks, mining excavators, crawler dozers, heavy-duty trucks, coneyor system and wheel loaders are some of the vehicles and machinery that operate in a mine. They are usually run on diesel or other fossil fuels, but a shift in the industry is happening, and several electric dump trucks and heavy-duty trucks are now on the market.

Also the concept of diesel-electric mining trucks have been introduced to the industry and thereby moving the industry to more clean energy. These diesel-electric mining trucks genrate electricity by converting the mechanical force generated by the diesel engine via and alternator. This then powers the elctric transmission in the truck and thetreby drives the vehicle. The diesel-electric mining trucks have several advantages. One of the advantages is that they do not need a gearbox, which means that the truck will not loose momentum going up the haul tracks and can thereby be more effecient. [16]

Besides electrifying the machinery and vehicles, another possibility for transitioning the vehicles from fossil fuels to clean energy is for them to use e-fuels as their energy consumption. These e-fuels might not be produced at the mining facility, but could be produced elsewhere in Greenland where there for example is good hydropower resources, and then transported by ship to the mining facility.

An additional clean energy technology that can be used for transitioning the mining vehicles is the technology of regenerative braking. Regenerative braking can help lower the emissions of the vehicles on the mining site, lower the fuel consumption and also lower the costs connected to maintenance of the mechanical brakes in the vehicles. The technology of regenerative braking is further explained in *Chapter 7. RES and PTX*.

Then there are the energy consumption of the ships who transport materials back and forth from the mines. These would also have to be transitioned to RES in the future. They could be transitioned to use e-methanol or e-amonia.



Figure 2-3: Electric dump truk [34]



Figure 2-4: Mining excavator [34]

Table 2-1: Overview of different dump trucks and their qualifications from the manufacturer Komatsu [34]

Type of vehicle	Engine Power	Max Speed	Body Capacity	Rated Payload
	kW/HP	km/h	m3 SAE	t
Rigid dump truck HD325-8	386 or 518	68.0	24.0	36.5
Rigid dump truck HD405-8	386 or 518	66.0	27.3	40.0
Rigid dump truck HD465-8	578 or 778	70.0	34.2	55.0
Rigid dump truck HD465-10	610 or 818	70.0	37.1	55.5
Rigid dump truck HD605-8	578 or 778	70.0	40.0	63.0
Rigid dump truck HD605-10	610 or 818	70.0	43.0	64.0
Rigid dump truck HD785-8	895 or 1200	65.0	60.0	92.2
Rigid dump truck HD1500-8	1180 or 1580	56.6	78.0	139.0
Articulated dump truck HM300-5	248 or 332	58.6	N/A	28.0
Articulated dump truck HM400-5	353 or 473	56.0	N/A	40.0
Electric dump truck 730E-10	1492 or 2000	64.5	133.0	186.0
Electric dump truck 830E-5	1865 or 2500	64.5	158.0	227.0
Electric dump truck 930E-5	2014 or 2700	64.5	202.0	290.0
Electric dump truck 980E-5	2610 or 3500	64.0	250.0	363.0

3. Clean Energy

In this category we include all relevant renewable energy sources for Greenland, except biomass fuels, which are incorporated in the boiler and CHP categories, and hydro technologies, which are incorporated in the Energy Storage tab.

As the world is looking for affordable renewable energy this category is important to compare cost of generating energy, in the form of electricity, gas or heat taking into account the economy of scale.

3.1 Solar PV

A solar cell is a semiconductor component that generates electricity when exposed to light. The photovoltaic (PV) modules are typically 1 – 2 m2 in size and have a power density in the range 100 - 210 Wp pr. m2. They are sold with a product guarantee of typically two-five years, a power warranty of minimum 25 years and an expected lifetime of more than 30 years. PV modules are characterised according to the type of absorber material used:

In addition to PV modules, a grid connected PV system also includes Balance of System (BOS) consisting of a mounting system, dc-to-ac inverter(s), cables, combiner boxes, optimizers, monitoring/surveillance equipment and for larger PV power plants also transformer(-s).

Solar PV systems can be effectively used in Arctic conditions, although they face unique challenges such as extreme cold, snow accumulation, and limited daylight during winter months. Cold temperatures can actually improve the efficiency of solar cells, as they perform better at lower temperatures. However, snow and ice can cover panels and block sunlight, reducing energy production. To mitigate these issues, panels can be installed at steeper angles to facilitate snow shedding and include heating elements to melt ice buildup. Additionally, the long daylight hours during summer can compensate for the low winter production, making solar PV a viable energy source in Arctic regions.

3.1.1 Technical- and economic assumptions

Table 3-1: Technical- and economic assumptions for a photovoltaics systems (2030) [28]

Technology	Rooftop PV Residential	Rooftop PV comm. and industrial	Utiliy Scale PV	Utility Scale PV tracker
Energy/technical data				
Generating capacity for one unit [MW_e]	0.01	0.1	40	40
Forced outage []	0	0	0	0
Planned outage [weeks per year]	0	0	0	0
Technical lifetime [years]	40	40	40	40
Construction time [years]	0	0	0.5	0.5
Space requirement [1000 m2/MW_e]	4.57	4.78	12.26	15.93
Regulation ability				
Primary regulation (of full load, per 30 seconds) []				
Secondary regulation (of full load, per minute) []				
Financial data				
Nominal investment (*total) [MEUR/MW_e]	0.84	0.57	0.38	0.45
Nominal investment (*total, per DC) [MEUR/MW_e]	0.80	0.51	0.31	0.36
Nominal investment (grid connection) [MEUR/MW_e]	0.03	0.04	0.05	0.05
Nominal investment (inverter) [MEUR/MW_e]	0.14	0.11	0.02	0.02
Nominal investment (pv modules) [MEUR/MW_e]	0.27	0.24	0.14	0.14
Nominal investment (tracker related costs) [MEUR/MW_e]				0.07
Nominal investment (installation) [MEUR/MW_e]	0.23	0.11	0.1	0.1
Nominal investment (other, i.e. residual balance of plant) [MEUR/MW_e]	0.17	0.07	0.04	0.03
Nominal investment (soft costs) [MEUR/MW_e]			0.03	0.04
Fixed O&M (*total) [EUR/MW_e/y]	10700	8900	9500	10400
Fixed O&M (land rent) [EUR/MW_e/y]			3900	4800
Technology-specific data				
Generating capacity for one unit (DC-value) [MW_e]	0.01	0.11	50	50
Space requirement (per DC) [1000m2/MW_e]	4.35	4.35	9.8	12.75
Nominal investment (installation, per DC) [MEUR/MW_e]	0.22	0.1	0.08	0.08
Nominal investment (inverter, per DC) [MEUR/MW_e]	0.14	0.1	0.02	0.02
Nominal investment (other, i.e. residual balance of plant, per DC) [MEUR/MW_e]	0.16	0.06	0.03	0.02
Nominal investment (pv module, per DC) [MEUR/MW_e]	0.26	0.22	0.11	0.11

Nominal investment (soft costs, per DC) [MEUR/MW_e]			0.02	0.03
Nominal investment (tracker related cost, per DC) [MEUR/MW_e]			0.04	0.06
Nominal investment (transformer and grid connection, per DC) [MEUR/MW_e]	0.0	0.03	0.04	0.04
Fixed O&M (*total, per DC) [EUR/MW_e/y]	10200	8100	7600	8300
Fixed O&M (land rent, per DC) [EUR/MW_e/y]			3100	3800
Fixed O&M (other, per DC) [EUR/MW_e/y]	10200	8100	4500	4500
Average annual degradation of full-load hours []	0.00	0.00	0.00	0.00
Global horizontal irradiance [kWh/m2/y]	1068	1068	1068	1068
Transposition factor	1.1	1.1	1.17	1.35
Performance ratio (contribution from bifaciality) []		0	0.05	0.05
Performance ratio (measure of combined losses) []	0.9	0.9	0.95	0.95
PV module conversion efficiency []	0.23	0.23	0.23	0.23
Inverter lifetime [years]	15	15	15	15
Sizing factor (DC/AC) [W_e/W_e]	1.05	1.1	1.25	1.25
Average annual full-load hours (DC-value) [MWh_e/MW_e]	1116	1116	1187	1370
Average annual full-load hours [MWh_e/MW_e]	1172	1228	1484	1712

3.2 Wind Onshore

Modern onshore wind turbines typically feature a horizontal-axis design with three blades, positioned upwind. These turbines employ active pitch, variable speed, and yaw control systems to maximize electricity generation across varying wind speeds. Wind turbines operate by capturing kinetic energy from the wind via their rotor blades, which is then transferred to a drive shaft. This shaft is connected either to a gearbox and a high-speed generator or directly to a low-speed generator, converting rotational energy into electrical power.

Blade pitch control is critical for optimizing power output at low wind speeds while maintaining consistent power and minimizing mechanical stress at high wind speeds. Turbines operate within a wind speed range defined by a "cut-in" speed (3-4 m/s) and a "cut-out" speed (around 25 m/s), with future models potentially extending to 30 m/s using a soft cut-out approach.

The efficiency of wind turbines is represented by the power coefficient (Cp), which varies with wind speed and typically reaches a maximum of around 45% at approximately 8 m/s. Modern onshore wind turbines in Denmark exhibit capacity factors around 35%, corresponding to roughly 3100 full load hours annually. These factors are influenced by the average wind speed at the installation site, which is affected by geographical location, hub height, and surface roughness.

Onshore wind project costs have fluctuated due to changes in electricity prices and manufacturing expenses. Between 2018 and 2020, turbine prices fell below manufacturing costs, leading to a subsequent 30% increase in project costs by 2022. The integration of additional cost components such as land procurement, compensation for neighboring entities, and the acquisition of old turbines has also influenced overall project expenses.
The capital cost of onshore wind projects is primarily driven by the turbine cost, with additional expenditures for grid connection, land purchase, and other ancillary costs. The operational and maintenance (O&M) costs, which cover service agreements, administrative costs, insurance, and electricity purchase, have been reduced significantly over the past decade.

Onshore wind turbines can be effectively deployed in Arctic conditions, though they face unique challenges such as extreme cold and ice accumulation during winter months. Cold temperatures can enhance turbine efficiency due to denser air, but ice formation on blades can reduce performance and cause mechanical issues. Solutions like blade heating systems and ice-resistant coatings are essential to mitigate these problems. Arctic regions benefit from high wind speeds and long daylight hours during the summer, which can compensate for reduced winter production. The robust design and advanced control systems of modern turbines make them well-suited for Arctic deployment, ensuring reliable operation in harsh environments.

3.2.1 Technical- and economic assumptions

Table 3-2: Technical- and economic assumptions for a onhsore wind turbines [28]

Technology	**Onhsore Turbines**								
year	**2020**	**2025**	**2030**	**2040**	**2050**	**2020**	**2020**	**2050**	**2050**
est	**ctrl**	**ctrl**	**ctrl**	**ctrl**	**ctrl**	**lower**	**upper**	**lower**	**upper**
Energy/technical data									
Generating capacity for one unit [MW_e]	4.2	4.5	5	5.5	6	2	6	1.5	8
Forced outage [%]	0.03	0.03	0.02	0.02	0.02	0.01	0.05	0.01	0.05
Planned outage [%]	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01
Technical lifetime [years]	27	27	30	30	30	25	35	25	40
Construction time [years]	1.5	1.5	1.5	1.5	1.5	1	3	1	3
Space requirement [1000 m2/MW_e]	-	-	-	-	-	-	-	-	-
Regulation ability									
Primary regulation (of full load, per 30 seconds) []	-	-	-	-	-	-	-	-	-

Secondary regulation (of full load, per minute) []	-	-	-	-	-	-	-	-	-
Financial data									
Nominal investment (*total) [MEUR/MW_e]	1.11	1.18	1.15	1.11	1.09	0.87	1.31	0.80	1.19
Nominal investment (equipment) [MEUR/MW_e]	0.78	0.86	0.83	0.79	0.78	0.63	0.94	0.62	0.93
Nominal investment (installation/development) [MEUR/MW_e]	0.09	0.09	0.09	0.08	0.08	0.07	0.11	0.06	0.10
Nominal investment (decommissioning of existing turbines) [MEUR/MW_e]	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.03	0.04
Nominal investment (grid connection) [MEUR/MW_e]	0.02	0.02	0.02	0.02	0.02	0.01	0.02	0.01	0.02
Nominal investment (purchase of neighbour settlements) [MEUR/MW_e]	0.08	0.07	0.07	0.07	0.07	0.06	0.09	0.06	0.09
Nominal investment (land purchase/rent) [MEUR/MW_e]	0.11	0.11	0.11	0.11	0.11	0.09	0.13	0.09	0.13
Variable O&M (*total) [EUR/MWh_e]	2.11	2.06	1.98	1.89	1.85	1.69	2.54	1.48	2.22
Fixed O&M (*total) [EUR/MW_e/y]	16397	17387	16663	15965	15602	13118	19676	12482	18722
Technology-specific data									
Availability [%]	0.97	0.97	0.98	0.98	0.98	0.99	0.95	0.99	0.95
Hub height [m]	85	90	100	105	110	85	120	85	150
Rotor diameter [m]	130	135	145	155	165	90	130	100	150
Specific power [W_e/m2]	316	310	303	291	281	314	452	191	453
Average capacity factor []	0.39	0.40	0.41	0.42	0.43	0.23	0.46	0.23	0.51
Average annual full-load hours [MWh_e/MW_e]	3400	3500	3600	3700	3800	2000	4000	2000	4500

Table 3-3: Technical- and economic assumptions for a onhsore domestic wind turbines [28]

Technology	**Domestic Turbines**						
year	**2020**	**2030**	**2050**	**2020**	**2020**	**2050**	**2050**
est	**ctrl**	**ctrl**	**ctrl**	**lower**	**upper**	**lower**	**upper**
Energy/technical data							
Generating capacity for one unit [MW_e]	0.01	0.01	0.01	0	0.03	0	0.03
Forced outage []	0.03	0.03	0.03	0.02	0.1	0.02	0.1
Planned outage [weeks per year]	0.16	0.16	0.16	0.05	0.26	0.05	0.26
Technical lifetime [years]	20	20	20				
Construction time [years]	1	1	1	0.5	1.5	0.5	1.5
Space requirement [1000 m2/MW_e]	0.8	0.8	0.8				
Regulation ability							
Primary regulation (of full load, per 30 seconds) []	-	-	-	-	-	-	-
Secondary regulation (of full load, per minute) []	-	-	-	-	-	-	-
Financial data							
Nominal investment (*total) [MEUR/MW_e]	4.04	3.84	3.65	3.19	6.38	3.19	6.38
Nominal investment (equipment) [MEUR/MW_e]	0.96	0.96	0.96	0.90	1.01	0.90	1.01
Nominal investment (installation) [MEUR/MW_e]	0.11	0.11	0.11	0.16	0.05	0.16	0.05
Variable O&M (*total) [EUR/MWh_e]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fixed O&M (*total) [EUR/MW_e/y]	101020	95704	90387	0.00	0.00	0.00	0.00
Technology-specific data							
Fixed O&M (*total) [EUR/unit/y]	540	540	540	350	700	350	700
Hub height [m]	18	18	18	14	18	14	18
Rotor diameter [m]	11	12	14	4	14	4	14
Average annual full-load hours [MWh_e/MW_e]	1800	2000	2200	1000	2300	1000	2300

3.3 Wind Nearshore

Nearshore wind turbine projects are defined as wind turbines located close to the coastline and are not equipped with an offshore substation. Cables from Nearshore projects are directly connected to onshore substations and therefore nearshore projects tend to be less expensive. Due to possible environmental or social impact, Nearshore projects could have limitations regarding the turbine size, which for those projects is not assumed to increase as much as for offshore projects in this context. Capacities of nearshore wind turbines will not be as high as capacities of offshore wind turbines. However, due to the simplified grid arrangement with no offshore substation as well as shallow waters and shorter distances to service hubs, nearshore wind farms have lower cost levels for both investment and O&M.

For nearshore wind farms, smaller projects are assumed with 20 WTGs and a WTG size that does not exceed 15 MW. The reason for this is that visual impact is assumed to be too problematic with very large WTGs. This assumption requires that smaller turbines will still be available while the offshore market is expected to announce even bigger turbines going forward. Historically, there has not been a distinction between available "offshore" and "nearshore" turbines, but there has only been once certain generations of turbines (with a given size) available on the market.

The mean wind speed is set to 9 m/s 100m a.s.l. for nearshore projects, for which offshore substations are not considered as part of the project development. Water depth is for all years set to 15 m and distance to shore to 10 km. The wake losses are here assumed fixed at 2.5 pct, as nearshore projects are expected typically just to be established in a single-row layout with fewer losses than what can be expected in a generic square layout. The distance is considered to be at 4 RD (Rotor Diameters).

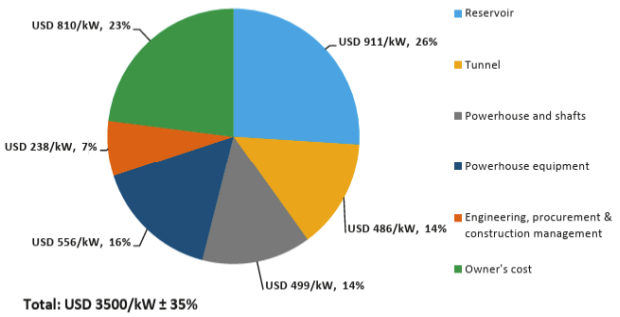
3.3.1 Technical- and economic assumptions

Table 3-5: Technical- and economic assumptions for nearshore wind turbines [28]

Technology	Nearshore Turbines								
year	2020	2025	2030	2040	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	ctrl	ctrl	lower	upper	lower	upper
Energy/technical data									
Generating capacity for one unit [MW_e]	8.4	10	15	15	15	8.5	11.5	11.25	18.75
Forced outage []	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Planned outage [weeks per year]	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Technical lifetime [years]	27	30	30	30	30	25	35	25	35
Construction time [years]	2.5	2.5	2.5	2.5	2	2	3	1.5	2.5
Space requirement [1000 m2/MW_e]	32.0	35.2	35.8	35.8	35.8	29.9	40.5	26.9	44.8
Regulation ability									
Primary regulation (of full load, per 30 seconds) []									
Secondary regulation (of full load, per minute) []									
Minimum load (of full load) []									
Warm start-up time [hours]									
Cold start-up time [hours]									
Financial data									
Nominal investment (*total) [MEUR/MW_e]	1.70	1.49	1.38	1.24	1.19	1.49	1.49	1.19	1.19
Nominal investment (installation) [MEUR/MW_e]	0.39	0.31	0.25	0.23	0.22	0.31	0.31	0.22	0.22
Nominal investment (project development etc.) [MEUR/MW_e]	0.39	0.33	0.29	0.26	0.25	0.28	1.31	0.18	0.98
Nominal investment (array cables) [MEUR/MW_e]	0.01	0.01	0.01	0.01	0.01	0.01	0.05	0.01	0.04
Nominal investment (foundation) [MEUR/MW_e]	0.13	0.13	0.12	0.11	0.11	0.11	0.51	0.08	0.42
Nominal investment (grid connection) [MEUR/MW_e]	0.05	0.05	0.05	0.05	0.05	0.04	0.20	0.04	0.19
Nominal investment (turbines) [MEUR/MW_e]	0.72	0.66	0.65	0.58	0.56	0.56	2.63	0.42	2.24
Variable O&M (*total) [EUR/MWh_e]	5.0	4.2	3.9	3.4	3.3	3.6	16.7	2.4	13.0
Fixed O&M (*total) [EUR/MW_e/y]	50000	42000	39000	34000	33000	35700	48300	24750	49500
Technology-specific data									
Hub height [m]	104	116	138	138	138	98	133	104	207
Rotor diameter [m]	167	191	236	236	236	162	220	177	354
Specific power [W_e/m2]	383	349	343	343	343	411	303	457	191
Specific area coverage [MW_e/km2]	31.2	28.4	27.9	27.9	27.9	33.4	24.7	37.2	22.3
Average annual full-load hours [MWh_e/MW_e]	4100	4325	4450	4450	4450	3675	4975	3250	6500

3.4 Hydropower

Hydropower converts the gravitational potential energy of stored or flowing water into electricity. Water is routed through turbines that drive electrical generators; the resource can be run-of-river (no large storage), reservoir-based (dams and reservoirs that store water), or pumped-storage (two reservoirs at different elevations used to store and release energy). Hydropower is dispatchable (can be scheduled to follow demand), provides grid services (inertia, frequency control, reserves) and — when well sited and managed — is a long-lived, low-carbon source of electricity. The CAPEX costs components for hydropower can be grouped into two main components civil works (project development and infrastructure development costs like dam, reservoir, tunneling, canal, powerhouse, site access stc. construction) and costs related to electro-mechanical equipment. It can in some cases be possible to upgrade an existing hydropower plant, either by adding aditional generators or by expanding the water volume. Implementing a new hydropower facility comes with high up-fron CAPEX costs, but will have very low variable costs (OPEX) and a long lifetime.
CPEX costs for hydropower in Greenland could potentially be above the typical European averages per. kW, as projects in Greenland face remoteness, harsh Artic construction conditions, long access roads/ports, long transmission distances to load centers, and compex environmental and permitting processes.



Cost breakdown of a 500 MW hydropower project in the United States. [38]

Country	Technology	Net capacity (MWe)	Capacity factor (%)	Overnight costs (USD/kWe)	Investment costs (USD/kWe)		
					3%	7%	10%
Austria	Run of river (< 5 MW)	2.2	51%	2 361	2 544	2 809	3 023
Germany	Run of river (>= 5 MW)	24.5	65%	3 000	3 233	3 569	3 842
Italy	Run of river (< 5 MW)	0.02	55%	6 510	7 015	7 745	8 336
	Run of river (< 5 MW)	0.1	34%	3 013	3 247	3 585	3 859
	Run of river (< 5 MW)	0.2	55%	5 503	5 930	6 547	7 047
	Run of river (< 5 MW)	0.25	15%	3 647	3 930	4 339	4 670
	Run of river (< 5 MW)	0.25	8%	3 266	3 520	3 886	4 183
	Run of river (< 5 MW)	0.25	19%	1 592	1 715	1 894	2 039
	Run of river (< 5 MW)	0.5	20%	1 070	1 153	1 273	1 370
	Run of river (< 5 MW)	0.50	15%	3 782	4 075	4 499	4 843
	Run of river (< 5 MW)	0.50	22%	2 398	2 584	2 853	3 071
	Run of river (< 5 MW)	0.7	55%	4 411	4 753	5 248	5 649
	Run of river (< 5 MW)	1	15%	956	1 030	1 137	1 224
	Run of river (< 5 MW)	2.1	50%	3 216	3 466	3 826	4 119
	Run of river (>= 5 MW)	5	37%	3 052	3 289	3 631	3 908
	Reservoir (< 5 MW)	0.32	65%	3 966	4 274	4 719	5 079
	Reservoir (>= 5 MW)	15	38%	3 108	3 349	3 697	3 980
Japan	Reservoir (>= 5 MW)	12	45%	5 819	6 271	6 923	7 452
Norway	Reservoir (>= 5 MW)	30	52%	1 899	2 047	2 260	2 432
	Run of river (< 5 MW)	3.0	47%	1 964	2 117	2 337	2 515
United States	Run of river (< 5 MW)*	4.8	62%	6 383	6 879	7 594	8 175
	Run of river (>= 5 MW)*	82	64%	5 810	6 261	6 912	7 441
	Run of river (< 5 MW)*	4.2	60%	4 275	4 607	5 086	5 475
	Run of river (>= 5 MW)*,**	45	60%	4 031	4 344	4 795	5 162
	Run of river (< 5 MW)	3.7	66%	7 484	8 065	8 904	9 585
	Run of river (>= 5 MW)	44	66%	6 681	7 200	7 949	8 556
	Run of river (< 5 MW)	4.3	62%	6 544	7 052	7 786	8 380
	Run of river (>= 5 MW)**	94	66%	5 891	6 349	7 009	7 544
Non-OECD countries							
Brazil	Run of river (>= 5 MW)	248	50%	2 326	2 507	2 768	2 979
India	Reservoir (>= 5 MW)	175	60%	2 449	2 639	2 914	3 136

* These are projects for powering non-powered dams (NPD). They are thus brownfield projects, for which part of the investment costs have already been amortised.
** Indicated as reference datasets by the providing country.

Hydropower overnight and investment costs. [37]

3.5 Tidal Energy

Wave and tidal energy harness the kinetic energy from ocean waves and tidal movements to generate electricity. Wave energy converters fall into three main categories: point absorbers, terminators, and attenuators, each utilizing different mechanisms to capture wave energy. Despite various designs being tested, no commercially dominant technology exists. The energy content in waves varies geographically.

Today tidal energy is considered an emerging renewable technology, though it has shown considerable promise in recent years. Tidal power generation leverages the natural power of the tides, either their rise and fall (driven primarily by the gravitational pull of the moon and the sun) or the horizonal velocity of its currents, to generate electricity. While the technology is not as widely deployed as solar, wind, or hydro, it is gradually gaining momentum, especially in regions with strong tidal activity like the UK, Canada, and South Korea. Tidal energy has shown to be reliable, mainly due to the predictability of tides and the fact that it is not influenced by weather conditions, but the challenge has been scaling up while reducing costs and overcoming environmental and logistical hurdles.

Currently, only a few tidal power stations are operational in several countries, with some of the largest located in South Korea, France, and the UK. The Sihwa Lake Tidal Power Station in South Korea is the largest, with a capacity of 254 MW.

Tidal energy can be particularly interesting around narrow bodies of water like the fjords in Greenland and has also shown to be effective in areas with a large difference between high-tide and low-tide. Tidal energy is harnessed through tidal turbines, that can either be fixed to the seabed or be floating with moorings attached to the seafloor. The tidal energy potential in Fjords of Greenland could be a suitable technology for decarbonizing remote mines in Greenland since the mines tend to be located close to fjords

One of the key factors for the turbines that use the velocity of the tidal currents is current velocity. In Greenland, currents around the coastal areas are shaped by the interaction of the ocean and fjord systems, significantly varying depending on the region, with stronger tidal currents typically found in the south and eastern coasts due to the interaction between the Greenland Current and local topography.

3.6 Regenerative Braking

Regenerative braking is a technology used to recover energy that is typically lost as heat during braking. This energy recovery process converts kinetic energy back into stored energy, which can be reused to power the vehicle or transport mechanism. This technology is particularly advantageous in vehicles operating in environments with frequent stops and starts, such as mining dump trucks and underground mine cars or transport mechanisms as conveyers.

In a regenerative braking system, when the driver applies the brakes, the electric motor running the vehicle operates in reverse, acting as a generator. This process slows down the vehicle and converts its kinetic energy into electrical energy. The generated electricity is then stored in the vehicle's battery or a capacitor for future use. This mechanism not only improves energy efficiency but also extends the vehicle's range and reduces wear on mechanical braking components.

Hybrid mining trucks, which combine conventional internal combustion engines with electric motors, significantly benefit from regenerative braking. These trucks often encounter long downhill slopes and frequent starts and stops, making them ideal candidates for this technology. Studies have shown that the regenerative braking system in hybrid mining trucks can recover up to 65.01% of the braking energy [35]. The system's effectiveness is influenced by various factors, including the initial charging current, battery state of charge, and the distribution of braking force. Effective control strategies are crucial for maximizing the energy recovery rate and ensuring safety. This improvements not only enhance the endurance of the mine cars but also contribute to better energy utilization and reduced carbon emissions.

The adoption of regenerative braking technology in mining vehicles presents several benefits. It leads to reduced fuel consumption, lower emissions, and decreased maintenance costs due to less wear on mechanical brakes [36]. As the technology advances, further improvements in energy recovery rates and system integration are expected, making regenerative braking a standard feature in mining and other heavy-duty vehicles.

3.6.1 Technical and economic assumptions

Table 3-7: Technical- and economic assumptions for regenerative braking [35][36]

Category	Parameter	Value		
Energy/Technical Data	Energy recovery rate	[p to 65.01%		
Energy/Technical Data	Braking force distribution	heel parallel drive		
Energy/Technical Data	Motor type	tarter Generator (ISG)		
Energy/Technical Data	Battery type	m iron phosphate		
Energy/Technical Data	Charging current	ptimal at 50A		
Energy/Technical Data	Maximum regenerative braking force	.93% (motor)		

Energy/Technical Data	Energy recovery improvement (compared to similar studies)	gher (curve I strategy)			
Energy/Technical Data	SOC (State of Charge) improvement with optimal control strategy	5.27% (less battery impact)			
Financial Data	Investment cost for regenerative braking system				
Financial Data	Maintenance cost reduction	(reduced brake wear)			
Economic Impact	CO2 emissions reduction	ntified, but implied			
Economic Impact	Endurance improvement for underground mine cars	~20%			
Economic Impact	Reduction in system energy consumption	ot quantified			
Performance Data	Recovery rate under broken line control strategy	65.01%			
Performance Data	Comparison with other recovery rates	ior performance			

3.7 Power-to-X

Power-to-X (PtX) technology represents an innovative approach to harnessing renewable energy for the production of various forms of sustainable fuels, chemicals, and other materials. The "X" in PtX stands for the diverse end products that can be derived from this technology, including hydrogen (H2), synthetic natural gas (SNG), ammonia, methanol, and other carbon-based compounds.

The core principle of PtX involves converting excess renewable electricity, primarily from sources like wind, solar, and hydropower, into chemical energy carriers through processes like electrolysis and subsequent synthesis.

PtX technologies have gained significant traction the last few years. They are particularly pivotal in sectors where direct electrification is challenging, such as heavy industry, aviation, and maritime transport. The ability of PtX to store and transport renewable energy in the form of hydrogen or synthetic fuels provides a viable solution to the intermittency of renewable sources and supports the stabilization of power grids.

In the context of Greenland and the Arctic, PtX technology presents both unique opportunities and challenges. Greenland's vast renewable energy potential, particularly from hydropower and wind, positions it as a prime candidate for PtX deployment. The ability to convert surplus renewable electricity into exportable forms of energy could significantly bolster Greenland's economy and energy security, and could be a great source of fuel for the mining industry.

However, Arctic conditions pose specific challenges that need to be carefully considered. The production of any e-fuels should be possible as long as winterization measures take place, these measures are already used in many other places of the world where temperatures go below 0°C in the winter motnhs (such as Denmark), however they add an extra cost to the manufacturing process of PtX. Infrastructure development in remote and rugged terrains adds another layer of complexity. Additionally, the environmental sensitivity of the Arctic region necessitates rigorous safeguards to minimize ecological impact.

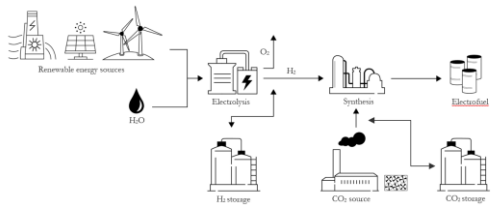


Figure 1: Simplified flow diagram of electrofuel production

3.7.1 Hydrogen

Water electrolysis is a mature technology that offers a promising route for producing zero-carbon hydrogen. In this process, electricity is used to split water into hydrogen and oxygen. The hydrogen produced can be used directly in fuel cell vehicles, injected into the gas grid, or converted into a wide range of electrofuels when combined with a suitable carbon source. . Various water electrolysis technologies exist, categorized by their operating temperature into low and high-temperature electrolysers:

Alkaline Electrolysis
Alkaline electrolysis uses an aqueous alkaline solution as the electrolyte, typically consisting of potassium hydroxide (KOH) or sodium hydroxide (NaOH), with hydroxide ions (OH-) serving as the charge carriers. Operating at temperatures between 60-80°C and under atmospheric or pressurized conditions, alkaline electrolysers produce hydrogen, oxygen, and excess heat, which can be utilized for district heating. Pressurized operation reduces the energy required for hydrogen compression but decreases efficiency and purity compared to atmospheric conditions. Advantages of AEC include low capital costs, the ability to build large plants, and long lifespans of about 30 years. However, they have limitations such as low energy efficiency, use of corrosive electrolytes, and long start-up times, making them less flexible for intermittent renewable energy sources. Continuous energy supply is recommended due to these drawbacks.

Polymer Electrolyte Membrane (PEM) Electrolysis
PEM electrolysers differ from AEC by using a solid polymer membrane, typically Nafion, as the electrolyte with protons (H+) as the charge carriers. Operating at temperatures of 50-80°C and capable of higher pressure operations (up to 80 bar), PEM electrolysers offer efficiency between 40-69%. Despite higher costs due to the use of expensive materials, costs are expected to decline in the near future.

PEM electrolysers provide benefits such as fast cold-start times, high operational flexibility, and high purity hydrogen (99.99%). However, their high costs and relatively short lifespans are notable disadvantages.

Solid Oxide Electrolysis Cell (SOEC)
SOECs operate at high temperatures (600-1000°C), using oxygen ions (O2-) as charge carriers. SOECs achieve high conversion efficiencies, with potential for even greater efficiencies due to the use of heat in the energy supply. SOECs are suitable where high-temperature heat sources are available and can integrate heat for subsequent synthesis processes, enhancing overall efficiency. Although SOECs offer advantages like reversible operation modes and high efficiency, challenges include material degradation and limited long-term stability due to high operating temperatures. The need for constant temperature control to avoid thermal stress-induced fractures is crucial for stable operation.

Technical- and economic assumptions

Table 3-8: Summary of advantages and disadvantages of electrolysis technologies [28]

Technology	Advantages	Disadvantages
AEC	1. The technology is very mature and scalable. 2. AEC has a low operating temperature, with a quick start up (pressurized) for response in grid services making it suitable for use as a flexible technology. 3. Long stack lifetime of more than 70,000h (2020) currently. 4. MW scale electrolyser systems are already being deployed.	1. Less flexibility under atmospheric operation. 2. The use of highly caustic electrolyte in AEC. 3. Leakage of KOH. 4. High membrane resistance. 5. Low maximum operational current density, nominally operated around 0.6-1 A/cmÂ² as average [17].
PEMEC	1. PEMEC has a low operating temperature, low noise, high power density. 2. Quick response time. 3. Pressurized hydrogen can be produced for direct storage without compression; however, it is challenging. 4. Current densities >2.0 A/cmÂ² can be used for operational systems leading to compact system sizes. 5. MW scale electrolyser systems are already being deployed. 6. Smaller footprint than AEC.	1. Very sensitive to impurities, with a prerequisite of very pure water (Type I) as input. 2. Lifetime of the commercially available systems is still uncertain 3. Catalyst used in electrode layers are expensive and scarce. 4. PEMEC constituents are expensive due to catalysts and bipolar plates (oxide resistant stack elements). 5. Cost efficient water treatment and drying the hydrogen at high pressure is still challenges to be addressed.
SOEC	1. SOEC has high efficiency (up to 95 %), high production rates. 2. SOECs can be used to make synthesis gas from co-electrolysis of steam and CO2. 3. CO-electrolysis plants have been commercialized. 4. SOECs can cope with transient variation due to quick response time. 5. SOECs can be used reverse mode as a fuel cell for grid balancing.	1. SOECs are still in demonstration phase for large scale applications for hydrogen production and are not readily commercially available. 2. SOECâ€™s units are about 10 times smaller in H2 output than PEMEC and AEC. 3. The stack components are susceptible to corrosion 4. Commercially available lifetime system is short compared to PEMEC and even shorter to AEC. 5. SOECs can be operated only at current densities up to 0.5 A/cmÂ².

Table 3-9: Technical- and economic assumptions for alkaline eletrolysis systems (2025) [28]

Technology	Alkaline electrolysis -	Alkaline electrolysis -	Alkaline electrolysis - 1GW
Energy/technical data			
Typical total plant size [MW input_e]	10.00	100.00	1000.00
Typical total plant size [kgH2 / day of max output]	4666	46656	466563

Input			
Electricity (% total input [MWh / MWh])	100.00	100.00	100.00
Electricity consumption [stack level, KWh/kgH_2]	51.44	51.44	51.44
Electricity consumption [stack+BOP level, KWh/kgH_2]	56.69	56.69	56.69
Ultrapure Water for electrolysis [kg / MWh input_e]	174.96	174.96	174.96
Output			
Hydrogen Output (% total input_e [MWh / MWh])	58.7	58.7	58.7
ΔE from HHV to LHV (% total input_e [MWh / MWh])	11.9	11.9	11.9
Heat loss (% total input_e [MWh / MWh])	29.4	29.4	29.4
- here of unrecoverable heat loss [%-points of heat loss]	3	3	3
- here of recoverable for district heating [%-points of heat loss]	26.4	26.4	26.4
Hydrogen [kg / MWh input_e]	19.4	19.4	19.4
Forced outage [%]	3	3	3
Planned outage [days per year]	11	11	11
Technical lifetime of plant [years]	25	25	25
Frequency of stack replacement [h]	80000	80000	80000
Construction time [years]	1	2	3
Financial data (2020 price level)			
Specific investment [€ / kW of total input_e]	1400	875	800
- hereof electrolyser stack [€ / kW of total input_e]	186.8	183.7	190.6
- hereof electrolyser system [€ / kW of total input_e]	490.1	393.7	409.2
- hereof BOP [€ / kW of total input_e]	320.5	115.6	102.6
- hereof Control System [€ / kW of total input_e]	122.2	56.3	39.7
- hereof Civil Infrastructure [€ / kW of total input_e]	66.8	28.5	23.4
- hereof Indirects [€ / kW of total input_e]	213.6	97.2	34.4
Specific investment [€ / kgH2 / day of max output]	3000.7	1875.4	1714.7
- hereof equipment [%]	95	90	90
- hereof installation [%]	5	10	10
Fixed O&M [% of specific investment / year]	4	4	4
Variable O&M [€ / kWh of total input]	-	-	-
Technology-specific data			
Current Density [A / cm2]	1	1	1
Flexibility			0
- cold start up time [min from 0 to 100%]	60.4	60.4	60.4
Stack size [MW]	5.00	5.00	5.00
Degradation rate [% / 1000 h]	0.13	0.13	0.13
Electrolyser Unit [m2/MW]	21.3	21.3	21.3
Plant Footprint [m2 / MW input_e]	240.9	183.8	168.5
Weight of Electrolyser Stack [MW/tons]	18	18	18

Table 3-10: Technical- and economic assumptions for PEMEC eletrolysis systems (2025) [28]

Technology	PEMEC electrolysis - 10MW	PEMEC electrolysis - 100MW	PEMEC electrolysis - 1GW
Energy/technical data			
Typical total plant size [MW input_e]	10	100	1000
Typical total plant size [kgH2 / day of max output]	4457	44566	445662
Input			
Electricity (% total input [MWh / MWh])	100	100	100
Electricity consumption [stack level, KWh/kgH_2]	53.9	53.9	53.9
Electricity consumption [stack+BOP level, KWh/kgH_2]	60.5	60.5	60.5
Ultrapure Water for electrolysis [kg / MWh input_e]	167.1	167.1	167.1
Output			
Hydrogen Output (% total input_e [MWh / MWh])	55	55	55
ΔE from HHV to LHV (% total input_e [MWh / MWh])	11.3	11.3	11.3
Heat loss (% total input_e [MWh / MWh])	33.7	33.7	33.7

- here of unrecoverable heat loss [%-points of heat loss]	3	3	3
- here of recoverable for district heating [%-points of heat loss]	30.7	30.7	30.7
Hydrogen [kg / MWh input_e]	18.6	18.6	18.6
Forced outage [%]	3	3	3
Planned outage [days per year]	11	11	11
Technical lifetime of plant [years]	25	25	25
Frequency of stack replacement [h]	65500	65500	65500
Construction time [years]	1	2	3
Financial data (2020 price level)			
Specific investment [€ / kW of total input_e]	1425	975	900
- hereof electrolyser stack [€ / kW of total input_e]	337.8	333.2	335.2
- hereof electrolyser system [€ / kW of total input_e]	491.4	399.0	400.9
- hereof BOP [€ / kW of total input_e]	203.9	58.3	59.5
- hereof Control System [€ / kW of total input_e]	120.7	53.5	38.0
- hereof Civil Infrastructure [€ / kW of total input_e]	53.8	22.6	27.7
- hereof Indirects [€ / kW of total input_e]	217.4	108.3	38.8
Specific investment [€ / kgH2 / day of max output]	3197.5	2187.8	2019.5
- hereof equipment [%]	95	90	90
- hereof installation [%]	5	10	10
Fixed O&M [% of specific investment / year]	2	2	2
Variable O&M [€ / kWh of total input]	-	-	-
Technology-specific data			
Current Density [A / cm2]	2.8	2.8	2.8
Flexibility			
- cold start up time [min from 0 to 100%]	0.3	0.3	0.3
Stack size [MW]	1.5	1.5	1.5
Degradation rate [% / 1000 h]	0.2	0.2	0.2
Electrolyser Unit [m2/MW]	8.5	8.5	8.5
Plant Footprint [m2 / MW input_e]	171.9	76.6	69.8
Weight of Electrolyser Stack [MW/tons]	14.1	14.1	14.1

Table 3-11: Technical- and economic assumptions for SOEC eletrolysis systems (2025) [28]

Technology	SOEC electrolysis - 1MW	SOEC electrolysis - 10MW	SOEC electrolysis - 100MW
Energy/technical data			
Typical total plant size [MW input]	1	10	100
Typical total plant size [kgH2 / day of max output]	608.6	6085.6	60855.8
Input			
Electricity (% total input [MWh / MWh])	79.5	79.5	79.5
Electricity consumption [stack level, KWh/kgH2]	39.4	39.4	39.4
Electricity consumption [stack+BOP level, KWh/kgH2]	43.4	43.4	43.4
Heat (% total input [MWh / MWh])	20.5	20.5	20.5
Ultrapure Water for electrolysis [kg / MWh input]	228.2	228.2	228.2
Output			
Hydrogen Output (% total input [MWh / MWh])	67.4	67.4	67.4
ΔE from HHV to LHV (% total input [MWh / MWh])	15.5	15.5	15.5
Heat loss (% total input [MWh / MWh])	17.1	17.1	17.1
Hydrogen [kg / MWh input]	25.4	25.4	25.4
Forced outage [%]	3	3	3
Planned outage [days per year]	11	11	11
Technical lifetime [years]	25	25	25
Frequency of stack replacement [h]	34500	34500	34500
Construction time [months]	1	1	2
Financial data (2020 price level)			
Specific investment [€ / kW of total input]	2875	2075	1300
- hereof electrolyser stack [€ / kW of total input_e]	891.3	882.3	884.0
- hereof electrolyser system [€ / kW of total input_e]	833.8	483.9	143.0
- hereof BOP [€ / kW of total input_e]	373.8	202.1	91.0
- hereof Control System [€ / kW of total input_e]	172.5	126.8	25.1
- hereof Civil Infrastructure [€ / kW of total input_e]	86.3	63.4	12.5
- hereof Indirects [€ / kW of total input_e]	517.5	316.5	144.4
Specific investment [€ / kgH2 / day of max output]	4724.3	3409.7	2136.2

- hereof equipment [%]	95	95	90
- hereof installation [%]	5	5	10
Fixed O&M [% of specific investment / year]	12	12	12
Variable O&M [€ / kWh of total input]	-	-	-
Technology-specific data			
Current Density [A / cm2]	0.85	0.85	0.85
Flexibility			
- cold start up time [min from 0 to 100%]	550	550	550
Stack size [kW]	50	50	50
Degradation rate [% / 1000 h]	0.4	0.4	0.4
Electrolyser Unit [m2/MW]	25.5	25.5	25.5
Plant Footprint [m2 / MW input_e]	481.7	240.9	183.8
Weight of Electrolyser Stack [MW/tons]	2.4	2.4	2.4

3.7.2 Hydrogen pipeline distribution

E-fuel pipelines and transport technologies encompass the movement of synthetic fuels such as Hydrogen (H2), Ammonia (NH_3), Dimethyl Ether (DME), and Liquid Organic Hydrogen Carrier (LOHC) through pipelines, trucks, and ships. Transporting these fuels involves complex considerations, including the energy density of the fuels, the material of construction required to handle different chemical properties, and safety measures. Pipelines are preferred for large quantities and stable routes due to low operational costs, despite their high initial investment. Trucks and ships, though more flexible and suitable for varying distances, come with higher operational risks and costs.

For the larger distances in Greenland and the challenging terrain between the settelments and mining sites pipelines will not be feasible for transporting e-fuels. Additionally, the absence of a road network rules out the use of trucks for fuel transport. However, the use of ships could be a viable option, given Greenland's extensive coastline and reliance on maritime transport for connecting its remote communities. Ships can efficiently transport e-fuels between coastal areas, making them a more feasible solution for Greenland's unique logistical challenges.

Technical- and economic assumptions

Table 3-19: Technical- and economic assumptions for E-Fuel Shipping distribution (2030) [28]

Technology	Main distribution line - DME
Energy/technical data	
LH2: Energy demand [MJ/km]	2025
L20: Energy demand [MJ/km]	2205
LHC: Energy demand [MJ/km]	2205
Technical life time [years]	20
Financial Data	
LH2 Investment cost [EUR/tonH2]	14887.2
L20: Investment cost [EUR/tonL20]	1978.8
LHC: Investment cost [EUR/tonLHC]	780.2
LH2: Fixed O&M cost [EUR/tonH2/y]	74.4
L20:Fixed O&M cost [EUR/tonL20/y]	9.6
LHC: Fixed O&M cost [EUR/tonLHC/y]	4.3
LH2: Port cost [EUR/tonH2]	6.4
L20: Port cost [EUR/tonH2]	1.8
LHC: Port cost [EUR/tonLHC]	1.5

3.8 Carbon Capture

Carbon capture and storage (CCS) and carbon capture utilization (CCU) are essential technologies in the fight against climate change. CCS involves capturing carbon dioxide (CO2) emissions from industrial sources, transporting them, and storing them underground in geological formations. CCU, on the other hand, involves using captured CO2 as a raw material to produce chemicals, synthetic fuels, and building materials. Ideally, producing electrofuels can be carbon neutral if the CO2 is sourced from direct air capture (DAC), biomass, or end-of-life treatment of CO2-based products. Biomass is particularly advantageous as the CO2 absorbed during its growth is equivalent to the CO2 emitted during its combustion.

3.8.1 Technical- and economic assumptions

Table 3-12: Technical- and economic assumptions for Post-Combustion Carbon Capture systems (2025) [28]

Technology	Post-combustion CC retrofit - 100 MW(th) WtE or biomass CHP	Post-combustion carbon capture retrofit - 500 MW(th) biomass-	Post-combustion carbon capture - Retrofit 4500 ton clinker per day
Energy/technical data			

Typical total plant capacity [tCO2/hour] (CO2 output)	32	164	152
- Inputs at max capacity			
A] Mass of Fluegas [t/tCO2] (CO2 output)	5.1	5.1	5.1
B1] CO2 share in fluegas input [%-vol, dry]	15.0	17.0	20.0
B2] Flue gas temperature [°C]	35.0	35.0	125.0
C1] Heat input [MWh/tCO2] (CO2 output)	0.8	0.8	0.8
C2] Eletricity input [MWh/tCO2] (CO2 output)	0.0	0.0	0.0
C3] Amine make-up [kg/tCO2] (CO2 output)	0.3	0.3	0.3
Y] Auxiliary products inputs [kg/tCO2] (CO2 output)			
- Outputs at max capacity			
A1] CO2 purity prior to post cleaning [% vol]	97	97	97
A2] Total pressure of CO2 gas [kPa(a)]	160	160	160
A3] CO2 capture rate, net [%]	90	90	90
C1] Heat out [MWh/tCO2] (CO2 output)	0.8	0.8	1.7
C2] Temperature of heat out [°C]	60	60	60
X] Other Non-energy outputs [kg/tCO2] (CO2 output)			1.0
- other technical data			
Forced outage [%]	5	5	5
Planned outage [weeks per year]	3	3	3
Technical lifetime [years]	25	25	25
Construction time [years]	2.5	3.0	3.0
Finacial Data			
Specific investment [mill €/[tCO2/hour]] (CO2 output)	5.9	2.9	3.0
Fixed O&M [mill €/[tCO2/hour]] (CO2 output)	0.2	0.1	0.1
Variable O&M [€/tCO2] (CO2 output)	2.5	2.5	2.5
Startup cost [€/startup/(tCO2/hour)] (CO2 output)	25	25	25
Technology Specific Data			
CO_2 liquefaction - Electricity input [MWh/tCO2] (CO2 output)	0.2	0.2	0.2
CO_2 liquefaction - Heat out [MWh/tCO2] (CO2 output)	0.3	0.3	0.3

Table 3-13: Technical- and economic assumptions for Oxy-Fuel Carbon Capture systems (2025) [28]

Technology	Oxy-fuel carbon capture - Retrofit 500 MW biomass boiler excluding
Energy/technical data	
Typical total plant capacity [tCO2/hour] (CO2 output)	175
- Inputs at max capacity	
A] Mass of Fluegas [t,/t CO2] (CO2 output)	1.9
B1] CO2 share in fluegas input [% vol]	0.3
B2] H2O share in fluegas Input [% vol]	0.6
C1] Heat input [MWh/t CO2] (CO2 output)	0
C2] Eletricity input [MWh/t CO2] (CO2 output)	0
D] mass of O_2 input [tO2/tCO2] (CO2 output)	0.9
- Outputs at max capacity	
A2] CO2 purity prior to post cleaning [% vol]	0.8
A3] Total pressure of CO2 gas [kPa(a)]	100
Ax] CO2 capture rate, net [%]	1.0
B1] Mass of H2O [t/t CO2] (CO2 output)	0.8
C1] Heat out [MW/tCO2/hour] (CO2 output)	0.5
C2] Temperature of heat out [C]	30
- other technical data	
Forced outage [%]	0.1
Planned outage [weeks/year]	3
Technical lifetime [years]	25
Finacial Data	
Specific investment [mill € /(tCO2/hour)] (CO2 output)	1.45
- hereof equipment [%]	
- hereof installation [%]	
Fixed O&M [mill € /(tCO2/hour)] (CO2 output)	0.04

Variable O&M [€/tCO2] (CO2 output)	2
Startup cost [€/startup/(tCO2/hour)] (CO2 output)	100
Technology Specific Data	
Specific investment optional O_2 plant (ASU) [mill € /(tCO2/hour] (CO2 output)	0.8
Electricity input for optional O_2 plant (ASU) [MW/tCO2/h]	0.2
Electricity input CO_2 post treatment (CPU) [MWh/tCO2] (CO2 output)	0.2
Heat output CO_2 post treatment [MWh/tCO2] (CO2 output)	0.3

Table 3-14: Technical- and economic assumptions for DAC Carbon Capture systems (2025) [28]

Technology	Liquid Absorption DAC plant	Solid
Energy/technical data		
Typical total plant capacity [tCO2/hour] (CO2 output)	125.0	4.5
- Inputs at max capacity		
A] Air flow rate [t/tCO2] (CO2 output)	2200	1800
Makeup water for water loss [tH2O/tCO2] (CO2 output)	8.2	
C1] Heat input [MWh/tCO2] (CO2 output)		1.5
Temperature heat input [C]	900	100
C2] Eletricity input [MWh/tCO2] (CO2 output)	1.5	0.3
Y] Auxiliary products inputs [kg/tCO2] (CO2 output)		
- Outputs at max capacity		
A2] CO2 purity prior to post cleaning [% vol]	98	99
A3] Total pressure of CO2 gas [kPa(a)] (CO2 output)	15	15
B1] Mass of H2O [t/tCO2] (CO2 output)		1
C1] Heat out prior water knockout [MWh/tCO2] (CO2 output)	0	1.3
C2] Temperature of heat out prior water knockout [C]	315	50
- other technical data		
Forced outage [%]	5	5
Planned outage [weeks/year]	3	3
Technical lifetime [years]	25	25
Construction time [years]	2	2
Finacial Data		
Specific investment [mill €/(tCO2/hour)] (CO2 output)	4.3	4.8
Fixed O&M [mill €/(tCO2/hour)]	0.2	0.2
Variable O&M [€/tCO2] (CO2 output)	5	
Startup cost [€/startup/(tCO2/hour)]		
Technology Specific Data		
Land use for DAC unit [km^2/(MtCO2/year] (CO2 output)	0.1	0.1
CO_2 compression and dehydration - Electricity input [MWh/tCO2] (CO2 output)	0.1	0.1
CO_2 compression and dehydration - Heat out [MWh/tCO2] (CO2 output)	0.2	0.2

3.9 Fuel Synthesis - Methanol

The conversion of hydrogen to methanol is a key process in PtX concepts and projects due to methanol's versatility as a chemical building block and its potential as a green fuel. Methanol production from hydrogen and carbon dioxide (CO2) is a sustainable pathway when green hydrogen, produced by electrolysis using renewable energy, and green CO2, sourced from biogenic processes or direct air capture (DAC), are utilized. Methanol is arguably the most advanced e-fuel.

In green methanol production, the syngas is replaced with a mix of green hydrogen and CO2. The direct conversion pathway, such as that used at the George Olah Renewable Methanol Plant in Iceland, involves the catalytic reaction of hydrogen and CO2 at temperatures of 200-300°C and pressures of 50-100 bar. This exothermic process releases significant heat, which can be harnessed for other applications like steam generation for the distillation of methanol.

Green methanol production can also involve pathways such as the reverse water-gas shift (RWGS) reaction to precondition the feedstocks, or co-electrolysis using solid oxide electrolysis cells (SOECs) to produce a syngas mixture. Another pathway involves using biogas, which combines methane and CO2, converting it to methanol with the addition of hydrogen. The inputs for this process are primarily hydrogen and CO2. The hydrogen is typically supplied at 70 bar and the CO2 at 100 bar. The system must maintain these pressure levels to avoid additional compression costs. The outputs include high-purity methanol, purge gases, and by-products. Effective handling and treatment of these outputs are essential for environmental compliance and operational efficiency.

3.9.1 Technical- and economic assumptions

Table 3.15: Technical- and economic assumptions for methanol production from hydrogen and CO2 [28]

Technology	Methanol production from H2 and CO2								
year	2020	2025	2030	2040	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data									
Typical total plant size [TPD]	300	300	600	900	1200				
Typical total plant size [MW-methanol]	69	69	138	207	276				
Input									
CO2 [ton/ton-methanol]	1.4	1.4	1.4	1.4	1.4	100%	110%	100%	110%
Hydrogen [ton/ton-methanol]	0.2	0.2	0.2	0.2	0.2	100%	110%	100%	110%
Hydrogen [MWh/ton-methanol]	6.4	6.4	6.4	6.4	6.4	100%	110%	100%	110%
Electricity [MWh/ton-methanol]	0.1	0.1	0.1	0.1	0.1	80%	120%	80%	120%
Net steam [MWh/ton-methanol]	0.6	0.6	0.6	0.6	0.6	80%	120%	80%	120%
Output									
Methanol [MWh/MWh total input]	0.8	0.8	0.8	0.8	0.8	100%	110%	100%	110%
District heating [MWh/MWh total input]	0.2	0.2	0.2	0.2	0.2	90%	110%	90%	110%
Heat loss [MWh/MWh total input]	0.0	0.0	0.0	0.0	0.0	90%	110%	90%	110%
Water [ton/ton-methanol]	0.6	0.6	0.6	0.6	0.6	100%	110%	100%	110%
Forced outage [%]	5	4	3	3	2				
Planned outage [weeks per year]	3	3	3	3	3				
Technical lifetime [years]	30	30	30	30	30				
Construction time [years]	2	2	2	2	2				
Financial Data									
Specific investment [M€/MW-methanol]	1.3	1.3	1.1	1.0	0.9	50%	150%	50%	150%
- equipment [%]	85	85	85	85	85				
-installation [%]	15	15	15	15	15				
Fixed O&M [k€/[MW-methanol/year]]	39.1	39.1	30.4	30.4	26.1				
Variable O&M [€/MWh-methanol]	0	0	0	0	0				
Start up [M€/MW-methanol]	0	0	0	0	0				
Fixed O&M [EUR/(tCO2/h)/year/km]									
Specific energy content [GJ/ton-methanol]	19.9	19.9	19.9	19.9	19.9				
Specific density [kg/l] or [ton/m3]	0.8	0.8	0.8	0.8	0.8				
Specific investment [M€/TPD]	0.3	0.3	0.3	0.2	0.2	50%	150%	50%	150%
- equipment [%]	85	85	85	85	85				
-installation [%]	15	15	15	15	15				
Fixed O&M [M€/[1,000 TPD/year]]	9	9	7	7	6				
Variable O&M [M€/1,000 ton-methanol]		0	0	0	0	0			
Start up [M€/TPD]		0	0	0	0	0			

3.10 Fuel Synthesis - Ammonia

Ammonia production today primarily uses the Haber-Bosch process, combining nitrogen and hydrogen under high pressure and temperature with a catalyst. While nitrogen is readily available from ambient air, hydrogen is traditionally produced via steam reforming of natural gas, resulting in significant CO2 emissions. Green ammonia aims to mitigate these emissions by using green hydrogen produced through electrolysis powered by renewable energy. This transition is crucial for reducing the carbon footprint of ammonia, which is a critical component in fertilizers and a potential carbon-neutral fuel for maritime transport and other applications.

Green ammonia production involves three main components: hydrogen production via electrolysis, nitrogen production through an air separation unit (ASU), and ammonia synthesis using the Haber-Bosch process. This approach contrasts with conventional ammonia production, which relies on fossil fuels, and blue ammonia, which incorporates carbon capture technologies to reduce emissions.

The traditional Haber-Bosch process synthesizes ammonia by reacting hydrogen and nitrogen under high pressure (150-250 bar) and temperature (350-550°C) in the presence of a catalyst. This exothermic reaction generates significant heat, which can be recovered to produce steam for use within the plant or for power generation.

Inputs for green ammonia production include hydrogen and nitrogen, typically delivered at specific pressures to avoid additional compression costs. The electrolysis unit requires water and significant electrical energy, ideally from renewable sources. Outputs include high-purity ammonia, steam (which can be used internally or exported), and minimal purge gases due to the purity of the feedstocks.

The energy balance in a green ammonia plant is heavily influenced by the electrolysis process, which accounts for the majority of the plant's power consumption. Efficient heat recovery from the exothermic ammonia synthesis can offset some of the energy demands, particularly by generating steam for internal use or district heating.

In Arctic conditions, additional insulation and heating measures may be necessary, but since a part of the process already takes palce at low temperatures, the weather conditions do not pose much of a problem for the production of green ammonia. Compared to Methanol, Ammonia does not need CO2 and therefore is not dependent on a source of CO2, however, it's reaction is more demanding and requires heat to start it. One of the main things to consider is that ammonia production normally takes place at extremely large scales and therefore requires an important economic commintment and a clear need for a big amount of ammonia to be produced. While there are clear concerns about toxicity and corrosiveness, accidents mainly happen due to poor planning and management (human error) not due to the dangerous properties of ammonia.

3.10.1 Technical- and economic assumptions

Table 3-16: Technical- and economic assumptions for Green Ammonia production [28]

Technology	Green Ammonia plant: Hydrogen to ammonia (excl. electrolyzer and excl.							
year	2020	2030	2040	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data								
Typical total plant size, [TPD] (ton per day)	229	458	916	2290	1	1	1	1
Typical total plant size, [MW] (Ammonia output)	50	100	200	500	1	1	1	1
Input								
N2 Consumption, [t/t] Ammonia	0.8	0.8	0.8	0.8	0.98	102%	98%	102%
Hydrogen Consumption, [t/t] Ammonia	0.2	0.2	0.2	0.2	0.98	102%	98%	102%
Hydrogen Consumption, [MWh/MWh Total Input]	0.9	0.9	0.9	0.9	0.98	102%	98%	102%
Electricity Consumption, [MWh/MWh Total Input]	0.1	0.1	0.1	0.1	0.95	110%	75%	150%
Output								
Ammonia Output, [MWh/MWh Total Input]	0.8	0.8	0.8	0.8	0.98	102%	98%	102%
High value heat Output [MWh/MWh Total Input]	0.11	0.11	0.11	0.11	0.98	102%	98%	102%
District Heating Output, [MWh/MWh Total Input]	0.04	0.04	0.04	0.04	0	100%	0%	100%
Forced outage [%], unplanned shutdown	0.05	0.03	0.03	0.02	0.02	8%	2%	4%
Planned outage [weeks per year]	0.03	0.03	0.03	0.03				
Operation capacity	20-100%	20-100%	20-100%	20-100%	0.29	100%	20%	100%
Technical lifetime [years]	30	30	30	30				
Construction time [years]	2	2	2	2				
Financial Data								
Specific investment [M€ /MW Ammonia output]	1.7	1.4	1.1	0.9	1.32	222%	61%	101%
- equipment [%]	50	50	50	50				
-installation [%]	50	50	50	50				
Fixed O&M [k€/MW Ammonia/year]	51	41	34	26	42.1	70.9	19.3	32.2
Variable O&M [€/MWh Ammonia]	0.02	0.02	0.02	0.02	0.01	0.04	0.01	0.04
Start up [M€ /1,000 t Ammonia]	N.A.	N.A.	N.A.	N.A.				
Fixed O&M [EUR/(tCO2/h)/year/km]								
Specific investment mark-up factor optional ASU	1.1	1.1	1.1	1.1	0.97	1	0.97	1
Specific energy content [GJ/ton Ammonia]	19	19	19	19				
Specific density [kg/l] or [ton/m3] Ammonia	626	626	626	626				
Specific investment [M€ /TPD Ammonia output]	0.4	0.3	0.2	0.2	0.3	0.5	0.1	0.2
Fixed O&M [k€ /TPD Ammonia]	11.0	9.0	7.4	5.7	8.1	13.7	3.7	6.2
Variable O&M [€ /t Ammonia]	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2
Start up [M€ /TPD Ammonia]	N.A.	N.A.	N.A.	N.A.				

3.11 Fuel Synthesis - Methane

Methane is a non-toxic, non-corrosive gas that is lighter than air and forms a liquid phase at -161.6°C at atmospheric pressure or at 45.9 bar at room temperature. With a high octane number of around 130, methane is excellent for spark ignition engines. Its limited flammability range makes it safer than both petrol and diesel. Methanation involves converting hydrogen (H2) and carbon dioxide (CO2) or carbon monoxide (CO) into a methane-rich gas mixture, commonly referred to as synthetic natural gas (SNG). This can be injected into the natural gas grid or used as a fuel in various industrial applications. Methane production can be carried out either catalytically or biologically, each with distinct processes and applications.

The catalytic methanation reaction, known as the Sabatier reaction, is highly exothermic and involves the conversion of CO2 and hydrogen into methane and water. This reaction typically occurs over a nickel-based catalyst at temperatures between 250-400°C and pressures of 10-30 bar. Catalytic methanation is efficient, converting over 99.5% of syngas into methane with an efficiency of around 77%. The process is highly exothermic, and the heat generated can be used to improve the efficiency of other processes, such as steam production for solid oxide electrolysis cells (SOEC) or enhancing the efficiency of the CO2 source system. Catalytic methanation has been implemented at a pre-industrial scale, commonly using fixed-bed reactors, although newer reactor types like three-phase methanation and microreactors are under development.

In Arctic conditions, methane synthesis processes must be adapted to handle extreme cold temperatures employing winterization measures. Catalytic methanation, which operates at high temperatures and pressures, requires robust insulation and heating systems to maintain operational efficiency. Biological methanation, with its lower operational temperatures, may face challenges in maintaining the required constant temperature, necessitating additional heating solutions. Utilizing excess heat for district heating can provide significant benefits in these regions, enhancing the overall sustainability and efficiency of methane synthesis operations.

3.11.1 Technical- and economic assumptions

Table 3-17: Technical- and economic assumptions for Methane production [28]

Technology	Moving-bed Methane Decomposition (MBR)							
year	2020	2030	2040	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data								
Typical total plant size [MW input]	N/A	77	85	94	39	116	47	140
Typical total plant size [MW H2 output]	N/A	32	35	39	16	48	20	59
Typical total plant size [kg H2/day output]	N/A	23000	25000	28000	12000	35000	14000	42000
Inputs								
Natural Gas (% total input[MWh/MWh])	N/A	78	80	82	76	80	78	84
Electricity (% total input[MWh/MWh])	N/A	22	20	18	20	24	16	22
Output								
Hydrogen Gas Output (% total input [MWh/MWh])	N/A	41	42	43	37	45	39	47
Carbon Black Output (% total input [MWh/MWh])	N/A	28	29	30	25	31	27	33
Methane Output (% total input [MWh/MWh])	N/A	9	8	7	4.5	13.5	3.5	10.5
Recovered Heat (% total input [MWh/MWh])	N/A	16	15	14	8	24	7	21
Heat loss (% total input [MWh/MWh])	N/A	6	6	6	5	9	3	9
Forced outage [%]	N/A	20	10	1	10	30	0	2
Planned outage [weeks per year]	N/A	10	4	2	10	22	0	0
Technical lifetime [years]	N/A	20	25	25	15	25	20	30
Construction time [years]	N/A	2	2	2	1.5	2.5	1.5	2.5
Financial data								
Specific investment [M€/MW of total H2 output]	N/A	0.6	0.6	0.5	0.3	0.9	0.2	0.7
- hereof equipment [%]	N/A	50	50	50	45	55	45	55
- hereof installation [%]	N/A	50	50	50	45	55	45	55
Fixed O&M [€ / MW of total H2 output]	N/A	12760.5	11697.1	10314.7	6000	18000	4900	15000
Variable O&M [€ / MWh of total H2 output]	N/A	4.3	3.8	3.4	2.1	6.4	1.7	5.2
Startup cost [€ / MW of total H2 output]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Technology-specific data								
Methane conversion [%]	N/A	89	90	91	N/A	N/A	N/A	N/A

Table 3-18: Technical- and economic assumptions for Methane production [28]

Technology	Plasma-assisted Methane Decomposition (plasma)							
year	2020	2030	2040	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data								
Typical total plant size [MW input]	N/A	273	300	330	136.50	409.50	165	495
Typical total plant size [MW H2 output]	N/A	125	140	150	62.50	187.50	75	225
Typical total plant size [kg H2/day output]	N/A	89000	98000	110000	45000	130000	55000	160000
Inputs								
Natural Gas (% total input[MWh/MWh])	N/A	84	86	88	82	86	86	90
Electricity (% total input[MWh/MWh])	N/A	16	14	12	14	18	10	14
Output								
Hydrogen Gas Output (% total input [MWh/MWh])	N/A	45	46	47	41	49	43	51
Carbon Black Output (% total input [MWh/MWh])	N/A	30	31	32	27	33	29	35
Methane Output (% total input [MWh/MWh])	N/A	9	8	7	4.50	13.50	3.50	10.50
Recovered Heat (% total input [MWh/MWh])	N/A	11	10	10	5.50	16.50	5	15
Heat loss (% total input [MWh/MWh])	N/A	5	5	4	4	10	2	8
Forced outage [%]	N/A	20	10	1	10	30	0	2
Planned outage [weeks per year]	N/A	16	4	2	10	22	2	4
Technical lifetime [years]	N/A	20	25	25	15	25	20	30
Construction time [years]	N/A	2	2	2	1.50	2.50	1.50	2.50
Financial data								
Specific investment [M€/MW of total H2 output]	N/A	0.89	0.82	0.71	0.43	1.30	0.30	1.00
- hereof equipment [%]	N/A	50	50	50	45	55	45	55

- hereof installation [%]	N/A	50	50	50	45	55	45	55
Fixed O&M [€ / MW of total H2 output]	N/A	26584	24458	21267	13000	38000	10000	31000
Variable O&M [€ / MWh of total H2 output]	N/A	4.3	3.8	3.4	2.1	6.4	1.7	5.2
Startup cost [€ / MW of total H2 output]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Technology-specific data								
Methane conversion [%]	N/A	89	90	91	N/A	N/A	N/A	N/A

4. Established Power Generation Technologies

Boiler plants are the simplest technology that can be the baseline for all other alternatives in a low carbon and sustainable energy system.

The boiler plants can serve several purposes:
- Back-up and peak capacity for heating.
- Base load capacity for heating from biomass boilers, which use local ressources
- Electric boilers, which use low cost surplus electricity from fluctuating resources and offer services to the power grid, e.g. frequency stabilization
- Process energy in the form of superheated temperature, e.g. 160 °C or steam.

Combined Heat and Power (CHP) plants are highly efficient systems that simultaneously generate electricity and heat. Typically, conventional power plants lose heat through cooling towers or by discharging it into seawater, which represents a significant waste of energy. CHP plants, on the other hand, capture this waste heat and utilize it for heating purposes, such as district heating or industrial processes, thereby significantly enhancing overall efficiency.

The electric heat pump is a key technology in the low carbon energy system, as it can integrate three of the energy carriers, electricity, district heating (DH) and district cooling (DC). Moreover, in the general concept the heat pump can also operate as a heat only heat pump, which waste the cooling (e.g. ground source heat pumps) or as a cooling-only heat pump, which waste the heat (e.g. chiller).

4.1 Biomass Boiler

Biomass boilers are efficient heating systems that utilize biomass fuels such as wood pellets, wood chips, and logs to produce heat for space heating and hot water. Waste products from fishing industry in Greenland could also be utilized as biomass fuels. There are two main types: automatic and manual stoking boilers.

Automatic biomass boilers typically use wood pellets as fuel, which is fed into the boiler via an auger feeder. Combustion occurs in a burner unit, with heat transferred to water through boiler tubes or plates. These boilers can be equipped with condensing units to enhance efficiency by capturing low-temperature and latent heat from exhaust gases. Fuel can be supplied from various storage options, including external tanks, storage rooms, or integrated hoppers. Advanced models allow for remote system control via phone apps or internet browsers.

Manual biomass boilers, on the other hand, use wood logs as fuel. These boilers often employ down-draught combustion, where wood is heated, dried, and gasified before the gases are combusted with secondary air. Modern manual boilers can be paired with pellet burners for greater flexibility and continuous operation. These boilers are usually installed with an accumulation tank to store heat and ensure consistent supply.

Biomass boilers range in capacity from small domestic units (8 kW) to large commercial systems (up to 500 kW). Automatic systems can modulate between 30% to 100% of their capacity, with some models operating efficiently from 10% to 120% of their nominal heat output. Manual boilers, while robust and simple, require regular cleaning, ash removal, and manual feeding of fuel.

In Arctic conditions, such as in Greenland, biomass boilers present a viable heating solution, although, considerations include ensuring adequate insulation of fuel storage to prevent freezing, regular maintenance to handle the cold environment, and robust design to withstand harsh weather. Automatic biomass boilers may require additional features to ensure reliable operation in extreme cold, while manual systems need provisions for continuous fuel handling and storage. Overall, biomass boilers can be an effective heating solution in Arctic regions, provided they are adapted to the unique environmental challenges.

4.1.1 Technical- and economic assumptions for an automatic stoking boiler

Table 4-1: Technical- and economic assumptions for an automatic biomass boiler (2025) [28]

Technology	Single Family House - Existing	Housing Complex - Existing Building	Single Family House - New	Housing Complex - New Building
Energy/technical data				
Heat production capacity for one unit [kW_h]	10	400	8	160
Expected share of space heating demand covered by	1	1	1	1

Expected	1	1	1	1
Heat efficiency (annual average, net) [p.u.]	0.84	0.87	0.79	0.87
Auxiliary Electricity consumption [kWh_e/y]	230	2300	185	1360
Technical economic lifetime [years]	20	20	20	20
Electric regulation ability				
Primary regulation (per 30 seconds) [p.u.]				
Secondary regulation (per minute) [p.u.]				
Minimum load (of full load) [p.u.]				
Warm start-up time [hours]				
Cold start-up time [hours]				
Environment				
SO_2 [g/GJ_i]	25	25	25	25
PM2.5 [g/GJ_i]	14	14	14	14
NO_X [g/GJ_i]	60	60	60	60
CH4 [g/GJ_i]	2	2	2	2
N2O [g/GJ_i]	4	4	4	4
Financial data				
Nominal investment (*total) [k€/unit, 2020]	4.7	85.8	4.6	51.7
Nominal investment (equipment) [k€/unit, 2020]	3.7	68.7	3.6	41.4
Nominal investment (installation) [k€/unit, 2020]	1.0	17.2	1.0	10.3
Nominal investment (additional) [k€/unit, 2020]	6	14.6	5	8.8
Variable O&M (*total) [€/kWh, 2020]	0	0	0	0
Fixed O&M (*total) [€/unit/y, 2020]	367.7	1490.7	368.2	991.2
Fixed O&M (electricity cost) [€/unit/y, 2020]	19.6	195.5	15.7	115.6
Fixed O&M (other) [€/unit/y, 2020]	348.1	1295.2	352.5	875.6
Annual O&M (time spent on manual maintenance) [h	20	40	16	32

Table 4-2: Technical- and economic assumptions for a manual biomass boiler (2025) [28]

Technol	Single
y/technical data	
Heat production capacity for one unit [kW_h]	25
Expected	1
Expected share of hot tap water demand covered by unit [p.u.]	1
Heat efficiency (annual average, net) [p.u.]	0.8
Auxiliary Electricity consumption [kWh_e/y]	190
Technical economic lifetime [years]	20
Electric regulation ability	
Primary regulation (per 30 seconds) [p.u.]	
Secondary regulation (per minute) [p.u.]	
Minimum load (of full load) [p.u.]	
Warm start-up time [hours]	
Cold start-up time [hours]	
Environment	
SO_2 [g/GJ_i]	25
PM2.5 [g/GJ_i]	14
NO_X [g/GJ_i]	60
CH4 [g/GJ_i]	2
N2O [g/GJ_i]	4
Financial data	
Nominal investment (*total) [k€/unit, 2020]	5.2
Nominal investment (equipment) [k€/unit, 2020]	3.7
Nominal investment (installation) [k€/unit, 2020]	1.6
Nominal investment (additional) [k€/unit, 2020]	0.0
Variable O&M (*total) [€/kWh, 2020]	0.0
Fixed O&M (*total) [€/unit/y, 2020]	425.6
Fixed O&M (electricity cost) [€/unit/y, 2020]	16.2
Fixed O&M (other) [€/unit/y, 2020]	409.4
Annual O&M (time spent on manual maintenance) [hours/unit/y]	50

4.2 Biomass CHP

Biomass Combined Heat and Power (CHP) plants use combustion of wood chips, wood pellets, or straw for energy production. Waste products from fishing industry in Greenland could also be utilized as biomass fuels. CHP plants generate both electricity and heat, while HOPs focus solely on heat. Biomass boilers feed steam turbines, either backpressure or extraction types, with the former ending expansion in district heat condensers and the latter capable of running in both backpressure and condensing modes.

Flue gas condensation is common in biomass plants to recover additional energy, especially in larger installations. This technology significantly boosts efficiency, particularly with high-moisture fuels like wood chips. Straw-fired plants may use bag filters for flue gas cleaning due to less efficiency in electrostatic precipitators with straw.

Biomass inputs include wood chips, wood pellets, straw, and other residues. Combustion is feasible for feedstocks with moisture content up to 60% for wood chips and up to 25% for straw. The primary outputs are electricity and heat, with efficiencies enhanced by flue gas condensation.

CHP plants operate from 20% to 100% load for once-through suspension fired boilers, while grate-fired boilers range from 40% to 100% load. Some large plants can operate in power-only mode with increased electrical efficiency. Heat-only plants regulate 25-100% capacity, with straw-fired plants maintaining above 40% load due to emission standards.

Advantages include the ability of extraction units to optimize power production during high market prices and the versatility of handling various biomass types. Challenges include high corrosion and slagging in straw-fired plants due to chlorine and potassium deposits.

Modern biomass plants incorporate advanced flue gas cleaning systems, including DeNOx, SO2 capture, and dust abatement.

Biomass plants in rual Arctic conditions must address fuel supply reliability and extreme weather impacts on operations. Insulation and robust infrastructure are critical. High-moisture fuels pose challenges in cold climates, necessitating advanced flue gas condensation and efficient thermal storage solutions for consistent energy supply.

4.2.1 Wood chips CHP

Table 4-4: Technical- and economic assumptions for wood chips CHP (2030) [28]

Technology	Large Wood Chips	Large Wood Chips	Medium Wood	Small Wood Chips
	2020	2021	2020	
Energy/technical data				
Generating capacity for one unit [MW_e]	183.28	170.47	23.86	2.93
Electrical efficiency (net, annual average) []	0.29	0.27	0.28	0.14
Electrical efficiency (net, name plate) []	0.31	0.28	0.30	0.15
Cb coefficient (50°C/100°C)	0.38	0.35	0.37	0.15
Cv coefficient (50°C/100°C)	1	1	1	1
Auxiliary Electricity consumption (share of heat gen.)	0.03	0.03	0.03	0.03
Forced outage []	0.03	0.03	0.03	0.03
Planned outage [weeks per year]	3	3	3	3
Technical lifetime [years]	25	25	25	25
Construction time [years]	5	5	3	1
Space requirement [1000 m2/MW_e]	0.08	0.09	0.21	0.68
Regulati				
Primary regulation (of full load, per 30 seconds) []	0.02	0.02		
Secondary regulation (of full load, per minute) []	0.04	0.04	0.04	0.10
Minimum load (of full load) []	0.45	0.45	0.20	0.20
Warm start-up time [hours]	2	2	2	0.25
Cold start-up time [hours]	12	12	8	0.5
Environment				
SO2 (degree of desulphuring) []	0.98	0.98	0.98	0.98
NOX [g/GJ_i]	20	20	40	60
CH4 [g/GJ_i]	2	2	2	10
N2O [g/GJ_i]	6	6	1	1
Particles [g/GJ_i]	0.3	0.3	0.3	0.3
Financia				
Nominal investment (*total) [MEUR/MW_e]	3.32	3.56	3.57	6.72
Nominal investment (equipment) [MEUR/MW_e]	2.15	2.31	2.39	4.17
Nominal investment (installation) [MEUR/MW_e]	1.17	1.25	1.18	2.54
Variable O&M (*total) [EUR/MWh_e]	4.65	4.87	4.75	9.85

Fixed O&M (*total) [EUR/MW_e/y]	94640.2	102083.8	148872.2	298807.7
Technol				
Heat efficiency (net, annual average) []	0.83	0.82	0.83	0.97
Heat efficiency (net, name plate) []	0.81	0.81	0.81	0.97
Nominal investment (*total) [MEUR/MW_i]	1.01	1.01	1.06	0.99
Nominal investment (equipment) [MEUR/MW_i]	0.66	0.66	0.71	0.62
Nominal investment (installation) [MEUR/MW_i]	0.36	0.36	0.35	0.37
Variable O&M (*total) [EUR/MWh_i]	1.42	1.38	1.41	1.45
Fixed O&M (*total) [EUR/MW_i/y]	29030	29030	44449	43811
Fuel storage specific cost in excess of 2 days	0.01	0.01	0.01	0.02
Steam reheat	0	0	0	0
Output of recovered condensate [t/MWh_i]	0.22	0.19	0.22	0.25
Flue gas condensation	1	1	1	1
Combustion air humidification	1	1	1	1
Additional heat potential with heat pumps (of	0.02	0.04	0.02	0.02

4.2.2 Wood pellets CHP

Table 4-5: Technical- and economic assumptions for wood pellets CHP (2030) [28]

Technology	Large Wood 2020	Large Wood 2021	Medium Wood 2020	Small Wood Pellets
Energy/technical data				
Generating capacity for one unit [MW_e]	268.84	254.15	24.75	3.09
Electrical efficiency (net, annual average) []	0.32	0.30	0.29	0.15
Electrical efficiency (net, name plate) []	0.34	0.32	0.31	0.15
Cb coefficient (50°C/100°C)	0.52	0.49	0.46	0.19
Cv coefficient (50°C/100°C)	1	1	1	1
Auxiliary Electricity consumption (share of heat gen.)	0.03	0.03	0.03	0.02
Forced outage []	0.03	0.03	0.03	0.03
Planned outage [weeks per year]	3	3	3	3
Technical lifetime [years]	25	25	25	25
Construction time [years]	5	5	2.50	1.0
Space requirement [1000 m2/MW_e]	0.06	0.06	0.18	0.49
Regulation ability				
Primary regulation (of full load, per 30 seconds) []	0.02	0.02		
Secondary regulation (of full load, per minute) []	0.04	0.04	0.10	0.10
Minimum load (of full load) []	0.15	0.15	0.15	0.20
Warm start-up time [hours]	2	2	0.25	0.25
Cold start-up time [hours]	12	12	8	0.50
Environment				
SO2 (degree of desulphuring) []	0.98	0.98	0.98	0.98
NOX [g/GJ_i]	20	20	40	40
CH4 [g/GJ_i]	0	0	0	0
N2O [g/GJ_i]	1	1	1	1
Particles [g/GJ_i]	0.3	0.3	0.3	0.3
Financial data				
Nominal investment (*total) [MEUR/MW_e]	2.28	2.40	3.03	6.11
Nominal investment (equipment) [MEUR/MW_e]	1.27	1.34	1.94	3.99
Nominal investment (installation) [MEUR/MW_e]	1.00	1.06	1.10	2.13
Variable O&M (*total) [EUR/MWh_e]	1.82	1.83	1.97	4.13
Fixed O&M (*total) [EUR/MW_e/y]	62739	66992	124415	277540
Technology-specific data				
Heat efficiency (net, annual average) []	0.67	0.66	0.69	0.84
Heat efficiency (net, name plate) []	0.65	0.65	0.68	0.83
Nominal investment (*total) [MEUR/MW_i]	0.77	0.77	0.94	0.95
Nominal investment (equipment) [MEUR/MW_i]	0.43	0.43	0.60	0.62
Nominal investment (installation) [MEUR/MW_i]	0.34	0.34	0.34	0.33
Variable O&M (*total) [EUR/MWh_i]	0.62	0.58	0.61	0.64
Fixed O&M (*total) [EUR/MW_i/y]	21267	21267	38494	42854

Fuel storage specific cost in excess of 2 days	0	0	0	0
Steam reheat	0	0	0	0
Output of recovered condensate [t/MWh_i]	0.06	0.03	0.06	0.06
Flue gas condensation	1	1	1	1
Combustion air humidification	1	1	1	1
Additional heat potential with heat pumps (of	0.02	0.04	0.02	0.02

4.2.3 Straw CHP

Table 4-6: Technical- and economic assumptions for straw CHP (2030) [28]

Technology	Large Straw CHP 2020	Large Straw CHP 2021	Medium Straw 2020	Small Straw CHP
Energy/technical data				
Generating capacity for one unit [MW_e]	41.72	39.11	25.36	3.06
Electrical efficiency (net, annual average) []	0.30	0.28	0.30	0.15
Electrical efficiency (net, name plate) []	0.32	0.30	0.32	0.15
Cb coefficient (50°C/100°C)	0.46	0.43	0.46	0.18
Cv coefficient (50°C/100°C)	1	1	1	1
Auxiliary Electricity consumption (share of heat gen.)	0.03	0.03	0.03	0.02
Forced outage []	0.03	0.03	0.04	0.04
Planned outage [weeks per year]	3	3	4	4
Technical lifetime [years]	25	25	25	25
Construction time [years]	3	3	3	1
Space requirement [1000 m2/MW_e]	0.24	0.26	0.28	0.98
Regulation ability				
Primary regulation (of full load, per 30 seconds) []	0.02	0.02		
Secondary regulation (of full load, per minute) []	0.04	0.04	0.04	0.10
Minimum load (of full load) []	0.4	0.4	0.4	0.5
Warm start-up time [hours]	2	2	2	0.25
Cold start-up time [hours]	8	8	8	0.5
Environment				
SO2 (degree of desulphuring) []	0.99	0.99	0.99	0.99
NOX [g/GJ_i]	30	30	50	50
CH4 [g/GJ_i]	0	0	0	8
N2O [g/GJ_i]	1	1	1	1
Particles [g/GJ_i]	0.3	0.3	0.3	0.3
Financial data				
Nominal investment (*total) [MEUR/MW_e]	3.41	3.64	3.60	6.74
Nominal investment (equipment) [MEUR/MW_e]	2.11	2.25	2.18	3.81
Nominal investment (installation) [MEUR/MW_e]	1.31	1.39	1.42	2.93
Variable O&M (*total) [EUR/MWh_e]	2.23	2.28	2.22	4.79
Fixed O&M (*total) [EUR/MW_e/y]	122288	130795	142492	321139
Technology-specific data				
Heat efficiency (net, annual average) []	0.71	0.70	0.70	0.86
Heat efficiency (net, name plate) []	0.69	0.69	0.69	0.86
Nominal investment (*total) [MEUR/MW_i]	1.07	1.07	1.14	1.03
Nominal investment (equipment) [MEUR/MW_i]	0.67	0.67	0.45	0.45
Nominal investment (installation) [MEUR/MW_i]	0.41	0.41	0.69	0.58
Variable O&M (*total) [EUR/MWh_i]	0.70	0.67	0.70	0.73
Fixed O&M (*total) [EUR/MW_i/y]	38600	38600	45300	49021
Fuel storage specific cost in excess of 2 days	0.06	0.06	0.06	0.07
Steam reheat	0	0	0	0
Output of recovered condensate [t/MWh_i]	0.09	0.06	0.09	0.09
Flue gas condensation	1	1	1	1
Combustion air humidification	1	1	1	1
Additional heat potential with heat pumps (of	0.02	0.04	0.02	0.02

4.4 Compression Heat Pump

Compression heat pumps operate by moving heat from a low-temperature source to a higher temperature sink using a mechanical process. They use a refrigerant that absorbs heat from the source at low pressure and releases it at a higher pressure. These systems typically achieve a Coefficient of Performance (COP) of 3 to 5, meaning they deliver three to five units of heat for every unit of electricity consumed. The main components include a compressor, evaporator, condenser, and expansion valve.

Compression heat pumps can utilize various heat sources such as ambient air, groundwater, seawater, and industrial excess heat. Their flexibility makes them suitable for both residential and industrial applications, including district heating systems. They can provide both heating and cooling, making them versatile for year-round use.

The efficiency of compression heat pumps is influenced by the temperature difference between the heat source and the sink. Higher source temperatures and lower sink temperatures yield better efficiency. For instance, industrial excess heat with a higher source temperature can result in a higher COP compared to ambient air or seawater sources.

In Arctic conditions, the performance of compression heat pumps can be challenged by extremely low ambient temperatures. However, advanced designs, such as those using refrigerants like CO2, can maintain efficiency even in cold climates. These systems often incorporate defrosting mechanisms to manage ice buildup on external components, ensuring reliable operation even in harsh winter conditions.

4.4.1 Technical- and economic assumptions

Table 4-9: Technical- and economic assumptions for a electrical compression heat pumps - arisource (2030) [28]

Technology		Electrical Comp. HP - Airsource - Small - 1MW	Electrical Comp. HP - Airsource - Medium - 3MW	Electrical Comp. HP - Airsource - Large - 10MW
		2020	2021	2021
Energy/technical data				
Generating capacity for one unit [MW_h]		1	3	10
Heat efficiency (net, annual average) []		3	3.6	3.85
Heat efficiency (net, name plate) []		2.65	3.2	3.55
Auxiliary Electricity consumption (share of heat gen.)		0.01	0.01	0.01
Forced outage []		0	0	0
Planned outage [weeks per year]		1	1	1
Technical lifetime [years]		25	25	25
Construction time [years]		0.5	0.6	0.6
Space requirement [1000 m2/MW_h]		1	0.8	0.6
Regulation ability				
Primary regulation (of full load, per 30 seconds) []		0.05	0.05	0.05
Secondary regulation (of full load, per minute) []		0.1	0.1	0.1
Minimum load (of full load) []		0.25	0.25	0.25
Warm start-up time [hours]		0.1	0.1	0.1
Cold start-up time [hours]		1	1	1
Environment				
SO2 (degree of desulphuring) []				
NOX [g/GJ_i]				
CH4 [g/GJ_i]				
N2O [g/GJ_i]				
Particles [g/GJ_i]				
Financial data				
Nominal investment (*total) [MEUR/MW_h]		1.41	0.91	0.81
Nominal investment (equipment) [MEUR/MW_h]		1.06	0.72	0.65
Nominal investment (grid connection)		0.03	0.02	0.02
Nominal investment (installation) [MEUR/MW_h]		0.26	0.16	0.15
Variable O&M (*total) [EUR/MWh_h]		2.86	2.67	1.80
Variable O&M (electricity cost) [EUR/MWh_h]		0	0	0
Variable O&M (other O&M) [EUR/MWh_h]		2.86	2.67	1.80
Fixed O&M (*total) [EUR/MW_h/y]		2127	2127	2127
Startup cost [EUR/MW_h/startup]		10.63	10.63	10.63

Table 4-10: Technical- and economic assumptions for a electrical compression heat pumps - excess heat (2030) [28]

Technology	Electrical Comp. HP - Excess Heat - Small - 1MW	Electrical Comp. HP - Excess Heat - Medium - 3MW	Electrical Comp. HP - Excess Heat - Large - 10MW
Energy/technical data			
Generating capacity for one unit [MW_h]	1	3	10
Heat efficiency (net, annual average) []	4.3	4.8	5.3
Heat efficiency (net, name plate) []	4.2	4.7	5.2
Auxiliary Electricity consumption (share of heat gen.)	0.01	0.01	0.01
Forced outage []	0	0	0
Planned outage [weeks per year]	1	1	1
Technical lifetime [years]	25	25	25
Construction time [years]	0.5	0.5	0.5
Space requirement [1000 m2/MW_h]	0.1	0.05	0.03
Regulation ability			
Primary regulation (of full load, per 30 seconds) []	0.05	0.05	0.05
Secondary regulation (of full load, per minute) []	0.1	0.1	0.1
Minimum load (of full load) []	0.25	0.25	0.25
Warm start-up time [hours]	0.1	0.1	0.1
Cold start-up time [hours]	1	1	1
Environment			
SO2 (degree of desulphuring) []			
NOX [g/GJ_i]			
CH4 [g/GJ_i]			
N2O [g/GJ_i]			
Particles [g/GJ_i]			
Financial data			
Nominal investment (*total) [MEUR/MW_h]	1.21	0.81	0.61
Nominal investment (equipment) [MEUR/MW_h]	0.91	0.65	0.49
Nominal investment (grid connection)	0.02	0.02	0.01
Nominal investment (installation) [MEUR/MW_h]	0.22	0.15	0.11
Variable O&M (*total) [EUR/MWh_h]	2.86	2.67	2.14
Variable O&M (electricity cost) [EUR/MWh_h]	0	0	0
Variable O&M (other O&M) [EUR/MWh_h]	2.86	2.67	2.14
Fixed O&M (*total) [EUR/MW_h/y]	2127	2127	2127
Startup cost [EUR/MW_h/startup]	10.63	10.63	10.63

Table 4-11: Technical- and economic assumptions for a electrical compression heat pumps - Seawater (2030) [28]

Technology	Electrical Comp. HP - Seawater - Small - 20MW
Energy/technical data	
Generating capacity for one unit [MW_h]	20
Heat efficiency (net, annual average) []	3.7
Heat efficiency (net, name plate) []	3.4
Auxiliary Electricity consumption (share of heat gen.)	0.01
Forced outage []	0
Planned outage [weeks per year]	1
Technical lifetime [years]	25
Construction time [years]	1
Space requirement [1000 m2/MW_h]	0.03
Regulation ability	
Primary regulation (of full load, per 30 seconds) []	0.05
Secondary regulation (of full load, per minute) []	0.1
Minimum load (of full load) []	0.25
Warm start-up time [hours]	0.2
Cold start-up time [hours]	2
Environment	
SO2 (degree of desulphuring) []	

NOX [g/GJ_i]	
CH4 [g/GJ_i]	
N2O [g/GJ_i]	
Particles [g/GJ_i]	
Financial data	
Nominal investment (*total) [MEUR/MW_h]	0.40
Nominal investment (equipment) [MEUR/MW_h]	0.34
Nominal investment (grid connection) [MEUR/MW_e]	0
Nominal investment (installation) [MEUR/MW_h]	0.06
Variable O&M (*total) [EUR/MWh_h]	1.61
Variable O&M (electricity cost) [EUR/MWh_h]	0
Variable O&M (other O&M) [EUR/MWh_h]	1.61
Fixed O&M (*total) [EUR/MW_h/y]	4253.49
Startup cost [EUR/MW_h/startup]	10.63

4.5 Absorption Heat Pump

Absorption heat pumps utilize heat as their driving energy instead of mechanical work. They operate based on the absorption refrigeration cycle, where a refrigerant (typically ammonia or water) is absorbed by a secondary fluid (like water or lithium bromide). High-temperature heat sources, such as steam or hot water, drive the process. These systems typically achieve a COP of around 1.7, with two-stage systems reaching up to 2.3.

Absorption heat pumps are particularly suitable for industrial applications where waste heat or other high-temperature heat sources are available. They are used in district heating systems and can effectively utilize low-grade energy sources, making them efficient for combined heat and power (CHP) plants.

The efficiency of absorption heat pumps is less sensitive to temperature variations compared to compression heat pumps. They maintain a stable COP as long as the required temperature differences are met. This makes them suitable for applications where the temperature of the heat source and sink are relatively constant.

In Arctic conditions, absorption heat pumps can face challenges with maintaining the necessary high temperatures for the driving heat source. Ensuring an adequate supply of high-temperature heat is crucial for their operation. However, their ability to use industrial excess heat makes them advantageous in locations with industrial activities, where waste heat can be effectively utilized to maintain efficiency despite the cold climate.

4.5.1 Technical- and economic assumptions

Table 4-12: Technical- and economic assumptions for an absorption heat pumps for district heating (2030) [28]

Technology	Absorption heat pumps - district
Energy/technical data	
Heat generation capacity for one unit (MW_{heat})	12
Total efficiency, net (%), name plate	1.73
Total efficiency , net (%), annual average	
Electricity consumption for pumps etc. (% of heat	0.01
Forced outage (%)	0
Planned outage (weeks per year)	0
Technical lifetime (years)	25
Construction time (years)	0.5
Space requirement (1000m2 per MW)	0
Regulation ability	
Primary regulation (% per 30 seconds)	
Secondary regulation (% per minute)	
Minimum load (% of full load)	0.1
Warm start-up time (hours)	0
Cold start-up time (hours)	0.5
Environment	
SO_2 (g per GJ fuel)	0
NO_X (g per GJ fuel)	0
CH4 (g per GJ fuel)	0
N2O (g per GJ fuel)	0

Financial data	
Nominal investment (*total) [MEUR/MW_h]	0.54
Nominal investment (equipment) [MEUR/MW_h]	53.17
Nominal investment (installation) [MEUR/MW_h]	53.17
Variable O&M (*total) [EUR/MWh_h]	1.33
Variable O&M (electricity cost) [EUR/MWh_h]	1.06
Variable O&M (other O&M) [EUR/MWh_h]	0.27
Fixed O&M (*total) [EUR/MW_h/y]	2126.75

4.6 Diesel Generator

A disel generator produces electricity as an output through diesel or other light fuels as an input.

Diesel generators are often used to provide standby power generation for large industrial or commercial sites that cannot afford to lose power in the even of interruptions in the electricity networt supply. The diesel generators can also be used to provide electricity for the peak power demand. An advantage of using diesel generators, is that they are capable of starting and reaching full load very quickly, which minimizes the time with no power generation in times of interruptions. Another advantage of using a diesel generator is that it is possible to harvest the surplus heat generated form a working generator.

In networks with renewable energy sources, where the electricity production can be fluctuating, it is essential to have a back-up generation. This could be a diesel generator. The diesel generator capacity installed should be able to supply the full peak demand, to accommodate the demand in hours where production from RES is not present.

In the latest tender for capacity market and short term operating reserve in the UK, the typical farm size was between 3 MW and 50 MW. However, given the modularity of the solution, it is potentially expandable to higher ratings. A very large number of plants awarded are around 18 – 20 MW, constituted by a variable number of engines rated 400 kW – 2 MW each. This is assumed as the typical capacity of the plant.

The start-up time of diesel generators are amongst the lowest compared to other generation facilities. A typical figure for the cold start-up time of these types of generators is down to 2-3 minutes. The ramping capabilities are also good, with a typical engine able to provide 50% output in around 15 seconds and full capacity after 5 additional seconds. Part load generation does not result in a large drop of efficiency due to the modular nature of the diesel farm. When the plant has to be regulated downward, some generators can be switched off and each online generator can be kept at the optimal output level (for emissions and efficiency).

Table 6-13: Technical- and economic assumptions for a disel generator [28]

Energy/technical data	2015	2020	2030	2050
Generating capacity for one unit [MW_e]	18			
Electrical efficiency (net, annual average) []	35%	35%	35%	35%
Electrical efficiency (net, name plate) []	37%	37%	37%	37%
Cb coefficient (50°C/100°C)				
Cv coefficient (50°C/100°C)				
Forced outage []	1%	1%	1%	1%
Planned outage [weeks per year]	0.17	0.17	0.17	0.17
Technical lifetime [years]	25	25	25	25
Construction time [years]	1	1	1	1
Regulation ability				
Primary regulation (of full load, per 30 seconds) []	100%	100%	100%	100%
Secondary regulation (of full load, per minute) []	100%	100%	100%	100%
Minimum load (of full load) []	1%	1%	1%	1%
Warm start-up time [hours]	0.02	0.02	0.02	0.02
Cold start-up time [hours]	0.09	0.09	0.09	0.09
Environment				
SO2 [g/GJ_i]	23	23	23	23
NOX [g/GJ_i]	942	942	942	942
CH4 [g/GJ_i]	24	24	24	24
N2O [g/GJ_i]	2.1	2.1	2.1	2.1
Particles [g/GJ_i]	5	5	5	5
Financial data				
Nominal investment (*total) [MEUR/MW_e]	0.37	0.36	0.36	0.36
Nominal investment (equipment) [MEUR/MW_e]	0.24	0.23	0.23	0.23
Nominal investment (installation) [MEUR/MW_e]	0.13	0.13	0.13	0.13
Variable O&M (*total) [EUR/MWh_e]	6.38	6.38	6.38	6.38
Fixed O&M (*total) [EUR/MW_e/y]	9357.68	9357.68	8983.37	8609.07
Startup cost [EUR/MW_e/startup]	0.00	0.00	0.00	0.00

5. Energy storage

The biggest challenge in developing Net Zero Communities is not to generate renewable energy, but to use it. The renewable energy or surplus energy sources, which can contribute to forming Net Zero Communities, are normally not available when needed, and it can even be more expensive to store the energy than to generate it. A good example is that the renewable energy sources wind, solar and hydro can generate electricity, as the wind blows, the sun shines and the rain falls, whereas the power grid it self can not store the electricity.

Therefore energy storage options are extremely important, especially in rual areas where there is no connection to a collective gird and maybe no connection to backup power.

In order to identify the most cost effective storage it is necessary to look both at the production, the real end-use demand and how its fluctuations deviates from the production. The dynamic fluctuations of the production in seconds, hours, days, weeks, months and years have to be taken into account. Load management and energy transformation has to be considered. In case heating is the final end-use, it is e.g. much more cost effective to transform the electricity to hot water the moment is it generated and use thermal storages instead of electric batteries.

In this section we will compare the cost of all relevant energy storage options and in the design of energy systems we will show a number of conceptual design concepts of integrated systems, which can store the fluctuating renewable energy.

5.1 Large Scale Hot Water Tanks

Thermal storage technologies are divided into three main types: sensible, latent, and chemical stores. Sensible stores utilize the heat capacity of materials, primarily water, due to its high specific heat, low cost, and non-toxicity. These stores are typically steel tanks insulated and connected to district heating systems, operating efficiently with a layering method for enhanced storage. Latent stores rely on the material's latent heat during phase changes, while chemical stores use reversible chemical reactions, such as the heat of adsorption or absorption in pairs like zeolite-water or water-lithium bromide. Among these, sensible hot water storage vessels dominate the market due to their simplicity, versatility, and cost-effectiveness.

At continental European states, steel tanks for hot water storage are common, with insulation thickness varying based on storage duration—typically 300 mm for daily use and 450 mm for long-term storage. Heat loss is influenced by tank size and insulation; theoretical models show losses of 1.0% to 2.1% per week at 90°C with 300 mm insulation. This is at Danish average temperatres.

These tanks can store heat for periods ranging from a few hours to two weeks, balancing peak demands by charging overnight and throughout the day. In smaller systems, they can also serve seasonal storage needs more cost-effectively than small-scale pit heat storages. Despite their benefits—such as low investment costs and high specific heat capacity of water—disadvantages include space requirements, energy losses, and the need for corrosion protection. Large tanks might impact the landscape, but this is typically minimal as they are installed near district heating plants. Future research in Denmark focuses on optimizing existing technologies for lower temperatures and integrating cooling storage within large tanks. The tanks also offer peak capacity and improve resilience. Finally the tank can maintain the pressure in the network and offer storage capacity for make-up water.

When it comes to Greenland, large hot water tanks are less ideal due to several factors specific to its arctic climate and lack of infrastructure. Maintaining the heat in water tanks in extremely cold temperatures (0°C to -30°C) would require significant extra insulation and energy, leading to higher operational costs and energy inefficiency. Additionally, transporting and installing large, insulated tanks in remote and harsh environments is logistically difficult and expensive. These challenges make hot water tanks less practical compared to other energy storage solutions better suited for extreme conditions.

5.1.1 Technical- and economic assumptions

Table 5-1: Space Requirements for a large hot water tank

Storage (m^3)	Storage (MWh)	Ratio h:D	Space (m^2)	Space (m^2/MWh)
1,000	58	2	72	1
1,000	58	3	67	1
3,000	173	2	85	0
3,000	173	3	78	0
5,000	288	2	93	0
5,000	288	3	85	0

Table 5-2: Technical- and economic assumptions for a large hot water tank [28]

Technology	Large Hot Water Tank							
year	2020	2030	2040	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data								
Form of energy stored	Heat	Heat	Heat	Heat	Heat	Heat	Heat	Heat
Energy storage capacity for one unit	175	175	175	175	45	315	45	315
Output capacity for one unit [MW]	2.9	2.9	2.9	2.9	0.8	5.3	0.8	5.3
Input capacity for one unit [MW]	2.9	2.9	2.9	2.9	0.8	5.3	0.8	5.3
Round trip efficiency [%]	98	98	98	98	96	99	96	99
- Charge efficiency [%]	100	100	100	100	100	100	100	100
- Discharge efficiency [%]	100	100	100	100	100	100	100	100
Energy losses during storage [%/day]	0.19	0.19	0.19	0.19	0.14	0.24	0.14	0.24
Auxiliary electricity consumption [% of	1	1	1	1	0	1	0	1
Forced outage [%]	0	0	0	0	0	3	0	3
Planned outage [weeks/year]	1	1	1	1	0	4	0	4
Technical lifetime [years]	40	40	40	40	30	50	30	50
Construction time [years]	0.5	0.5	0.5	0.5	0.5	1	0.5	1
Regulation ability								
Primary regulation [%/30 sec]								
Secondary regulation [%/minute]								
Financial data								
Specific investment	3.04	3.04	3.04	3.04	2.21	8.18	2.21	8.18
- hereof equipment [%]	67.41	67.41	67.41	67.41	67.41	67.41	67.41	67.41
- hereof installation [%]	28.89	28.89	28.89	28.89	28.89	28.89	28.89	28.89
Fixed O&M [EUR/MWhCapacity/year)	8.81	8.81	8.81	8.81	4.88	34.14	4.88	34.14
Variable O&M [EUR/MWhoutput]	0	0	0	0	0	0	0	0
Technology-specific data								
Tank volume of example [m3]	3000	3000	3000	3000	1500	5000	1500	5000
Typical temperature difference in storage	55	55	55	55	30	60	30	60

5.2 Small Scale Hot Water Tanks

Hot water storage vessels in private homes serve various purposes, including domestic hot water supply, space heating, and load shifting. These vessels ensure adequate water flow for high-demand activities like showers and baths, while also enhancing the efficiency of heat pumps and biomass boilers by extending their operating periods. They are particularly useful for load shifting, capturing off-peak electricity and using it during peak times, thereby improving the utility's capacity factor and financial health. In solar domestic hot water systems, heat exchangers from solar collectors are usually placed at the bottom of the storage tank, with an additional coil at the top to boost temperature when needed. In Denmark, hot water vessels are typically made of steel, protected against corrosion by enamel and an anode, although stainless steel is also used elsewhere despite its higher cost.

For domestic hot water storage, typical tank capacities range from 60 to 160 liters for single-family homes, depending on the heat source and demand. For solar water heaters, without seasonal storage, the volume is about 50-65 liters per square meter of solar collector. Larger volumes are limited by available space, with cupboard solutions providing up to 300 liters within a compact footprint. The usual storage period is a few hours, allowing for efficient operation of the heat production system. Compact tanks, up to 200-300 liters, are often designed as cabinet solutions to fit in utility rooms, while larger tanks have a circular footprint with diameters around 80-100 cm.

They are cost-effective, easy to produce, and widely used, with millions manufactured annually. However, they occupy considerable space due to insulation needs and may pose issues such as legionella bacteria and high return temperatures in district heating systems. Ongoing research aims to develop tanks with higher storage density and reduced losses, such as those using zeolite beads for significantly increased storage capacity.

Their performance in extremely cold temperatures needs careful consideration, as insulation must be robust to prevent heat loss and ensure efficiency. Potential issues like space requirements should be managed with proper installation and maintenance. Overall, they are a viable option but woudl require adaptations for the Arctic climate.

5.2.1 Technical- and economic assumptions

Table 5-3: Technical- and economic assumptions for a small hot water tank [28]

Technology	Small Hot Water Tank							
year	2020	2030	2040	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data								
Form of energy stored	Heat	Heat	Heat	Heat	Heat	Heat	Heat	Heat
Energy storage capacity for one unit	3	3	3	3	2	19	2	19
Output capacity for one unit [MW]	20	20	20	20	10	40	10	40
Input capacity for one unit [MW]	20	20	20	20	10	40	10	40
Round trip efficiency [%]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
- Charge efficiency [%]	100	100	100	100	100	100	100	100
- Discharge efficiency [%]	100	100	100	100	100	100	100	100
Energy losses during storage [%/day]	2.1	2.1	2.1	2.1	2.5	1	2.5	1
Auxiliary electricity consumption [% of	1	1	1	1	0	1	0	1
Forced outage [%]	0	0	0	0	0	3	0	3
Planned outage [weeks/year]	1	1	1	1	0	4	0	4
Technical lifetime [years]	30	30	30	30	15	50	15	50
Construction time [years]	0	0	0	0	0	0	0	0
Regulation ability								
Primary regulation [%/30 sec]								
Secondary regulation [%/minute]								
Financial data								
Specific investment	419.86	419.86	419.86	419.86	522.27	133.13	522.27	133.13
- hereof equipment [%]	48.15	48.15	48.15	48.15	38.52	33.71	38.52	33.71
- hereof installation [%]	49.93	49.93	49.93	49.93	59.21	63.84	59.21	63.84
Fixed O&M [EUR/MWhCapacity/year)	51.20	51.20	51.20	51.20	25.60	81.92	25.60	81.92
Variable O&M [EUR/MWhoutput]	0.72	1.02	1.23	1.23	0	0.72	0	1.23
Technology-specific data								
Efficiency at typical cycle period [%]	92	92	92	92	97	90	97	90
Tank volume of example [l]	90	90	90	90	50	300	50	300
Typical temperature difference in storage [hot/cold, K]	30	30	30	30	30	60	30	60

5.3 Pumped Hydro Storage

For bulk electricity storage in utility grids, pumped hydro power plants are a common option around the world, with approximately 100 GW in service.

Pumped hydro storage (PHS) works by moving water between two reservoirs at different elevations. During periods of low electricity demand, excess energy is used to pump water from the lower to the upper reservoir, storing energy as potential energy. When electricity demand is high, the stored water is released back to the lower reservoir, flowing through turbines to generate electricity. This process converts the potential energy back into electrical energy. PHS systems are efficient (70-85%) and help balance supply and demand, providing grid stability and backup power.

A typical PHS consists of two water reservoirs (lakes), tunnels that convey water from one reservoir to another, a reversible pump-turbine, a motor-generator, transformers, and transmission connection. The amount of stored electricity is proportional to the product of the volume of water and the height between the reservoirs. As an example, storing 1,000 MWh requires an elevation change of 300 m and a water volume of about 1.4 million m3.

A new PHS, including dams, has high capital expenditures and a long construction time. If an existing hydro plant is extended to also be a PHS, the investment per installed MW is significantly lower and the construction time between 2 and 3 years.

Pumped hydro storage is a flexible and well-established energy storage technology, often coupled with renewable resources in mid-latitudes. However, in the high Arctic, its benefits can be offset by the need to keep water from freezing during winter. Consequently, the feasibility of pumped hydro storage is highly dependent on specific site conditions. While pumped thermal energy storage, using various working fluids, offers a more site-independent and cost-effective solution, pumped hydro has not been extensively implemented in cold climates or Arctic regions, despite its use in isolated mid-latitude systems.

5.3.1 Technical- and economic assumptions

Table 5-4: Technical- and economic assumptions for a pumped hydro storage [28]

Technology		Pumped hydro storage		
	Unit	2020	2030	2050
Energy/technical data				
Generating capacity	MW	10-1000	10-1000	10-1000
Total efficiency net	%	70-80	70-80	70-80
Technical lifetime	years	50	50	50
Construction time	years	2-3	2-3	2-3
Financial data				
Investment, pump part	M€/MW	0.6	0.6	0.6
Investment, total, greenfield	M€/MW	4	4	4
Fixed O&M- 1-2 % of	€/MW/year	9000	9000	9000
Variable O&M	€/MWh	Depends on power	Depends on power	Depends on power

5.4 Electric Batteries

There are several battery technologies available or being developed for storing electricity.

The battery technology with the broadest base of applications today is the lithium-ion battery, used e.g. in laptop computers and electric vehicles. The ability of lithium-ion batteries to economically serve electric utility applications has not yet been demonstrated, except for some ancillary services provisions to independent system operators. Three main battery types are most relevant for large-scale electricity storage:

- Advanced lead acid batteries
- NaS (Sodium Sulphur) batteries
- Flow batteries, in particular:
    - o Vanadium Redox (VRB)
    - o Zinc-bromine (ZnBr)

The lead-acid battery is one of the oldest and most developed battery technologies. A lead-acid battery is an electrical storage device that uses a combination of lead plates or grids and an electrolyte consisting of a diluted sulphuric acid to convert electrical energy into potential chemical energy and back again. Even though standard Lead-acid batteries suffer substantial performance losses in cold environments recent advancements have led to the development of lithium-ion batteries with modified anodes that can operate at very low temperatures (well under 0°C).

The sodium-sulfur (NaS) battery operates at high temperatures (~300°C) with molten sulfur and sodium electrodes separated by a ceramic electrolyte. During discharge, sodium ions move through the electrolyte, generating an external electrical current. Flow batteries, using a liquid electrolyte, produce power through a membrane, with performance based on membrane size and electrolyte volume.

Flow batteries have a high potential for long duration energy storage, but are not currently as affordable or industrially established. The Vanadium redox battery (VRB) uses vanadium ions in different oxidation states for energy storage with very low self-discharge. The Zinc-bromine (ZnBr) battery has two electrolytes flowing past electrodes in separate compartments divided by a membrane. For grid applications, reliable power conversion systems are needed to convert AC to DC and back.

Batteries are a very attractive option for microgrids today but in their challenge is the same as with heat storage, the energy loss is large and increases at low temperatures. Most batteries in Greenland for mining will have to incorporate some kind of themal control system or be placed in insulated places.

5.4.1 Technical- and economic assumptions

Table 5-5: Technical- and economic assumptions for a Sodium Sulphur (NaS) battery [28]

Technology				NaS battery						
year				2020	2030	2050	2020	2020	2050	2050
est				ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data										
Form of energy stored				Electricity	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity
Energy storage capacity for one unit				300	300	300	30	3000	30	3000

Output capacity for one unit [MW]	50	50	50	5	500	5	500
Input capacity for one unit [MW]	50	50	50	5	500	5	500
Round trip efficiency - DC [%]	83	85	85	71	92	74	96
- Charge efficiency [%]	-	-	-	-	-	-	-
- Discharge efficiency [%]	-	-	-	-	-	-	-
Energy losses during storage [%/day]	0	0	0	0	1	0	1
Forced outage [%]	0	0	0	0	2	0	2
Planned outage [weeks/year]	0	0	0	0	0	0	0
Technical lifetime [years]	19	24	24	10	28	14	36
Construction time [years]	0.5	0.5	0.5	0.2	2	0.2	2
Regulation ability							
Response time from idle to full-rated	0.001	0.001	0.001	0.001	0.02	0.001	0.02
Response time from full-rated charge to	0.05	0.05	0.05	0.001	0.05	0.001	0.05
Financial data							
Specific investment [MEUR/MWh]	0.39	0.24	0.21	0.27	0.78	0.14	0.41
- energy component [MEUR/MWh]	0.27	0.15	0.12	0.19	0.53	0.09	0.24
- capacity component [MEUR/MW]	0.44	0.35	0.35	0.23	0.83	0.19	0.68
- other project costs [MEUR/MWh]	0.05	0.03	0.03	0.04	0.11	0.02	0.05
Fixed O&M [% total investment]	1.5	1.5	1.5	0.8	7.2	0.8	7.2
Variable O&M [EUR/MWh]	1.91	1.91	1.91	0.32	5.96	0.32	5.96
Technology-specific data							
Alternative Investment cost [MEUR/MW]	2.34	1.49	1.28	1.60	4.68	0.85	2.45
Lifetime in total number of cycles	5600	7500	7500	1100	11200	1500	15000
Specific power [W/kg]	9.3	9.3	9.3	6.98	11.63	6.98	11.63
Power density [W/m3]	4300	4300	4.3	3225	5375	3225	5375
Specific energy [Wh/kg]	56	56	56	42	70	42	70
Energy density [Wh/m3]	26000	26000	26000	19500	32500	19500	32500

Table 5-6: Technical- and economic assumptions for a Vanadium Redox Battery (VRB) [28]

Technology	**Vanadium Redox Battery (VRB)**						
year	**2020**	**2030**	**2050**	**2020**	**2020**	**2050**	**2050**
est	**ctrl**	**ctrl**	**ctrl**	**Lower**	**Upper**	**Lower**	**Upper**
Energy/technical data							
Form of energy stored	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity
Energy storage capacity for one unit	2	2	2	0.4	800	0.4	800
Output capacity for one unit [MW]	0.5	0.5	0.5	0.1	200	0.1	200
Input capacity for one unit [MW]	0.5	0.5	0.5	0.1	200	0.1	200
Round trip efficiency - DC [%]	78	78	78	62	88	67	95
- Charge efficiency [%]	-	-	-	-	-	-	-
- Discharge efficiency [%]	-	-	-	-	-	-	-
Energy losses during storage [%/day]	0	0	0	0	0.2	0	0.2
Forced outage [%]	0.5	0.5	0.5	0	5	0	5
Planned outage [weeks/year]	0	0	0	0	0	0	0
Technical lifetime [years]	20	20	20	6	23	8	32
Construction time [years]	1	1	1	0.2	2	0.2	2
Regulation ability							
Response time from idle to full-rated	0.1	0.1	0.1	0.005	2	0.005	2
Response time from full-rated charge to	0.07	0.07	0.07	0.004	1.4	0.004	1.4
Financial data							
Specific investment [MEUR/MWh]	0.64	0.37	0.35	0.56	1.22	0.32	0.62
- energy component [MEUR/MWh]	0.48	0.26	0.23	0.40	1.00	0.20	0.47
- capacity component [MEUR/MW]	0.44	0.35	0.35	0.46	0.51	0.37	0.41
- other project costs [MEUR/MWh]	0.05	0.03	0.03	0.04	0.10	0.02	0.05
Fixed O&M [% total investment]	2	1.5	1.5	0.8	4.1	0.6	3.1
Variable O&M [EUR/MWh]	0.96	0.96	0.96	0.21	2.98	0.21	2.98
Technology-specific data							
Alternative Investment cost [MEUR/MW]	2.6	1.5	1.4	2.2	4.9	1.3	2.4
Lifetime in total number of cycles	-|-	-|-	-|-	-|-	-|-	-|-	-|-
Specific power [W/kg]	2.9	2.9	2.9	1.45	3.63	1.45	3.63
Power density [W/m3]	2260	2260	2260	1130	2825	1130	2825
Specific energy [Wh/kg]	11.8	11.8	11.8	5.9	14.75	5.9	14.75
Energy density [Wh/m3]	9040	9040	9040	4520	11300	4520	11300

Table 5-7: Technical- and economic assumptions for a Lithium-Ion NMC battery [28]

Technology	Lithium-ion NMC battery (Utility-scale, Samsung SDI E3-R135)							
year	2020	2030	2040	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data								
Form of energy stored	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity
Energy storage capacity for one unit	6	7	8	8	5	9	7	12
Output capacity for one unit [MW]	18	21	24	24	16	21	22	28
Input capacity for one unit [MW]	3	3.5	4	4	2.7	3.5	3.7	4.7
Round trip efficiency [%] AC	91	92	92	92	90	92	91	94
Round trip efficiency [%] DC	95	96	96	96	95	96	95	97
- Charge efficiency [%]	98	98.5	98.5	98.5	98	98.5	98	99
- Discharge efficiency [%]	97	97.5	97.5	97.5	97	98	97	98
Energy losses during storage [%/day]	0.1	0.1	0.1	0.1	0.05	0.2	0.05	0.15
Forced outage [%]	0.38	0.35	0.3	0.25	0.2	0.5	0.1	0.3
Planned outage [weeks/year]	0.2	0.1	0.1	0.1	0.1	0.25	0.05	0.2
Technical lifetime [years]	20	25	30	30	15	25	20	45
Regulation ability								
Response time from idle to full-rated	0.08	0.08	0.08	0.08	0	0.08	0	0.08
Response time from full-rated charge to	0.08	0.08	0.08	0.08	0	0.08	0	0.08
Financial data								
Specific investment [MEUR/MWh]	1.11	0.66	0.42	0.27	0.94	1.94	0.18	1.04
- energy component [MEUR/MWh]	0.14	0.07	0.05	0.04	0.07	0.20	0.03	0.12
- capacity component [MEUR/MW] PCS	0.29	0.17	0.11	0.06	0.26	0.54	0.04	0.27
- other project costs [MEUR/MWh]	0.11	0.09	0.05	0.04	0.10	0.12	0.02	0.12
Fixed O&M [kEUR/MW/year]	0.57	0.57	0.57	0.57	0.48	0.57	0.43	0.57
Technology-specific data								
Energy storage expansion cost	0.25	0.15	0.10	0.08	0.17	0.28	0.05	0.19
Output capacity expansion cost	0.29	0.17	0.11	0.06	0.26	0.54	0.04	0.27
Alternative Investment cost [MEUR/MW]	0.35	0.21	0.13	0.09	0.30	0.62	0.05	0.33
Lifetime in total number of cycles	14000	30000	40000	50000	10000	16000	20000	70000
Specific power [W/kg]	315	417	522	627	300	420	450	900
Power density [kW/m3]	390	519	648	780	450	600	600	1200
Specific energy [Wh/kg]	105	139	174	209	100	140	150	300
Energy density [kWh/m3]	130	173	216	260	150	200	200	400

Table 5-8: Technical- and economic assumptions for a Na-NiCl2 battery [28]

Technology	Na-NiCl2 battery						
year	2020	2030	2050	2020	2020	2050	2050
est	ctrl	ctrl	ctrl	Lower	Upper	Lower	Upper
Energy/technical data							
Form of energy stored	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity	Electricity
Energy storage capacity for one unit [MWh]	6	7	8	5	9	7	7
Output capacity for one unit [MW]	18	21	24	16	21	22	22
Input capacity for one unit [MW]	3	3.5	4	2.7	3.5	3.7	3.7
Round trip efficiency [%] AC	91	92	92	90	92	91	91
Round trip efficiency [%] DC	95	96	96	95	96	95	95
- Charge efficiency [%]	98	98.5	98.5	98	98.5	98	98
- Discharge efficiency [%]	97	97.5	97.5	97	98	97	97
Energy losses during storage [%/day]	0.1	0.1	0.1	0.05	0.2	0.05	0.05
Forced outage [%]	0.38	0.35	0.25	0.2	0.5	0.1	0.1
Planned outage [weeks/year]	0.2	0.1	0.1	0.1	0.25	0.05	0.05
Technical lifetime [years]	20	25	30	15	25	20	20
Regulation ability							
Response time from idle to full-rated discharge [sec]	0.08	0.08	0.08	0	0.08	0	0
Response time from full-rated charge to full-rated discharge [sec]	0.08	0.08	0.08	0	0.08	0	0
Financial data							

Specific investment [MEUR/MWh]	1.11	0.66	0.27	0.94	1.94	0.18	1.04
- energy component [MEUR/MWh]	0.14	0.07	0.04	0.07	0.20	0.03	0.12
- capacity component [MEUR/MW] PCS	0.29	0.17	0.06	0.26	0.54	0.04	0.27
- other project costs [MEUR/MWh]	0.11	0.09	0.04	0.10	0.12	0.02	0.12
Fixed O&M [kEUR/MW/year]	0.57	0.57	0.57	0.48	0.57	0.43	0.57
Technology-specific data							
Energy storage expansion cost [MEUR/MWh]	0.25	0.15	0.08	0.17	0.28	0.05	0.19
Output capacity expansion cost [MEUR/MW]	0.29	0.17	0.06	0.26	0.54	0.04	0.27
Alternative Investment cost [MEUR/MW]	0.35	0.21	0.09	0.30	0.62	0.05	0.33
Lifetime in total number of cycles	14000	30000	50000	10000	16000	20000	70000
Specific power [W/kg]	315	417	627	300	420	450	900
Power density [kW/m3]	390	519	780	450	600	600	1200
Specific energy [Wh/kg]	105	139	209	100	140	150	300
Energy density [kWh/m3]	130	173	260	150	200	200	400

5.4.2 Technical- and economic assumptions

Table 5-9: Technical- and economic assumptions for a Sodium Sulphur (NaS) battery [28]

Technology	**Lithium-ion NMC battery (Utility-scale, Samsung SDI E3-R135)**							
year	**2020**	**2030**	**2040**	**2050**	**2020**	**2020**	**2050**	**2050**
est	**ctrl**	**ctrl**	**ctrl**	**ctrl**	**Lower**	**Upper**	**Lower**	**Upper**
Energy/technical data								
Form of energy stored	Chemical	Chemical	Chemical	Chemical	Chemical	Chemical	Chemical	Chemical
Energy storage capacity for one unit [MWh]	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7
Output capacity for one unit [MW]	-	-	-	-	-	-	-	-
Input capacity for one unit [MW]	0.095	0.09	0.08	0.08	0.1	0.99	0.085	0.08
Round trip efficiency [%]	0.88	0.89	0.90	0.90	0.88	0.88	0.90	0.90
- Charge efficiency [%]	0.88	0.89	0.90	0.90	0.88	0.88	0.90	0.90
- Discharge efficiency [%]	1	1	1	1	1	1	1	1
Energy losses during storage [%/day]	1	1	1	1	0	1	0	1
Auxiliary electricity consumption [% of output]	1	1	1	1	0	1	0	1
Forced outage [%]	0	0	0	0	0	0	0	0
Planned outage [weeks/year]	3	2	1.5	1	3	3	1.5	0.5
Technical lifetime [years]	25	30	30	30	25	25	30	30
Construction time [years]	0.5	0.4	0.4	0.3	0.5	0.5	0.3	0.2
Regulation ability								
Primary regulation [%/30 sec]	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Secondary regulation [%/minute]	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Financial data								
Specific investment [MEUR/MWh]	0.06	0.05	0.03	0.02	0.06	0.06	0.04	0.02
Compressor component [MEUR/MWh]	0.03	0.03	0.01	0.01	0.03	0.03	0.02	0.01
Type I tanks component [MEUR/MWh]	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01
Installation, equipment, manhours	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Fixed O&M [EUR/MW/year]	638.04	531.70	531.70	425.36	638.04	638.04	478.53	319.02
Variable O&M [EUR/MWh]	-	-	-	-	-	-	-	-
Technology-specific data								
Gravimetric energy density [kWh/kg]	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3
Volumetric energy density @0oC and	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Permeation characteristics for Type I	2.84×10-	2.84×10-	2.84×10-27	2.84×10-	2.84×10-	2.84×10-	2.84×10-27	2.84×10-

5.5 E-fuel Storage

E-fuel storage is a crucial technology for various industrial applications, particularly in the transportation and power generation sectors. Currently, most e-fuels (electrofuels) are synthesized using renewable electricity to produce hydrogen, which is then combined with carbon dioxide to form synthetic hydrocarbons such as e-methanol, e-diesel, or e-kerosene.

With growing interest in decarbonization, e-fuels are gaining traction as a means to store surplus renewable energy, enable sector coupling in energy systems, and provide a sustainable alternative for hard-to-electrify sectors like aviation, shipping, and heavy-duty transport.

E-fuel storage technologies can be categorized into gaseous, liquid, and solid-state methods. Gaseous e-fuels, such as synthetic methane or hydrogen-rich blends, require compression or liquefaction to be stored effectively, often at high pressures or cryogenic temperatures. Liquid e-fuels, including e-methanol and e-diesel, can be stored in conventional tanks, making them more compatible with existing logistics and distribution networks.

In Greenland, e-fuel storage could provide a reliable energy source by utilizing surplus renewable electricity for on-site fuel production. This could be particularly beneficial for off-grid areas, islands, or regions with fluctuating renewable energy supply. However, challenges include the need for robust storage facilities to prevent fuel degradation, infrastructure investments to handle synthetic fuel distribution, and regulatory frameworks to ensure safe handling and environmental compliance.

Table 5-10: Technical- and economic assumptions for a hysrogen storage. [28]

Energy/technical data	2020	2030	2040	2050
Form of energy stored	Chemical	Chemical	Chemical	Chemical
Application	Local	Local	Local	Local
Energy storage capacity for one unit [MWh]	16.7	16.7	16.7	16.7
Output capacity for one unit [MW]	-	-	-	-
Input capacity for one unit [MW]	0.095	0.09	0.08	0.08
Round trip efficiency [%]	88%	89%	90%	90%
- Charge efficiency [%]	88%	89%	90%	90%
- Discharge efficiency [%]	100%	100%	100%	100%
Energy losses during storage [%/period]	1	1	1	1
Auxiliary electricity consumption [% of output]	1	1	1	1
Forced outage [%]	0	0	0	0
Planned outage [weeks/year]	3	2	1.5	1
Technical lifetime [years]	25	30	30	30
Construction time [years]	0.5	0.4	0.4	0.3
Regulation ability				
Primary regulation [%/30 sec]	3.3	3.3	3.3	3.3
Secondary regulation [%/minute]	6.7	6.7	6.7	6.7
Financial data				
Specific investment [MEUR/MWh]	0.061	0.048	0.029	0.022
Compressor component [MEUR/MWh]	0.032	0.025	0.014	0.008
Type I tanks component [MEUR/MWh]	0.019	0.017	0.012	0.010
Installation, equipment, manhours [MEUR/MWh]	0.010	0.008	0.007	0.005
Fixed O&M [EUR/MW/year]	638.04	531.7	531.7	425.36
Variable O&M [EUR/MWh]	-	-	-	-
Technology-specific data				
Gravimetric energy density [kWh/kg]	33.3	33.3	33.3	33.3
Volumetric energy density @0oC and 1atm pressure [kWh/m3]	0.09	0.09	0.09	0.09
Permeation characteristics for Type I tanks [mol/s/m/MPa1/2]	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}	2.84×10^{-27}

5.6 Hydro Reservoir Storage

Hydro reservoir storage systems consist of a dam constructed across a river, creating a large reservoir of water. The stored water represents potential energy, which can be converted into electricity by releasing it through turbines situated at the base of the dam. As water flows from the reservoir through these turbines, it spins the turbines' blades, converting kinetic energy into mechanical energy. This mechanical energy is then transformed into electrical energy via a generator connected to the turbine.

The energy generation capacity of a hydro reservoir system is primarily dependent on the height of the water column (hydraulic head) and the flow rate of the water. The greater the height and the higher the flow rate, the more electricity can be produced. Hydro reservoir plants can range from small-scale installations to massive projects capable of generating gigawatts of power.

Unlike pumped hydro storage, which involves two reservoirs at different elevations and the ability to pump water back up to the higher reservoir, hydro reservoir storage relies solely on the gravitational flow of water from a single reservoir to generate power. Hydro reservoir storage offers several advantages. It provides a consistent and reliable source of electricity, capable of meeting both base-load and peak-load demands. The systems have a long operational life, often exceeding 50 years with proper maintenance. The energy conversion efficiency of hydro reservoir plants is relatively high, typically between 70-90%. Additionally, these systems can store large amounts of energy, making them suitable for large-scale energy storage needs. As a renewable and clean energy source, hydro reservoir storage produces no direct emissions during operation.
However, there are disadvantages to hydro reservoir storage. The construction of dams and reservoirs can have significant environmental impacts, including habitat disruption, changes in water quality, and effects on ecosystems. The initial capital investment required for building these systems is substantial. The effectiveness of hydro reservoirs is heavily dependent on hydrological conditions, with droughts or changes in precipitation potentially reducing energy generation capacity.

In Greenland, the potential for hydro reservoir storage is considerable due to abundant water resources from melting glaciers and high precipitation rates. Greenland's reservoirs could harness meltwater from glaciers, but this is subject to seasonal and climate change-related variations. Greenland has significant hydropower potential, but only a small portion is currently utilized by five plants near towns. Large untapped resources exist, requiring local energy-intensive industries due to the impracticality of building extensive transmission lines.

The unique and fragile ecosystems in Greenland require careful consideration to minimize environmental impacts. Additionally, developing hydro reservoir projects in remote and rugged terrains can be challenging and costly due to the need for extensive infrastructure.

5.6.1 Technical- and economic assumptions

Table 5-11: Technical- and economic data for key Hydropower storage plants [37]

Country	Technology	Net capacity	Capacity factor	Overnight costs	Investment costs 3%	Investment costs 7%	Investment costs	LCOE 3%	LCOE 7%	LCOE 10%
		MWe	%	USD/kW	USD/kW	USD/kW	USD/kW	USD/MWh	USD/MWh	USD/MWh
Italy	Reservoir (<= 5 MW)	0.32	0.65	3966	4274	4719	5079	24.32	55.93	55.93
Japan	Reservoir (>= 5 MW)	15.00	0.38	3108	3349	3697	3980	32.95	75.78	114.47
Japan	Reservoir (>= 5 MW)	12.00	0.45	5819	6271	6923	7452	51.90	119.38	180.33
Norway	Reservoir (<= 5 MW)	30.00	0.52	1899	2047	2260	2432	14.66	33.72	50.94
India	Reservoir (>= 5 MW)	175.00	0.60	2449	2639	2914	3136	16.38	37.68	56.92

Table 5-12: Technical- and economic general figures for Hydro Reservoir facilities [38]

Category	Data
Total Installed Costs (Large-Scale Projects)	USD 1,000/kW to USD 3,500/kW
Costs for Existing Dams	As low as USD 500/kW
Remote Sites Costs	Significantly more than USD 3,500/kW
US Average Capital Cost	USD 1,650/kW
World Average Investment Cost	USD 1,000/kW
US 90% Projects Cost	Below USD 3,350/kW
World 90% Projects Cost	USD 1,700/kW or less
Small Hydro Projects Costs (UK, 1-7 MW)	USD 3,400 to USD 4,000/kW

Small Hydro Projects Costs (<1 MW)	USD 3,400 to USD 10,000/kW or more
Economic Lifetimes (Large-Scale Projects)	40 to 80 years
Economic Lifetimes (Small-Scale Projects)	Typically 40 years
Cost Breakdown (500 MW Greenfield, US)	
- Reservoir	USD 911/kW (26%)
- Tunnel	USD 486/kW (14%)
- Powerhouse and Shafts	USD 499/kW (14%)
- Powerhouse Equipment	USD 556/kW (16%)
- Engineering, Procurement & Construction Management	USD 238/kW (7%)
- Owner's Cost	USD 810/kW (23%)
O&M Costs (Large-Scale Projects)	2% to 2.5% of investment cost per kW per year
O&M Costs (Small-Scale Projects)	Around 4% of total capital cost
Average O&M Costs (Large-Scale)	USD 45/kW/year
Average O&M Costs (Small-Scale)	USD 52/kW/year

Table 5-13: Technical- and economic potential key figures for selected Hydro Reservoir facilities

	Umiviit: 07.f	**Tasersiaq 07.e**	**Imarsuup 06.g**	**Buksefjorden 2: 06.b-1**	**Buksefjorden 3: 06.b-2**	**Combining all potentials**
Output (MW)	100	360	150	65	45	720
Energy produced (GWh)	875	3150	1300	570	390	6300
Energy delivered (GWh)	830	3000	1250	540	370	5955
CAPEX (MM $)	365	680	285	200	115	1645
OPEX (MM $)	11	21	9	6	4	51
LCOE ($/MWh) Cost of capital (5%)	48	25	26	42	37	31
LCOE ($/MWh) Cost of capital(10%)	65	35	36	49	43	42

5.7 Diesel Tank System

Diesel tanks are used for storing the diesel used for the diesel generators at the remote mines.

High capacity diesel tanks are needed in cases where the mines are located in remote places, and where supplies will only come a few times a year.

Table 5-14: Classification guidelines for CAPEX estimate

Estimate classification					
Estimate class	**Scope Definition**	**End Usage**	**Methodology**	**Expected Accuracy Range**	**Expected Contingency**
Class 5	0% to 2%	Screening study	Capacity factors, pragmatic models, judgement, or analogy	-50% / 100%	25% - 40%
Class 4	1% to 15%	Feasibility study	Equipment factored or parametric models	-30% / +50%	25% - 40%
Class 3	10% to 40%	FEED study	Semi-detailed unit costs with assembly level line items. Some vendor items	-20% / +30%	15% - 30%
Class 2	30% to 70%	Budget MCE	Detailed unit cost with forced detailed take -off, and vendor quotations	-15% / +20%	10% - 20%
Class 1	65% to 100%	Execute CCE	Detailed unit cost with detailed take -off	-10% / +15%	7% - 15%

Table 5-15: Disel tank CAPEX and OPEX for a basis of 2 steel tanks with a weight of 1000 tonne. At 2024 costs.



Cost items	Values	€	%
PM& Engineering	480 000	Euro	6 %
Procurement of tank & facilities	4 800 000	Euro	59 %
Instalaltion of tank and facilities	2 000 000	Euro	24 %
Civil work	800 000	Euro	10 %
Commisasioning	100 000	Euro	1 %
CAPEX values	8 180 000	Euro	
Weight t	2000	Tonne	
Benchmarking	4090	€/t	
OPEX yearly	81 800		



Basis 2 steel tank with a weight of 2000 tonne
Todays (2024) cost

6. Microgrids

When planning for heating and electricity networks in Arctic conditions, such as in Greenland, additional considerations must be made due to the extreme climate and geographical challenges. Greenland's energy landscape is characterized by isolated microgrids that serve individual communities, which are essential due to the vast distances between settlements and the absence of a national grid. The harsh Arctic climate imposes significant stress on infrastructure, making reliability and resilience crucial. Planning must account for the potential impact of severe weather events, the availability of local renewable energy sources like hydropower, and the difficulty of maintaining and repairing infrastructure in remote and challenging environments. Additionally, the integration of renewable energy into these microgrids must be carefully managed to ensure stability, particularly given the variability of sources like wind and solar power in such extreme climates.

A microgrid is a localized group of electricity sources and loads that normally operates connected to and synchronous with the traditional wide area synchronous grid (macrogrid), but can also disconnect to "island mode" — and function autonomously as physical or economic conditions dictate. In this way, a microgrid can effectively integrate various sources of disitrbuted generation (DG), especially renewable energy sources (RES) - renewable electricity, and can supply emergency power, changing between island and connected modes.

Control and protection are challenges to microgrids. A very important feature is also to provide multiple end-use needs as heating, cooling, and electricity at the same time since this allows energy carrier substitution and increased energy efficiency due to waste heat utilization for heating, domestic hot water, and cooling purposes (cross sectoral energy usage).

Arctic microgrids emphasize the importance of robust and simple designs due to the harsh environmental conditions and limited technical expertise available on-site. Alaska's microgrids for example demonstrate that modest energy storage and innovative thermal energy management can significantly enhance project success, particularly in achieving high penetration of renewable energy sources like wind. Solar energy, despite seasonal challenges, can also play a crucial role in these regions.

6.1 Distric Heating Transmission and Distribution Networks

District heating is a centralized system that provides heat to multiple buildings from a single source, such as a power plant, waste incineration facility, or renewable energy installations like geothermal or biomass plants. The heat generated at these plants is transported through a network of insulated pipes filled with hot water or steam. These networks are divided into two main parts: the transmission network and the distribution network.

The transmission network consists of large pipes that carry the hot water or steam over long distances from the central heat source to various local areas or substations. Transmission network will not be relevant in microgrids as it will run in island-mode.

The distribution network is a smaller-scale system within the transmission network that takes the heat from the local substations and delivers it directly to individual buildings, and will be the prfered network in microgrids. The distribution network includes smaller pipes and infrastructure such as heat exchangers and meters, which ensure that heat is delivered safely and efficiently to each end user.

Greenland does not have a centralized district heating (DH) transmission network due to its isolated and dispersed settlements. However, within each microgrid or town, there is a local distribution network that delivers heat from centralized sources, such as waste incineration plants or local boilers, to individual buildings. These distribution networks operate independently within each community, ensuring that heat is efficiently supplied to residential and commercial buildings within the microgrid's geographical area.

6.1.1 Technical- and economic assumptions

Table 6-1: Technical- and economic assumptions for DH main transmission cables (2030)[28]

Technology					Energy Transport DH Transmission, electricity cables
Energy/technical data					
Energy losses, lines 1-20 MW [%]					3
Energy losses, lines 20-100 MW [%]					1
Energy losses, lines above 100 MW [%]					0.5
Energy losses, Heat exchanger stations [%]					5
Energy losses, Pumping stations [%]					N/A
Auxiliary electricity consumption [%] energy transmitted					2
Technical life time [years]					40
Typical load profile (-)					1
Construction time [years]					4
Financial data					
Investment costs; single line, 0 - 50 MW					27

Investment costs; single line, 50-100 MW	13
Investment costs; single line, 100 - 250 MW	10
Investment costs; single line, 250-500 MW	6
Investment costs; single line, 500-1000 MW	N/A
Investment costs; single line, above 1000 MW	N/A
Reinforcement costs [EUR/MW]	N/A
Investment costs; type 1 station [EUR/MW]	
Investment costs; type 2 station [EUR/MW]	
Investments, percentage installation	1
Investments, percentage materials	0
Fixed O&M [EUR/MW/km/year]	N/A
Variable O&M [EUR/MWh/km]	0.1

Table 6-2: Technical- and economic assumptions for electric main transmission cables [28]

Technology	Energy Transport DH Distribution, Rural	Energy Transport DH Distribution, Suburban	Energy Transport DH Distribution, City	Energy Transport DH Distribution, New developed areas
Energy/technical data				
Energy losses, lines [%]	15	14	5	18
Energy losses, Heat exchanger stations [%]	5	5	5	5
Auxiliary electricity consumption [%] of energy delivered	2	2	2	2
Technical life time [years]	40	40	40	40
Typical load profile (-)				
- Residential	0.2	0.2	0.2	0.2
- Commercial	N/A	N/A	N/A	N/A
Construction time [years]	1	1	1	1
Financial data				
Distribution network costs [EUR/MWh/year], Rural	766	696.51	160	696.51
Investment costs; service line, 0 - 20 kW [EUR/unit]	4025	4280	4939	3110
Investment costs; service line, 20 - 50 kW [EUR/unit]	4397	4676	5343	3589
Investment costs; service line, 50-100 kW [EUR/unit]	5035	5354	6045	4014
Investment costs; service line, above 100 kW [EUR/unit]	N/A	N/A	6588	N/A
Investment costs; single line, 0-50 kW [EUR/m]	297	316	336	191
Investment costs; single line, 50-250 kW [EUR/m]	377	401	426	249
Investment costs; single line, 100-250 kW [EUR/m]	393	418	444	266
Investment costs; single line, 250 kW - 1 MW [EUR/m]	489	520	553	340
Investment costs; single line, 1 MW - 5 MW [EUR/m]	681	724	770	484
Investment costs; single line, 5 MW - 25 MW [EUR/m]	1260	1340	1425	957
Investment costs; single line, 25 MW - 100 MW [EUR/m]	N/A	N/A	N/A	N/A
Reinforcement costs [EUR/MW]	N/A	N/A	N/A	N/A
Heat exchanger station [EUR/MW]			106337	
Pumping station [EUR/MW]	95704		95704	95704
Investments, percentage installation	0.85	0.85	0.85	0.75
Investments, percentage materials	0.15	0.15	0.15	0.25
Fixed O&M [EUR/MW/year]	N/A	N/A	N/A	N/A
Variable O&M [EUR/MWh]	1.6	1.6	1.6	1.6
Technology-specific data				
Heat exchanger station below 1 MW[EUR/MW]			281794	
Pumping station below 1 MW [EUR/MW]			255209	

6.2 Electric Transmission and Distribution Networks

Electrical transmission and distribution networks are integral parts of the power system.

The Transmission Network is the high-voltage part of the system, responsible for transporting electricity over long distances from power plants to substations. Transmission lines typically operate at voltages ranging from 69 kV to over 765 kV, allowing efficient movement of large amounts of electricity with minimal losses. This network handles the bulk transfer of electricty across regions. After electricity reaches substations, it is stepped down to lower voltages (usually between 4 kV and 33 kV) and distributed to homes, businesses, and industries through the distribution network. This network includes distribution lines, transformers, and other infrastructure that delivers electricity directly to end users.

Greenland does not have an interconnected electrical transmission network like many other countries. Each microgrid operates independently, generating electricity locally through a combination of hydropower plants, diesel generators, and renewable energy sources like wind and solar and through a distribution network. Within these microgrids, distribution networks deliver electricity from local generation sources to homes, businesses, and other consumers. These networks include transformers, power lines, and substations, ensuring that electricity reaches end-users efficiently within the microgrid's limited geographical area.

6.2.1 Technical- and economic assumptions

Table 6-3: Technical- and economic assumptions for electric main transmission cables [28]

Technology	Energy Transport Electricity Main
Energy/technical data	
Energy losses, lines 1-20 MW (%)	0.3
Energy losses, lines 20-100 MW (%)	0.3
Energy losses, lines above 100 MW (%)	0.3
Energy losses, stations [Type 1] (%)	0.2
Energy losses, stations [Type 2] (%)	N/A
Auxiliary electricity consumption (% energy transmitted)	N/A
Technical life time (years)	40
Typical load profile (-)	0.45
Construction time (years)	1.5
Financial data	
Investment costs; single line, 0 - 50 MW (EUR/MW/m)	6
Investment costs; single line, 50-100 MW (EUR/MW/m)	3.9
Investment costs; single line, 100 - 250 MW (EUR/MW/m)	3.1
Investment costs; single line, 250-500 MW (EUR/MW/m)	N/A
Investment costs; single line, 500-1000 MW (EUR/MW/m)	N/A
Investment costs; single line, above 1000 MW (EUR/MW/m)	N/A
Reinforcement costs (EUR/MW)	15800
Investment costs; [type 1] station (EUR/MW)	76000
Investment costs; [type 2] station (EUR/MW)	4476
Investments, percentage installation	0.42
Investments, percentage materials	0.58
Fixed O&M (EUR/MW/km/year)	21.79
Variable O&M (EUR/MWh/km)	N/A

Table 6-4: Technical- and economic assumptions for electric main transmission cables [28]

Technology	Energy Transport Electricity Distribution, Rural	Energy Transport Electricity Distribution, Suburban	Energy Transport Electricity Distribution, City	Energy Transport Electricity Distribution, New developed areas
Energy/technical data				
Energy losses, lines (%)	5.25	3.00	2.25	3.00
Energy losses, stations (%)	1.13	1.13	1.13	1.13
Auxiliary electricity consumption (% of energy delivered)	N/A	N/A	N/A	N/A
Technical life time (years)	40	40	40	40
Typical load profile (-)	0.44	0.48	0.50	0.48
- Residential	0.44	0.48	0.50	0.48
- Commercial	0.44	0.48	0.50	0.48

Construction time (years)	1	1	1	1
Financial data				
Distribution network costs (EUR/MWh/year) Rural	173	385	365	173
Investment costs; service line, 0 - 20 kW (EUR/unit)	524	1436	2149	524
Investment costs; service line, 20 - 50 kW (EUR/unit)	1412	4031	5618	1412
Investment costs; service line, 50-100 kW (EUR/unit)	1583	4243	5774	1583
Investment costs; service line, above 100 kW (EUR/unit)	3745	9066	12131	3745
Investment costs; single line, 0-50 kW (EUR/m)	N/A	N/A	N/A	N/A
Investment costs; single line, 50-250 kW (EUR/m)	N/A	N/A	N/A	N/A
Investment costs; single line, 100-250 kW (EUR/m)	36	N/A	N/A	36
Investment costs; single line, 250 kW - 1 MW (EUR/m)	36	75	115	36
Investment costs; single line, 1 MW - 5 MW (EUR/m)	41	80	120	41
Investment costs; single line, 5 MW - 25 MW (EUR/m)	88	128	169	88
Investment costs; single line, 25 MW - 100 MW (EUR/m)	N/A	N/A	N/A	N/A
Reinforcement costs (EUR/MW) (Station)	11500	11500	11500	11500
Investment costs; [type 1] station (EUR/MW)	67500	38000	38000	38000
Investment costs; [type 2] station (EUR/MW)	N/A	N/A	N/A	N/A
Investments, percentage installation (cables)	0.62	0.80	0.86	0.80
Investments, percentage materials (cables)	0.38	0.20	0.14	0.20
Investments, percentage installation (stations)	0.22	0.14	0.05	0.14
Investments, percentage materials (stations)	0.78	0.86	0.95	0.86
Fixed O&M (EUR/MW/year)	1605	2644	0	1339
Variable O&M (EUR/MWh)	N/A	N/A	N/A	N/A