Opportunities for thermal energy storage in Longyearbyen

Koen van Greevenbroek
Department of Computer Science, UiT The Arctic University of Norway, Tromsø, Norway
koen.v.greevenbroek@uit.no
orcid.org/0000-0002-6105-2846

Lars-Stephan Klein
Department of Physics, University of Freiburg, Germany
orcid.org/0000-0003-1090-4970

Executive summary. Energy storage is needed in Longyearbyen to enable a transition to local renewable energy sources. As heating accounts for more than half the energy use in Longyearbyen, affordable large-scale thermal storage is a good option. We investigate the opportunities for hot water, molten salt and hot rocks storage systems using a techno-economic optimisation model for the Longyearbyen energy system. Some of our **key findings** include:

- Thermal storage, in combination with hydrogen and batteries, can effectively absorb variations in wind and solar power generation for Longyearbyen.
- Different storage options can play different roles, and including thermal storage can reduce total Longyearbyen energy system costs significantly.
- Thermal storage technologies can be integrated with the district heating system, are proven technologies used at industrial scale and have a low environmental impact.

Based on our findings, we make the following **recommendations** concerning the development of the energy system in Longyearbyen:

- Consider integrating a variety of different storage technologies, including thermal storage, hydrogen storage and batteries with a local renewable energy supply for Longyearbyen.
- Investigate heat sources such as fjord water and geothermal boreholes for a large scale heat pump to drive the district heating system.
- Conduct a more detailed feasibility study into the integration of thermal storage with the district heating system, including siting, heat pump design and technological details such operating temperatures and varying efficiencies.

2nd July 2021. Longyearbyen, Svalbard.
Produced during the UNIS course AGF-353/853.

1 Introduction

Longyearbyen is facing a unique challenge: in the next decade, the complete energy supply must switch away from the current coal power plant. There are many options for the future development of the Longyearbyen energy system, but the long-term goal is to use as much renewable energy as possible [1]. While wind turbines and PV (solar) panels are well-tested renewable energy technologies with good potential around Longyearbyen [2], their generation profile is highly variable. Therefore, any highly renewable local energy system will need energy storage to even out the variations in wind and solar output.

A distinct feature of Longyearbyen is its district heating system, which provides almost all heating needs year-round [3]. While the district heating system is current driven mainly by the coal power plant, it is desirable to preserve the heating infrastructure beyond the end of coal-burning. Therefore, renewable energy solutions for Longyearbyen should work well together with district heating.

Variable wind and solar power driving a district heating system naturally leads us to consider thermal energy storage. Large scale thermal storage solutions tend to be cheaper than alternatives such as hydrogen storage and batteries, and they can feed directly into the district heating system. Moreover, thermal energy storage has already been shown to be a viable option for Longyearbyen in a previous report [4].

In this report, we explore the opportunities for three different kinds of thermal energy storage in Longyearbyen: hot water storage, molten salt storage and hot rock storage. The scenario we explore is one where Longyearbyens entire electricity and heat demand are satisfied by local wind and PV power. In this case, heating is electrified using a heat pump drawing on Isfjorden, which provides a constant temperature. Apart from thermal energy storage, we also consider the options of hydrogen storage and batteries.

Question: In a scenario where Longyearbyen is supplied by local renewable energy sources,

1. Is the use of thermal energy storage cost-effective?
2. What mix of storage technologies is the most effective?

In order to answer these questions, we design and implement a techno-economic bottom-up optimisation model for the Longyearbyen energy system. We design the model to accurately capture short- and long-term variations in weather, and optimise capacities and operation of both generation and storage units.

1.1 Previous work

Electric thermal energy storage for Longyearbyen was previously explored in a report by Duchini, Fliegner, Grabinsky *et al.* [4]. They consider only hot rocks storage, and focus more on technological details and implementation. However, they do not model synergies with renewable energy sources or the interaction of storage with the wider energy system.

The Longyearbyen energy system has been modelled before by Ringkjøb, Haugan and Nybø [5]. The TIMES-Longyearbyen model presented in [5] integrates a larger variety of technologies than we could (including thermal energy storage), but is not capable of resolving weather variations on the scale of weeks. This is because it only models a number of representative days from different seasons. Storage in the TIMES-Longyearbyen model can therefore only be used on a strictly daily or seasonal scale, which severely limits its application in combination with

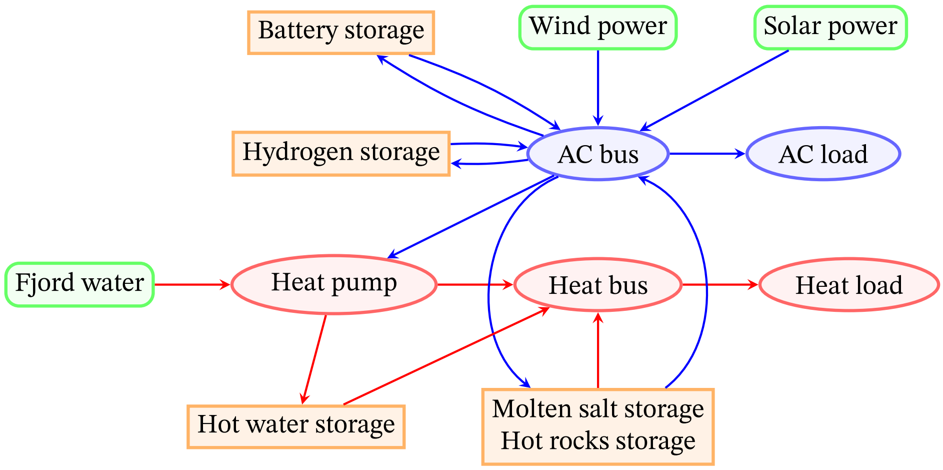

Figure 1: A schematic of the energy system model for Longyearbyen. Blue and red arrows indicate flow of electricity and heat, respectively.

wind turbines. The model presented in this report is run at a full hourly resolution over 9 weather years, allowing an accurate and robust representation of different storage technologies.

2 Methods

We first elaborate on the design and implementation of the model we used to investigate the Longyearbyen energy system. Afterwards, we look more closely at the different storage technologies we decided to include, and how the heating sector can be electrified using a heat pump.

2.1 Model design and implementation

The main objective of our model is to find the most affordable combination of generation and storage technologies satisfying the energy demand in Longyearbyen. The model takes a bottom-up greenfield approach: we assume that the coal power plant is decommissioned, and look for the most cost-effective solution starting with no other existing components than the district heating system. As such, the model is a tool to explore what the future energy system of Longyearbyen *could* look like. See [6], [7] for broad introductions to current methods and challenges in energy systems modelling. Figure 1 shows a schematic of the different components included in the model, and how they are connected.

Our model is designed to optimise both the installed capacities of included technologies (wind, PV, heat pump, storage) and their operation over the course of one or multiple years. In order to ensure feasibility of the system, its operation is simulated at an hourly resolution. See Figure 2 for an overview of the inputs and outputs of the model. The model is formulated as a linear optimisation model, with total system cost as the objective function. The system cost is a combination of variable costs and annualised investment costs. In our case, almost all significant costs are investments in renewable generation, heat pumps and storage.

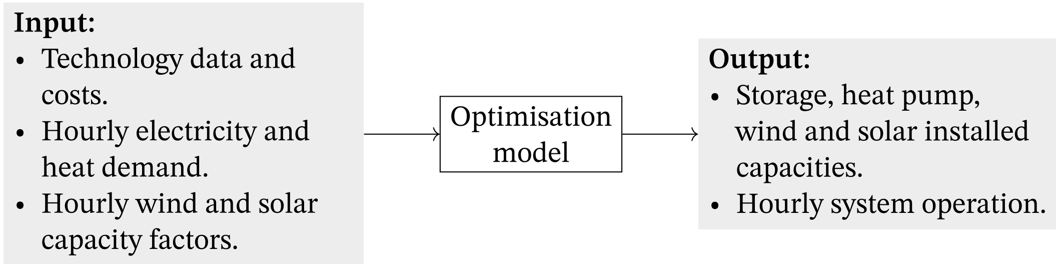

Figure 2: Overview of the input and output of the Longyearbyen energy system model.

2.2 Input data

To model the local energy system and the potential to integrate renewable energy and storage, we need a number of input time series.

Wind data is collected from measurements at three different locations around Longyearbyen for the years 2011–2020, and converted to capacity factors using the power curves of a number of different wind turbines. This processing was done in [9], and we refer to that report for details on the wind data used.

PV hourly capacity factors for the years 2011–2019 are calculated from reanalysis data using `renewables.ninja` [10], [11].

Load data, both heat and electricity, were obtained from NVE on an hourly basis for 2017 and 2018 [12]. In order to run the model for longer periods of weather data, we extended the load data to the period 2021–2020 by repeating the two given years.

Costs of the various technologies included in the model were obtained from a number of different sources. Costs and other parameters for some of the key technologies studied in this report were collected by the authors mainly from commercial sources. Costs of other technologies needed for the model were adapted from the PyPSA-Eur model [13]. The costs and their sources are documented in detail together with the model source code at `https://gitlab.com/koenvg/pypsa-longyearbyen`.

2.3 Thermal storage

For the thermal storage multiple main objectives have been identified which serve as frame conditions for the choice of a suitable system:

1. **Reliability and cost-effectiveness.** Out of the great number of thermal storage concepts this white paper focuses on field-tested technologies only that have reached commercial use at industrial scale.
2. **Low environmental impact.** The system shall provide a high energy density to require a minimal amount of storage volume and consequently a minimal amount of new building area.
3. **Local acceptance.** The impact of the transition to renewable energy on the local community shall be minimised. This means that the existing system heating system shall be continued with the same water temperatures such that no modifications of the heaters in the buildings are necessary.

Three techniques have been chosen for the model that fulfil these criteria:

Mathematical modelling formulation

For this study we use a linear optimisation model to solve the *capacity expansion problem*. The model is implemented using the PyPSA framework [8], and sticking to established naming conventions, we call our model *PyPSA-Longyearbyen*. Its source code is openly available at `https://gitlab.com/koenvg/pypsa-longyearbyen`. We refer to the source code and accompanying documentation for a complete and precise description of the model.

What follows is a simplified description of a linear program describing the capacity expansion problem. Here we consider N generators (index i), M storage units (index j) and T time steps (index t), but leave out the heating sector and a number of details for brevity. The objective function is the total investment cost. Note in particular that the first and second constraints respectively ensure that demand d_t is satisfied, and that the state of charge of the storage units is updated from one time step to the next.

Minimise:

$$\sum_i C_i \cdot g_i + \sum_j C_j^{\text{pow}} \cdot s_j + \sum_j C_j^{\text{store}} \cdot s_j^{\text{store}}$$

Such that:

$$\begin{array}{rcll}
\sum_i g_i \cdot x_{it} + & & & \\
\sum_j s_j \cdot y_{jt}^{\text{out}} - \sum_j s_j \cdot y_{jt}^{\text{in}} & = & d_t & \text{for all } t \in \{1, \dots, T\} \\
e_{jt} + s_j \cdot y_{jt}^{\text{in}} - s_j \cdot y_{jt}^{\text{out}} & = & e_{j(t+1)} & \text{for all } t \in \{1, \dots, T-1\} \text{ and } j \in \{1, \dots, M\} \\
x_{it} & \leq & c_{it} & \text{for all } t \in \{1, \dots, T\} \text{ and } i \in \{1, \dots, N\} \\
y_{jt}^{\text{in}}, y_{jt}^{\text{out}} & \leq & 1 & \text{for all } t \in \{1, \dots, T\} \text{ and } j \in \{1, \dots, M\} \\
e_{jt} & \leq & s_j^{\text{store}} & \text{for all } t \in \{1, \dots, T\} \text{ and } j \in \{1, \dots, M\} \\
g_i & \leq & g_i^{\text{max}} & \text{for all } i \in \{1, \dots, N\} \\
x_{it}, y_{jt}^{\text{in}}, y_{jt}^{\text{out}}, e_{jt}, g_i^{\text{exp}} & \geq & 0 & \text{for all } t \in \{1, \dots, T\}, i \in \{1, \dots, N\} \text{ and } j \in \{1, \dots, M\} \\
e_{j0} & = & 0 & \text{for all } j \in \{1, \dots, M\}
\end{array}$$

The meanings of the variables are as follows:

Variable	Meaning	Role	Unit
i, j, t	Indices for generators, stores and time steps	Index	Unit-less
x_{it}	Commitment of generator i at time t	Dec.	Unit-less
$y_{jt}^{\text{in}}, y_{jt}^{\text{out}}$	In- and outflow from storage j at time t	Dec.	Unit-less
g_i	Inst. capacity of generator i	Dec.	MW
s_j	Inst. charger/discharger capacity storage j	Dec.	MW
s_j^{store}	Size of storage j	Dec.	MWh
e_{jt}	State of charge of storage j	Dec.	MWh
C_i	Investment cost generator i	Input	EUR / MW
C_j^{pow}	Investment cost storage j charger/discharger	Input	EUR / MW
C_j^{store}	Investment cost storage j size	Input	EUR / MWh
d_t	Energy demand at time t	Input	MW
c_{it}	Capacity factor of generator i at time t	Input	Unit-less
g_i^{max}	Maximum allowed size generator i	Input	MW
g_i^{max}	Maximum allowed size generator i	Input	MW

1. **Hot water tank** in which liquid water with a temperature up to 140 °C is stored under pressure and can be directly used for the district heating system down to a temperature of 90 °C. The water is heated by a heat pump.

2. **Molten salt tank** in which a liquid eutectic salt mixture with 60 % sodium nitrate ($NaNO_3$) and 40 % potassium nitrate (KNO_3) is stored. The mixture stays liquid down to 250 °C and can be used in a temperature span of 550 °C down to 290 °C. The salt is heated by a electric resistance heater [14].

3. **Hot rock thermal storage** using crushed rocks in an insulated storage unit at temperatures of 800 °C down to around 400 °C. The stones are heated by an electric heater blower [15].

While a hot water tank can be directly integrated into the district heating system, solutions 2 & 3 require salt-to-water and air-to-water heat exchanger respectively. However, molten salt tanks and hot rock thermal storages allow to produce electricity from the thermal energy using a steam turbine. For the hot rock storage crushed hazelnut-sized basalt stones have been considered in the model since multiple large-scale facilities are running with this configuration and a large number of data are available [15], [16] that have been used for the model.

2.4 Centralised heat pump

A standard practice when electrifying heating is to use a heat pump. In our scenario, we assume that the district heating system is driven by a combination of a centralised heat pump and thermal storage. At the same time, hot water storage can also be charged using a heat pump.

Heat pumps use electric energy to transport heat from a cooler space to a warmer reservoir. As they use external heat sources they have a significantly higher heat yield than direct heating techniques such as electrical heating elements from the same amount of electrical energy. While heat pumps can use different media to extract the heat from, such as air and water, this white paper only considers techniques that extract the heat from water due to its significantly higher specific heat capacity.

Around Longyearbyen two main sources of thermal energy can be identified: The water in Isfjorden and geothermal boreholes. While for the water in Isfjorden data about its temporal and spatial temperature distribution are available only few data are available regarding the possibility of geothermal energy in Longyearbyen. As such, the latter option is considered as a future option but not further considered within this report.

Side-branches of the West Spitsbergen Current transport warmer waters along the southern side of Isfjorden all year round [17]. This water has temperatures of up to 2 °C and can be reached by a pipe at Vestpynten close to Longyearbyen. Furthermore, in the summer warmer surface water with up to 5 °C can be used to run the heat pump more efficiently. For the given salinity at this place of the fjord heat can be extracted until the outflow water reaches approximately -1.5 °C without freezing which would lead to increased workload for the water pumps and consequently to a reduced overall efficiency.

Exploring detailed design of such a heat pump falls outside the scope of this report. Hence, we only model a standard centralised heat pump with an assumed constant coefficient of performance of 3.0. However, we also explore a scenario with a coefficient of performance of only 2.0.

Hot water storage size:	1975.11	MWh
Heat pump to hot water storage:	3.54	MW
Heat exchanger hot water storage to DHS:	8.24	MW
Molten salt storage size:	443.20	MWh
Molten salt charger:	12.08	MW
Heat ex. molten salt to DHS:	0.43	MW
Molten salt thermal generator to AC:	4.50	MW
Hot rocks storage size:	0	MWh
Heat pump to district heating:	1.67	MW
Hydrogen storage size:	1512.50	MWh
Electrolyser:	2.02	MW
Fuel cell:	7.56	MW
Battery storage size	14.26	MWh
Battery (dis)charge capacity	2.38	MW

Table 1: Optimal storage sizing for Longyearbyen.

3 Results

The optimisation model was run over a period of nine consecutive weather-years in order to get a resilient solution. Some key outputs of the model are as listed in Table 1. On the generation side, the model installs 38.88 MW of wind turbines at different locations around Longyearbyen, and 1.71 MW of PV panels in Longyearbyen.

Figure 3 shows the electricity and heat demand in Longyearbyen for one year, compared with wind and solar capacity factors. Figure 4 shows the state-of-charge profiles for the different storage technologies included by the model. We can clearly see each storage technology operate at a different time scale.

3.1 Sensitivity analysis

In order to gain more understanding into the model, we performed some limited sensitivity analysis on some key parameters. In particular, we ran four separate variations of the model with:

1. No thermal storage included.
2. Costs of thermal storage doubled.
3. Coefficient of performance of the heat pump lowered from 3.0 to 2.0.
4. Cost of wind turbines increased by 50%.

The impact of these changes on total system costs by technology are visualised in Figure 5.

4 Discussion

Many conclusions and insights can be drawn from the model output. We consider first some implications for thermal energy storage specifically, and then make some general observations

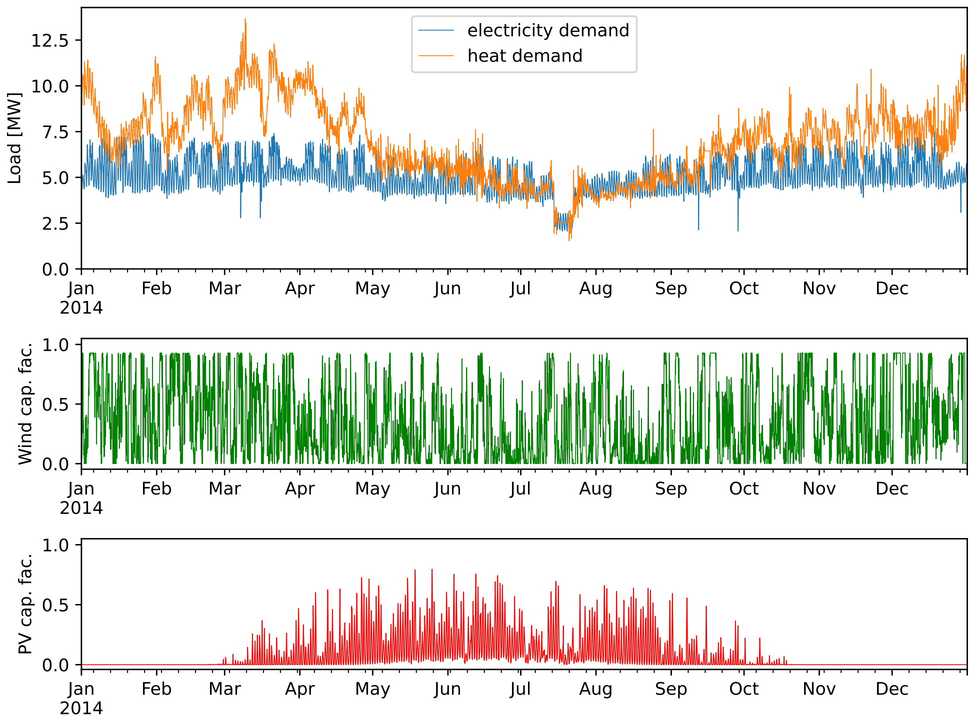

Figure 3: One year of electricity and heat demand in Longyearbyen, compared with wind and solar capacity factors.

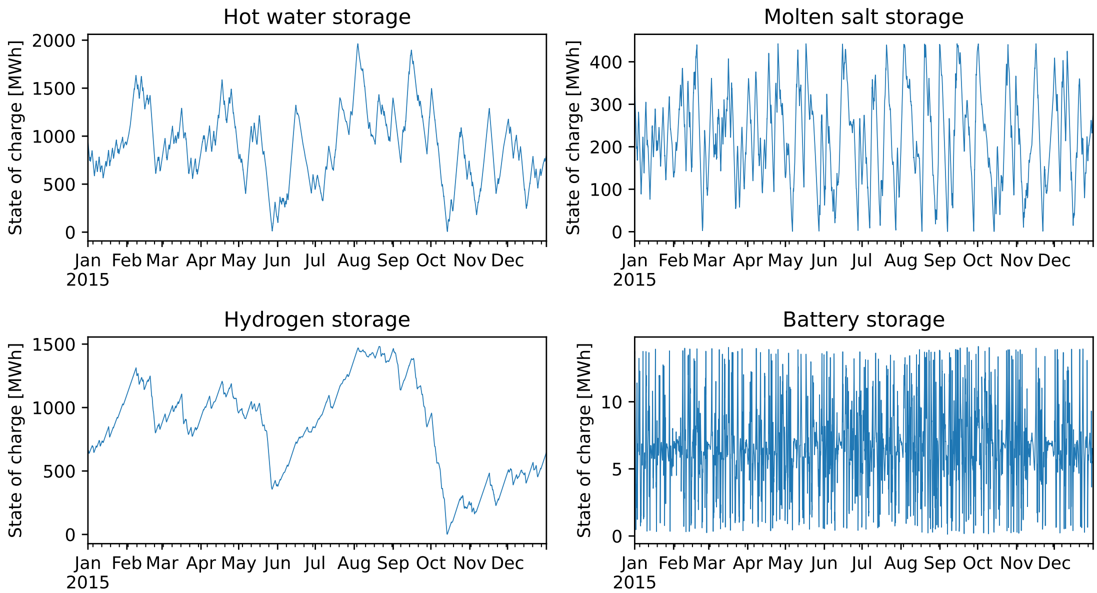

Figure 4: State-of-charge profiles for the different types of installed storage.

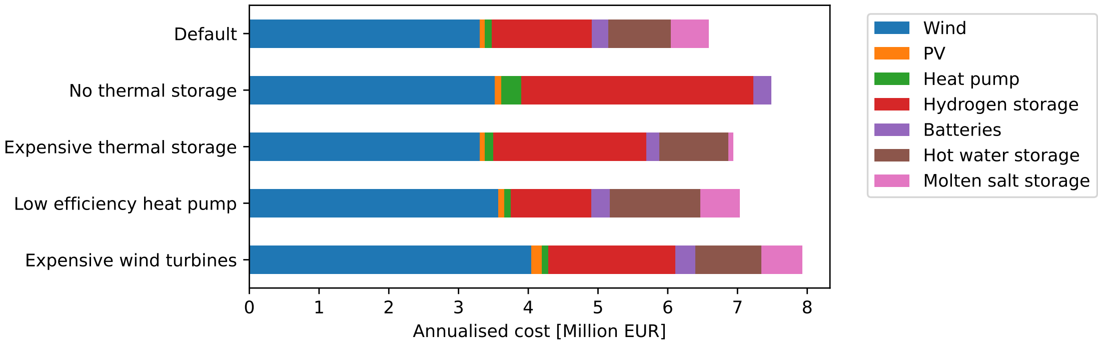

Figure 5: Cost comparison between different scenarios. In the "Expensive thermal storage" scenario, cost of molten salt, hot rocks and hot water storage are doubled. In the "Low efficiency heat pump", the coefficient of performance of the heat pump is reduced from 3.0 to 2.0. In the "Expensive wind turbines" scenario, the cost of wind turbines is increased by 50%.

about the Longyearbyen energy system.

For a study on the opportunities for hydrogen storage in Longyearbyen, conducted using the same model as here, we recommend [18].

4.1 Thermal energy storage in Longyearbyen

Molten salt storage and hot rocks storage play much the same role in the wider energy system, since they can both drive the district heating system or generate electricity. Generally, due to the high investment costs of approximately 80 EUR/kWh [19] the hot rock thermal storage was is not considered to be suitable for the thermal energy storage at this point. However, with the ongoing implementation of bigger facilities in Europe an investment price drop up to 50 % in the coming years is discussed [19]. Further cost reductions might be achieved by using local rocks.

For the hot water storage a volume of at least 33 000 m^3 would be necessary to store 1975 MWh as obtained from the model. Standard storage tanks have a volume of up to 50 000 m^3 and are broadly used in European district heating systems [20].

One special consideration for Longyearbyen is how to insulate thermal energy storage from permafrost. Melting permafrost can cause ground stability issues, and therefore either a passive, active or hybrid cooling solution will be needed for the thermal energy storage facilities.

4.2 System considerations

Based on the obtained state-of-charge profiles (Figure 4) the characteristics of the storage techniques are apparent. Hydrogen is mainly used to save energy for longer time periods while hot water is mainly used for mid-term energy storage. Molten salt is used as energy carrier for high-intensity short term energy storage and is charged with up to 12 MW. Batteries serve as shortest term (minutes and hours) energy storage and can compensate short term fluctuations of the renewable energy sources. This optimised multi-storage model leads to significant total cost reduction of approximately 15 % compared to a system that does not include thermal storage systems (Figure 5).

Further insight is gained with the additional sensitivity analysis exploring the impact of different component costs and heat pump efficiency. We see that:

- A mix of different storage technologies is always used by the model. In particular, every variation on the default scenario includes significant volumes of hot water, hydrogen and battery storage.
- Molten salt and hot rocks storage are the most sensitive to cost, and are out-competed by hydrogen and hot water storage if too expensive.
- The system is not very sensitive to the coefficient of performance of the heat pump.
- Wind turbines are generally speaking more suitable for Longyearbyen than PV panels. The overall system composition is not sensitive to wind turbine costs, and a lower installed wind power capacity can be compensated with larger hydrogen storage.

4.3 Comparison with previous studies

It is worth noting that the results produced by our model differ significantly from some earlier results on the same topics. Most significantly, the scale and cost of the system produced by our model differ substantially from the figures produced in [5] by the TIMES-Longyearbyen model. In particular, while the isolated scenario in [5] needs more than 200MW of installed wind and PV capacity, our model only requires less than 40MW installed wind and PV capacity. This is despite [5] working with a lower demand scenario than we consider. We speculate that this is a result of inadequate representation of storage technologies in the TIMES-Longyearbyen model. Storage in the TIMES-Longyearbyen model does not operate on the scale of many consecutive weeks and is therefore unable to effectively even out variations in wind generation, leading to greatly oversized wind and solar capacities. A more detailed comparison between the two models is our of scope of this report.

In a technical report prepared for the Norwegian Oil and Energy Department [21], a renewables-based scenario for Longyearbyen is explored with 88 MW of installed wind and solar capacity, combined with diesel backup generation. This is also significantly more than then 40 MW suggested by our model (which does not even include diesel backup generation).

The sizes of storage suggested by our model are also generally lower than what has previously been suggested. While our model installs around 4 GWh of storage in total with a mix of different technologies, 22–31 GWh of hydrogen storage is suggested by the TIMES-Longyearbyen model. A report on electric thermal energy storage [4] suggests that 9.2 GWh of hot rocks storage is needed to satisfy the Longyearbyen energy demand.

We conclude that previous studies systematically overestimate the amount of wind, PV and storage capacity needed to satisfy the Longyearbyen energy demand reliably. It is therefore crucial that future studies consider the flexibility of wind and PV power combined with a mix of storage solutions, revealed by detailed hourly modelling over multiple years.

4.4 Limitations

Our study and the model it is based on have a number of limitations which need to be considered when using the results presented here. We emphasize that our model can be used to explore possible future scenarios, but is not designed to accurately predict likely future development. While the results help us understand what kind of role thermal storage could play in Longyearbyen, we advice against using any of the figures produced by the model as more than broad indications. We can loosely divide limitations of the model into different categories: *omissions*, *simplifications*, *inaccuracies* and *uncertainties*.

The model omits a number of important factors. The transport sector is not included, nor are any energy generation or storage technologies not mentioned in this report. Moreover, we do not considered any possibility to import energy, nor the possibility of a transmission line to the mainland of Norway.

A number of significant simplification have been made to the representations of different technologies in the model. For dispatchable units, we do no consider ramping rates, minimum loads or other non-linear operational constraints. We assume that each energy conversion process (heat pump, storage (dis)charge) has a constant efficiency. We also do not represent operating temperatures of the thermal units in the model.

Some of the data used for the model is inaccurate. This is especially the case for the energy demand data, which is from 2017–2018 and includes electricity use by the coal mine. While we model a 100% renewable energy system for Longyearbyen, we make no attempt to exclude the coal mine load from the model. Moreover, we expect gains in energy efficiency of building stock in Longyearbyen over the next decade, but this is not taken into account.

Finally, the cost data used in the model is highly uncertain. Changes in technology costs can have a large impact on model output, but it is difficult to assess costs for Longyearbyen specifically.

Acknowledgements

We would like to thank Lars H. Smedsrud for organising the course AGF-353/853 at UNIS during which this report was written, and also thank all the guest lecturers for their valuable contributions.

Our gratitude also goes to Aleksander Grochowicz, Daniel Heineken and Sondre Wennberg for their work on the wind power capacity factors used in the model. Likewise, thanks to Maximilian Roithner and Håvar Alexandersen for providing the PV power capacity factors. Thanks also to Hans-Kristian Ringkjøb for helping us obtain electricity and heat production time series data from the Longyearbyen coal power plant.

Thanks in particular to Aleksander Grochowicz, Maximilian Roithner and Oskar Vågerö for many fruitful discussions on the Longyearbyen energy system.

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