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Developing hydrogen energy hubs: The role of H_2 prices, wind power and infrastructure investments in Northern Norway

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ABSTRACT

Hydrogen is seen as a key energy carrier to reduce CO_2 emissions. Two main production options for hydrogen with low CO_2 intensity are water electrolysis and natural gas reforming with Carbon Capture and Storage, known as green and blue hydrogen. Northern Norway has a surplus of renewable energy and natural gas availability from the Barents Sea, which can be used to produce hydrogen. However, exports are challenging due to the large distances to markets and lack of energy infrastructure. This study explores the profitability of hydrogen exports from this Arctic region. It considers necessary investments in hydrogen technology and capacity expansions of wind farms and the power grid. Various scenarios are investigated with different assumptions for investment decisions. The critical question is how exogenous factors shape future regional hydrogen production and export. The results show that production for global export may be profitable above 90 €/MWh, excluding costs for storage and transport, with blue hydrogen being cheaper than green. Depending on the assumptions, a combination of liquid hydrogen and ammonia export might be optimal for seaborne transport. Exports to Sweden can be profitable at prices above 60 €/MWh, transported by pipelines. Expanding power generation capacity can be crucial, and electricity and hydrogen exports are unlikely to co-exist.

1. Introduction

Hydrogen might become central to the energy transition due to its versatility as an energy carrier. It can significantly contribute to decarbonizing sectors where direct electrification is challenging, such as heavy industry and transportation. It offers a sustainable alternative to fossil fuels by enabling the storage and transport of energy from renewable sources, thus facilitating a more flexible and resilient energy system. Sweden, a neighboring country to Norway, may have a significant hydrogen demand in the future, for instance, for use in transportation and the steel industry [1–4]. The Swedish Energy Agency targets high clean hydrogen production of up to 42 TWh and 84 TWh by 2030 and 2045 [5]. However, wind power and hydrogen infrastructure development have been lacking [1], suggesting an opportunity for Norwegian hydrogen export to Sweden. Another close-by country is the United Kingdom (UK), which can significantly reduce their CO_2-emissions by implementing clean hydrogen [6,7]. The Department for Business and Trade estimates a 2035 hydrogen demand of 80 to 140 TWh [8], and hydrogen imports from Norway can help establish a domestic hydrogen economy and enhance energy security while national production scales up.

Hydrogen's ability to be produced from various sources positions it as a key player in achieving a clean, secure, and affordable energy future [9,10]. However, there are difficulties when it comes to incorporating significant amounts of hydrogen into our current energy infrastructure. Large-scale production of green hydrogen, produced through water electrolysis using renewable electricity, requires massive renewable power generation [10]. Blue hydrogen, produced by natural gas with Carbon Capture and Storage (CCS) to reduce emissions, also represents a significant production option [10]. Such investments can be costly, and detailed planning is needed to ensure optimal use of resources in the existing system.

Because production is not necessarily best placed close to utilization, it may require long-distance transport and infrastructure investments. For example, this can be done in gas form by either new or re-purposed gas pipelines [11]. For very long distances, seaborne transport can be cheaper and more feasible. The hydrogen gas can be liquefied into a much more energy-dense product or stored within another compound, such as ammonia [12].

While Northern Norway has long distances to Europe or hydrogen markets, it has been identified to have excellent wind resources, including onshore wind [13]. Wind power can be harvested for export or

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local use, including developing green hydrogen production, as there are already a few green hydrogen projects in discussion for the region [14]. Additionally, there is a significant amount of natural gas in the Barents Sea, pumped up to Hammerfest (the Northernmost town in the world) and exported as liquefied natural gas (LNG). This natural gas could be used for blue hydrogen production, explored in the Barents Blue project [15]. However, the Arctic area has limited power line capacity to accommodate new power generation, and obtaining licenses for wind farm developments is challenging. This raises several challenges and critical questions: What are the incentives and possibilities for hydrogen production in Northern Norway, and can the region become a hydrogen energy hub for exports? These questions confront the recurring challenge of whether or not to develop a regional hydrogen infrastructure. Consequently, the paper explores the following research questions:

1. What are the factors in developing the hydrogen infrastructure? To what degree are hydrogen markets and prices incentivizing regional infrastructure development?
2. How do variations in hydrogen, natural gas, and electricity prices impact the profitability of hydrogen production and subsequent export? Which export market is more favorable: Sweden or the global market?
3. How do wind power investments shape the hydrogen export strategy? How do green and blue hydrogen production methods influence investments in transport options, wind generation, and power line capacities?

To address these questions, this paper uses the model EnergyModelsX (EMX) [16]. The model provides an optimization investment strategy subjected to operations for a multi-carrier system tailored to regional cases. Four main scenarios are investigated: First, a base case considers the energy system without access to hydrogen markets. Secondly, a scenario includes pipeline access to a hydrogen market in Kiruna, Sweden. Thirdly, the second scenario is extended with access to a global market available by seaborne transport of liquid hydrogen or ammonia from Hammerfest. Transport efficiencies and costs are not included in this scenario due to the large uncertainty related to liquid hydrogen transport costs and losses [17] as well as the potential global market for liquid hydrogen and ammonia. The latter complicates the design of harbor infrastructure and calculating the loss during transport. Instead, it is assumed that both liquid hydrogen and ammonia are delivered at the gate of the plant. The last scenario is similar to the third but with hard constraints on where wind investments can occur. Additionally, sensitivity analyses are done on hydrogen, natural gas, and electricity energy prices.

This article is structured as follows: Section 2 reviews existing scientific literature and outlines research contributions. Section 3 describes the methodology and model used in the work. Section 4 presents the case study, the data inputs, and modeling decisions. Section 5 focuses on the results and discusses the main takeaways and limitations. Lastly, the main findings are concluded in Section 6.

2. Related literature

Recent research on hydrogen in the context of energy system modeling has been diverse, focusing on the integration of hydrogen energy systems into existing power grids, the role of hydrogen in decarbonizing energy systems, and the development of multi-carrier energy systems that include hydrogen [9,18]. There is also a rich literature focused on hydrogen technological development, *i.e.*, Ahad et al. [19] gives a broad overview of challenges in the production and utilization of fuel cells and hydrogen embrittlement during transmission and storage.

Another active stream in the hydrogen literature is analyzing infrastructure developments vis-à-vis the hydrogen pathways. The International Energy Agency (IEA) recommends governments and industry take quick actions, pointing at the political and business momentum with increased hydrogen demand over the years [20]. Kim et al. [21] review the status of hydrogen supply infrastructure, where most hydrogen is produced by fossil fuel (48 % natural gas, 30 % oil, and 18 % coal) and transported by pipelines, but transport of liquid hydrogen (LH_2) or ammonia (NH_3) are considered safe alternatives. The paper highlights national differences in hydrogen roll-out strategies, where abundant renewable energy resources drive water electrolysis. Ishimoto et al. [12] consider hydrogen production in Northern Norway with export to Japan, where the authors found that the value-chain of LH_2 can be more efficient than NH_3, even with long-distance transport. The Hydrogen Backbone initiative [11] aims to connect the supply and demand of hydrogen within Europe by cross-border pipeline but does not include hydrogen supply from Northern Norway. The literature lacks research on the effects of hydrogen prices on infrastructure development in supplying regions, often instead driven solely by decarbonization goals. However, our paper considers the possible investment and operational options in Northern Norway, with profit as the main incentive. Greenhouse gas reductions are indirectly included through emission penalties. It also allows for export to Kiruna in Sweden by pipeline or to a global market via seaborne export for LH_2 or NH_3 from Hammerfest, providing insights into two vastly different export options in a concrete case.

Among the production options with low CO_2 intensity, green and blue are the most prominent, investigated in various papers. Much of the literature focuses on the chemical and environmental impacts of different production technologies, such as [22]. Yu et al. [23] present challenges with green as costly, and blue is considered a transition solution as it is still emitting some CO_2, and the price is primarily affected by natural gas or coal prices. Ueckerdt et al. [24] found that with high CO_2 prices, high-emission blue hydrogen would not be competitive with green. However, George et al. [25] consider blue hydrogen most likely to be the most cost-effective option, also in the long-term. Durakovic et al. [26] found that green and blue hydrogen can both exist in 2050, where allowing blue hydrogen can vastly reduce costs but is sensitive to natural gas prices. While the latter paper provides an extensive sensitivity analysis of natural gas and electrolyzer costs, this is not true for most literature. This work contributes to green and blue hydrogen production analysis with sensitivity analysis on essential components. We emphasize tailoring production to a specific region instead of focusing on possible cost decreases towards 2050 and beyond. A detailed spatial resolution includes multiple pipeline paths from production to market.

This level of spatial resolution is less common in much of the research, which often focuses on global or national scales such as [27], or within Europe as [26,28]. However, it can also be beneficial to consider regional variances, existing systems, more detailed production locations, and transport paths. [9] looked at fundamental challenges in current energy system modeling, and among these, it found a subnational resolution valuable and multi-carrier increasingly important. Furthermore, many models cover only a single geographical point, and the literature on regional studies that include multiple interconnected geographical areas is lacking. This is supported by the EMX model, used in [29] to analyze offshore electrolysis production from offshore wind in the North Sea. It benefited from modeling electricity and hydrogen in the same system and the flexibility to cover a self-determined spatial resolution. This work divides Northern Norway into nine regions, covering about one-fifth of Norway's total land area. This includes differences in wind profiles, power line capacities, power generation and demand, and natural gas availability within a 75'000 km^2 area.

Based on the identified gaps, this paper contributes knowledge on analyzing the key economic and energy infrastructure factors that facilitate the integration of hydrogen into the energy system. The potential synergy effects of blue and green hydrogen are considered, with profit as the primary metric while also including CO_2 emission penalties. Using the EMX model, an hourly resolution for operational periods is used to represent intermittent renewable energy sources such as wind power effectively. A sub-national resolution with piecewise-linear cost assumptions for hydrogen pipelines and semicontinuous investments for technologies such as autothermal reforming (ATR), hydrogen liquefaction, and Haber-Bosch (ammonia production) plants provides a more realistic picture for regional-scale systems. The main contributions include:

- Novel model: We utilize a novel energy system model, EnergyModelsX, in one of its first case studies.
- Model development and extensions: We propose an intuitive approach for modeling start-up and shut-down phases in energy system models.
- A case study in Northern Norway: We conduct an in-depth analysis of an Arctic region, specifically Northern Norway, exploring the advantages and challenges unique to this region in becoming a hydrogen hub for export.
- Detailed sensitivity analysis: We provide insights into hydrogen production and export through scenario and sensitivity analysis and uncover critical factors influencing successful hydrogen integration in the energy system.

3. Methodology

3.1. The EMX model

This study utilizes and extends EnergyModelsX (EMX) [30], a novel energy system optimization modeling framework. EMX supports multiple energy carriers, a two-level time structure for operational and investment decisions, and representative periods. The mathematical optimization modeling framework is implemented in Julia for Mathematical Programming (JuMP) [31], which provides computational efficiency and flexibility. EMX is particularly well-suited for specialized or regional case studies because of its flexibility and modularity.

As a mathematical optimization model, the objective is to maximize the net present profit while satisfying all constraints. The objective function is formulated in Eq. (1) and includes revenues from energy sales (r), variable and fixed operating expenses (OPEX) for operational decisions for nodes and links (o^{Var} and o^{Fix}), capital expenditure (CAPEX) of investment decisions for nodes and links (k), and emissions penalties for CO_2 emissions (e). Discount variables are determined in Eqs. (2) and (3). A yearly discount rate of 7 % is used, reflecting the required rate of return on investments. Investment decisions are assumed to occur at the start of a strategic period, using the former definition. Operational decisions and emissions within each year are assumed to repeat multiple times within each strategic period, and thus, the average discounting of the strategic period is used. The model terminology is found in Appendix A.

$$\begin{aligned}\max z = \sum_{t^{\mathrm{Inv}}\in\mathcal{T}^{\mathrm{Inv}}} \delta^{\mathrm{Avg}}_{t^{\mathrm{Inv}}}\cdot\Bigg(&\overbrace{\sum_{n\in\mathcal{N}} r_{n,t^{\mathrm{Inv}}}\Delta t^{\mathrm{Inv}}}^{\text{Revenues}} - \overbrace{\sum_{n\in\mathcal{N}}(o^{\mathrm{Var}}_{n,t^{\mathrm{Inv}}}+o^{\mathrm{Fix}}_{n,t^{\mathrm{Inv}}})\Delta t^{\mathrm{Inv}}}^{\text{Variable and fixed OPEX for nodes}}\\ &-\overbrace{\sum_{l\in\mathcal{L}}\sum_{m\in\mathcal{M}_l}(o^{\mathrm{Var}}_{l,m,t^{\mathrm{Inv}}}+o^{\mathrm{Fix}}_{l,m,t^{\mathrm{Inv}}})\Delta t^{\mathrm{Inv}}}^{\text{Variable and fixed OPEX for links}} - \overbrace{E^{\mathrm{Cost}}_{t^{\mathrm{Inv}}}e^{\mathrm{Sp}}_{t^{\mathrm{Inv}}}}^{\text{Emission penalties}}\Bigg)\\ &-\sum_{t^{\mathrm{Inv}}\in\mathcal{T}^{\mathrm{Inv}}}\delta^{\mathrm{Start}}_{t^{\mathrm{Inv}}}\cdot\Bigg(\overbrace{\sum_{n\in\mathcal{N}^{\mathrm{Inv}}}k_{n,t^{\mathrm{Inv}}}}^{\text{CAPEX for nodes}}+\overbrace{\sum_{l\in\mathcal{L}}\sum_{m\in\mathcal{M}^{\mathrm{Inv}}_l}k_{l,m,t^{\mathrm{Inv}}}}^{\text{CAPEX for links}}\Bigg)\end{aligned} \tag{1}$$

$$\delta^{\mathrm{Start}}_{t^{\mathrm{Inv}}} = \left(\frac{1}{1+d}\right)^{t^{\mathrm{Inv}}_{\mathrm{Year}}} \qquad t^{\mathrm{Inv}}\in\mathcal{T}^{\mathrm{Inv}} \tag{2}$$

$$\delta^{\mathrm{Avg}}_{t^{\mathrm{Inv}}} = \frac{\left(\frac{1}{1+d}\right)^{t^{\mathrm{Inv}}_{\mathrm{Year}}} - \left(\frac{1}{1+d}\right)^{t^{\mathrm{Inv}}_{\mathrm{Year}}+\Delta t^{\mathrm{Inv}}}}{\ln(1+d)\cdot\Delta t^{\mathrm{Inv}}} \qquad t^{\mathrm{Inv}}\in\mathcal{T}^{\mathrm{Inv}} \tag{3}$$

The main constraints include energy balancing constraints for the nodes, capacity restrictions, flow logic for links, accumulation of costs, ratios between nodal inputs and outputs, bounds on investments, and emissions of CO_2, as described in [16]. A general overview of the EMX framework and its structure is provided in Appendix B.

The model is structured in packages that can be combined to incorporate additional mathematical descriptions for, *e.g.*, a specific nodal mathematical description. The individual packages are described in Appendix B.2. Within this study, we combined the Base package, consisting of basic nodes and links, with the Geography, Investments, RenewableProducers, and the CO_2 package.

The study implements two representative weeks each year, capturing the winter and summer seasonal differences. Hourly operational periods capture the variability in power demand and renewables. Strategic periods are modeled with a duration of five years to reflect necessary planning and construction speed of investments and align with other models such as EMPIRE [32]. Given the extended time horizon (2030–2055), representative periods were essential for achieving mathematical optimality within a reasonable timeframe. Weekly durations capture variations in weekday power demand while remaining solvable in the Mixed-Integer Linear Programming (MILP) problem. Notably, the necessary mathematics for hydropower reservoirs using representative periods are laid out in [33], which looks at how to handle long-term storage in multi-horizon stochastic programs.

3.2. Hydrogen technologies

The hydrogen production technologies for electrolysis and natural gas reforming are modeled as basic network nodes, implying that they have inputs and outputs with specified conversion rates. Natural gas reforming with CCS has as output captured CO_2 while emitting the non-captured CO_2 at an emission penalty. Network nodes are used for hydrogen liquefaction and ammonia production (Haber-Bosch process), converting hydrogen in gas form (H_2) into LH_2 or NH_3, respectively. Hydrogen can be exported from Northern Norway to the global market by ship, as LH_2 or NH_3, or from Northern Norway to Sweden by pipeline. Appendix B.4 illustrates a simplified case of how the hydrogen value chain is implemented in the model.

3.3. New model extensions

Additional modifications and extensions are made to tailor the model to the Northern Norway case study. Heat recovery for electrolysis is achieved by modifying the electrolyzer technology and adding heat as an energy carrier. This heat can be used in the model to cover the heating demand, which is otherwise met by flexible electricity used in district heating, thus lowering the electricity demand.

The existing modeling tool has no delay in starting and shutting down production. However, this added layer of complexity could enhance the realism behind processes such as natural gas reforming and hydrogen liquefaction. Thus, a modified network node, the Start-Shut Network (SSN) node, is created to consider this. This node can be in four states: $\mathcal{S}^{\mathrm{SSN}} = \{Off, Start, On, Shut\}$, and must be in one and only one state at each time step. This is enforced in Eq. (4), using binary variables $\sigma^{s}_{n,t}\in\{0,1\}$ to indicate if the node is in state s.

$$\sum_{s\in\mathcal{S}^{\mathrm{SSN}}}\sigma^{s}_{n,t} = 1 \qquad n\in\mathcal{N}^{\mathrm{SSN}}, t\in\mathcal{T} \tag{4}$$

Production can only occur in the *On* state, and an envelope structure is used to achieve a variable big M with a tight formulation. This is formulated in Eqs. (5)–(8), exploiting the nature of multiplications between a continuous and binary variable.

$$m_{n,t}\geq 0 \qquad n\in\mathcal{N}^{\mathrm{SSN}}, t\in\mathcal{T} \tag{5}$$

$$m_{n,t}\geq C^{\mathrm{Maxinst}}_{n,t}(\sigma^{\mathrm{On}}_{n,t}-1)+c^{\mathrm{Inst}}_{n,t} \qquad n\in\mathcal{N}^{\mathrm{SSN}}, t\in\mathcal{T} \tag{6}$$

$$m_{n,t}\leq C^{\mathrm{Maxinst}}_{n,t}\cdot\sigma^{\mathrm{On}}_{n,t} \qquad n\in\mathcal{N}^{\mathrm{SSN}}, t\in\mathcal{T} \tag{7}$$

$$m_{n,t}\leq c^{\mathrm{Inst}}_{n,t} \qquad n\in\mathcal{N}^{\mathrm{SSN}}, t\in\mathcal{T} \tag{8}$$

This variable big M is then used to constrain production in Eq. (9).

$$c^{\mathrm{Use}}_{n,t} \leq m_{n,t} \qquad n \in \mathcal{N}^{\mathrm{SSN}}, t \in \mathcal{T} \tag{9}$$

The cyclic pattern for the states is enforced in Eqs. (10)–(13).

$$\sigma^{\mathrm{Off}}_{n,t-1} \geq \sigma^{\mathrm{Start}}_{n,t} - \sigma^{\mathrm{Start}}_{n,t-1} \qquad n \in \mathcal{N}^{\mathrm{SSN}}, t \in \mathcal{T} \setminus t_0 \tag{10}$$

$$\sigma^{\mathrm{Start}}_{n,t-1} \geq \sigma^{\mathrm{On}}_{n,t} - \sigma^{\mathrm{On}}_{n,t-1} \qquad n \in \mathcal{N}^{\mathrm{SSN}}, t \in \mathcal{T} \setminus t_0 \tag{11}$$

$$\sigma^{\mathrm{On}}_{n,t-1} \geq \sigma^{\mathrm{Shut}}_{n,t} - \sigma^{\mathrm{Shut}}_{n,t-1} \qquad n \in \mathcal{N}^{\mathrm{SSN}}, t \in \mathcal{T} \setminus t_0 \tag{12}$$

$$\sigma^{\mathrm{Shut}}_{n,t-1} \geq \sigma^{\mathrm{Off}}_{n,t} - \sigma^{\mathrm{Off}}_{n,t-1} \qquad n \in \mathcal{N}^{\mathrm{SSN}}, t \in \mathcal{T} \setminus t_0 \tag{13}$$

The minimum number of operational time steps for the states *Start*, *Shut*, and *Off* is enforced in Eq. (14). As an illustrative example, start-up, shut-down, and minimum off times of 12, 6, and 24 h were used to test the effects of these constraints in the ATR node.

$$\sum_{t'=t}^{t+T^s_n-1} \sigma^s_{n,t'} \geq T^s_n(\sigma^s_{n,t} - \sigma^s_{n,t-1}) \qquad n \in \mathcal{N}^{\mathrm{SSN}}, s \in \mathcal{S}^{\mathrm{SSN}} \setminus On,$$
$$t \in \mathcal{T} \setminus t_0, t \leq (|\mathcal{T}| - T^s_n + 1) \tag{14}$$

Costs for start-up and shut-down are included, as well as the cost of keeping the technology in the *On* state and the standard usage cost, as demonstrated in Eq. (15).

$$o^{\mathrm{Var}}_{n,t^{\mathrm{Inv}}} = \sum_{t \in t^{\mathrm{Inv}}} \Big(\overbrace{O^{\mathrm{Var}}_{n,t} \cdot c^{\mathrm{Use}}_{n,t}}^{\text{Variable costs}} + \overbrace{O^{\mathrm{Start}}_{n,t} \cdot \sigma^{\mathrm{Start}}_{n,t}}^{\text{Start-up costs}}$$
$$+ \overbrace{O^{\mathrm{On}}_{n,t} \cdot \sigma^{\mathrm{On}}_{n,t}}^{\text{Running costs}} + \overbrace{O^{\mathrm{Shut}}_{n,t} \cdot \sigma^{\mathrm{Shut}}_{n,t}}^{\text{Shut-down costs}} \Big) \Delta t \qquad n \in \mathcal{N}^{\mathrm{SSN}}, t^{\mathrm{Inv}} \in \mathcal{T}^{\mathrm{Inv}} \tag{15}$$

4. Data and case study

4.1. Northern Norway

As the introduction outlines, this article focuses on energy system modeling in Northern Norway, specifically in the Troms and Finnmark counties. To achieve a more nuanced spatial resolution, this area is subdivided into multiple regions based on the municipalities [34] and transmission lines, as presented in Fig. 1. The power grid is modeled using data from The Norwegian Energy Regulatory Authority (NVE) [35], supplemented with information about grid constraints from the transmission system operator (TSO) of Norway, Statnett [36]. Within each region, aggregated power demand is based on historical data from 2022 [37,38], with a 1 % annual increase assumed to reflect forecasted consumption development [39]. The expected increase in power demand resulting from the electrification of Melkøya in Hammerfest from 2030 is also included. Water inflow to the hydropower is gathered from NVE for the region and distributed to each hydropower plant by their rate capacities [40]. Existing hydropower and wind power are each aggregated for every region, with the option to make further investments in wind power capacity. The EMPIRE model was used to generate future estimates for electricity prices in FIN (the price zone in Finland) and NO4 (the northernmost price zone in Norway) [26]. These price estimates serve as boundary conditions connecting the investigated region with the neighboring electricity network for the winter and summer seasons, with hourly resolution. Note that the modeled region is part of the price zone NO4. For this study, a constraint is imposed to prevent the area from having a net negative power export. Consequently, a zero value in the results could suggest that additional power imports would be advantageous from the model's perspective.

Hammerfest is a unique region where a constant inflow of natural gas from Melkøya is assumed [41]. The inflow is equal to the quantity delivered by Hammerfest LNG (HLNG) at an expected production rate of 6.5 billion cubic meters per year [42]. At this rate, the Snøhvit reservoir is estimated to last for about 20 years [43]. This study assumes a continuation of natural gas inflow from the Barents Sea, considering the potential for discovering new reservoirs.

Table 1
Renewables' capacities assumed before 2030 for hydropower (HP) and wind power (WP).

Region	HP storage [GWh]	HP rate [MW]	WP rate [MW]
Adamselv	22.7	56.3	39.1
Alta1	8.8	12.1	0
Alta2	57.6	150.7	0
Gouda	323.5	198.6	0
Kvænangen	119.4	88.1	0
Lakselv	2.3	2.7	0
Skaidi & Hammerfest	30.5	20.7	59.1
Tromsø	12.9	39.6	362.1
Varanger	208.6	83.4	320
SUM	786.3	652.1	677.3

Due to the existing district heating infrastructure operated by Kvitbjørn Varme AS in Tromsø, this study incorporates the option of heat recovery from the electrolyzer process for this region [44–46].

The model can invest in hydrogen technologies, including ATR with CCS for blue hydrogen production, electrolyzers for green hydrogen production, H_2 liquefaction, NH_3 production, and hydrogen pipelines. It is assumed that CO_2 storage facilities exist for storing emissions captured by the CCS technology and electric LNG liquefaction by the start of 2030. Hydrogen storages are not considered in this study, and a continuous export is assumed possible. This implies that hydrogen produced in one specific period is also assumed to be sold in that same period.

Power demand within Northern Norway should be met, as any deficit incurs a penalty of 5000 €/MWh. Excess power can be sold to FIN or NO4, increasing revenues. From Hammerfest, it is assumed that seaborne transmission options are available for LNG, LH_2, and NH_3. Pipelines can also transport hydrogen to Sweden [11]. District heating demand in Tromsøthat is not covered by the combustion of waste or bio-energy is assumed to be met by electricity or waste heat from electrolyzer units in Tromsø, utilizing the existing infrastructure. In 2022, the total district heating demand in Tromsøwas 170 GWh, of which flexible electricity covered 21 %. The district heating infrastructure is assumed to be expanding until 2030 [44]. This study assumes, for simplicity, a yearly heating demand of 65.7 GWh that can met by electricity or electrolyzer waste heat. This is based on 21 % from the demand in 2022 and an addition of 30 GWh. The yearly demand is decomposed into hourly heating demand based on weather factors, as shown in [47].

This study does not impose hard constraints on CO_2 emission levels but instead uses emission penalties. These penalties are based on OpenEntrance's model [48], with incremental costs from 2030 onwards of 40, 84, 152, 305, and 524 €/tonne.

4.2. Existing capacities

The maximal capacity for existing power lines is estimated based on a report from Statnett [36], and provided in Appendix E. Existing capacities for hydropower and wind power before 2030 are gathered from NVE [35] and displayed in Table 1. Note that these values are uncertain and prone to being outdated quickly due to ongoing development plans in power generation and transport in the region and Norway overall. Licensed wind power is expected to be built and operational before 2030. More information about wind conditions is provided in Appendix D. The annual capacity factors for wind generation are generally assumed to be 0.39 in Northern Norway but adjusted to 0.40 in Adamselv and 0.46 in Varanger founded on data from existing plants, with hourly variations based on [49].

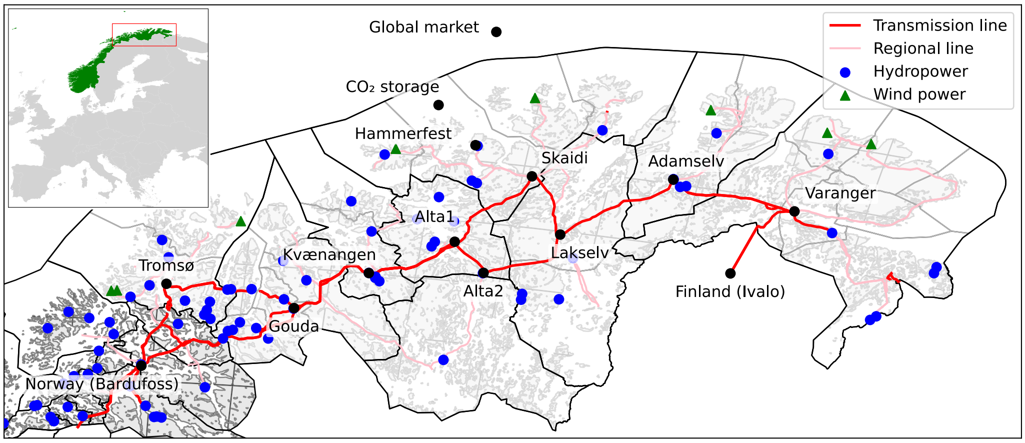

Fig. 1. A map over regions, transmission lines, hydropower, and wind power in Northern Norway.

Table 2
Electrolyzer CAPEX over time.

Period	2030	2035	2040	2045	2050
CAPEX [€/kW H_2]	576	498	419	378	337

Table 3
Wind power costs over time.

Period	2030	2035	2040	2045	2050
CAPEX [€/kW]	1161	1161	1010	1010	943

4.3. Technology node costs and efficiencies

An overview of units for the various energy carriers is provided in Appendix F, with Euros (€) used as the monetary unit. Investments in existing natural gas infrastructure and technologies are assumed to be sunk costs, and this study considers only the associated variable costs for natural gas. While these costs naturally vary, an average price from 2006 to 2016 is used, not including liquefaction or expenses of transporting the gas to the markets [12,50]. A variable cost of 18 €/MWh is used, with a maximal inflow rate to Hammerfest of 7.743 GWh/h. The CO_2 intensity of combusting natural gas is 0.2 t/MWh, with an estimated intensity in production of 0.0036 t/MWh [51,52].

Associated costs for electrolyzer nodes are fixed OPEX of 48.8 €/kW/a H_2, variable OPEX of 0.216 €/MW/h H_2, and decreasing CAPEX as provided in Table 2 [53]. Investments are considered continuous due to the reduced economies of scale of the largest contributor to the cost, the electrolysis stack. This is beneficial as non-continuous investments increase model complexity and solution time. They should generally not be used unless they offer some considerable advantage, such as enhanced realism.

For the ATR node, fixed OPEX of 35.6 €/kW/a and CAPEX of 757.5 €/kW are assumed [54]. The hydrogen liquefaction node has associated fixed OPEX of 65.4 €/kW/a and CAPEX of 1524.4 €/kW [12]. The plant for the Haber-Bosch process uses fixed OPEX of 82.2 €/kW/a and CAPEX of 791.5 €/kW [12]. A semicontinuous investment option is used for the ATR, H_2 liquefaction, and Haber-Bosch nodes. The most minor possible investments are 0.843 GW, 0.174 GW, and 0.255 GW.

The CO_2 storage assumes an unlimited capacity rate and storage, with variable OPEX varying slightly over time with a mean of 13.6 €/tCO_2, as used in [26]. This study further assumes that existing CO_2 pipelines from Hammerfest to a CO_2 storage have enough capacity.

Hydropower can generate renewable electricity with fixed OPEX of 25.5 €/kW/a and variable OPEX of 0.32 €/MW/h [26].

Wind power operates under similar conditions, featuring fixed OPEX of 14 €/kW/a and variable OPEX of 0.18 €/MW/h, alongside decreasing CAPEX outlined in Table 3 [26]. Investments are continuous, with a maximum added capacity of 0.5 GW in each strategic period for every region, constraining the construction pace in the Arctic region, accounting for the short period for construction.

Network nodes have inputs, outputs, and specific ratios between the input and output that determine their efficiencies. The assumed efficiencies in this paper are shown in Table 4.

Table 4
Overview of technology efficiencies.

Technology	Inputs	Outputs
Electrolyzer [53,55]	1.5 x Power (0.273 x Water)	1 x H_2 (0.181 x Heat)
ATR [54]	1.25 x NG 0.11 x Power	1 x H_2 (91% of CO_2 captured, the rest emitted)
LNG liquefaction [56]	1 x NG 0.0191 x Power	1 x LNG
H_2 liquefaction [12]	1 x H_2 0.188 x Power	1 x LH_2
Haber-Bosch [12]	1.169 x H_2 0.0869 x Power	1 x NH_3
Electric heating	1.005 x Power	1 x Heat

4.4. Transmission links

An overview of the costs associated with transmission links is provided in Table 5. Investments in power line capacity are considered continuous, with a premium on the CAPEX compared to the average over European countries due to the high labor costs, Arctic region, and use of N-0 capacities in the model [26]. The variable OPEX is considered negligible and not the main focus of the study. To avoid unrealistically large and fast expansions of the power line capacities, investments in power line capacities are limited to 0.5 GW each strategic period and a maximal cable capacity of 2 GW between any two regions. No investments are allowed in the power lines to the outside areas, NO4 and FIN, to avoid over-exploiting price differences.

A piece-wise linear formulation of the costs is used to account for the economies of scale in pipeline investments [11]. Small pipelines can accommodate capacities ranging from 0.5 to 4.7 GW, while larger pipelines can support capacities from 4.7 to 14 GW. Potential pipeline paths are provided in Appendix G.

4.5. Introducing the scenarios

As outlined in the introduction, different scenarios are created and solved to establish how larger factors would impact the future of the energy system in Northern Norway. These scenarios are presented briefly in Table 6.

(a) Pipeline options to Sweden.

(b) Hydrogen backbone envisioned pipelines [11].

Fig. 2. Possible connections between Northern Norway and Sweden (a), and previously envisioned hydrogen pipelines in Europe (b).

Table 5
Overview of energy transmission options.

Technology	CAPEX [€/MW/km]	CAPEX offset [k€/km]
Power line	1000	0
H_2 by small pipeline	200	1260
H_2 by large pipeline	72.3	1860.24

First, the model is solved without access to a hydrogen market. The results demonstrate how much wind power investments and power line capacity expansions are optimal, where LNG export continues from 2030 to 2055. The market price of LNG (excluding transport costs) is fixed at 30 €/MWh.

Secondly, the model is extended to access a Swedish hydrogen market in Kiruna. This is based on the Hydrogen Backbone report [11], where a network of hydrogen pipelines is envisioned for the future, including pipelines within Sweden to Kiruna. This region contains the World's largest iron ore mine [57], where hydrogen can be an alternative energy source to reduce CO_2 emissions in mining significantly. Additional hydrogen demands connected to the hydrogen backbone pipelines, such as Luleå, may further increase the feasibility of large-scale exports to Sweden [58]. This study allows for investments in hydrogen pipelines from Tromsø, Gouda, or Alta1, with an expected distance of 200, 180, or 265 km in a direct line to Kiruna, visualized in Fig. 2. Initially, the price of hydrogen is assumed to be 90 €/MWh.

Thirdly, a global hydrogen market is accessible beside the Swedish market. Such exports require seaborne transport of H_2 in the form of LH_2 or NH_3 from Hammerfest, where the current LNG export is situated. For simplicity, the prices of both compounds are initially fixed at the high price of 150 €/MWh.

Lastly, the model has access to both markets, but wind power investments are constrained to the Skaidi/Hammerfest region. The previous scenarios relied on the ability to invest up to 0.5 GW of wind power in each region every five years. However, constructing extensive wind farms has negative implications, particularly for preserving natural habitats and local wildlife. Notably, the Sami people, who are indigenous to Northern Norway, are at the forefront of opposing wind power development due to its impact on their traditional reindeer operations. NVE analyzed the most suitable areas in Norway for wind farms, considering wind conditions, power infrastructure, and environmental impacts [13]. In Northern Norway, they determined that the Skaidi and Hammerfest region is the best choice. As a result, they prioritize wind farm applications in this area. This scenario restricts wind power investments to only this region, aiming to observe the effect on the hydrogen case. All scenarios are solved to mathematical optimality.

Table 6
Overview of the scenarios.

Scenario	Description
No export (base)	No access to a hydrogen market.
Export to Sweden	Access by pipeline to a hydrogen market in Kiruna, Sweden.
Global export	Access using seaborne transport of LH_2 or NH_3 to a global market, in addition to the Swedish market.
Constrained wind	Access to Swedish and global hydrogen markets, but wind power investments are constrained to the Skaidi/Hammerfest region.

5. Results and discussion

5.1. No export

In the base case, some intuitive patterns emerge. Wind power investments are distributed across six out of nine regions, with Varanger receiving the most prominent investment due to its slightly higher capacity factor. This spread of wind power also allows for more rapid investments, given each region's investment limit of 0.5 GW. Approximately 2.3 GW of wind power will be invested in Northern Norway from 2030 to 2055, with the most significant investments occurring in the first strategic period (2030–2035). This is a severe increase compared to the existing renewable capacities provided in Table 1. The power line capacities between Hammerfest and Varanger are increased by 0.1 to 0.4 GW, possibly underestimated through the modeling assumptions. Fig. 3 visualizes the placement and quantities of the wind power and power line investments.

In Northern Norway, a net positive electricity export from Varanger to Finland is anticipated, with the peak net export occurring from 2040 to 2045, averaging about 1.22 TWh per year. There is no net export to Norway (Bardufoss) from Tromsøand Gouda. This behavior can be attributed to the balance between power generation and demand. The demand in 2030 is relatively high compared to renewable power generation, and the electricity surplus is low. By the end of 2044, all wind power investments are made, taking advantage of exports

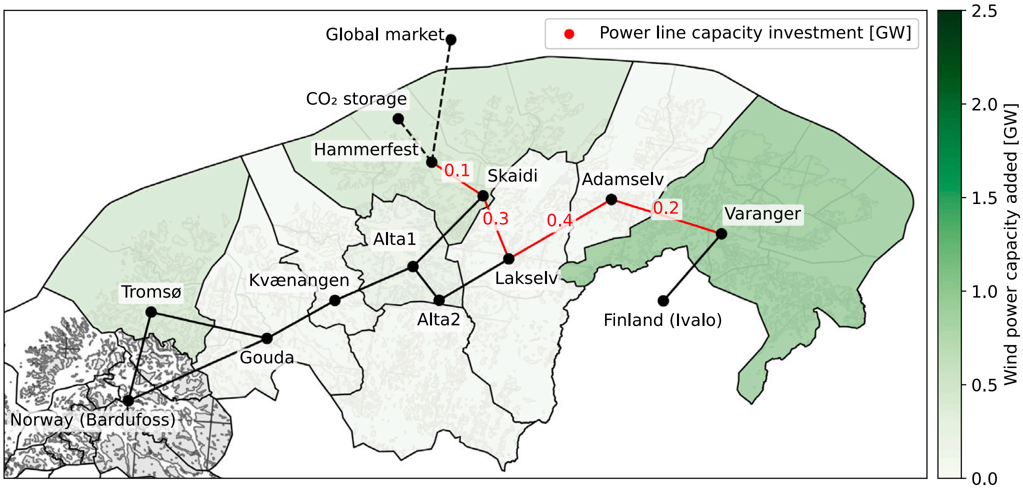

Fig. 3. Total wind power and power line investments without hydrogen.

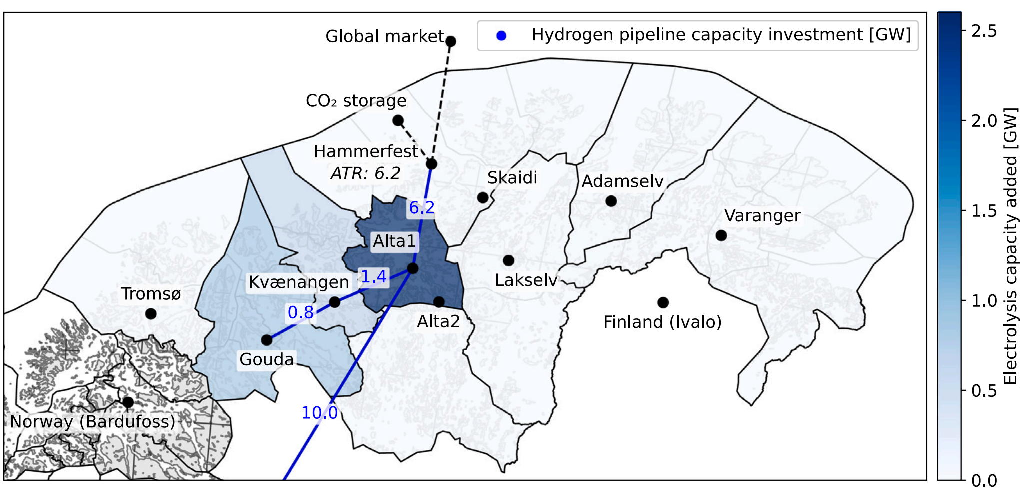

Fig. 4. Total electrolysis and pipeline investments with hydrogen exports to Kiruna, Sweden.

at higher power prices than in later periods. Without blue hydrogen production, all the natural gas is liquefied to LNG and exported from Hammerfest.

These findings support statements by Statnett, who plans to increase the power line capacity between Hammerfest and Varanger [36]. The report acknowledges that getting approval for new wind farms on land is challenging. However, it is essential to boost power generation to meet growing demand. Specifically, the electrification of the oil and gas industry in Hammerfest puts pressure on increasing power generation in the area to maintain a positive balance for power export.

5.2. Export to Sweden

In this scenario, total electrolysis investments amount to 3.9 GW and ATR of 6.2 GW,[1] with pipelines shown in Fig. 4. The maximal hydrogen production capacity in Northern Norway will reach 87 TWh per year in 2050, of which roughly 40 % is green and 60 % blue.

The increase in electricity demand triggers massive investments in wind power capacity of 18 GW in 2030–2050. Wind power investments are distributed across all regions, with necessary power line capacity expansions seen in Fig. 5. Despite these investments, the net power export remains zero for all strategic periods due to the higher profitability of selling hydrogen than electricity.

Appendix H provides additional results regarding the export of energy from Northern Norway while Appendices I and J illustrate the scale of electrolyzer production and hydropower dynamics with representative periods.

5.3. Export to the global market

The scenario is now extended to include access to a global hydrogen market at a high price. Investments in green production are 3.2 GW and in blue 6.2 GW, a slight decrease in green output from the previous scenario. These outcomes are detailed in Fig. 6. Yet, the wind investments are still 18 GW, with no net power export. Therefore, this reduction compensates for the added power demand from hydrogen liquefaction or ammonia production.

Both hydrogen liquefaction (3.5 GW) and ammonia production (2.3 GW) are used for global export, indicating a complementary effect of allowing both methods. In a more practical view, it can indicate that the cost difference between LH_2 and NH_3 is not that significant, given high enough wind power generation in the area. Hydrogen liquefaction is a more energy-efficient process but requires more electricity, as established in Table 4. Ammonia production indirectly utilizes some of the natural gas to lower the electricity demand in Hammerfest,

[1] Due to the assumption in natural gas inflow to Hammerfest of 7.743 GWh/h and ATR ratio of 1.25 NG for each unit H_2, the maximal ATR capacity is 6.2 GW.

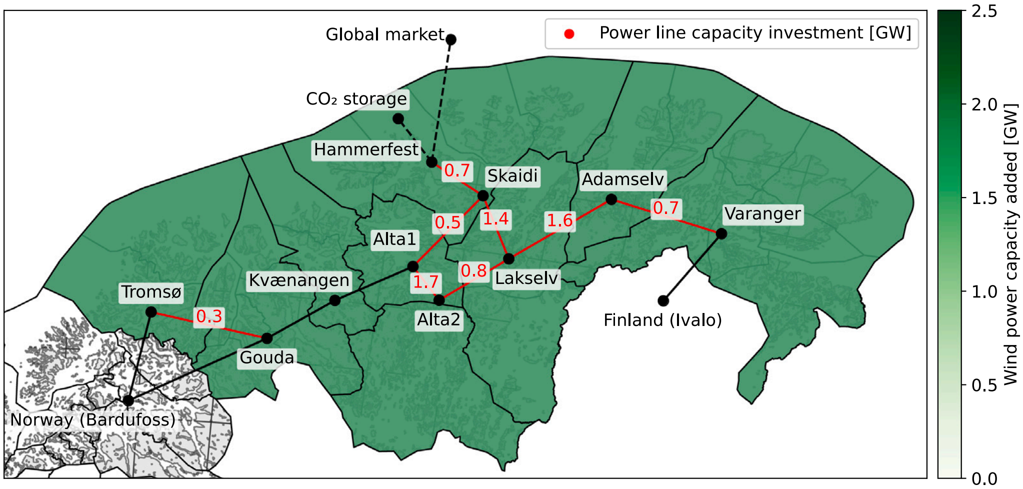

Fig. 5. Total wind power and power line investments with hydrogen exports to Kiruna, Sweden.

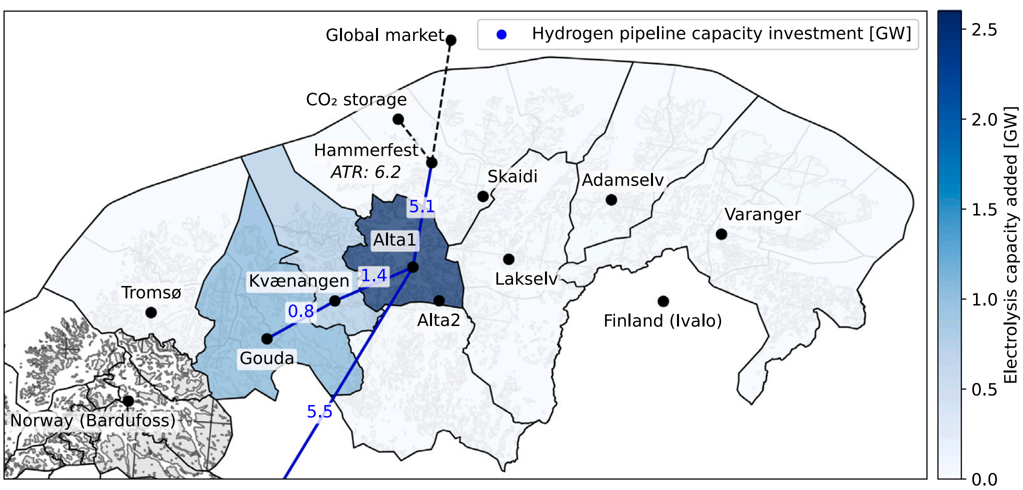

Fig. 6. Total hydrogen and pipeline investments with hydrogen exports to the global market and Sweden.

which is limited due to upper bounds on power lines and wind power investments. In this scenario, LH_2 and NH_3 are assumed to be sold at the same price. This might favor ammonia production, as energy loss through the cracking process is not considered. However, seaborne transport costs of NH_3 are generally found to be lower than those of LH_2 [12], complicating the comparison.

The price difference in Sweden and the global market promotes exports to both markets. All the hydrogen produced by electrolysis is exported to Sweden via Alta1. In the first period, 2030 to 2035, all the blue hydrogen (5.1 GW ATR capacity) is exported to Sweden. In 2035, an additional 1.1 GW capacity is added to ATR, and 41 % of blue hydrogen is exported to Sweden, while the other is converted to LH_2 (1 GW) or NH_3 (2.3 GW). From 2040, all blue hydrogen is sold on the global market, as LH_2 (60 %) or NH_3 (40 %).

Similar to earlier scenarios, rapid and widespread wind investments are prioritized. Fig. 7 illustrates location-specific wind power and power line investments. Rapid and significant investments, rather than location, seem to be the primary drivers for wind power support in large-scale hydrogen exports. The capacity investments in power lines into Hammerfest are even more significant than in the previous scenario due to the liquefaction and Haber-Bosch process. Electrolysis in multiple regions connected by hydrogen pipelines increases the model flexibility in power usage and, as a consequence, exerts less strain on the power grid between Gouda, Kvænangen, and Alta1.

Under these circumstances, there is no net export of electricity to either NO4 or FIN. The production patterns for LNG exports and blue and green hydrogen production are similar to Fig. H.1 but with lower green hydrogen capacity and some hydrogen loss in ammonia production.

5.4. Constrained wind power investments

Under the same assumptions regarding a maximum wind investment of 0.5 GW every five years, constraining wind power investments to the Skaidi/Hammerfest region would significantly impact the energy system. Overall, 2.4 GW of wind power is invested in the region, just below the upper bound. Additionally, investments in 0.2 GW additional power line capacity are made between Hammerfest and Skaidi. Specifically, the Northern Norway area experiences power deficits between 2030 and 2045, particularly in Tromsøand Hammerfest. However, Norway's Ministry of Petroleum and Energy is committed to achieving secure power delivery [59]. In other words, if this area aims to maintain a net surplus of electricity, it would need to build more than 100 MW of wind capacity annually in Skaidi/Hammerfest, especially in the earlier periods. Furthermore, these restrictions on wind investments would adversely affect the hydrogen case, resulting in no hydrogen production in this scenario. Additionally, the electricity needed for the pumping and liquefaction of natural gas would not be fully met between 2030 and 2045 due to the slow renewable investments and high penalty of not meeting the increasing power demand. Maximal levels of LNG exports will be restored first in 2050 when enough power generation is provided.

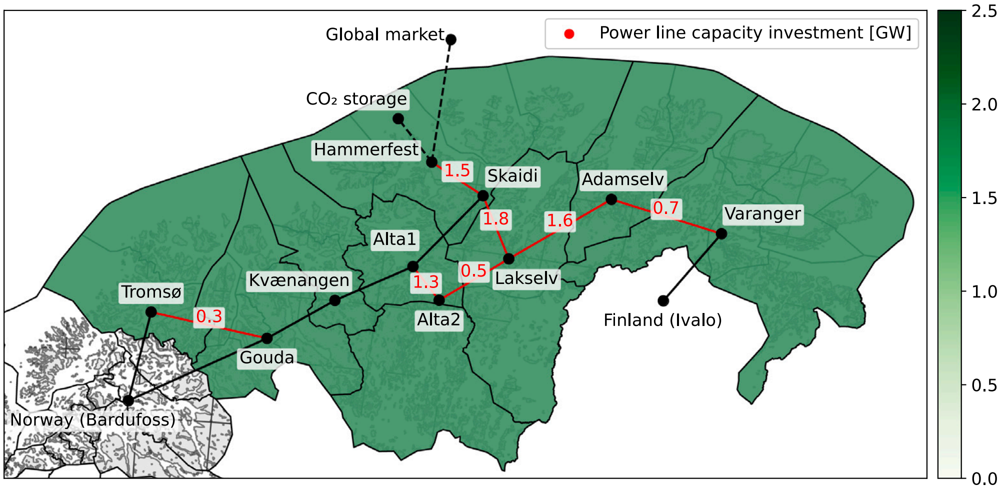

Fig. 7. Total wind power and power line investments with hydrogen exports to the global market and Sweden.

5.5. Sensitivity analysis on energy prices

5.5.1. Introducing the sensitivities

This study uses sensitivity analysis to explore the effect of various future natural gas, hydrogen, and electricity prices. Based on these estimates, a multiplier ranging from 0.5 (indicating a low price) to 2 (showing a high price) is applied to account for fluctuations in electricity prices in NO4 and FIN. When not explicitly varied, the external electricity prices follow the EMPIRE outputs. Natural gas and hydrogen prices are assumed to be flat throughout time, not factoring in forecasted increases or decreases in price. While natural gas prices can be highly volatile [60], disregarding these price fluctuations and avoiding speculation about future trends can be advantageous. This approach shifts the focus towards determining the optimal price level for specific investment strategies and simplifies the interpretation of results. Similarly, this study does not speculate how future hydrogen prices may behave. Instead, it examines how different price levels impact the system.

A step length of 5 (and 2.5 for critical values) is used for one-dimensional sensitivities, and a step length of 10 for hydrogen price and 15 for natural gas price is used in the two-dimensional sensitivities. When global hydrogen prices vary, hydrogen exports to Sweden are locked at 90 €/MWh, and the focus is the effect on production and international exports. Furthermore, when LNG prices are not varied explicitly, they are assumed constant at 30 €/MWh. The sensitivities are applied to both the *Export to Sweden* and the *Global export* scenarios. In the former scenario, two additional cases consider only green and only blue production, aiming to analyze the individual impacts.

5.5.2. Sweden market sensitivities

A one-dimensional sensitivity analysis on the hydrogen price shows that the price of hydrogen in Kiruna must be at least 60 €/MWh for pipeline investments from Tromsøto be profitable, illustrated in Fig. 8. Blue hydrogen production is maximized for prices over 65 €/MWh (*i.e.*, utilizing all available natural gas inflow) However, green production is still responsive to increases in price but flattens out for prices above 90 €/MWh. Wind investments are strongly correlated to electrolysis investments.

Blue hydrogen from Hammerfest to Sweden via Alta1 would still be profitable even when green hydrogen production is prohibited. In this case, the ATR capacity of 6.2 GW with 6.2 GW pipelines and investments in wind power are reduced to 3.6 GW. Similarly, not permitting blue hydrogen would still lead to exports, such as production in Gouda, Kvænangen, and mainly Alta1. The pipeline capacity would be 4.1 GW from Alta1 to Sweden. A synergy effect could exist because

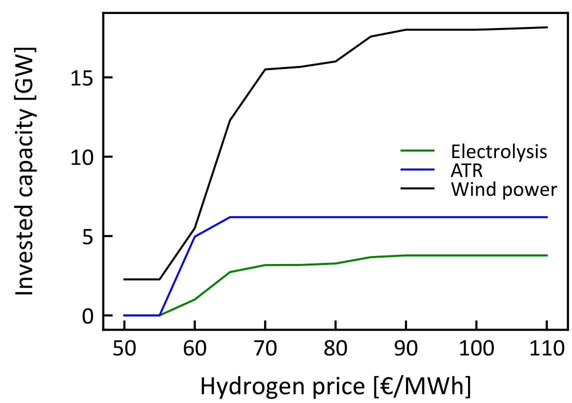

Fig. 8. Invested capacities in electrolysis, ATR, and wind power for varying prices of hydrogen in Sweden.

the pipeline capacity may not always be fully utilized. The combined pipeline capacity for individual blue and green exports to Sweden is 10.3 GW, 3 % higher than when both options are allowed.

A correlational analysis reveals some clear trends in the model behavior shown in Fig. 9, most of which can be attributed to the competitive use of power and natural gas. Total hydrogen production is mainly affected by ATR investments, as this generally allows for larger quantities produced at a given price. Power export is strongly negatively correlated with green hydrogen production due to the high power demand of water electrolysis. This is why higher wind investments lead to less power export, as the primary driving factor behind these investments is to support electrolysis.

Two main factors stimulate blue hydrogen production: the high price of hydrogen and the low price of natural gas. The contour plot[2] in Fig. 10 shows this trend is relatively straightforward, even with semicontinuous investment in pipelines and ATR.

On the other hand, green hydrogen production is mainly stimulated by high hydrogen prices and low electricity prices. As a non-negative net export is enforced for the region, the outside electricity prices do

[2] A contour plot shows three dimensions on a two-dimensional surface by utilizing color in addition to x and y-axes. In the following contour plots, the color is determined by hydrogen production volumes, where red color indicates high production, and blue indicates low production.

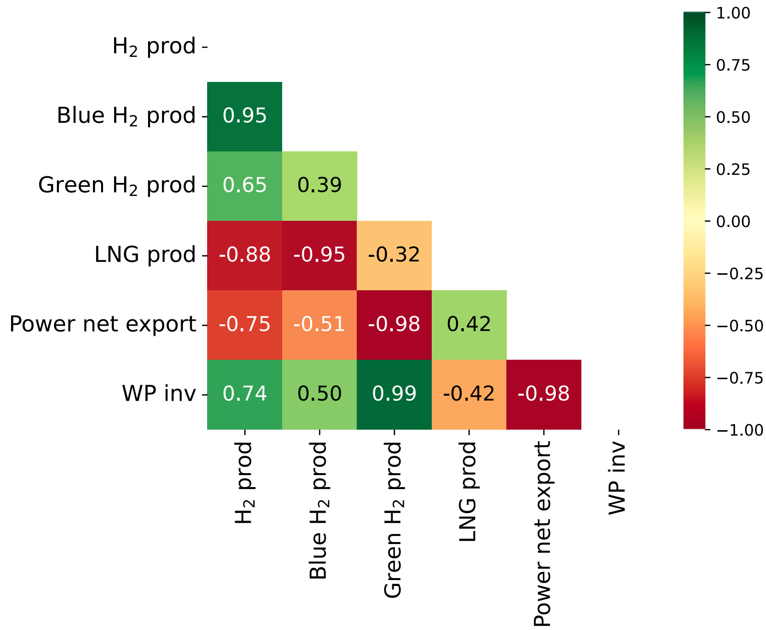

Fig. 9. Correlation matrix over the sensitivity runs with only the Swedish market.

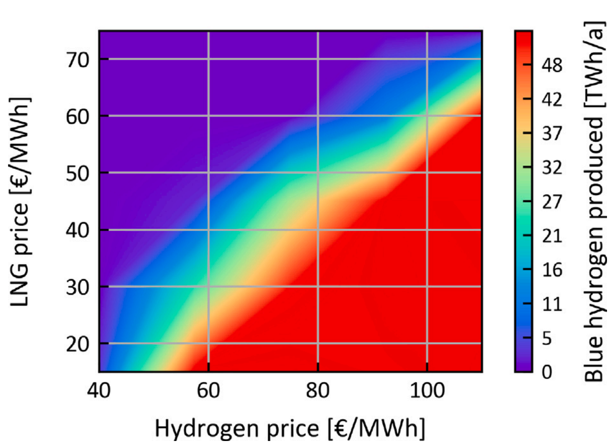

Fig. 10. Contour plot of blue hydrogen export to Sweden considering hydrogen and LNG prices.

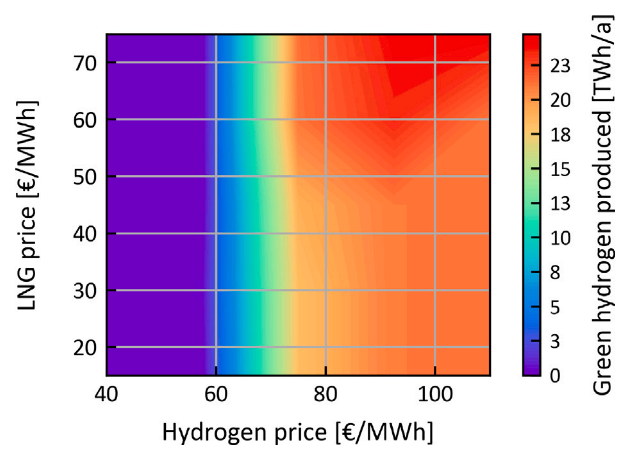

Fig. 11. Contour plot of green hydrogen export to Sweden considering hydrogen and LNG prices.

not significantly impact the model results when hydrogen is allowed. The contour plot in Fig. 11 illustrates the apparent effect of hydrogen prices. Additionally, higher LNG prices stimulate more green hydrogen, making for a compensatory effect of reductions in blue hydrogen production. This can be attributed to electrolysis being preferable over blue hydrogen, considering the opportunity cost of LNG sales. It can also be related to the economies of scale for pipelines, where low total hydrogen production can lead to more expensive exports. Also, the results further indicate that blue hydrogen investments may be a catalyzer for green, especially for lower prices (and thus smaller quantities of green production profitable).

As previously commented, the exogenous electricity prices in NO4 and FIN have a low impact on the model decisions. Net import is not permitted yearly, and the overall net export is generally minimal. The decisions made by the model do not explicitly affect the electricity price, and the model does not make any assertions about future electricity prices within the area. However, considering that the area had a surplus of power amounting to a little over 5 % of its total production in 2022, [61,62], a reduction to zero surpluses should theoretically contribute to an increased electricity price.

5.5.3. Global and Swedish market

Assuming either LH_2 or NH_3 is exported to the global market without access to the Swedish market, it can be shown how significant ATR investments would be made for different hydrogen prices, where LNG is fixed at 30 €/MWh. Fig. 12 illustrates that ATR investments are triggered by prices of 90 €/MWh or above, for both LH_2 and NH_3. Ammonia production is less energy efficient overall, but the bottleneck in power availability in Hammerfest favors the least power-demanding process, and ammonia may allow for larger export quantities. This does not consider pure hydrogen prices and ammonia cracking, which might benefit LH_2 more, or a combination of the approaches. When ammonia prices are fixed at $\frac{1}{1.15}$ of the LH_2 prices, as compensation for the cracking, hydrogen liquefaction is preferable.

Access to Sweden is now allowed at the fixed price of 90 €/MWh. Blue hydrogen production is only profitable for LNG under 50 €/MWh with low global prices as shown in Fig. 10. When the global prices reach about 130 €/MWh, some hydrogen is liquefied and exported to the worldwide market. This causes a reduction in quantity due to the high electricity demand for liquefaction and the power bottleneck in Hammerfest, observed by the yellow color in Fig. 13.

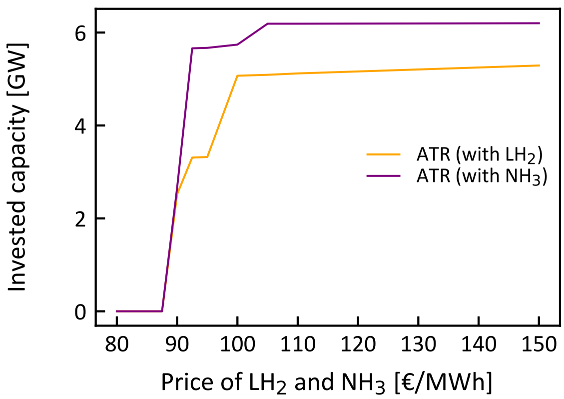

Fig. 12. Investments in ATR when either LH_2 or NH_3 is sold for varying prices.

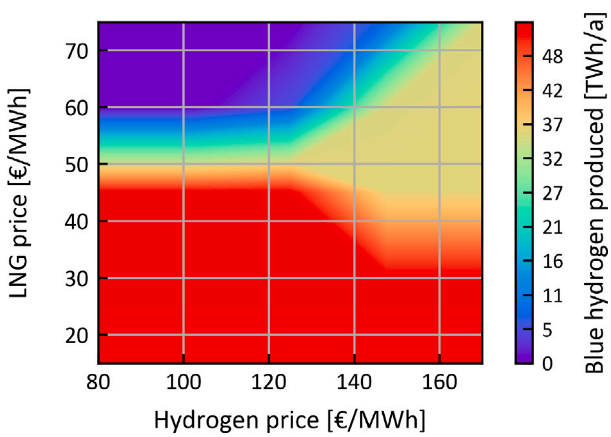

Fig. 13. Blue hydrogen production when hydrogen prices in Sweden are fixed at 90 €/MWh, and the price of LH_2 and LNG varies on the global market.

5.6. Implications and limitations

A comparison of scenarios is presented in Table 7. The power demand is expected to rise significantly from 2030 due to the electrification project in Melkøya in Hammerfest, and hydrogen production and export would contribute to further increases in demand. It is not unexpected that substantial investments in wind generation are the common trend following a hydrogen export strategy from Northern Norway. When examining the feasibility of high wind investments, particularly in scenarios 2 and 3 with hydrogen, there are valid concerns expressed by Statnett [36,63]. From reports by IEA, Norwegian wind capacity increased rapidly from 2010 to 2020 and was at 4.75 GW in 2021 [64,65]. However, licensing challenges that emerged in 2019 significantly slowed onshore investments, and this trend is expected to continue until 2030. Although a new licensing format was announced in 2022, designed to consider environmental factors and stakeholder interests, the feasibility of massive onshore wind investments beyond 2030 remains a complex question. As illustrated when constraining wind investments in scenario 4, this would make hydrogen export unfeasible and even have severe consequences for LNG export. In all scenarios, net-positive power exports did not exist in the model from 2050 and were generally low in prior periods.

The power line capacity in the Northern area has been pointed out as weak [36], and significant capacity expansions are expected when power generation increases. The Norwegian government states that the electrification of Melkøya is dependent on the increased capacity to Hammerfest [66], which also appears in scenario 1 to a certain extent. Note that power line capacities are estimates of N-0 capacity and may be overly optimistic. Furthermore, due to the deterministic model, risk considerations are not factored into the model decisions. Since hydropower is a large contributor to power generation in Norway, even in Northern Norway, it provides flexibility due to the storage option, which has a flattening effect on power transport [67]. The results indicate that green hydrogen production also can contribute to grid stabilization.

The main factors affecting Swedish exports are distances for hydrogen transport and the economic suitability of large-scale green production in different regions. Low exports promote a dense production pattern, while larger-scale production is more distributed. In the former case, production in Gouda with direct export to Sweden is chosen, while the path through Alta1 is optimal for higher quantities, especially when blue production is allowed. Alta1 is more centralized in the northern area, meaning existing power lines can be better exploited, and it enjoys the benefits of rapid wind investments in neighboring regions. Exports via Tromsøwere likely more expensive due to the region's higher power demands and the longer route from Hammerfest. A limitation of the study is that seaborne exports from other locations were not considered, for instance, from Tromsøor Varanger, which might have resulted in a different production and export pattern.

Similarly, hydrogen transport options can impact production locations. As shown by [68], both the transport distance and volume have an impact on the least cost transport option. Within this study, we focused exclusively on pipeline transport given the large distances and volumes as well as the limited road network in Northern Norway. However, truck transport using liquefied hydrogen may also be an option, resulting in distributed liquefaction due to the lower investment costs. As a consequence, it could have been more beneficial to produce hydrogen in regions with beneficial wind power profiles further away from the export regions.

Blue hydrogen production is affected by LNG prices, as demonstrated in the sensitivity analysis (Fig. 10). Thus, the price of LNG can make or break the profitability of blue hydrogen exports, representing an apparent risk factor for investors. While the results indicate a minor synergy effect between blue and green production, individual behaviors still dominate.

The gradual wind and electrolysis capacity investments for each scenario are presented in Fig. 14. The key takeaway from the investment behavior is that significant and early investments are valuable, even when accounting for future decreases in technology costs. Prices in the NO4 and FIN electricity markets do not consider changes in generation and demand in the modeled region. This limitation was attempted to neutralize by, to some degree, isolating Northern Norway by not allowing significant investments in the power lines to the outside and enforcing a non-negative net export. Furthermore, the Norwegian government has stated that Northern Norway should aim to increase its power supply to at least keep its current energy surplus in 2030 [69]. Net power imports, especially used for hydrogen production and exports, would likely not be politically acceptable for this area, which has a high potential for power supply and relatively low power demand.

Under certain assumptions, heat recovery for the electrolyzer units in Tromsømay promote earlier investments in this region, although its impact is not substantial. Due to the minimum capacity requirements for pipeline investments, the investment strategies are unlikely to change significantly, and in this case, the model did not favor electrolysis in Tromsø. However, when assuming that production and export on a tiny scale are possible (*i.e.*, continuous assumptions for hydrogen pipelines), adding heat recovery sometimes led to earlier investments in electrolyzer units. In this case, the inclusion of liquefied hydrogen trucks may have changed the results. As the heat demand that could be met by electrolyzer waste heat was relatively low in this study, the cost and indirect environmental benefits are minor in the larger

Table 7
Comparison of scenarios.

	Scenarios	1	2	3	4
	Wind power	2.3	18.0	18.0	2.4
Investments	Power line	71.3	420.7	412.6	6.8
(GW for nodes)	ATR	0	6.2	6.2	0
(GW km for links)	Electrolysis	0	3.8	3.2	0
	H_2 pipeline	0	3267.6	1996.8	0
	H_2 liquefaction	0	0	2.3	0
	Haber-Bosch	0	0	3.5	0
Exports	LNG	67.8	0	0	67.8
last year	Hydrogen	0	87.0	78.6	0
(TWh/a)	Power	0	0	0	0

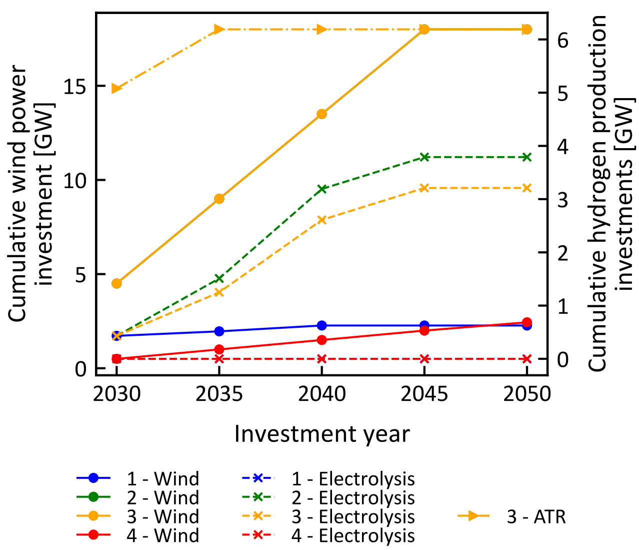

Fig. 14. Investments in wind power and electrolysis over time for the scenarios.

picture. In a more positive light, waste heat utilization did improve the efficiencies of green hydrogen production, and hence, reduced the primary energy demand.

In these analyses, incorporating start-up and shut-down time requirements did not significantly impact the results when applied to the ATR node. The assumption of time-independent potential for hydrogen sales, contrary to, *e.g.*, a time-varying demand, likely plays a crucial role. Furthermore, when blue hydrogen production becomes profitable, the model tends to maximize the utilization of the ATR plant.

A significant limitation of the presented study is the decision not to include uncertainty directly into the modeling framework. This includes operational uncertainties, such as wind and hydropower profiles, and strategic uncertainties, such as future hydrogen prices, capital expenditures, or efficiencies. Operational uncertainty may have especially an impact on the profitability of electrolysis in combination with wind power due to changing capacity factors. Hence, when operational uncertainty for hydropower inflow and wind power profiles is included, both higher and lower investments in electrolysis and wind power are possible outcomes. Strategic uncertainty may have even more pronounced impacts on the result. To this end, we included the sensitivity varying both the hydrogen and LNG prices. Although sensitivity analyses cannot provide comparable insights into optimization under uncertainty as stochastic programming, they are valuable in their own right and allow a deeper understanding of the solution space than scenario analysis.

6. Conclusion

The critical factors in developing hydrogen infrastructure are identifying key production locations, considering the possible energy surplus of electricity or natural gas, and the distance and transport method to a market. Higher hydrogen prices incentivize larger production and export capacities, which may prioritize cheap large-scale production over close distance to markets. Exports from Northern Norway to Sweden are cheaper than seaborne exports to the global market, as the latter requires liquefaction or conversion to ammonia.

Higher LNG prices provide higher alternative profits for LNG exports compared to blue hydrogen, thus reducing the attractiveness of blue hydrogen production. This development can make green production more attractive, even without decarbonization constraints. Additionally, the findings indicate that blue hydrogen production can stimulate green hydrogen for low hydrogen prices due to reduced transport costs.

Cheap electricity in high quantities is central for hydrogen production, especially green. By enforcing a positive net export of power from the area, outside electricity prices have a negligible effect. Rapid and significant investments in renewables, such as wind power, within the area are essential for future energy export. In the hydrogen export scenarios, investments in distributed renewables with associated power line capacity expansions trump factors such as wind profiles, location, and existing transport capacities.

Our analysis suggests that if Northern Norway manages to exploit its energy resources, there is significant potential for large-scale hydrogen exports. Furthermore, the results suggest what price level of hydrogen would make these investments in power and hydrogen infrastructure, as well as wind generation, pay off. Future research can include hydrogen storage with non-continuous seaborne export, stochasticity for wind power or costs, or explore areas with different pros and cons.

CRediT authorship contribution statement

Erik Svendsmark: Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Conceptualization. **Julian Straus:** Writing – review & editing, Validation, Supervision, Software, Project administration, Methodology, Funding acquisition, Conceptualization. **Pedro Crespo del Granado:** Writing – review & editing, Validation, Supervision, Methodology, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix A. Model indices, parameters, and variables

Nomenclature

Indices	
l	Index of link in the set of links $\mathcal{L}$
m	Index of mode in the set of transmission modes $\mathcal{M}_l$, or transmission modes that supports investments $\mathcal{M}_l^{\mathrm{Inv}} \subseteq \mathcal{M}_l$
n	Index of node in the set of all nodes $\mathcal{N}$, nodes that supports investments $\mathcal{N}^{\mathrm{Inv}} \subseteq \mathcal{N}$, or SSN nodes $\mathcal{N}^{\mathrm{SSN}} \subseteq \mathcal{N}$
s	Index of state in the set of states for an SSN node $\mathcal{S}^{\mathrm{SSN}}$
t	Index of time in the set of operational time periods $\mathcal{T}$, where Δt is the length of the operational period
t_0	Set of the first operational time periods in each representative period in the set of operational time periods $\mathcal{T}$
t^{Inv}	Index of time in the set of strategic time periods $\mathcal{T}^{\mathrm{Inv}}$, where Δt^{Inv} is the length of the strategic period
$t^{\mathrm{Inv}}_{\mathrm{Year}}$	The starting year of strategic time period $t^{\mathrm{Inv}} \in \mathcal{T}^{\mathrm{Inv}}$, assuming the first period starts in year zero
Parameters	
$C^{\mathrm{MaxInst}}_{n,t}$	The upper bound on capacity for node n in time period t
d	The yearly discount rate
$E^{\mathrm{Cost}}_{t^{\mathrm{Inv}}}$	The cost of CO_2 emissions in strategic time period t^{Inv}
$K^{\mathrm{Offset}}_{l,m,t^{\mathrm{Inv}}}$	The CAPEX offset parameter for transmission link l in mode m in strategic time period t^{Inv}
$K_{l,m,t^{\mathrm{Inv}}}$	The CAPEX parameter for transmission link l in mode m in strategic time period t^{Inv}
$K_{n,t^{\mathrm{Inv}}}$	The CAPEX parameter for node n in strategic time period t^{Inv}
$O^{\mathrm{Var}}_{n,t}$	Variable operation cost for node n in time period t
$O^{s}_{n,t}$	Operation cost for an SSN node n in time period t when in state s
T^{s}_{n}	Minimum time requirement in state s for an SSN node n
Variables	
$\delta^{\mathrm{Avg}}_{t^{\mathrm{Inv}}}$	The average discount factor in strategic time period t^{Inv}, for expenditure made throughout the strategic period
$\delta^{\mathrm{Start}}_{t^{\mathrm{Inv}}}$	The discount factor in strategic time period t^{Inv}, for expenditure made in the start of the strategic period
$\sigma^{s}_{n,t}$	1 if SSN node n is in state s at time t, else 0
$c^{\mathrm{Add}}_{l,m,t^{\mathrm{Inv}}}$	The capacity added for transmission link l in mode m in strategic time period t^{Inv}
$c^{\mathrm{Add}}_{n,t^{\mathrm{Inv}}}$	The capacity added for node n in strategic time period t^{Inv}
$c^{\mathrm{Inst}}_{n,t}$	The capacity installed for node n in time period t
$c^{\mathrm{Use}}_{n,t}$	The capacity used for node n in time period t
$e^{\mathrm{Sp}}_{t^{\mathrm{Inv}}}$	The amount of CO_2 emissions in strategic time period t^{Inv}
$k_{l,m,t^{\mathrm{Inv}}}$	The CAPEX for transmission link l in mode m in strategic time period t^{Inv}
$k_{n,t^{\mathrm{Inv}}}$	The CAPEX for node n in strategic time period t^{Inv}
$m_{n,t}$	A variable big M, representing the installed capacity for an SSN node n at time t if state s is *On*, else 0
$o^{\mathrm{Fix}}_{l,m,t^{\mathrm{Inv}}}$	The fixed OPEX for transmission link l in mode m in strategic time period t^{Inv}
$o^{\mathrm{Var}}_{l,m,t^{\mathrm{Inv}}}$	The variable OPEX for transmission link l in mode m in strategic time period t^{Inv}
$o^{\mathrm{Fix}}_{n,t^{\mathrm{Inv}}}$	The fixed OPEX for node n in strategic time period t^{Inv}
$o^{\mathrm{Var}}_{n,t^{\mathrm{Inv}}}$	The variable OPEX for node n in strategic time period t^{Inv}
$r_{n,t^{\mathrm{Inv}}}$	Revenues from sales to a sink node n in strategic time period t^{Inv}

Appendix B. The EMX model

B.1. Model description

The EMX model can be visualized as Fig. B.1. It takes in various inputs related to the economic and technological aspects of the energy system. These are all the parameter values, such as the costs of investing in and using technologies. These are used in the mathematical model formulation, where the objective is to maximize the net present value of the total profits through the entire time horizon.

At a high level, the modeling tool consists of various types of nodes and edges, as shown in Fig. B.2. Nodes can be categorized as sources, sinks, or network nodes, whereas the latter includes storage and availability nodes. Sources have only outputs, sinks only inputs, and network nodes have both inputs and outputs. Nodes represent real-world technologies like wind power, electricity demand, and electrolysis with differing mathematical descriptions. Edges (or links) transport energy from one node to another within an area or between geographical regions. These can represent power lines, pipelines, or other transport options such as seaborne liquid hydrogen and ammonia transport.

Constraints are implemented on several levels. There are nodal constraints, ensuring the proper ratio between inputs and outputs for network nodes and inflow or outflow for sources and sinks. These are linked to costs of usage (variable OPEX) and installed capacity (fixed OPEX). Link constraints make it possible to transport energy between nodes. If no energy loss is used, the input at one end of the link should equal the output at the other in the same period. Similarly, the energy balance is always maintained for areas and transmission links.

On the strategic level, constraints limit investments, such as the maximum capacity investments in wind power each strategic period. The model outputs provide the values of all operational and strategic decisions in the optimal solution. This can include production quantity for each operational period for every producing node or investments in electrolyzer capacity for each strategic period. An overview of the structure of the model is provided in [30], with direct links to the GitHub repository.

B.2. Utilized packages

The Geography-package allows for the use of geographical areas connected by transmission links. Within each area, energy flows freely, while transmission links allow for investments, costs, capacity constraints, energy loss, and more. This is crucial to model a more extensive energy system like Northern Norway.

The Investment-package is critical for capacity expansion and allows for investments at the start of each strategic period. Continuous investments are the simplest form, adding a real-number capacity to a node or transmission link within the upper bound of the investment. This paper also utilizes semicontinuous investments, which ensure investments either exceed a given lower bound or are not made. If the investment and the geography packages are loaded, investment decisions are also included for transmission infrastructure. This includes the potential for including the economy of scales for transmission investments through a piece-wise linear formulation. The implementation approach for the piece-wise linear formulation is explained in Appendix B.3.

The Renewable-Producers-package increases the realism of renewable sources, like hydropower and wind power. Hydropower nodes with reservoirs are utilized to simulate the dynamics of storing potential energy. The model makes operating decisions regarding these reservoirs, and historical data determine the water inflow. Wind power is modeled as non-dispatchable intermittent energy sources, with a seasonal profile determining power generation.

The CO_2-package contains a CO_2 storage node that accumulates stored CO_2 through the entire time horizon, containing information on total captured and stored emissions. This extension to the base package is necessary, as the basic storage node does not include preservation of storage level between strategic periods.

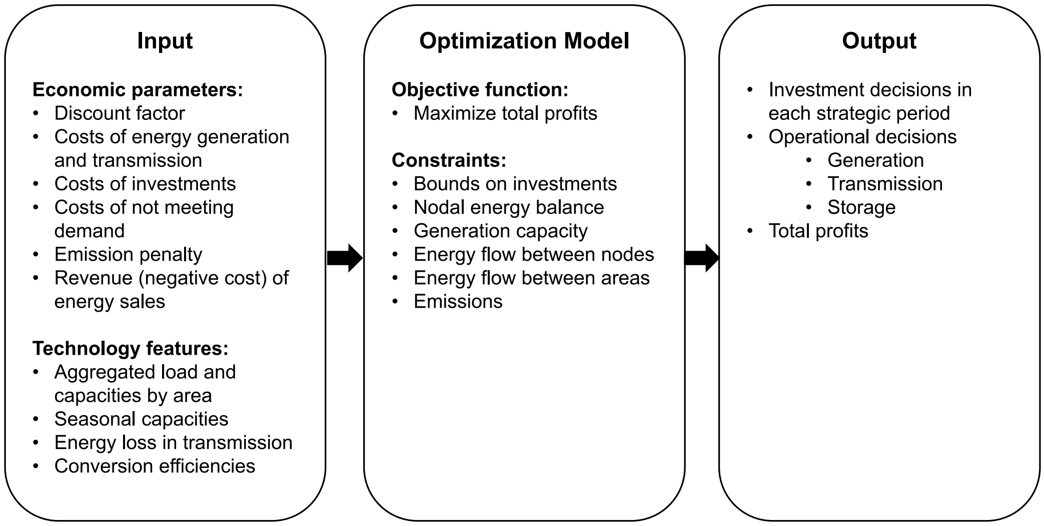

Fig. B.1. A general overview of the EMX model.

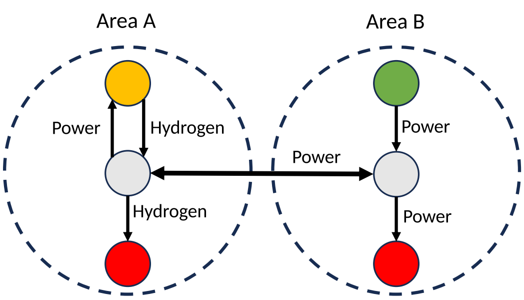

Fig. B.2. A simple graph consisting of a source node (green), a network node (yellow), and two sink nodes (red) in two distinct areas connected by a link representing a power line. Within each area, an availability node (gray) connects nodes.

B.3. Piece-wise linear formulation

The CAPEX in EMX is generally calculated using a linear relationship between the relative capital expenditures $K_{n,t^{\mathrm{Inv}}}$ and the invested capacity $c^{\mathrm{Add}}_{n,t^{\mathrm{Inv}}}$ of node n, as seen in Eq. (B.1).

$$k_{n,t^{\mathrm{Inv}}} = K_{n,t^{\mathrm{Inv}}} c^{\mathrm{Add}}_{n,t^{\mathrm{Inv}}} \qquad n \in \mathcal{N}^{\mathrm{Inv}}, t^{\mathrm{Inv}} \in T^{\mathrm{Inv}} \tag{B.1}$$

The same approach can also be used for investments in individual transmission links and modes.

EMX does not directly support piece-wise linear investments. Instead, the piece-wise linear formulation of investments is represented through distinctive transmission investment sizes with lower and upper bounds for investments represented as semicontinuous investments as economies of scales correspond to concave piece-wise linear functions. The CAPEX ($k_{l,m,t^{\mathrm{Inv}}}$) in Eq. (1) is then given by Eq. (B.2).

$$k_{l,m,t^{\mathrm{Inv}}} = K_{l,m,t^{\mathrm{Inv}}} c^{\mathrm{Add}}_{l,m,t^{\mathrm{Inv}}} + K^{\mathrm{offset}}_{l,m,t^{\mathrm{Inv}}} \qquad l \in \mathcal{L}, m \in \mathcal{M}^{\mathrm{Inv}}_{l}, t^{\mathrm{Inv}} \in T^{\mathrm{Inv}} \tag{B.2}$$

Here, $K^{\mathrm{offset}}_{l,m,t^{\mathrm{Inv}}}$ corresponds to the y-intercept (offset) of the linear equation. This is not directly a piece-wise linear formulation, but the calculated capital costs are equivalent to a procedure including a concave piece-wise linear cost function.

B.4. Simplified EMX model

A simplified model considering the hydrogen value chain is shown in Fig. B.3. It starts with energy production in source nodes, such as natural gas and renewable electricity, but water can also be included in certain analyses. From there, the natural gas (in conjunction with electricity) can produce blue hydrogen through ATR. This leads to some emissions at a penalty, and the captured CO_2 is stored in a sink node. Renewable electricity can also be used in water electrolysis to produce green hydrogen. Surplus heat output is also modeled, which can cover district heating demand in Tromsø, otherwise assumed to be met by electricity. The hydrogen is assumed to be exported and not used locally. In this regard, it may follow transmission links to Sweden. It may also be liquefied or used in ammonia production for seaborne exports to a global market. Blue hydrogen and LNG compete due to their reliance on natural gas. Efficiencies and costs for all the technologies are provided in Section 4.3.

Appendix C. EMPIRE model for external electricity prices

EMPIRE is a stochastic multi-horizon model optimizing the long-term investment strategy for the European power sector [32] while considering operational uncertainty. As the investigated region in this paper is coupled to the larger European power grid, it is important to consider said coupling when conducting analyses. Specifically, renewable power generation varies within Europe, and hence, can have a significant impact on the development in a region like Northern Norway.

To this end, the European electricity system was optimized with EMPIRE. We calculated the power prices in the NO4 and FIN price zones from the dual variables in the individual operational periods. The EMPIRE model uses in these optimization runs the same operational structure, hence allowing the direct transfer of the prices to the EMX model. The model has the potential to buy or sell electricity to both price zones, given the available capacities in the transmission power lines and the non-negative net export condition.

This implementation assumes that electricity generation and demand in the modeled region have no impact on the neighboring price regions. This is in general a strong assumption and would only be valid if the electricity transmission between the individual regions is restricted by the available transmission capacity. However, we deem this disadvantage acceptable as it allows for an increase in the geographical resolution and incorporation of more detailed technical descriptions.

Appendix D. Wind conditions

Northern Norway has good onshore wind conditions, and the Norwegian Government points to profitable wind generation as increasingly important in the long term [13]. In simple terms, wind turbines

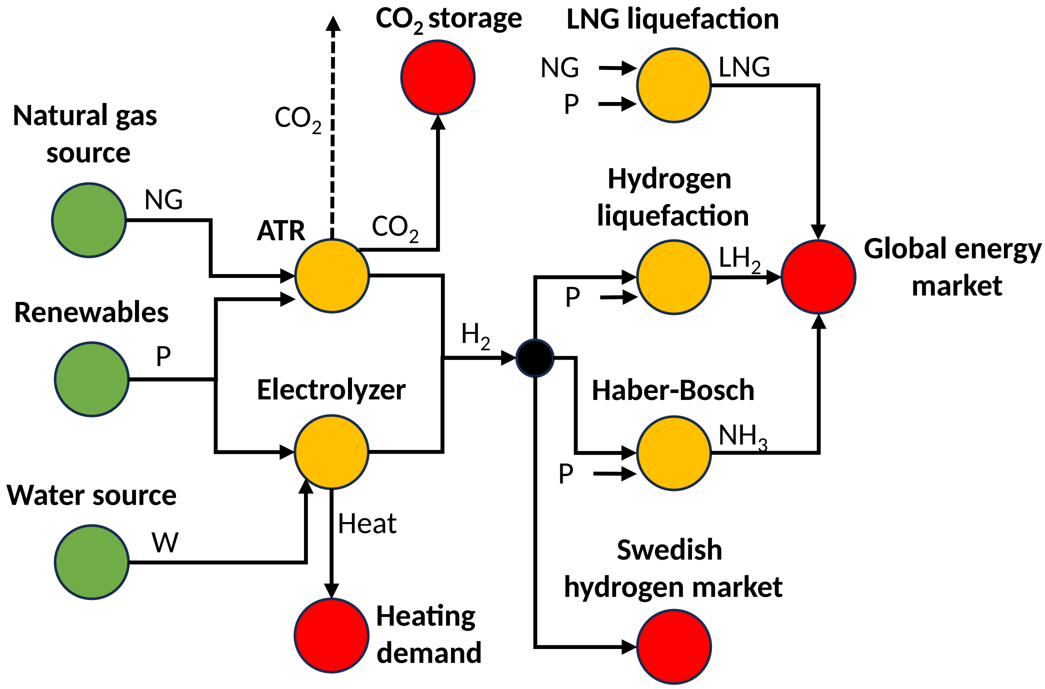

Fig. B.3. A simplified system of nodes and links modeling the hydrogen value chain. Abbreviations for energy carriers are used: natural gas (NG), power (P), and water (W).

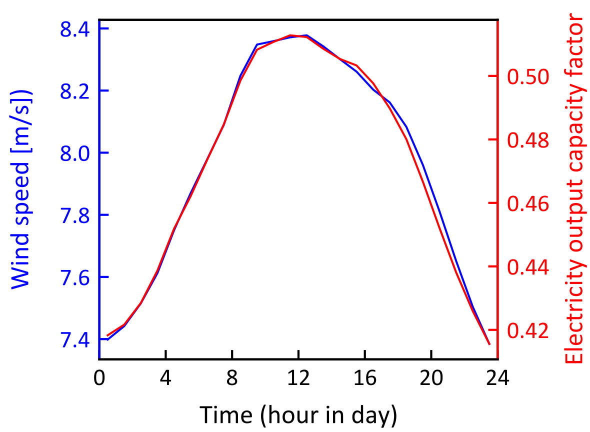

Fig. D.1. Hourly average wind speeds and wind power capacity factor in the winter months (December, January, and February) in Adamselv in Northern Norway.

produce power dependent on the wind speed. Very low wind speeds (<3–4 m/s) are generally insufficient for production, while the maximum effect is typically achieved at 11–15 m/s. A wind speed of above 25–28 m/s can put the wind turbine components at risk. Hence, they are typically turned off. The general hourly wind generation profile for electrical output is generated from [49] and illustrated in Fig. D.1 for the winter period in Adamselv. This figure shows a tight relation between wind speeds and electricity outputs. Profile variations between locations are not automatically implemented, but a few adjustments to the annual capacity factor are made. Overall, this is assumed to be 0.39 in Northern Norway but is adjusted to 0.40 in Adamselv and 0.46 in Varanger founded on data from existing plants [35].

Appendix E. Power line capacities

Power line capacities are given in Table E.1, based on data from NVE and Statnett.

Table E.1
Power line capacities between two regions assumed before 2030, based on [35,36].

Region 1	Region 2	Maximal capacity [MW]
Adamselv	Varanger	420
Alta1	Alta2	210
Alta1	Skaidi	740
Alta2	Lakselv	210
Gouda	Kvænangen	950
Gouda	Norway (Bardufoss)	740
Kvænangen	Alta1	950
Lakselv	Adamselv	210
Skaidi	Hammerfest	420
Skaidi	Lakselv	210
Tromsø	Gouda	420
Tromsø	Norway (Bardufoss)	420
Varanger	Finland (Ivalo)	210

Table F.1
Energy carriers and measurements.

Energy carrier	Unit
NH_3	GWh
CO_2	kilo tonnes (kt)
H_2	GWh
LH_2	GWh
LNG	GWh
NG	GWh
Power	GWh
Water	1000 m^3
Heat	GWh

Appendix F. Energy carrier units

The units for the modeled energy carriers are outlined in Table F.1. All energy carriers are modeled using their lower heating values.

Appendix G. Pipeline paths

Pipelines can be invested in for the paths described in Table G.1. The number of pipeline paths was reduced during the research. For

Table G.1
Hydrogen pipeline options for the sensitivity analysis.

Region 1	Region 2	Hydrogen pipeline option
Gouda	Kvænangen	Small or large
Kvænangen	Alta1	Small or large
Hammerfest	Alta1	Small or large
Tromsø	Gouda	Small or large
Gouda	Sweden (Kiruna)	Small or large
Alta1	Sweden (Kiruna)	Small or large

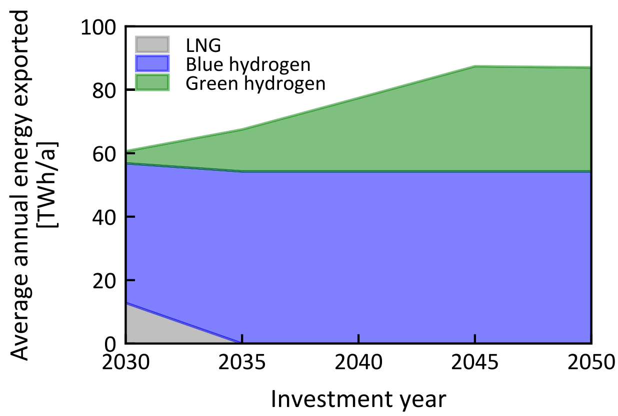

Fig. H.1. Exports over time with access to a hydrogen market in Kiruna, Sweden.

instance, the option of hydrogen production in Varanger was removed, as this was never optimal with Swedish markets, and access to the global market was assumed only through Hammerfest. Exports from Tromsøto Sweden were also pruned, as the route through Gouda or Alta1 dominated in all the tested instances. Fewer available paths reduce the computational time of solving the model, allowing for more runs in the sensitivity analysis and solving to mathematical optimality.

Appendix H. Energy exports over time

The evolution of exports from Northern Norway in the *export to Sweden* case over time is visualized in Fig. H.1 as an example of the composition of energy export from the region. This figure illustrates the quick adaptation of blue hydrogen and gradual increases in green in the subsequent years. The difference between both hydrogen production routes is most likely affected by the available power surplus in Northern Norway, which is gradually increased with onshore wind generation in the model. Blue hydrogen requires far less electricity, and when assuming access to the natural gas in Hammerfest, it can quickly be scaled up in the model.

Appendix I. Operational electrolyzer production

The electrolyzer capacity factor is high in most periods, here analyzed in the *export to Sweden* case. An optimized power flow makes this possible, flattening the effects of wind variation and power demand in producing locations. Hydrogen production in the model tends to centralize, likely due to the need for costly infrastructure. More distribution would be expected if hydrogen could be utilized near the production location. With centralized production, we see considerable power import to the producing regions, such as in Alta1 shown in Fig. I.1 (a). Here, hydropower generation is minimal, the 1.5 GW of local wind power invested is significant, but imported power (mostly from wind) is even more dominant. A small portion of this power is used to meet local power demand, but the massive amount of power to hydrogen illustrates the potential for power-intensive hydrogen production in the North, shown in Fig. I.1 (b).

Appendix J. Hydropower dynamics

Hydropower dominates power production in Norway, but the high potential for wind power development can alter the energy mix. In addition to flexible hydrogen production, hydropower can play a role in balancing wind generation. Fig. J.1 shows water magazine levels in Varanger in 2050–2055 in the *export to Sweden* case, illustrating a situation where storing energy in the winter for use in the summer is chosen by the model. The explanation is likely the high share of wind power, which is modeled with higher production in winter, combined with it being more profitable with stable hydrogen production utilizing as much of the electrolyzer capacity as possible.

Note that Fig. J.1 (a) corresponds to the representation with representative weeks, while Fig. J.1 (b) illustrates the translation of the

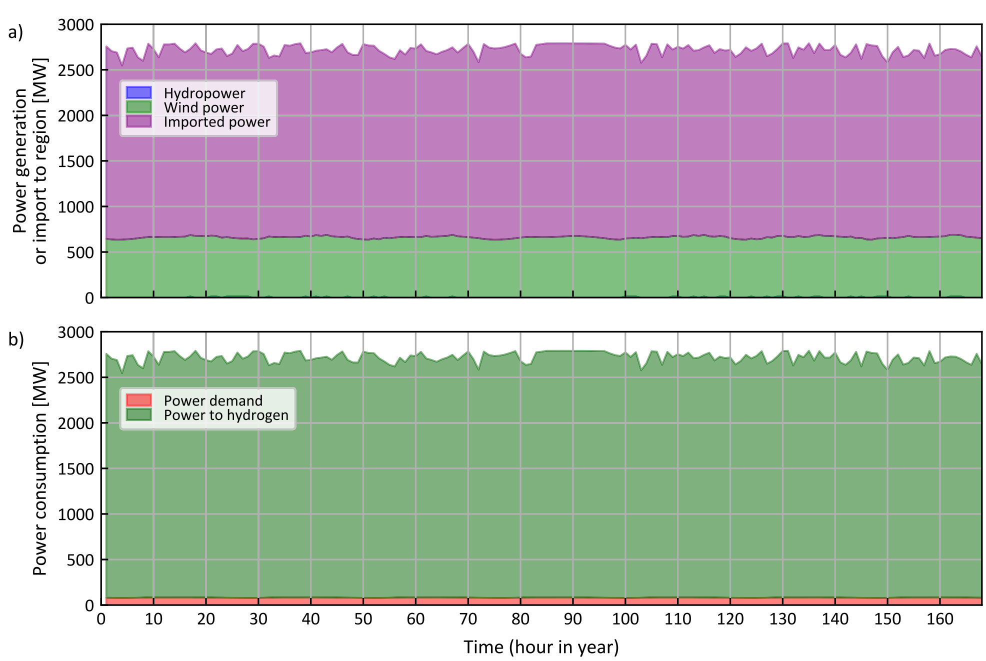

Fig. I.1. Local power generation and imports to Alta1 in the winter weeks of 2040–2045.

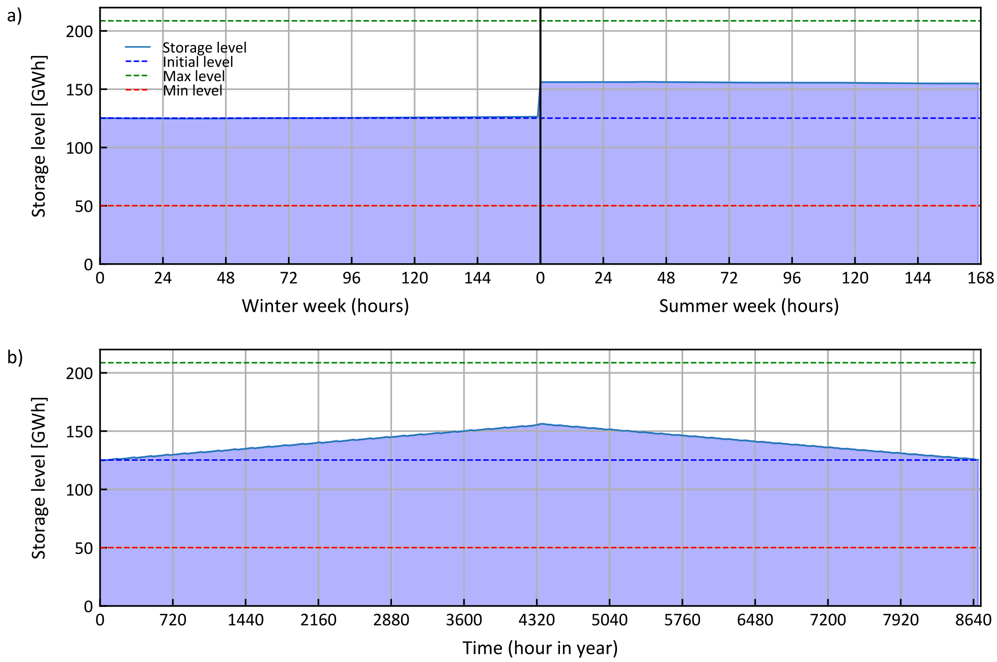

Fig. J.1. Hydropower storage levels in Varanger 2050–2055 with (a) representative weeks and (b) continuous timeline.

representative weeks into a continuous approach in which the representative weeks are repeated. The black line in Fig. J.1 (a) shows the transition between both representative weeks.

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