NORDIC POWER SYSTEMS FOR A COMPETITIVE AND SUSTAINABLE ECONOMY

A Quantified Carbon study
in collaboration with Fortum

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About this publication: *This report has been prepared by Quantified Carbon (QC) from the request of Fortum (Fortum Power and Heat – Nuclear Feasibility Study) to provide material for the Nuclear Feasibility Study and for the ongoing discussion on the Nordic electricity system.*

This report is an independent report by QC. The assumptions, data, the analysis, findings and views expressed in the report reflect the views of QC as they were interpretable based on public information and sources.

Fortum market data, information on investment costs or views on electricity market development or prices were not used in compiling this report. Assumptions concerning formed scenarios may deviate from Fortum's views (e.g., build-out of different generation technologies per scenario).

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Contents

Executive summary

This executive summary provides an overview of the analysis conducted on the transformation of the Nordic electricity system until 2050, focusing on the Finnish-Swedish power system. The goal is to determine the optimal balance between nuclear and renewable energy sources to meet a growing electricity demand while ensuring competitiveness and sustainability.

The analysis explores two demand growth scenarios, *Carbon Neutrality (CN)* & *Power to X (P2X)*, representing lower and higher demand trajectories towards a fossil-free society, respectively. The future years of 2035 and 2050 are considered, and three different shares of nuclear and renewable energy sources (low, medium, and high) are examined. The low nuclear share scenario assumes only existing nuclear, while the medium and high share scenarios allow for new nuclear buildout based on market conditions and total system cost effectiveness.

The methodology employed in the analysis combines power system modelling tools that excel in investment optimisation and electricity market modelling. In the investment optimisation stage, realistic Finnish-Swedish power systems are created based on the aforementioned scenarios, incorporating various energy sources and technologies such as nuclear energy, wind power, photovoltaic solar, battery storage and peaker plants. The subsequent electricity market modelling evaluates the performance of each power system under different weather years and fuel price scenarios, assessing security of supply, simulating power prices, and measuring price volatility.

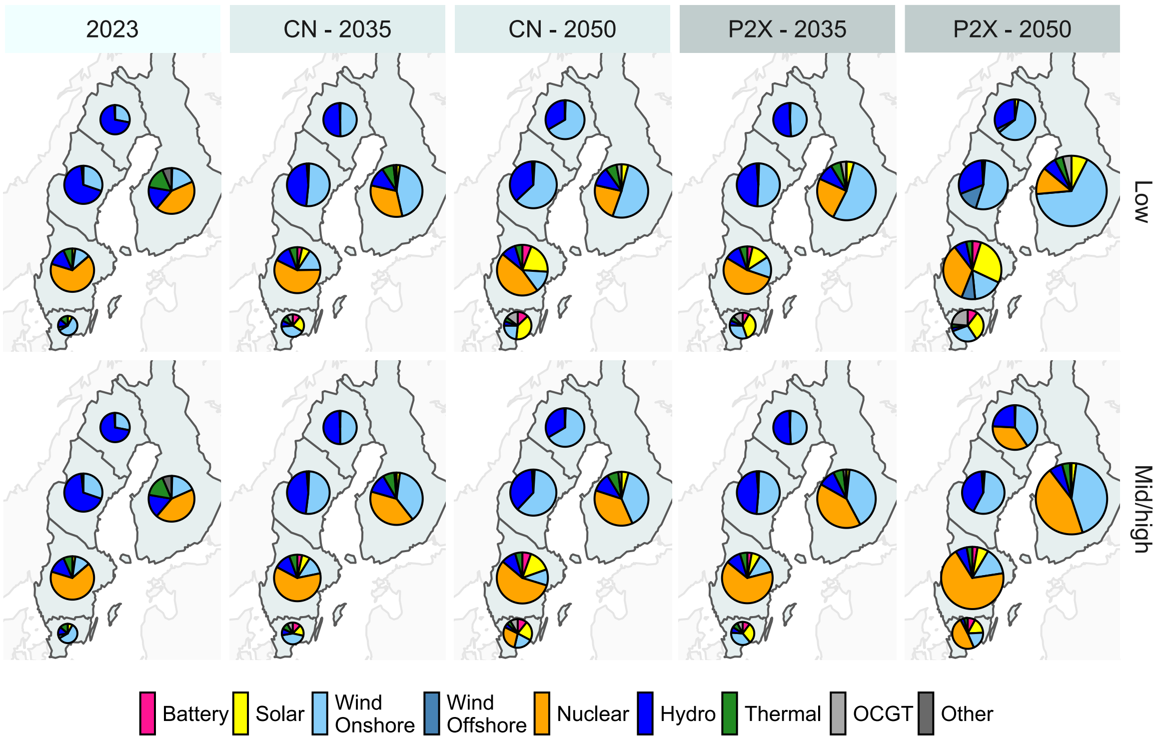

Figure 1. Share of annual power generation by resource and zone for the low (upper row) and mid/high (lower row) nuclear share scenarios, for current system modelled as of 2023 (first column) and future years in 2035 and 2050 for the two demand scenarios Carbon Neutrality (CN) and Power to X (P2X).

In a power system with growing demand but no new nuclear, wind power becomes the dominant source of energy with a share of annual generation of 35% in 2035 and 45% in 2050 of the annual generation. Nuclear accommodates to a corresponding share of annual generation of 25% in 2035 and 15% in 2050. More detailed shares of annual energy generation per resource, zones and scenario are presented in Figure 1. The inclusion of new nuclear power helps to keep the shares of nuclear and wind power roughly fixed at about 30% and 35%, respectively, in 2035 and 2050. The exception is the P2X high demand scenario where onshore wind power reaches its limits of expansion in Sweden, and new nuclear expands more significantly to cover 45% of the share in this case. Utility and roof-top solar PV coupled to battery storage mainly in southern Sweden, becomes a significant part of the total generation. Offshore wind power is only built in one scenario due to profit cannibalization and higher investment costs compared to onshore wind.

Table 1 below compiles main parameters of the power systems with low vs high share of nuclear in the Finnish-Swedish power system.

Table 1. Summarised results comparing main parameters of the power systems with low share of nuclear, including only existing nuclear power, to those with high which includes existing and new nuclear power.

Parameter	Nuclear share	
	Low (existing nuclear)	High (+new nuclear)
Electricity price level (median)	67 €/MWh	55 €/MWh
Electricity price volatility compared to historic average[1]	Higher	Similar
Security of supply	Increased sensitivity	More robust
Annual system cost (B€)	Similar	
Relative greenhouse gas emissions, land use and use of critical minerals	Higher	Lower

Analysis of the Finnish-Swedish power systems reveals significant differences when comparing low and high nuclear share scenarios. By introducing new nuclear power, the systems exhibit considerably lower electricity prices by 2035 and even more so by 2050. Conversely, the low nuclear scenarios show very high prices, underscoring the unlikelihood of achieving a high-demand growth P2X scenario without new nuclear as attracting such demand to the region requires competitive power prices. The combination of new nuclear power and an expanding wind power system enhances competitiveness in the Nordics.

[1] Excluding the extremes during the acute phase of the energy-crises of 2022.

While electricity price volatility remains consistent with historical averages for the Finnish-Swedish system when including new nuclear, scenarios with low nuclear shares experience a significant increase in sensitivity to weather variations and commodity prices. The heightened sensitivity introduces higher risks for both producers and consumers. On the other hand, the introduction of new nuclear power fosters a more robust system that can withstand external changes, creating a stable market environment and enabling opportunities for additional investments. Scenarios with low nuclear shares display an increased dependence on typically fossil-fuelled high marginal cost dispatchable capacity through imports and local peaking plant fuel consumptions, highlighting vulnerability to security of supply. The high nuclear share scenarios, with their more diverse energy supply, establish a more resilient Finnish-Swedish power system.

Total system costs for the Finnish-Swedish power system are similar across all various nuclear share scenarios. The inclusion of large scale and cost-efficient expansion of onshore wind contributes to achieving relatively low total system costs. Additionally, higher shares of nuclear energy result in more sustainable power systems, as demonstrated by reduced greenhouse gas emissions, minimized land use, and reduced reliance on critical minerals. Scenarios with low nuclear shares exhibit increased greenhouse gas emissions due to higher fuel consumption in peaker plants during unfavourable weather conditions. The greater use of land and critical minerals is driven by the increasing shares of onshore wind and solar energy.

Overall, the analysis highlights the strategic advantages and long-term benefits of integrating new nuclear power alongside an expanding wind power system in the Finnish-Swedish power systems. This approach leads to lower electricity prices, enhanced system resilience, reduced volatility, and improved sustainability, positioning the Nordics for a competitive and environmentally friendly energy future.

To fully capitalize on the increased competitiveness and sustainability that comes with the introduction of new nuclear in the Finnish-Swedish power system, the following prerequisites and main recommendations should be derived from the modelling results of this study:

- Invest in and ensure the continued operation of existing hydropower – this is a fundamental requirement across all modelled scenarios.
- Reinvest and make new investments to reinforce local, regional and national transmission grids to levels at least in accordance with currently announced plans, but also including significant increase in the transmission capacity of SE1-SE2 through power lines and hydrogen pipelines.
- Extend the operational lifetime of all existing nuclear power plants.
- Maximise the deployment of onshore wind power within the limitations of conflicts of interest (approximately 40 GW or ~110 TWh/year in both Sweden and Finland in this study).
- Implement plans to build new nuclear capacity that would roughly double today's existing capacity by 2050 in Finland and Sweden.
- Strengthen the system further, in addition to the aforementioned points, through the integration of utility-scale solar PV and battery storage installations primarily in southern Sweden and install offshore wind power in the most cost-effective locations. Reinforcing the transmission capacity for the SE1-FI transmission line is also a priority.

Policymakers should focus on reducing costs, eliminating barriers, and resolving conflicts of interest to facilitate the cost-effective and scalable deployment of the recommended measures. By aligning policy decisions with the findings and recommendations of this study, we can foster a Nordic power system characterized by competitive and predictable electricity prices that attract investments from green industries. With a power system that is more resilient to supply disruptions and external factors due to a diverse mix of energy generation sources, we can make progress towards an energy future that is not only economically viable but also environmentally responsible.

1 Introduction

The electricity system will undergo substantial changes in the coming decades due to the drive towards achieving decarbonization goals. In this report, we highlight these developments until 2050 both on the supply and demand side. Several factors including energy market design, variable renewable energy penetration, demand-side participation, capacity mechanisms, nuclear buildouts will influence the energy transition.

The Nordic countries as well as northern Europe are increasing the share of wind and solar power on the supply side, as well as electric heating on the demand side, resulting in an increase in the electricity system's weather-dependency. Phasing-out fossil-based thermal power plants is essential for reaching climate goals, but also challenging as these provide valuable heat demand following supply and all-year dispatchable supply. Therefore, it is becoming increasingly important to investigate new nuclear to improve security of supply and stable prices while ensuring a competitive economy and sustainable source of energy. [2]

This study confronts the above issues in the context of the Nordic power system. The addition of new firm nuclear capacity, complementing a strong increase in variable renewable energy, is analysed with a primary focus on the Finnish-Swedish power system. The overarching objective for the current work has been to answer the following question:

> "What is the optimal share of nuclear and renewable energy sources in the Finnish-Swedish power system for a *competitive & sustainable* economy in the Nordics until 2050?"

To provide answers to the question the following method has been applied:

Method:

Build Finnish-Swedish power systems that meet power demand every hour of the year and ensure profitability for producers based on the following:

- Two demand scenarios, *Carbon Neutrality (CN)* & *Power to X (P2X)*, reflecting different trajectories towards fossil-free society
- Future years *2035* & *2050*
- Low, medium & high share of nuclear vs renewable energy sources

Evaluate the Finnish-Swedish power systems based on:

- Total system investment and operational costs
- Security of supply, average electricity prices and volatility

[2] The key issues in the Nordic electricity system transformation towards 2050 are further discussed in the Appendix in section 8.1.

The study design and methodology are illustrated in Figure 2. The foundation of the approach is two modelling steps: (1) Power system optimization and (2) Electricity market modelling.

In the power system optimization, Finnish-Swedish power systems with the lowest combined investment and operational cost that meets power demand every hour of the year including demand-side response are built. This is done for all the variations in demand scenarios, future years, and nuclear shares. All modelling runs result in 10 different power systems, primarily defined by their installed production capacity of different energy sources. Nuclear capacity is governed by expansion limits, defined with the nuclear share which is introduced in detail below. The model builds renewable energy capacity, including onshore & offshore wind and photovoltaic solar as well as battery and peaker plants to meet remaining demand. The construction of each Finnish-Swedish power system comes with a total cost of capacity expansion investments and fixed and variable operational costs, referred to as total system costs.

In the second step electricity market modelling is applied to determine how well the power systems perform with regards to security of supply and to simulate electricity prices and price volatility. This is achieved by confronting each of the ten power systems to a set of different weather years (representing conditions: wet, dry, hot, cold, windy & calm) and commodity price scenarios.

The methodology combines the best of different types of modelling tools. The power system optimization identifies cost-optimal power systems *from the ground up* whilst ensuring that all production resources being profitable. The electricity market modelling achieves highly detailed dispatch profiles for the power systems built in the optimization step and can determine realistic electricity price series. Together, they deliver credible values of system costs, security of supply, electricity prices and electricity price volatility, thereby providing firm insights into competitiveness and sustainability.

The path towards a carbon neutral society in 2050 is investigated by touching down in 2035 as well as modelling the 2050 end point. On the path to 2050, year 2035 is a suitable middle point. The inclusion of 2035 is further motivated as follows; it is far enough into the future that significant and larger changes to the power system are possible and expected, both with regards to demand and supply. Year 2035 is also associated with Finland's goal of climate neutrality in 2035[3].

To assess the optimal share of nuclear in the Finnish-Swedish power system, three levels of share for new nuclear, *low, medium,* and *high,* have been introduced. Together they aim to span the space of possible outcomes for the build of new nuclear power in the Nordics. The low case represents a path with no build-out of new nuclear power while the medium & high cases allow the expansion of new nuclear capacity to different levels.

Definitions of nuclear share is shown in Table 2. The short timeframe until 2035 limits the possibilities of nuclear expansion. With this background, the current study has defined a maximum capacity limit of 1 GW and 3 GW for both Sweden and Finland in 2035 for the medium and high nuclear share, respectively. Considering only limits to construction, until 2050 the realm of possible nuclear growth

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[3] State treasury - Republic of Finland. Climate Neutral Finland 2035.

could be quite significant. Therefore, no upper limit has been introduced for the high nuclear share in 2050. Hence, high nuclear share is defined by the governing electricity market in the cost optimal Finnish-Swedish power system, which conditions will guide the expansion to the limit of profitability. Medium nuclear share is simply defined as half of the high share in 2050.

For 2035, all nuclear power plants currently in operation in Finland and Sweden remain in operation throughout all modelled scenarios. The same assumptions are also made for 2050, with the exception of the Finnish Loviisa nuclear power plant which retire about 1 GW of existing nuclear power in the model as further presented in Table 2. Loviisa nuclear power plants have permits that run out in 2050, as such model year 2050 represents a state of the power system post its retirement.

Table 2. Definition of new nuclear share in 2035 and 2050 and the existing nuclear capacity in Finland and Sweden. Note that for the Carbon Neutrality (CN) scenario, the medium and high nuclear share scenarios have been merged, denoted medium/high later in report[4], due to similar and more modest capacity expansions. "High/2" means that the medium share for 2050 is set to half the value obtained in the high scenario for which there is no maximum capacity limit in the expansion.

Model year	**New nuclear share**	**Existing nuclear capacity (GW)**		**Maximum *new* nuclear capacity (GW)**	
		FI	**SE**	**FI**	**SE**
2035	Low	4.4	6.9	0.0	0.0
	Medium			1.0	1.0
	High			3.0	3.0
2050	Low	3.4	6.9	0.0	0.0
	Medium			High/2	High/2
	High			-	-

[4] See Table 10.

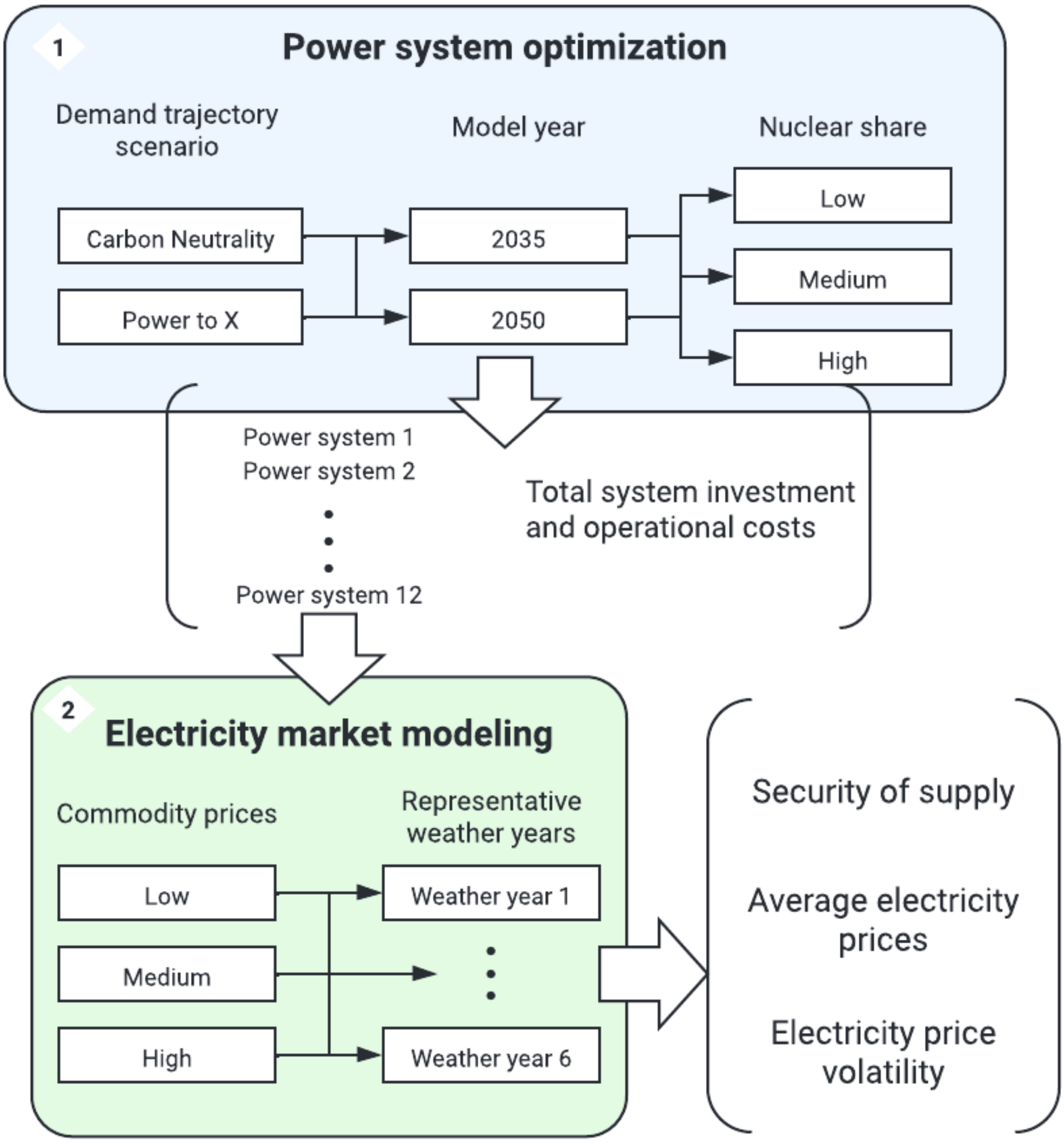

Figure 2. Flow chart illustrating study design and methodology.

The structure of the rest of the report is as follows: section 2 introduces the two demand scenarios that are considered in this study while comparing the previous work on this topic; the modelling strategy and tools developed to carry out the analysis are described in section 3; section 4 presents the main input assumptions along with motivations; section 5 provides the results on nuclear expansion, system costs, electricity prices and their volatility, investment sensitivity, transmission flows and grid development; a discussion around the observed results is provided in section 6; section 7 summarizes the report and the main outcomes; appendix 8 is included at the end of the report.

2 Demand scenarios

The shift away from fossil fuels is driving an increase in electricity demand, even as it often leads to a reduction in total energy use. This is evident when replacing internal combustion vehicles with more efficient electric vehicles or switching from boilers and direct electrical heating to heat pumps, even when considering power plant inefficiencies. Similarly, the electrification and transition of industrial processes away from fossil fuels can lower total energy consumption, while increasing electricity consumption. Numerous factors, such as industrial transformations, emerging demand sources, and the shift in transportation, impact long-term energy and electricity demand forecasting. Enhanced efficiency, notably in heating residential and commercial buildings, is expected to diminish electrical heating demand. Other critical influences include behavioural changes like altered consumption habits due to COVID-19, demographic growth, economic conditions, policy measures, and climate change.

Two demand scenarios, a Carbon Neutrality (CN) scenario and a Power to X (P2X) scenario, have been prepared for 2035 and 2050 for the current study. The CN scenario is in line with the climate neutrality goals[5] adopted by the governments in Finland and Sweden. It is dominated by decarbonization of industry, transport and hydrogen production by electrolysis for hard-to-abate sectors. The P2X has a similar base development as the CN scenario, but in addition also a significant increase of hydrogen production through electrolysis used for products for export, such as green iron, steel, and e-fuels. Direct export of electricity from the region stays on similar levels as before, but the export of embodied energy increases significantly making the region carbon negative as it contributes to global decarbonisation by exporting low-carbon intensive products.

2.1 Prepared demand scenarios and comparison

The two demand scenarios used in the current study are shown and compared with previous studies for Finland in Figure 3 and Figure 4 and for Sweden in Figure 5 and Figure 6. The Carbon Neutrality (CN) scenario for Finland overlaps with carbon-neutral scenarios studies[6,7] conducted on achieving carbon-neutrality in Finland by 2035, which is also matches with Fingrid's [8] Local Power scenario. The Finnish carbon neutral studies also have a base or business-as-usual scenario that sees a much more modest demand growth. The Power to X (P2X) is an ambitious scenario where demand grows from 87 to 223 TWh/a in 2050, an increase of 256% (which is higher than the 232% growth for the P2X scenario for Sweden). The Windy Seas scenario from Fingrid's latest vision study[8] is the closest match, but Fingrid also have two scenarios (Power to Products and Hydrogen from Wind) that explores even higher demand growths, where Finland would become a large exporter of energy mainly based on hydrogen produced by electrolysis and its derivatives. The P2X demand scenario prepared for this study assumes a more modest hydrogen growth expansion and Finland is more in-line with demand scenarios from Sweden.

[5] Finland aims for carbon neutrality by 2035, Sweden by 2045 and the EU by 2050. Carbon neutrality refers to when CO2 release is balanced by an equivalent amount being removed.

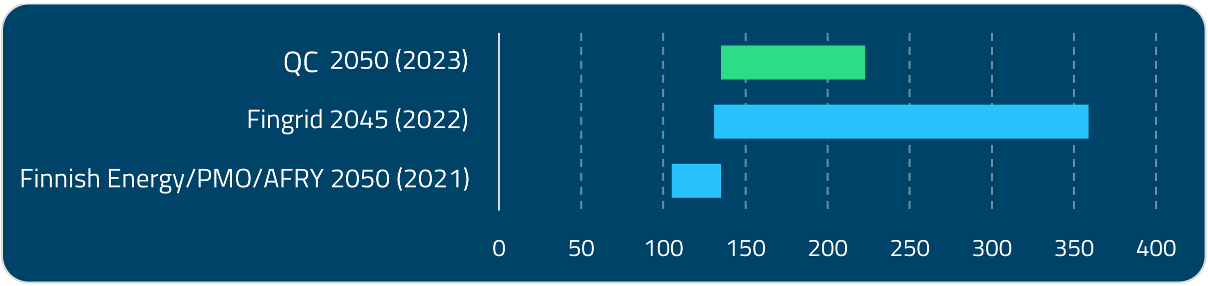

Figure 3. Comparison of ranges between low-high scenarios in demand projections (TWh/yr) for Finland between this study (light green) and previous studies conducted by AFRY for Finnish Energy[6] and the Prime Minister's Office[7] and Fingrid[8].

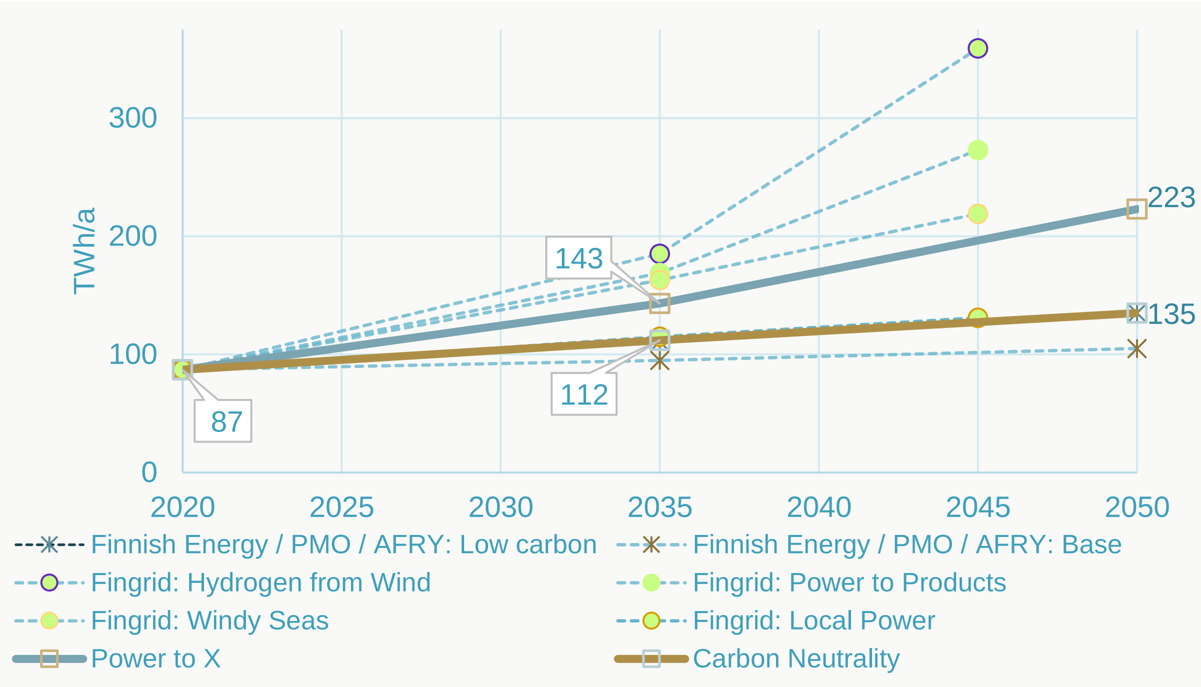

Figure 4. Comparison between demand scenarios for Finland in this study (light green and dark green) and previous studies conducted by AFRY for Finnish Energy[6] and the Prime Minister's Office[7] and Fingrid[8].

[6] AFRY (2020), Finnish Energy – Low carbon roadmap
[7] Prime Minister's Office (2021), Impact of carbon neutrality target to the power system
[8] Fingrid (2023), Electricity system vision

For Sweden (see Figure 6), the P2X scenario falls in-between the Low Electrification and High Electrification of the recent energy scenario system analysis by the Swedish Energy Agency[11] and slightly higher than the Electrification renewable energy scenario by SvK[8] this study is from 2021, SvK analysis for 2023 is more in line with Swedish Energy Agency, see also joint follow-up report[12]). In the CN scenario Sweden grows its demand with 171% by 2050, which can be compared to the 155% growth in Finland in the same scenario. This difference is mainly because iron ore reduction is assumed to grow larger than the domestic demand also in the CN scenario. This scenario is slightly lower than halfway between Sensitivity Case Industry and Low Electrification scenarios by Swedish Energy Agency[11] and about in middle of the four scenarios explored by SvK[9].

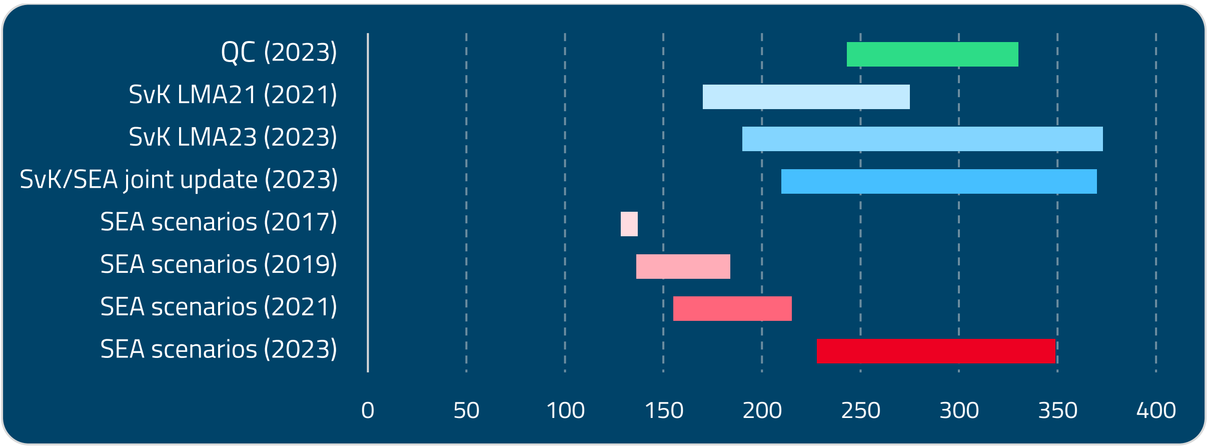

Figure 5. Comparison of ranges between low-high scenarios in demand projections (TWh/yr) for Sweden between this study (light green) and previous studies conducted by SvK[9], Swedenergy[10] and Swedish Energy Agency[11]. The latest long-term market analysis from SvK has not been released, but new numbers have been announced in joint 2023 update[12] together with Swedish Energy Agency.

[9] SvK (2021), Long-term market analysis
[10] Swedenergy (2023), Sweden's electricity needs in 2045
[11] Swedish Energy Agency (2023), Scenarios of Sweden's energy system
[12] SvK & SEA (2023), Joint government agency follow-up reporting ('Myndighetsgemensam uppföljningsrapport')

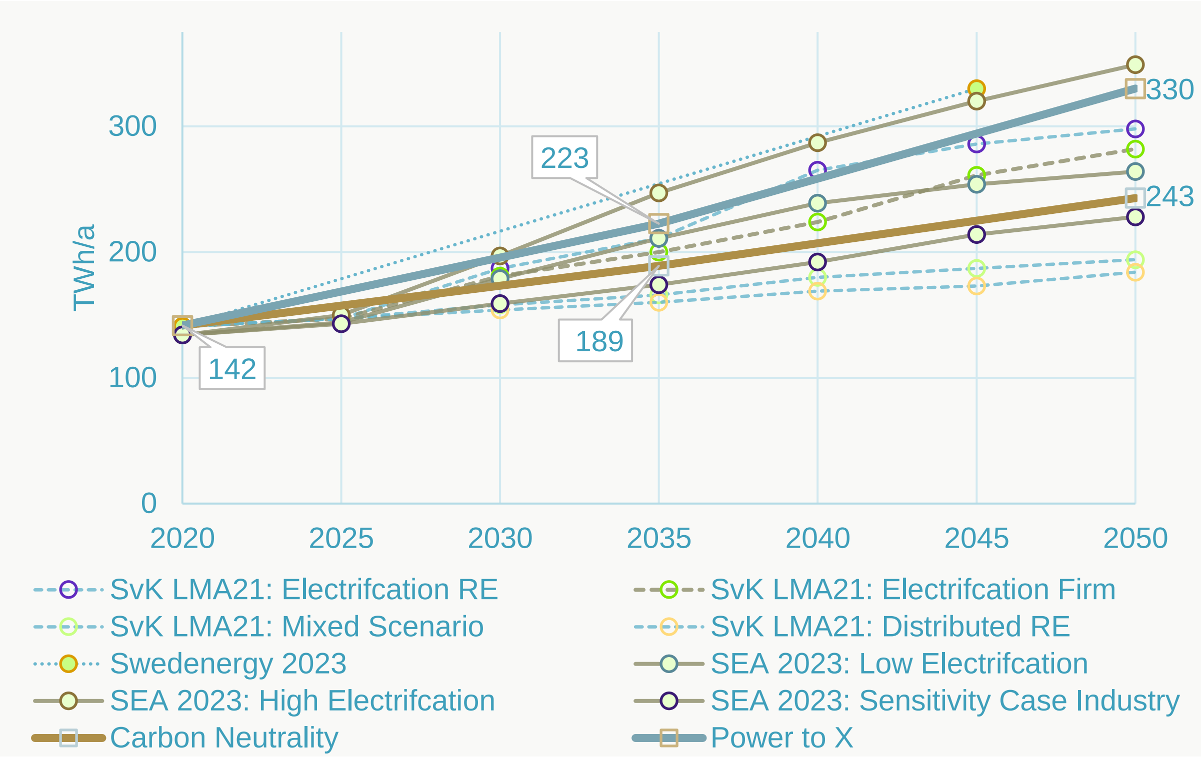

Figure 6. Comparison between demand scenarios for Finland in this study (light green and dark green) and previous studies conducted by SvK,[9, 12] Swedenergy[10] and Swedish Energy Agency[11].

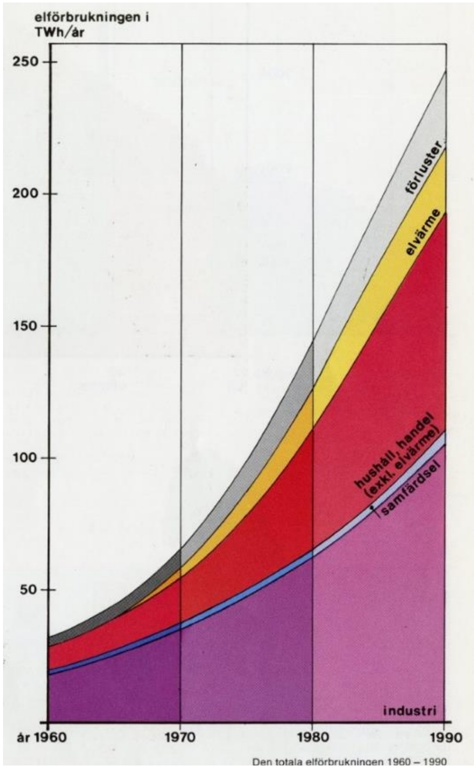

Figure 7. A 1972 prognosis from Centrala Driftledningen (CDL) estimated future electricity consumption to be approximately 250 TWh by 1990.

2.2 Key determinants

Predicting future energy and electricity demand is complex, often resulting in overestimations, as shown in Figure 7 and Figure 8. However, 10-to-15-year projections have typically demonstrated good accuracy, as found by the North European Energy Perspectives Project (NEPP)[13]. This applies also to the (often heavily criticized) demand scenarios made around 1970. Long-term forecasts, beyond two to four decades, are considerably less accurate.

Some "low scenario" projections have shown long-term accuracy, aligning with Sweden's steady energy consumption of 508 TWh in 2022. Despite static energy consumption in Sweden for three decades, global energy and electricity demand have increased significantly. It's predicted that Sweden's power demand will significantly grow, potentially exceeding 300 TWh by 2050, up from the current 140 TWh, due to an increase in industry transition projects.

[13] NEPP (2020), Insights and choices in the energy transition

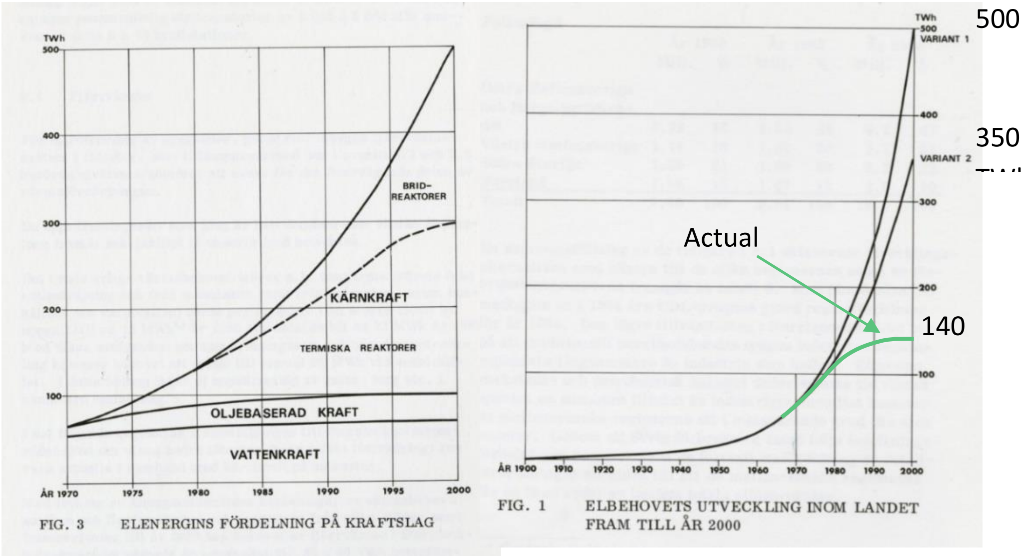

Figure 8. In 1967, the Swedish government's energy committee projected a power demand of 500 TWh by 2000. Contrarily, the actual demand during the 2000s was approximately 140 TWh, as depicted by the green curve added to the two trajectories in the right image.

The list below summarizes the key determinants of future electricity demand.

- Economic growth: Economic development typically leads to increased electricity demand, supporting industrial activities, commercial operations, and residential needs.
- Population growth and urbanization: A growing population and increased urbanization generally lead to higher electricity demand due to increased infrastructure, transportation, and general living needs.
- Technological advancements: Innovations in technology can influence electricity demand in both directions. For example, the rise of electric vehicles and data centres can increase electricity demand, whereas advancements in energy-efficient appliances and machinery can reduce it.
- Energy efficiency: Improvements in energy efficiency, particularly in the residential and commercial sectors, can significantly reduce electricity demand. This includes more efficient heating and cooling systems, better insulated buildings, and energy-efficient appliances.
- Policy and regulatory factors, including permitting: Government policies and regulations can greatly affect electricity consumption. These may include incentives for renewable energy, regulations for energy-efficient practices, or carbon pricing policies. It also includes permitting processes and conflicts of interest. If the permitting process for a power plant, transmission line or new industry projects is lengthy, complex or uncertain, it can slow the transition of the energy system and thus impact future electricity demand. This effect is both direct and through secondary effects, as projects (both on consumption and demand side) become more expensive to finance if investors perceive risks as significant. Conversely, if permitting processes are streamlined and efficient it can accelerate the deployment of new technologies and infrastructure, potentially leading to a faster transition and greater confidence from new investors, thereby driving down costs.
- Societal behaviour and lifestyle changes: Changes in societal behaviour can have a significant impact on electricity usage. Trends such as remote work, digitalization, and the adoption of electric vehicles can influence consumption patterns.

- Electricity prices: The cost of electricity can affect consumption levels. Higher prices might encourage conservation and the search for energy-efficient alternatives, while lower prices can lead to increased usage.
- Climate change and environmental concerns: Rising environmental awareness may drive a shift towards cleaner, renewable sources of electricity and more energy-efficient practices, potentially influencing overall electricity demand. As industries and transportation move towards electrification in an effort to reduce greenhouse gas emissions, electricity demand will increase.
- Industrial structure changes: As economies evolve, so do their industrial structures. For instance, a shift from manufacturing to services or high-tech industries can significantly alter electricity demand patterns.
- Shifts in energy sources, including energy storage: The adoption rate of alternative energy sources, like solar and wind, can influence electricity consumption. For instance, the efficiency and availability of these technologies can affect the overall consumption of electricity. The development and adoption of energy storage technologies, such as advanced batteries for grid storage or electric vehicles, can affect when and how much electricity is consumed.
- Changes in heating and cooling needs: Changes in climate or improvements in building design and insulation can influence the need for electric heating and cooling, thereby affecting electricity demand. Climate change also reduces heating needs, while warmer summers will increase demand from air conditioning.
- Demographic Changes: Age distribution, household size, and population density can all influence electricity consumption patterns.
- Global and regional politics: The location of new industries, particularly those manufacturing green technologies such as batteries, electric vehicles, or hydrogen and its derivatives, can significantly impact future electricity demand. This is largely influenced by political stability, energy policies, and regional incentives, all of which guide the decision-making process for investment in energy infrastructure and the adoption of innovative technologies.
- Natural disasters and pandemics: Events like earthquakes, hurricanes, or pandemics can have short-term and long-term effects on electricity demand, also through price effects. For example, the COVID-19 pandemic led to a significant shift in electricity demand patterns due to changes in remote working and living conditions.
- Consumer awareness, attitudes and preferences: Greater awareness about environmental sustainability and energy conservation can lead to changes in consumer behaviour and influence demand.
- Security of supply: This refers to the uninterrupted, dependable provision of energy and electricity at a reasonable cost. In the wake of Russia's full-scale assault on Ukraine in February 2022, the security of supply has ascended to the forefront of energy-related priorities for politicians and decision-makers. Various aspects of supply security influence future electricity consumption, potentially both augmenting and constraining demand growth. For instance, a secure supply facilitates the adoption of generation technologies not reliant on immediate fuel deliveries, like nuclear energy, completely fuel-independent ones such as renewables, or those utilizing domestically sourced fuels, like various forms of bioenergy. High-consumption entities might prioritize supply security over environmental goals, potentially reducing local future demand.

Table 3. Key factors and environmental variables influencing electricity demand, both short-term and longer term. A large check mark signifies a major impact, a small one denotes a moderate influence, and the absence of a check mark suggests minimal impact from the respective factor.

	Residential demand	**Services**	**Heating**	**District heating**	**Industry**	**Transportation**
Population growth & urbanisation	X	X	X	X	x	x
Economic growth	X	X	X	X	X	X
Technological advancements	x	x	x	x	X	X
Energy efficiency	X	X	X	x	X	X
Policy and regulatory factors, including permitting	x	x	x		X	
Societal behaviour and lifestyle changes	x		x	x		X
Electricity prices	x	x	x	x	X	
Climate change and environmental concerns	x		x	x	X	x
Industrial structure changes		X			X	
Shifts in energy sources, including snergy storage	x	x	x	X	x	x
Changes in heating and cooling needs	x	x	X	X		
Demographic changes	x	x	x	x	x	
Global and regional politics		x	x	x	X	
Natural disasters and pandemics	x	x			x	x
Consumer awareness, attitudes, and preferences	x		x	x		x
Security of Supply			x	x	X	x

2.3 General comparison with other studies

Different studies look at power systems in different ways, using different starting points, tools, and methods, depending on what they're trying to find out. An illustrative example of these differences can be seen in the context of the role and economic feasibility of nuclear energy. For instance, certain investigations dismiss nuclear energy entirely as a viable option, while others use a single high-cost assumption, making it economically unfeasible. Alternatively, there are studies that explore a range of cost estimates associated with nuclear energy. These contrasting assumptions can have a substantial impact on the study's results and ultimate conclusions.

Similarly, the potential for expansion of wind energy presents another domain where studies significantly diverge in their assumptions. Some research operates under the premise of virtually unlimited expansion potential (or uses a predefined expansion without taking profitability into account), while other studies adopt a more sophisticated approach. They scrutinize a variety of factors such as land use conflicts or the capture price of wind power to assess a realistic potential for wind energy development. These different assumptions can markedly influence the studies' outcomes and the derived implications.

Several parameters may vary depending on what is to be examined:

- Study Objectives: Studies may focus on various energy system aspects (like affordability, sustainability, balance), prioritizing these differently. Some may aim for complete decarbonization across sectors, while others focus on optimizing the power system.
- Methodology: Each study adopts unique methodologies, involving different models, assumptions, data sources, and scenarios. Methodological differences significantly influence study outcomes.
- Key Findings: Main conclusions or recommendations of each study.
- Geographical and Temporal Scope: Studies may concentrate on broad regions or specific countries, and either analyse energy systems at a certain time or project future scenarios.
- Policy Recommendations: Studies often propose policy actions to achieve optimal, affordable, sustainable, and balanced energy systems.
- Limitations: All studies have constraints like data uncertainties, assumptions, or unexplored energy system aspects, affecting the findings' reliability and applicability.
- Tools Used: Studies employ specific data analysis tools, such as energy system modelling tools or simulation software, influencing study results.
- Data Quality: The quality, timeliness, and reliability of data greatly affect study outcomes. Some studies use sensitivity analysis and various assumptions to account for data uncertainties.
- Scenario Development: Scenarios may be uniquely developed across studies, considering factors like technological advancements, policy changes, or energy price shifts. They can also rely on external assumptions from other studies. Or, perhaps more commonly, a mix of these two.
- Sustainability Metrics: When evaluating an energy system's 'sustainability,' it's crucial to identify the used metrics or indicators, as sustainability can be assessed in numerous ways.
- Stakeholder Involvement: All studies involve stakeholders (such as policymakers, energy companies, and/or members of the public) in their research process. The perspectives and priorities of these stakeholders can influence the outcomes of the study.

Since 2020, there have been four[14] major scenario analyses for a future Swedish energy system, by the Swedish Energy Agency, Svenska Kraftnät and by Svenskt Näringsliv (SNL)/QC. In the same time, there have been two scenario analyses made by AFRY for Finnish Energy and Finnish Prime Minister's Office (PMO) as well as one by Fingrid. There are also numerous academic papers and Nordic studies. One of the largest analyses for the Nordic is conducted by Nordic Energy Research, under the auspices of the Nordic Council of Ministers.

Study	Strengths	Weaknesses	Geographical focus
SvK (LMA21 & LMA23)	Very detailed analysis of various system's stability/security of supply with high temporal granularity, good representation of international electricity trade, and many different weather scenarios.	• Lack of economic analysis and investment optimization • Absence of analysis on emissions/environmental goals • Limited to individual analysis years rather than continuous assessment • Exclusion of sectors beyond the power market	Sweden
SNL/QC[15]	Complete dispatch and investment optimization with high spatial and temporal granularity and representation of operational limitations of different power types with assumed requirements regarding permissible CO2 emissions for the system.	• Simplified modelling of international electricity trade (incl. island operation) • Individual analysis years instead of a continuous analysis • Only the power market included	Sweden
SEA[16] (Scenarios20 & Scenarios23)	A comprehensive energy system model that handles sector couplings (for example, heat and electricity), with continuous investment optimization over the entire analysis period rather than individual years.	• Very low temporal granularity and low spatial granularity • Existing incentives (subsidies & taxes/fees) and political objectives embedded in all analysis cases.	Sweden

[14] Five studies if the as-not-yet-officially-released SvK (2023) Long term market analysis 2023, is included.
[15] Confederation of Swedish Enterprise, Projekt Kraftsamling elförsörjning
[16] Swedish Energy Agency (2020 & 2023), Scenarios of Sweden's energy system

Fingrid[17]	Very detailed analysis of various system's stability/security of supply with high temporal granularity, good representation of international electricity trade, and many different weather scenarios.	• Lack of economic analysis and investment optimisation. • Assumes perfect foresight over a 10-day time horizon. • Limited to individual analysis years rather than continuous assessment. • Exclusion of sectors beyond the power market.	Finland
NER (NCES2021[18])	Comprehensive, multinational initiative integrating optimisation of investments (ON-TIMES) with dispatch and operation analysis (BAMOREL). Significant sector coupling, including CCS and synthetic fuel production. High spatial granularity.	• TIMES assumes perfect foresight, i.e. all investments made with perfect knowledge of the future. • Limited geographical granularity (but great geographical scope). • Limited temporal granularity.	Nordics

3 Modelling

3.1 Modelling strategy

The power system optimisation in this study is based on a multistep process with several separate modelling codes, which are used to build in total 10 different power systems. These are detailed in Section 5.

The first step is a pre-optimization of installed generation capacities for wind and solar power in the regions surrounding Sweden and Finland. This is done using the code cGrid, which is described below. The starting point for the installed generation capacities in the surrounding regions are collected from ENTSOE as well as public data from national authorities. In the pre-optimization, the generation capacities are allowed to be adjusted slightly to ensure that trade between the Swedish-Finnish power system and outside regions remain realistic and credible. The motivation for this step is that the capacity expansion that is done for Sweden and Finland in the next step should neither subsidise a too low generation capacity in the surrounding regions, compared to their demand, nor be subsidised by artificially low import prices if the generation capacities in the surrounding regions are too high compared to their demand.

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17 Fingrid (2022), Finsgrid's electricity system vision 2022 – draft scenarios for the future electricity system

18 Nordic Energy Research (2021), Nordic Clean Energy Scenarios – Solutions for Carbon Neutrality

Following the pre-optimization, a greenfield[19] analysis of the Swedish and Finnish energy systems in 2035 and 2050 is made using the code GenX, which is described below. This analysis takes into account the technical and economic life of existing production systems in the years 2035 and 2050. The parts of the power system that are not yet in place, but for which investment decisions have been made are also considered here. The details of the analyses are presented below:

- The existing Swedish and Finnish hydropower, which was mostly built in the 1950s–80s, is assumed to continue to be in operation in all modelling cases, with no end date. Modernisation investments in many hundreds of large hydropower plants and dams over a very long period, from the early 2030s to well into the 2060s, will be required. The total system cost for this, described as an annuity that is outside the optimization analysis, is in the order of €700 million for Sweden[20] and €100 million for Finland[21].
- Reinvestments to keep the existing Swedish and Finnish national grids running (220 kV and 400 kV) with current transmission capacity between the Swedish and Finnish electricity areas and international connections are assumed to take place in all modelling cases. The costs for this have therefore been excluded from the optimization calculations.
- In addition, several reinforcements of transmission capacities are implemented in accordance with announced plans from TSOs. This concerns both internally between Sweden's bidding zones and to bidding zones in other countries.
- Reinvestments and new investments to maintain and expand the existing Swedish and Finnish local and regional networks use are assumed to take place in all modelling cases. These have therefore been excluded from optimization calculations. In total, investments of at least €50 billion in Sweden[22] and €30 billion in Finland[23] at all network levels during the period 2022–2050 are included in all modelled scenarios.
- Infrastructure investments related to the production, transmission, and storage of hydrogen have been excluded in the optimization. These investments are significant, especially in 2050 and for the Power to X demand scenario because of a low utilization of electrolysers and a storage duration of one week. In addition, to reflect the development of a hydrogen pipeline transmission network, the power transmission capacity between SE1 and SE2 has been increased with 5 GW. The investments are primarily to be carried by consumers (as such costs should not be added to the system), however they provide the power system valuable flexibility.
- Sweden's combined heat and power fleet is assumed to continue to be in operation with reinvestments such that the current installed production capacity is conserved throughout all modelling cases. In Finland, thermal power plants burning fossil fuels are retired in all modelling cases while generally those power plants using renewable sources are assumed to maintain their operation with reinvestments across all modelled scenarios. The thermal power plants have thus been excluded in the optimization. Associated reinvestment costs have been neglected.
- The underlying mechanisms for installing rooftop photovoltaic solar panels have been observed to follow their own trends. Investors are often not large energy producers, but instead companies or private individuals with different views on the profitability of their investment. Consequently, rooftop solar panel installations have been excluded from the optimization and are assumed to follow the projection on installed capacity described in Section 4.

[19] Greenfield is a general term which means that something new built from scratch.
[20] Energiföretagen (2019), Färdplan fossilfri el.
[21] Scaled value based on reinvestment costs for hydro power in Sweden.
[22] Sweco (2022), Investments into grid reinforcements for a fossil-free Sweden 2045.
[23] Scaled value based on reinvestment costs for grid reinforcement in Sweden.

- For both modelling years (2035 & 2050), it is assumed that all existing fossil-fuelled power plants in the Finnish and Swedish power systems are retired.

In the final analysis step, the power system obtained from the GenX analysis is simulated using the code cGrid/OptiL using weather data from 6 representative years combined with a sensitivity analysis on commodity prices. In total, 18 simulations per scenario are made. This step is done to obtain market prices under different weather years and commodity price scenarios in order to test the systems sensitivity to changes in external factors.

3.2 Modelling tools

3.2.1 GenX

GenX is a highly configurable open-source tool[24] for capacity expansion of generation resources, which includes several state-of-the-art methods for exploring cost-optimized power systems. In this study, an extended version of GenX v. 0.3.3 has been used here, which allows for:

- limiting the minimum and/or maximum consumption of each defined fuel type,
- limiting flows between zones at the same time resolution as other input values, thus taking into account a variable transmission capacity as well as asymmetries in the direction, and
- limiting the maximum instantaneous consumption of flexible loads.

GenX builds cost-optimal power systems based on the prerequisites presented earlier forming the main optimization step here. A limitation of GenX, in the context of the present study, is that it is not possible to couple GenX with the code OptiL, which is of high importance when modelling the future Nordic power system. A second limitation with GenX is that it is computationally rather heavy and therefore not well suited for sensitivity analyses where many weather years and different commodity prices are tested.

3.2.2 cGrid / Optil

The code cGrid is an electricity market modelling tool that was initially developed for market coupling with OptiL[25], which is a code that optimises the dimensioning and dispatch of the combined electrolysis, storage and direct reduction of iron ore under planning in northern Sweden. For studies that look at future systems in northern Scandinavia, this part is highly important as it will have a substantial impact on the dynamics of the power system.

In addition, cGrid is designed to simulate a realistic bidding pattern of reservoir hydro power dispatch. This is also an important feature for simulating the Nordics as hydropower plays a dominating role in the power system. cGrid is further capable of fine tuning the capacities of resources in the model, but unlike GenX it cannot perform a greenfield optimization, which is why the codes were used together. Finally, cGrid is also significantly faster to run than GenX, which makes it a natural choice for performing the sensitivity analysis in this study.

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[24] https://github.com/GenXProject/GenX

[25] See also Appendix 8.4

4 Input assumptions

This section presents the main input assumptions along with motivations. Further input assumptions are provided in Appendix in Section 8.2.

4.1 Demand

4.1.1 Demand by categories

This section delves more deeply into the demand scenarios and their specific components. Figure 9 shows the data per demand category. Industry is divided into electricity demand for electrolysis and 'Industry excl. electrolysis', this is because electrolysis is the main difference between the scenarios and is also assumed to be a much more flexible load. Tabulated data are in the 88.2, which includes data split per bidding zone for Sweden.

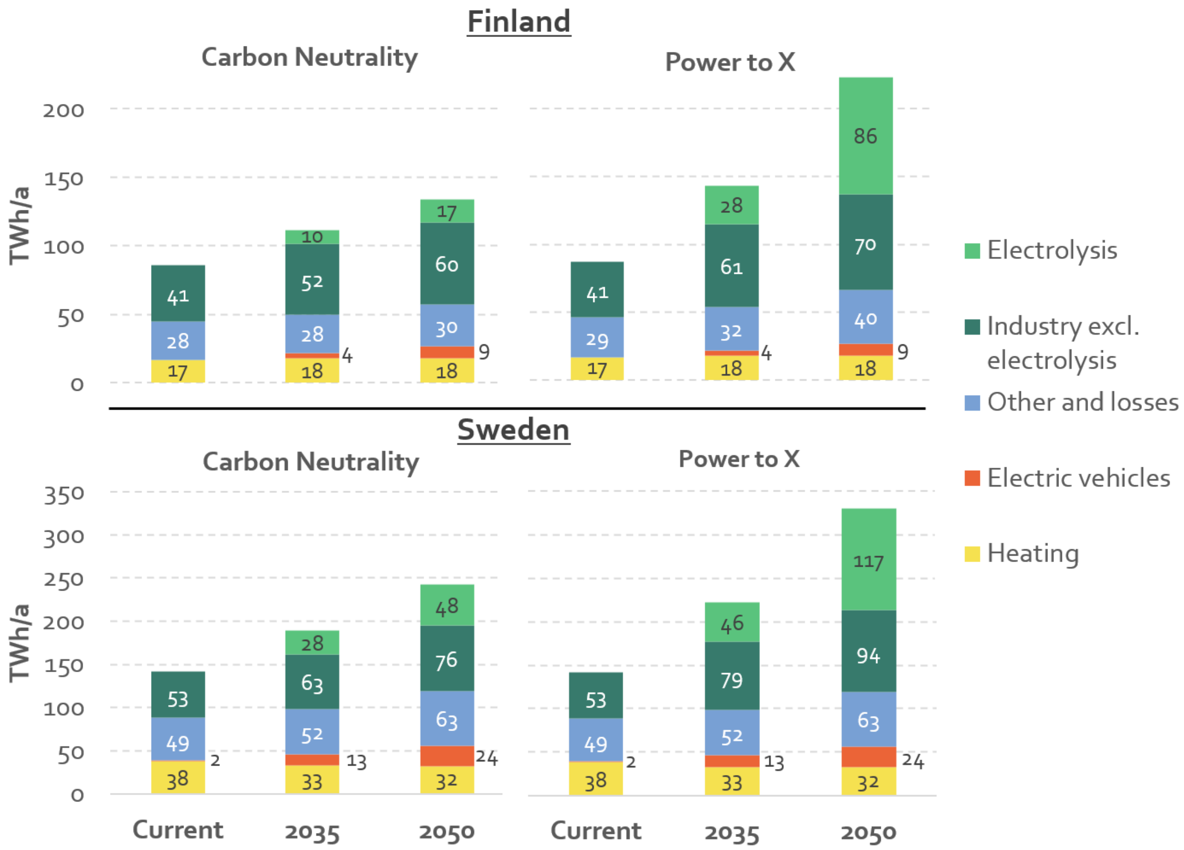

Figure 9. Demand scenarios in Finland (upper row) and Sweden (lower row) for studied years 2035 and 2050 as well as current demand.

4.1.2 Electrolysis

Hydrogen economy aims to reduce CO_2 emissions in sectors and processes where utilising other solutions are challenging. Figure 10 shows how electricity demand due to hydrogen production through electrolysis in Finland could develop for five scenarios covered in a study[26] by the Finnish government. Here scenarios are based on varying assumptions for the need for hydrogen in the future for e-fuel, heavy-duty transport, metal industry, and biofuel production both for domestic demand and for export.

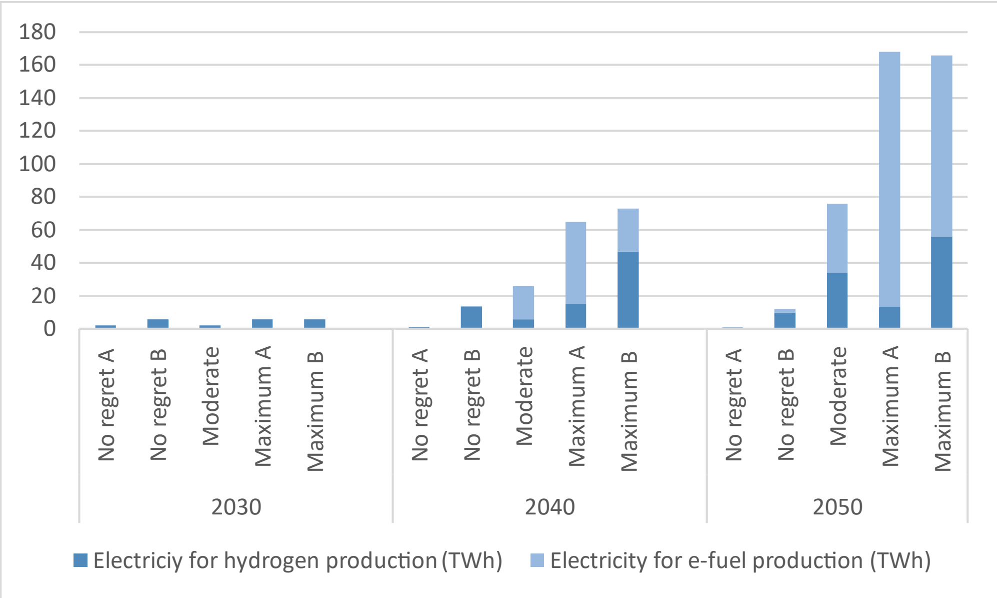

Figure 10. Electricity demand for hydrogen for industry and for e-fuels production for Finland in five different scenarios for 2030, 2040 and 2050 as presented in study by the Finnish Prime Minster Office[26].

In our Carbon Neutrality (CN) demand scenario, Finland has an annual electricity demand for hydrogen electrolysis of 10 TWh in 2035 and 17 TWh in 2050. Sweden has a demand of 28 TWh in 2035 and 48 TWh in 2050, whereof a majority is placed in SE1, while SE2, SE3 and SE4 see a more similar development as in Finland. Hydrogen is assumed to be mainly used for decarbonisation of current industry activities, except iron ore direct reduction that is assumed to grow to about 12 Mt/a or about double the amount required for the two countries' current domestic steel consumption. Most of the electrolysis for iron ore reduction is assumed to be placed in SE1. However, 6 TWh of electrolysis is placed in Finland, an amount corresponding to what is required to reduce iron ore to meet Finland's current domestic steel demand of about 2 Mt/a. The CN scenario is in-line with the 'No regret' scenarios shown in Figure 10.

In the Power to X (P2X) demand scenario, Finland has an annual electricity demand for hydrogen electrolysis of 28 TWh in 2035 and 86 TWh in 2050. Sweden has demand of 46 TWh in 2035 and 117 TWh in 2050, with a clear majority placed in SE1 with its 30 TWh in 2035 and 77 TWh in 2050. Direct reduced iron production is assumed to grow to 25 Mt/a, requiring about 83 TWh of electricity for electrolysis. Most of the electrolysis for iron ore reduction is assumed to be placed in SE1, but 6 TWh in 2035 and 17 TWh in 2050 of electrolysis is placed in Finland. The other 97 TWh of electrolysis would mainly be for e-fuels production in this scenario, where Finland would take a larger share of this market. The P2X scenario is in between the 'Moderate' and 'Maximum' scenarios in the Finnish hydrogen study[26].

[26] Finnish Prime Minister Office (2022), Hydrogen economy: Opportunities and limitations

4.1.3 Industry excl. electrolysis

This demand is based on data from TSO:s[27] as well as additional assumptions. Electrolysis is assumed to come with also more traditional industrial baseload demand. In the CN scenario electric arc furnaces are assumed to replace current blast furnaces by 2035. The P2X scenario assumes an additional electricity consumption by 2035 to meet an annual crude steel output increase of 5 Mt in SE1 and 2.5 Mt in Finland. Swedish Energy Agency[28] assumes a substantial increase in electricity consumption of 10 to 21 TWh for data centres, mainly located in northern Sweden by 2050. This growth scenario was produced before Sweden abandoned its tax exemption for data centres where these are classified as industry and pay tax on electricity at the EU lowest allowed level. Meanwhile Finland recently introduced such tax exemption for data centres (however, including requirements on energy efficiency or reuse of waste heat in for example district heating). In this study we assume a total for both Finland and Sweden of 10 TWh for the CN scenario and 20 TWh in the P2X, in 2050, and with a distribution between the bidding zones as follows: 50% to Finland, 30% to SE2, 10% to SE1 and 10% to SE3.

4.1.4 Electric vehicles

Electricity consumption for electric vehicles is assumed to develop in line with what Fingrid uses for Finland and SvK uses for Sweden in their electrification scenario, which corresponds to half of the passenger fleet being electric by 2035 and close to fully electric by 2050. The same development is assumed for both the CN and the P2X scenario.

4.1.5 Heating

Finland is assumed to increase its heating demand slightly by 1 TWh/a by 2035 and keep that level until 2050, which is in line with what Fingrid assumes. The energy efficiency improvements in the sector are assumed to be somewhat less than the increase due to continuous installation of heat pumps both as distributed and as part of district heating networks. Sweden is assumed to decrease its electric heating demand with about 5 TWh/a in 2035 and additional 1 TWh/a in 2050 due to energy efficiency measures in the sector (including replacing resistive heaters with heat pumps), which is lower than Swedish Energy Agency assumes in their scenarios. Same development is assumed for both scenarios (though the P2X scenario would have more waste heat available from electrolysis and nuclear plants and thus might have less adoption of heat pumps for district heating). The main reasons to the different development between the countries are that a) Sweden has more resistive heating to phase-out b) that Finland has introduced tax exemption for electricity used in district heating while Sweden currently has no such plans. Also, Finland has a larger share of fossil fuels in the district heating that will need to be phased-out, while Sweden has already largely decarbonized its district heating and has less need to adopt heat pumps to district heating.

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[27] Fingrid (2023), Electricity system vision and SvK (2021), Long-term market analysis

[28] Swedish Energy Agency (2023), Scenarios of Sweden's energy system

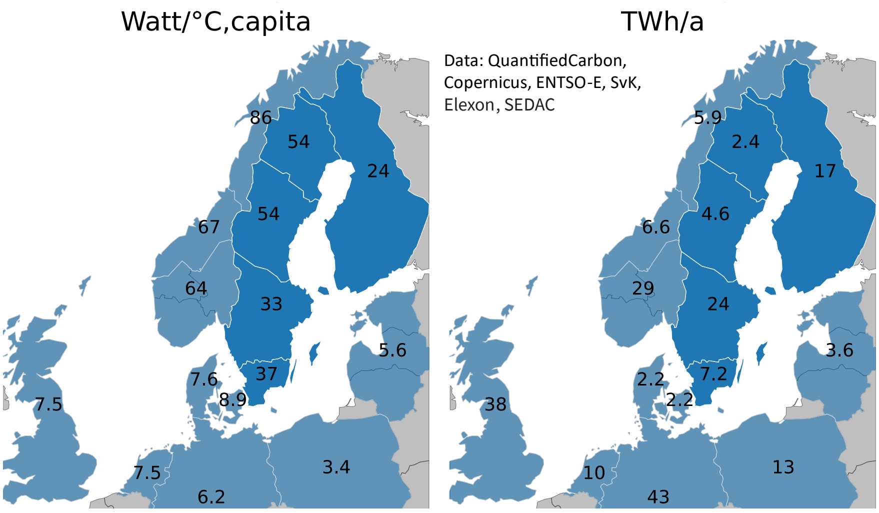

Figure 11. Electric heating per bidding zone in 2021, as detected by regression analysis using actual load and weather data.

Figure 11 shows current heating demand in North Europe, as identified by regression analysis using actual load and weather data from 2021. As can be seen in the left subfigure, both Sweden and Finland have a much larger share of electric heating than for example Germany. The energy crises have pushed for faster adoption of electric heating also in other parts of Europe (especially in the countries predominantly heated by natural gas) which is not fully reflected in the input demand data for this study.

4.1.6 Demand-side flexibility

The modelling includes two types of demand-side flexibility: shifting and cutting. Shifting demand response is modelled through three assumptions and input values:

- A time series of the demand deemed flexible.
- A maximum duration during which this flexible load can be shifted forward and backward.
- A corresponding capacity (MW) for the demand in the flexible load, defined as a share of the demand category type in combination with the utilization.

The energy of the flexible shifting load is always conserved. However, this is not the case for the cutting demand-side response, where demand is eliminated. Such loss of consumption is a consequence of high electricity prices and is also known as non-served energy. Table 4 presents the input assumptions used for the demand-side flexible loads in the model, grouped by demand scenario and by modelled year. Figure 12 presents the resulting demand-side response during consumption peaks based on the input assumptions in Table 4.

Table 4. General input assumptions of demand-side flexibility for their different categories and variations with regards to demand scenario and future model year.

Category (type)	Demand scenario	Year	Share	Utilization	Duration
Electrolysis (shifting)	CN	2035	77 %[29]	80%	24h
		2050		50%	168h
	P2X	2035		80%	24h
		2050		50%	168h
Electric vehicles (shifting)	CN	2035	50%[30]	50%	24h
		2050			
	P2X	2035			
		2050			
General (shifting)	CN	2035	10%	50%	8h
		2050			
	P2X	2035			
		2050			
General (cutting)	CN	2035	20%	-	-
		2050			
	P2X	2035			
		2050			

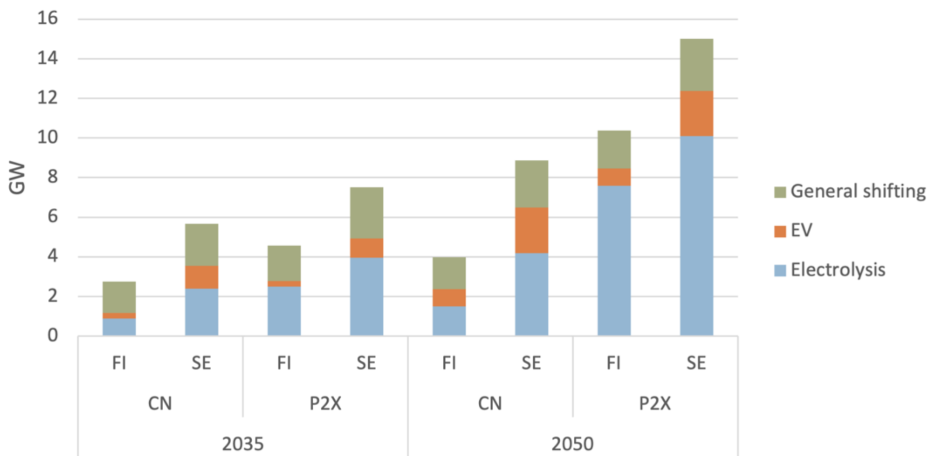

Figure 12. Demand-side response available during consumption peaks, per resource type, country, demand scenario and year.

The electrolysis category in Table 4 represents hydrogen production. In 2035, the hydrogen producers have limited utilization as well as hydrogen storage at hand, providing an electrolyser utilization of

[29] Determined based on simulations performed with the OptiL tool (see Appendix 8.4).

[30] DNV GL Energy Sweden (2021), Socioeconomic costs and benefits of smart electricity grids

80% and storage capabilities analogous to 24 hours of average hydrogen consumption. This is motivated by the limited possible growth of hydrogen networks and storage options in northern Europe by 2035. At this point the Nordic Hydrogen Route[31] (connecting SE1 and FI with hydrogen pipeline) is likely to be only partially constructed but expanding with a storage capacity limited to a single, recently built, lined rock cavern. Assuming a Nordic-Baltic H2 pipeline is established, one week's storage capacity should be assessable by 2050. It likely consists of multiple local lined rock caverns in Sweden and Finland complemented by underground storage in the Baltics. This storage, and required electrolyser overcapacity, is motivated by the financial gains gain from the flexibility in electricity price volatility market in the foreseen high-wind power system in the Nordics.

From the modelling perspective, the energy storage capacity is derived based on the product of the average hourly consumption and the duration of the flexible resource. As such, the hydrogen storage capacity scales with the total electrolysis demand in the respective zone. The corresponding energy storage capacity of hydrogen is presented in Table 5. However, the electrolyser load in SE1 is handled separately with the OptiL tool (see 8.48.4). Electrolyser utilization and hydrogen storage capacity (and many more parameters) and how facility operations are optimized based on the consumer perspective. Associated results are included in Section 5.

Table 5. Assumed installed energy capacity (H_2) [GWh] of hydrogen storage in Finland and Sweden. SE1 has not been included as the electrolyser load here and is handled separately.

Demand scenario	Year	FI	SE2	SE3	SE4
CN	2035	20	4.0	6.1	1.6
	2050	230	81	82	17
P2X	2035	40	4.1	15	4.0
	2050	890	160	210	42

Charging of electric vehicles is another load that is modelled as a shifting flexible load. Half of the electric vehicle load is assumed to be allowed to shift demand according to a time series representing frequency distribution of charging if no flexibility had been applied. A general shifting demand-side flexibility, amounting to 10% of the remaining demand (after reduction of electrolysis, electric vehicle demands and grid losses), has been applied to all modelling zones. This quite generous flexibility, with a duration of 8 hours, is aimed at representing flexibility in industry, commercial and domestic electricity use (both distributed and large-scale heating in district heating is part of the general shifting).

Finally, the parameters of the general cutting demand-side response category have been determined based on observations in 2022 when the European power system experienced high prices and consumers cutting their demand. Up to 20% of the remaining demand (after reduction of electrolysis,

[31] Nordic Hydrogen Route - Bothnian Bay

electric vehicle, and general shifting demands) may be cut in all modelling zones, with increasing costs linearly from 100 to 1000 EUR/MWh.

4.2 Supply

4.2.1 Solar PV

Solar PV capacities are included without being part of the optimization, representing behind the meter roof-top solar that have other incentives than pure day-ahead spot prices as these for example can avoid electricity tax and grid transfer fees and can be assumed to have lower requirements on return on capital. These are estimated based on watt/capita and solar yield potential per bidding zone and are shown in Table 6.

Table 6. Used inputs for roof-top PV capacities, shown per model year and bidding zone as well as aggregated for Sweden and for both countries.

Year / zone	2035			2050		
	Watt/capita	MW	GWh/a	Watt/capita	MW	GWh/a
SE1	627	185	159	1 333	394	338
SE2	666	432	390	1 415	918	828
SE3	721	4 976	4 795	1 531	10 566	10 181
SE4	744	1 455	1 440	1 582	3 094	3 063
FI	643	3 472	3 041	1 366	7 377	6 462
SE		6 988	6 672		14 849	14 178
FI + SE		10 460	9 713		22 226	20 640

4.2.2 Wind power

Table 7 shows the inputs for onshore wind power capacities. Existing wind parks in 2035 are estimates based on parks that are less than 25 years old in 2035 and have already been built or are fully permitted to be built before 2025. Parks that are older than 25 years are assumed to either be retired or be available for repowering at lower cost than new-built parks. Older parks with limited height permits are assumed to retire to a higher degree than newer parks, which affects SE3 and SE4 more than the other bidding zones with newer parks.

Table 7. Inputs for onshore wind power capacities (MW), shown per model year and bidding zone as well as aggregated for Sweden and for both countries.

Year / zone	**2035**				**2050**			
	Existing	Retire	Can repower	Limit	Existing	Retire	Can repower	Limit
SE1	3 566	80	57	6 000	0	766	2 800	13 000
SE2	6 218	141	230	11 000	0	1 311	4 907	18 000
SE3	3 206	795	135	5 000	0	1 250	1 956	9 000
SE4	1 575	525	193	3 000	0	697	878	4 000
FI	7 286	0	0	43 000	0	1 457	5 829	60 000
SE	14 565	1 542	614	25 000	0	4 023	10 542	44 000
FI + SE	21 851	1 542	614	68 000	0	5 481	16 370	104 000

Figure 13 visualises the capacity expansion limits for onshore wind power. For 2035 these are based on currently known projects[32] and assumptions on the likelihood of these getting through the permitting process, as well as there being additional not yet known projects. For 2050 it is assumed that additional land areas can be dedicated for wind power production as land-use conflicts (e.g., local acceptance and military defence interests) get resolved in favour of wind power development and the transmission systems get proactively strengthened and expanded to more remote areas.

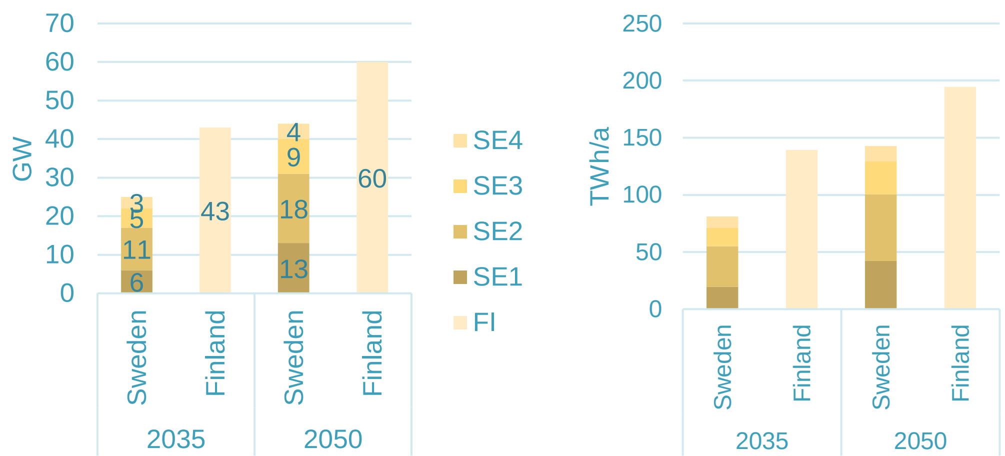

Figure 13. Capacity expansion limits for onshore wind per bidding zone (colour), country, and model year. Left subfigure shows the capacities used and right subfigure shows the limits in TWh/a using an average capacity factor of 0.37.

Looking at the country totals the limit for Sweden is lower than for Finland, which is mainly a reflection of there currently being more projects under development in Finland and that Finland is assessed to have more favourable conditions for grid connections, permitting and local incentives. Sweden have been building onshore wind for longer time than Finland and have had a more thorough testing of conflicting land-use interests. In Finland municipalities get substantial tax revenues from local power production which is a strong incentive especially for sparsely populated municipalities. Such incentives

[32] https://vbk.lansstyrelsen.se and https://tuulivoimayhdistys.fi/tuulivoima-suomessa

are not present in Sweden, although a recent governmental study[33] has suggested improvements aiming at increasing local public acceptance, but not really improving the incentives for the municipality that are responsible for the spatial planning and permitting.

Figure 14 shows currently existing wind power and parks known to be under development in Sweden and Finland. It can be noticed that most of the existing parks (blue) are in south Sweden and mid Sweden, with parks being much smaller in the south in contrast to more, larger and new built parks in the north. Parks under construction (green) are to a higher degree located to north Sweden and Finland, while parks in different stage of planning (pink) are located mainly in Finland, some in mid to north Sweden. Finally, the figure also illustrates the big potential for offshore wind power in both countries.

[33] https://www.regeringen.se/rattsliga-dokument/statens-offentliga-utredningar/2023/04/sou-202318

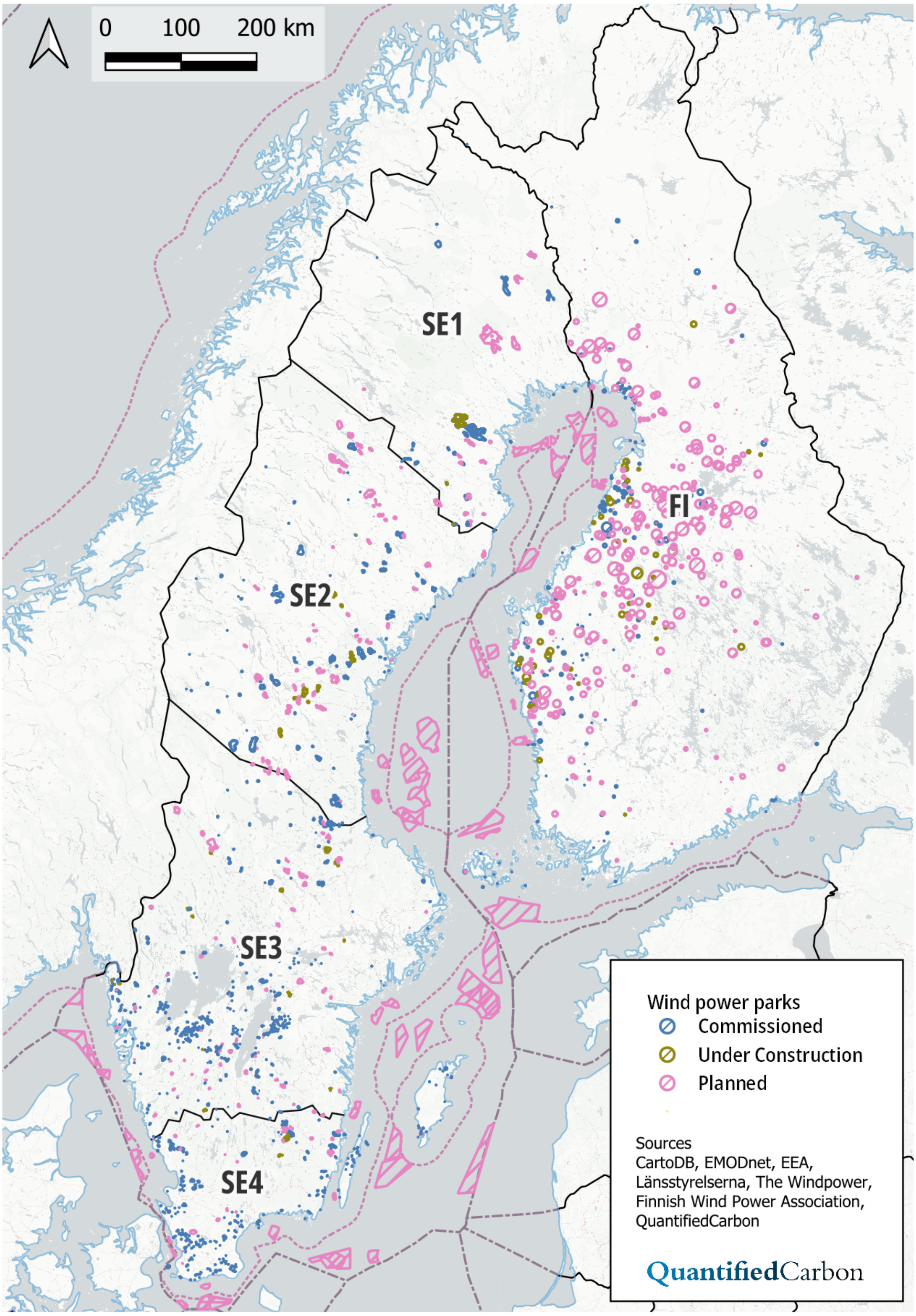

Figure 14. Known wind power park projects as of start of 2023 in Sweden and Finland. Offshore and onshore in Sweden shows actual project areas of the parks, while typical project areas for onshore in Finland are represented with on-scale circle areas. 'Planned' constitute of early concepts to fully permitted parks.

4.2.3 Peaker plants

In the current study, all existing fossil-fuelled power plants are retired in Finland and Sweden. However, during this study we have observed that regions with low levels of firm fossil free generation capacity need some form of peaking power that can step in during times of high demand and low wind and solar production. In the Nordic region such periods typically occur a few times per year and can last for about a week, which is why batteries are not a viable solution. Instead, some form of fuel-based solution is needed.

Therefore, in all modelling cases it is possible to build open-cycle gas turbine (OCGT) power plants in SE4 and Finland to cover the role of peaker plants. Today's peaker plants most commonly burn fossil fuels. In sustainable and carbon-neutral power systems, a likely scenario is that peaker plants either burn fossil-free hydrogen, biogas, or natural gas, where the latter plants could be equipped with carbon capture and CO2 storage (CCS) capabilities.

In the current study, the investment, and fixed operational costs of the OCGT power plants have been derived from natural gas OCGT plants[34]. These costs should approximate OCGT plants that burn hydrogen and biogas. If the plants built in the model are using natural gas as fuel, the investment costs associated with necessary CCS have been neglected, and the investment costs should therefore be seen as optimistic.

A marginal cost of 170 €/MWh has been set to model the variable operational and fuel costs of the peaker plants with the aim of capturing variations by fuel. The value corresponds to the marginal cost of burning natural gas at a price of 30 €/MWh in OCGT power plants and carbon pricing of 200 €/tCO2. The idea is that the carbon price is on par with the costs associated with CCS installations and thus reflects the marginal costs of a future natural gas plant with CCS.

As a comparison, according to an IEA report on the outlook for biogas[35], we could see biogas prices of 16 EUR/MMBTU in 2040 in Europe. For OCGT peaking plants burning biogas, this corresponds to 140 €/MWh pricing.

Pricing of hydrogen in a future scenario is difficult to predict. Based on an optimistic electricity price capture value of electrolysers at 50 €/MWh (a pre-study on Finland produced a yearly average of 75 €/MWh across all scenarios), burning hydrogen in an OCGT plant would correspond to about 190 €/MWh marginal cost. For the current study and in 2050, we assume a storage duration of one week. It is highly unlikely that peaker plants burning hydrogen would see lower marginal costs than this at times they are needed, i.e., lasting through a winter period with low winds and rather high electricity prices.

[34] OECD (2019), Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables.

[35] IEA (2020), Outlook for biogas and biomethane: Prospects for organic growth.

4.2.4 Nuclear power

The currently operating nuclear fleets in Sweden (6885 MW installed capacity)[36] and Finland (4394 MW installed capacity)[37] are assumed to be in operation for all modelled scenarios in 2035. For the year 2050, Loviisa nuclear power plant units are assumed to be retired (3380 MW installed nuclear power capacity in Finland remaining). Loviisa nuclear power plants have permits that run out in 2050, as such model year 2050 represents a state of the power system post its retirement. The power system optimization allows the retiring of existing nuclear power plants (newly commissioned Olkiluoto 3 excluded) if considered cost effective. However, costs associated with life extension[38] are comparably low, and reinvestments are made for all nuclear power capacity in all scenarios.

Nuclear power plants are modelled as "must run". This best reflects the operations of nuclear power plants in Sweden and Finland since reservoir hydro power takes on the role of "load following" in the Nordic countries. Load following with nuclear power typically does not save fuel costs since revision periods where the fuel is exchanged are planned several years in advance.

With higher electricity demand in the future, this may still be a good assumption in a power system as significant hydrogen production and storage provide additional system flexibility complementing the decreasing share of hydro power in the energy mix. Furthermore, at prices below zero wind and solar power are the ones first curtailed.

4.3 Investment costs

Figure 15 compares the overnight costs used in studies for building new wind, solar, and nuclear energy sources with values observed in recent periods.[39] The current study applies costs[40] based on the optimistic scenario in the Svenskt Näringsliv study[41], indicated by the orange circles in the figure. These costs are significantly lower than the actual values currently prevailing in the United States for 2021[42]. With surging prices of materials and fuels, solar and wind power are currently experiencing increased costs[43]. As the world emerges from crises, we are likely to see costs returning to their projected downward trends, especially for solar PV (utility scale), which has experienced a strong decrease throughout the last decade[44]. Based on a ten-time buildout and learning rate of 7%, another decrease of 20% lower overnight costs is applied for solar PV (utility scale) and 2050 in the modeling.

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[36] Forsmark-1,2 & 3, Oskarshamn-3 and Ringhals-3 & 4.

[37] Loviisa-1 & 2 and Olkiluoto 1,2 & 3.

[38] Svenskt Näringsliv (2020), Långsiktig Scenarioanalys.

[39] Overnight cost refers to the cost of a construction project assuming no interest was incurred during its construction, as if the project was completed "overnight." It presents a useful perspective on total investment costs.

[40] Throughout the report, all costs are assumed as real currency 2019.

[41] Svenskt Näringsliv - Långsiktig Scenarioanalys (2020).

[42] Annual Energy Outlook 2022, US Energy, and Information Administration (2022).

[43] For instance, https://nawindpower.com/new-onshore-wind-project-costs-increase-7-percent-from-2021-to-2022

[44] IRENA (2022), Renewable Power Generation Costs in 2021, International Renewable Energy Agency, Abu Dhabi.

For new nuclear projects, the overnight costs used in the current study are lower than those of the most expensive recent projects in the US and Europe (e.g., EPR in west-Europe, with an average of 6500 EUR/kW). However, they are significantly higher than the world average for projects between 2000 and 2020. The assumptions used in the current study do not fully account for the cost-cutting possibilities with serially produced Small Modular Reactors (SMR). This is indicated by the range annotated "SMR" in Figure 15 for nuclear new build representing the span from low costs for serially produced units to high costs for first-of-a-kind units, based on data for GE-Hitachi's new BWRX-300 design[45]. The more moderate cost assumptions made for new nuclear in the current study match the average of all nuclear reactor projects built worldwide in the period 2000-2020, excluding projects in China, Pakistan, India, Russia, and South Korea, resulting in an average of 4100 EUR/kW[46]. Or equivalent to what VVER and APR reactors are being built for today in the West even in countries that previously lacked nuclear power (e.g., the United Arab Emirates, Turkey).

More on actual input values for investment and operational costs are presented in detail in Appendix 8.2.

Figure 15. Comparison overnight costs used in studies for building new solar PV power (utility scale), onshore and offshore wind power, solar, and nuclear power with the values observed in recent periods. Green range of costs stem from the span of values used in the recent Svenskt Näringsliv study[47]. Values used in the current study are indicated with orange circles in contrast to seen costs in the US in 2021[48] shown with purple circles. World average overnight cost for nuclear projects[49] is included with the blue circle.

[45] Svenskt Näringsliv - Långsiktig Scenarioanalys (2020).
[46] Energiforsk (2021), El från nya anläggningar.
[47] Långsiktig Scenarioanalys, Svenskt Näringsliv (2020).
[48] Annual Energy Outlook 2022, US Energy and Information Administration (2022).
[49] Energiforsk, El från nya anläggningar (2021).

4.4 Modelling region & transmission capacities

Investment optimization is performed within Finland, and Sweden's four bidding zones for power generation and storage. Dispatch optimization is performed for all 14 regions illustrated in Figure 16. The regions outside Finland and Sweden have fixed power systems constructed based on published plans that are pre-optimized to ensure realistic market conditions where producers are profitable, as further described in Section 3.

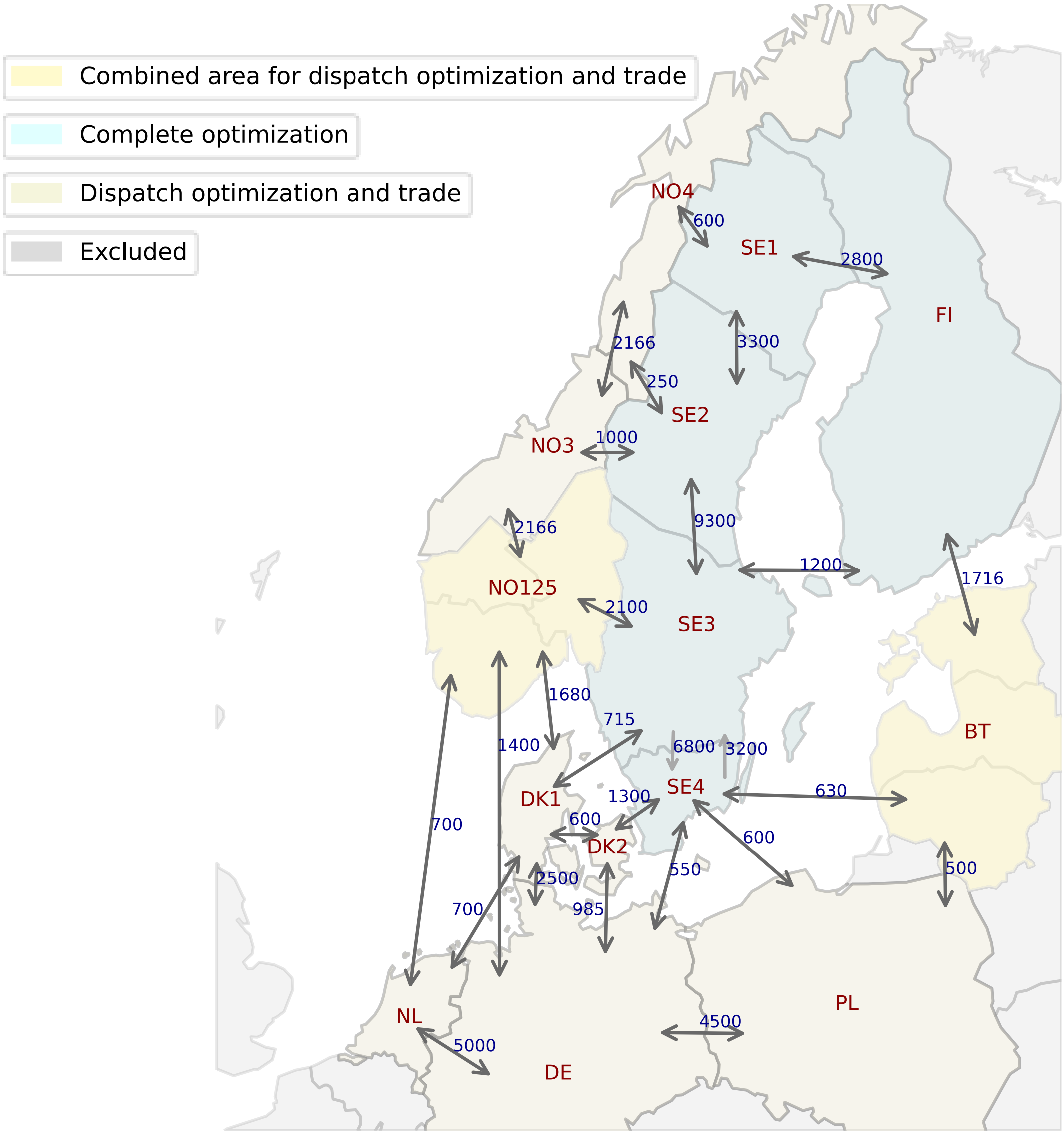

Figure 16. Geographical boundaries with regions included in the modelling and how they are treated in the optimization. Modelled existing maximum transmission capacity (NTC) in 2035 is further indicated with the arrows between the regions.

When setting up the geography in the model, and deciding which zones to include, a trade-off has to be made between accuracy and computational complexity. To reduce the calculation time without causing simplifications that affect the electricity market modelling, an analysis was conducted to determine which electricity areas that can be merged in the modelling. The outcome indicated that a merger of southern Norway (NO1-NO2-NO5) and the Baltics (Estonia-Latvia-Lithuania) allowed for a shorter calculation time without significantly changing the capacity expansion results in Finland and

Sweden. Further, the surrounding countries included in the model were determined in a similar way. Here, large zones, like DE and PL act as buffer zones and expanding the model further south does not significantly improve the quality of the results for Sweden and Finland.

The directionally dependent maximum transmission capacity for the 26 lines included in the modelling is presented in Figure 16. For the modelling of the existing transmission capacity in 2035 and 2050, the basis has been the TYNDP-2022 regional investment plan for the Baltic Sea region. The plan has been complemented with the modified transmission capacities as shown in Table 8. Lines between Finland and Baltics to Russia has been assumed to permanently be decommissioned.

The transmission capacity between SE1 and SE2 is assumed to increase substantially by 2050. The reason is that in the model, most of the hydrogen production for industrial use in SE1 could also be produced in SE2. This would result in a severe bottleneck between SE1 and SE2 with wind power production being locked into SE2. A realistic scenario would be to produce parts of the hydrogen locally in SE2 and transport it to SE1 in a pipeline, which typically has an equivalent capacity of about 5 GW. Since hydrogen trade is currently neither a part of GenX nor cGrid, an equivalent electric transmission is added instead.

Table 8. Transmission capacity (MW) in 2035 and 2050 for lines treated specially.

Line	2035	2050	Comment
FI-SE1	2800	2800	Aurora line in 2026 and additional 600 MW
FI-EE	1716	1716	As Fingrid[50]
SE1-SE2	3300	8300	Reinforcement representing both electric and H_2 pipeline transmission capacities
SE2-SE3	9300	10500	In accordance to plans of Svenska Kraftnät

For the modelling scenarios in 2050, the model can expand the transmission capacities for the lines within Sweden and those between Finland and Sweden. Associated direct and annual investment costs are presented in Table 9, with an assumed lifetime of 60 years for overhead lines (OHL) and 40 years for High-Voltage Direct Current lines (HVDC), the discount rate is 6%. The time from decision to operation is for OHL > 10 years, for HVDC cable projects it could be < 5 years. Costs have been calculated from the average lengths of the existing lines between the areas. The internal cost for connecting production or consumption to the existing main grid is not included.

[50] Fingrid (2023). Fingrid's electricity system vision.

Table 9. Direct and annual investment costs for the transmission lines allowed to expand capacities for the 2050 model year.

Transmission line	Direct costs (k€/MW)	Annual investment costs (k€/MW)
SE1-SE2	720	45
SE2-SE3	580	36
SE3-SE4	290	18
SE1-FI	580	36
SE2-FI	720 (HVDC)	48
SE3-FI	960 (HVDC)	64

4.5 Weather years

The simulations in this study were based on weather data from the years 2011-2016. However, when running a capacity expansion optimisation, a representative year is needed. If the system is expanded based on a difficult year, for instance very cold and long periods with low wind conditions, it will on average be overpowered, and the electricity prices will be too low with generators not receiving enough revenue. On the other hand, if it is expanded based on an easy year, for instance a warm and windy year, it will on average be underpowered, and the electricity prices will on average be too high.

Finding a suitable reference year to base the capacity expansion on was done in an exploratory way, and it was observed that systems using weather data from 2013 typically ended up with price levels in the middle of the range, compared with systems that were optimised based on other weather years. For this reason, 2013 is used as the reference weather year throughout this study when power systems are optimised. The exception is the P2X scenario for 2050, which uses 2012 as reference year based on the same logic. All other weather years are later used to evaluate the sensitivity of the systems.

4.6 EU CO_2 allowances and natural gas prices

For EU CO2 allowances a price of 125 €/ton was used in 2035 and 200€/ton in 2050, in-line with assumptions by Agora Industry[51]. For natural gas, a price of 30€/MWh was used both in 2035 and in 2050, which is slightly lower than the 35 €/MWh used in Agora Industry report but more in-line with what gas futures are currently traded at as of May 2023. For the sensitivity analysis average gas prices of 15 €/MWh and 45 €/MWh were used.

5 Results

Results of the nuclear capacity expansion introduces the results section as it defines the share of nuclear vs renewables for the scenarios. In the following, the power systems analysed in the current study are introduced along with their constituents for model years 2035 and 2050. Examples of time series profiles of the dispatched power in all zones are described. Peaker plants and hydrogen electrolysis are two aspects that are described on their own. Grid development with transmission capacity expansions and costs as well as observed transmission flows in the different scenarios follow. Total system costs are presented and discussed. Finally, results from electricity market modelling with

[51] Agora Industry (2023), Transforming industry through carbon contracts

electricity prices and volatility as well as discussions around capture value of different technologies conclude the section.

The input assumptions on the upper limit for onshore wind expansion in Sweden are quite optimistic in the current study. If the expansion does not materialise, it will have large effects on the results. It therefore appears as a discussion point many times throughout the section.

Some further detailed results are given in Appendix in Section 8.3

5.1 Scenarios and compiled nuclear expansion

The nuclear share definitions have been introduced in Section 1. In the current section, the overall resulting expansion of new nuclear power is compiled to give a first overview of the results and provide a background to the power system analysis further presented in the results section. The new nuclear capacity for each scenario is compiled in Table 10. As indicated in the table, the maximum limit of new nuclear is only reached in the Power to X (P2X) scenarios, meaning that expansion of additional new nuclear is still profitable beyond that point. For the Carbon Neutrality (CN) scenario in 2035 and 2050, the medium and high nuclear share scenarios have been merged due to similar and more modest capacity expansions. As expected, reinvestment in existing nuclear power is done in all scenarios.

Table 10. Scenarios modelled, total demand in Finland and Sweden and the resulting new nuclear capacity built. New nuclear buildout reaching their maximum capacity limit are marked with a star.

#	Demand scenario	Model year	Nuclear share	Demand (TWh)		*New* nuclear capacity (GW)	
				FI	SE	FI	SE
1	CN	2035	Low	112	189	0.0	0.0
2			Medium/High			1.2	0.5
4		2050	Low	135	243	0.0	0.0
5			Medium/High			2.1	2.5
7	P2X	2035	Low	143	223	0.0	0.0
8			Medium			1.0*	1.0*
9			High			3.0*	2.4
10		2050	Low	223	330	0	0
11			Medium			4.7*	3.8*
12			High			9.4	7.6

5.2 Power systems

5.2.1 Model year 2035

In 2035, the additional demand is covered primarily by the expansion of onshore wind production as depicted in Figure 17, where results for the Power to X (P2X) scenario are shown. In all scenarios, onshore wind expansion in SE1 and SE2 reaches its limits, and same goes for SE3 except for the CN and low nuclear share scenario, while SE4 is approaching its limit in all scenarios. This means that in practice onshore wind power shows an optimistic buildout from today's 15 GW approaching 25 GW in Sweden. Installed capacity in Finland grows from today's 7 GW to 16-32 GW depending on scenario.

This is in line with Fingrid estimate reaching about 20 GW by 2030 but stands with a large margin to its upper limit of 43 GW in 2035 that was assumed for this study. The results further show that the onshore wind expansion in Finland has the potential to play a vital role in supplying electricity to meet the increasing demand in northern Sweden, especially in case the optimistic Swedish onshore wind expansion does not come to a realisation and only a limited buildout of new nuclear power is achieved.

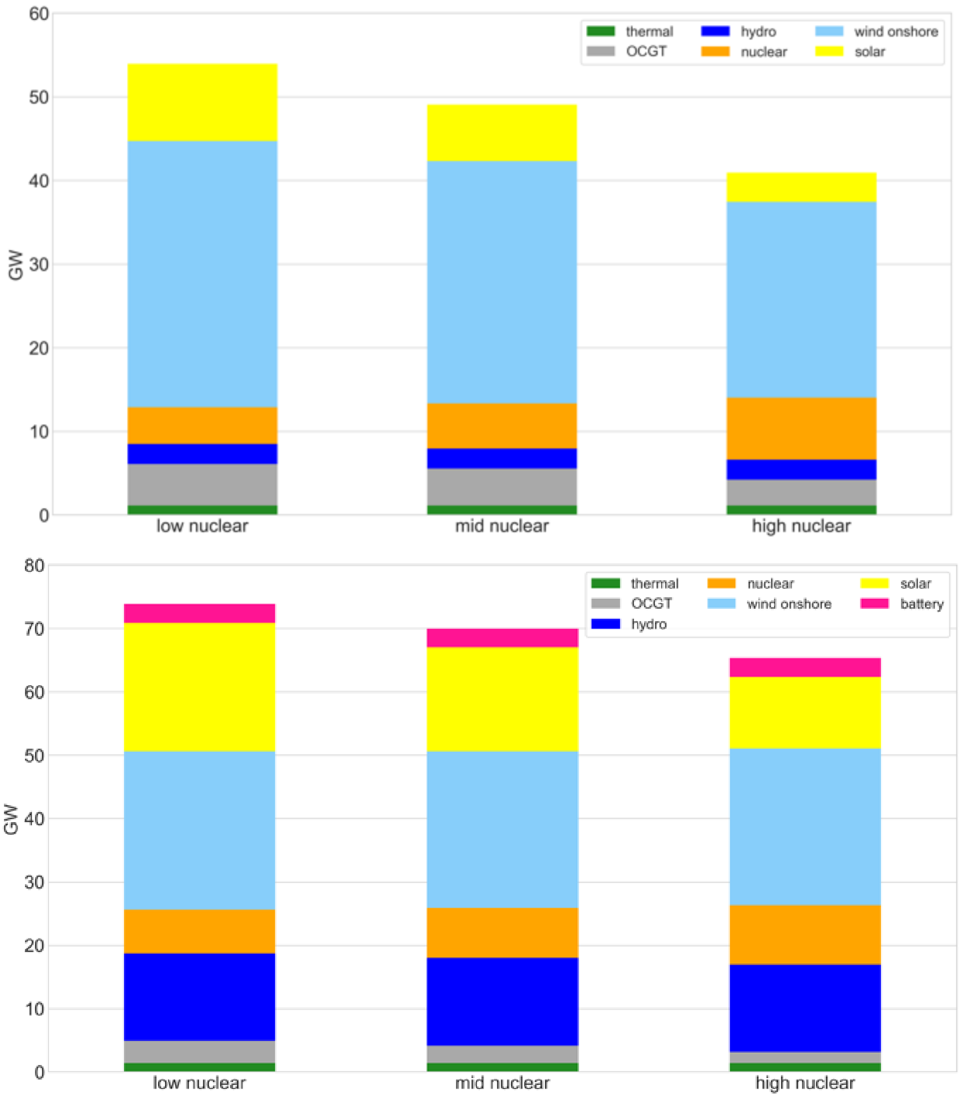

Figure 17. Total installed capacity of different energy sources in Finland (top) and Sweden (bottom) in the P2X scenario and year 2035.

The existing roof-top solar amounting to 7 GW in Sweden is joined with new utility solar and battery storage in southern Sweden, irrespective of scenario. Installed capacity, in addition to roof-top solar, ranges from 1 to 13 GW depending on scenario. However, Finland sees no new utility solar PV. Southern Sweden has already begun to see price cannibalization due to the increasing solar capacity installations in continental Europe, albeit still only during weekends with lower electricity demand[52]. The model has battery storage installations which smoothens out the electricity prices over the day increasing the capture value of the new utility solar.

[52] https://twitter.com/lukstroem/status/1655455068085207042?s=20

In the CN scenario, nuclear experiences a modest expansion, 1.2 GW in Finland and 0.5 GW in Sweden, thanks to the possibility of expanding cheap onshore wind, which together with hydro power can balance the system for the associated modest demand growth. If the exceptionally large modelled onshore wind power expansion in Sweden is not fully realised, the expansion of additional nuclear power, especially in Sweden, will become profitable and cost effective from a power system perspective. This may already be seen from the P2X results. Here all of the allowed 3 GW of new nuclear capacity is built in Finland whilst 2.4 GW is built in Sweden for the high nuclear scenario.

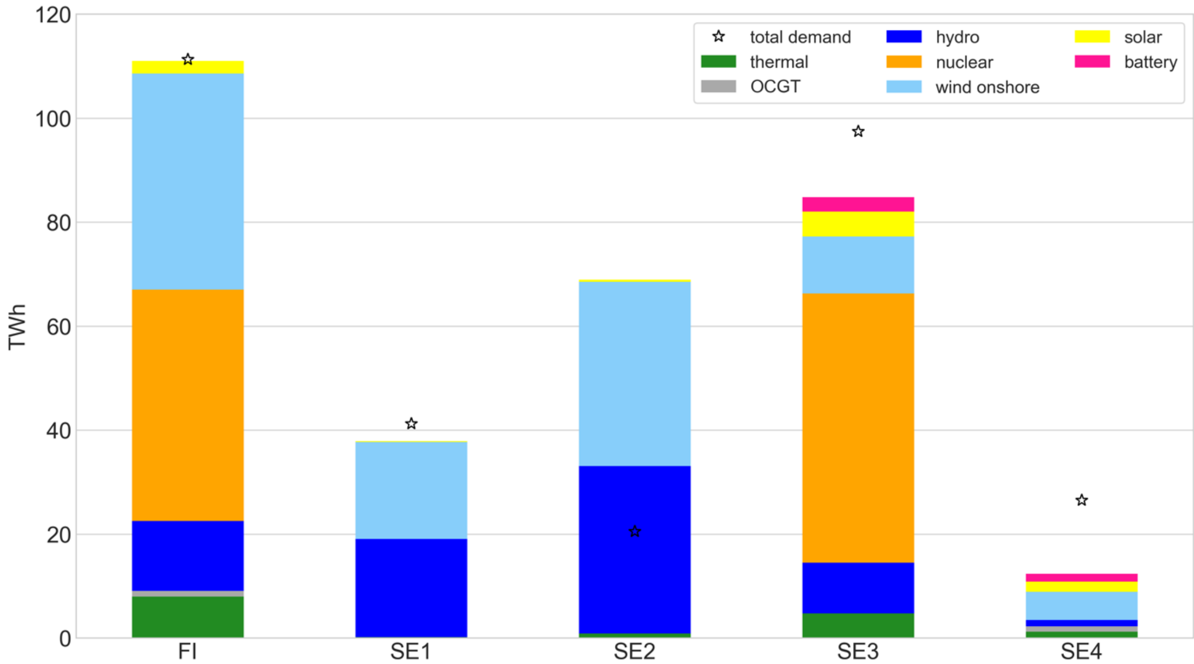

Figure 18. Distribution of annual generated energy by source and bidding zone along with total annual demand for the CN scenario and medium/high nuclear share in 2035.

Figure 18 tells a story of how the energy production and consumption has developed to in 2035 in the CN scenario. Largest transformation has happened in SE1, which despite a significant onshore wind expansion has become a region dependent on net import owing to the industry transformation's increasing electricity consumption (see also discussion of flows below). In all scenarios, the majority of new energy production is established in FI, SE1 and SE2 while new nuclear capacity is placed exclusively in SE3.

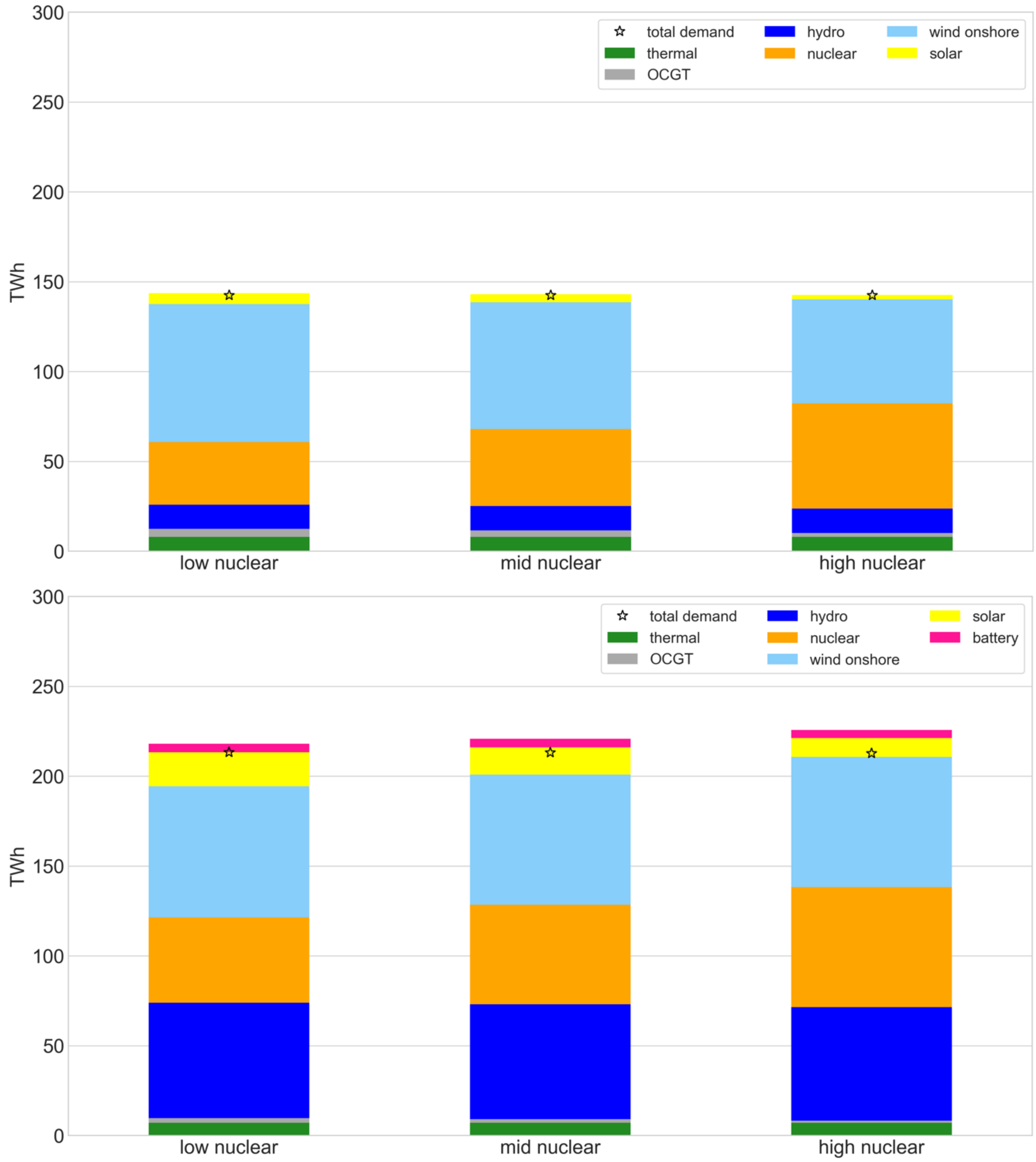

Figure 19. Total annual generation by energy source for Finland (top) and Sweden (bottom) for the P2X scenario in 2035. Total annual demand is indicated with stars.

The total annual generation by energy source split in Finland and Sweden is depicted in Figure 19. In all scenarios for 2035, Finland shows a net zero import/export over the year while Sweden continues to be a net exporter, like today. If onshore wind expansion in northern Sweden would not materialize to the optimistic level used for the current study, onshore wind expansion in Finland would increase to finally reverse the situation, with the strongest effects seen in the low nuclear share scenarios.

In Figure 20 we show an example of the modelled system in January 2035 using the reference weather and commodity year. The scenario shown is the low nuclear P2X; this scenario is chosen for illustration as it best illustrates the dynamics of the different processes in the system.

During the January month we observe a weeklong period with high demand combined with low wind and solar production throughout the entire modelled system. The period is roughly between hours 250 and 400. Consequently, the system uses a large amount of fossil backup generation in regions that do not have firm fossil free capacity (hydro and nuclear). Further, we see an example of how the hydrogen production for direct reduction of iron ore in SE1 ramps down during this week as a response to the high prices. The hydrogen production in Finland is only assumed to have a storage capacity of 24 hours in 2035. This is too low compared to the duration of a dunkelflaute period, which can last for a week or two. Consequently, only a limited flexing is seen in Finland.

In Figure 21 we show a second example of the same system, but during June 2035. Although wind power production is high in Finland, the rest of the system sees quite low levels of wind power. Instead, solar power is producing a significant share of the required power, and especially in Germany, battery storage is starting to play a significant role in smoothing the daily production. Fossil power use is also limited during this month as renewables production is able to supply a larger fraction of the demand.

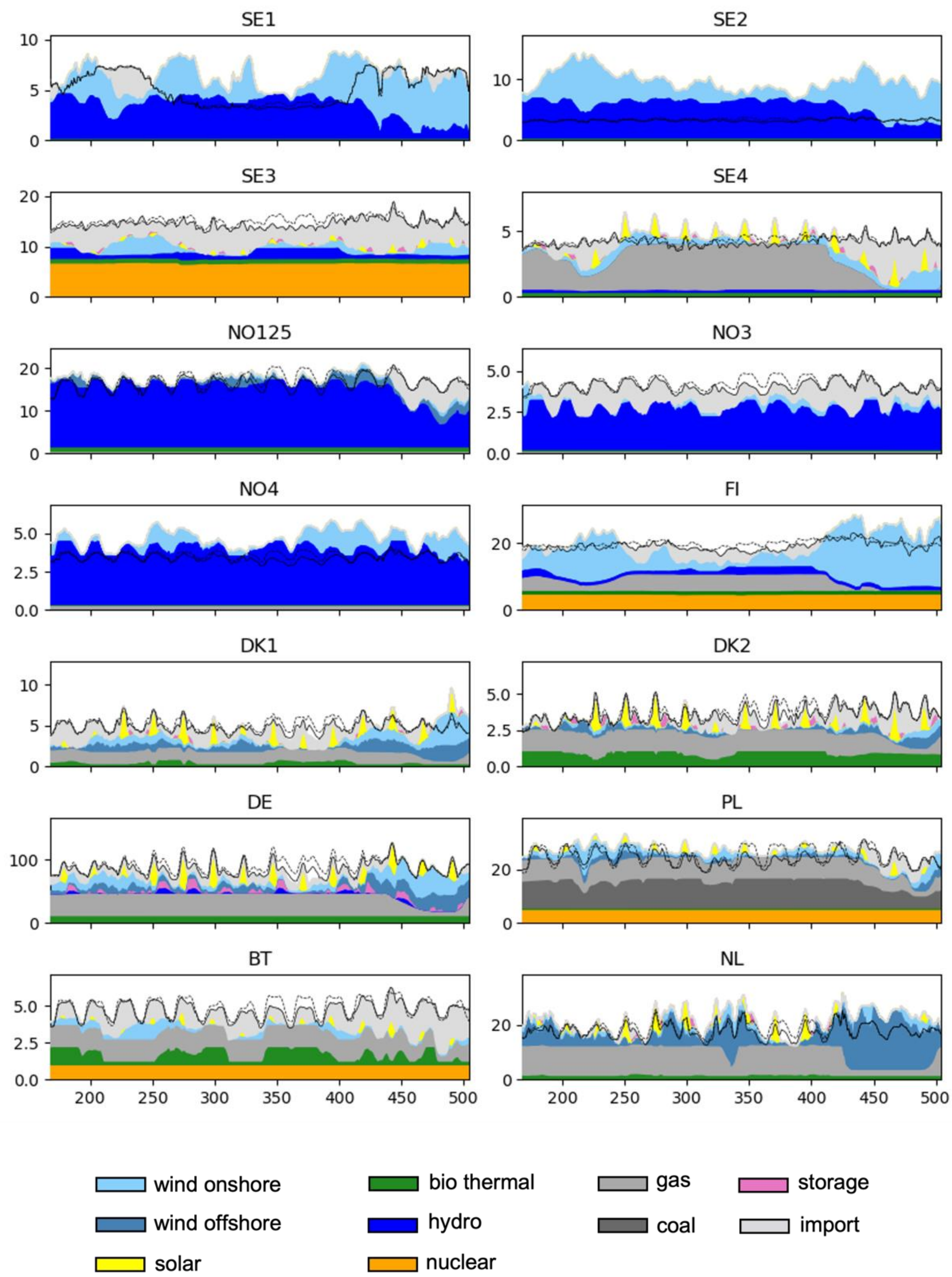

Figure 20. Example of power production in the modelled system during a winter month. The scenario is P2X with low nuclear in 2035. Different resources are colour coded. The input demand before flex and demand reduction is shown as a light dotted line, and the resulting demand after flex and demand reduction is shown as a full drawn black line.

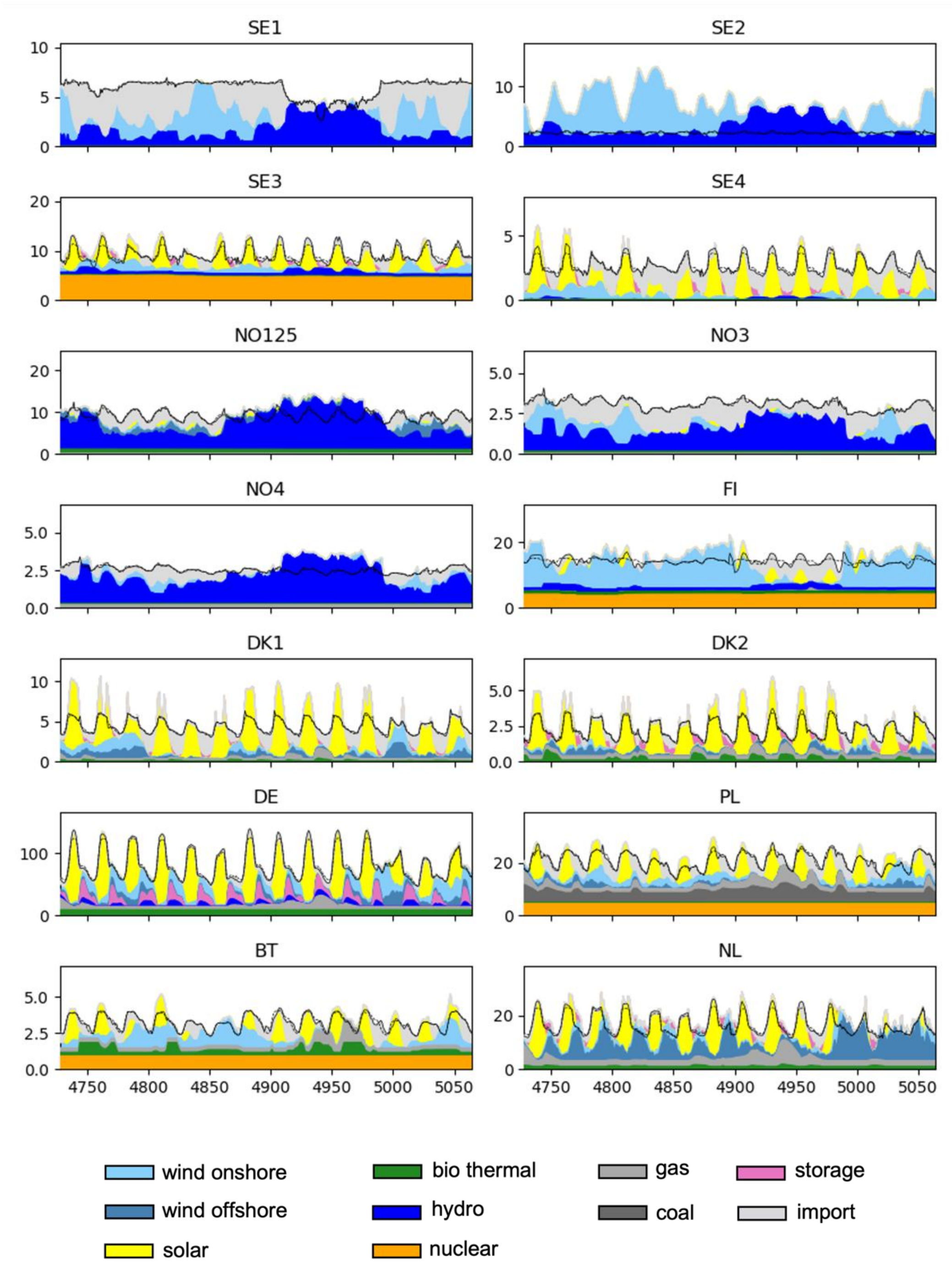

Figure 21. Example of power production in the modelled system during a summer month. The scenario is P2X with low nuclear in 2035. Different resources are colour coded. The input demand before flex and demand reduction is shown as a light dotted line, and the resulting demand after flex and demand reduction is shown as a full drawn black line.

5.2.2 Model year 2050

The capacity expansion for 2050 follows similar trends as in 2035. In all the scenarios with low nuclear share, onshore wind expands to its maximum limit in SE1, SE2 and SE3. In the case of low nuclear share in the P2X high demand scenario, onshore wind reaches the limit across all Swedish zones as well as in Finland. Overall this means that onshore wind expansion exceeds 40 GW (110 TWh) of installed capacity in Sweden. For Finland onshore wind expansion settles to around 20 GW (50 TWh) for the CN demand scenario but shows a big range of possibilities, as it ranges from 30 GW (80 TWh) to 60 GW (140 TWh) for the P2X scenario. 60 GW of installed onshore wind capacity in Finland in 2050 does not seem impossible from today's point of view but certainly challenging. If wind expansion in Sweden stops around the 2035 limit of 25 GW the situation becomes more extreme. The model would in this case expand Finnish onshore wind to beyond 80 GW to supply energy to northern Sweden further requiring a reinforcement of around +5 GW transmission capacity for SE1-FI.

Enjoying low modelled investment costs, the expansion of solar-battery storage systems is significant in southern Sweden (SE3 & SE4) in all modelling scenarios while only becoming cost effective in SE1 and FI in the low nuclear P2X scenario. Solar expansion is primarily restricted by the negative correlation between production and electricity demand on a seasonal basis in northern Europe, which decreases its system value. There is also a high correlation between Finnish-Swedish solar power and the rest of Europe's strongly expanding solar power (same time zone ± 1 hour), which cannibalizes revenues and affects profitability.

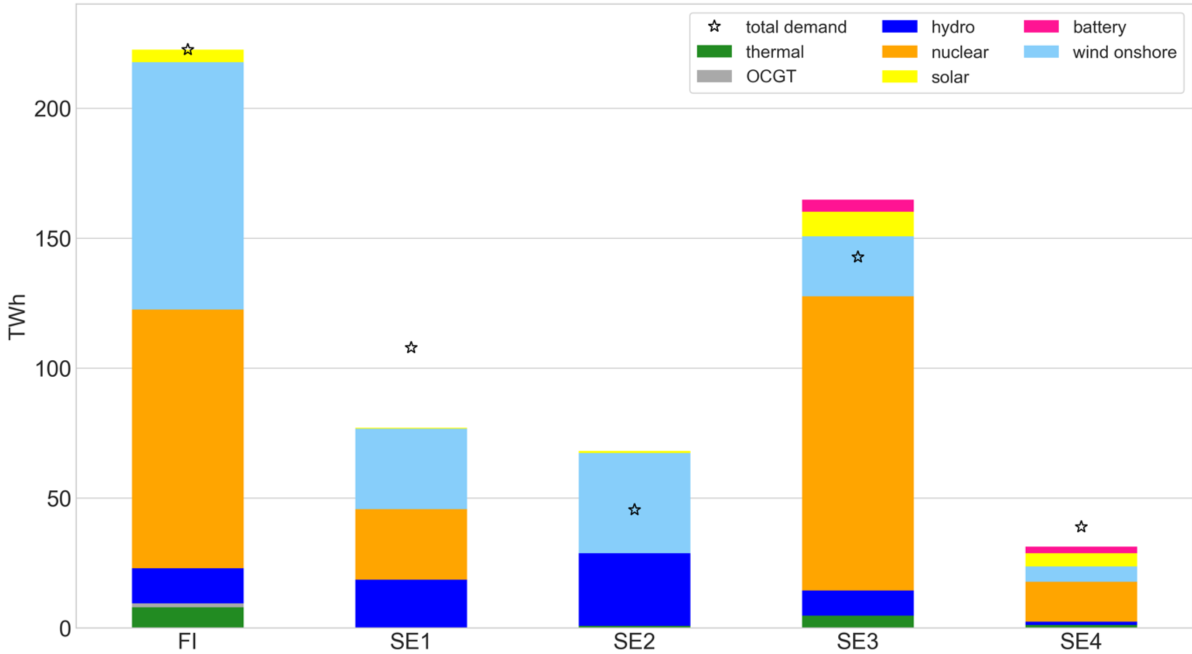

Figure 22. Distribution of annual generated energy by source and bidding zone along with total annual demand for the P2X scenario and high nuclear share in 2050.

Typical distribution of generated energy across Finnish-Swedish bidding zones for the P2X scenario in 2050 with high nuclear share is shown in Figure 22. In this scenario, new nuclear is built in all zones except SE2 (3.5 GW in SE1, 8.3 GW in SE3 and 2.0 GW in SE4). In the other scenarios where new nuclear is allowed the model prefers building new nuclear in FI and SE3. In the CN scenario, 1.6 GW is built in SE3 and 0.9 GW in SE4 while 2.1 GW is built in Finland.

If wind power expansion saturates at the 2035 limits, nuclear power expansion in Sweden increases in the CN scenario from about 2 GW to 6 GW. In the P2X scenario, nuclear expansion becomes quite large primarily due to onshore wind reaching its capacity expansion limits. However, needs to increase transmission capacities and balancing power of hydro decreasing with the larger demand both increase the relative value of nuclear energy to the system.

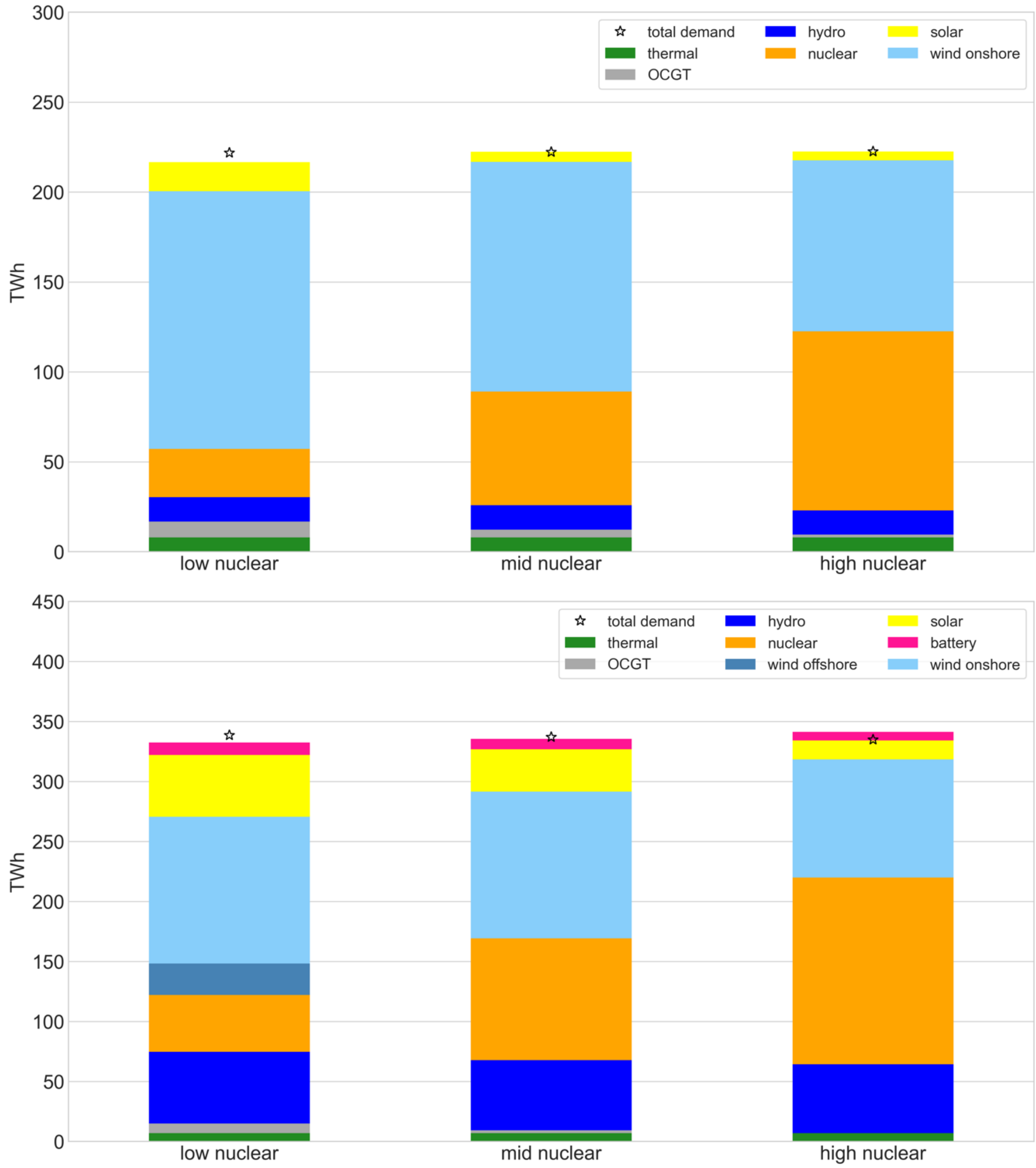

Figure 23. Total generation by energy source for the Finnish(top)-Swedish(bottom) power system in the P2X scenario in 2050.

In difference to 2035, Finland and Sweden display similar annual import/export as can be seen in Figure 23.

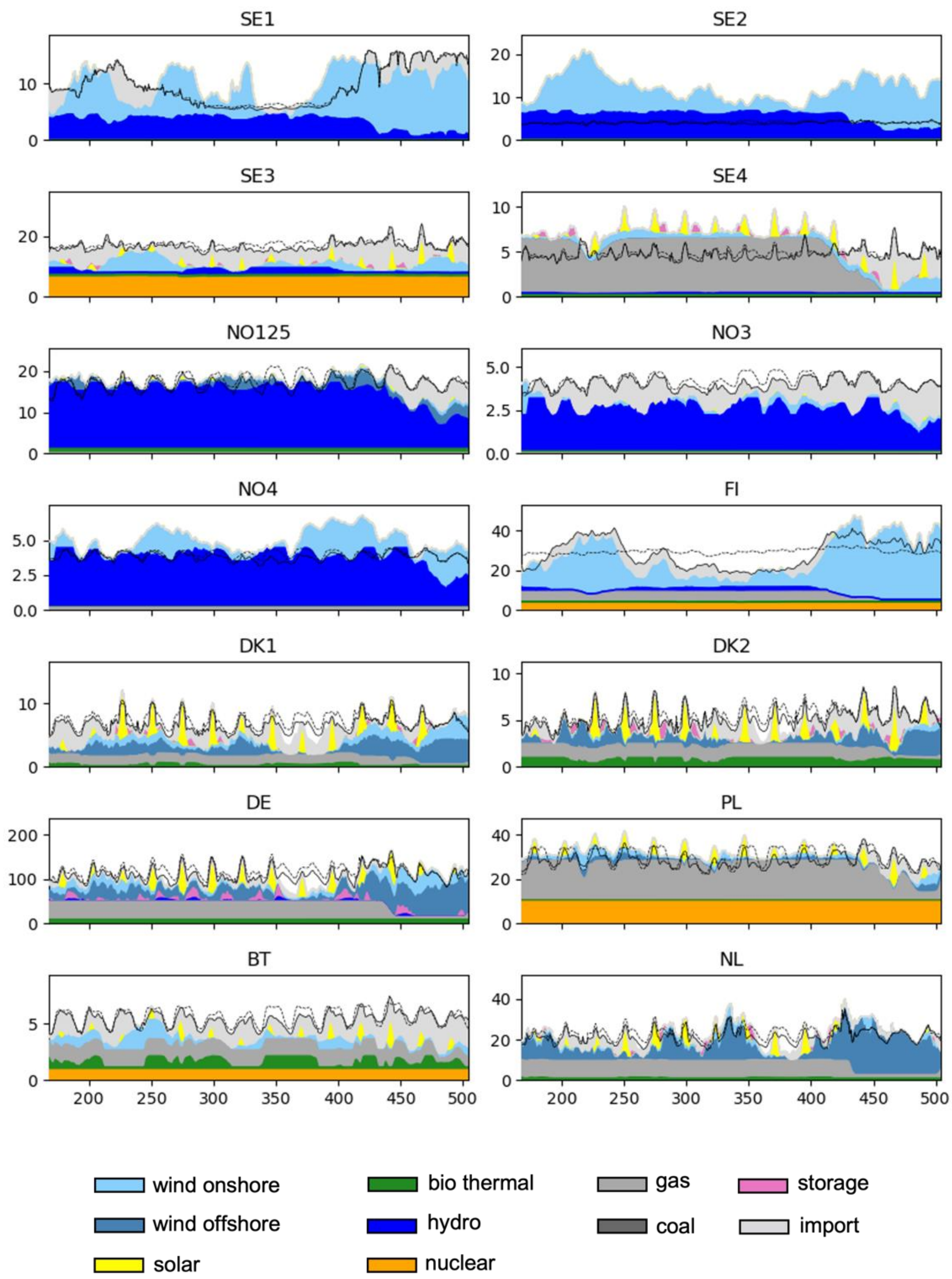

Figure 24. Example of power production in the modelled system during two weeks in January for model year 2050. The scenario is P2X with low nuclear. Different resources are colour coded. The input demand before flex and demand reduction is shown as a light dotted line, and the resulting demand after flex and demand reduction is shown as a full drawn black line.

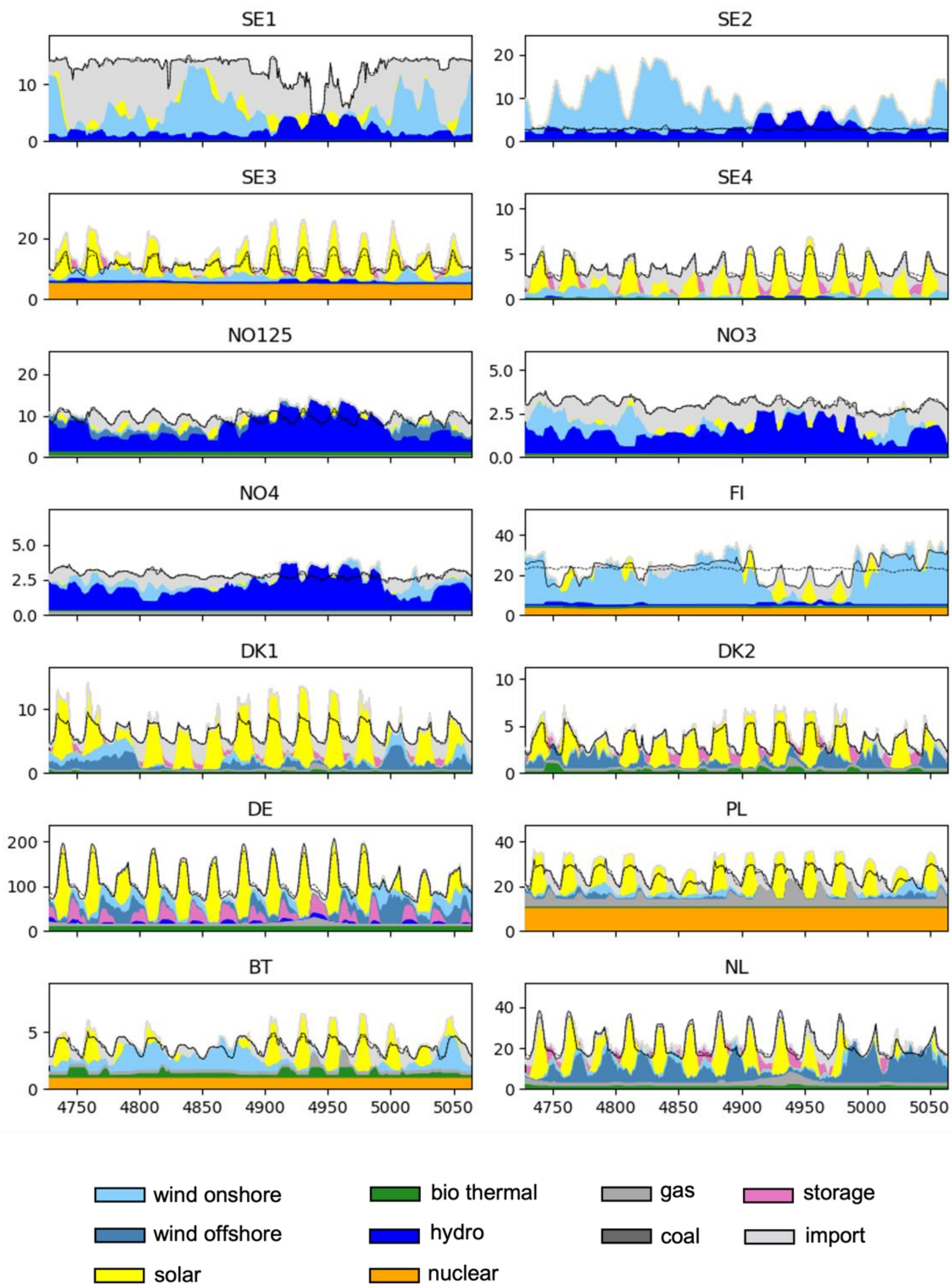

Figure 25. Example of power production in the modelled system during two weeks in July for model year 2050. The scenario is P2X with low nuclear. Different resources are colour coded. The input demand before flex and demand reduction is shown as a light dotted line, and the resulting demand after flex and demand reduction is shown as a full drawn black line.

An example of the power production during January 2050 is shown for the reference weather and commodity year. Like what was seen for 2035, we see a prolonged period of low wind and solar production, a so called dunkelflaute, which still requires fossil peaking plants to cover up for the low renewables production. The amount of peaking power needed is however lower in 2050 compared to 2035. As for 2035, we clearly see how the hydrogen production in SE1 is responding by ramping down around hours 250 to 400. However, in contrast to 2035 we see a similar pattern also in Finland as we now assume that the storage capacity covers a full week, which is more in line with a typical period of low renewables production.

In Figure 25, we show the same system but for June 2050. The same trends that were seen in 2035 are seen here as well, but more pronounced. Solar power is even more dominating, and fossil power use is even lower.

5.2.3 Peaker plants

All modelled scenarios expand OCGT peaker plants, with capacity split in bidding zones FI and SE4. The peaker plant is deemed the most cost-effective option to handle periods of exceptionally low wind and solar production in the winter period, so called dunkelflaute, despite its low utilization and expensive fuel. The amount of installed peaker plant capacity (generation) for Finland in 2050 is about 3 GW (2-3 TWh) for the cases with new nuclear and about 5 GW (4-6 TWh) for the low nuclear case[53].

The required electricity demand to produce hydrogen and then burn it in the OCGT to generate 4 TWh is about 15 TWh. This value is approaching the total electrolysis demand in Finland for the CN scenario of 17 TWh in 2050. It is therefore not realistic that the peaker plant exclusively burns hydrogen in the CN scenario as no hydrogen would be left for the dedicated products. It does become a more viable option in the P2X scenario where the total annual electrolysis demand in Finland reaches 86 TWh. However, it is worth noting that the required excess generation to provide hydrogen for peaker plants has not been included in the modelling.

The produced hydrogen is best utilized in processes where it is directly needed, e.g., direct reduction of iron, and a similar logic may be applied to biogas. Therefore, the peaker plants would most likely consume natural gas. Irrespective of type of fuel, the need for peaking plant capacity and fuel increases with lower share of nuclear in the power system.

5.2.4 Hydrogen electrolysis flexibility

The assumptions on the flexibility of hydrogen electrolysis are described in Section 4. In SE1, the hydrogen production for direct reduction of iron ore is performed by the code OptiL, which also performs an optimisation of the dimensioning of the electrolysers and storage. Typical values for electrolyser utilisation obtained from OptiL are about 70% with storage capacities of about 1 week. Compared to the numbers obtained from OptiL, the assumptions on storage capacity are consistent. However, the assumptions on electrolyser utilisation are optimistic at 50%. These assumptions on the flexibility of the electrolyser loads means that the power system can more easily incorporate a higher penetration of weather dependent renewable energy.

[53] Finland is here taken as an example, but similar values and trends are observed for Sweden.

5.3 Grid development

5.3.1 Transmission capacity expansion

As described in Section 4, all transmission lines within the Swedish zones and between Sweden and Finland were allowed to expand further for the modelled scenarios in 2050. Results are shown in Table 11 for lines SE1-FI and SE3-FI while the rest of the lines did not show any reinforcement. The model always chose to expand SE1-FI from its planned 2.8 GW capacity to 3.6-5.4 GW depending on scenario. In the low or medium nuclear share scenarios, the SE3-FI interconnection was also reinforced from the initial capacity of 1.2 GW to 1.9 GW in the CN scenario up to 4.8 GW in the P2X scenario. Relative to the total annual system costs in the order of tens of billions, the network expansion costs are small. In the electricity market modelling for the year 2050, SE1-FI has been defined at 3.8 GW and SE3-FI 2.7 GW.

Table 11. Results of the transmission capacity expansion with new transmission capacity (GW) of the lines expanded presented along with associated annual costs.

Demand scenario	Model year	Nuclear share	SE1-FI (GW)	SE3-FI (GW)	Annual costs (M€)
CN	2050	Low	1.6	0.7	102
		Medium/High	0.8	0	29
P2X	2050	Low	2.6	3.6	324
		Medium	2.4	1.5	182
		High	2.3	0	83

5.3.2 Estimate of zone-intrinsic grid reinforcement costs

Costs associated with grid reinforcement necessary for adequate transmission capabilities intrinsic to each bidding zone has not been included in the power system optimization. These costs have been estimated based on a recent report of the Finnish power system transmission operator, Fingrid[54]. Table 12 presents grid reinforcement costs based on future year, demand scenario and nuclear share in the Finnish power system. The primary driver of the additional transmission costs is the amount of onshore wind power and its distance to load areas. The costs have been derived from representative Fingrid scenarios, providing the total length of additional 400 kV lines, which then is scaled according to the onshore wind power production seen in the current study. Additional costs comes on top of the Fingrid general grid investment program amounting to 3€ billion as well as annual reinvestments into the local, regional and transmission grids as presented in Section 4.

[54] Fingrid (2023). Fingrid's electricity system vision.

Table 12. Estimated additional grid reinforcement costs based on future year, demand scenario and nuclear share in the Finnish power system.

Demand scenario	Year	Nuclear share	Annual costs (M€)
P2X	2035	High	120
		Medium	140
		Low	140
CN	2035	Medium/High	9.1
		Low	12
P2X	2050	High	87
		Medium	160
		Low	210
CN	2050	Medium/High	28
		Low	99

For Sweden, the bulk of grid reinforcements are either included through the transmission capacity expansion as presented above or included as part of reinvestments and investments into the Swedish grid as presented in Section 4.

5.3.3 Transmission flows

Figure 26 visualises the transmission flows between bidding zones with so called violin distributions, which indicates the transmission flows that are most frequent. The largest changes are observable between 2023 and 2035, especially in the flows between Finland and Sweden where Finland goes from importing to a more balanced transmission flow between the countries for all scenarios. SE1-FI goes from spending almost all time at exporting in 2023 to showing a more equally distribution between importing and exporting. In the CN scenario, SE1-FI shows a “nail”-shaped distribution with a high yearly average export both in 2035 and 2050, while in the P2X shows a more “dumbbell”-like shape and a yearly average export close to zero. SE3-FI is often at either end of its capacity limits in 2023 and shows very extremely “dumbbell”-shaped distributions in 2035 which indicates that the transmission capacity should be expanded, which the capacity expansion model also does for 2050.

Looking at flows between the Swedish bidding zones, it can be observed that the SE1-SE2 change direction in 2035 and spend most time importing at full capacity (which shows up as upside-down “nail”-shaped distribution), indicating a need to expand the capacity to satisfy the growing energy demand in SE1. SE2-SE3 is mainly at full export in 2023, but in 2035 and 2050 it shows more evenly distributed shapes indicating the transmission is used for balancing the system rather than pure energy export to the south. The yearly energy flow from north to south stays relatively stable from 2023 to 2035, but for the P2X scenario and year 2050 the yearly average goes close to zero. Which still giving south Sweden plenty of time to adopt and built its own supply for a situation where there is less energy export available from the north.

The transmission flows to countries not part of the full optimization is also shown in an aggregated form. The aggregated Sweden to Norway flows, SE-NO, show relatively minor change but Sweden goes from small import to exporting slightly over year. And the shapes thinness out in the middle, indicating that more time is spent at either full import or export (would show up more clearly if the transmission links were shown individually). Sweden’s transmission flows to its southern neighbours Denmark, Germany, Poland as well as Lithuania are aggregated into one figure. The distribution changes from “nail”-shaped in 2023 to a more “dumbbell”-like shape, indicating that more time is spent on either full import or full export to balance out the effects of more weather dependent and variable energy supply. FI-BT (Finland-Estonia link) shows a relatively stable “nail”-like shape and yearly net export in all scenarios, besides in the low nuclear P2X scenario for year 2050 where Finland starts to import more often instead.

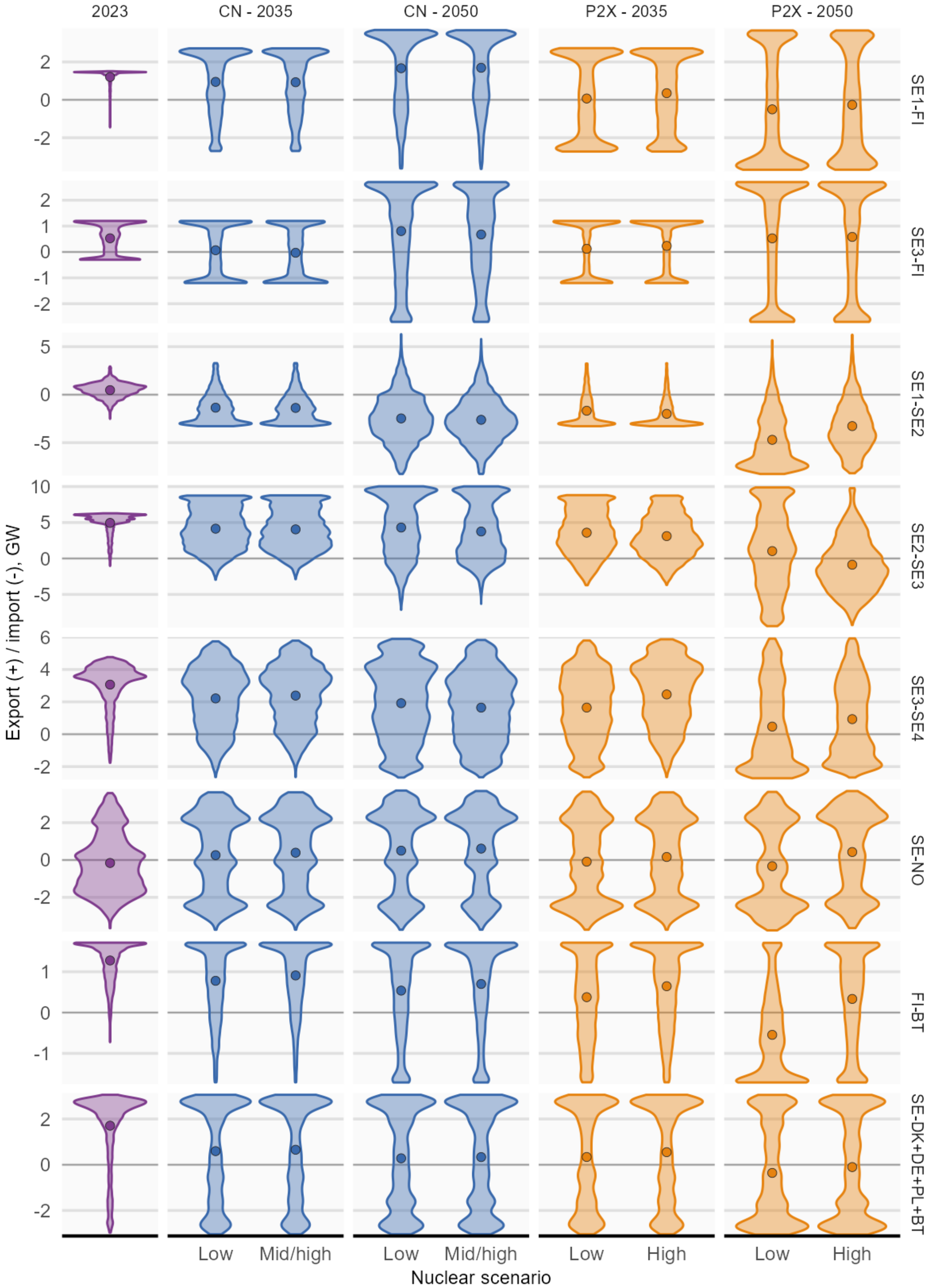

Figure 26. Hourly transmission flow distributions and yearly averages (dots) based on cgrid simulations using weather year 2013. SE-NO is an aggregation of the four transmission lines between Sweden and Norway. The last subfigure row is an aggregation of Sweden's transmission links with Denmark, Germany, Poland, and Lithuania.

5.4 Total power system costs

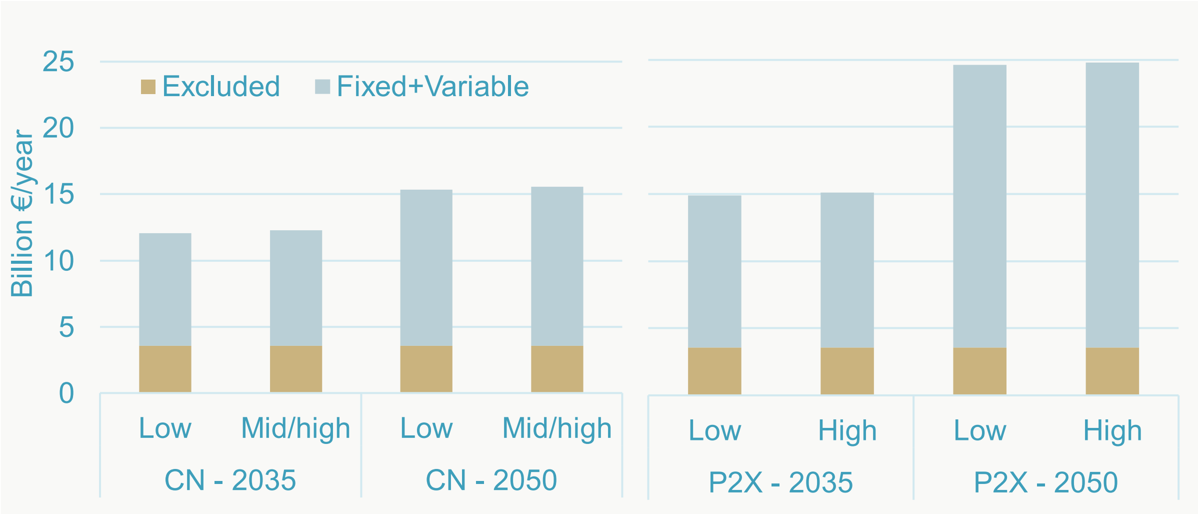

Figure 27. Total annual Finnish-Sweden power system costs for low/high scenarios. Excluded costs in red represent reinvestments and investments to maintain hydro power capacity and maintain and expand regional and local networks in Sweden and Finland. Costs for system services (e.g., inertia, power, and frequency reserve) have not been accounted for.

Total system costs across all scenarios in the current study are shown in Figure 27. Larger system costs for the model year 2050 reflects the larger production that needs to be built to meet the increased demand compared to 2035 as well as retired production capacity (mainly onshore wind). Similar arguments hold for the comparison of total system costs for the CN and P2X demand scenarios.

Differences between the systems with low and high nuclear shares are relatively small. The largest difference between the low and high share is found in the P2X scenario for 2050 which amounts to 1% or 0.2 billion € in annual costs. However, larger costs in system services should be associated with a system with more variable renewable energy, i.e., the scenarios with low nuclear share. These costs have not been calculated in the current study but could well be of the order to make up for the difference observed between low and high nuclear share[55]. This combined with uncertainties in costs, it is therefore difficult to argue that costs are significantly different between the scenarios.

Additional costs in transmission capacity have been analysed in Sections 5. They do show higher costs for scenarios with lower shares of nuclear. However, in the context of total system costs as presented in Figure 27 they are small.

It is relevant to emphasize that the optimization finds the least power system cost for the entire model, including regions outside Finland and Sweden. Capacity expansion and dispatch optimization is performed for resources in the Finnish-Swedish power system while resources in other regions are merely optimized by their dispatch. This means that only variable and fuel cost associated with these resources and costs for non-served energy for regions outside the Finnish-Swedish power system enter the objective function that is minimized in the power system optimization.

[55] See also Svenskt Näringsliv (2022), Rapport stödtjänster.

The scenarios with higher nuclear share expands more production capacity in the Finnish-Swedish power system increasing exports to lower variable cost and costs for non-served energy throughout the entire model. In contrast, the scenarios with lower nuclear share turns to import electricity instead of investing in more production capacity in the Finnish-Swedish power system as a mean to lower system costs. This trend may be observed from Figure 23. Considering all regions in the model, not just Sweden and Finland, total system costs are lowest for the scenarios with high nuclear share. This is inherent to the model. The high nuclear scenarios remove variable costs and costs of non-served energy throughout the model which means in practice lowering electricity prices for northern Europe. The relationship between the variable costs (primarily determined by the assumed commodity prices) and the investment costs for expanding production capacity[56] in the Finnish-Swedish power system guides the utilization of trade for the cost-optimal power system.

It is worth noting that the inclusion of OCGT peaker plants significantly lowers system costs in all scenarios. If the model instead of the peaker plants would have been forced to build hydrogen storage resources which produces hydrogen and then converts it back to electricity by means of a gas turbine, the costs for the scenarios with low share of nuclear power increases significantly compared with the high nuclear share scenario.

Finally, the total system costs in all scenarios rely on the strong expansion of onshore wind power. If the development is not realised, higher system costs would be observed irrespective of scenario.

5.5 Electricity market modelling

5.5.1 Electricity prices and volatility

In Figure 28 and Figure 29 a price sensitivity analysis is presented for model years 2035 and 2050, respectively. Here the power system that was optimised for the reference year, as described above, is simulated using data from all 6 weather years and at 3 levels of commodity prices. In total 18 simulations are run for each scenario. The boxes in the plots show how sensitive the resulting electricity prices are to variations in the external factors. It should be noted for clarity that the median prices shown in the boxes are obtained from the price spread in all 18 simulated cases. This number is not necessarily the same as the market average shown in the tables above, which was obtained from the reference year only.

[56] Whether it is correlated variable renewable energy or firm baseload capacity also matters.

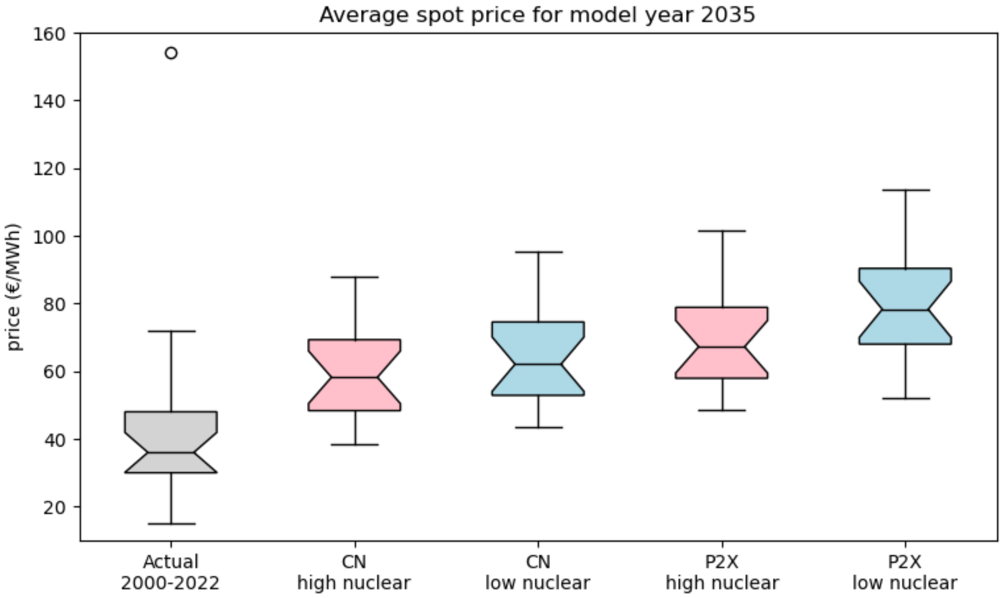

Figure 28. Box plots showing the range of the first and third quartiles of the yearly average electricity prices in Finland for model year 2035. This includes simulations using all weather years as well as low, medium, and high fuel prices. The lines show the total range of the prices, and the centreline of the box is the median price. Also shown for comparison are the actual yearly average prices in Finland between 2000 and 2022. The outlier at close to 160 €/MWh is 2022.

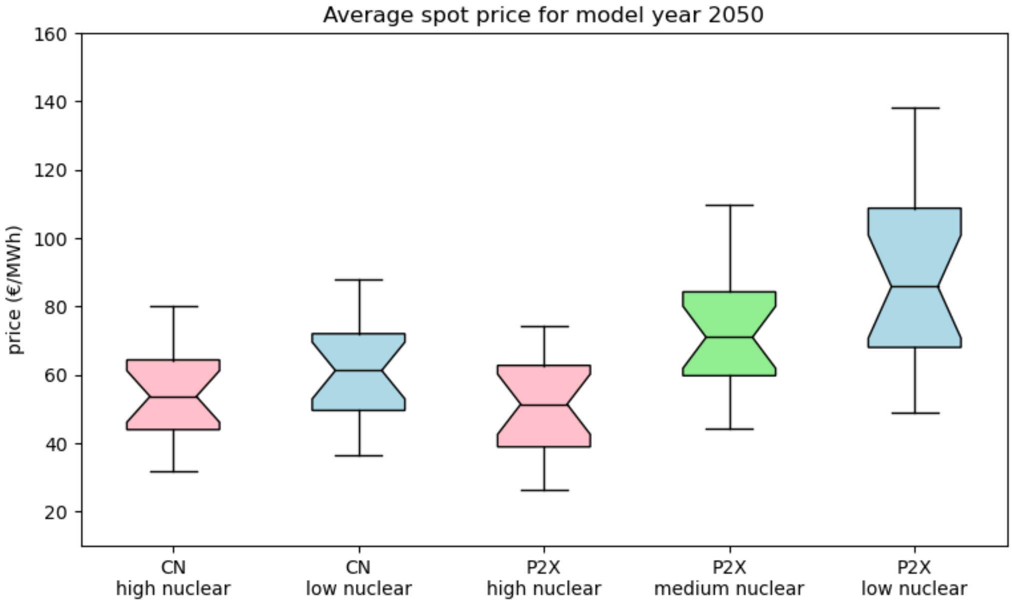

Figure 29. Box plots showing the range of the first and third quartiles of the yearly average electricity prices in Finland for model year 2050. This includes simulations using all weather years as well as low, medium, and high fuel prices. The lines show the total range of the prices, and the centreline of the box is the median price.

From these ranges it can be concluded that the price sensitivity is generally around 50 €/MWh, with the low nuclear P2X scenario being the exception having a range of about 80 €/MWh. Moreover, there is a tendency for a slight asymmetry towards higher prices, rather than lower, for some of the scenarios.

In Figure 28, the prices for model year 2035 are also compared with the actual average prices during the years 2000 – 2022[57]. Given the projected demand growth and expansion of new generation capacity, together with CO2 prices expected to be considerably higher than the historical averages, it is unlikely that the average future prices will return to the historical values (excluding the energy crisis in 2022). However, there is large overlap between the distributions and some future years with favourable weather conditions are still expected to reach down to the historical averages.

5.5.2 Capture values by technology

In Table 13 and Table 14 the average capture prices for different power producers in Finland[58] are shown for model years 2035 and 2050, respectively. The numbers are taken from the expansion simulations and therefore represent the situation for the reference year used in each scenario. Also given in the tables are the average market prices together with the average prices seen by the hydrogen producers.

Table 13. Yearly average capture prices in Finland for the model year 2035 and the reference weather year. Average prices for market and electrolysers are also given. All prices are given in €/MWh.

	CN 2035		P2X 2035	
Nuclear share	**High**	**Low**	**High**	**Low**
Solar	29	32	36	42
Wind onshore	32	32	33	32
Hydro	65	69	73	81
Thermal bio	60	62	65	71
Nuclear	56	59	62	68
Peaker	293	283	274	256
Market	54	57	60	66
Electrolysis	53	55	59	64

[57] http://nordpoolgroup.com/
[58] Finland is here used as reference but is representative for all Swedish bidding zones too.

Table 14. Yearly averages of capture prices for generator technologies in Finland for the model year 2050 and the reference weather year. Average prices for market and electrolysers are also given. All prices are given in €/MWh.

	CN 2050		P2X 2050	
Nuclear share	**Medium/High**	**Low**	**High**	**Medium**
Solar	24	25	20	35
Wind onshore	32	32	33	34
Hydro	64	67	57	73
Thermal bio	59	61	53	64
Nuclear	56	58	57	65
Peaker	284	278	250	237
Market	53	55	50	63
Electrolysis	39	39	43	49

From Table 13 three different kinds of generators can be identified. Generator technologies that can flex their power output can receive a capture price well above the market average. An example here is hydro, which has a capture price around 20% higher than the market average since it is able to flex its production in response to the power price. The most extreme example is the peaker plants that receive about to 250 – 300 €/MWh. This is however expected since they only run during periods of high demand combined with low solar and wind production.

Base load producers that generally do not respond to power prices, such as nuclear, will see a capture price close to that of the market average.
Table 14 shows nuclear receiving a slightly higher capture price than market average. This is a result of the revision period that is here assumed to take place during the summer, when the prices typically are lower.

The third example are the weather dependent renewable technologies solar and wind that typically see capture prices well below the market average. This is fundamentally a result of price cannibalisation. When variable renewable resources become a dominating part of the system, they will drive down prices during periods of high production. The higher the installed capacity, the more prices will go down. On the other hand, during periods of low production prices typically go up. The variable renewable resources can however not fully benefit from these higher prices as their production is low during these periods. This price cannibalisation is the direct reason that the model almost never builds offshore wind power, which is directly competing with onshore wind power as their production profiles are highly correlated. The only scenario where offshore wind power is built is the low nuclear P2X scenario, where 1.8 GW is added in SE2.

Since the expansion and optimisation of resources in this study requires them to be financially viable, the expansion of a resource will typically result in an average capture price close to that of its LCOE. As the model increases the capacity of a resource it will gradually push the capture price of that resource down until it reaches the LCOE and the expansion stops. The numbers for LCOE and the underlying assumptions are summarised in Appendix 8.2.

There are however some exceptions where the capture price does not reach the LCOE given in the appendix. First, some expanded resources hit a threshold. An example being the Finnish onshore wind power in the low nuclear P2X scenario in 2050, which hits the capacity ceiling of 60 GW and obtains a capture price of 49 €/MWh, instead of the listed LCOE at 31 €/MWh. Had it been allowed to expand further it would eventually have reached its LCOE, but that expansion has been deemed unlikely for other reasons as explained in Section 4.

Another exception is for resources that experience curtailment, which reduces their capacity factor compared with the value given in the appendix. This increases the LCOE of that resource, and the expansion instead stops at a level where the resource obtains the higher LCOE. An example is solar power in the low nuclear P2X scenario in 2050, where the capacity factor is decreased to about 7%, raising the LCOE to 38 €/MWh.

A final exception is rooftop solar power, which follows a different logic. Many private households install solar panels not strictly based on profitability. Also, the financial calculation is different for many microgenerators with schemes such as net-metering and behind the meter consumption. For this reason, the assumed level of solar roof-top installations typically results in revenues lower than the LCOE quoted in in Appendix 8.2. This occurs for all scenarios except the low nuclear in P2X for year 2050.

6 Discussion

Comparing the two demand scenarios Carbon Neutrality (CN) and Power to X (P2X), we can see two rather different stories unfold. In the CN scenario, the focus for Finland and Sweden is on domestic emissions and for example iron ore reduction and e-fuel productions are scaled back to mainly meat domestic demand of the two countries. While in the P2X scenario, the region seizes the opportunity of growth by increasing its production of clean products for export and thereby also decreases non-domestic CO_2 emissions.

Under this assumption, the inclusion of new nuclear capacity in Sweden and Finland is not strictly required to reach a reasonably robust system, although the inclusion of new nuclear power has the potential to lower the prices by about 10%. In CN scenarios, it is however highly important that the very ambitious onshore wind power expansion outlined in this report can continue uninterrupted. Should the expansion slow down for any reason, e.g., due to local opposition, the role of nuclear power becomes much more important also for the CN demand scenario.

In the P2X scenario on the other hand, allowing for new nuclear is a prerequisite. The low nuclear scenario shows considerably higher prices than the high nuclear scenario. The spread due to different weather years is also considerably higher, with negative consequences for any investor in energy intensive industries. All things taken together, the P2X scenario without new nuclear power cannot be seen as a credible path forward since the resulting price level is simply too high to attract the industries that make up the demand in the first place. An exclusion of new nuclear power would instead likely lead to a system more resembling the ambitions of the CN scenario.

Finally, it should be emphasised that the inclusion of new nuclear power in any scenario should not be seen as a relaxing condition for onshore wind power, which is still required to continue the transition at very high pace. Depending on the scenario, between 30 and 44 GW of onshore wind power is required in Sweden by 2050, often reaching the maximum capacity limits that were set in SE1 and SE2. In Finland between 20 and 60 GW are required. This furthermore highlights the importance onshore wind power expansions plays in a cost-effective future Finnish-Swedish power system.

At first sight, it might seem counter intuitive that the total system costs for scenarios with and without new nuclear power are so similar (c.f. Figure 27) yet lead to completely different price levels (c.f. Figure 28 and Figure 29). However, one should keep in mind that the system costs reported here are just the cost for building and maintaining the modelled power production in Sweden and Finland. With a much lower firm capacity in the low nuclear scenarios, the model relies to a larger degree on neighbouring countries for balancing the system. Since the weather correlates significantly over northern Europe, the likelihood that neighbouring regions are experiencing low wind and solar production at the same time as Sweden and Finland is high, resulting in price coupling at times of high prices. Had Sweden and Finland instead been modelled as an isolated region, with no imports and exports available, the balancing would need to have been done by local producers and storage systems The system cost for the low nuclear case would then have increased accordingly, when compared to the high nuclear case.

It should be emphasized here that unless the interconnectors to neighbouring regions are fully saturated, the spot prices will couple between bidding zones and the regions will experience the same price. The situation in the Nordics during the energy crisis in 2022 serves as a good example here. Even if e.g., Sweden was a net exporter to continental Europe, the prices in SE3 and SE4 were often coupled to those in for example Germany.

Finally, it can be mentioned that the more balanced systems obtained in the high nuclear scenarios also provide additional benefits due to its higher diversity of supply. A more diverse system will naturally be more robust to external shocks in different parts of the system. The sensitivity analysis using six weather years showed that a system with low nuclear has a much larger sensitivity to different weather years than the high nuclear case. Which would likely to be further emphasized if including more and for the energy system more severe weather years. This is owed to that these systems depend on imports of dispatchable firm capacity with high marginal costs as well as to a larger extent local peaker plants raising electricity prices.

7 Summary

Several future power systems have been explored for 2035 and 2050. Exploring different share of nuclear, from low to medium/high share, to meet the growing demand from two scenarios, a more modest denoted Carbon Neutrality (CN) and high demand growth scenario denoted Power to X (P2X). Evaluation of electricity prices, electricity price volatility and investment and operational costs of the different power systems, was performed with the aim to find the share of nuclear best realising a sustainable and competitive economy until 2050.

The power system optimization and capacity expansion resulted in the shares of generation for the Finnish-Swedish power systems compiled in Figure 30. In the power systems in the low nuclear share scenario, wind power annual generation starts to dominate already in 2035 with a share of 40% compared to nuclear and hydro both at around 23%. In 2050 wind power almost reaches half the share of the annual generation in Finland and Sweden. Utility and roof-top solar PV is becoming significant, especially in southern Sweden with a total model share of 10%. The inclusion of new nuclear results in a wind and nuclear power share of 35% and 30% in 2035, respectively. By 2050, the nuclear power share increases to level with wind power at 36% of the annual share, supporting a dinner plate model of power system generation in the Nordics. The increase in nuclear share is primarily driven by onshore wind reaching expansion limits in Sweden, but needs to increase transmission capacities, as well as the balancing power of hydro decreases with the larger demand, increases the relative value of nuclear energy to the system. Due to competing production profile with onshore wind power and the relatively higher investment costs for offshore compared, offshore wind power is only built in one scenario. Finally, based on the transmission capacity expansion, the line SE1-FI is reinforced in addition to a 2.8 GW typically reaching at least 3.6 GW.

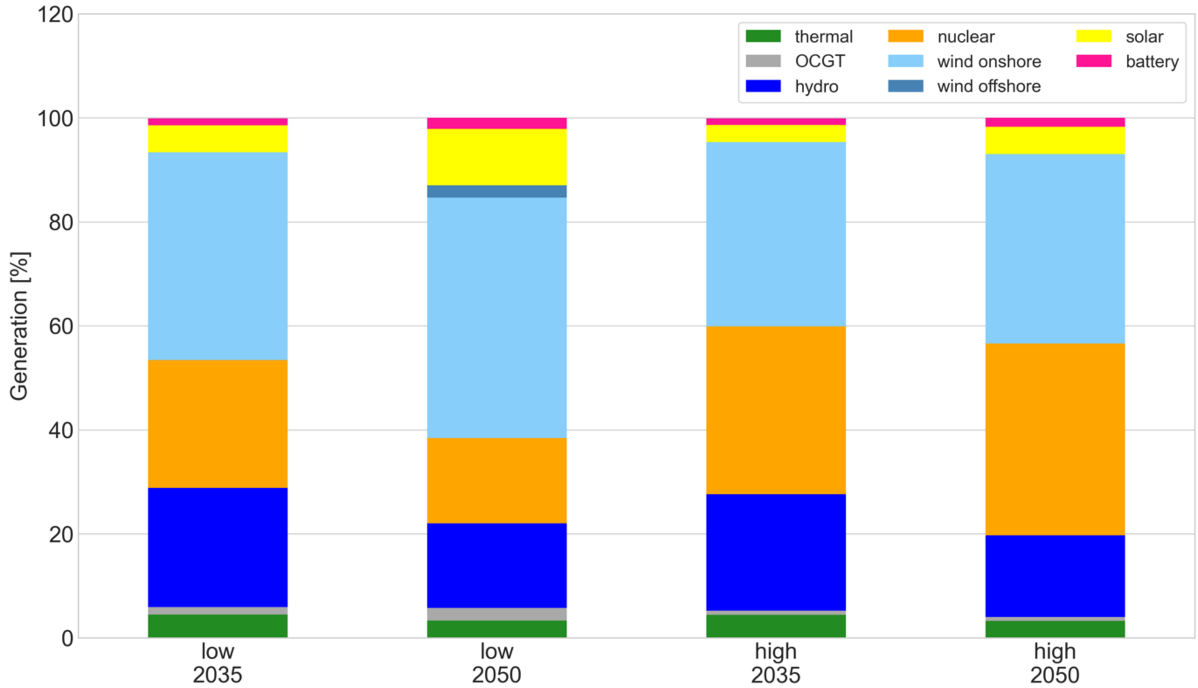

Figure 30. Average share of annual power generation by resource for the low and high nuclear share scenarios and in 2035 and 2050.

Table 15 aims to highlight the power systems' performance regarding sustainability and competitiveness between scenarios. It presents a summary comparing relevant results for the low nuclear share scenario (including only existing nuclear power) with the medium/high shares, which allow for the building of new nuclear power as demand grow. Reducing greenhouse gas emissions and mitigating land exploitation helps protect ecosystems, support food security, and promote resource efficiency, all of which are essential for achieving a more sustainable future. The use of critical raw materials, such as minerals, is also central to the transition to a more sustainable energy system[59]. However, the concentration of supplies in a small number of quasi-monopolistic countries, poses significant risks to the security of supply. Energy systems not as dependent on critical raw materials, promote both sustainability and economic competitiveness, while also safeguarding the security of supply and promoting democratic values. Quantified lifecycle greenhouse gas emissions, land use and use of critical minerals aim to probe how the power systems with different shares of nuclear energy perform with respect to these matters.

The following lists the main take-aways of this study:

- When introducing new nuclear in the Finnish-Swedish power systems the electricity prices are considerably lower in 2035 despite the modest expansion of new nuclear until then. By 2050 the differences become significant, to the extent where the credibility of a high demand growth with no new nuclear may be questioned. Thus, new nuclear combined with a strong expansion of wind power provide direct advantages to competitiveness in the Nordics.
- Electricity price volatility is similar compared to historical average for the Finnish-Swedish power system. By 2050, the power systems in the low nuclear share scenarios show a significant increase in sensitivity to varying weather and commodity prices further implying higher risks associated with investments for producers and consumers. With new nuclear energy, the Finnish-Swedish power system becomes more robust to changes in external factors creating more stable market conditions opening for more investments.
- With regards to security of supply, two aspects indicate an increased sensitivity in the low nuclear share scenarios (i) increased dependency of typically fossil-fuelled high marginal cost dispatchable capacity outside Finland and Sweden through import as well as local peaking plant fuel consumption, and (ii) increased dependency on critical minerals. With a more diverse energy supply, the medium/high nuclear share scenarios paint a picture of a more robust Finnish-Swedish power system.
- Total system costs for the Finnish-Swedish power system are similar between all the different nuclear share scenarios. As the expansion of onshore wind reaches its maximum capacity limit in one or more zones for all scenarios, total system costs will increase for all scenarios if less onshore wind would be built.
- Values of greenhouse gas emissions, land use and use of critical minerals, show that larger shares of nuclear energy results in more sustainable power systems. The increased greenhouse gas emissions in the low nuclear share scenarios are primarily driven by higher fuel consumption in peaker plants needed during unfavourable weather conditions, while larger use of land and critical minerals is driven by increasing shares of both onshore wind and solar.

[59] European Commission (2023), Critical Raw Materials: ensuring secure and sustainable supply chains for EU's green and digital future.

Table 15. Summarised results comparing main parameters of the power systems with low share of nuclear, including only existing nuclear power, to those with high which includes existing and new nuclear power.

Parameter	Year	Nuclear share	
		Low (existing nuclear)	High (+new nuclear)
Electricity price level (median)	2035	62 €/MWh	57 €/MWh
	2050	72 €/MWh	52 €/MWh
Electricity price volatility compared to historic average[60]	2035	Similar	
	2050	Higher	Similar
Security of supply		Increased sensitivity	More robust
Annual system cost (B€)[61]	2035	14	14
	2050	19	19
Life-cycle greenhouse gas emissions (gCO_2/kWh)[62]	2035	16-23	14-17
	2050	20-31	14-17
Land use (km^2)[63]	2035	1900	1600
	2050	3600	2300
Use of critical minerals (Mt)[64]	2035	0.7	0.6
	2050	1.4	1.0

[60] Excluding the extremes during the acute phase of the energy-crises of 2022.

[61] See also Section 5.

[62] Based on Life Cycle Assessment for Vattenfall's electricity for hydro, onshore wind, solar, nuclear and biothermal energy sources. Peaker plant values stem from UNECE (2018), Life Cycle Assessment of Electricity Generation Options assuming the use of natural gas as fuel. The lower and upper value is the result of peaker plant values based on CCGT with CCS and OCGT with no CCS, respectively.

[63] Based on National Renewable Energy Laboratory (2009), Land-Use Requirements of Modern Wind Power Plants in the United States for onshore wind and UNECE (2022), Integrated Life-cycle Assessment of Electricity Sources for utility solar.

[64] Based on IEA (2022), The role of critical minerals in the clean energy transition only considering energy generation sources and not, for instance, the electricity grid.

8 Appendix

8.1 Key issues in the Nordic electricity system

Balancing security of supply, affordability, and sustainability in an evolving electricity system

The energy and electricity system are undergoing significant transformations driven by global concerns over climate change, technological advancements, evolving consumer demands and a new set of priorities, where security of supply has quickly risen as the top concern of many decision-makers. This section explores the dynamic landscape of the electricity system, highlighting the importance of achieving equilibrium among these key pillars to foster a resilient, economically viable and environmentally friendly energy and electricity system.

Figure 31. The Energy Trilemma of security of supply, affordability, and sustainability.

Balancing supply and demand

The increase in weather-dependent, zero marginal cost generators coupled with the need for substantial expansion in both electricity generation and demand is intensifying the need for balancing supply and demand in the electricity system. These issues have many aspects to it:

Insufficient demand-side flexibility

The focus on renewable energy has made the supply side more variable while less development has happened so-far on the demand side flexibility. Flexibility can be voluntary, market-based or forced. In most contexts, demand-side flexibility is better understood as long-term demand side management, distinct from flexibility as an ancillary service used to balance the grid under abnormal operating conditions.

Flexibility is a resource which costs money

The optimal solution lies between an extreme absence and an excess of flexibility. Flexibility, as a resource enabling consumers to capture lower average prices, comes with the trade-off of increased infrastructure investments. The cost of flexibility varies depending on the scale, with homeowners requiring minimal investment (e.g., through mobile apps for electric vehicle charging), while large industrial consumers face significant costs in overinvesting in infrastructure.

The role of a strong, robust grid

Leveraging demand-side flexibility on a large scale necessitates a robust power grid capable of accommodating substantial power fluctuations throughout the Nordic grid. However, the introduction of numerous control circuits and independent flexible actors must be executed meticulously to avoid potential complications that could hinder the full realization of consumer flexibility and lead to grid instability.

For large industrial consumers (or aggregate functions for many small-scale consumers) are going to be able to realise their full potential, hypothetically regulating consumption by several hundreds or thousands of MW, the grid must be able to handle massive movements of power that can be circulating around the entire Nordic power grid. This is a massive challenge that must not be underestimated.

The introduction of large amounts of control circuits and independent flexible actors can be compared to surgically fixating a broken leg. If not done correctly, consumers which depend on their flexibility for their business model may find themselves forbidden to decrease or increase consumption – potentially 'stuck' on the grid with very high prices, or unable to refill depleted storages – as the grid is not able to handle it.

Electrification opportunities and flexibility

The ongoing electrification of industries in the Nordics presents an opportunity to enhance grid flexibility. Hydrogen, for example, can serve as a storage medium, dynamically adjusting consumption levels based on the grid's conditions. This flexibility also stimulates further expansion of new generation by increasing prices during periods of very low prices.

The need for a new electricity market structure

The liberalization of the energy market in the Nordic countries marked a significant shift in the regulation of electricity supply. It began with Norway in 1991 and was followed by the gradual deregulation of national generation and marketing of electricity in the region. Sweden joined the common Nordic power market in 1996, Finland in 1998, and Western and Eastern Denmark in 1999 and 2000, respectively. Iceland later integrated its electricity sector into the common Nordic power market in 2006. This progressive deregulation and market integration across national borders transformed the historically regulated Nordic electricity supply landscape.
This deregulation has fulfilled its intended purpose, efficient dispatch of generators in the short-term market and the streamlining of previous overcapacity in generation. Today, however, there is need for more generation of all kinds and especially dispatchable generation. In the deregulated market, very little generation has been built overall without some type of subsidy or incentive. This holds especially true for dispatchable generation, where the capacity of dispatchable generation in Nordics has instead decreased. The phase-out of fossil-based thermal power plants in Finland is an essential part of the energy transition but also challenging as these provide important heat demand following

supply as well as all-year available dispatchable supply.
It is becoming increasingly apparent that the current electricity ‘energy only’ market is not designed to facilitate a smooth clean energy transition while also balancing security of supply and affordability. The current electricity market design must be supplemented for a better balance between all three aspects of the Energy Trilemma.

Resolving conflicts of interest and speeding up permitting processes.

As long approval processes and extensive conflicts of interest may hinder society’s ability to build enough infrastructure to manage the clean energy transition. This is equally important both on the demand and supply side, as investors in new generation depend on timely permitting processes of new industries, and vice versa. Public acceptance of large-scale energy infrastructure remains a significant concern that may intensify as renewable electricity generation and grid infrastructure become more prevalent in the landscape.

Volatile prices

The combination of high costs associated with fossil-based power and the increasing share of low marginal cost variable renewables has resulted in highly volatile electricity prices. Such price volatility escalates risks for all stakeholders, making the entire system more costly. Furthermore, electricity price risk is highly asymmetrical, with prices seldom falling below zero but theoretically capable of soaring infinitely high due to continuously adjusted price caps. This necessitates increased securities in power trading, causing cash flow challenges for power system participants. Extremely high power prices can also lead to financial distress within a short period, as evidenced by the unprecedented rise in electricity costs during the winter storm Uri in Texas. In fact, the total revenue from electricity consumption during the first two months of 2021, including the storm Uri, surpassed the cumulative revenue from 2018 to 2020. To stabilize prices, it is imperative to prioritize firm baseload capacity, long-term energy storage, and a more flexible demand side.

Lack of electric grid infrastructure and connection capacity

For a long time the focus of the system has been to add more MWh, more energy, into the system. This has successfully increased the amount of electricity generated, but this approach has also brought forth challenges related to maintaining transmission capacity and facilitating the connection of new generation and consumption. Insufficient grid infrastructure and connection capacity for both generators and consumers hinder the efficient expansion and integration of these elements into the system.

Lack of long-term energy storage

The absence of sustainable and large-scale energy storage poses challenges in effectively balancing peak electricity demand during periods of unfavourable weather conditions (known as "Dunkelflaute") and in meeting the daily requirements of supply and demand. The lack of long-term energy storage also impacts prices, with the risk of low or negative prices during periods of low load and limited sunshine, even in the near term.

Increased weather dependence

The significant variations in weather conditions pose challenges to electricity production from weather-dependent renewable sources. For instance, Germany experienced a prolonged period of reduced wind conditions in the first half of 2021, resulting in a nearly 25% decrease in wind production, significantly higher wholesale electricity prices, increased coal consumption, and a rise in emissions compared to the same period in 2020. Similarly, many regions in Sweden witnessed fewer than five hours of sunlight during the first half of December 2020. As weather patterns impact renewable energy generation across several countries, the increased weather dependence must be accounted for, including potential dry years or extreme hot/cold conditions.

High supply dependencies and disconnection from Russian energy supply.
The pursuit of a clean energy transition carries the risk of developing new supply dependencies. Phasing out existing dependencies, such as the displacement of piped Russian gas supply with more expensive shipped LNG, affects the electricity market, as gas power often sets the price in the spot market. Historical electricity imports from Russia have provided firming effects, particularly during periods when Nordic hydro power faced lower inflows. This is also true for new materials required for the clean energy transition.

Labour shortages
The clean energy transition requires a skilled workforce across various sectors. Shortages of key competencies, including electricians, construction workers proficient in welding and concrete casting, and skilled project managers, are anticipated due to the demand for these skills in construction projects ranging from transmission infrastructure to transport infrastructure, industrial facilities, and new generation capacities.

Technology neutrality
Technology neutrality is a valuable policy approach that aims to treat different generation technologies fairly, considering their individual strengths and weaknesses. However, it is important to strike a balance and avoid excessive application of technology neutrality. For instance, offshore wind presents specific challenges that differ from onshore wind. Implementing an auction system or a similar mechanism could expedite the deployment of offshore wind, reducing uncertainty for investors and promoting its growth.

8.2 Input assumptions

8.2.1 Investment and operational cost assumptions

Table 16. Investment and operational cost input assumptions

All costs as real currency 2019	Onshore Wind	Offshore Wind	Solar PV[65]	Nuclear	Battery storage	Gas OCGT
Discount rate (%)	6	6	6	6	6	6
Overnight cost [EUR/kW]	870	1800	410 & 330	3600	280	630
Overnight cost [EUR/kWh]	0	0	0	0	55	0
Build time [years]	2	2	1	5	1	2
Fixed OPEX [EUR/kW/yr]	21	25	3.8	68	3.1	180
Variable OPEX [EUR/MWh]	0	0	0	11.5	0	170
Capacity factor [%]	36	44	9	91	0	5
Lifetime [years]	25	25	30	60	15	30
LCOE [EUR/MWh]	31	48	45 & 37	57	-	320

[65] Values represent costs for 2035 and 2050, respectively. Lower costs in 2050 stem from an implemented learning rate of 7% and an assumed ten times buildout.

8.2.2 Existing installed generation capacities

Table 17. Input assumptions regarding existing installed capacity resources. If not indicated, assumptions are identical for 2035 and 2050.

Resource	Zone	Existing capacities [MW]		Fixed OPEX [EUR/kWyr]	Nominal total generation [TWh][66]	Comment
Year		2035	2050			
Nuclear	SE3	6900		120	-	Reactors $F_{1,2\&3}$,$R_{3\&4}$ and O_3
	FI	4400	3400			Reactors $OL_{1,2,\&3}$. $Loviisa_{1\&2}$ only in 2035.
Thermal	SE1	35		67	0.2	Must run according to average yearly profile
	SE2	160			0.9	
	SE3	930			4.8	
	SE4	270			1.2	
Thermal bio	FI	1100			8	Must run according to average yearly profile with dispatchable part
Hydro	SE1	4600		45	20	Hydro reservoir dispatchable with target generation
	SE2	6700			41	
	SE3	2300			9.7	Must run according to weather-year profile with dispatchable part
	SE4	240			1.2	
	FI	2400			13	

[66] Based on weather year 2013. For hydro reservoir power, this further corresponds to target generation.

8.2.3 Demand scenarios

Table 18. Annual demand (TWh) per category for the two demand scenarios and studied years.

Bidding zone / country and demand category	Carbon Neutrality (CN)		Power to X (P2X)	
	2035	2050	2035	2050
FI / Finland	112	134	143	223
Electric vehicles	4	9	4	9
Electrolysis	10	17	28	86
Heating	18	18	18	18
Industry excl. electrolysis	52	60	61	70
Other and losses	28	30	32	40
Sweden	189	243	223	330
Electric vehicles	13	24	13	24
Electrolysis	28	48	46	117
Heating	33	32	33	32
Industry excl. electrolysis	63	76	79	94
Other and losses	52	63	52	63
SE1	39	61	52	111
Electric vehicles	1	1	1	1
Electrolysis	20	31	30	77
Heating	2	2	2	2
Industry excl. electrolysis	10	15	13	19
Other and losses	6	12	6	12
SE2	23	33	27	46
Electric vehicles	1	2	1	2
Electrolysis	2	8	3	16
Heating	4	4	4	4
Industry excl. electrolysis	11	13	15	18
Other and losses	4	6	4	6
SE3	98	116	113	137
Electric vehicles	9	16	9	16
Electrolysis	4	8	10	20
Heating	20	20	20	20
Industry excl. electrolysis	33	37	41	47
Other and losses	32	35	32	35
SE4	28	32	31	36
Electric vehicles	3	5	3	5
Electrolysis	1	2	3	4
Heating	6	6	6	6
Industry excl. electrolysis	9	10	10	11
Other and losses	9	10	9	10

8.3 Additional results

Table 19. Results from the capacity expansion in the model year 2035. Swedish numbers are summed over the four bidding zones. Solar rooftop and existing nuclear are not included in the expansion but are also shown for reference. All numbers are given in GW.

	CN 2035 (FI)		P2X 2035 (FI)		
Nuclear share	High	Low	High	Medium	Low
Solar rooftop	3.5	3.5	3.5	3.5	3.5
Solar utility	-	-	-	3.3	5.8
Wind onshore	16.7	19.5	23.4	30.0	31.8
Nuclear existing	4.4	4.4	4.4	4.4	4.4
Nuclear new	1.2	-	3	1.0	-
OCGT	1.8	2.6	3.1	4.4	5.0
	CN 2035 (SE)		**P2X 2035 (SE)**		
Nuclear share	High	Low	High	Medium	Low
Solar rooftop	7	7	7	7	7
Solar utility	0.7	1.9	4.2	9.3	13.1
Wind onshore	24	24.8	24.8	24.8	25.1
Nuclear existing	6.9	6.9	6.9	6.9	6.9
Nuclear new	0.5	-	2.4	1.0	-
OCGT	1.7	1.9	1.8	2.8	3.5

Table 20. Results from the capacity expansion in the model year 2050. Swedish numbers are summed over the four bidding zones. Solar rooftop and existing nuclear are not included in the expansion but are also shown for reference. All numbers are given in GW.

	CN 2050 (FI)		P2X 2050 (FI)		
Nuclear share	High	Low	High	Medium	Low
Solar rooftop	7.4	7.4	7.4	7.4	7.4
Solar utility	-	-	-	1.7	19.4
Wind onshore	18.9	24.6	37.8	54.9	60
Nuclear existing	3.4	3.4	3.4	3.4	3.4
Nuclear new	2.0	-	9.2	4.6	-
OCGT	3.3	4.6	2.2	3.8	5.0
	CN 2050 (SE)		**P2X 2050 (SE)**		
Nuclear share	High	Low	High	Medium	Low
Solar rooftop	15.0	15.0	15.0	15.0	15.0
Solar utility	7.8	19.9	2.8	26.6	48.8
Wind onshore	34.8	37.6	35.7	44.1	44.1

Wind offshore	-	-	-	-	8.1
Nuclear existing	6.9	3.4	6.9	6.9	6.9
Nuclear new	2.4	-	13.7	6.9	-
OCGT	3.2	4.7	-	2	6

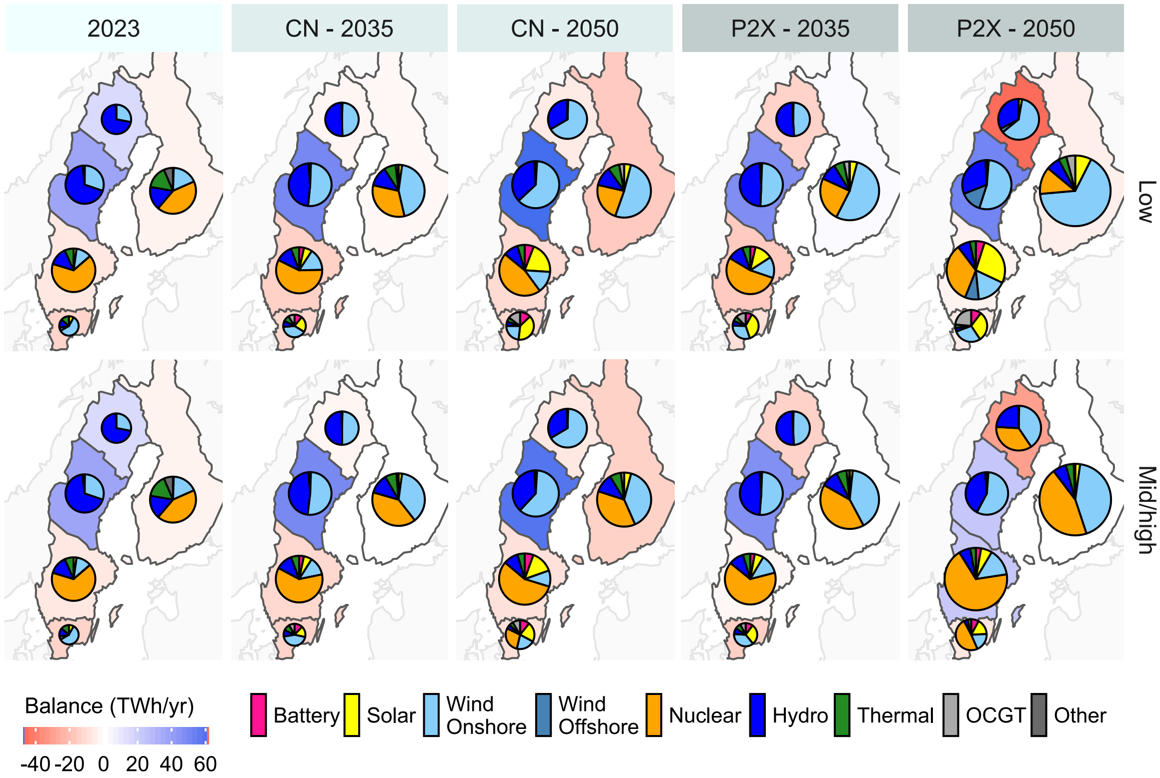

Figure 32. Share of annual power generation by resource and zone for the low (upper row) and Mid/high and high (lower row) nuclear share scenarios, for current system modelled as of 2023 (first column) and future years in 2035 and 2050 for the two demand scenarios Carbon Neutrality (CN) and Power to X (P2X). Zones are colored according to their annual net generation.

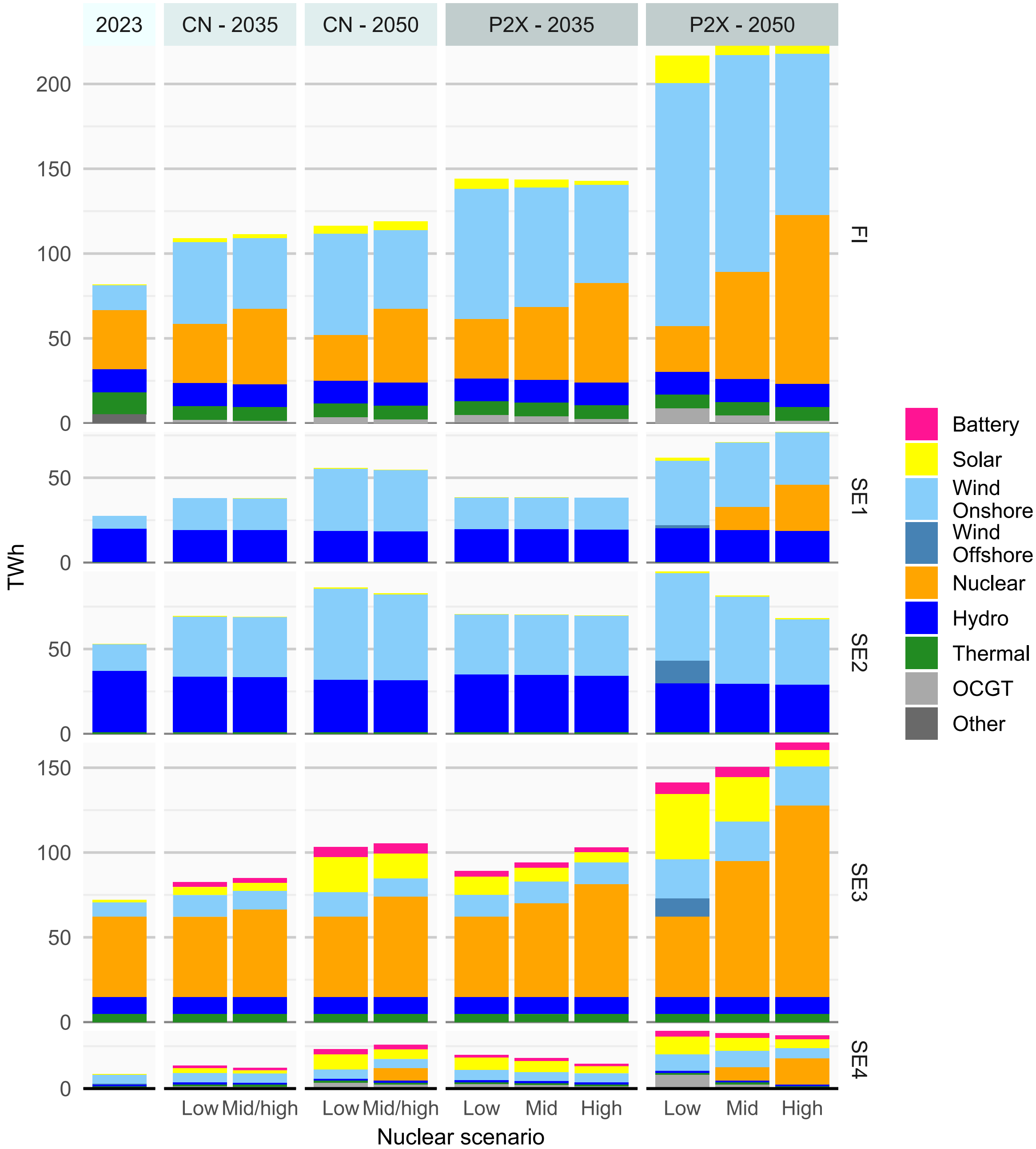

Figure 33. annual power generation by resource and zones (the rows) for the low, Mid, Mid/high and high nuclear share scenarios, for current system modelled as of 2023 (first column) and future years in 2035 and 2050 for the two demand scenarios Carbon Neutrality (CN) and Power to X (P2X)

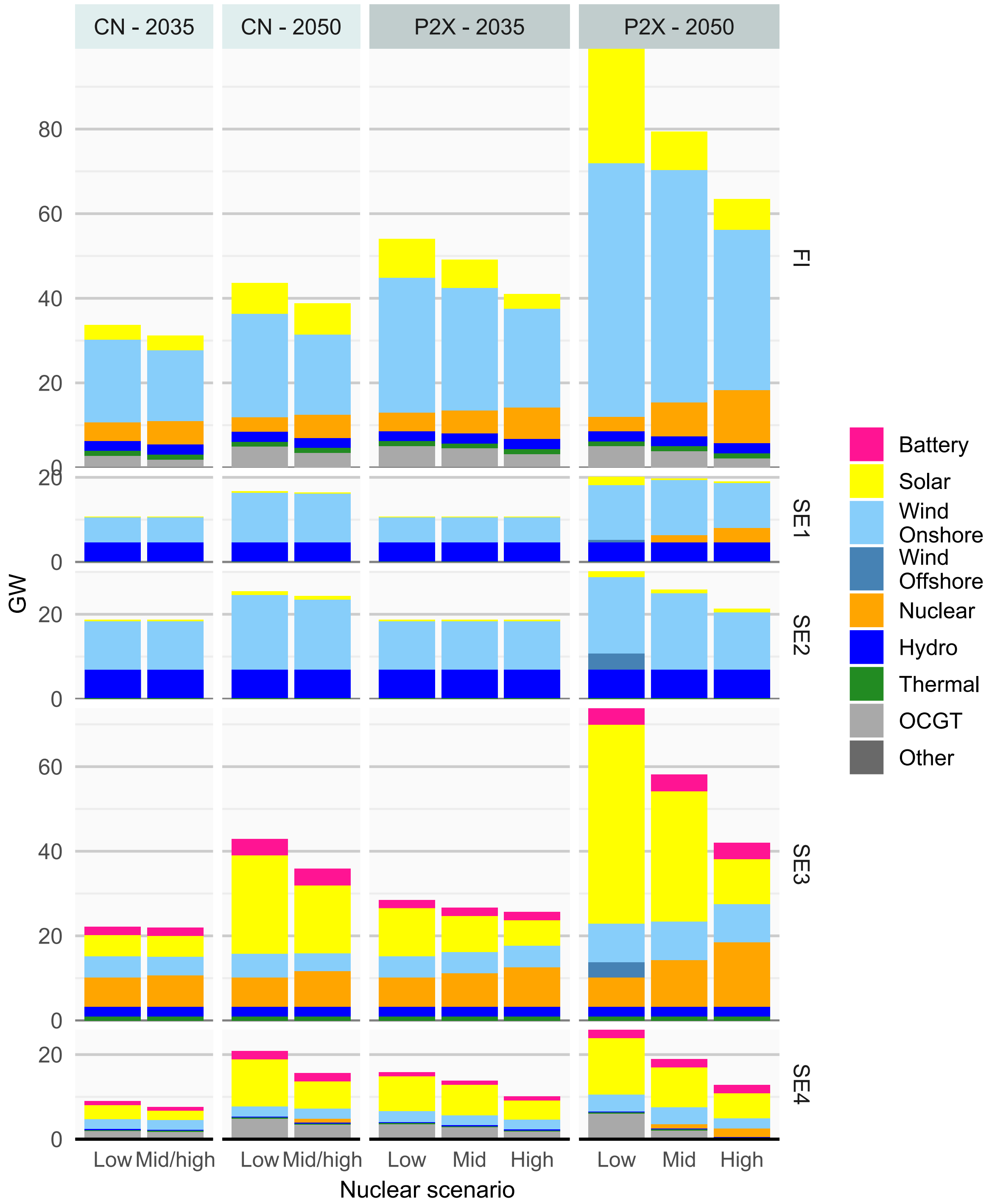

Figure 34. Installed generation capacity by resource and zones (the rows) for the low, Mid, Mid/high and high nuclear share scenarios, for current system modelled as of 2023 (first column) and future years in 2035 and 2050 for the two demand scenarios Carbon Neutrality (CN) and Power to X (P2X)

8.4 OptiL

OptiL is a new modelling tool for optimizing plants for hydrogen-based direct reduction of iron ore. The tool dimensions & optimizes electrolysers, hydrogen storages, compressors, turbo-expanders, heat exchangers, hydrogen turbines, fuel cells and the energy balance over the entire system from pelletization to finished sponge iron. The tool also recommends hour-by-hour operating strategy for all components over an arbitrary period of time (usually one year) as well as scheduling maintenance periods for individual parts of the system. OptiL consists of approximately 10,000 lines of Python/Pyomo code and requires about 500 externally defined input values & parameters for a run. For plant systems of a size limited to a level where operating decisions do not have a fundamental impact on electricity pricing, it is possible to find an optimized solution in under 10 minutes with free available solvers. The more advanced model versions that can also handle situations where the plants' decisions have a major impact on the electricity market require Gurobi version 9.5.0 or later as a solver.

Interested readers are referred to the most recent report from Svenskt Näringsliv[67].

[67] Svenskt Näringsliv (2022), Scenarioanalys 290 TWh.