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Article

Analysis of Severe Scarcity Situations in Finland's Low Carbon Electricity System Until 2030

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Abstract: This paper presents PLEXOS modelling of the Nordic and Baltic low-carbon electricity market until 2030, using a total of 35 different weather years' (1982–2016) ERAA profiles as inputs for the modelling and focusing on the occurrence of severe electricity scarcity situations in Finland, analyzing their duration and depth. The expected development of generation and demand is modelled based on available authoritative sources, such as ENTSO-E TYNDP and national projections. The present amount of nuclear power in Finland and growing amounts of wind and solar generation across the Nordic electricity system are modelled. This study analyzes scarcity situations by calculating residual loads and the expected electricity spot market prices assuming the different weather years with the generation fleet and demand in 2024 and 2030 scenarios. This study finds that, despite the very significantly growing amount of variable renewable generation (42.5 TWh/a increase in wind generation from 2024 to 2030 in Finland only), the frequency and severity of scarcity situations will increase from 2024 to 2030. The main reasons are the retirement of Combined Heat and Power plants and the transition to more electrified district heating in Finland and the expected demand growth. The findings indicate that without further measures Finland is not sufficiently prepared for cold winter periods with high heating and electricity demand and events of serious scarcity can occur.

Keywords: electricity market; electrification; Nordic area; peak demand; residual load; winter

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1. Introduction

Finland's official target of reaching carbon neutrality by the year 2035 is among the most ambitious in the EU [1,2]. Finland has already for a long time emphasized low-carbon electricity generation as one essential measure in carbon dioxide emission reductions. With the Olkiluoto 3 nuclear power plant of 1600 MW starting regular operation in 2023, Finland's nuclear generation capacity is 4300 MW. Currently, Finland is also among the most attractive countries in the EU regarding wind power construction. The current amount of wind power capacity is 8000 MW and in recent years it has already been built without any economic subsidies, i.e., in a fully market based manner. Simultaneously, utility-scale solar PV plant construction is experiencing a boom, even though economic subsidies for solar generation do not exist in Finland.

With its abundance of low-carbon electricity, Finland has been among the EU regions with the cheapest electricity market prices [3]. In July 2024, the electricity spot market price was the cheapest in the EU. Due to the declining electricity prices and rising prices of the EU Emissions Trading System (EU ETS) carbon dioxide allowances [4,5], Combined Heat and Power (CHP) plants in Finland's cities have lost much of their profitability. As a key measure to respond to the challenge of carbon neutrality, district heat companies are developing the utilization of excess heat streams with large-scale heat pumps and even electric boilers together with large heat storages.

Finland's record electricity consumption thus far, 15,100 MW, occurred in January 2016. Jääskeläinen et al. analyzed the capacity adequacy in such a situation and found that, back then, one large outage in either a power plant or in an international transmission line would not have caused a scarcity situation [6]. Galinis et al. [7] analyzed energy security in the Baltic countries and Finland with the TIMES model and found that interconnectors will be crucial for the energy security of the region when the EU ETS carbon dioxide prices increase. In addition, out of these countries, Finland was found to have the largest challenges in energy security in the 2030s. Both Finland and the Baltic countries have been for the past decades net importers of electricity [8–10]. However, there still exists a gap in analyzing in detail the most challenging wintertime situations in the Northern European electricity market. This is rapidly becoming more and more important with the ongoing closure of conventional capacity and electrification of society, including heating, transportation, and industry. Extreme weather has been identified as a major cause for energy supply disruptions in the literature [11], with "Dunkelflaute"-events, periods of sustained low wind and PV production, having received particular attention [12]. Recent modelling work has studied the impacts of reduced gas supply and cold winters at the European level and for Switzerland. The work also showed that Switzerland, with abundant hydro power reserves, could experience a shortage of electricity supply due to restricted natural gas availability for its neighbours [13]. Pollitt [14] analyzed the European energy crisis of 2021–2023. He also emphasized paying attention to the price impacts of climate policies and preparedness with proper and well-justified measures to maintain affordable energy prices for households and industries, instead of reactive and unnecessarily costly policy interventions.

During 2023–2024, Finland's nuclear power plants have experienced an unusually large number of unplanned outages, typically lasting a few weeks. The reasons have been various, such as increased moisture inside the turbine, individual malfunctional temperature measurement, or delays in scheduled maintenances. Together with the highly variable wind power production, this has made Finland's electricity market very volatile, with prices ranging from zero to 500 EUR/MWh or more, even outside the winter months. The first week of January 2024 was exceptionally cold both in Finland and in Sweden. During the week, several conventional power plants experienced problems such as malfunctioning fuel feeders. As a result, on Friday 5th January, Finland's spot price of electricity reached 2000 EUR/MWh and the system was estimated to be close to forced rotating outages.

Electricity demand is expected to grow in the near future both in Finland and in nearby regions. With the current trend of early closures of especially CHP capacity, it is important to analyze the development of capacity adequacy in the near future and also in the case of unexpected power plant outages. This contribution collects the most recent authoritative estimates of generation and demand development in the Nordic and Baltic electricity market and uses altogether 35 different weather years to quantify the foreseeable electricity market development, focusing on the generation adequacy issue in Finland's market area.

The main research questions of this contribution are as follows:

- What is the overall exposure to scarcity events in a 2024 system and a 2030 system in Finland?
- How often do these events occur?
- How severe are these events?

This paper responds to the research questions by first examining the distribution of residual loads, and then focusing on the occurrence of maximum price events which indicate a power deficit both in a present 2024 system and in a future 2030 system. These events are further examined by comparing the number of these events. Their severity is analyzed by examining the two-week sum of residual loads.

The paper is structured as follows: in Section 2, the materials and methods used in the study are presented. Section 3 presents the results, and in Section 4, the discussion and the main conclusions are presented.

2. Materials and Methods

In this study, a Nordic and Baltic power system model is used to identify electricity scarcity situations in Finland. The Nordic and Baltic power system is implemented in PLEXOS, version 9.2, a commercially used power system model.

2.1. PLEXOS

PLEXOS is an energy market simulation platform developed by Energy Exemplar Ltd. (Adelaide, Australia) [15]. PLEXOS minimizes the overall system costs by optimizing the dispatch of different resources. While it is possible to optimize investments also within PLEXOS, in this work, the Projected Assessment of System Adequacy (PASA), the medium-term (MT) and the short-term (ST) schedules are used.

The main advantage of PLEXOS is its high configurability and quick solution times due to the use of different solution schedules within the simulation engine. Therefore, it can solve even relatively complex systems with reasonable solution times.

While the PASA optimizes the maintenance schedules of thermal plants, it has been excluded in this work from nuclear power plants, as they have fixed maintenance schedules. For other thermal plants, their specific maintenance is optimized by PASA. The model, with maintenances scheduled either manually or by the PASA phase, are then passed onto the MT schedule. The MT schedule models the entire year with simplified details. MT simulates the year by first changing the data into load duration curves, which are further split into blocks. The number of blocks can be defined by the user, as well as whether the duration curves are calculated for days, weeks, months, or the whole year. In this work, the number of blocks was three, and the load duration curves are calculated for each day. Therefore, the MT schedule is simulating only 3 × 365 (or 366 during a leap year) periods, significantly reducing the computational complexity. However, the MT simulation results are then finally sent to the ST schedule. For example, the MT schedule sends certain targets for hydro storage levels, which should be met by the ST schedule at the end of each ST period.

ST Schedule is a mixed-integer programming-based chronological unit commitment and economic dispatch model. In this work, full chronology is used. ST Schedule has been configured to consist of 73 five-day periods in a normal year, and 61 six-day periods during a leap year. ST has been configured to an hourly interval within this work, but it is possible to have it set at, e.g., 5 min intervals. Therefore, each year has 8760 hourly intervals after the model has been run, or 8784 intervals if the year is a leap year.

In all the above steps, the model is run 35 times with 35 distinct samples, thus cycling through all the samples. These samples are data of the specific weather years, which is described more in Section 2.2.

A simplified objective function with main constraints representing the modelled system is presented below in Equation (1):

$$\begin{gathered} min \sum_{t=1}^{T} c_{elect.SRMC,t} + c_{heatSRMC,t} \\ st. \\ electricity\ balance \\ heat\ balance \\ hydro\ constraints \\ storage\ constraints \\ transmission\ constraints \end{gathered} \tag{1}$$

The MT and ST schedules of PLEXOS aim to minimize the sum of costs incurred from electricity and heat generation during the modelled year. These are represented by the short-run marginal costs (SRMC). These costs include the variable operation and maintenance costs, cost of startup and shut down, fuel costs, and emission costs. T is either 8760 h during a normal year, or 8784 h during a leap year. The main constraints within the model are the electricity and heat balance constraints, which mean that the hourly demand must be met either with generation or from storage. Hydro constraints relate to hydro dispatch, storage, and inflow constraints, while storage constraints relate to similar constraints present within electricity and heat storage. For example, a cycling storage was enforced within this model, meaning that all hydro reservoirs and other storages must have the same content at the end of the model as in the beginning of the modelling period. Finally, transmission constraints regulate the transmission of power between the nodes within the modelled system. It is also important to note that each of these optimizations is run separately and independently for each sample. Heat demand and production was modelled only in the Finnish node.

It is important to note that in this paper, the long-term schedule is not used. Therefore, investment costs have no impact on the objective function, and no capacity optimization was conducted.

2.2. The Modelled Power System

Even though this study focuses on Finland, it is important to model the entire Nordic power system to accurately analyze scarcity in the power system, due to the high interconnection between the Nordic and Baltic countries. The bidding zones of Finland, Estonia, Latvia, and Lithuania, as well as bidding zones SE1–SE4 in Sweden, NO1–NO5 in Norway and DK1 and DK2 in Denmark are modelled. The modelled power system with the labelled bidding areas is presented in Figure 1. Additionally, power may be exchanged with the external zones of Great Britain, Germany, the Netherlands, and Poland, but these external zones are not modelled, and only power trading with static exogenous prices is incorporated within these zones. To properly account for various weather conditions, 35 different weather years, ranging from 1982 to 2016, were used. In practice, this means that all scenarios are then run with the 35 different individual weather years, to account for varying weather phenomena that occur. Using existing weather data from such a long period is especially important in northern locations, where cold temperatures induce strongly growing electricity demand. In addition, in the study region of the Nordic and Baltic electricity system hydropower is an essential part of electricity generation and it varies strongly between years, depending on the amount of rainfall. Furthermore, wind conditions determine wind generation. These profiles were retrieved from the Pan-European-Climate-Database (PECD) and they were released as part of the European Resource Adequacy Assessment 2022. Demand and Variable climate data have been downloaded from the ENTSO-E ERAA webpage [16], while hydro data were downloaded from Zotero [17].

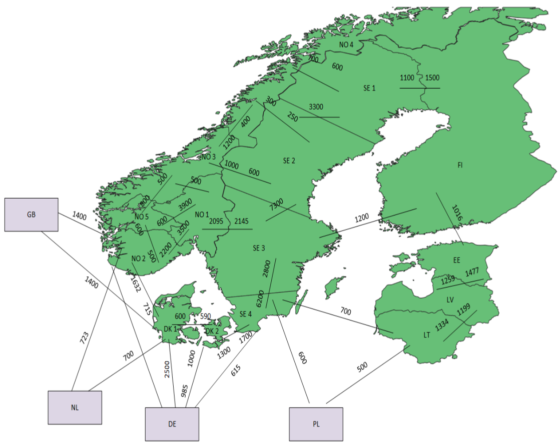


Figure 1. Figure showing the extent of the modelled electricity market regions in this model. External regions are shown as rectangles. Transmission lines in 2024 between regions are noted, with their transmission capacities reported in MW. For example, the maximum flow from SE1 to FI is 1500 MW, while from FI to SE1 it is 1100 MW. Symmetrical capacities are reported with one value. For example, between FI and EE, the maximum power flow is 1016 MW to either direction. Transmission capacities are according to ENTSO-E [18].

The modelled power system consists of two scenarios: a 2024 scenario, to represent the current system with respect to capacities, demand, and transmission connections, and a 2030 scenario, to represent a future system with the expected amount of variable and conventional generation capacities, demand and the new transmission connections, which are decided and scheduled to be built by 2030. For all regions, power generation and demand are modelled at an hourly level. Additionally, for Finland, the district heating (DH) production and consumption is modelled at an aggregated level. DH demand data have been retrieved from Helen, the DH company of Helsinki [19]. The generation capacities and demand assumptions are presented in Table 1 for 2024 and Table 2 for 2030. The current generation capacities have been estimated according to ENTSO-E [18], and for 2030 generation capacities, Final Supply Inputs After Public Consultation for 2024 TYNDP by ENTSO-E are used [20]. Transmission between nodes is calculated with net transfer capacities. Full capacity is always available for transmission between the nodes. The capacities are shown in Figure 1. In the 2030 scenario, additional lines are modelled. These capacities are shown in Table 3. Of note is the massive increase in variable renewable resources. PV generation is expected to increase almost tenfold and wind generation by threefold.

Table 1. Modelled capacities in 2024 (MW). Fossil capacities include coal, gas, oil and oil shale plants. The values are based on the ENTSO-E TYNDP work [20].

Bidding Area	Wind, Onshore	Wind, Offshore	PV	Hydro (PHS)	CHP	Nuclear	Fossil	DSM	Demand (TWh/a) [1]
FI	7238	-	1073	3200	4540	4394	-	1240	85
EE	503	-	812	-	-	-	2460	126	7.9
LV	180	-	303	1400	-	-	432	105	7
LT	1335	-	1174	110 (900)	-	-	745	190	12.6
SE1	3057	-	0	4500	-	-	-	167	11
SE2	7230	-	67	6500	-	-	-	248	15.9
SE3	4025	-	2017	1800	-	6987	120	1460	85.8
SE4	2424	-	702	280	-	-	662	385	22.6
NO1	400	-	104	3000	-	-	-	580	35.6
NO2	920	-	339	10,000	-	-	-	600	36.7
NO3	2425	-	76	3800	-	-	381	140	28.9
NO4	1108	-	0	5100	-	-	230	315	21.4
NO5	921	-	339	7000	-	-	328	277	17
DK1	4084	1278	3188	-	2419	-	-	365	22.9
DK2	958	1028	1179	-	1958	-	787	243	14.1

[1] Indicates the average electricity demand over all modelled weather years. Does not include electric boilers or heat pumps within district heating systems for Finland (3.3 TWh), which operate according to the model optimization.

The demand-side management (DSM) generators represent the demand response (DR) of the load. The amount of available demand response has been scaled to represent 10% of the average yearly maximum load. The DSM is also split into five different segments, with different prices. The first 20% is available at 200 EUR/MWh, with the following segments being available at 300 EUR/MWh, 400 EUR/MWh, 700 EUR/MWh, and finally the last 20% at 1000 EUR/MWh, respectively. If these generators are still not enough to cover the demand, a reserve generator is available at each node that will then supply electricity at a price of 3999 EUR/MWh, to represent the maximum possible price currently in use in Nord Pool that is currently 4000 EUR/MWh.

Table 2. Modelled capacities in 2030 (MW). Capacities are the same for the entire year. The values are based on the ENTSO-E TYNDP work [20].

Bidding Area	Wind, Onshore	Wind, Offshore	PV	Hydro (PHS)	CHP	Nuclear	Fossil	DSM	Demand (TWh/a) [1]
FI	25,992	-	10,695	3200	4150	4394	-	1689	106
EE	861	-	1160	-	-	-	2460	109	6.8
LV	365	-	146	1400	-	-	432	157	10.5
LT	5000	-	5000	110 (900)	-	-	745	274	18.1
SE1	3581	-	0	4500	-	-	-	173	11.4
SE2	8280	-	334	6500	-	-	-	307	19.9
SE3	3868	-	4852	1800	-	6987	120	1726	102.9
SE4	2223	-	2116	280	-	-	662	471	28.1
NO1	400	-	400	3000	-	-	-	728	45
NO2	920	-	1300	10,000	-	-	-	760	47
NO3	2425	-	1000	3800	-	-	381	454	32
NO4	1108	-	0	5100	-	-	230	370	25
NO5	921	-	1300	7000	-	-	328	40	21
DK1	6150	5093	12,859	-	2419	-	-	535	34
DK2	1155	4097	4885	-	1958	-	787	354	20.9

[1] Indicates the average electricity demand over all modelled weather years. Does not include electric boilers or heat pumps within district heating systems for Finland (9 TWh), which operate according to the model optimization.

Table 3. Modelled future transmission lines in the 2030 scenarios. Lines are operating from the 1st of January of the specified construction year. Max flow represents the flow according to the line name and min flow the flow opposite to the line name, e.g., from node FI to SE1 a maximum of 900 MW can be exported from Finland through line FI-SE1 FL1, but only 800 MW can be imported to Finland. These are gathered from national sources, such as the Finnish TSO Fingrid and the ENTSO-E TYNDP work [20].

Line Name	Max Flow MW	Min Flow MW	Year of Construction
EE-LV FL	1000	−1000	2030
FI-SE1 FL1	900	−800	2025
DK1-DE FL	1000	−1000	2025
DK2-DE FL	1200	−1200	2030
LT-PL FL	500	−1000	2025
NO5-GB FL	1400	−1400	2027
SE4-DE FL1	700	−700	2026

The modelled PV capacity developments for Finland are less than what is currently in the project planning stage. According to Motiva, there are 16,000 MW of PV projects under planning in Finland [21]. However, many of the planned projects can be expected to be realized only when electricity demand also increases considerably. TSO Fingrid's estimate is 10,000 MW of PV capacity by 2030, which is practically the same as in this study. Fingrid, the Transmission system operator (TSO) of Finland, released prospects for future electricity consumption in October 2024. Fingrid has estimated that electricity consumption in 2030 would be between 99 and 126 TWh/a, depending on the scenario. Additionally, Fingrid has estimated that wind power would generate 60 TWh/a, and solar PV 10 TWh/a in 2030 with projected capacities of 18.6 and 9.4 GW, respectively [22].

2.3. Evaluation of the Scarcity Events

To evaluate the severity of the scarcity situations, residual load in Finland is calculated and analyzed. The residual load is calculated by subtracting from the hourly electrical load the respective hourly wind and solar PV generation. Only electricity fed in the grid from these generators is considered, and any possible curtailment is ignored. Calculation of the hourly residual load is presented in Equation (2). The result is the hourly residual load in MW.

$$P_{residual\_load} = P_{load} - P_{PV} - P_{Wind\_Onshore} \tag{2}$$

The load in Equation (1) includes the electric load of heat pumps and electric boilers used in district heating. These loads are dynamically dispatched by the model and are price sensitive. Therefore, they are only added to the load when the price is moderately low and does not contribute to the exacerbation of scarcity events.

To further analyze the severity of the scarcity, the hourly price extracted from the model is also analyzed. High residual loads are not possibly an issue themselves, as the neighboured nodes can supply electricity to Finland. But an increase in the modelled price will indicate an approaching scarcity. To further inspect the sensitivity of the system to possible faults, a fault in the Olkiluoto 3 (OL3) nuclear power plant is simulated. The plant, located in Finland, is the largest single power generation unit in the Nordic power system with a nameplate capacity of 1600 MW. The fault is modelled as a one-month forced outage, and it is modelled separately for the winter months of either January, February, November or December. OL3 is in all scenarios in a scheduled maintenance from March to early April.

The scarcity events are inspected in the following ways:

- The minimum and maximum range as well as the average hourly residual load assuming individually all the weather years of 1982–2016 are analyzed to inspect the overall seasonal pattern within the distribution of the residual loads.
- The largest residual load from all the weather years from 1982 to 2016 within both the 2024 and 2030 scenarios is identified, and the day containing this load is plotted. Additionally, the price of that day and weather year is plotted, as well as the price were the OL3 nuclear power plant to malfunction during that day. The OL3 outage price is retrieved from the specific scenario, i.e., if the highest period is in January, the OL3 scenario where the forced outage is in January is used.
- To analyze longer patterns, ten two-week periods with the highest sum of residual loads are plotted. These periods are non-overlapping, and full-day periods are considered. These periods also have the prices plotted, with both the base case and the case with OL3 malfunctioning. The OL3 outage price is retrieved similarly again from the specific scenario as in the previous point.

To further evaluate the level of power scarcity, a deficit margin is calculated for the periods with high residual loads. This deficit margin shows how much demand response is available, and in case of reserve deployment, it shows negative values. This type of representation has been chosen since the reserve deployment already indicates an acute power deficit within the system, which would lead to other measures, including load shedding. The hourly DSM and reserve generation values are retrieved from the model results, and the deficit margin has been calculated from these values in the following way:

- The dispatched DSM generation is deducted from the total DSM capacity. If no DSM is dispatched, then the deficit margin equals to the DSM capacity.
- If all DSM capacity has been dispatched, then a negative value of the dispatched reserve capacity is displayed as the deficit margin.

3. Results

In the following, the main results of the analysis are presented, and the most severe situations are shown in detail. In addition, the main indicators describing the outcomes from the whole data set are presented.

3.1. Overview of the Residual Load Distribution in 2024 and 2030 Scenarios

Figure 2a shows the range of residual loads in the 2024 system, with the different capacities from Figure 1 and Table 1 highlighted. The firm generation capacity is 11.5 GW (the firm generation capacity includes only 2.6 GW of hydro capacity, as this is the maximum assumed rated capacity of the hydropower in Finland), while total transmission line import capacity is 3.7 GW and demand-side management capacity is 1.2 GW. Figure 2b shows the same values for the 2030 system, with firm generation capacity being 11.1 GW, transmission line import capacity being 4.5 GW, and demand-side management capacity being 1.6 GW. As can be seen from the figures, the residual load is the highest in January and February, while being lowest during summer. Therefore, the most severe scarcity situations occur during the beginning of the year. In the 2024 scenario, the scarcity situation is much more manageable than in the 2030 scenario. While the average residual load decreases in the 2030 scenarios compared to the 2024 scenarios, the range between minimum and maximum values during the 35 weather years increases. In the 2024 scenario, residual loads do not exceed even the theoretical import capacity of electricity. In the 2030 scenario, however, even the maximum theoretical power output capacity is approached. It is important to note that these capacities are the theoretical maximum capacities. In the model, it may be possible that not all imports are possible due to power being exported to other regions. In any case, the situation in the 2030 scenario looks dire if the system is in some weather years already so close to even the theoretical upper limit of power dispatch, including the assumed DSM capacity. The average annual generations of different generation technologies are outlined in Table 4. The solar PV and wind generation is expected to increase significantly from 2024 to 2030.

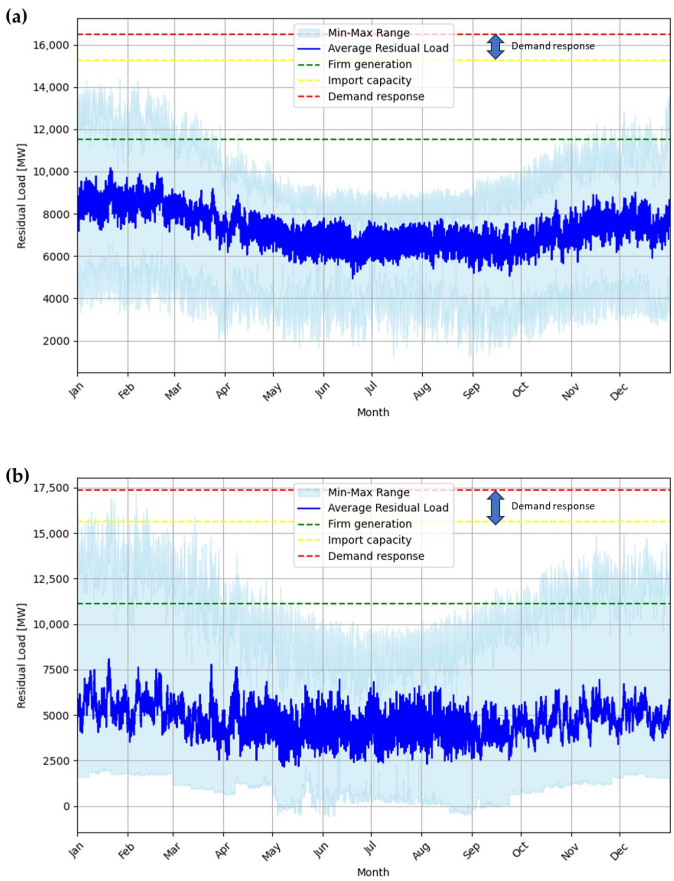


Figure 2. Residual load in 2024 (**a**) and 2030 (**b**), with the theoretical maximum cumulative capacity of different generation capacities highlighted. The figure shows the hourly minimum, maximum, and average residual load of the 35 different weather years. The lines indicate what type of generation must be dispatched. For example, if the residual load is above the green line, then some power must be net imported, and if the yellow line is crossed, then some amount of demand response must be dispatched. Crossing the red line would mean load shedding or other similar measures, even if all available capacity were available. The available demand response is between the import capacity (yellow dashed line) and demand response (red dashed line).

To analyze the actual scarcity within the samples, we will next analyze the time periods with the highest sums of residual loads and plot the prices from the model to show what is occurring within the model at these times.

Table 4. Average annual electricity generation from different technologies in Finland in both the 2024 and 2030 scenarios. Values are rounded to nearest GWh.

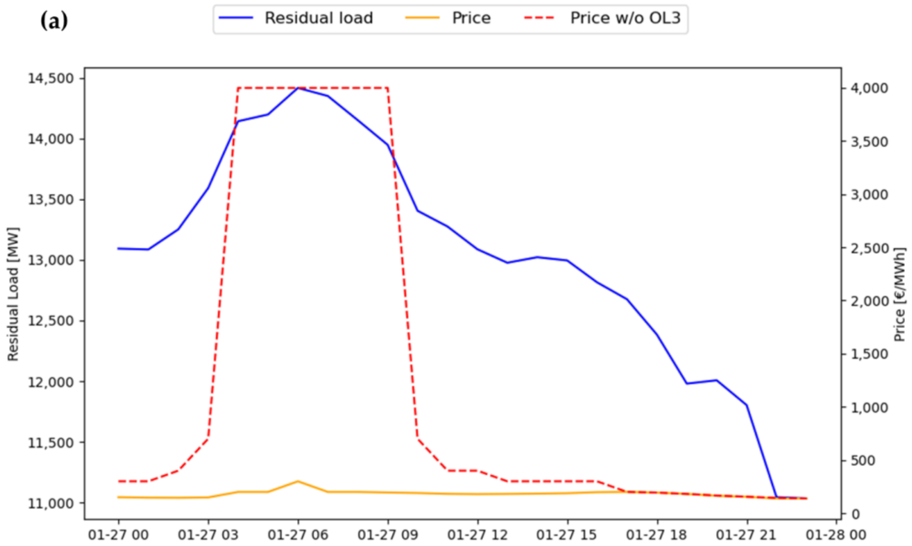
Technology	Electricity Generation (GWh/a)	
	2024	**2030**
Nuclear	33,549	31,504
Solar	1000	9987
Wind Onshore	22,165	64,721
Hydro	13,998	13,840
CHP	15,656	13,749
Reserves	0	1
DSM	4	26

3.2. Analysis of the Most Severe Scarcity Situations

The most severe single scarcity situations during all the 35 individual weather years are presented in Figure 3a,b. In Figure 3a, scarcity is shown during the 2024 scenario. The highest residual load is 14.4 GW at 6 a.m. on the 27th of January when assuming the weather year 1985. From this figure, even in the highest scarcity situation, the price remains at a stable level if everything is working as intended. However, if the OL3 nuclear plant were unavailable at this time, there would be a scarcity event lasting around 7 h. This is indicated by the price reaching the 3999 EUR/MWh level, which implies the need for rotating outages. In Figure 3b, the situation is different. The maximum residual load is 17.2 GW on the 6th of February at 6 a.m., during the weather year 2007. Here, however, a scarcity event would occur even with all capacity being available, while a fault in OL3 plant would exacerbate the situation further. As is evident from Figure 3, the absolute amount of residual load cannot be directly used to indicate an ongoing scarcity event. For example, during the afternoon of the maximum residual load day in the 2030 scenario, the price still reaches the maximum price of 3999 EUR/MWh, even with the residual load being around 1 GW smaller than during the morning. This highlights the importance of running a multi-node model, as the generation balance in the other regions is also affecting the status in the Finnish market node. Additionally, this might indicate that the scarcity event is very alarming, with the generation inadequacy being more than 1 GW.

Increasing wind power deployment affects the type of scarcity situations that are encountered. For example, in the 2024 scenario, the day in 1985 was very cold even in southern Finland, so the scarcity is especially due to high demand. In Helsinki, during 26 and 27 January 1985, the average temperature in Helsinki was −26.5 and minimum ground temperature was below −30 degrees Celsius. The 6 February 2007 was not, on the other hand, especially cold, with the temperature being −17 to −18 degrees Celsius (These temperature data were from the Finnish Meteorological institute using the temperature data from Helsinki Kaisaniemi weather station [23]).

However, at this time, the simulated wind power production was especially low, around 800–900 MW for 7 consecutive hours, while in the 2024 system during the maximum residual load period, wind generation was also around 700–900 MW. However, the wind capacity in 2030 is over three times larger. Therefore, the occurrence of low-wind periods can have a large impact on system resiliency even if the gross electricity demand has not yet peaked.



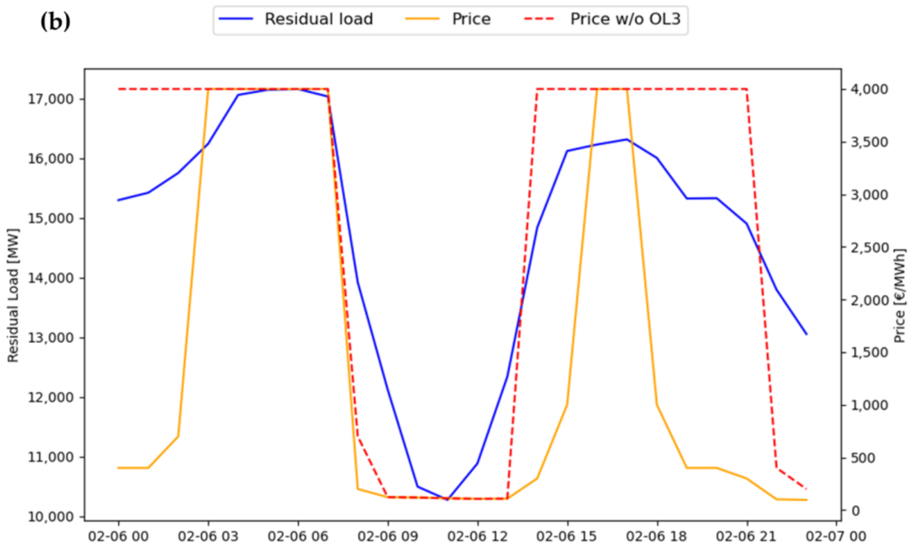


Figure 3. The day that includes the largest residual load of (**a**) 14.4 GW in the 2024 scenario and (**b**) 17.2 GW in the 2030 scenario out of the 35 individual weather years. The residual load is shown in blue, with the price in the base scenario shown in yellow, and the dashed red line showing the price when OL3 is not operational. Notice the different y-axes. The residual load is on the left while the price is shown on the right. The price level of 3999 EUR/MWh indicates a scarcity situation. The x-axis shows the day in the format month-day-hour. The maximum residual load in 2024 scenario is in the weather year 1985, while for 2030 the weather year with the maximum residual load is 2007.

3.3. Analysis of the Top 10 Two-Week Scarcity Periods

Figures 4 and 5 represent the top 10 two-week scarcity periods in 2024 and 2030, respectively. Deficit margins for these periods are shown in Figures A1 and A2. Values in Table 5, which represent the number of hours when the maximum area price is reached in Finland, supplement these figures. The first observation that can be made is that between the results of 2024 and 2030, different weather years emerge as the most difficult. This is most likely due to the larger impact of wind power in the 2030 scenario than in the 2024 scenario. Secondly, in the 2024 scenario without any OL3 faults, there is no power scarcity present in the system. This is not the case with faults in OL3. In 2030, however, there are scarcity events even with OL3 being available. Faults in OL3 exacerbate the issues, as can be expected. From the deficit margin figures, the severity of the missing power can be discerned. In the 2024 scenarios (Figures 4 and A1), the most severe instance is the event

Figures 4 and A1i, where the power deficit is around 1 GW if OL3 is not operational. The power deficits are much greater in the 2030 scenarios. This can be seen by comparing event Figures 5 and A2h in the 2030 scenario with event Figures 4 and A1i in the 2024 scenario. These occur at the same time, but the power deficit is much higher in the 2030 scenario, reaching nearly 3 GW.

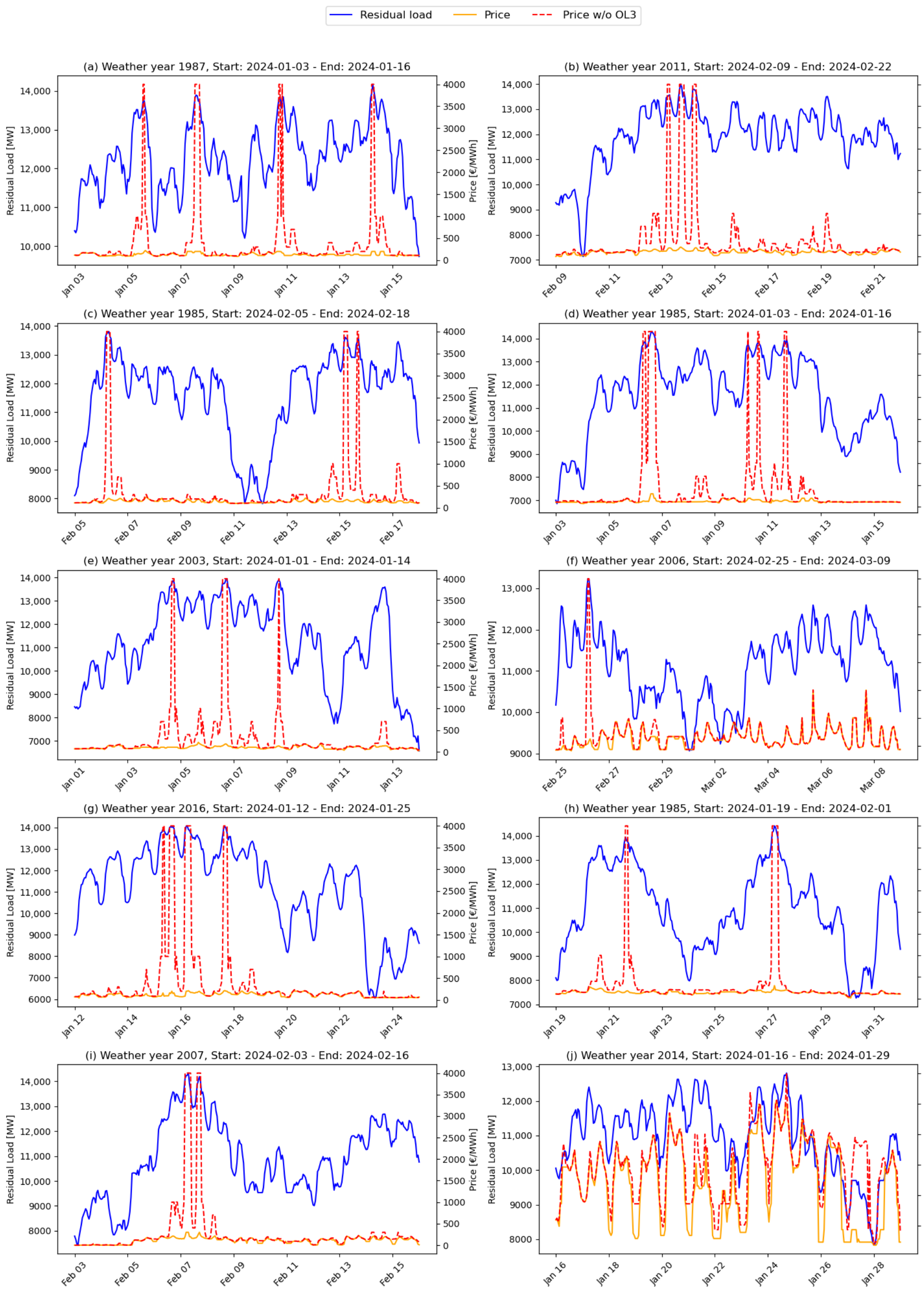


Figure 4. This figure shows the top 10 two-week scarcity periods in the 2024 scenario. The periods are in descending order, with (**a**) being the highest scarcity and (**j**) the 10th highest period of scarcity. The subplot titles present the weather year and the beginning and end dates of the periods. With a blue line and using the left *y*-axis, the residual load is shown during these periods. With an orange line, the price during these events in the base model is shown while the dashed red line represents the price if OL3 power plant is not available. Note the different price scales in (**f**,**j**).

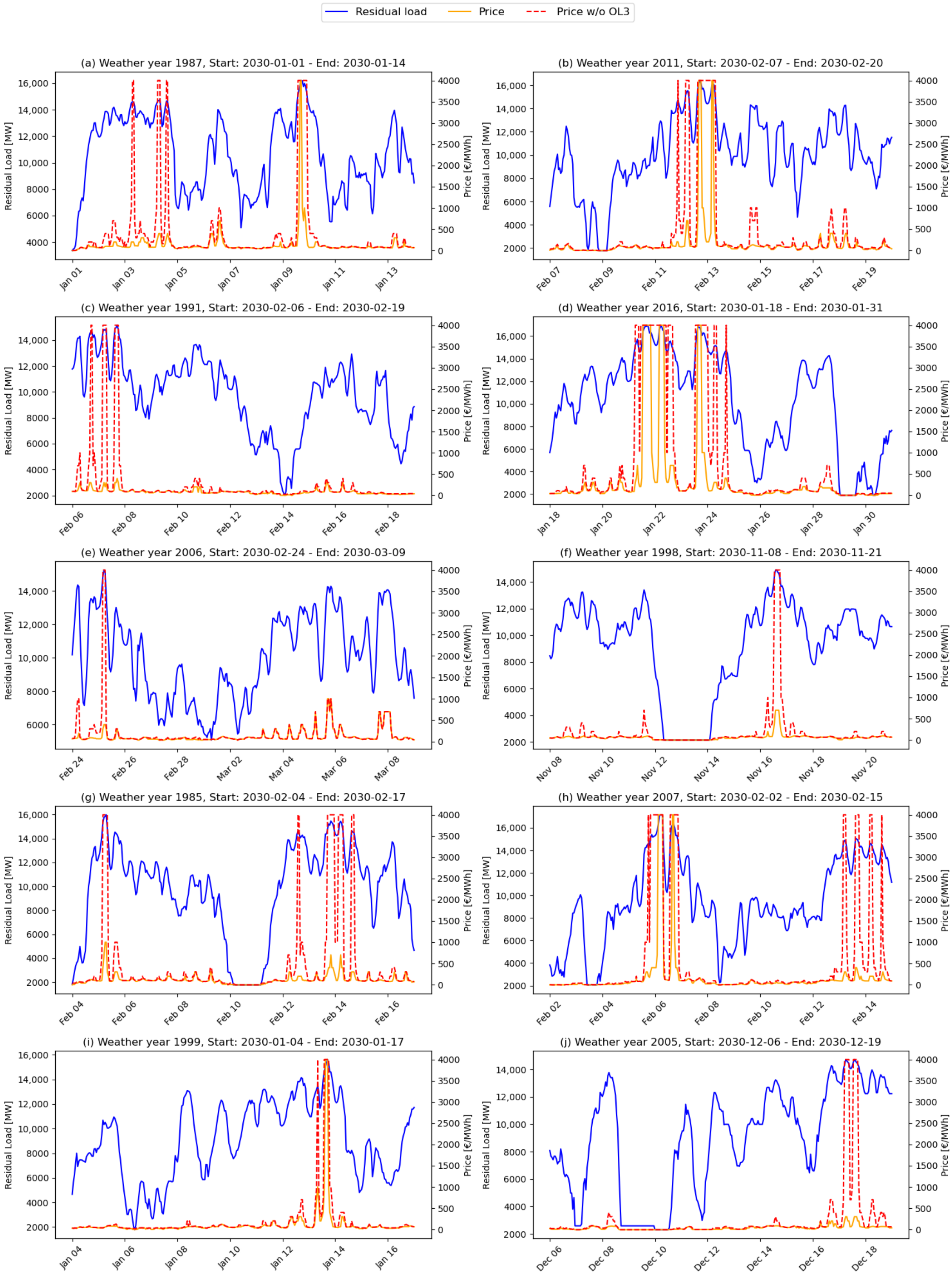


Figure 5. This figure shows the top 10 two-week scarcity periods in the 2030 scenario. The periods are in descending order, with (**a**) being the highest scarcity and (**j**) the 10th highest period of scarcity. The subplot titles present the weather year and the beginning and end dates of the periods. The residual load is shown during these periods with a blue line and using the left *y*-axis. The price during these events in the base model is shown with an orange line, while the dashed red line represents the price if OL3 power plant is not available.

Table 5. The number of scarcity hours during the 2024 and 2030 scenarios, with the OL3 fault scenarios separated. In January, the OL3 is offline for the whole month within the model, and the same applies to the other months. The scarcity hour is defined as an hour where the area price of Finland reaches 3999 EUR/MWh, indicating reserve deployment. In all these situations, all other resources, including DSM, have already been activated.

Scenario Year	2024					2030				
Weather Year	Base	January	February	November	December	Base	January	February	November	December
1982	0	1	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	6	2	0	0
1984	0	0	0	0	0	4	4	4	4	4
1985	0	25	10	0	0	0	68	24	0	0
1986	0	1	0	0	0	0	23	7	0	0
1987	0	13	0	0	0	21	35	28	21	21
1988	0	0	0	0	0	3	3	7	3	3
1989	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	4	0	0	1
1991	0	0	0	0	0	0	0	14	0	0
1992	0	0	0	0	0	0	0	0	0	0
1993	0	0	0	0	0	0	7	0	0	0
1994	0	0	0	0	0	0	5	5	0	0
1995	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	3	3	3	3	3
1998	0	0	0	0	0	0	0	0	6	0
1999	0	0	12	0	0	3	6	19	6	3
2000	0	0	0	0	0	0	0	5	0	0
2001	0	0	0	0	0	0	0	1	0	0
2002	0	0	0	0	0	0	0	0	0	7
2003	0	9	1	0	0	0	23	7	0	0
2004	0	0	0	0	0	0	8	3	0	0
2005	0	0	0	0	0	5	5	5	5	15
2006	0	0	0	0	0	0	0	5	0	0
2007	0	0	12	0	0	7	7	34	7	7
2008	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	4	4	0
2010	0	0	0	0	19	1	20	4	1	1
2011	0	0	12	0	0	9	26	26	9	9
2012	0	0	0	0	0	0	10	0	0	6
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	7
2015	0	0	0	0	0	0	0	0	0	0
2016	0	20	0	0	0	17	58	17	17	17
Average h/a	0	1.97	1.34	0	0.54	2.09	9.17	6.40	2.46	2.97

The scarcity patterns are not uniform but vary greatly. In the 2024 scenario with OL3 faults, the scarcity events can either be concentrated or dispersed. For instance, in event Figure 4a, which has the largest sum of residual load for the two-week period, there are four scarcity events that occur every few days. Conversely, in event Figure 4b, the scarcity hours are very concentrated. However, the individual scarcity events in 2024 are still quite short, mostly lasting only for a few hours. The same is not true for the 2030 scenario. For example, in Figure 5b,d events, the scarcity lasts for multiple consecutive hours. This kind of scarcity may be more difficult to counter with additional measures.

Additionally, it is important to notice how quickly the situation may change in a heavily wind-dominated system. In the 2030 scenario in event Figures 5 and A2g, the residual load collapses to around 2GW in the middle of two scarcity events, showing that the power system must be able to cope with power swings of around 14 GW within a two-week period in 2030. To give some context, that is almost the total current maximum load in Finland. It can be seen that during some of the periods, the deficit margins are highly negative, even below 2 GW, if OL3 is not available, in events (b), (d), (h), and (i) in the 2030 scenarios in Figure A2.

From Table 5, it can be discerned that January and February are especially vulnerable months for scarcity situations, if a fault in OL3 would occur, while the overall effects of a fault in either November or December are less. This is true for both 2024 and 2030 systems, indicating that overall periods of low wind and high demand are most common in the beginning of a year.

It is important to also note that an overwhelming majority of the scarcity situations within the Nordic and Baltic market area occur in Finland. In fact, in the 2030 base scenario, only four of the high price hours in Finland are caused by other regions (There is one hour occurring in March during the weather year 1987 and three consecutive hours on 13th of January, during the weather year 1999), while in total there were 73 recorded high-price hours. Therefore, the Finnish region is in a uniquely vulnerable position within the Nordic and Baltic power system with respect to extreme scarcity events. In addition, in some events when there are problems with security of supply in Finland, it is occurring at the same time as in some other area as well.

3.4. Overall Analysis of Scarcity in 2024 and 2030

In Table 6, the total amount of generation produced by the "reserve" generator in Finland is presented by weather year. In reality, this would mean the need for load shedding or undelivered electricity. In all weather years, except for in 1982, the situation remains the same or worsens in 2030 when compared to 2024. This change can be seen when the average amount of yearly dispatched reserve generation is examined. In the scenarios with OL3 faults, in the 2024 scenario, the average annual reserve deployment is under 0.4 GWh/a. In the 2030 base scenario, this value is almost 0.8 GWh/a, while with OL3 faults, this value increases considerably, up to 6.18 GWh/a if the OL3 is not operational during January. Similar trends can be seen in Table A1, which represents the use of demand response, although dispatch of the DSM is naturally much greater than reserve generation.

Table 6. The annual missing electricity generation in the 2024 and 2030 scenarios in GWh. This could mean the amount of load shedding performed by the transmission system operator (TSO). Months refer to the time when OL3 is offline for the whole month.

Scenario Year	2024					2030				
Weather Year	**Base**	**January**	**February**	**November**	**December**	**Base**	**January**	**February**	**November**	**December**
1982	0	0.02	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	5.07	0.01	0	0
1984	0	0	0	0	0	0.78	0.78	0.78	0.78	0.78
1985	0	6.61	1.03	0	0	0	37.22	14.07	0	0
1986	0	0.01	0	0	0	0	17.67	2.13	0	0
1987	0	1.94	0	0	0	8.34	18.64	11.39	8.34	8.34
1988	0	0	0	0	0	2.11	2.11	3.06	2.11	2.11
1989	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	1.91	0	0	0.02
1991	0	0	0	0	0	0	0	3.52	0	0
1992	0	0	0	0	0	0	0	0	0	0
1993	0	0	0	0	0	0	1.49	0	0	0
1994	0	0	0	0	0	0	2.63	1.53	0	0

Table 6. *Cont.*

Scenario Year	2024					2030				
Weather Year	**Base**	**January**	**February**	**November**	**December**	**Base**	**January**	**February**	**November**	**December**
1995	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	1.08	1.08	1.08	1.08	1.08
1998	0	0	0	0	0	0	0	0	4.99	0
1999	0	0	2.32	0	0	0	4.25	17.7	0.32	0.68
2000	0	0	0	0	0	0	0	1.25	0	0
2001	0	0	0	0	0	0	0	0.1	0	0
2002	0	0	0	0	0	0	0	0	0	1.19
2003	0	1.21	0.03	0	0	0	11.7	1.72	0	0
2004	0	0	0	0	0	0	4.33	0.29	0	0
2005	0	0	0	0	0	2.04	2.04	2.04	2.04	4.01
2006	0	0	0	0	0	0	0	2.47	0	0
2007	0	0	4.59	0	0	4.2	4.2	30.85	4.2	4.2
2008	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0.75	0.58	0
2010	0	0	0	0	7.06	0.11	13.41	0.89	0.11	0.11
2011	0	0	2.89	0	0	1.76	23.44	22.48	1.76	1.76
2012	0	0	0	0	0	0	2.33	0	0	2.29
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	1.32
2015	0	0	0	0	0	0	0	0	0	0
2016	0	3.79	0	0	0	7.03	61.98	7.03	7.03	7.03
Average GWh/a	0	0.39	0.31	0	0.2	0.78	6.18	3.58	0.95	1

4. Discussion and Conclusions

Demand response potentials are one source of uncertainty in this study. Demand response was modelled as five steps of equal magnitude, depending on the market price, so that the first step would activate when the market price exceeds 200 EUR/MWh and the last one at 1000 EUR/MWh. The whole potential of these five steps together was assumed to be 10% of the average yearly maximum load. These assumptions are based on available information about consumer reactions to various price levels and the actual demand response possibilities. In reality, the quantification of the available demand response is very difficult; in severe situations, there might be more than assumed here, but equally well the assumed quite significant total amounts may not be realized in actual situations. For instance, electrical heating is common in Finnish detached houses. When a prolonged cold-weather period takes place, buildings need gradually more and more heating to maintain a certain indoor temperature level.

A close investigation of the modelling results showed the importance of proper multiregional modelling when estimating the scarcity events. For instance, the residual load amount alone was found to not reliably indicate the severity of the situation, as the available import from the neighbouring regions was also decisive in the outcome.

When interpreting the results presented here, it is important to note that there can also be simultaneous restrictions on transmission capacities or other power plant outages. The scenario of the OL3 1600 MW nuclear power plant was chosen as it is the single largest power-generating unit in the Nordic power system. In reality, the situation might be even more severe. For example, faults may occur simultaneously in many units, which was seen in January 2024 due to an exceptionally cold weather period. Additionally, the transmission between the regions might be constrained due to other reasons, which could either directly or indirectly affect the import capability of Finland due to congestion.

Currently, the national standard for Loss of Load Expected (LOLE) in Finland is 2.1 h/a, and Expected Energy Not Served (EENS) is 1.1 GWh/a [24]. While these standards cannot directly be compared to our results presented in Tables 5 and 6, as these scenarios have not been conducted with the standardized ERAA methodology, the 2030 situation looks concerning. The LOLE threshold is almost breached in the base scenario, which is, as already explained earlier, too optimistic, as it does not contain any randomized faults or forced outages excluding yearly maintenance. Therefore, it is certainly possible that this threshold could be breached. Moreover, faults in OL3 in either January or February would also cause the EENS target to be violated. It is also important to state that the problems are also highly concentrated in single weather years. In the 2030 base scenario, 10 out of the 35 weather years had some scarcity hours, but only 2 had more than 10 scarcity hours. Similar concentrations can be seen in the amount of missing electricity generation. This emphasizes the importance of using of long-term weather data.

The problems occurring in Finland are mainly due to two main issues: the significant increase in load and the decrease in CHP capacity due to the electrification of heating. This can then lead to issues in maintaining the power supply in situations where load is high or even moderately high if it is combined with extremely low wind power production.

Even though the amount of residual load on average is expected to reduce by 2030, the extreme situations will become more severe. Attention should be paid immediately to this issue. The main problem would be to find some flexible generation that could be deployed during these few problematic periods. Suitable flexibility technologies could include pumped hydro storage (PHS), as Finnish companies are studying potential locations. Alternatively, traditional peaking power plant technologies, such as gas turbines could also be a solution. However, finding such investments is challenging, considering that most of the time the system is rather oversupplied than in a scarcity situation and the market prices are low. The uptimes of these plants could be extremely low. Therefore, policy actions or changes in market incentives should be considered. Recently, different capacity market mechanisms have been under review in Finland. The 2023 government programme includes a mention of creating a "cost-effective capacity mechanism… that will ensure sufficient amount of available electricity at all times" [25].

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Data Availability Statement: Data including the hourly dispatch of DSM, load, wind and PV generation, as well as area price for Finland for both 2024 and 2030 scenarios is available on reasonable request.

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Conflicts of Interest: The authors declare no conflicts of interest.

Appendix A Deficit Margin in Top 10 Two-Week Periods

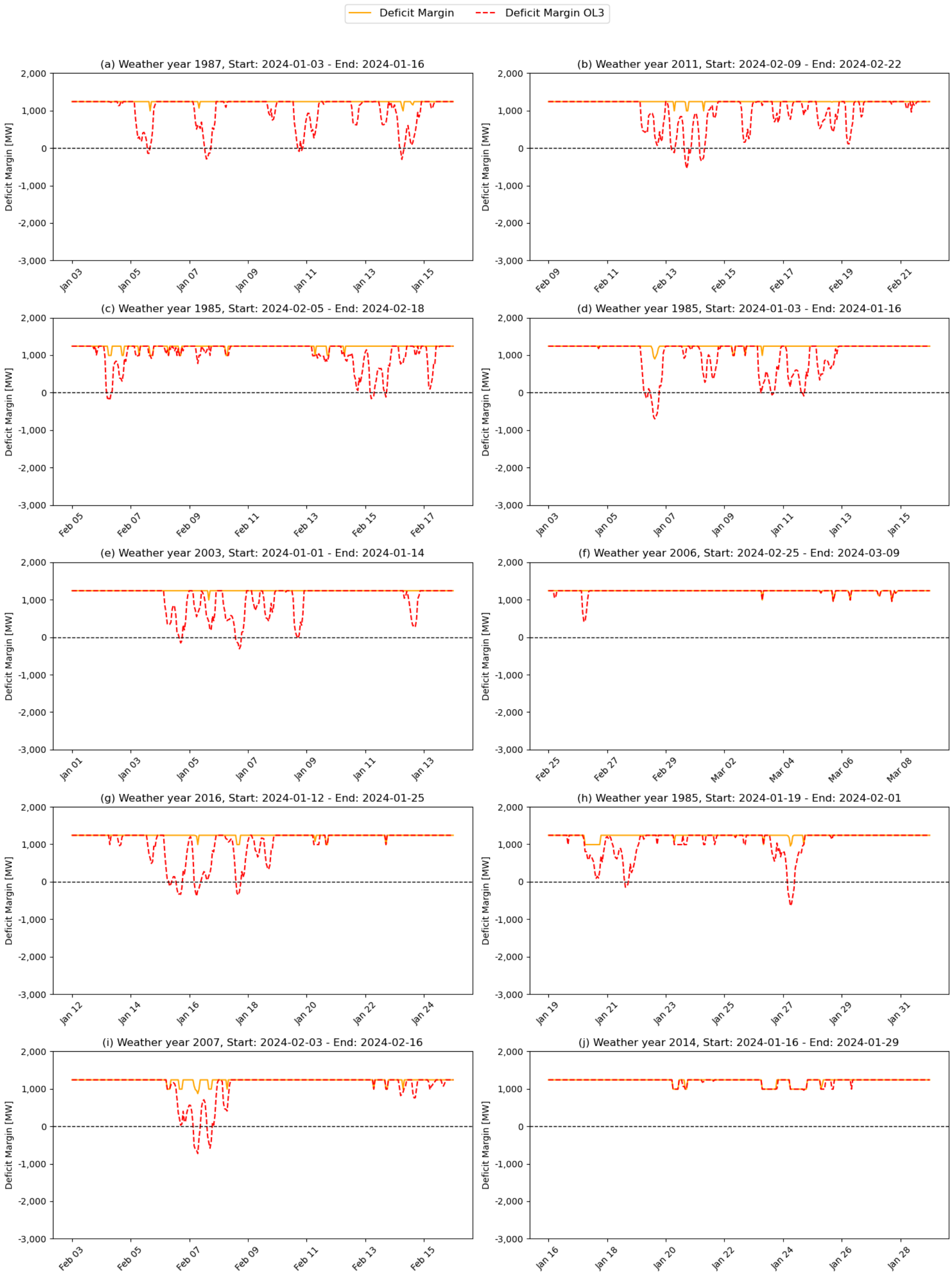

Figure A1. This figure shows the top 10 two-week scarcity periods in the 2024 scenario, with available deficit margin shown in the picture. A negative value means deployment of "reserve" generator within the model, which means an acute scarcity within the power system. The solid orange line depicts the situation with no OL3 issues, while the dashed line represents the situation with OL3 being offline.

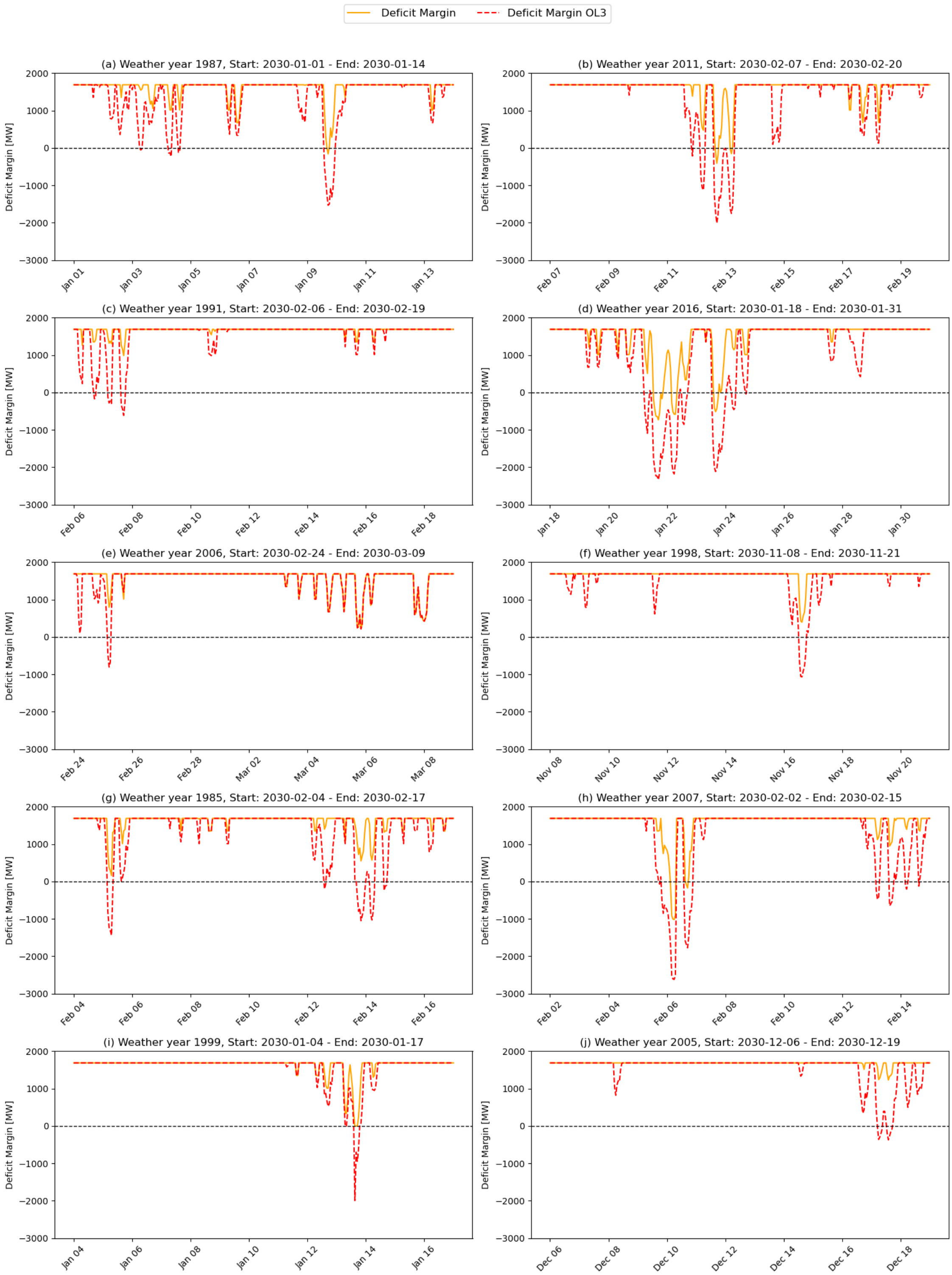

Figure A2. This figure shows the top 10 two-week scarcity periods in the 2030 scenario, with available deficit margin shown in the picture. A negative value means deployment of "reserve" generator within the model, which means an acute scarcity within the power system. The solid orange line depicts the situation with no OL3 issues, while the dashed line represents the situation with OL3 being offline.

Appendix B

Table A1. The annual DSM deployment in 2024 and 2030 scenarios in GWh.

Scenario Year	2024					2030				
Weather Year	**Base**	**January**	**February**	**November**	**December**	**Base**	**January**	**February**	**November**	**December**
1982	2.95	14.91	2.87	2.87	2.87	10.27	25.04	13.69	10.45	9.08
1983	0.74	4.48	2.83	0.74	0.74	8.9	32.39	15.92	10.8	13.82
1984	7.12	10.14	7.37	7.12	7.12	33.7	39.82	44.29	34.92	34.19
1985	11.5	128.2	86.4	12.09	12.73	91.31	220.4	170.0	91.62	99.52
1986	5.19	33.77	17.76	5.09	6.28	38.11	89.67	65.21	38.6	42.42
1987	15	96.04	20.93	15.26	14.45	108.9	188.9	141	120.7	109.7
1988	0.25	0.5	7.17	0.69	0.29	10.89	15.79	22.77	21.57	10.94
1989	0	1.04	0	0	0.29	0.34	2.22	0.06	1.33	15.71
1990	0	2.17	0	0	0.13	3.34	18	3.41	3.2	14.12
1991	2.32	2.95	5.78	2.32	2.42	14.7	29.46	62.33	14.6	15.46
1992	0.5	2.71	1.31	0.5	0.66	0.38	3.18	2.53	3.35	0.55
1993	3.73	5.99	4.24	3.79	7.2	11.07	49.56	11.43	25.64	15.56
1994	8.44	11.64	13.31	8.46	8.26	11.47	33.7	41.25	14.38	11.29
1995	0.51	0.75	1.2	1.74	5.1	3.88	4.28	7.01	3.69	17.38
1996	8.34	12.68	15.25	8.7	8.1	19.72	31.79	39.64	19.42	19.53
1997	0.58	2.91	0.58	0.58	1.39	22.34	22.93	22.47	37.78	22.52
1998	1.43	1.52	8.06	6.4	1.5	10.13	14.02	13.78	56.06	10.57
1999	8.78	18.27	46.4	8.58	10.4	45.85	78.55	78.67	53.9	45.57
2000	1.3	5.33	2.69	1.27	2.01	10.23	14.64	27.95	10.34	11.26
2001	0.5	0.74	7.01	0.5	1.42	17.77	19.1	39.51	19.74	30.7
2002	1.28	4.28	3.82	1.77	1.28	2.58	11.85	12.73	13.5	23.89
2003	3.03	69.11	13.22	3.03	3.03	48.26	104.1	78.57	60.05	47.43
2004	3.5	4.84	3.66	3.3	3.3	19.35	69.64	51.19	21.69	21.45
2005	9.17	13.01	9.52	9.14	10.35	26.87	33.66	27.09	29.77	83.87
2006	2.34	2.51	8.2	2.55	2.34	41.43	49.1	78.56	45.05	41.44
2007	11.72	12.53	54.4	11.87	11.74	35.55	53.09	105.4	38.81	35.55
2008	0.98	3.22	1.11	1.09	1.07	2.99	2.99	4.02	6.29	5.87
2009	1.05	1.05	3.64	1.33	1.8	18.28	29.24	68.31	41.69	23.31
2010	12.94	23.24	21.19	13.15	60.12	39.35	79.94	74.9	42.64	48.51
2011	4.82	33.11	78.42	4.64	4.52	57.39	91.63	108.4	57.84	57.23
2012	7.71	9.08	8.86	7.69	11.29	18.83	59.87	22.01	28.05	40.51
2013	3.91	14.94	5.01	3.96	4.33	21.84	38.19	30.88	23.8	22.53
2014	10.78	13.27	11.87	11.52	10.67	7.14	20.78	7.97	30.5	30.1
2015	2.01	6.12	2.26	2.01	2.01	1.42	3.04	1.12	2.76	1.09
2016	2.27	83.4	2.13	2.45	4.4	85.87	179.1	85.55	102.6	84.98
Average GWh/a	4.48	18.59	13.67	4.75	6.45	25.73	50.27	45.13	32.49	31.93

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