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Article

Balancing Electricity Supply and Demand in a Carbon-Neutral Northern Europe

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Abstract: This work investigates how to balance the electricity supply and demand in a carbon-neutral northern Europe. Applying a cost-minimizing electricity system model including options to invest in eleven different flexibility measures, and cost-efficient combinations of strategies to manage variations were identified. The results of the model were post-processed using a novel method to map the net load before and after flexibility measures were applied to reveal the contribution of each flexibility measure. The net load was mapped in the space spanned by the amplitude, duration and number of occurrences. The mapping shows that, depending on cost structure, flexibility measures contribute to reduce the net load in three different ways; (1) by reducing variations with a long duration but low amplitude, (2) by reducing variations with a high amplitude but short duration and low occurrence or (3) by reducing variations with a high amplitude, short duration and high occurrence. It was found that cost-efficient variation management was achieved by combining wind and solar power and by combining strategies (1–3) to manage the variations. The cost-efficient combination of strategies depends on electricity system context where electricity trade, flexible hydrogen and heat production (1) manage the majority of the variations in regions with good conditions for wind power while stationary batteries (3) were the main contributors in regions with good conditions for solar power.

Keywords: flexibility measures; variation management; VRE; electricity system modeling; wind power integration; solar power integration; sector coupling

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1. Introduction

The aim of this work is to visualize how variations in a future northern European electricity system can be cost-efficiently managed. The work first examines climate neutral energy systems with extensive electrification of the industry, transport and heating sectors. Outlooks for Nordic [1], northern European [2,3] and European [4] electricity systems have been presented in recent years. The common features of these outlooks are a substantial increase in electricity demand which, to a large extent, is supplied by wind and solar power. Given the varying generation of wind and solar power, the ability of the electricity system to manage these variations have become a question of high priority [5].

There exists a wide range of technologies and strategies to provide flexibility, ranging from shifting the electricity demand for heat pumps in time in single-family dwellings by exploiting the thermal inertia of buildings, to using large-scale underground storage of hydrogen produced for industrial applications. Lund and Lindgren [6] have compiled a comprehensive overview of the different approaches for increasing energy system flexibility. Flexibility measures serve two main purposes: to assure the reliability or increase the cost efficiency of a given electricity system. This work concerns the latter subset, i.e., flexibility measures with the purpose to manage variability such that the social cost of electricity is reduced. This subset is referred to as variation management strategies (VMSs) [7,8]. The potential of flexibility measures to reduce the social cost of meeting the demand for electricity is well documented. Previous work investigating the impact of flexibility measures on the operation of a given electricity system reported reduced costs because of reduced curtailment [7,9] and because of reduced operation of peak generation units in favor of varying renewable electricity (VRE) and base load generation [10]. Studies on the impact of flexibility measures on the cost-optimal system composition reported reduced costs as investments in varying renewable electricity generation capacity replace investments in more expensive electricity generation options [8,11]. Johansson et al. [8] investigated the impact of a range of variation management strategies on the cost-optimal system composition of electricity systems with different preconditions for VRE. It was found that different strategies influenced the operation of the electricity system and investment in electricity generation capacity in different ways. In addition, it was found that the cost-optimal investments in variation management strategies depends on the preconditions for VRE generation. These findings indicate that there are different types of variability which need to be matched with the most cost-efficient strategies for each type. It is reasonable to assume that all types of variations are present in all electricity systems, albeit to different degrees, and what we look for is a balanced combination of strategies adequate for the given electricity system.

Few outlooks for the northern European electricity system address in detail how variations in the electricity system can be met cost efficiently. Pursiheimo and Kiviluoma [3] analyzed electrification scenarios for northern Europe with a focus on Finland. They applied the model of Backbone [12], an investment model with a high time resolution and consequentially with the ability to balance options to cost-efficiently manage variations. Variation management was addressed by illustrating the dispatch of one winter week and one summer week for the Finnish electricity system. The illustrations of the dispatch of electricity systems provided a detailed understanding of how the demand for electricity was met every hour, including how variations were managed when plotted for a limited time span such as a couple of weeks. However, to give an overview of how variations are managed more generally across one or several years, other options for visualization are needed. Several efforts have been made to measure and graphically represent flexibility provision in the electricity system. IEA [13] proposed a flexibility assessment tool (FAST) to estimate if there is sufficient flexibility in a given electricity system to accommodate additional wind and solar power, accounting for flexibility on the demand and supply side as well as the storage and interconnection capacity. Yasuda and Carlini [14] introduced flexibility charts which map the capacity for flexible generation and interconnections relative to the peak capacity of a given electricity system. The tools by IEA and Yasuda et al. rely on statistics which are easy to access to give a first idea of the ability of a given electricity system to manage variations. Using time series from actual or modelled electricity system operations, the contribution of each flexibility supplier can be assessed in more detail. Heggarty and Bourmaud [15] introduce two graphical tools, the flexibility solution modulation stacks and the flexibility solution contribution distribution, to visualize the contribution of flexibility suppliers on annual, weekly and daily timescales.

This paper adds to the previous outlooks for future northern European electricity systems by focusing on how variations in the electricity system are managed using a novel approach of visualizing the net load variability and the contribution of different strategies to reduce this net load. A cost-efficient combination of strategies to manage the net load was derived using a cost-minimizing electricity system model with high temporal resolution representing 11 strategies to manage variations on the demand side and the generation side, as well as pure storage technologies. The contribution of each strategy was visualized using a novel graphical representation in the space spanned by the amplitude, duration and the number of occurrences of the net load variations. Based on the results, the functionality of different strategies to manage variations can be generalized and connected to a functionality-based framework for strategies to manage variations which facilitate the choice of a strategy for a given electricity system context.

2. Method

To find cost-efficient strategies to meet the demand for electricity, heat and hydrogen in a carbon-neutral northern Europe, the cost-minimizing electricity system model ENODE was applied. Given a time-resolved demand for electricity, heat and hydrogen, together with costs and technical limitations of generation and storage technologies, ENODE generates investments in and operations of technologies for generating and storing electricity, heat and hydrogen. From these results, net loads (i.e., electricity demand which cannot be moved in time, reduced by wind and solar power generation) for each region with and without accounting for strategies to manage variations were produced to visualize the role of each strategy in a carbon-neutral northern Europe.

2.1. Electricity System Investment Model

In this work, cost-efficient deployment of variation management strategies was identified using the cost-minimizing electricity system investment model ENODE. The objective of the ENODE model is to minimize the cost of investments and operation while meeting a given demand for electricity, heat and electricity-based hydrogen. The ENODE model was first presented in [16] and further developed in [8,17] to include more options to manage variations and to better represent the heat sector. The model has a high temporal resolution and a detailed technology description, while the temporal scope is limited to 1–2 years. As such, the model results provide a good understanding of the interplay between electricity generation technologies and variation management strategies on the timescale of hours to seasons. In this work, the model was run with a 3 h time resolution for two years (with investment costs represented as annualized costs) representing the year 2050 in terms of technology costs and carbon emission limitation, i.e., only technologies without net carbon dioxide emissions were included as investment options. Existing hydropower was assumed to remain in place together with the new nuclear power in Finland and the nuclear power under construction in the UK.

In this work, the ENODE model was applied to northern Europe subdivided into 14 regions as given by the map in Appendix A Figure A1. The demand for electricity, heat and hydrogen must be met in each region at every timestep. Electricity could be traded between regions. The existing transmission grid was assumed to remain in place and additional investments in transmission capacity of up to 5 GW per connection was allowed.

On the supply side, nine technology options were included including thermal base load generation such as nuclear power, biomass-based combined heat and power and bio-blended coal with carbon capture and storage as well as thermal peak generation in terms of biogas open-cycle and combined-cycle gas turbines. A total list of the technologies together with their cost properties are given in Appendix B. On- and offshore wind power and solar PV were represented using time-resolved wind and solar power production potential for the investigated regions. The power production potential was derived using [18] which relies on ECMWF ERA5 [19] and the Global Wind Atlas [20] for the historical years 1991–1992. These two years were chosen since they represent one year with a lower hydropower inflow in the Nordic countries (1991) and one year with a higher hydropower inflow in the Nordic countries (1992). The potential for wind and solar PV investments per region together with their respective full load hours are given in Appendix B. The electricity demand corresponding to temperature variations in the historical years 1991–1992 was also derived using [18].

This work investigated a future northern European electricity system assuming a carbon-neutral energy system which was targeted to be attained by the European Union by around 2050 [4]. By 2050, it is expected that we will have already experienced a significant increase in temperature due to global warming [9]. Thus, in this work, we assumed an increase in global mean temperature of 2 degrees. In northern Europe, a warmer climate is expected to mainly impact the energy system through altered hydropower inflow, reduced demand for heating and increased number of incidents induced by extreme weather [21]. In this work, we accounted for the two former factors based on [22] which showed an increased annual average hydropower production distributed more evenly across the year in the Nordic countries together with reduced demand for district heating and electricity for heating purposes in the wintertime.

In this work, an electrification of the transport sector and the industry sector was assumed together with a shift from natural gas for heating purposes to individual heat pumps in Germany, the Netherlands, Poland and the UK. The electricity demand for the heating of single-family dwellings was calculated according to Nyholm [23], accounting for energy efficiency improvements. In addition, there was a heat demand corresponding to the demand for district heating in the investigated regions [24]. The heat demand could be met by heat-only boilers, but also combined heat and power plants (CHP), heat pumps and electric boilers. The inclusion of thermal energy storage enabled a temporal decoupling between heat production and electricity production/consumption and facilitated an adapted heat production which offered flexibility to the electricity system.

The electrification of industry includes electrification of steel, cement and ammonia. The total production of steel, cement and ammonia in the investigated regions was assumed to remain at today's levels. In cement production, we assumed plasma burners were used for high temperature heating with a continuous demand for electricity over time. There was an exogenous demand for electricity-based hydrogen (i.e., hydrogen produced from electricity) corresponding to the electricity demand from the steel industry and the ammonia industry. The hydrogen demand was a simplified representation of an electrification of industry and was distributed evenly across all hours of the year, assuming a continuous operation of industrial processes. By overinvesting in the electrolyzer capacity and hydrogen storage, an adapted hydrogen production, which offers flexibility to the electricity system, can be achieved.

A full electrification of the road transport was assumed. The majority of vehicles were assumed to charge as they are parked. However, 30% of the cars charged flexibly over time and could also discharge back to the grid. Vehicle charging was implemented as described by Taljegard [25]. It should be noted that flexible cars were also constrained to meet the demand for transportation as defined by the vehicle movement data collected by Kullingsjö and Karlsson [26].

Furthermore, the model included the option to invest in stationary batteries to manage variations as well as fuel cells to regenerate electricity stored as hydrogen. Thus, the strategies to manage the variations included in this work encompassed supply side, demand-side, and pure storage options. Table 1 list the strategies to manage variations included in this work together with the technologies they involve.

Table 1. Strategies to manage variations included in this work together with the technologies involved and their key properties. CCGT = Combined Cycle Gas turbine, CHP = Combined Heat and Power Plant.

Strategy	Technology	Investment Cost [kEUR/MW(h)]	Efficiency [%]	Fixed O&M Costs [kEUR/MW(h), year]	Lifetime [year]
Charging or discharging of electric vehicles		-	-	-	-
Charging or discharging Li-Ion batteries	Charge/discharge	80	1	1	25
	Storage capacity	70			25
Charging or discharging hydrogen storage system	Fuel cell	500	50	55	10
	Electrolyzer	390	79	18	20
	Hydrogen storage	10	100	-	40
Adapted hydrogen production	Electrolyzer	390	79	18	20
	Hydrogen storage	11	100	-	50
Adapted heat production	Heat pump	1000	300	8	25
	Tank storage	3	80	-	25
Opportunistic heat production	Electric boiler	50	100	-	20
Opportunistic biogas open-cycle electricity production	Gas turbine	450	42	17	30
Adapted biogas combined-cycle electricity production	CCGT	900	61	15	30
Adapted biomass combined heat and power production	CHP	3260	30	105	40
	Tank storage	3	80	-	25
Adapted biomass electricity production	Steam turbine	1980	35	52	40
Adapted nuclear power production	Steam turbine	3980	33	123	60

2.2. Visualizing the Net Load

The method to visualize the net load suggested in this work is based on the proposition that variability can be defined by its amplitude, duration and number of occurrences. Here, we refer to number of occurrences as how often variations with a certain amplitude and duration takes place. According to time series analyses, any time series in a linear system can be described in two dimensions: amplitude and frequency. Weather systems, wind speeds and thus the net load in electricity systems supplied to a large extent by wind power, are composed of a combination of linear and non-linear phenomena. For this reason, we find it practical to subdivide the frequency into duration and number of occurrences and we will refer to the three-dimensional space spanned by the amplitude, duration and number of occurrences as the variation space.

Algorithm 1 describes how to map the net load of any electricity system into the variation space in six steps. The resulting plot illustrates to which extent the net load variations to be managed are variations with a high amplitude, long duration, high occurrence or any combination of these. We refer to the map of the net load in the variation space as the variation profile of the electricity system. An overview of the variation profile is a first step in identifying cost-efficient strategies to manage the net load variations.

To understand the role of different strategies to manage variations in an existing electricity system, or a future system proposed by electricity system models, the remaining net load after the strategy is applied is calculated and plotted. By comparing the original variability profile and the variability profile after a strategy has been applied, it is possible to identify to which extent the strategy reduces variations with a high amplitude, long duration or high number of occurrences.

Algorithm 1. Creating the Variability Profile.

1: Calculate the net load $n_t \in N$ as the total electricity demand fixed in time and reduced by non-dispatchable generation for every timestep $t \in T$.

2: Define a list L:= (min N:max N, s) where the step length s is small enough to give a high resolution of the amplitude in the plots. Here, we use s = 0.1 GW.

3: Make a vector $c_{l,t}$ which counts up as long as the net load n is above amplitude $l \in L$ (or as long as net load n is below amplitude l for negative net loads).
    For $l \in L$:
        For $n_t \in N$:
            if $l > 0$ **and** $n_t < l$:
                $c_{l,t} = c_{l,t-1} + 1$
        else if $l < 0$ **and** $n_t > l$:
            $c_{l,t} = c_{l,t-1} + 1$
        $n_t = n_{t+1}$
    $l = l + s$

4: Find the end of each variation interval and obtain the duration $d_{l,t}$.
    For $l \in L$:
        For $n_t \in N$:
            if $l > 0$ **and** $n_{t-1} > l$ and $n_t < l$:
                $d_{l,t} = c_{l,t}$
            else if $l < 0$ **and** $n_{t-1} < l$ and $n_t > l$:
                $d_{l,t} = c_{l,t}$
        $n_t = n_{t+1}$
    $l = l + s$

5: Count the number of occurrences $o_{l,d}$ for a certain combination of duration and amplitude.
    For $d \in T$:
        $o_{l,d} = \sum_t d_{l,t}$
        $d = d + 1$

6: Plot occurrences of variations with amplitude l on the x-axis, duration d on the y-axis and occurrences o on the z-axis.

3. Results

Figure 1 shows the annual electricity demand for the investigated regions. The historic electricity demand (grey) represents the electricity demand prior to electrification. The direct electricity demand from the transport (yellow) and industry sectors (green) and the electricity for hydrogen production (blue) are a consequence of the assumptions and input data presented in the Section 2. The electricity demand for heating (orange) corresponds to electricity for individual heat pumps replacing natural gas, which is given exogenously, but also electricity demand for district heating, which can be met by combined heat and power plants and heat-only boilers as well as heat pumps and electric boilers. The total electricity demand for heating was thus a result of the optimization. For the case investigated, the increase in electricity demand from electrification corresponded to an increase in the annual electricity demand of around 80% in northern Europe. As illustrated in Figure 1, the electricity demand following the electrification of the transport sector was particularly high in the regions with a high population density such as southern Germany (DE_S), southern Poland (PO_S) and southern UK (UK_S). The electricity for hydrogen production was located in regions with an extensive industrial sector (Sweden, Germany, Poland, the BENELUX region and the UK).

Figure 2 shows the annual electricity production in the investigated regions calculated by the electricity system model presented in the Section 2. Applying the costs presented in the Appendix, it was found to be cost-efficient to meet 2/3 of the annual electricity demand in northern Europe with wind power (blue). As illustrated in Figure 2, there were two major clusters of offshore wind power in northern Europe: one off the coast of northern Germany, the Netherlands and Denmark and one off the coast of the UK. With very good conditions for wind power but a limited electricity-intensive industry, Denmark was the single largest exporter of electricity (DK exports 90 TWh/year). The opposite was true for southern Germany which imported 165 TWh/year for the investigated years. Solar PV energy supplied 1/5 of the electricity demand in northern Europe and was mainly located in the southmost regions (southern Germany and southern Poland) from which other regions imported solar power. The southern UK also had large solar PV investments to complement wind power since import capacity from continental Europe was limited. The model was limited to northern Europe and trade outside the modeled scope was omitted. In reality, there is significant transmission capacity between northern Europe and continental Europe and the results for regions on the border with central Europe (southern Germany and southern Poland) should be viewed with this simplification in mind.

Figure 3 shows the installed capacity of energy storage for the investigated regions. The total energy storage capacity in northern Europe corresponded to 11 TWh. The volume of energy storage capacity reflected the investment cost of energy storage capacity. Tank heat storages were the cheapest energy storage option but were only relevant in regions with district heating (district heating is very limited in Norway and the UK). Hydrogen storage was the second cheapest option for energy storage, and was relevant to regions with a demand for hydrogen. Batteries were significantly more expensive and battery investments were mainly located in regions with substantial electricity supplies from solar PV energy. To investigate the role of energy storage in the different regions and how electricity demand and supply was balanced every hour, four regions with different conditions for wind and solar power and different access to flexibility measures were further investigated.

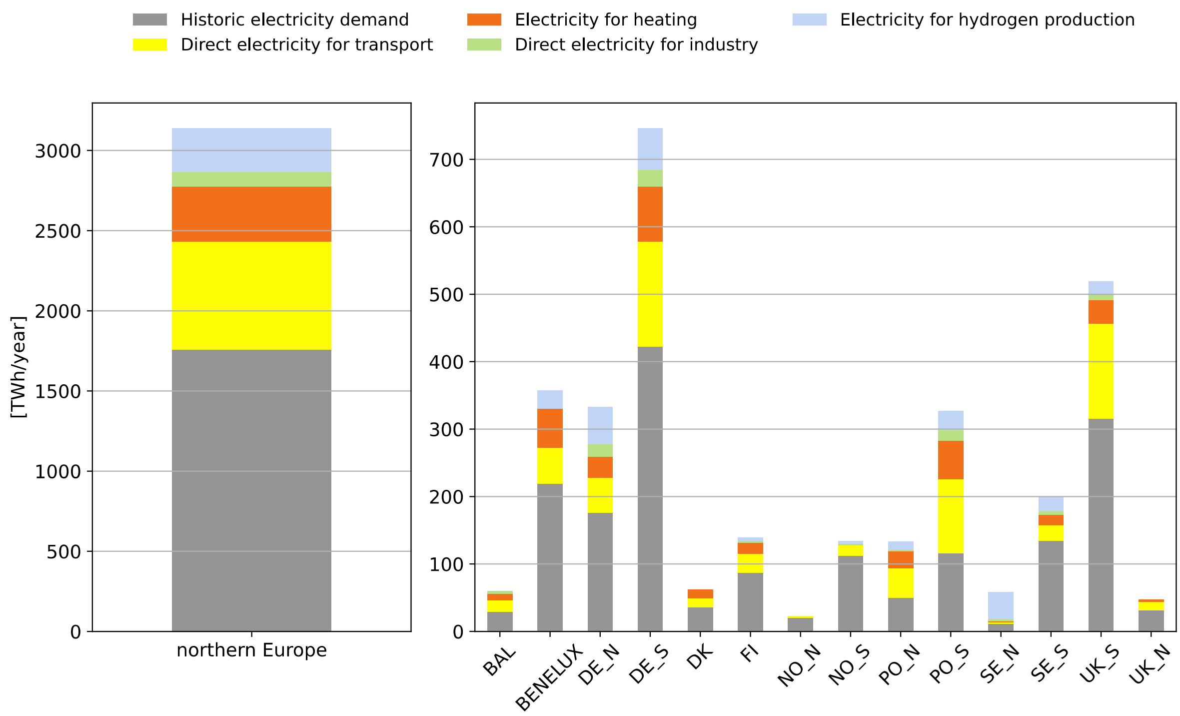

Figure 1. Annual electricity demand for northern Europe as a whole (**left**), together with electricity demand by region investigated in this work (**right**), subdivided into electricity demand of today (grey), electricity demand for heat pumps in district heating systems (orange), for new individual heat pumps replacing natural gas (yellow), for hydrogen production (blue), for light vehicles (light green) and for trucks and buses (dark green).

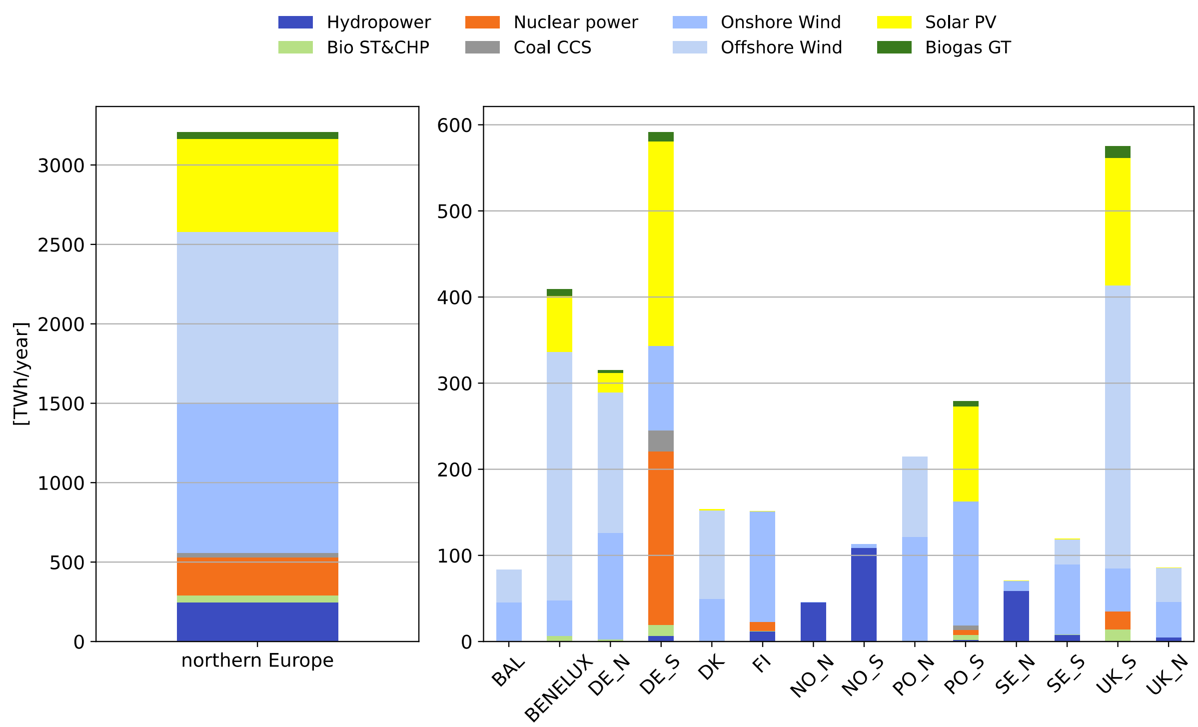

Figure 2. Annual electricity production in northern Europe (**left**) and by region (**right**). ST&CHP = steam turbine and combined heat and power, CCS = carbon capture and storage, GT = gas turbine (open cycle and combined cycle).

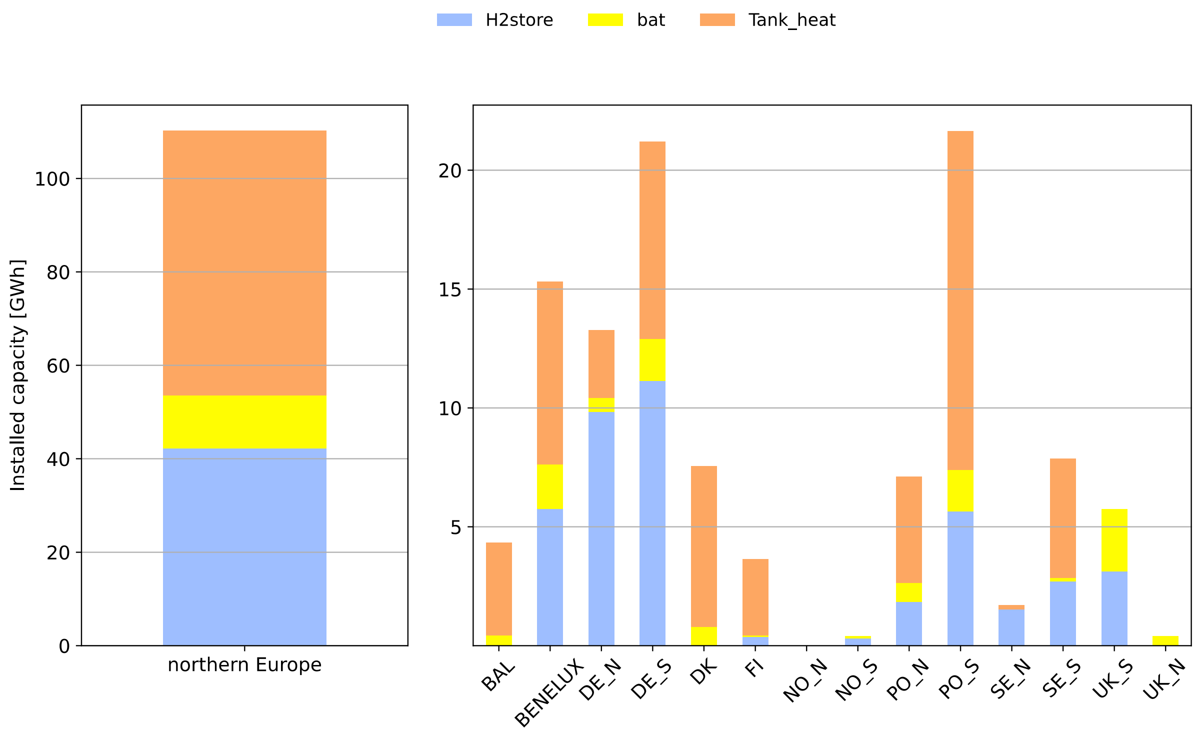

Figure 3. Installed energy storage capacity for northern Europe (**left**) and by investigated region (**right**), subdivided into underground lined-rock cavern hydrogen storage (blue), stationary lithium-ion batteries (yellow) and hot water tank storage in district heating systems (orange).

Figures 4a, 5a, 6a and 7a show the variation profile for DE_S, DK, UK_S and SE_S as defined in the Section 2. These four regions represent four different types of regions observed in the model of northern Europe; regions with extensive solar PV capacity (DE_S and PO_S), regions with extensive wind power for domestic use and export (DK, BAL, PO_N and UK_N), regions with a combination of wind and solar power (UK_S, BENELUX and DE_N) and regions with access to hydropower (SE_S, SE_N, FI, NO_N and NO_S). The color scale was limited at 50 occurrences, implying that the number of occurrences may be higher in the deep red fields. The y-axis was limited at 168 h (one week). Some variations with a longer duration occurred and plots with a y-axis of 300 h for all regions are shown in Appendix C (Figures A2–A15).

As Figures 4a, 5a, 6a and 7a show, net load variations were very different between the investigated regions. Net load variations in Denmark (Figure 5a), with a supply side dominated by wind power, had a low amplitude and number of occurrences but long duration. This was contrasted by net load variations of southern Germany (Figure 4a) with a high amplitude and high number of occurrences but few variations with a long duration. The pattern of the variations in solar power dominated Germany and represented the nature of solar PV energy with a high occurrence in positive net load at a duration of 12–15 h corresponding to night, high number of occurrences in positive net load with high amplitude and a duration of a few hours corresponding to afternoon peaks and high number of occurrences of negative net load with a duration of 2–10 h and varying amplitude corresponding to daytime solar PV production. Variations with a longer duration reoccurred with 24 h intervals and corresponded to cloudy days. The variation profile of southern UK (UK_S) was a combination of the variation profile of southern Germany and Denmark, with the typical pattern of solar PV variations, but with lower amplitudes and lower number of occurrences than those in southern Germany due to a lower total installed capacity, but there were also positive and negative variations with a longer duration which are characteristic of wind power. The variation profile of southern Sweden (SE_S) resembles the one of Denmark, indicating a wind-dominated net load. However, the net load was oriented towards positive amplitudes corresponding to a need for additional generation capacity to complement the wind power to meet the load.

Figures 4–7 illustrate how strategies to manage variations reduced the net load variability in the four example regions. The 11 strategies in Table 1 were aggregated into six groups of strategies to facilitate an overview. Here, the category Thermal includes all thermal electricity generation options except open-cycle gas turbines (adapted biogas combined-cycle electricity production, adapted biomass combined heat and power production, adapted biomass electricity production, adapted nuclear power production). Based on the electricity generation supplied by different sources (see Figure 2), nuclear power dominated this group of strategies. Batteries included stationary batteries and charging of electric vehicles since previous work showed that these strategies act on the same timescales in the electricity system [2]. This implies that we added a load, which was fixed to 70% and flexible to 30% according to assumptions, together with the charging and discharging of stationary batteries. Finally, here, Heat includes both heat production with heat pumps and electric boilers connected to the district heating system (adapted heat production and opportunistic heat production in Table 1). However, this group mainly represents variation management by heat pumps since electric boilers played a very minor role in all investigated regions.

Figure 4b–g shows the net load reduction by six different strategies for southern Germany. Electricity was imported to solar PV-dominated southern Germany, reducing the positive nighttime net load. The positive net load was further reduced by base load generation (Figure 4d). At the same time, base load generation increased the negative net load with long durations. Due to the limited flexibility of nuclear power, production was not only added when needed but also during hours of low net load. The negative net load with a long duration caused by base load generation was reduced by adapted production of hydrogen and heat (Figure 4f–g). However, in the solar PV-dominated southern Germany, the strategy with the largest impact on the net load was batteries (Figure 4e). Stationary batteries matched the charging of electric vehicles (in this work, 70% of the vehicle charging was fixed in time) to the solar PV generation and thereby reduced the net load variations. Batteries have a relatively low cost of charging and discharging power and high efficiency which makes them well suited for the solar PV variations with a high amplitude and high number of occurrences. In general, it can be observed that investments in stationary batteries were particularly substantial in regions with a large demand for electricity for transport (cf. Figures 1 and 3) and that solar PV generation was high in the same regions (Figure 2). The net load variations with a low amplitude, duration and a low number of occurrences which remained in Figure 4f was supplied by biogas open-cycle gas turbines.

Figure 5b–g shows the gradual net load reduction by the six strategies to manage the variations in Denmark. Denmark has some of the best conditions for offshore wind power in northern Europe and together with its central location between the Nordic countries and continental Europe it becomes an ideal exporter of electricity. The majority of this electricity was exported to northern Germany and onwards to load centers in southern Germany. The extensive export results in a strong reduction of the wind-dominated net load variations (Figure 5b). Trade with Germany also introduced solar variations in Denmark, as seen in Figure 5b. These variations were efficiently reduced by batteries. The remaining net load variations had a low amplitude but sometimes had a long duration. In Denmark, these variations were primarily reduced by heat pumps in the district heating system (Figure 5g).

Figure 6b–f shows the net load reduction by strategies to manage variations in the southern UK. The system composition here was a combination of wind and solar power, as illustrated in Figure 2, and the net load had both variations with a long duration and variations with a high amplitude and a high number of occurrences. It is important to note that by combining wind and solar power in the electricity mix, net load variations were, to some extent, already reduced from the start. In particular, solar PV production reduced the duration of low wind events and wind power reduced the positive nighttime net load of solar power. These complementary effects can be visualized by comparing the net loads in Figure 6a to those in Figures 4a and 5a. Trade, primarily with northern UK, further reduced net load variations with a 20–24 h duration. However, it was by combining wind and solar power together with the use of batteries for variations with a high amplitude and high number of occurrences that the majority of the variations in this region were managed. Some variations with a low duration and low number of occurrences were managed by adapted production of hydrogen. The net load which remained in Figure 5f was managed by biogas open-cycle gas turbines.

Figure 7b–f illustrates how the net load was reduced by five different strategies to manage variations in southern Sweden. Figure 7b shows the net load reduced by trade (except for northern Sweden). As the figure shows, trade shifted the net load to the left, indicating that southern Sweden imported electricity. However, since the electricity was mainly imported from Denmark, which is wind-dominated like southern Sweden, the variability of the net load curve was similar after accounting for trade. Some solar variations with a high number of occurrences and high amplitude but short duration were introduced with the trade. Figure 7c shows the net load reduced by trade and hydropower, including trade with northern Sweden. Even though electricity demand in northern Sweden increased substantially, hydropower from the north was exported to southern Sweden during low wind events since the demand in the north was predominantly composed of electricity for hydrogen production which was avoided during low wind events. As the figure shows, the positive net load was drastically reduced by hydropower and hydropower managed positive net loads of any duration. Batteries and the charging of electric vehicles reduced the amplitude of the remaining negative net load (Figure 4e). The remaining net load had a low amplitude and any duration which was managed by adapted production of hydrogen (Figure 4f) and heat (Figure 4g). With the high cost of electricity consumption capacity (electrolyzer and heat pump) but low cost of energy storage (underground hydrogen storage and storage of hot water), variations with a low amplitude but long duration matched the cost structure of these strategies. It is important to note that adding electricity consumption adapted to the net load, i.e., adapted production of heat and hydrogen, does not only imply that "excess" electricity was consumed. These flexible electricity demands stimulated investments in wind power production without increasing consumption during low wind events. Since there was also some wind power production during low wind events, adapted consumption of hydrogen and heat reduced the net load during these events. The little remaining net load visible in Figure 7f was met by open-cycle gas turbines.

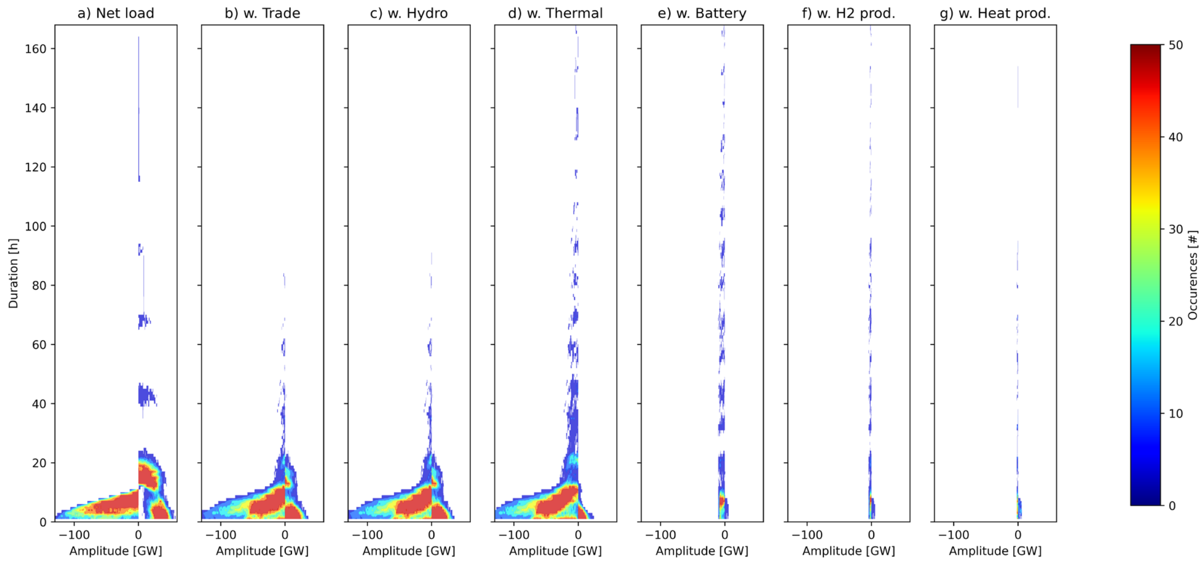

Figure 4. Net load of southern Germany (DE_S) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields. The y-axis was limited at 168 h (one week).

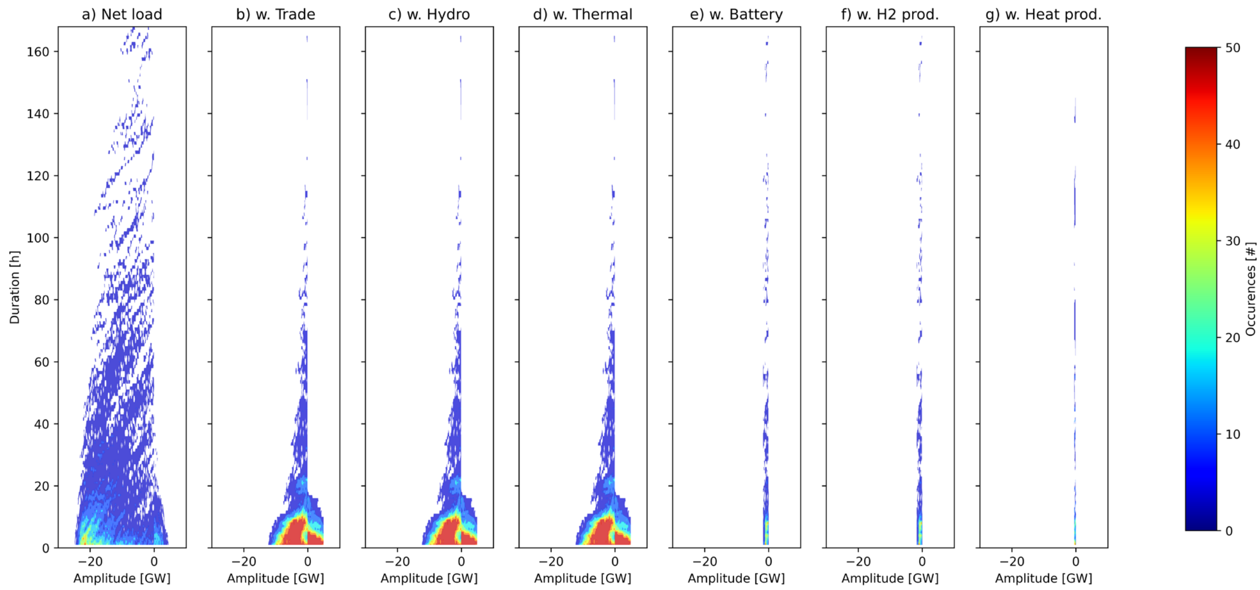

Figure 5. Net load of Denmark (DK_T) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields. The y-axis was limited at 168 h (one week).

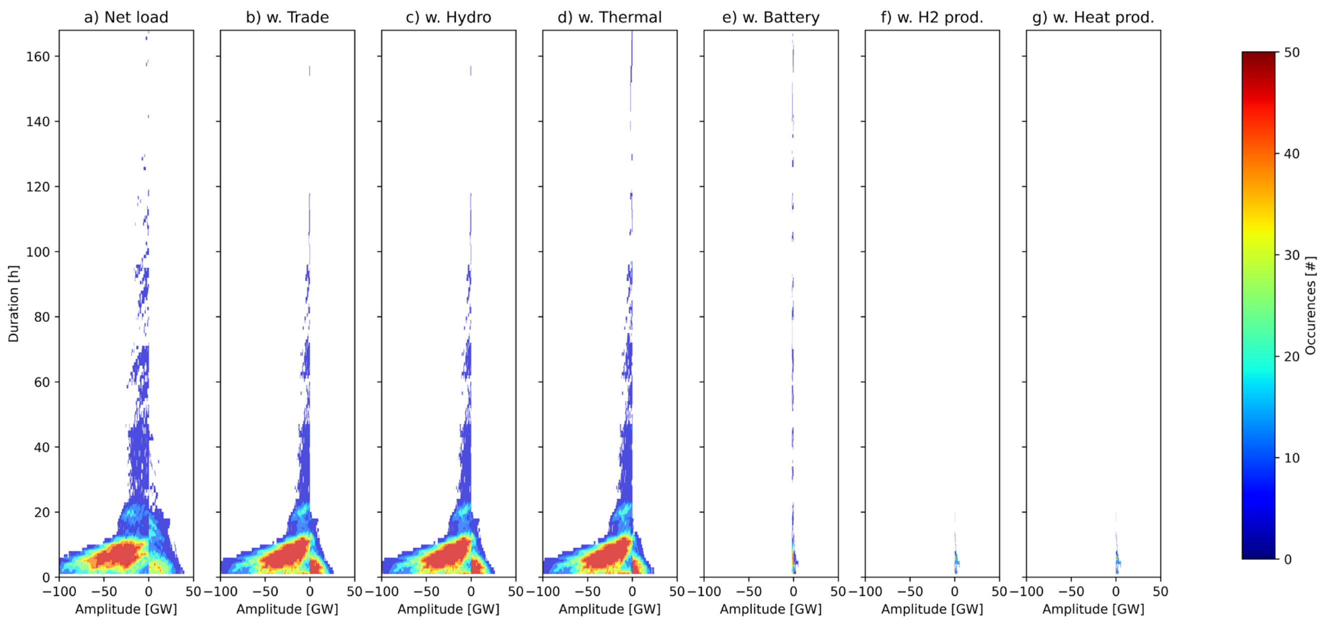

Figure 6. Net load in southern UK (UK_S) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields. The y-axis was limited at 168 h (one week).

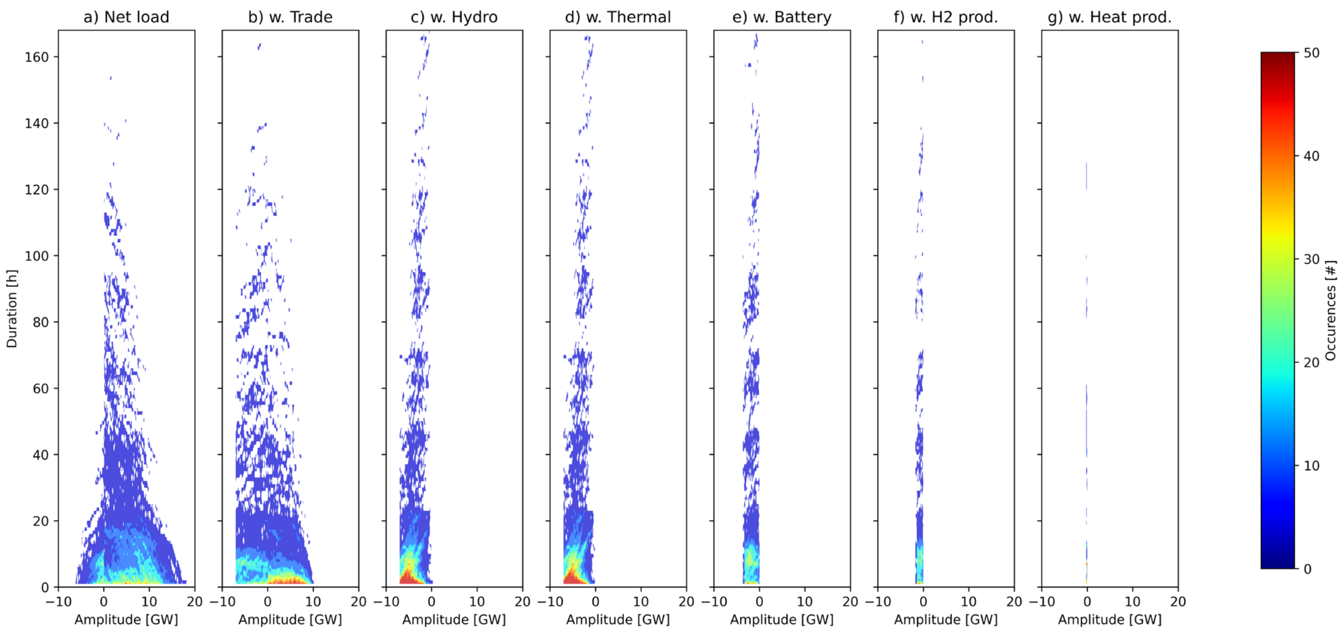

Figure 7. Net load in southern Sweden (SE_S) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields. The y-axis was limited at 168 h (one week).

4. Categorizing the Cost-Efficient Contribution of Variation Management Strategies

The results confirm that different variation management strategies contributed with different functionalities in the electricity system. At the same time, the contribution from each strategy, in terms of reduction in net load amplitude and number of occurrences on different timescales, was qualitatively similar in the four investigated regions. However, the size of the investments in different strategies and their quantitative contribution was different in the different system contexts.

As the objective of the model applied in this work was to minimize the total cost of the electricity system, the investments in, and operation of, the variation management strategies as given in this work was cost efficient given the available options. That is, the functionality provided was motivated by the cost structure and technical limitations of each strategy. High reductions in the amplitude of recurring variations were cost-efficiently supplied by strategies with a low cost of charging and/or discharging power, such as batteries. To manage variations over longer timescales, a low cost of energy storage is required. In the examples given in this work, the cost of hydrogen storage represents the cost of storing hydrogen in large-scale underground caverns, which is low compared to energy storage in batteries. The cost of storing heat in tank storages is even lower. The cost of storing fuel for thermal generation was omitted in the model, which allows combined-cycle gas turbines and combined heat and power plants to manage the variations with a long duration. Variations with a low number of occurrences were managed most efficiently using strategies with a low investment cost, such as open-cycle gas turbines. With a low number of occurrences a high running cost is acceptable.

The roles identified by these measures can form the basis for a functionality-based categorization of strategies to manage variations. Whereas previous categorizations of strategies to manage variations were based on the technical properties of the strategies, a categorization supporting the understanding of the functionality of the strategies to manage variations in the electricity system should rely on the cost structure. Based on the above reasoning and the work by [7,8], the following categories are proposed:

- Peaking strategies, which manage variations with a low number of occurrences. Similar to peak production plants, peaking variation management strategies have low investment costs in terms of charging, discharging and storage capacity. However, the low investment cost is typically accompanied by a high operational cost, i.e., a high cost of electricity discharged or low value of electricity charged.
- Shifting strategies, which reduce recurring variability on shorter timescales. These strategies are associated with a low cost of charging and discharging capacity and a low cost of operation, since variability on shorter timescales have high amplitude and high number of occurrences. However, a low cost of charging and discharging capacity is typically associated with a high cost or a limited capacity to store energy. Thus, these strategies are mainly applied for shifting loads or production during shorter time intervals.
- Complementing strategies, which manage recurring variations on longer timescales. These strategies are associated with a low cost of energy storage. However, since the amplitude of variations on longer timescales is lower, a higher cost associated with the charging and discharging power is acceptable. A low to medium cost of operation is required from these strategies since the variations being managed have a long duration and medium recurrence. This category could be further subdivided to differentiate between complementing strategies managing variations on weekly and seasonal timescales.

A categorization based on the cost structure has the advantage that the category reveals the functionality of the strategy. This categorization thus facilitates the choice of variation management strategies for different system services and contexts.

5. Discussion and Limitations

In this work, net load variations were plotted in the space spanned by amplitude, duration and number of occurrences (i.e., the variation space) to better understand how different strategies to manage variations complement each other. For this analysis, the cost-efficient combination of a large set of strategies provided by the electricity system investment model was required. However, plotting a gradually reduced net load in the variation space can also be useful to understand how variations are managed in an existing system, using electricity production data.

Applying the method proposed to map the contribution of flexibility measures to reduce the net load, functionality-based categories of variation management strategies can be identified. The vast majority of previous categorizations have focused on the technical properties of the flexibility measures. For example, Fuchs and Lunz [27] and Zhao and Wu [28] subdivided electricity storage systems into electrical, mechanical, chemical and thermal storage units, while Sauer [29] differentiated between electricity-to-electricity storage, electricity-to-anything storage and anything-to-electricity storage systems. Palizban and Kauhaniemi [30] have mapped energy storage systems with respect to those applications for which they are suitable and unsuitable for, using a color-coded matrix. Other categorizations have focused on the motive for the investment, such as single-use/double-use [31] which distinguished between investments that are actively made and are dedicated to provide flexibility in the electricity system (single-use) and those cases in which assets that are already integrated in the electricity system for other purposes are used (double-use). While all these categorizations support the understanding of flexibility measures, measures with the same functionality in the electricity system are distributed between the categories in the above-mentioned frameworks. A previous work by the author [7] proposed instead a functionality-based framework, organizing variation management strategies according to the service they provide in the electricity system. This work further developed this framework.

The strategies applied in the regions modeled in this work are cost efficient from an energy-only perspective. However, without the perfect foresight of the modelled world, flexibility markets may be needed to stimulate investments prior to large electricity price variations. In the design of flexibility markets, a market for each of the above-mentioned categories would assure competition between strategies providing the same function to the electricity system and stimulate investments in a balanced set of strategies. The size of the different markets should be defined by the electricity system context, i.e., the need for the different functionalities based on the variability profile of the present and future electricity systems.

This work investigates strategies to manage variations on the timescale of hours to a couple of years. Variations within the hour as well as variations with very a low number of occurrences (e.g., once every ten or thirty years) is outside the scope of this work. Meng and Zafar [32] provided an overview on how variations on very short timescales, to recover the frequency after faults, can be managed in electricity systems with a high share of wind and solar power. They concluded that batteries with grid-forming converters, with the ability to provide active power very rapidly, are able to replace synchronous generators while maintaining the ability to recover the frequency after a fault. However, if synchronous generators can be replaced completely remains to be investigated. Ullmark [33] showed that if batteries are allowed to meet the demand for variations within the hour, these variations can be managed at a low cost (<1% of total system cost).

Ruhnau and Qvist [34] investigate the impact of variations in the German electricity system over a 30-year period and found that there were low wind events with a long duration (60 days with short periods of interruption) which occurred very rarely. As shown in this work, the choice of strategy for a certain type of variation depends on the cost structure. Variations with a long duration and low number of occurrences are cost-efficiently managed by strategies with a low cost of storage and low investment cost. A cost-efficient strategy to manage the variations identified by [34] would thus be biogas

gas-turbines with a sufficiently large storage of biogas. Sufficient biogas turbine capacity is likely to already be available to the electricity system to manage variations with a shorter duration occurring on a yearly basis. The fuel costs during the 60-day period would be significant but, since these events occur very rarely, this fuel cost would have a low impact on the total system cost and the overall electricity system composition.

6. Conclusions

In this work, a novel tool to map variations in electricity systems was applied to visualize how variations can be cost-efficiently managed in a future northern Europe. The results show that cost-efficient variation management depends on the system context. More specifically, it depends on the nature of the variations present in the electricity system as well as the context-specific prerequisites for variation management, such as extensive demand for hydrogen from industry, availability of district heating grids or access to hydropower. In particular, the access to strategies suitable to manage variations with a long duration varied between the investigated regions. As a consequence, the dominant strategy to manage variations with a long duration varied between, for example, Denmark, where adapted heat production has an important role, and southern Sweden, which relies more on hydropower and adapted hydrogen production to manage these variations.

Electricity systems with good conditions for solar power and extensive electricity demand for transportation were subject to variations with a high amplitude and high number of occurrences which can be cost-efficiently managed using batteries with a low cost of charging and discharging power and low losses per cycle. Examples of such regions in northern Europe were southern Germany and southern Poland, with inland locations and high population densities. In these regions, there may also be potential for some base load generation.

Electricity systems with good conditions for wind power, such as Demark, the Netherlands and northern Germany, managed variations through trade, including import of solar PV energy and adapted production of hydrogen and/or heat. Extensive industrial hydrogen demand or district heating systems facilitated the integration of wind power since wind variations have long durations and hydrogen and heat can be stored at a relatively low cost.

In regions with good conditions for wind power but limited trade, such as the UK, it was cost efficient to combine wind power capacity with solar PV capacity to reduce the duration of low wind events. It was often cost efficient to combine hydropower with batteries, where the former managed the positive net loads with short and long durations but the latter managed variations with a high amplitude including negative net load. In general, cost-efficient variation management was achieved by combining wind and solar power, and with strategies to manage variations with different cost structures.

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Data Availability Statement: The key data applied in this work are provided in the manuscript, in the appendix or is referenced. The data can be made available on request.

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Conflicts of Interest: The author declares no conflict of interest.

Appendix A

Figure A1. Northern Europe subdivided into 14 regions as applied in this work.

Appendix B

Table A1 shows the investment costs together with the operation and maintenance costs (O&M) for electricity and heat generation applied in this work. The costs are based on IEA [35] and the Danish Energy Agency [36], except for nuclear power and wind power with low specific power (SP). The investment costs for nuclear power were estimated after dialogues with experts. It corresponds to the average investment cost in the case where several units are invested in and is lower compared to levels given for Europe by the IEA. The cost to manage waste (today 4 EUR/MWh in Sweden) was expressed as a small addition to the variable cost (0.5 EUR/MWh) to manage fuel waste and a larger fixed cost to manage the plant at the time of decommissioning (corresponding to 3.5 EUR/MWh after 60 years with 90% utilization) were allocated to fixed O&M. Nuclear energy was assumed to be able to vary its output between 70–100% of rated power. The majority of wind turbines today have a specific power around 300 W/m^2. However, turbines with a lower specific power (generator capacity over swept rotor area) are advantageous for sites with lower average wind speeds and offshore locations. Hodel and Göransson [37] assessed cost-efficient turbine designs in different system contexts using a cost model to assess the cost of a range of wind turbine designs. Investment costs for onshore wind turbines with a specific power of 100 W/m^2 and tower height of 150 m and for offshore wind turbines with 200 W/m^2 and 150 m tower height were based on their work.

Table A2 shows the cost and properties of the energy storage options. These costs were based on the Danish Energy Agency [36]. The cost of transmission capacity was assumed to 2k EUR/MW and km, where the distance is taken as the distance between a point in each region with extensive grid capacity. The calculations applied annual investment costs which were derived using a 5% interest rate and technical lifetimes as given in Table A1. Table A3 shows the fuel costs applied in this work.

Table A1. Costs and properties of electricity and heat generation units. CHP = Combined Heat and Power, CCS = Carbon Capture and Storage, CCGT = Combined Cycle Gas Turbine, OCGT = Open Cycle Gas Turbine.

Technology	Investment Cost [MEUR/MW(h)]	Variable O&M Cost [EUR/MWh]	Fixed O&M Cost [kEUR/MW, year]	Technical Lifetime [year]	Efficiency [%]
Biomass steam	2.0	2.1	52	40	35
Biomass CHP	3.3	2.1	105	40	30
Coal w. CCS [1]	3.5	2.1	107	40	40
Biogas CCGT	0.90	0.8	17	30	61
Biogas OCGT	0.45	0.4	15	30	42
Nuclear power	4.0	7.1	123	60	33
Solar PV power	0.3	0.5	7	40	100
Onshore wind power (100 W/m^2 150 m)	1.65	1.1	13	30	100
Onshore wind power (300 W/m^2 100 m)	1.0	1.1	13	30	100
Offshore wind power (200 W/m^2 150 m)	1.75	1.1	36	30	100
Heat pump	0.9	2.2	2	25	3
Electric boiler	0.1	1	1	20	1

[1] Coal was assumed to be mixed with biomass in order to compensate for emissions which are not captured.

Table A2. Costs and properties of storage technologies. Investment costs for batteries (power), electrolysis and fuel cells are given in MEUR/MW while costs for batteries (energy) hydrogen storage and heat storage are given in MEUR/MWh.

Technology	Investment Cost [MEUR/MW(h)]	Efficiency (ch/disch) [%]	Fixed O&M Cost [kEUR/MW(h), year]	Technical Lifetime [year]
Battery, Li-ion (energy)	0.08	96/96	-	25
Battery, Li-ion (power)	0.07	100	0.5	25
Electrolysis	0.4	70	18	20
Fuel cell	0.5	50	55	10
Hydrogen storage	0.011	100	-	40
Heat storage	0.003	100 [1]	0.009	25

[1] Heat storages have a continuous loss corresponding to 0.023% per unit of time and energy stored.

Table A3. Cost of fuel applied in the calculations.

Fuel	Fuel Cost [EUR/MWhth]
Biomass	40
Biogas	77
Uranium	1.65
Coal w. biomass blend	7.5

On- and offshore wind power and solar PV power were represented using time-resolved wind and solar power production potential for the investigated regions derived using [18] which rely on ECMWF ERA5 [19] and the Global Wind Atlas [20] for the historical years 1991–1992. These two years were chosen since they represent one year with a lower hydropower inflow in the Nordic countries (1991) and one year with a higher hydropower inflow in the Nordic countries (1992). The potential for wind and solar PV investments per region together with their respective full load hours are given in Tables A4 and A5. Electricity demand corresponding to temperature variations in the historical years 1991–1992 was also derived using [18]. After the removal of unsuitable and protected areas, the potentials for onshore wind power, offshore wind power and solar power were derived applying an assumed factor of social acceptability. For offshore wind power and solar PV power, 33% and 5% of the share of the remaining land was assumed to be available in all regions, respectively. For onshore wind power, 8% of the remaining land was assumed to be available except for Norway (1%), Sweden, the UK and Ireland (4%) where acceptance for wind power investments has proven to be low. The potential area for wind power was subdivided into five wind classes for each region representing different wind conditions. Wind turbine technologies were chosen to match the conditions of their respective area, with wind turbines with 100 SP (Specific Power, i.e., generator capacity relative to swept rotor area in W/m^2) and 150 m hub height for onshore sites with low average wind speeds (i.e., wind class 1–3), 300 SP and 100 m hub height for areas with high average wind speeds (i.e., wind class 4–5) and 200 SP and 150 m hub height for offshore wind turbines.

Table A4. Potential for electricity production (GW) for the five classes of onshore wind power (WON1-WON5), the five classes of offshore wind power (WOFF1–WOFF5) and solar PV parks (PV) for the regions considered in this work. SP = Specific Power, i.e., generator capacity relative to swept rotor area in W/m^2.

Region	WON1 100SP	WON2 100SP	WON3 100SP	WON4 300SP	WON5 300SP	WOFF1 200SP	WOFF2 200SP	WOFF3 200SP	WOFF4 200SP	WOFF5 200SP	PV
SE_N	0.7	5.1	5.3	3.4	2.1	0.0	0.0	1.7	16.3	2.8	86.3
SE_S	0.2	1.5	7.0	8.2	0.9	0.0	0.0	0.1	22.9	47.7	44.1
DE_N	0.0	0.0	2.9	18.7	9.6	0.0	0.0	0.0	0.0	29.4	161.4
DE_S	1.0	5.1	6.7	10.1	0.6	0.0	0.0	0.0	0.0	0.0	180.2
BAL	0.0	0.0	7.3	34.9	0.5	0.0	0.0	0.0	10.5	41.9	193.5
PO_S	0.1	0.9	8.4	27.3	0.1	0.0	0.0	0.0	0.0	0.0	256.3
NO_N	0.1	0.3	0.5	1.8	2.0	0.1	0.7	1.3	4.9	7.9	194.5
DK_T	0.0	0.0	0.0	1.1	10.8	0.0	0.0	0.0	0.1	77.4	53.2
BENELUX	0.0	0.0	0.4	6.2	4.2	0.0	0.0	0.0	0.0	83.5	51.3
FI	0.0	7.1	26.1	7.7	0.9	0.0	0.0	1.4	27.3	31.6	43.7
NO1	0.4	0.6	0.6	1.1	1.0	0.0	0.0	0.1	2.2	18.3	125.0
PO3	0.0	0.1	4.2	27.4	0.4	0.0	0.0	0.0	1.0	17.5	160.2
UK1	0.0	0.0	0.1	5.4	12.2	0.0	0.0	0.0	0.8	134.5	181.6
UK2	0.0	0.0	0.2	2.9	9.5	0.0	0.0	0.0	0.3	46.7	85.6

Table A5. Full load hours before curtailment for the five classes of onshore wind power (WON1-WON5), the five classes of offshore wind power (WOFF1–WOFF2) and solar PV parks (PV) for the regions considered in this work. SP = Specific Power, i.e., generator capacity relative to swept rotor area in W/m^2.

Region	WON1 100SP	WON2 100SP	WON3 100SP	WON4 300SP	WON5 300SP	WOFF4 200SP	WOFF5 200SP	PV
SE_N	4127	5062	-	-	4244	-	-	1006
SE_S	4162	5178	5823	3451	4131	5159	5348	1233
DE_N	-	4932	5734	3556	4265	5338	5577	1263
DE_S	3313	4560	5190	3417	3987	-	-	1320
BAL	-	5387	5799	3407	4076	5256	-	-
PO_S	3762	4808	5644	3364	4006	-	-	1288
NO_N	3614	-	-	-	4393	-	-	-
DK_T	-	-	-	3823	4270	-	5555	1299
BENELUX	-	5020	5475	3483	4106	-	5198	1267
FI	4607	5470	5852	-	4340	-	-	998
NO1	3319	-	-	3429	4251	-	4869	1156
PO3	-	5424	5838	3490	4086	5215	5390	1271
UK1	0	0	5303	0	4254	5026	5237	1237
UK2	0	4933	5345	3624	4558	0	5501	1087

Appendix C

Appendix C.1 Solar PV Dominated Regions (DE_S, PO_S)

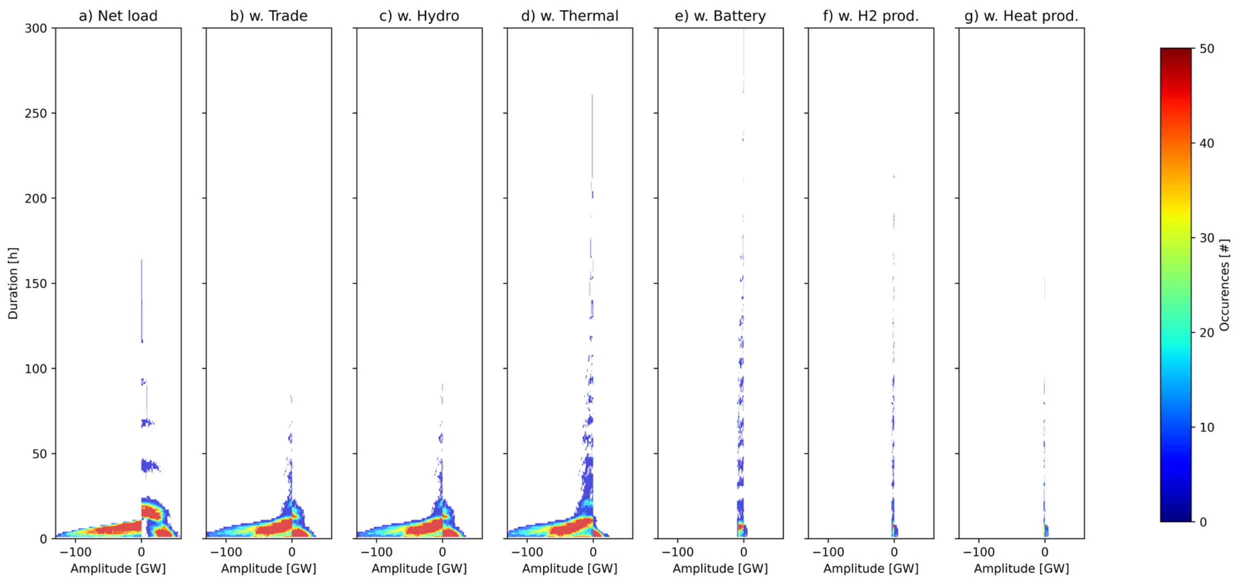

Figure A2. Net load in southern Germany (DE_S) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

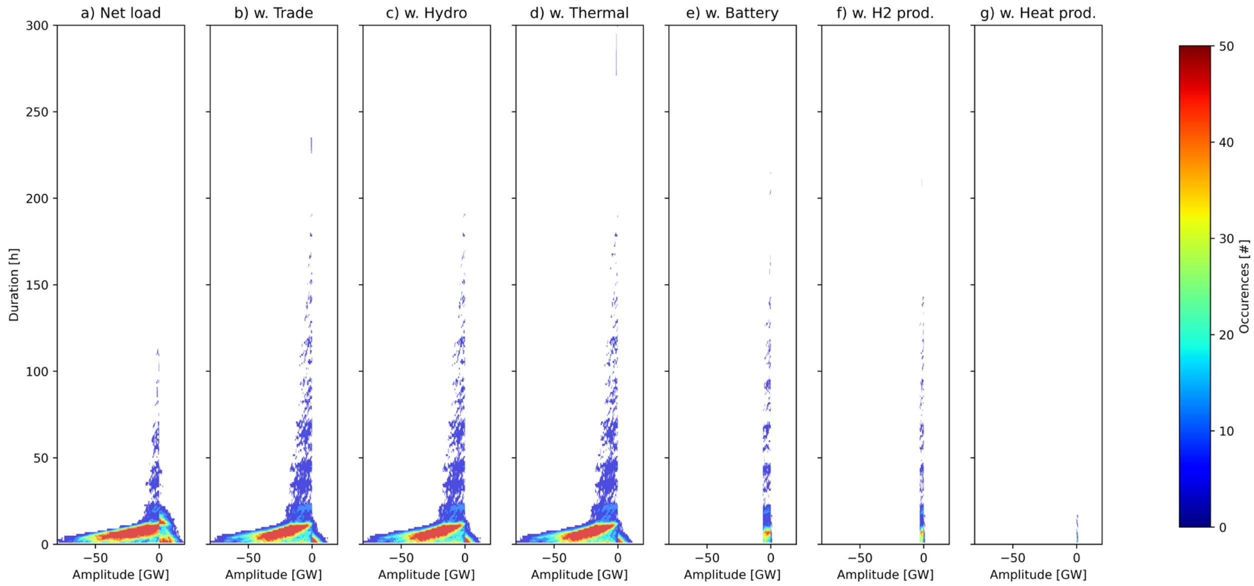

Figure A3. Net load in southern Poland (PO_S) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

Appendix C.2 Wind Dominated Exporting Regions (DK_T, BAL, PO3, UK_N)

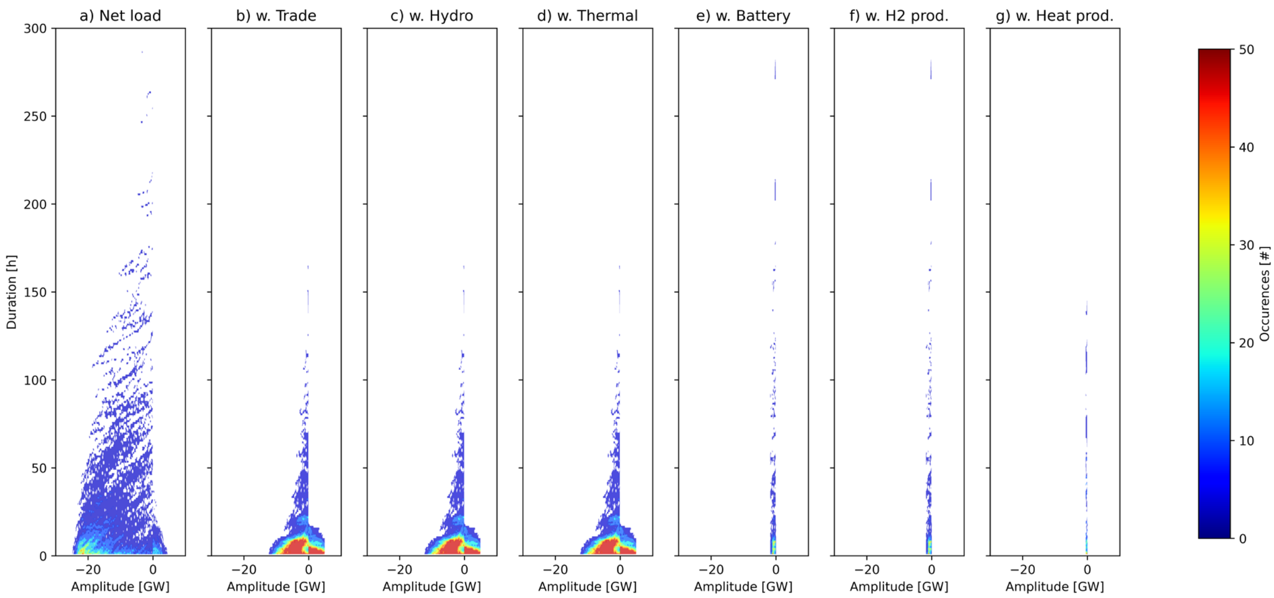

Figure A4. Net load in Denmark (DK_T) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

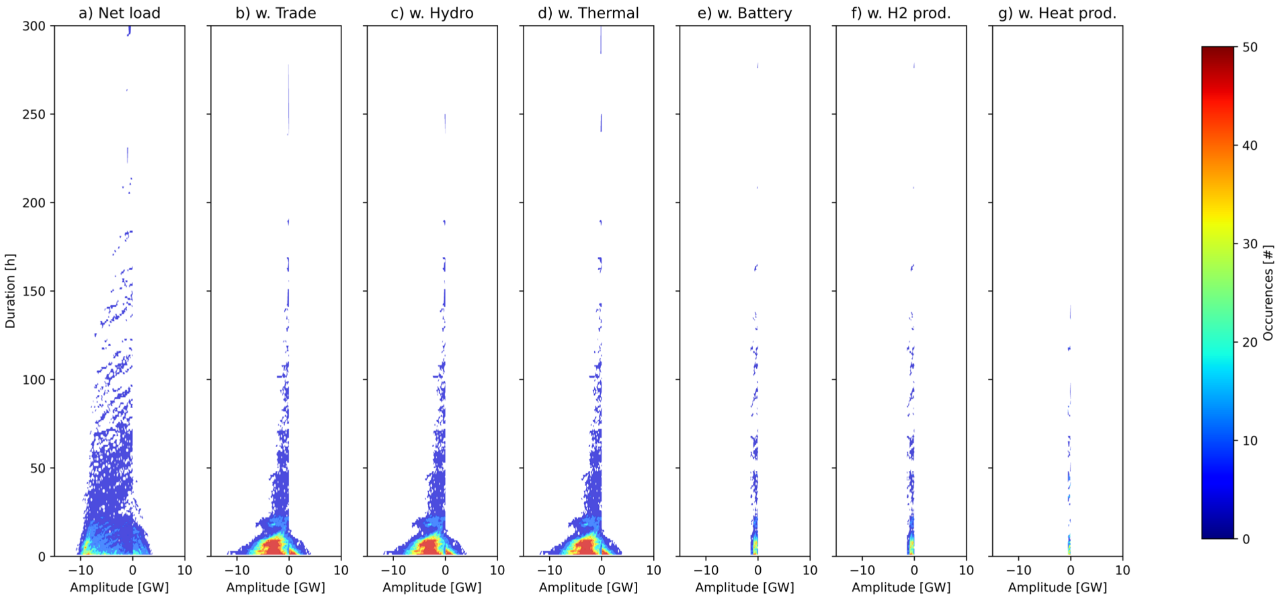

Figure A5. Net load in Estonia, Latvia and Lithuania (BAL) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

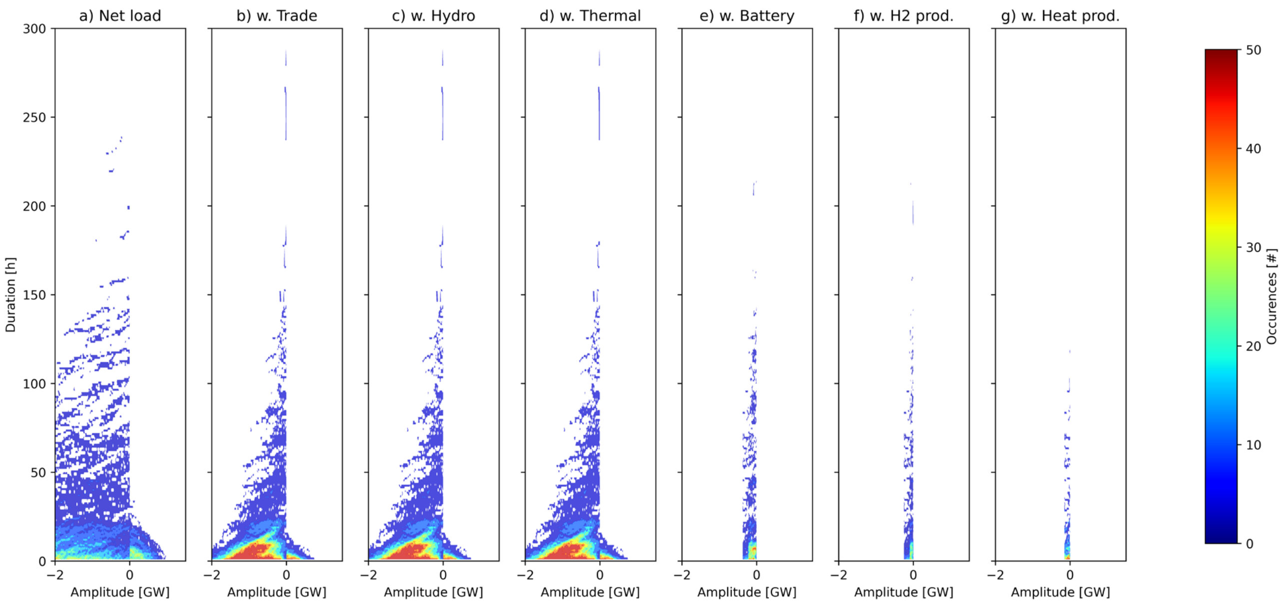

Figure A6. Net load in northern Poland (PO_N) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

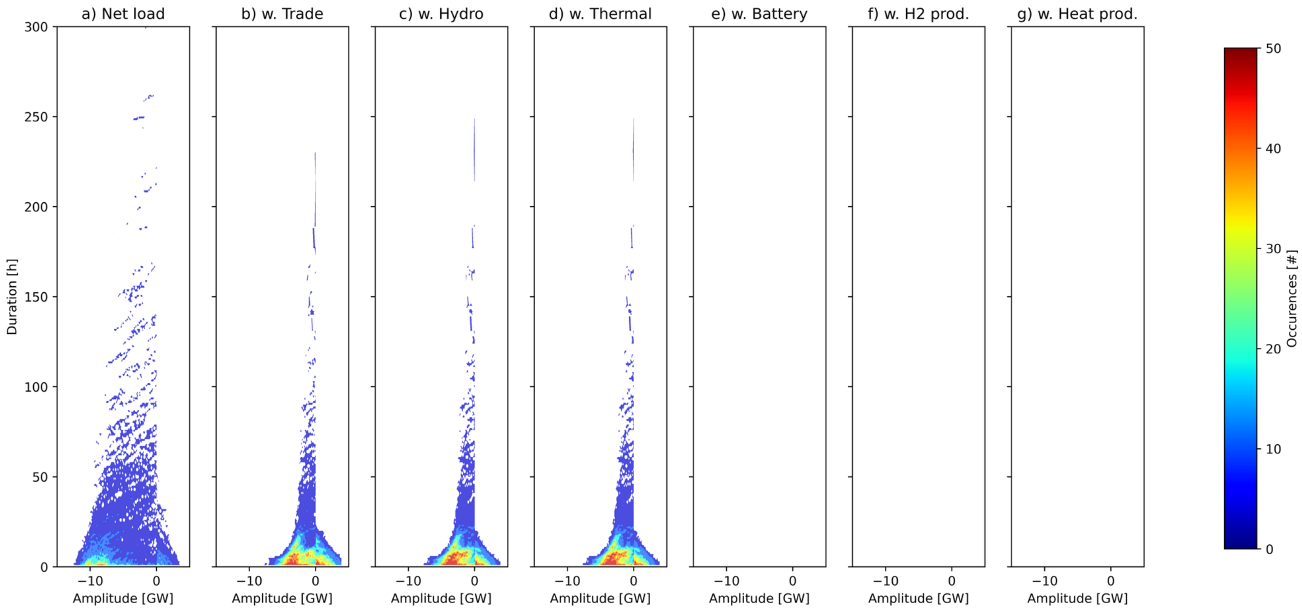

Figure A7. Net load in northern UK (UK_N) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

Appendix C.3 Regions with Wind and Solar Power (UK_S, DE_N, BENELUX)

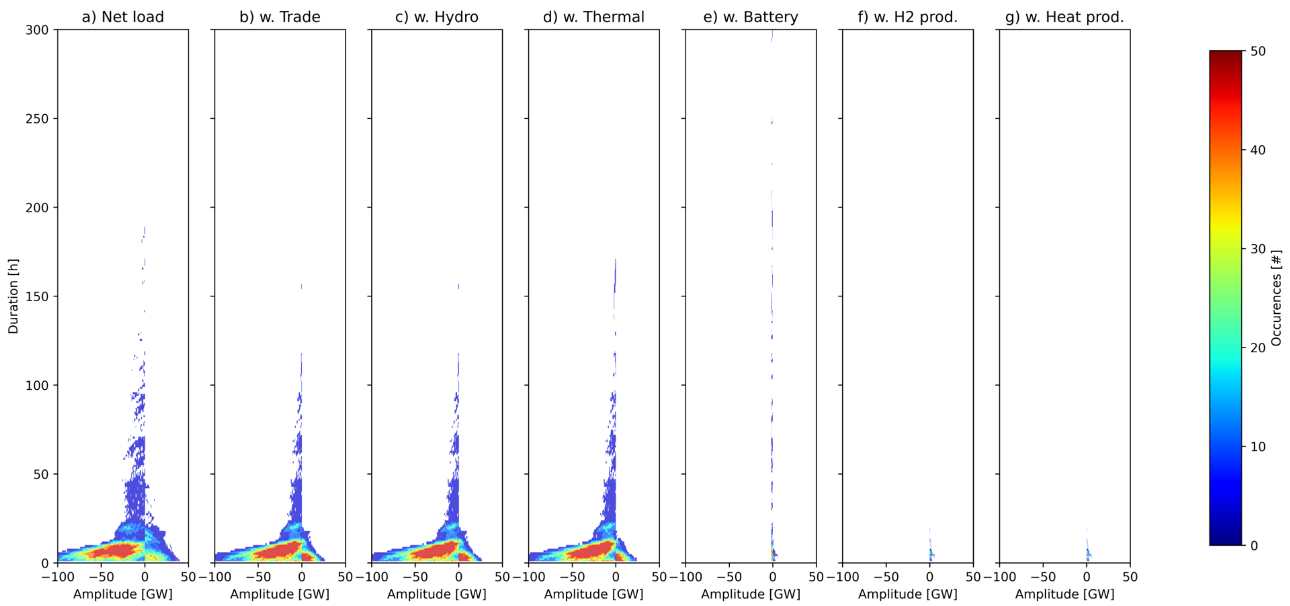

Figure A8. Net load in southern UK (UK_S) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

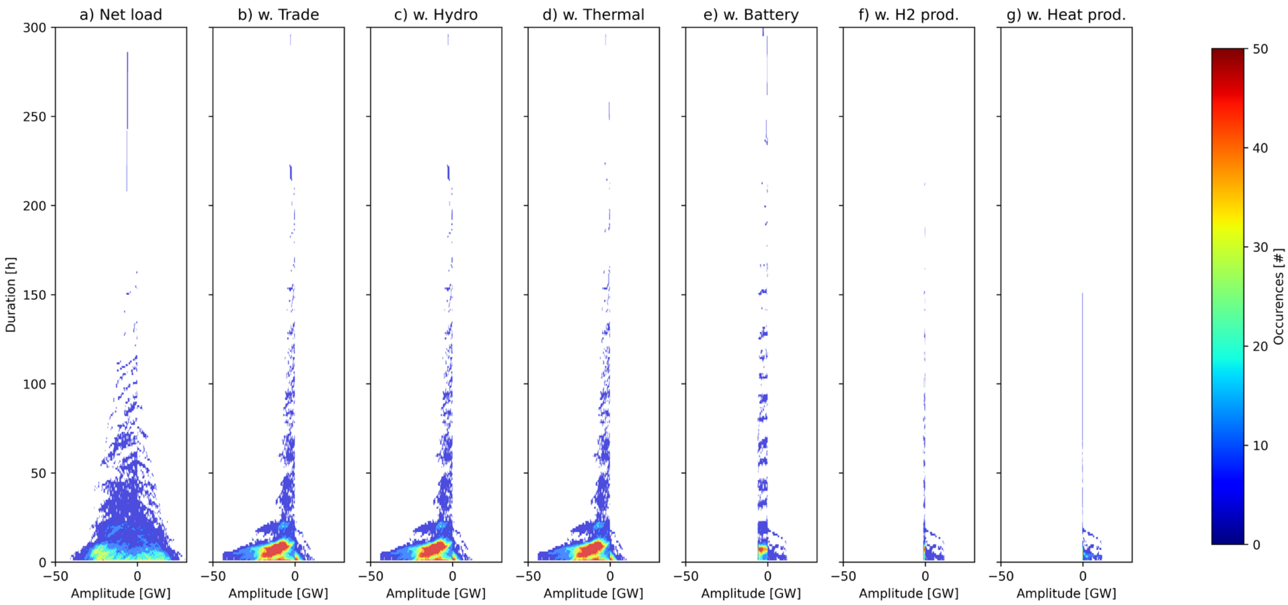

Figure A9. Net load in northern Germany (DE_N) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

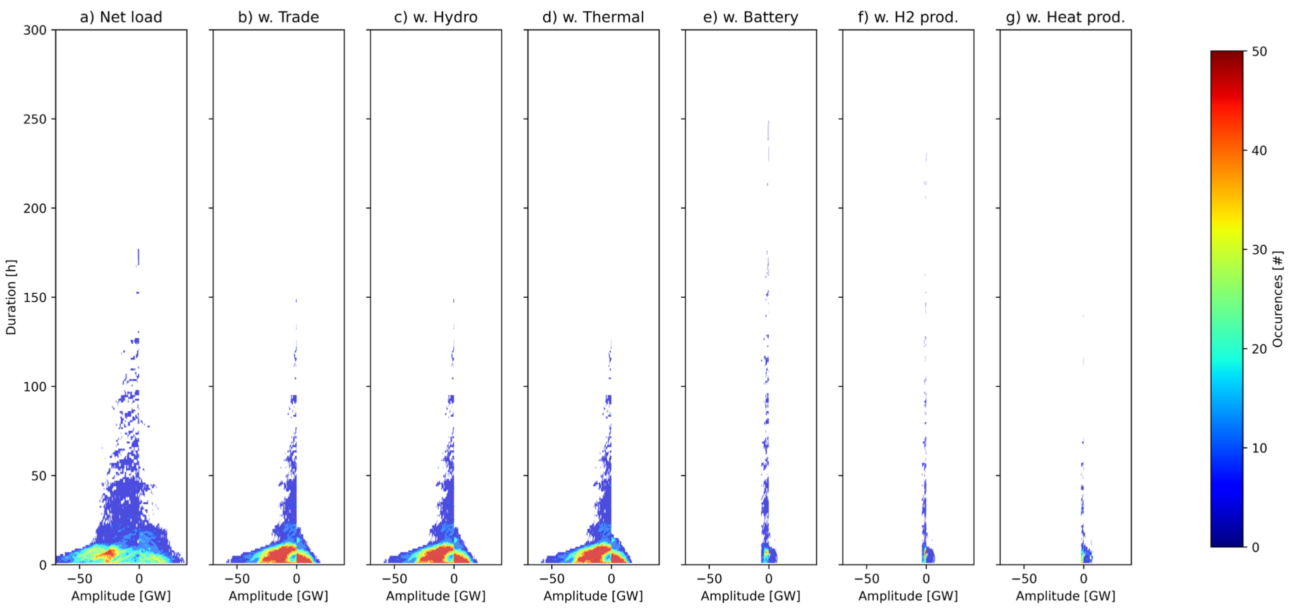

Figure A10. Net load in Belgium, the Netherlands and Luxemburg (BENELUX) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

Appendix C.4 Regions with Access to Hydropower (SE_S, FI, NO1, SE_N, NO_N)

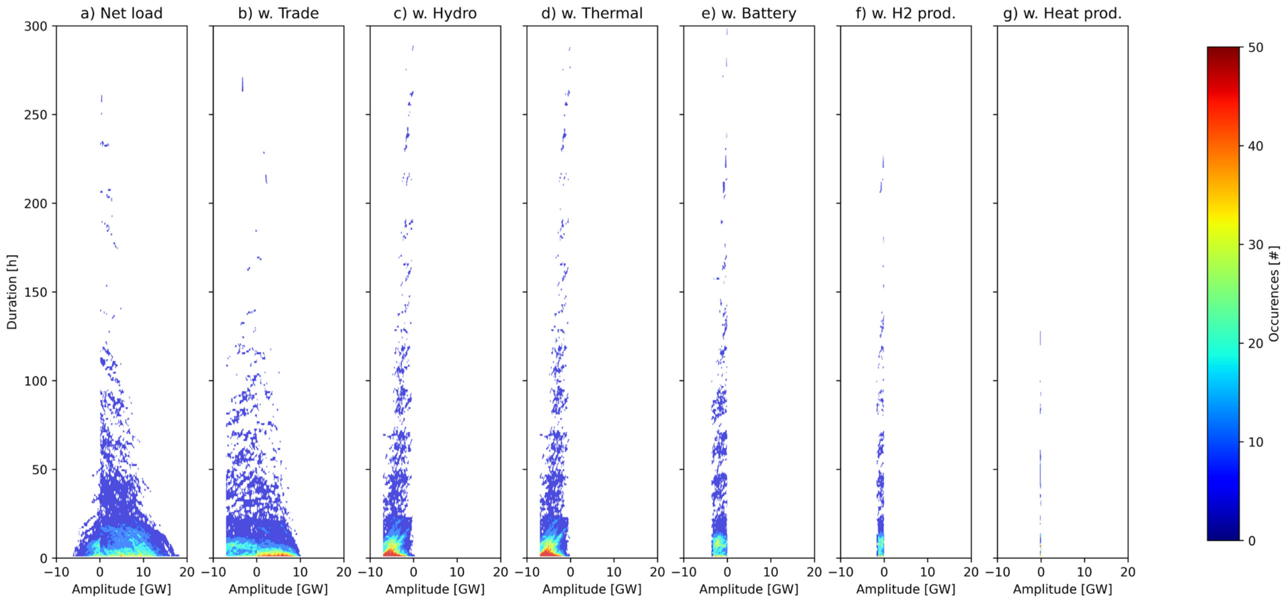

Figure A11. Net load in southern Sweden (SE_S) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

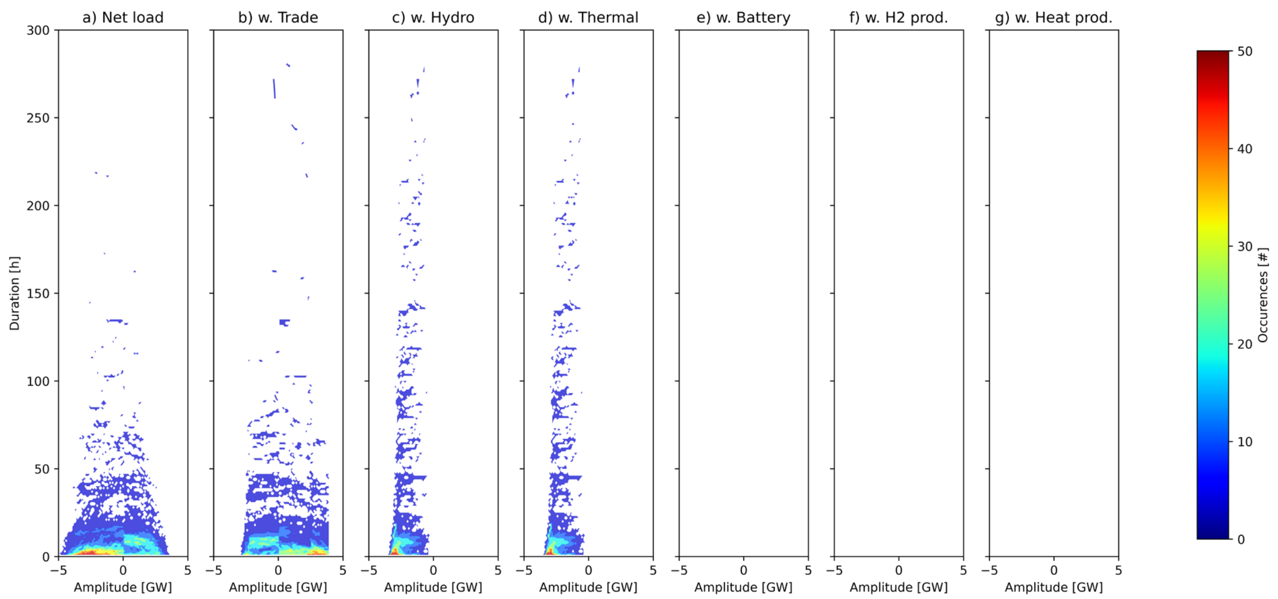

Figure A12. Net load in northern Sweden (SE_N) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

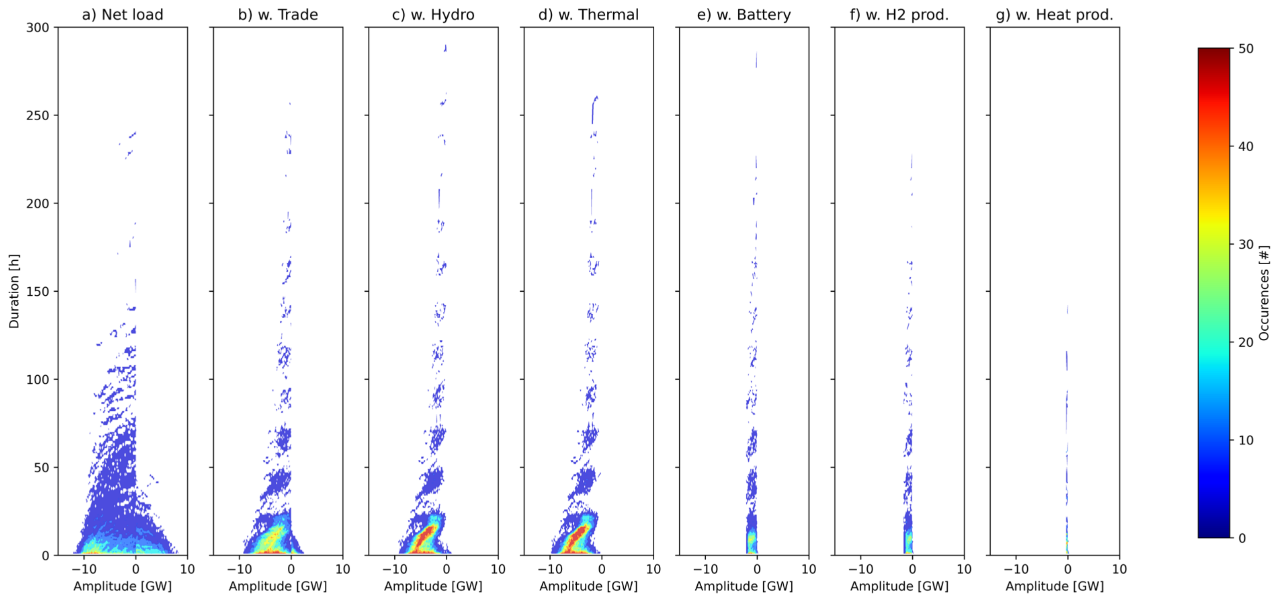

Figure A13. Net load in Finland (FI) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

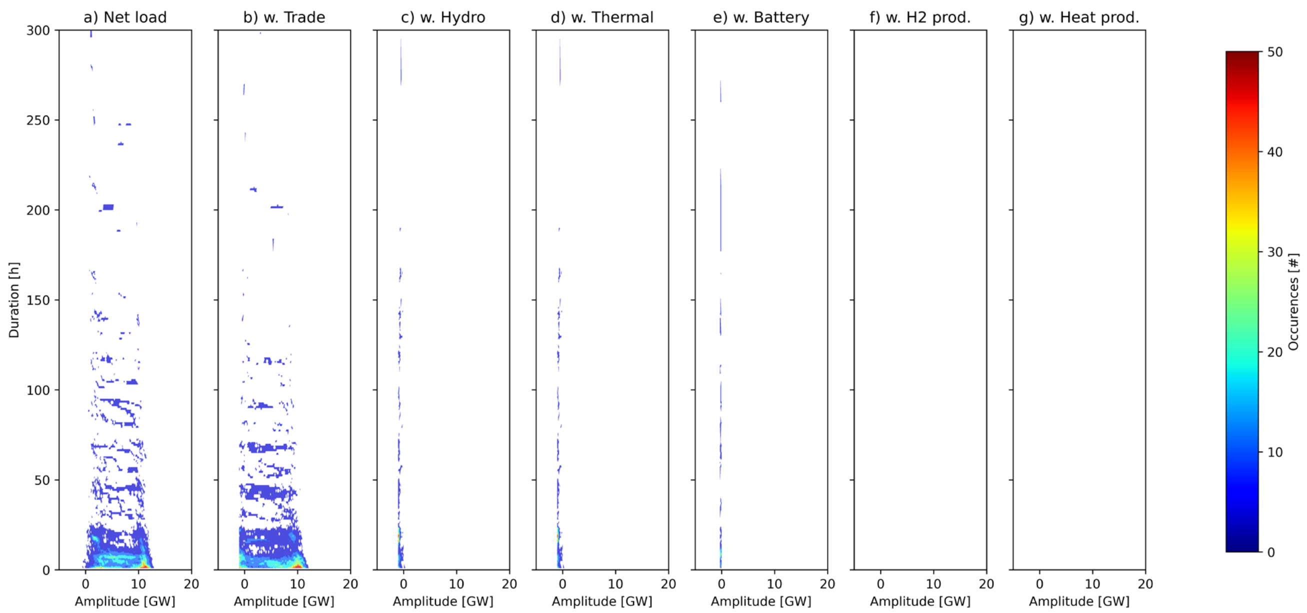

Figure A14. Net load in southern Norway (NO_S) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

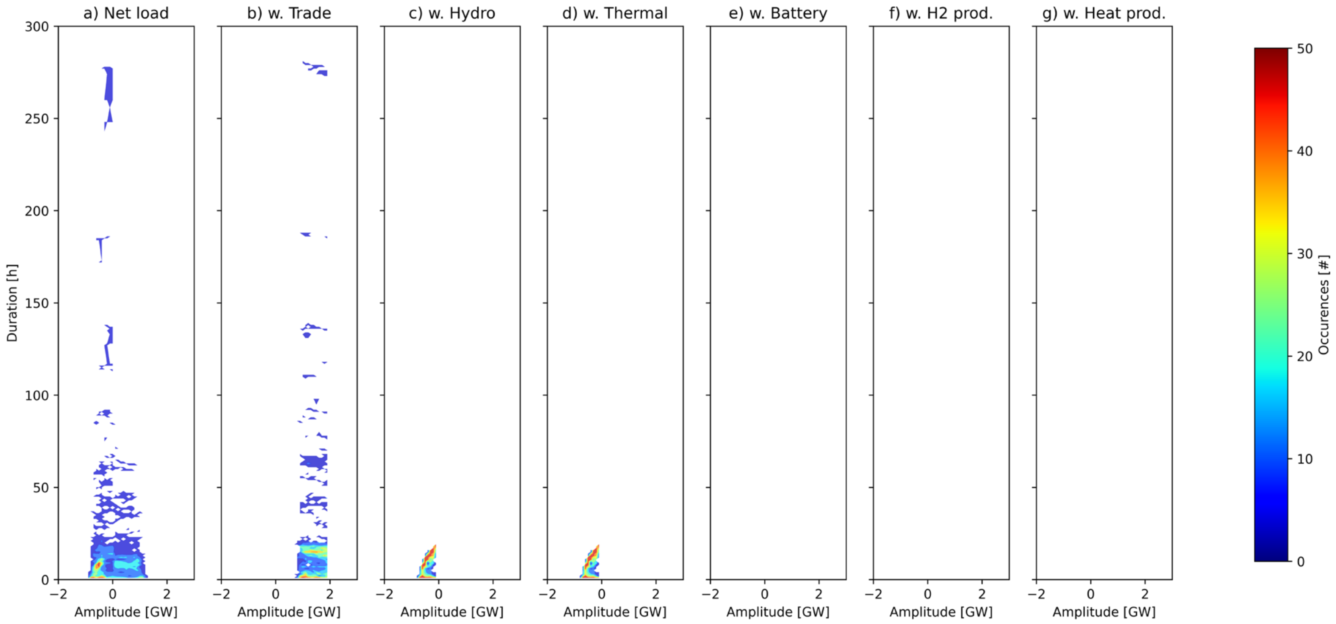

Figure A15. Net load in northern Norway (NO_N) (**a**) reduced by (**b**) trade, (**c**) trade and hydropower, (**d**) trade, hydropower and base load, (**e**) trade, hydropower, base load and batteries, (**f**) trade, hydropower, base load, batteries and adapted hydrogen production and (**g**) trade, hydropower, base load, batteries, adapted hydrogen production and adapted heat production. The color scale indicates number of (#) occurrences and was limited to 50 occurrences, implying that the number of occurrences may be higher in the deep red fields.

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