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Electricity adequacy in Switzerland and Europe for the winter 2022-2023

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Abstract

The European electricity system enters the winter of 2022-2023 facing challenges such as reduced availability of French nuclear power, lower than average stored hydro energy and possible gas shortages in the power industry. These challenges limit the amount of energy available to the system during the winter and reduce the system's ability to meet peak demand and. This study quantitatively analyses the security of electricity supply in Europe (with a focus on Switzerland) between November 2022 and April 2023 by simulating electricity generation and trading under various supply and climate scenarios. To provide a conservative analysis, we exclude certain measures such as demand reduction targets and fuel switching efforts. The results show that Europe, and France in particular, can avoid transmission congestion and power shortages in the event of reduced French nuclear availability. However, in a cold winter, supply shortages may occur in gas-dependent countries if reduced French nuclear availability is combined with gas generation being limited to historical levels. Furthermore, if a 20% gas saving is enforced, Europe could face supply shortages in various weather realisations. On the other hand, Switzerland faces few challenges even in cold winters with the reduced availability of French nuclear and the implementation of 10% gas savings in the electricity system. This is due to the flexibility of the Swiss hydro system and trading opportunities with neighbouring countries.

1.Introduction

Given the importance of electricity in today's modern society, the adequacy of electricity supply is routinely analysed at the national level (Federal Office of Energy, 2022b) and at the international level, such as the European level (ENTSO-E, 2022). In the case of Europe, winter electricity adequacy in particular is a major concern, as most countries currently have a winter peak demand and many European countries still have limited seasonal storage, e.g., in the form of hydro reservoirs. The European power system faces additional challenges in the winter 2022-2023 due to:

- possible reduced availability of gas for electricity generation in Europe (as a result of the Russian invasion of Ukraine),
- low nuclear availability in France, and
- relatively low water reservoir reserves at the beginning of the winter in Southern Europe and Norway due to the drought over summer and higher electricity consumption for air conditioning.

Following concerns in Europe about the security of electricity supply, Switzerland could also face challenges in the winter of 2022-2023. While on average Switzerland has a balanced electricity trade on an annual basis, Switzerland is mainly an importer in the winter half of the year (Figure 1).



Figure 1 Total export (positive values) and import (negative values) for Switzerland in the winter half year (left) and annually (right) – Source: Fig. 19 (Federal Office of Energy, 2022a)

In this analysis we analyse the security of supply on a European scale with a focus on Switzerland. We quantify the amount of energy not served (ENS) under different conventional generation and climate scenarios. On the conventional generation side, we cover several scenarios of gas availability for the power sector as well as the availability of French nuclear power plants. We simulate the European power system between November 2022 and April 2023.

Section 2 briefly explains the simulation methodology and the system adequacy index analysed. Section 3 describes the scenarios in terms of conventional fleet development and climate scenarios. The results are presented in section 4. Section 5 concludes the paper.

2. Simulation method

The simulation methodology is based on an adapted version of the simulation approach used in the medium and long-term system adequacy analysis for Switzerland (Weigt, Demiray, Maurer, Fuchs, & Darudi, 2022).¹ The European electricity markets are coupled using a zonal market approach. However, the zonal market is based on inputs from a simplified but detailed nodal representation of the power system. To replicate such an approach, our model simulates the European electricity market using two sub-modules: the **nodal** model and the **zonal** market model. The nodal model provides a technical/physical benchmark of the European power system, which ultimately prepares inputs to the zonal market model.

¹ The name of the report in English is "Modeling of Supply and System Capacity (System Adequacy) in Switzerland in the Electricity Sector 2022." The report is originally prepared for the Swiss Federal Office of Energy in German.



Figure 2 Model chain

The nodal model, as the name suggests, has a nodal geographical resolution. It models generation and consumption on a nodal basis and takes into account the physical constraints of the transmission system and power plants in the European system, including Switzerland (CH), AT, DE, FR, IT, BE, CZ, DK, ES, GB, HU, LU, NL, NO, PL, PT, SE, SI and SK (Figure 3). The nodal model has an hourly time resolution and uses a linearized (DC) load flow to model electric flow in the transmission system. The model simulates dispatch plan of the system by minimizing system costs considering data on transmission lines, power plants capacity and availability, generation costs, demand, renewable infeed, etc. Based on this model stage, the necessary parameters for market model are determined in a next step.

Electricity markets in Europe mostly trade with each other using flow-based market coupling (FBMC), which partially takes into account congestion on transmission lines using a simplified representation of the entire network. In contrast, trade between Switzerland and its neighbours is managed using Available Transfer Capacity (ATC), i.e. a maximum trade between Switzerland and its



Figure 3 Geographical coverage of the models

neighbors is defined in such a way that any specified limits are not violated. The nodal sub-model provides the parameters needed to model the markets in Europe, such as:

- a list of Critical Network Element and Contingency (CNECs) and their limit values. CNECs are network elements (e.g. transmission lines) that have been shortlisted as having the potential to limit the amount of power exchanged, possibly because they are at risk of being overloaded.
- Zonal Power Transfer Distribution Factors (zonal PTDF), which indicate the change in transferred power in a network element when the net-generation of a zone changes.
- ATC values between Switzerland and each of its neighbors, calibrated on the basis of current trade flows according to Frontier Economics (2021), Table 11, NTC "Status Quo."²

The zonal market model uses zonal PTDFs to track the impact of inter-zonal trade on the system and allows trade to minimize the cost of the whole European network as long as it does not violate the limits on CNECs and ATCs. The market model covers the same area as the nodal system and has an hourly time resolution. The market model uses the same datasets as the nodal model, except that the model includes a more detailed representation of the hydro system in Switzerland, taking into account e.g. hydro cascade structures.

Both models are deterministic and assume complete information. Unplanned outages are not modelled. Instead, the average monthly availabilities of different power plant types are applied. Moreover, the power system is optimized for the whole period knowing the demand and RES infeed for the whole simulation period. On the hydro side, the model ensures that the studied countries start the summer of 2023 with as much stored energy as in 2022, i.e. the end state for stored hydro energy is constrained to be at least as high as the corresponding reported values for April 2022. As a result, some of the supply shortages reported in the paper could have been avoided simply by hydro operators relaxing the end condition and allowing more hydro generation at the cost of entering summer with less stored hydro energy.

Indicator

In this report, we focus on Energy Not Served (ENS) as the main indicator for the security of supply. ENS describes the amount of unserved demand in a simulation period, i.e., the demand that cannot be met due to insufficient available supply or grid bottlenecks:

$$ENS = \sum_{h \in period} LostLoad(h)$$

where LostLoad(h) is the unmet demand in the hth hour of the studied period.

3.Scenarios

A set of scenarios for the *conventional fleet* and *climate* scenarios are defined to cover various possible challenges in the European power system in winter 2022-2023. The data regarding installed capacities, current stored energy in hydro reservoirs and historical gas generation for 2021-2022 are obtained from the ENTSO-E Transparency Platform.³ Availability factors for renewables are obtained from Renweables.Ninja (Staffell & Pfenninger, 2016). Demand time series are taken from time series of 2025 in TYNDP 2020 (ENTSO-E, 2020). Finally, Swiss data are obtained from Swissmod datasets (Dujardin et al., 2022) or Energy Perspectives 2050+ (Federal Office of Energy, 2021).

In order to provide a conservative analysis, we exclude peak demand reduction, demand response programs, and fuel switching plans announced by policymakers in the region. Switzerland has introduced additional policies on the supply side to ensure security of supply in winter 2022-2023. As planned by Federal Office of Energy, we have assumed and extra 250 MW of gas power plants start

² These ATC values are equivalent to the "fair ATC" scenario in SA2022.

³ https://transparency.entsoe.eu

operating at the end of February.⁴ Given that they are expected to run on substitute fuels such as oil, we assume they are able to generate electricity even in the case of gas shortages. However, the hydro energy reserve policy is excluded from the modelling⁵.

Scenarios for the conventional fleet

Conventional power generation faces several challenges this winter:

Potential reduced availability of gas for power generation: gas-fired power plants are the third largest source of electricity generation in Europe. Although gas plants are typically at the top end of the merit order, Europe relies on gas-fired plants to meet demand during high-demand winters. As shown in Figure 4, in the geographical region covered, gas-fired power plants generated 276 TWh of electricity in winter 2021-2022 (November 2021 to April 2022), accounting for 21% of total demand. Countries differ in their reliance on gas-fired power plants: Italy and the UK are the most dependent on their gasfired power plants compared to other countries, both in absolute terms (both around 60 TWh) and in terms of percentage of demand covered (44% and 37% respectively). However, Europe faces a gas crisis as it has dramatically reduced its imports from Russia (formerly supplying around 45% of gas consumption to the EU) following the Russian invasion of Ukraine. Even though gas storages in Europe are almost full before the start of the winter (due to increasing LNG imports, gas-saving measures, reduced consumption due to high prices, and relatively warm weather), there could still be a risk of gas shortages in Europe in the following winters. The risk of gas shortages is relatively lower for France, Spain and Portugal, as their LNG capacity (and pipeline export capacity) was high (low) enough that they experienced lower prices than the rest of mainland Europe (particularly the Dutch Title Transfer Facility, TTF). The extent of gas shortages (if any) is uncertain due to uncertainties on both the supply side (e.g. uncertainty about LNG regasification plant outages) and the demand side (e.g. uncertainty about household gas consumption, which is highly weather dependent).



 $^{^4} See \ https://www.bfe.admin.ch/bfe/de/home/news-und-medien/medienmitteilungen/mm-test.msg-id-90210.html$

⁵ See https://www.bfe.admin.ch/bfe/de/home/news-und-medien/medienmitteilungen/mm-test.msg-id-90259.html

Figure 4 Generation from gas power plants in winter 2021/2022 vs. approximate simulated demand– absolute values on the y-axis and gas generation share in percentages as annotations.

Reduced availability of nuclear plants in France: while France, on average, generates 70% of its electricity from its nuclear fleet, many of the plants are facing outages due to inspections followed by identifying stress corrosion. As shown in Figure 5, as of September 2022, RTE (the French transmission network operator) envisioned around 10 GW lower availably of nuclear plants in France for winter 2022-2023. As a result, France, formerly one of Europe's large exporters of electricity in winter, may require imports.





We define the following scenarios to represent and analyze the challenges in the winter of 2022-2023:

- **Benchmark**: The availability of the French nuclear fleet follows historical values (Table 1) and gas fuel is fully available to the power generation industry.
- **Reduced availability of the French Nuclear:** the availability of the fleet is reduced to values similar to the RTE's main projection as of 15th of November 2022 (Table 1).
- Reduces gas availability as fuel for the power generation industry: the generation of gas-fired power plants in each country depends on a given gas-saving target compared to the previous year's generation in the same simulation period. For example, in the "0% gas-saving target", electricity generation in each country cannot exceed the corresponding value of the previous winter. France, Spain, and Portugal are excluded as they appear to have non-binding LNG regasification constraints. Also Norway faces no gas limit (Figure 3). In such a simulation, while the total amount of gas available is limited, power plants are free to allocate generation to different hours of the study period (subject to their usual constraints, such as generation capacity, etc.).
- **Combinatory scenarios:** reduced French nuclear availability is combined with gas savings targets of 0, 10, 20 and 30%. For example, in the reduced French nuclear scenario with a 30% gas-saving target, French nuclear availability is adjusted according to Table 1 and countries (except France, Spain, Portugal and Norway) have to reduce their gas-fired generation by 30% in the same period compared to last year.

In addition to the main scenarios described above, we also simulate a sensitivity analysis. While the main simulations assume availability factors for conventional plants according to historical averages (e.g. 72% availability for Swiss nuclear plants), a sensitivity analysis assumes that Swiss nuclear plants are fully available during winter. As a result, the Swiss nuclear generation potential increases from 9.2

TWh to 12.9 TWh. All other factors remain the same as in the main simulations. We only use the results of this sensitivity analysis when analysing the ENS results in Switzerland.

Table 1 Available capacity of French nuclear plants in benchmark case vs. scenarios with reduced availability

Available capacity (GW)	Nov.	Dec.	Jan.	Feb.	March	April.
Benchmark (historical averages)	42.3	49.0	53.4	51.6	46.6	41.7
Reduced availability	29.5	41.0	41.5	42.0	40.0	40.0

Climate scenarios

Electricity demand, PV and wind generation and hydro inflows are weather dependent. On the demand side, the TYNDP profiles are used, i.e. 1982, 1984 and 2007. These years were chosen by ENTSO-E from a pool of available years because they represent three different clusters of historical weather years. Demand time series from the National Trends scenario for the year 2025 are used. In a set of consistent demand weather analyses, these demand time series of these three years are paired with other weather dependent time series (PV/wind availability factor and hydro inflows) corresponding to the same year.

In addition to the three consistent weather years, three other combinatory/synthetic weather combinations are introduced to represent weather realizations that may be more *extreme*. We define extreme realisations based on the residual load time series (demand minus PV and wind generation to be met by conventional power plants). First, we calculate several possible residual load time series by combining the given demand time series (from the three weather years in TYNDP 2020) with some RES generation availability from weather conditions similar to 1982-2016. We focus on the aggregated residual load time series in the region including Switzerland and its neighbouring countries. Then we find the combinations that lead to the extreme cases defined below:

- the highest daily residual load (a day with the highest residual load).
- the most severe "dunkelflaute" (has the highest residual load in a two-week period).
- the highest total residual load over the whole winter half-year.

Table 2 shows the selected weather combinations. The combination of the 2007 demand profile and the 1997 PV/wind availability results in the highest remaining load in one day. In the simulation of this weather combination, the demand time series of 2007 is applied simultaneously with the availability factors and the hydro inflow of 1997. Similarly, a demand-weather combination of 2007-2009 leads to the dunkleflaute case. Finally, a demand-weather combination of 1984-1985 leads to the winter with the highest residual load. 1985 also happens to be the year with the lowest winter hydro inflow in the Swiss hydro system.

Criteria	Demand profile year – weather profile year			
	(PV/ wind availability and hydro inflow)			
Consistency (in TYNDP as a representative year)	1982-1982			
Consistency (in TYNDP as a representative year)	1984-1984			
Consistency (in TYNDP as a representative year)	2007-2007			
A day with the highest residual load	2007-1997			
Dunkelfalute	2007-2009			
Highest residual load in winter (and worst hydro	1984-1985			
inflow for Switzerland)				

Table 2 Demand - weather year combinations used in the analysis

Figure 6 Figure 6 illustrates the impact of the climate and demand scenarios on the total renewable generation and the residual load for the study region. While total PV generation varies only between 57-60 TWh, wind plays a more important role, varying between 249-279 TWh. The total hydro generation is mainly influenced by the initial stored energy, the final stored energy and the winter inflow. However, the power system conditions may affect hydro generation, particularly the pump-storage operation. The reported hydro generation values in Figure 6 correspond to hydro generation for the **benchmark** cases. The right panel of Figure 6 shows the residual load, defined as total demand minus PV, wind and hydro generation. The residual load varies between 992 and 1090 TWh, which has to be met by conventional power plants.



Figure 6 Total renewable generation and residual load of the whole system per weather combination scenario (on the x-axis, the first and second value denotes the climate year corresponding to the demand and renewable time series, respectively. For instance, 1984_1985 represents a run with 1984 demand time series and PV/wind availability factor and hydro inflow corresponding to 1985).

Figure 7 shows the Swiss energy balance (demand versus generation) for the benchmark case. Swiss total demand in the studied period is around 34 TWh. Nuclear power plants constantly run at their maximum available capacity as they have a low marginal cost of generation. As a result, Swiss nuclear plants generate around 9.2 TWh in all weather years, as we assume an average availability factor of 72%. PV generation varies between 1.63 and 1.85 TWh. Wind generation is negligible due to Switzerland's low installed capacity of 88 MW. In the benchmark case, hydro generation varies between 13.14 TWh and 15.36 TWh. The remaining import required to meet the demand varies between 6.7 and 9.0 TWh.



Figure 7 Generation and demand for different weather combinations of the benchmark cases for Switzerland



4. Results

Figure 8 Energy not served (ENS) across scenarios.

Figure 8 illustrates the total ENS in the studied region. As expected, the benchmark demonstrates no lost load, as there is no limit on gas and nuclear fleet availability. In the case of limiting gas fuel availability to previous year values, 0% gas saving, low values of ENS is observed only in scenarios with demand weather year of 1984, which had the highest total winter demand of 1624 TWh. The ENS is mostly observed in Italy and the UK as they rely on gas plants the most.

The scenario with reduced availability of French nuclear does not lead to ENS in France or neighboring countries. Figure 9 hints at how having enough capacities of different sorts helps cover the demand by comparing the available generation capacity with demand on the European scale in this scenario. The hourly demand in all weather combinations varies between around 200 GWh to 500 GWh. On the supply side, the European power system is still characterized by lots of conventional dispatchable technologies. The system includes around 207 GW of available capacity for fully dispatchable power plant technologies, i.e., nuclear, coal, oil, biomass, etc. Another 178 GW of available gas capacity helps

cover part of the demand, if necessary. Having 139 GW of peak-hour-running hydro plants will also help provide energy to cover demand. In addition, 208 GW and 147 GW of wind and solar PV capacity, respectively, provide intermittent extra energy for the system. The fact that the reduced French nuclear simulations have led to no ENS demonstrates that the transmission network has been able to transmit the available energy to the demand nodes.



Figure 9 Available capacity of conventional power plants in January for the case of reduced French nuclear availability and installed capacity of wind and PVs versus frequency of the hourly demand in all weather years.

When both constraints on nuclear and gas plants are considered, the amount of ENS increases. In the scenario with reduced French nuclear and 10% gas saving, the occurrence of ENS remains weather dependent, i.e., a significant amount of ENS happens only in the demand weather year of 1984. However, as the target gas saving increases to 20% (and then 30%), the ENS happens in all weather years.

While facing constraints on nuclear and gas technologies, the power system tries to avoid ENS by increasing dirty generation (from coal and oil plants) or gas-fule-based generation in the non-constraint region (France, Spain, and Portugal). Figure 10 compares total generation per type for gas, nuclear, and coal plus oil and ENS for different scenarios for the weather combination 1982_1982 (consistent demand and renewable availability corresponding to 1982). Compared to the benchmark, the 0% gas-saving scenario compensates for its reduced gas generation by increasing generation from coal plus oil power plants (from 275 to 335 TWh). In the reduced nuclear availability, nuclear generation reduced from 372 TWh to 332 TWh, which is partially compensated by extra generations from gas and coal, and oil plants. Gas production from non-constraint countries also helps cover the demand. When comparing the 0% gas-saving case with the combination of 0% gas-saving and reduced nuclear availability, gas generation increases from 273 to 289 TWh, which corresponds mostly to increased gas generation in gas non-constraint countries. As the gas saving target increases, gas generation decreases. Despite the increases in generation from coal & oil plants, demand cannot be fully covered, and, as a result, ENS increases.



Figure 10 Generation per type for different scenarios for the weather combination 1982_1982 (renewable and hydro generation are excluded as they are rather stable between scenarios).

In the following, we analyze the results for selected regions/countries. First, we establish that the Iberian Peninsula has (limited) export possibilities in severe scenarios. Then, we discuss how Germany and, accordingly, France have low ENS in at least mild scenarios. Then we showcase the effect of reliance on gas by analyzing Italy. Additionally, we analyze the effect of weather realization on Norway's outcomes. Finally, we focus on Switzerland.

Iberian Peninsula

The Iberian Peninsula can export electricity to neighbors (i.e., France) as its gas fleets face no fuel limitation. Figure 11 illustrates the total energy generation by sources and imports (negative import denotes exports) of Spain plus Portugal for the weather combination of 1984_1984. While in the benchmark case the Iberian Peninsula is essentially balanced in winter (low total exports), as the whole system faces limitations in the other scenarios, the peninsula provides exports to the rest of the system. However, the export saturates at around 16 TWh, i.e., the extent of the exports is limited mostly due to transmission network limitations.



Figure 11 Electricity trade balance and generation per type for the Iberian Peninsula the weather combination 1984_1984 (negative import denotes export).

Germany

Germany faces a rather low amount of shortages, even in extreme scenarios. To showcase Germany's reaction and outcomes in an extreme scenario, we analyze the scenario of reduced nuclear and 30% gas-saving target in the weather combination 1984_1984. Figure 12 compares Germany's hourly demand versus Germany's supply side, conventional capacity availability (in January as an example), installed renewable capacity, and maximum realized import/exports. In our analysis, Germany's hourly demand varies between 40 and 84 GWh. On the supply side, Germany has 37 GW of available capacity of fully dispatchable power plants. In addition, gas and hydro fleet (with available capacities of 29 GW and 12 GW, respectively) are limited in the amount of energy they can provide in the winter (due to hydro inflow and gas limitations). Still, they are flexible in shifting their production to the most required hours.

On the other hand, Germany benefits from high renewable capacities (64 GW and 58 GW of wind and PV, respectively) and net import potentials (e.g., 20 GW of realized maximum import in this scenario). Of course, such sources are intermittent or dependent on conditions in the neighboring countries. However, in conjunction with the flexible gas and hydro fleet, they have mostly covered the German demand with an ENS of 1 TWh, as shown in the last column of Figure 13. On top of that, Germany even provided net exports of up to 22 GWh in some hours (Figure 12). Nevertheless, from the winter aggregate point of view, Germany is not net exporting in the cases of gas savings combined with reduced nuclear availability (Figure 13). The same pattern happens in other weather combinations, too: as the gas saving target increases, Germany becomes more reliant on imports for the whole season, but still, hours with high net export to neighboring countries occur depending on renewable generation.



Figure 12 Germany's hourly demand frequency versus available capacity of conventional power plants (in January) and installed renewable capacity, and maximum import/export values for the combinatory scenario of reduced nuclear and 30 % gas-saving for the weather combination 1984_1984.



Figure 13 Germany's electricity trade balance and generation per type for the weather combination 1984_1984 (negative import denotes export).

France

In the analyzed scenarios, France demonstrates insignificant ENS amounts (always below 0.2 TWh) in the combinatory scenario of reduced nuclear and 0% gas-saving. Figure 14 compares the available capacity of different technologies, the maximum imported amount, and the frequency of demand realizations. The hourly demand maxes at around 90 GW. On the supply side, the system includes around 54 GW of dispatchable technologies (including unconstraint gas plants). Furthermore, 15 GW of hydro, 20 GW of wind, and 13 GW of PVs also may contribute to the supply side, subject to availability. Additionally, export capacities in the neighboring regions (e.g., Germany and the Iberian Peninsula) and the transmission interconnections availability have allowed France to net import at a maximum of between 16 and 22 GWh. This combination of various sources has allowed France to prevent significant amounts of ENS in this scenario.

As the gas saving target increases, France may experience higher ENS, particularly in weather combinations with the demand pattern 1984. For instance, in gas saving targets of 10% and 20%, the highest simulated ENS is 1.3 TWh and 1.8 TWh, both happening in weather combination 1984_1985. In perspective, the sum of the demand in the simulated period for France is around 288 TWh. In the same scenarios, while weather scenario 1984_1984 leads to ENSs slightly below 1984_1985, other weather combinations lead to no/insignificant ENSs.



Figure 14 France's hourly demand frequency (corresponding to all three weather years) versus available capacity of conventional power plants (in January) and installed renewable capacity, and maximum import values realized maximum import over different weather combinations, for the combinatory scenario of reduced nuclear and 0 % gas saving for the weather combination 1984_1984

Italy

As shown in Figure 8 (and Figure 22 in the Appendix), Italy experiences a considerable amount of ENS in gas-saving scenarios, particularly when combined with reduced nuclear availability. For instance, in the case of reduced nuclear combined with 30% gas saving, Italy faces a minimum of 17 TWh of ENS (while total demand is 166 TWh). Italy is sensitive to gas shortages due to its reliance on gas-fueled power plants;⁶ as shown in Figure 15, Italy benefits from 39 GW of gas plants (available in January), while the other conventional dispatchable technologies and hydro plants have a total capacity of 14 GW and 13 GW, respectively. Given low wind and PV capacities (11 and 5 GW, respectively) and limited import capacities, especially at higher gas-saving target scenarios (e.g., a maximum of 10

⁶ Note that possible fuel switching efforts in the power industry in Italy is not modeled.

GW realized hourly import capacity in the scenario with 30% gas saving), there is simply not enough energy available for the system so that the flexibility of gas and hydro plants would succeed in covering demand.⁷



Figure 15 Italy's hourly demand frequency versus available capacity of conventional power plants (in January) and installed renewable capacity, and maximum import/export values for the combinatory scenario of reduced nuclear and 30 % gas saving for the weather combination 1984_1984

Norway

Southern Norway, among several other European regions, faced a drought in the summer of 2022. As a result, the stored energy in Norway's hydro reservoirs was below its average value of 2015-2021 at the beginning of winter and throughout 2022 (Figure 16). Low stored energy in the hydro system is particularly problematic for Norway as its power system is hydro-dominated. Hydropower plants alone (27 GW of hydro reservoir, 1 GW of pump storage plants, and 7 GW of run-of-river) can cover the winter peak demand of around 25 GWh.⁸ Figure 17 illustrates how the weather developments in winter affect the security of supply in Norway when it starts winter with lower-than-average hydro-stored energy.

⁷ Refer to Appendix for more detailed analysis of available energy amount in Italy.

⁸ In perspective, the two other technologies with the highest capacities are wind and gas plants, with an installed capacity of 5 GW and 0.6 GW, respectively.



Figure 16 Stored energy in Norway's hydro reservoirs



Figure 17 Norways's ENS

Figure 18 compares Norway's generation and demand for different weather combinations and illustrates the required import for Norway to cover its winter demand. Note that for each weather combination, only one total generation per technology is reported since Norway's values are rather independent of the conventional fleet scenarios. On the hydro side, total hydro generation in our model almost entirely depends on the start and end conditions of the hydro storage as well as hydro inflows in the given weather combination, all of which are fixed.⁹ As a result, total hydro generation is mostly independent of nuclear and gas scenarios but dependent on the weather scenario. Similarly, other

⁹ The start and end conditions of the hydro storage is fixed in the simulation approach to be equal to the initial values in the beginning of the simulation value and values in the previous year, respectively. On the other hand, the hydro inflows are fixed for a given weather combination.

generation sources (e.g., zero marginal cost renewables and the small gas fleet) have limited variations or effects across conventional fleet variations.

Norway's ENS depends on not only the hydro inflow but also the intensity of the situation in the rest of Europe. The former (alongside demand) determines the import required, and the latter affects Norway's import possibility. Weather combinations 1982_1982, 2007_1997, and 2007_2007 require no imports in total as a result of sufficient inflows. They lead to no ENS given the sufficient flexibility and capacity of the hydro system in Norway. On the other hand, weather combinations 1984_1984, 2007_2009, and 1984_1985 lead to the highest import requirement (16.1, 10.6, and 5.5 TWh, respectively) to avoid ENS. Weather combinations 1984_1984 and 1984_1985 lead to ENS in the reduced nuclear and gas scenarios (Figure 17) because the remaining countries cannot provide exports to Norway as they face their own challenges to avoid ENS. On the other hand, 2007_2009 leads to lower ENS compared to 1984_1985 despite requiring more imports (10.6 compared to 5.5 TWh) since the rest of the European system has fewer problems in this weather combination and may provide more exports to Norway.

Note that in any of the scenarios with ENS, Norway may avoid ENS by simply loosening the condition that the end state of the stored hydro energy must not be any lower than its corresponding value in 2021.



In our analysis, Sweden also shows similar ENS pattern as Norway, as

Figure 18 Norway's hydro generation, other generation, total demand and required imports for different weather combinations

Switzerland

ENS results in Switzerland are presented and compared in Figure 19. Switzerland faces no/insignificant amount of ENS in the reduced French nuclear availability and 0% gas saving measures and their combination. The main reason is that the exporting countries to Switzerland, i.e., Germany and France, have few shortages in these scenarios. More precisely, even though Germany and France may have a few hours with tight security margins, the hydropower plants in Switzerland have been able to provide enough flexibility to avoid ENS in Switzerland.

As the gas saving target increases, Switzerland experiences ENS, particularly in 1984_1984 and 1984_1985 weather combinations. For example, first, we analyze the scenario with reduced French nuclear and 10% gas saving. Both 1984_1984 and 1984_1985 weather combinations lead to ENS of

around 1 TWh in Switzerland. This is partly because neighboring countries except for Germany are experiencing ENS (e.g., in weather combination 1984_1984, Austria, France, and Italy have ENS of 0.85, 0.78, and 20 TWh, respectively). In other weather combinations, Swiss ENS is insignificant. Moreover, if Swiss nuclear is fully available, the ENS becomes insignificant in Switzerland in all weather combinations. Also, in the 20% gas-saving scenario, ENS happens only in 1984_1984 and 1984_1985 weather combinations. In the 30% gas-saving scenario, all weather combinations lead to ENS in main scenarios; however, ENS in the weather combinations excluding 1984 is relatively low, which becomes even insignificant if Swiss nuclear plants are fully available.



Figure 19 Switzerland's ENS (CH 100% Nuclear: if CH nuclear runs at 100% capacity instead of the 71% based on historical data)

Figure 20 illustrates the average weekly dispatch and stored hydro energy in Switzerland for the scenario with reduced French nuclear availability and a 20% gas-saving target, weather combination 1984_1984, and full availability of nuclear plants in Switzerland. No ENS occurs in April despite having low stored hydro energy in Switzerland, which is caused by several factors. Firstly, consumption in Switzerland decreases as the cold winter period has passed. Secondly, run-of-river generation has compensated for part of the lower generation from reservoir plants. Thirdly, sufficient import capacity is available for Switzerland (as neighboring countries also experience lower residual loads). Finally, increased PV generation and generation from new gas power plants have also helped. Consequently, in April, Switzerland can import more than its conventional consumption so that pump storage plants may even fill their higher reservoirs, which in turn leads to increased stored energy from 1 TWh to 1.2 TWh (the exogenously set final condition).



Figure 20 Average weekly dispatch in Switzerland in the scenario with reduced French nuclear and 20% gas-saving target for the weather combination 1984_1984. All values in GWh except for Stored Energy that is in TWh.

Figure 21 illustrates the hourly dispatch in Switzerland in the first week of December in the same scenario as above. In this specific week, the value of ENS maxes at 1.6 GWh. Hydro plants are dispatched to generate a relatively stable generation throughout the week. However, when enough imports can be secured (particularly in off-peak hours on the weekend), hydro generation is reduced to keep the energy for the rest of the winter.



Figure 21 Hourly dispatch in Switzerland in the first week of December in the scenario with reduced nuclear and 20% gas-saving target for the weather combination 1984_1984.

5. Conclusion

Europe started winter 2022-2023 facing several possible challenges with regard to both covering the peak demand and providing enough energy thorough the winter. The reduced availability of French nuclear reduces the capability of French to cover demand in peak hours and leads to lower available winter generation in the system. On the other hand, lower-than-average stored hydro energy and the possibility of reduced availability of gas as fuel for power plants threatens the ability of the system to provide enough energy throughout the winter.

On the European scale, Europe and particularly France is able to avoid electricity shortages in the case of reduced French nuclear availability. Similarly, only limiting gas usage in the power industry to historical values causes only limited amount of ENS (almost exclusively in countries with very high reliance on gas power). However, a combination of the two challenges may cause ENS in cold winters with high demand. Furthermore, if gas saving target of 20% and more should be implemented, shortages happen throughout various weather realizations.

Switzerland imports electricity in winter but also benefits from a flexible hydro system. In a typical winter, Switzerland is able to import enough electricity to cover its demand because the European system and particularly the neighbors have some hours with surplus generation. Such a surplus existed because the European system usually had enough available generation capacities to meet peak demand. Those available generation capacities are mostly dispatchable technologies because the European power system is still mostly based on conventional technologies. As a result, Switzerland had no issues in the benchmark cases (a typical European system) in any weather realizations, even if up to 9 TWh of imports were required. However, when a gas shortage occurs in Europe, gas plants turn from fully dispatchable assets to assets with limited generation potential. As a result, less generation *surplus* will be available in the system. However, until exporting countries have no supply issues of their own, possibly enough surplus capacity will remain available for Switzerland to import. In cold winters with a gas saving target of 20% (and more), Switzerland faces electricity shortages since it cannot from its neighbors that have insufficient surplus of energy and mostly face ENS of their own.

Appendix

Italy

Figure 22 Illustrates ENS in Italy for various scenarios. Figure 23 focuses on the scenarios with weather combination 1984_1984 to illustrate the amount of available energy in different conventional fleet scenarios. As the gas saving target increases (moving towards the columns more to the right), Italy is forced to reduce gas generation, and at the same time, import opportunities decrease as neighboring regions face challenges. Given that there is limited generation potential from other sources (hydro, coal, and oil plants), ENS has to increase.







Figure 23 Italy's electricity trade balance and generation per type for the weather combination 1984_1984

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