ENTSO-E Report

The Assessment of Future Flexibility Needs in Practice

October 2021

entsoe

ENTSO-E Mission Statement

Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the **association for the cooperation of the European transmission system operators (TSOs)**. The 42 member TSOs, representing 35 countries, are responsible for the **secure and coordinated operation** of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E **brings together the unique expertise of TSOs for the benefit of European citizens** by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the **security of the interconnected power system in all time frames at pan-European level** and the **optimal functioning and development of the European interconnected electricity markets**, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

Our vision

ENTSO-E plays a central role in enabling Europe to become the first **climate-neutral continent by 2050** by creating a system that is secure, sustainable and affordable, and that integrates the expected amount of renewable energy, thereby offering an essential contribution to the European Green Deal. This endeavour requires **sector integration** and close cooperation among all actors.

Europe is moving towards a sustainable, digitalised, integrated and electrified energy system with a combination of centralised and distributed resources.

ENTSO-E acts to ensure that this energy system **keeps consumers at its centre** and is operated and developed with **climate objectives** and **social welfare** in mind.

ENTSO-E is committed to use its unique expertise and system-wide view – supported by a responsibility to maintain the system's security – to deliver a comprehensive roadmap of how a climate-neutral Europe looks.

Our values

ENTSO-E acts in **solidarity** as a community of TSOs united by a shared **responsibility.**

As the professional association of independent and neutral regulated entities acting under a clear legal mandate, ENTSO-E serves the interests of society by **optimising social welfare** in its dimensions of safety, economy, environment, and performance.

ENTSO-E is committed to working with the highest technical rigour as well as developing sustainable and **innovative responses to prepare for the future** and overcoming the challenges of keeping the power system secure in a climate-neutral Europe. In all its activities, ENTSO-E acts with **transparency** and in a trustworthy dialogue with legislative and regulatory decision makers and stakeholders.

Our contributions

ENTSO-E supports the cooperation among its members at European and regional levels. Over the past decades, TSOs have undertaken initiatives to increase their cooperation in network planning, operation and market integration, thereby successfully contributing to meeting EU climate and energy targets.

To carry out its **legally mandated tasks**, ENTSO-E's key responsibilities include the following:

- Development and implementation of standards, network codes, platforms and tools to ensure secure system and market operation as well as integration of renewable energy;
- Assessment of the adequacy of the system in different timeframes;
- Coordination of the planning and development of infrastructures at the European level (Ten-Year Network Development Plans, TYNDPs);
- Coordination of research, development and innovation activities of TSOs;
- Development of platforms to enable the transparent sharing of data with market participants.

ENTSO-E supports its members in the **implementation and monitoring** of the agreed common rules.

ENTSO-E is the common voice of European TSOs and provides expert contributions and a constructive view to energy debates to support policymakers in making informed decisions.

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Executive Summary

In the ENTSO-E Position Paper on the Assessment of Future Flexibility Needs, ENTSO-E proposes specific metrics for ramping and scarcity period flexibility needs, which a TSO and ENTSO-E can apply to determine whether and at what point in the future a particular new flexibility gap might occur.

In this report, the suggestions raised in the position paper are tested for three countries (Germany, Belgium and France) with illustrative examples based on ENTSO-E's Mid-term Adequacy Forecast (MAF) data for 2025, which is the year with most constraints within MAF 2020, leading to conclusions from the application of the proposed flexibility metrics.

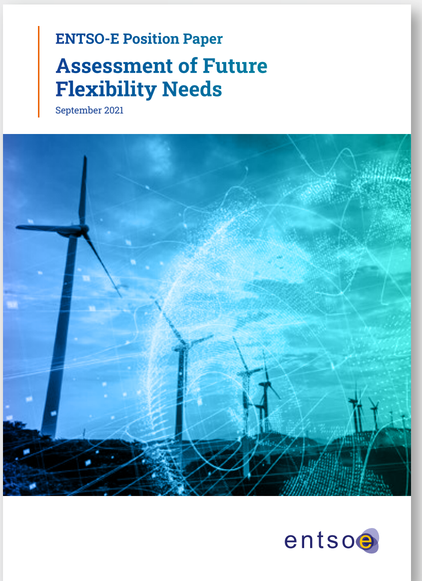
Belgium, Germany, and France were selected since they represent a significant part of the European power system, include significant variable renewable energy sources (RES) generation (especially in Germany), but also have temperature-dependent loads (in France), thus raising the possibility of difficult-to-manage scarcity periods and ramps.

The analysis of these three countries and their aggregated values is intriguing, since the integration of variable RES becomes easier in large interconnected systems of countries with different weather conditions and resource mixes; this is one of the major reasons why interconnection capacities support an affordable energy transition while maintaining system reliability.

This report expands upon the position paper by testing and interpreting the proposed flexibility metrics through actual ENTSO-E MAF data.

In the coming years, ENTSO-E plans to develop and introduce several additional flexibility need assessment methods along with the corresponding metrics, thus seeking to ensure that flexibility gaps and the use of flexibilities from neighbouring countries are captured both in reliability assessments and in the evaluation of new interconnection or storage projects in the TYNDP. The results and conclusions drawn from the illustrative examples in the ENTSO-E position paper and this report could serve as a basis for TSOs to produce and fine-tune their own analyses of ramping and scarcity period flexibilities.

Additional future flexibility needs are of equal importance and are addressed separately, especially those related to stable frequency (inertia, RoCoF, fast frequency response), congestion management, voltage stability, and to the actual day-ahead, intraday and real-time operational management of the balance of demand and supply while taking into account forecast errors and unforeseen short-term variations.



Download the ENTSO-E Position Paper on the Assessment of Future Flexibility Needs

1 Proposed metrics to assess future flexibility needs

The scope of this report is limited to the assessment of future flexibility needs insofar as they relate to adequacy in the day-ahead timeframe, i. e. to those flexibility needs arising from increasing variability in the balance of generation, demand and storage. Therefore, while a wide range of flexibility needs are being investigated by TSOs and ENTSO-E, this report further explores the methodological approaches and metrics that are foreseen for ramping and scarcity period flexibility and which were described in the ENTSO-E Position Paper on the Assessment of Future Flexibility Needs. These metrics combine simple-to-analyse residual (net) loads with selected outputs of complex Europe-wide chronological probabilistic simulations of resource adequacy, which are performed routinely by TSOs and by ENTSO-E.

Although adjusting in the future the resolution of these models in terms of market time units and geography could help focus on adequacy challenges from flexibility gaps, it is sufficient to utilise the standard outputs of current adequacy studies for the metrics defined here. The illustrative analysis based on actual ENTSO-E adequacy analysis data for 2025, utilises outputs routinely available from existing market and adequacy studies. Although the analysis presented herein might use european resource adequacy assessment (ERAA) or ten-year network development plan (TYNDP) outputs, this extension should be performed elsewhere.

The ENTSO-E position paper flexibility metrics, indicated in bold text, are briefly repeated below for convenience:

› **1. Ramping flexibility needs:** These metrics measure large daily residual load gradients, for example, at sunset in regions with large PV generation capacities. The approach is partly based on experiences from California ISO and EirGrid (see Appendix). Residual load is the load left after subtracting VRE generation like wind, PV and run-of-river hydro from the demand. Explicit and implicit demand flexibility was considered as part of the dispatchable capacity, and not in the residual load calculation. The treatment of these capacities in the methodology could be further improved.

- a) The **highest annual residual load MW ramps**, calculated as the differences between residual loads 1, 3 and 8 hours apart (or more as necessary for managing the uncertainty in a materially weather dependent system), can be easily compared between all market zones and years if they are normalised to the market zone's dispatchable capacity including demand response, and accounting for forced outage derations.
- b) The metrics **percent of loss of load expectation (LOLE), expected energy not served (EENS)**, and **curtailed surplus energy during the 5 % highest ramp periods** indicate how the ramping issue can also pose an adequacy and economic problem. They will be assessed separately for positive and negative residual load ramps and for 1-, 3- and 8-hour ramps (or more as necessary for managing the uncertainty in a materially weather dependent system) as well as the corresponding prior hours for potential pre-emptive curtailment. Hourly values for LOLE, EENS and curtailed energy are among the outputs of chronological probabilistic market simulations used for adequacy and TYNDP studies. The necessary fine-tuning of this indicators will not only address the 5 % threshold but also involve examining how ramping capabilities of all resources are modelled in market simulations, especially demand response and VRE curtailment.

- **2. Scarcity period flexibility needs:** These are metrics focused on contiguous-day EENS problems during scarcity periods when Variable Renewable Energy (VRE) resources are not available for extended and continuous periods, such as windless winter weeks in Northern Europe.

  - a) If the **maximum annual value of 120-hour residual load rolling averages,** including Frequency Containment and Frequency Restoration Reserves (FCR and FRR) requirements and normalised to the market zone's derated dispatchable capacity, is near 100 %, short-term flexibility resources such as batteries or DSR are unlikely to cover power needs. But as in the case of ramping, this metric can indicate small sets of hours in a given year when flexibility challenges are especially strong, while market simulation can show quantified reliability risks from detailed simulation of dispatchable capacity, demand response, battery use, and mutual support between countries, as well as weather and outage probabilities.

  - b) Therefore, as in 1b, the **LOLE and EENS percentages over the maximum 120-hour average residual load periods** indicate what fraction of overall adequacy concerns stem from seasonal scarcities involving extended periods of high residual load and low VRE generation. For further interpretation of scarcity periods, it can be useful to also examine the climate years with high LOLE and EENS contributions during the identified 120-hour scarcity periods in market simulations, and the average generation as a percentage of the installed capacities of all VRE resources during these periods. These will help understand which climatic conditions can lead to scarcity periods. Part of the necessary fine-tuning of this indicator will not only address the focus on the single worst 5-day period, but also involve examining how the availabilities of flexibility resources during scarcity periods are modelled in market simulations, especially implicit demand response and sector coupling resources such as vehicle-to-grid or seasonal thermal or hydrogen storage.

2 Application of the combined metrics of residual load and expected energy not served

Both in the case of ramping and of scarcity period flexibility gaps, the combination of residual load analysis and the results of detailed chronological adequacy simulations provide crucial insights into the severity and characteristics of risks related to the security of supply, which neither approach could provide alone.

Hourly results and annual averages from chronological simulations show the severity of these risks. Residual load analysis helps focus on times with the highest specific risks regarding ramping capabilities of the portfolio during all time periods, including those with adequacy concerns and without. The combination of these metrics allows for a realistic and focused perspective on the major gaps and risks regarding the resource ramping capabilities, so that the best measures can be found to manage those risks that could also jeopardise the security of supply, even in cases when no resource adequacy concerns (EENS) are found in the system, i.e. when risks are linked to lack of ramping capabilities in the portfolio rather than to a structural lack of sufficient resources to ensure adequacy.

To further analyse this issue, we utilised the results for Belgium, France, and Germany from the ENTSO-E 2020 MAF models for the year 2025, primarily using climate data from climate year (CY) 1985, which was an extreme winter with very high residual load. This should provide a view of one of the worst-case scenarios. If issues are discovered, further analysis will be needed to see if these problems remain in less extreme scenarios. We then performed a combined residual load and EENS analysis based on the aforementioned flexibility metrics.

To illustrate the value of this combined view, Figure 1 illustrates the expected unserved energy during the periods with the most severe ramping and scarcity period flexibility challenges. The values depicted were derived from the MAF 2020 simulations[1] of the year 2025 as follows:

- Belgium, Germany, and France were chosen as three contiguous countries which represent a significant part of the European power system and which have significant variable RES generation (especially in Germany), but also exhibit temperature-dependent load (in France), and thus the potential for difficult-to-manage scarcity periods and ramps.

- The analysis of these three countries by themselves is intriguing, but so is that of the three countries' aggregated values, as the integration of variable RES becomes easier in large interconnected systems of countries with different weather conditions and resource mixes (one of the major reasons why interconnection capacities support an affordable energy transition while maintaining system reliability).

- From the analysis of German residual loads cited in the position paper and below, it was known that the period from 8 through 12 January in CY 1985 presented sustained high net loads, i.e. it was a windless winter week, and thus a potential scarcity period risk, even if overall EENS values were still low.

- The additional analysis here examines the EENS values for the three countries over the entire year 2025 and finds that for the MAF chronological simulation of CY 1985, the vast majority of the hours in that year show zero EENS values for all three countries (where 20 sample runs were performed with random-draw generation outages). In fact, Germany shows only 5 hours with non-zero EENS values on 10 January 2025, while Belgium and France show a few more days during January with some non-zero EENS hours.

1 ENTSO-E Mid-Term Adequacy Forecast 2020: Appendix 1 – Detailed results and input data (entsoe.eu)

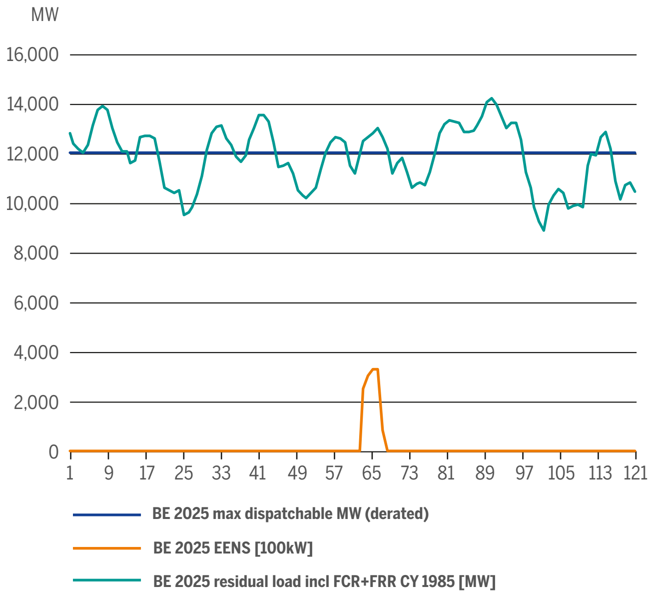


Figure 1: Belgian high 2025 residual loads

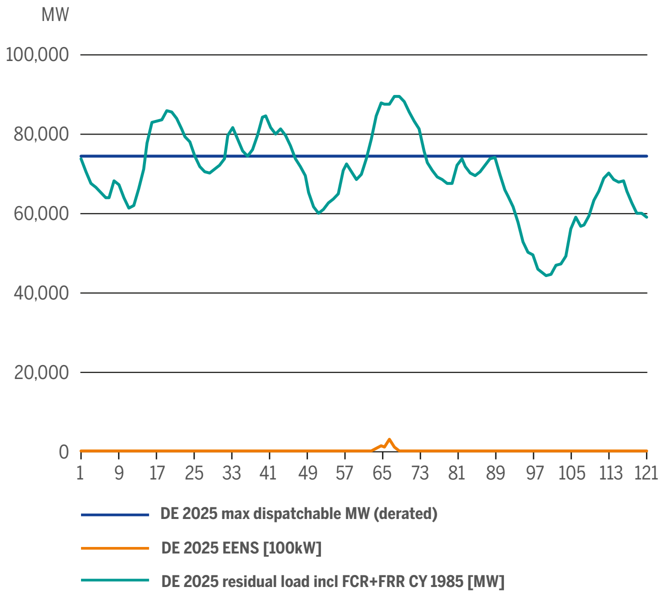


Figure 2: German high 2025 residual loads

For all graphs:
high 2025 residual loads 8.1. 1 h – 12.1. 24 h vs. expected energy not served (EENS @ 100 kW instead of MW scale for illustration)

Source: Guidehouse Analysis based on ENTSO-E's MAF 2020 data.

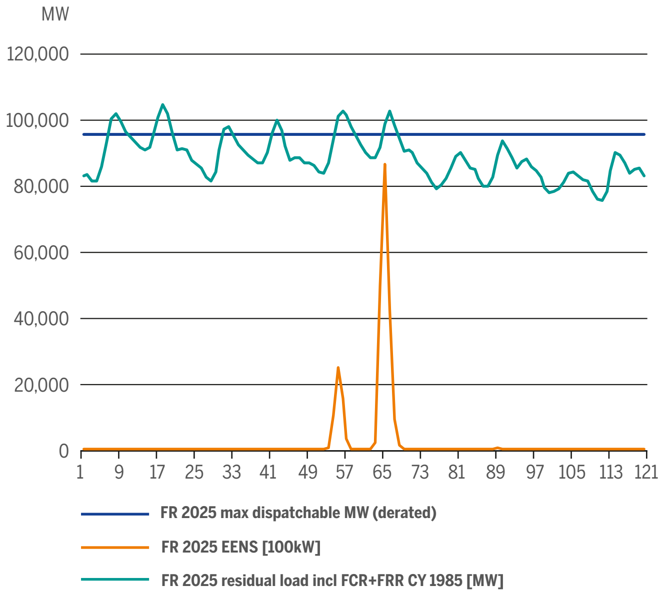


Figure 3: French high 2025 residual loads

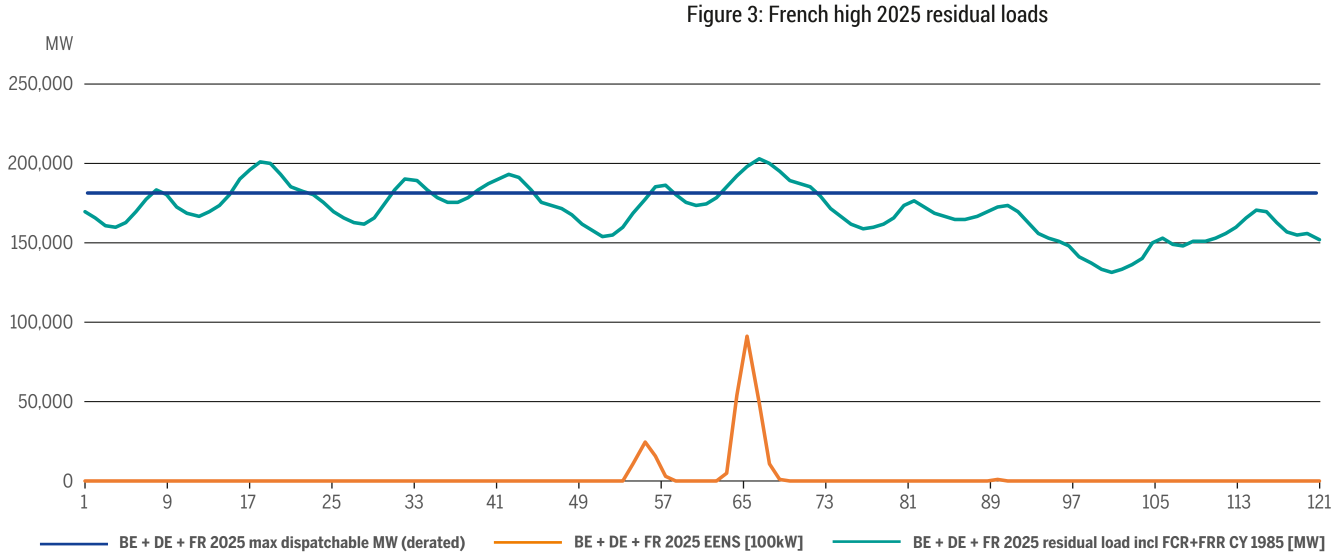


Figure 4: Sum Belgian + German + French high 2025 residual loads

Residual load analysis helps to pinpoint periods with higher ramping risks, which can occur in hours with or without resource adequacy concerns (RAC). Furthermore, the residual load analysis in hours with EENS could indicate whether ramping risks might accompany adequacy risks. In any case, more detailed and focused flexibility assessment studies, such as those proposed in Elia or RTE, may be implemented in preparation for decisions about which preventive measures, if any, may need to be taken to cover risks and flexibility gaps.

Based on the steps mentioned previously, our analysis (Figures 1 through 4) identified a scarcity period by combining the outcomes of detailed chronological adequacy simulations with the simple residual load analysis. This period is also one of a very small number during the simulated year 2025 in which the detailed chronological adequacy simulation shows a non-zero level of EENS. The detailed adequacy simulation confirms that sustained high residual loads in January 2025 imply a scarcity period with the most severe risks of unserved energy within the entire year. Note that this holds true not only for the three countries individually but also for their aggregated values. Note also that the overall EENS values are still low.

Figure 4 is especially important. Since ENTSO-E's MAF analysis models mutual support during scarcity, thus including the possible effects of scarcity prices, this figure shows that during this simulated period, scarcities are so severe that despite mutual support between these three countries and even with all other countries, not all energy demand can be served. Due to limited knowledge of the marginal demand function for these residual loads, this analysis is a very conservative estimation of the 'scarcity' situation. In practice, the price responsiveness of some loads may lead to lower or even non-existent energy-not-served, which will necessitate results from ongoing studies that aim to produce a better understanding of demand-side response capacity in scarcity situations.

Potential ramping risks were also analysed for Germany, which has the highest contribution of VRE compared to loads and dispatchable capacities among the three countries. Figures 5 and 6 illustrate how increasing flexibility needs for ramping and scarcity periods could evolve towards 2025 and 2030, again based on ENTSO-E's MAF 2020 data.

Figure 5 shows the 2025 and 2030 maximum upward ramps in the residual load over 1-, 3- and 8-hour timesteps (although both up and down ramps were analysed) which reach substantial fractions of or even exceed the total German dispatchable capacity, derated for forced outage rates of coal, gas, storage hydro and other capacities, as well as demand-side response. This indicates a serious ramping flexibility challenge, especially for the 2030 data, since in order to cover such ramps, either dispatchable capacity or other flexibilities would need to be imported from neighbouring countries, or RES would need to be curtailed.

Figure 6 shows a windless winter week where residual loads are almost as high as the loads themselves due to minimal VRE contributions. The maximum over the year of the 120-hour or 5-day average residual load, plus necessary frequency containment and restoration reserves (FCR + FRR) amount to 96 % of maximum dispatchable capacities for 2025 and 102 % for 2030. In the example 5-day period in January, many of the 120-hour periods exceed dispatchable capacities, which also indicates dependence on support from neighbouring countries.

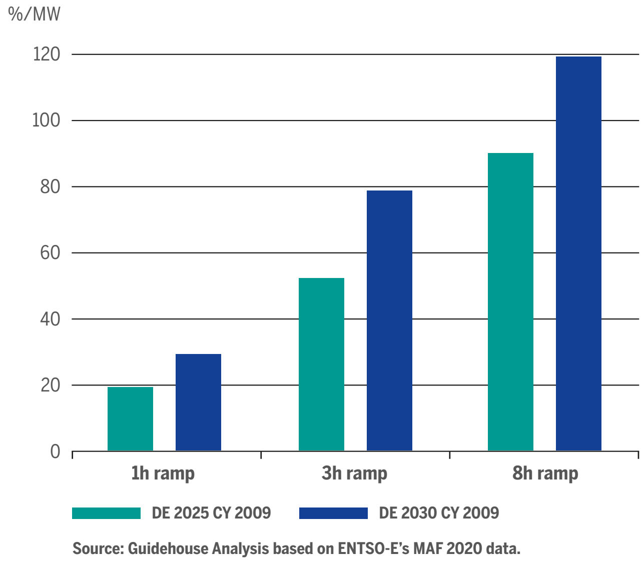


Figure 5: Germany max 1h, 3h, 8h ramps in % of max dispatchable MW 2025 vs. 2030

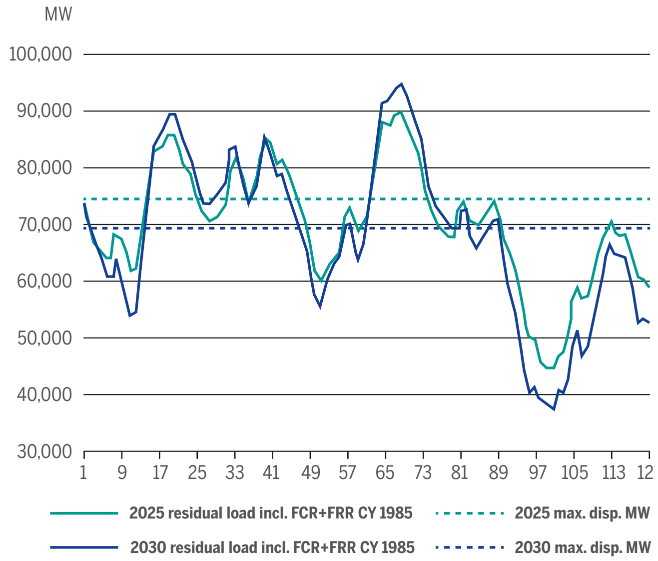


Figure 6: Germany sustained high net loads (8.1. 1 h–12.1. 24 h)

The results from the 8-hour ramps appear very challenging in the context of the residual load analysis for Germany in Figure 5, as they are already 89 % as high as the dispatchable capacity in 2025, and even exceed the dispatchable capacity by 19 % in 2030. Ramps are less serious in Belgium and France because of relatively lower RES contributions and are not shown here. However, in Germany, none of the short periods when high 8-hour ramps occur—in March, April, June, July, August and December—is associated with the risk of expected energy not served observed in January which was analysed for scarcity period flexibility gaps above.

Thus, at least for 2025 and for the three countries analysed, ramping flexibility gaps are not yet sufficiently severe to seriously endanger security of supply, based on the results of detailed chronological simulations. One important reason for this lies in the mutual support which countries in Europe can provide to each other through the meshed grid and various interconnections. Especially for short-term challenges such as ramping, the load, resource mix and weather diversity are so high that even Germany's challenging ramps, as shown in Figure 5, can be covered through imports and exports with neighbouring countries. Thus, the combination of a robust European grid with strong interconnections between all countries, with functioning and ever-improving day-ahead, intraday, and balancing markets can cover ramping risks more easily than scarcity period risks in this illustrative analysis of MAF data. It is important to reiterate that this analysis does not necessarily ensure that all flexibility needs following the day-ahead timeframe (intra-day and real-time) are covered. In parallel to this work, TSOs and ENTSO-E are looking at other equally important flexibility needs, including those related to fast frequency response[2], voltage stability and congestion management.

2 For example: Grid-Forming Capabilities: Ensuring system stability with a high share of renewables

3 Conclusions

The differences between ramping vs. scarcity period flexibility gaps show the value of combining results from metrics based on a relatively simple residual load analysis with those based on results which are available from sophisticated, detailed chronological adequacy simulations already routinely performed by TSOs and ENTSO-E.

In this context, it is important to recall that in ENTSO-E's MAF analysis, mutual support during scarcities is fully modelled in the simulations, which calculate the exchanges between all ENTSO-E countries for each hour based on market price equilibria and thus include the possible effects of scarcity prices.

As shown in the above illustrative analysis, the aggregate residual loads of the example countries, Belgium, Germany and France, are easier to manage with these countries' dispatchable capacities than the individual country residual loads, but the windless winter week conditions in this simulated period are so severe that despite mutual support between these three countries and in fact with all other countries as well, not all energy demand can be served.

On the other hand, despite results from the 8-hour ramps appearing very challenging in the residual load analysis for Germany, none of the short periods with high 8-hour ramps is associated with the risk of expected energy not served shown in the scarcity period analysis.

At this point, TSOs would need to assess whether the risks found during the analysis, such as the 10 January scarcity risk from the example, are manageable within the current market framework or whether further actions need to be taken to ensure that these flexibility gaps are covered.

This illustrative analysis of MAF data shows how the metrics proposed in the ENTSO-E Position Paper on the Assessment of Future Flexibility Needs can point TSOs towards possible flexibility gaps and risks which so far might be understood in less detail. Hence, as mentioned in the Position Paper, flexibility need assessments should be integrated into the TSOs'— and likely also the DSOs'— planning methods soon. The example also shows how the suggested methods and metrics for several types of flexibility needs can unearth these risks and could be used in the coming years to assess when flexibility gaps might occur. This in turn could support ENTSO-E and TSOs in preparing possible ways to manage the identified risks and flexibility gaps in advance, e. g. with grid service products and the stakeholder consultations and regulatory discussions that may be needed for any such measures.

Finally, it is important to emphasise again that the metrics illustrated in this paper for two flexibility challenges—ramping and scarcity periods—will be complemented through future ENTSO-E investigations into other flexibility challenges, related to stable frequency (inertia, RoCoF, fast frequency response), congestion management, voltage stability, and to the actual day-ahead, intraday and real-time operational management of the balance of demand and supply, taking in account forecast errors and unforeseen short-term variations.

Appendix: Flexibility needs analysis – current experiences and best practices

An increasing number of countries are introducing new assessment methodologies, market reforms, and regulations to measure flexibility needs and active new resources. Five cases, California ISO and ERCOT in the USA and ELIA, RTE and EirGrid in Europe, show how different transmission grid operators are analysing their flexibility needs and in some cases the services that they have created to cover these flexibility needs.

California ISO

California's independent system operator, California ISO, has proposed several changes in the power market to incentivise system flexibility due to large solar PV generation.

One of the changes proposed is to change the granularity from 1 hour to 15 minutes in the day-ahead market (California ISO, 2018a). The reduction in scheduling intervals would allow power-generating resources to follow the load curve more closely as forecasted by California ISO. California ISO also may be able to reduce procurement from the real-time market, especially during morning and evening ramping times. In November 2016, California ISO implemented a separate flexibility ramping product on the ancillary services market: Flexible Ramp Up and Flexible Ramp Down Uncertainty Awards, which are products designed to procure ramp-up and ramp-down capability for 15-minute and 5-minute time intervals through the ancillary services market. The product is procured in terms of megawatts of ramping required in a five-minute duration, and any resource capable of fulfilling the ramping requirement can participate. The price for providing ramp-up service is capped at USD 247/MWh, and the price for providing ramp-down service is capped at USD 152/MWh.

California ISO determines the quantity of flexible capacity needed each month to reliably address its flexibility and ramping needs for the upcoming resource adequacy year. This methodology involves calculating the seasonal amounts of three flexible capacity categories and determining seasonal must-offer obligations for two of these flexible capacity categories.

The main differences in weather in the California ISO system are between summer and non-summer months, where California ISO proposes to use this as the basis for the seasonal breakout of the needs for the flexible capacity categories.

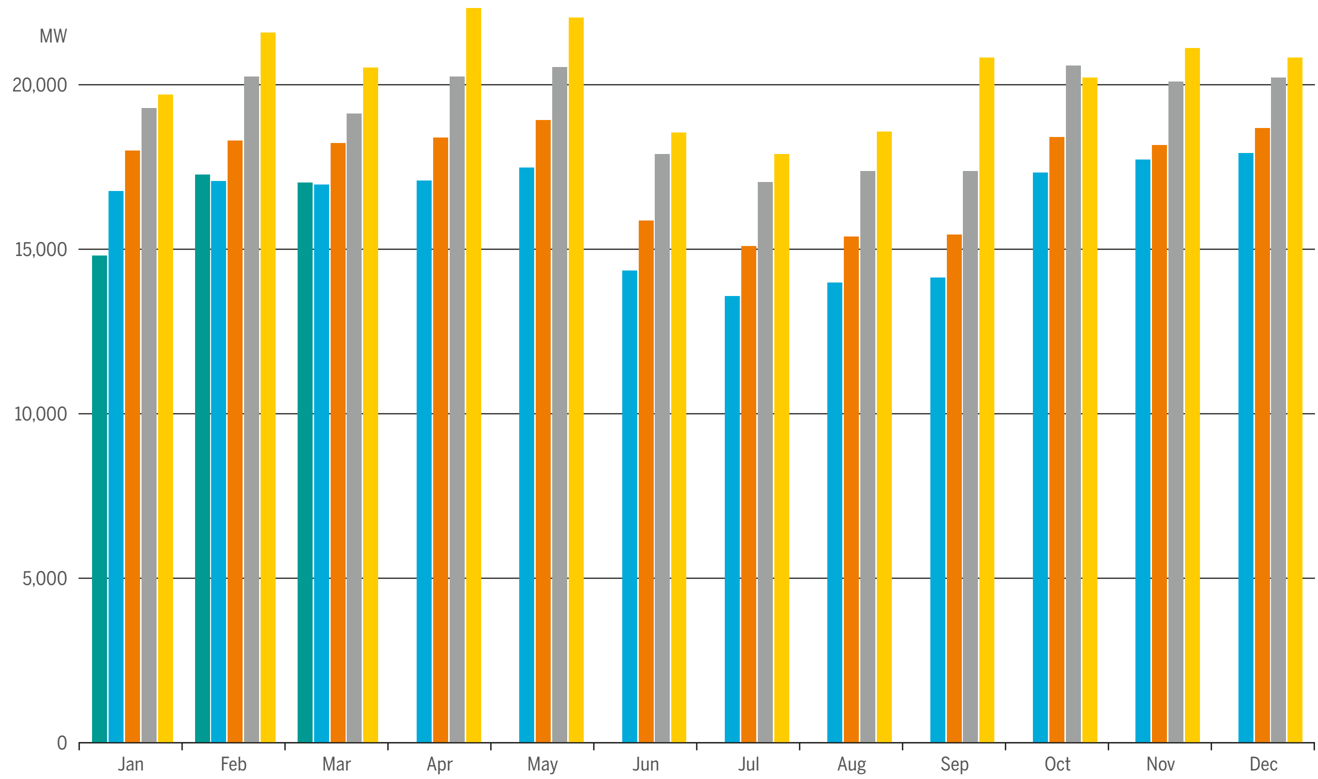
To manage seasonal flexibility needs, California ISO proposes to maintain two flexible capacity needs seasons that mirror the existing summer season (May through September) and non-summer season (January through April and October through December) currently used for resource adequacy. This division is done based on statistical analysis of historical data and relies on California ISO's wind, front-of-the-meter solar and net load forecasts (net load captures all behind-the-meter resources).

California ISO divides its flexible capacity needs into various categories based on the operational needs of the system. These categories are based on the characteristics of the system's net load ramps and define the mix of resources that can be used to meet its flexible capacity needs.

- **Base Flexibility:** Operational needs determined by the magnitude of the largest three-hour secondary net load ramp.
- **Peak Flexibility:** Operational need determined by the difference between 95 % of the maximum three-hour net load ramp and the largest three-hour secondary net load ramp.
- **Super-Peak Flexibility:** Operational need determined by 5 % of the maximum three-hour net load ramp for the month.

There is a maximum amount of flexible capacity that can come from resources that only meet the criteria to be counted under the peak flexibility or super-peak flexibility categories. Usually, base flexibility as defined above is used for the whole year.

The following graph shows how California ISO's flexible requirements will grow as ramp rates continue to climb:



14,795	17,259	17,012									
16,760	17,061	16,959	17,071	17,464	14,345	13,572	13,973	14,133	17,311	17,709	17,911
17,990	18,294	18,212	18,377	18,911	15,863	15,085	15,382	15,429	18,400	18,150	18,669
19,283	20,24 1	19,110	20,228	20,519	17,877	17,033	17,363	17,358	20,568	20,087	20,205
19,687	21,573	20,511	22,309	22,029	18,536	17,882	18,565	20,815	20,206	21,092	20,808

2021 Actual
2021_3_HrRamp
2022_3_HrRamp
2023_3_HrRamp
2024_3_HrRamp

Figure 7: How California ISO's flexible requirements will grow as ramp rates continue to climb. Source: Flexibility Requirements at the California ISO, Neil Millar (California ISO), ENTSO-E Workshop assessments of future flexibility needs, 26 April 2021

ERCOT

Texas ERCOT performed a study to reveal the impact of renewable penetration and Electrical Vehicle (EV) use on system reliability and reserves.

It ran a sensitivity study between different scenarios with different levels of renewable and EV penetration, which showed a positive correlation between EV adoption, gas generation additions, and generation retirements, and a negative correlation with solar generation additions.

Renewable generation penetration may cause huge transmission expansion, for example considering the ERCOT system, the addition of solar generation in the western part of the state coupled with the retirement of coal and gas generation in the eastern part of the state could result in significant increases in west-to-east power flows on the transmission system. This could result in significant transmission improvements.

Their results show that gas generation remains the primary technology used to meet ERCOT load throughout the renewable penetration study period [3].

ERCOT uses two primary reserves for the short term, non-spinning reserve and responsive reserve:

- **Non-Spinning Reserve Service:** The fixed value of a percentile ranging between the 70th percentile and 95th percentile will be assigned to the net load forecast uncertainty calculated previously. Periods where the risk of net load ramp is highest will use the 95th percentile compared to the 70th percentile for periods with the lowest risks.

  To account for possible future wind capacity forecast errors, ERCOT calculates the net impact. The net impact is calculated by multiplying the projected wind capacity growth between the current month and year and the same month of the next year by an incremental MW adjustment to the Non-Spin value per 1,000 MW of incremental wind generation capacity. The incremental MW adjustment to the Non-Spin value per 1,000 MW is calculated as the change in the 50th percentile of the historical wind over-forecast error for 4-hour blocks of each month in the past 5 years, which is then normalised to per 1,000 MW of installed wind capacity.

- **Responsive Reserve (RRS):** ERCOT will procure amounts of RRS that vary by hour and by month. These RRS amounts will be published by month in six separate blocks covering four-hour intervals. These amounts will be based on expected diurnal load and wind patterns for the month, will cover 70 % of historic system inertia conditions for each block of hours for the month, and will use the equivalency ratio for RRS between load resources and generation resources to establish the conditions for each block of hours. More details of RRS can be found in this report[4].

3 2018 Long-term System Assessment for the ERCOT Region, December 2018
4 Item 8: 2020 ERCOT Methodologies for Determining Minimum Ancillary Service Requirements, Nitika Mago

ELIA

In its 'Adequacy and flexibility study for Belgium 2020–2030' report[5], Elia quantifies Belgium's anticipated adequacy and flexibility needs for the period from 2020 to 2030. 'Adequacy' and 'flexibility' are two crucial pillars of a smoothly operating electricity system and also help maintain security of supply.

The new methodology for undertaking flexibility assessments, introduced in the flexibility assessment conducted in 2019, focuses on unexpected variations in generation and demand after the day-ahead time frame and is based on three steps:

› First, the method focuses on the risks of unpredicted variations in demand or generation after the day-ahead time frame. The flexibility needs are then calculated based on an extrapolation of historic forecast errors in demand, renewable and decentral generation, as well as forced outages of large generation units or HVDC-interconnectors. Different categories of flexibility needs are identified: ramping (to react in 5 minutes), fast flexibility (15 minutes) and slow flexibility (in 5 hours). These flexibility needs are to be covered by market players, or as a last resort by Elia by means of reserve capacity.

› Second, the flexibility needs are assessed during scarcity risk periods, i.e. periods with high residual load conditions. This capacity is considered in the adequacy simulations by means of reserving capacity for generation and demand response assets. This capacity approximately aligns with Elia's reserve capacity needs and ensures that sufficient flexibility is available to deal with forced outage and prediction error risks during periods with a high risk of scarcity.

› In the third and final step, the flexibility needs are compared with the operational availability of the same flexibility in the system. This is based on (1) installed capacity projections regarding generation, storage, and demand side management; and (2) the hourly schedules of this capacity following adequacy simulations. This permits an assessment of whether the system possesses the required flexibility means to cover the identified flexibility needs.

The model Elia uses for the probabilistic assessment of adequacy also enables the assessment of the available flexibility means, which thus enables the calculation of both indicators.

Given the position of Belgium in the heart of the European electricity system and its structural dependency on electricity imports for its security of supply, the modelling includes a large part of Europe.

To determine the prediction risks of renewable generation, as well as the demand, Elia uses historic time series of generation data and forecasts for onshore wind power, offshore wind power, solar power, decentralised must-run units (e. g. CHP) and demand. These allow to construct the aggregated forecast error time series for Belgium, representing different horizons (day-ahead and intraday). These are used for the three-primary metrics: ramping, fast flexibility and slow flexibility.

To represent forced outage risk, Elia utilises three parameters, two for adequacy assessment and one for flexibility:

› **The forced outage rate (used for the adequacy assessment):** This consists of the amount of unavailable energy due to forced outage (FO) divided by all the other moments when the unit was available and in forced outage.

› **The average forced outage duration (used for adequacy and flexibility assessment):** This is the average length of a forced outage (FO).

› **The average amount of events (only used in the flexibility assessment):** This is the average number of outage events that happen per year. For the flexibility assessment, it is particularly important to cover unexpected outage events immediately after they occur (fast flexibility) and during intraday (slow flexibility). After day-ahead, these fall under the scope of the adequacy analysis, in which the duration and the outage rate are particularly important (i.e. the time a unit is effectively in outage).

After the flexibility needs are determined, the available flexibility means in the system are assessed by integrating the required minimum flexibility needs into the adequacy assessment and ensuring the availability of this flexibility during periods with a scarcity risk, as well as by assessing the available flexibility means during all periods by means of an ex-post analysis of the adequacy simulation results.

5 Adequacy and flexibility study for Belgium 2020 – 2030, Elia Group, 2019

RTE

In the paper "Quantifying power system flexibility provision"[6], RTE proposes the use of a Flexibility Solution Modulation Stack model (FSMS) to evaluate annual, weekly and daily flexibility requirements through a set of frequency-spectrum-analysis-based metrics and examine the sensitivity of these flexibility requirements to five variables: the degree of network interconnection and the penetration of wind power, solar power, electric heating and cooling.

RTE proposes studying the effect of each of these variables on all timescales, along with the interactions between variables.

The aim of FSMS is to help its users understand how individual flexibility sources modulate over time to provide flexibility in order to match generation with demand on annual, weekly and daily timescales. By tracking how each flexibility source modulates around its mean value (each signal's integral is equal to zero), this is exactly what is expressed by the signals resulting from pre-processing.

The FSMS model divides flexibility sources into generation, storage, interconnections, and loads. To show the relative roles of each flexibility source, these modulations can then be stacked in a plot (FSMS), as one would stack generation time series to see how electricity demand is covered. By construction, at any point in time, the sum of the flexibility source modulations is equal to the variations of the residual load (here, load minus wind, solar and run-of-river hydro).

The results, showing the power and energy requirements based on RTE's simulation with three different penetrations of VREs (named 2017, Volt and Ampère) can be observed in the following graphic:

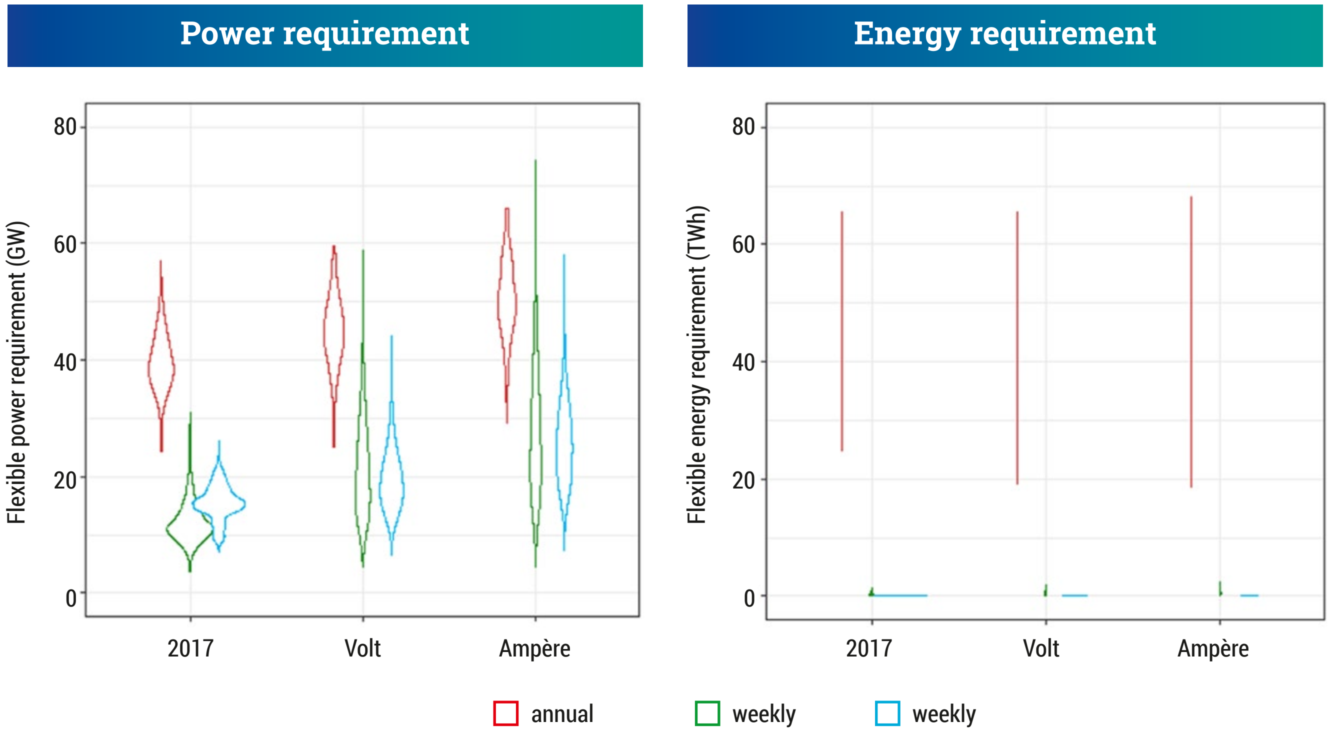


Figure 8: Flexibility requirement in 2017 and 2035, based on RTE simulation (Source: Overview of existing flexibility metrics, Thomas Heggarty (RTE/ Mines Paristech), ENTSO-E Workshop assessments of future flexibility needs, April 26 2021)

6 Heggarty et al, "Quantifying power system flexibility provision ", Applied Energy, 2020

EirGrid

To meet the challenge of operating the electricity system in a secure manner while achieving its 2020 renewables target, EirGrid and SONI introduced their Delivering a Secure, Sustainable Electricity System (DS3[7]) Programme in 2011. The DS3 Programme has enabled EirGrid and SONI to increase the level of instantaneous system non-synchronous penetration (SNSP) from 50 % to 75 %[8] in 2020.

- **Ramping:** DS3 introduced a ramping policy that sets out the power system ramping requirements for 1-, 3- and 8-hour ramping periods. These requirements are set by the control centre Ramping Tool and are fed into the market scheduling system. The ramping policy ensures that there is sufficient ramping capability margin in the power system to withstand any issue relating to generator trips, generators failing to start correctly, or forecasting errors in renewable generation.

- **Operational Reserves:** The Operational Reserves Policy requires an update in order to set a requirement for Fast Frequency Response (FFR). This requirement will be treated in the same manner as the requirement for Primary Operating Response (POR), or any of the other reserve categories, in the scheduling of generation in the control centre.

- **Fast Frequency Response (FFR):** The DS3 transition plan for 2020 introduced an FFR service. FFR provides a fast-acting response of less than 2 seconds following a frequency event in the power system. FFR is essential to the operation of the power system when operating it to a limit of 1 Hz/s and reducing the inertia floor.

- **Dynamic Reactive Response (DRR) & Fast Post-Fault Active Power Recovery (FPFAPR):** The DS3 transition plan also called for the introduction of DRR and FPFAPR, which are needed in order to transition from 70 % SNSP to 75 % SNSP. Both DRR and FPFAPR provide a fast-acting response for reactive power and active power following a fault or trip on the system. These fast injections are required to maintain system stability at very high levels of non-synchronous generation

7 Delivering a Secure, Sustainable Electricity System (DS3) Programme Overview – 2014, EirGrid and SONI, 2014

8 DS3 Programme Transition Plan Q4 2018 – Q4 2020, EirGrid and SONI, 2018

Abbreviations

Acronym	Meaning
CY	Climate Year
DRR	Dynamic Reactive Response
EENS	Expected Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
EV	Electrical Vehicle
FCR	Frequency Containment Reserve
FFR	Fast Frequency Response
FRR	Fast Restoration Reserve
FO	Forced Outage
FPFAPR	Fast Post-Fault Active Power Recovery
FSMS	Flexibility Solution Modulation Stack
MAF	Mid-term Adequacy Forecast
RAC	Resource Adequacy Concern
RES	Renewable Energy Sources
RR	Responsive Reserve
SNSP	System Non-Synchronous Penetration
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
VRE	Variable Renewable Energy

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