ENTSO-E Report on Flexibility from Renewable Energy Sources

November 2025

Foreword

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association of the European transmission system operators (TSOs). The **40 member TSOs, representing 36 countries,** are responsible for the secure and coordinated operation of Europe's electricity system, the **largest interconnected electrical grid in the world.**

Before ENTSO-E was established in 2009, there was a long history of cooperation among European transmission operators, dating back to the creation of the electrical synchronous areas and interconnections which were established in the 1950s.

In its present form, ENTSO-E was founded to fulfil the common mission of the European TSO community: to power our society. At its core, European consumers rely upon a secure and efficient electricity system. Our electricity transmission grid, and its secure operation, is the backbone of the power system, thereby supporting the vitality of our society. ENTSO-E was created **to ensure the efficiency and security of the pan-European interconnected power system** across all time frames within the internal energy market and its extension to the interconnected countries.

ENTSO-E is working to secure a carbon-neutral future. The transition is a shared political objective through the continent and necessitates a much more electrified economy where sustainable, efficient and secure electricity becomes even more important. **Our Vision: "a power system for a carbon-neutral Europe"*** shows that this is within our reach, but additional work is necessary to make it a reality.

With the present Strategic Roadmap, ENTSO-E has reorganised its activities around two interlinked pillars, reflecting this dual role:

- "Prepare for the future" to organise a power system for a carbon-neutral Europe; and
- "Manage the present" to ensure a secure and efficient power system for Europe.

ENTSO-E is ready to meet the ambitions of Net Zero, the challenges of today and those of the future for the benefit of consumers, by working together with all stakeholders and policymakers.

* https://vision.entsoe.eu/

Contents

1 Introduction

In line with the "Fit for 55" ambitions and the goals of the RePowerEU plan, the revised Renewable Energy Directive (cf. Directive (EU) 2023/2413) sets a new target for the share of renewables in the EU's gross final energy consumption of at least 42.5 % by 2030 (with a 2.5 % indicative top-up, to reach at least 45 % by 2030). Given the starting point of 23 % in 2022, this requires a massive expansion in renewable capacity.

This makes the efficient integration of renewable energy sources (RES) into markets and systems more crucial than ever to ensure these targets are met in a way that benefits European society and safeguards the reliability of the European power grid. Moreover, efficient RES integration is essential for ensuring affordable energy and a secure energy supply, both of which are critical to maintaining Europe's industrial competitiveness, as highlighted in the recent Clean Industrial Deal.

The ENTSO-E study System Flexibility Needs for the Energy Transition examines the evolution of system flexibility needs through 2030 and beyond, leveraging datasets from the European Resource Adequacy Assessment (ERAA) 2023 as a primary input. This work focuses on the effects of low renewable generation, as well as expected and unexpected variations in renewable generation. In parallel, ENTSO-E and DSO Entity are developing methods in line with the European Market Reform directive to conduct national flexibility needs assessments that support the integration of renewable generation into the system.

Security of supply and resource adequacy are common challenges, with "dunkelflaute" posing a key risk. These are periods with low sun and wind, which can leave high-RES systems unable to generate enough power to meet electricity demand. This risk has often required targeted measures to ensure security of supply, such as capacity mechanisms (e.g. capacity markets and strategic reserves).

This paper will not focus on the dunkelflaute case, though it illustrates the gravity and impact of weather dependence in RES if left unaddressed. This work concentrates on the opposite problem: what if renewable generation significantly exceeds demand? Recent years have seen numerous instances of negative prices, with continued pressure on downwards balancing reserves (for concrete examples, cf. Annex). Aside from not being economically efficient (renewables and other generation units operate at a net market loss under negative prices), this can push TSO balancing reserves and capabilities for congestion management to the limit if plant operators lack incentives to reduce production or increase demand, even at extremely negative prices, including at the lower price limits of electricity exchanges. Given the large volume of RES capacity expected to connect to the grid in the coming years, such events will increase in frequency and impact if not properly managed.

In principle, there are two ways to adequately address situations with high generation potential. First, it makes economic sense to maximise the use of available electricity. To this end, flexibility options like batteries, electric vehicles (EVs), electrolysers, power-to-heat applications, and demand-side response (DSR) can be used to increase the load. However, to achieve a very high share of RES in electricity generation, their installed capacity must significantly exceed the load – including any flexibility options (see **Section 4**). Therefore, RES must also reduce their feed-in, if necessary. In this paper, we focus on this part of the solution.[1]

1 Expanding the transmission grid and international interconnections is another important method of compensating for local fluctuations in situations of "dunkelflaute", or excess RES generation.

Technically, wind and solar energy can be highly flexible, as shown by their ability to reduce output in response to market prices and participate in ancillary services across many systems (for example, in the Spanish case described in Sections 3, 5, and the Annex). To unlock the full flexibility potential of these technologies for reducing feed-in, future market design must provide RES with appropriate price incentives. Today, support schemes often prevent exposure to the right incentives. ENTSO-E's position paper Sustainable Contracts for Difference Design elaborates on this problem and proposes various solutions.[2]

In this work, we examine a more complete picture of market solutions to ensure efficient integration of rapidly growing RES capacity. To this end, we will define the problem statement in more detail in **Section 2**, detailing when excess generation scenarios may arise and how they can affect system operations. In **Section 3**, we show that these challenges are not merely theoretical, having recently occurred. We describe the market background for RES feed-in at negative prices and describe historical cases, which we discuss in more detail in the Annex. To illustrate the relevance of the problem, in **Section 4**, we present an outlook on near-term developments to illustrate that RES flexibility is essential for a secure and efficient electricity system. In Section 5, we elaborate on the necessary solutions, including the conditions that enable market players to act in ways that benefit the system. Residual TSO measures may also be necessary to maintain system security and meet the standards expected of the European power grid. In doing so, we support the achievement of European RES targets while preventing excess generation from becoming a major issue.

2 Available at: Position Paper on Sustainable Contracts for Difference Design (entsoe.eu)

2 Problem statement

To integrate RES appropriately, it is crucial to understand how these assets behave in situations where large generation potential coincides with low demand. In such cases, the residual load (defined as the difference between the demand and the RES generation) can be extremely low or even negative. The left side of **Figure 1** illustrates such a situation. With appropriate bidding behaviour, this would lead to negative prices on electricity exchanges. The primary objective should be for market participants to behave rationally in such situations by reducing generation and shifting load (including charging storage) to these periods, thus ensuring a balanced system.

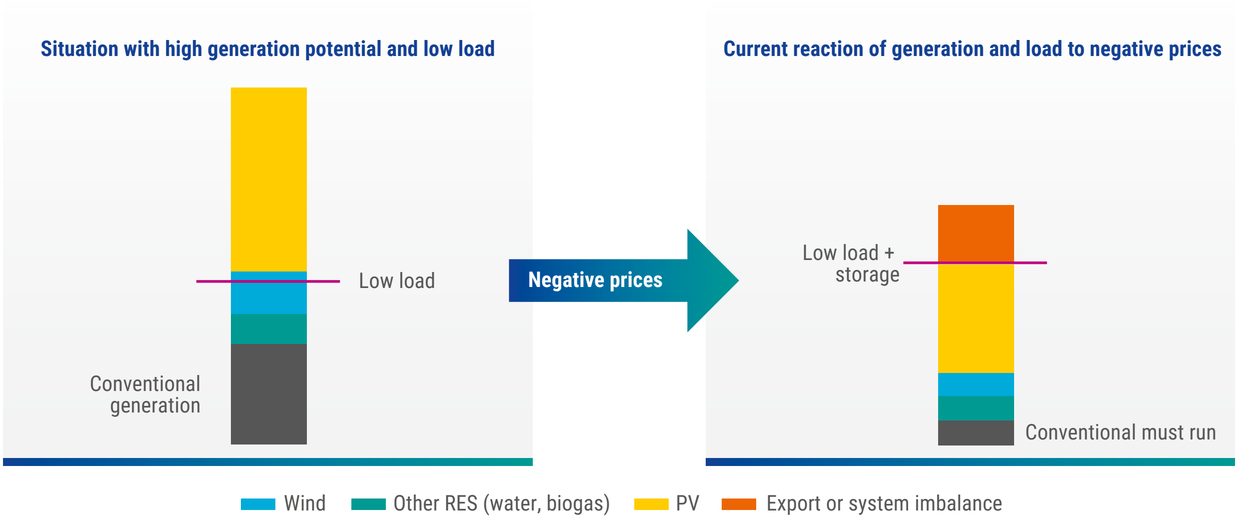


Figure 1: Situation with high generation potential and low load and the current reaction on negative prices.

The current electricity system has barely tapped into the potential of flexible loads. Even with very negative prices, it is primarily large-scale storage facilities that slightly increase the load. On the generation side, most conventional power plants will not produce when prices are negative. However, certain must-run units continue to produce due to other constraints, such as the need to provide ancillary services or (process) heat from combined heat and power (CHP) plants.

RES plants need suitable infrastructure for controllability and subsidy regimes, along with appropriate financial incentives, to reduce feed-in when prices are negative (see **Section 3** and **Section 5**).

If most RES installations operate under support regimes that provide no incentive to reduce production, even at very negative prices, completely price-inelastic generation can exceed low load in certain situations. For the net position of an individual country, the resulting surplus would then have to be exported. However, such situations occur simultaneously in many countries under certain weather conditions. In such cases, if balance responsible parties (BRPs) cannot balance their portfolio due to insufficient liquidity in integrated and internal wholesale markets, generation-consumption mismatches create system imbalances already visible in the day-ahead time frame. TSOs must manage these situations by activating downwards balancing reserves, in addition to addressing unexpected forecast errors.

This can be particularly challenging when high levels of distributed, price-inelastic renewable generation – particularly small-scale solar PV – are connected to medium and low voltage levels. In these situations, TSOs face the challenge of maintaining sufficient downwards frequency restoration reserves (FRR), as small-scale PV have limited ability to regulate their output or provide the necessary balancing reserves. Therefore, if FRR activations are insufficient to offset the remaining imbalances, the resulting energy surplus may jeopardise the reliable operation of the system.

In addition, vertical and horizontal congestion problems can arise when non-controllable systems feed into local clusters, including during planned outages for network reinforcement.[3] This phenomenon was already observed in several countries in 2024. In such cases, system operators must force plants to shut down, either by activating an appropriate measure from the system defence plan – pushing the system into an emergency state – or, when permitted at the national level, using specific remedial actions. These measures require reliable mechanisms to issue and implement instructions quickly to restore balance between generation and offtake or resolve grid congestion.

3 For example, these congestion problems may also lead to cancellations of planned outages for network reinforcement. This delays and increases the cost of network expansion, which could otherwise alleviate future congestion problems.

3 What have we already seen?

The problems detailed in the previous section are not merely theoretical – they have already occurred in the recent past. To ensure a robust solution, this section performs root cause analysis into the market design for historical cases. ENTSO-E conducted a brief internal survey (cf. Annex) to gather essential input data, including support schemes, BRP price incentives, and information about market prices and system conditions during periods of excess RES production. The following subsections are organised accordingly.

Impact of support schemes

Most countries have different schemes depending on technology type and asset size. The majority of survey respondents report that RES receive some form of initial investment support, either direct monetary aid (for energy or installed capacity), tax reductions, or certificates that may hold monetary resale value depending on national policies. Fixed feed-in tariffs, which used to be the main funding method, are still quite common among the respondents. However, their use is slowly declining due to the observed negative effects on the market and the grid. The 2022 guidelines on State aid for climate, environmental protection and energy require that support schemes avoid causing undue market distortions – for example, by not providing support during periods when the market value of production is negative.

One-sided market premium models and two-sided contracts for difference (CfDs) with restrictions aim to support RES deployment while also partially mitigating the negative effects of older models. However, such schemes remain in the minority and still retain distortions. Since funding mechanisms vary by asset size and technology, the surveyed countries reported differing responses to negative prices. While some technology schemes always incentivise maximum feed-in, even during negative price periods, others reduce financial payouts during such times, encouraging reduced feed-in. Other schemes pay based on installed capacity, which does not encourage negative bidding. In conclusion, while improved regulation has reduced market distortions, many existing schemes still incentivise excess generation and will remain in effect for years due to long funding periods.

BRP incentives

The primary goal must be to ensure that any problems can be solved either by market participants themselves or by system operators via the market. In general, BRPs are responsible for balancing fluctuating RES production, like any other asset within their balance group. In general, BRPs have sufficient incentives to remain balanced through the imbalance price, and in some cases, through additional components of imbalance settlement prices.

However, in several countries, BRPs have limited to no ability to directly control RES assets to ensure alignment with the schedule. This is due to limited steering capabilities from plant operators or the absence of legal requirements on the controllability of small assets. Additionally, when the imbalance is caused by RES assets, BRPs cannot always hold the associated grid users directly financially accountable for the imbalances they cause, particularly for behind-the-meter installations (self-consumption).

Historical cases of excess generation

Most RES assets are subsidised with some sort of state aid scheme, and they continue to feed in despite negative prices. In half of the surveyed countries, TSOs observed a (partial) reduction of RES feed-in during hours with negative prices. However, in most countries, negative effects arose from RES feed-in during periods with negative prices, as well as issues with forecast deviations or quality.

This has affected load flow on the grid, impacted available resources for congestion management, and caused system balance issues (including adequacy). The Annex provides a summary of the survey along with selected noteworthy historical cases shared by ENTSO-E members. They highlight current practical challenges while also offering a positive example: in Spain, the requirements for observability and controllability are sufficiently fulfilled.

4 Near-future development scenario

There are clear indications that excess generation events will become common in the near future. The ENTSO-E's national trends scenario projects a significant increase in the penetration of intermittent renewables (solar and wind) by 2030 (see **Figure 2**), with levels exceeding the 10-Year Network Development Plan (TYNDP) estimated peak load[4] of each system, in some cases by a considerable margin.

An extreme case is the Netherlands, where the total installed capacity of intermittent RES is expected to be 300 % higher than the estimated peak load by 2030. Based on scenario estimations, other countries with high intermittent RES with respect to peak load are Spain, Greece, Belgium, Poland, and Germany. The risk is particularly pronounced in Greece and Spain, where solar PV capacity factors are much higher than in other EU Member States (although some existing measures offset the risk in Spain, which will be described in the next section), and in Germany, where the expected installed capacity exceeds the peak load by more than 200 GW. Looking at the peak load, it becomes evident that excess generation may also occur in high-load situations. However, the picture becomes even more critical when considering periods of low load, particularly during weekends and public holidays. This is illustrated by the expected minimum load in 2030. In Greece, the Netherlands, and Germany the installed renewable generation capacity is more than 10 times higher than the minimum load.

The described development will also be considered in the national flexibility needs assessment, where situations with high RES feed-in are a key area of focus. Excess generation situations occur less frequently when load-side flexibility and storage react to market prices, making them an important component in addressing the challenge. However, the comparison between peak load and installed capacity suggests that this alone will not be sufficient, and that RES will have to switch off in some situations. This is confirmed, for example, by a scenario that the German TSOs have developed for the years up to 2030.[5] Even taking into account the flexibility of electrolysers, large-scale storage systems, and decentralised flexibility options, plants smaller than 25 kW will have to be switched off to avoid excess generation. The next section outlines the solutions needed to unlock this potential.

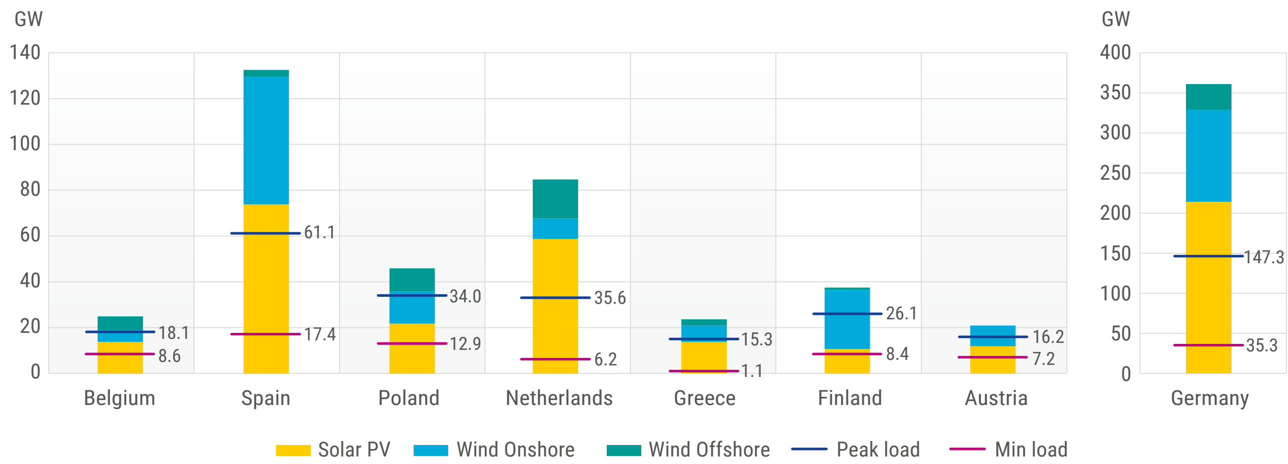


Figure 2: Comparison of estimated intermittent RES installed capacity (2030 – national trends scenario) with TYNDP forecasted peak and minimum load for 2030.

4 The specified load takes into account the market price–oriented behaviour of batteries, electrolysers, and DSR.

5 Koch, Papadis (2024): Negative Preisspitzen durch erneuerbaren Erzeugungsüberschuss: energiewirtschaftliche Folgen und Handlungsbedarf. Energiewirtschaftliche Tagesfragen, 10/2024, 55 – 58.

5 Solutions

The analysis in the previous sections demonstrates the need to efficiently integrate RES into the electricity system. In general, these assets should be developed alongside demand, storage, and network to limit oversupply and congestion. In addition, conditions must be established to fully leverage the flexibility of RES. This requires asset observability and controllability, as well as financial incentives to discourage feeding in when prices are negative. This section takes a closer look at the proposed solutions, addressing the requirements for both large and small assets.[6] Significant differences exist based on asset size, not only in terms of regulation but also from the technical and economic perspectives.

Observability and controllability

Observability is the basic prerequisite for assessing network status. Access to meter data is key for tapping flexibility potential. Without observability, TSOs and DSOs cannot monitor network status or detect when action is needed to address issues and maintain system security through appropriate remedial measures. Access to meter data also enhances system visibility and is essential for providing suitable financial incentives to reward system response. The metering equipment interface can also be used as a port to receive control instructions. While this is generally not an issue for large assets, at least in some countries, the limited rollout of smart meters poses a major obstacle, as it prevents measurement and balancing at 15-minute resolution for small assets. It is therefore essential to accelerate the rollout of smart meters and ensure that Member States implement the relevant EU legislation (e.g. Energy Performance of Buildings Directive [EPBD] Art. 16 and Art. 7b in the Electricity Regulation pursuant to the Electricity Market Design Reform [EMDR]) to enable the data behind the meter to be accessed and shared. This would also allow small assets, which are not required to exchange data as significant grid users per System Operation Guideline, Article 2, to engage in simplified data exchange with system operators and/or other relevant market or technical parties. This would allow for greater visibility into generation and consumption patterns, improving the forecast of balancing needs and network status – commonly referred to as "enhanced observability" for small assets. It would also enable devices behind the meter to provide flexibility to the market (e.g. directly monetising output reduction for solar PV).

In terms of controllability, Commission Regulation (EU) 2016/631 establishes a network code on requirements for grid connection of generators. It allows TSOs to classify assets according to their size and grid connection level, subject to approval by the relevant regulatory authority. Assets with active power reduction can be smaller than 1 MW, and in some countries, the threshold can be as low as 100 kW. However, due to the rapid expansion of PV, future projections indicate that current limits will not be sufficient.

Even smaller assets must be controllable to avoid excess generation (see **Section 4**). In this case, it is necessary to lower the national limits to align with the specific needs of the local system. This also requires that the necessary infrastructure be in place. In some countries, the smart meter infrastructure is used for this purpose via dedicated control boxes. It is also possible to leverage existing manufacturer interfaces, although IT security regulations in some countries restrict this, especially when it comes to control requirements by system operators. In such cases, dedicated control boxes must be quickly implemented to fully harness the flexibility of the systems. Reinforcing cybersecurity at the product level is also essential to prevent external attacks and increase overall resilience. SolarPower Europe also made this demand in its recently published position paper.[7]

6 Differences in controllability requirements for assets can be based on their size: On the one hand, larger assets often have more stringent requirements due to their potential impact on grid stability and the need for more sophisticated management systems. On the other hand, smaller assets may have less rigorous requirements, although they still must comply with certain standards to ensure safe and reliable operation. To account for this difference, the solutions proposed in this section pertain to these two categories. There is no universal definition for "small" or "large" – it depends on national requirements. However, the threshold for small assets is generally below 1 MW.

7 SolarPower Europe: A Harmonised Cybersecurity Baseline for Solar PV.

For large installations, data exchange and controllability are typically required under the relevant regulatory and contractual framework, in line with the implementation of requirements outlined in Part II -Title 1 and Title 2 of Regulation 2017/1485 and its subsequent methodologies. However, despite such regulations, past experiences in many countries have shown additional steps must be taken to fully implement controllability in practice. Potential obstacles include technical issues, such as controlling technology being prone to failure (especially in older installations), and limited access to plant control. In general, control interfaces vary widely depending on the manufacturer.

Standardising these interfaces could make it easier for market players – such as BRPs, suppliers, or aggregators who bundle systems from many different operators – to control these assets. However, standardisation should include cybersecurity measures. In addition, it is crucial to ensure that RES assets connected to the distribution network are fully controllable, especially in countries with high levels of distributed renewable generation.

Depending on the national approach or system user type, controllability of RES in the distribution network can be implemented either directly by the TSO or through the relevant DSO. In addition, regular tests should be conducted to ensure controllability is also implemented in practice.

There are positive examples of TSO control for units above a certain threshold. In Spain, the TSO control centre receives real-time data for all single production facilities above 1 MW, or clusters of units that share a connection point and have an aggregated installed capacity higher than 1 MW. It can also send set points to all units above 5 MW (or even lower if they opt in voluntarily), as well as sets of units sharing a connection point with an aggregated capacity above 5 MW. Both the observability and controllability requirements are applied regardless of which grid they are connected to (transmission or distribution).[8] These requirements, among others, allow RES to participate in balancing services and redispatching processes. Additionally, the implementation of the Automatic Power Reduction System (described in the Annex[9]) represents a key milestone in maximising RES integration, as it reduces the need for curtailment to solve post-contingency overloads by replacing preventive solutions with corrective ones.

8 Any contingency detected by the DSO that requires topology actions in the transmission network or limitations of units larger than 1 MW is communicated to the TSO, which executes these actions.

9 Also in this article from Ministerial Magazine (only in Spanish): https://www.mintur.gob.es/Publicaciones/Publicacionesperiodicas/EconomiaIndustrial/RevistaEconomiaIndustrial/431/11_ENCABO_1.pdf

Financial incentives

When managing excess generation, the goal is for market players to proactively reduce asset feed-in during relevant situations, minimising the need for TSOs to intervene except in exceptional cases. This requires the right financial incentives – in other words, appropriate support schemes. ENTSO-E published a paper in 2024 describing various CfD options.[10] Non-production-based support schemes provide the best incentives for market-compliant behaviour. Appropriate subsidy regimes can also support the system by offering incentives for system-friendly configurations; for example, PV systems with an east–west orientation that produce more electricity in the morning or afternoon and less during the midday peak. Additionally, system-friendly support schemes allow resources to participate in ancillary services, which is crucial for accommodating large volumes of RES in the electricity system. In contrast, legislators must revise inappropriate subsidy regimes, such as hourly CfDs with hourly reference periods and payments despite negative prices, as they fail to incentivise reduced production even when prices reach the lowest limits on electricity exchanges.

On the other hand, market players will always compare the losses of a non-reduction with the costs of a reduction. The first question here is who is responsible for the costs associated with feed-in at negative prices and the imbalance costs caused by RES. Shared responsibility between BRPs and the plant operator could incentivise both parties to cooperate in implementing processes that encourage appropriate plant behaviour. This includes sufficient data exchange between plant operators and the BRP (which also improves the accuracy of day-ahead and intra-day schedules), implementing and maintaining control infrastructure, and settling reduced feed-in between all parties involved. To reduce costs, the processes between plant operators, BRPs, and system operators must be as automated as possible. Furthermore, improving trading opportunities, such as the introduction of 15-minute products and shortening the gate closure time, is expected to help market participants correct schedule deviations by trading surplus energy or buying energy to cover underproduction. The expectation is that if financial losses increase significantly due to strongly negative prices, economic actors will do everything possible to improve asset controllability.

In terms of financial incentives for small assets, the support schemes in European countries aim to provide secure income streams for investments by private customers. These include fixed feed-in tariffs, where every kilowatt hour fed into the grid is compensated with the same reward, regardless of the spot market price. In addition, prosumers benefit from self-consumption privileges, meaning they are exempt from grid fees, levies, or taxes for the electricity produced by their own power plant that they consume themselves. Some countries use a net metering concept, where self-consumption privilege extends beyond immediate use. This allows for netting over a longer period, further reducing grid fees, regardless of whether the consumer behaves in a system-friendly manner.

In the first phase of the energy transition, these support concepts were understandable – based on the premise of providing the simplest possible conditions for private investments. However, alternatives are necessary to prevent price-inelastic generation and demand from becoming too large and causing the challenges described in the sections above. Aside from developing more flexible electricity demand (as discussed throughout the text), negative spot prices should be applied during these hours if electricity is fed back into the grid, to incentivise a reduction of injection when necessary.[11]

Measures that retain market price incentives have the advantage of encouraging the use of local flexibility potential. Before reducing production, a prosumer should charge EVs or home storage systems during times of high RES feed-in to use as much of the self-produced electricity as possible. In contrast, flat-rate self-consumption privileges are not sufficient. As every kilowatt hour of self-consumption currently has the same value regardless of the time, the shiftable potential of EVs and home storage systems is charged primarily in the morning and does not deliver a positive value at noon, when RES feed-in is particularly high. Tariffs that consider variable spot prices would be beneficial in this case. Whether these tariffs are fully dynamic or offered at a fixed rate with reduced conditions by service providers, as long as they allow for optimal marketing of flexibility.

10 https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/Position papers and reports/2024/240220_ENTSO-E_CfDs_Position_Paper.pdf

11 Some countries, like Spain, impose a tariff on self-consumers that exposes a portion of them to market signals, including negative prices.

Especially for small assets with limited controllability, there should be clear incentives and rules to ensure compliance with operating constraints, which could be defined based on specific grid conditions, such as congestion management. Such operating constraints should be included in the regulatory and contractual framework.

To ensure that small assets comply with these constraints using their flexibility, system operators should define appropriate financial penalties for non-compliance.

To conclude this section, **Table 1** provides an overview of measures improving observability, controllability, and market behaviour.

Aim	Measures
Improving observability	› Roll out smart metering or other granular metering systems (e.g. Art. 7b in the Electricity Regulation as per the EMDR) › Improve data exchange requirements between plant operators and BRPs
Improving controllability	› Facilitate controllability of assets by plant operators or professional parties (BRP, supplier, or RES aggregator), i.e. by standardising interfaces › Enforce controllability requirements of requirements for generators (RfG) by TSOs and national authorities based on local system needs, enabling its use in TSO's system defence plan or remedial actions, including regular testing › Roll out necessary infrastructure (dedicated control boxes) › Reinforce cybersecurity at the product level
Improving market-dependent behaviour	› Establish appropriate support schemes (see ENTSO-E's paper on sustainable CfD design) › Stop net metering where it is currently applied › Facilitate dynamic feed-in and grid tariffs for small-scale power plants › Automate processes (control and settlement) to reduce the cost of shutting down assets › Provide incentives for adherence to operating constraints, as determined by the relevant system operator › Foster participation of RES in balancing or other system services (through appropriate support schemes and aggregation for small-scale assets)

Table 1: Overview of measures improving observability, controllability, and market behaviour.

6 Conclusion

Integrating RES into the electricity system is more important than ever to ensure the efficient attainment of decarbonisation targets while safeguarding the reliability of the European power grid. This requires flexibility, not only during a possible dunkelflaute but also when high RES generation potential meets low demand. In addition to the use of load-side flexibility and storage, RES must also contribute to system security in these situations.

Otherwise, there may be excess generation, which can cause grid congestion or system imbalance. The first signs of these problems are already visible in some European countries. To prevent further ambitious RES expansion from exacerbating this problem, we must establish the necessary conditions for RES plants to reduce their feed-in when necessary.

The key factors in achieving this are observability, controllability, and appropriate financial incentives. We must roll out the necessary measurement infrastructure to monitor the fulfilment of control instructions and reward the response of the assets. For an efficient and resilient electricity system, market players must reduce asset feed-in during appropriate situations on their own initiative. This will only occur if they see switching off as financially worthwhile.

To achieve this, we need appropriate support schemes and low transaction costs for system shutdowns (e.g. by standardising control interfaces and automated accounting processes). Small-scale assets must be incentivised to adhere to operating constraints as determined by the relevant system operator. However, TSOs must always be able to take action in emergency situations to ensure safe system operation. To do this, they need the ability to control assets up to the required minimum size. This requires the necessary infrastructure and regular tests of the control route.

With these measures in place, we will be able to leverage the flexibility potential of RES and ensure the continued safe operation of the electricity system in the future.

Annex

Summary of the TSO survey

Here we present an overview of a survey in which TSOs from 13 countries[12] took part. Information was collected on the topics of funding, BRP settlement, and historical cases.

Out of the 13 countries, 12 have different subsidy regimes depending on technology or the size of the asset (see **Figure 3**). With two exceptions, support schemes that incentivise feed-in at negative prices (fixed feed-in tariffs, net metering concepts, or fixed tax reduction in EUR/MWh) remain in place, particularly for smaller plants. Meanwhile, 12 TSOs report that their countries have support schemes that incentivise reduced feed-in at negative prices (i.e. do not neutralise market signals). These include investment funding on its own (not combined with other funding schemes, such as fixed feed-in tariff) and market premiums or CfDs with no payment for hours with negative prices.

In every country surveyed, BRPs bear the full responsibility for RES imbalance. However, seven TSOs note that BRPs in their countries face challenges that hinder their ability to respond adequately to negative prices, particularly their limited ability to control assets and bill RES operators for the imbalance.

The negative consequences of the missing incentives described above are already observable in the electricity system. For instance, eight TSOs noted that a large share of RES still fed into the grid in situations with negative prices, proving that these assets have limited to no reaction to market signals. This negatively affects system operation. High RES feed-in affected the load flow situation and available redispatch potentials in six countries. The limited reaction of RES to negative prices has impacted system balance, with six TSOs reporting that they had to implement countermeasures such as balancing reserve activations, emergency measures, or RES curtailment. The next section provides a more detailed description of some historical cases.

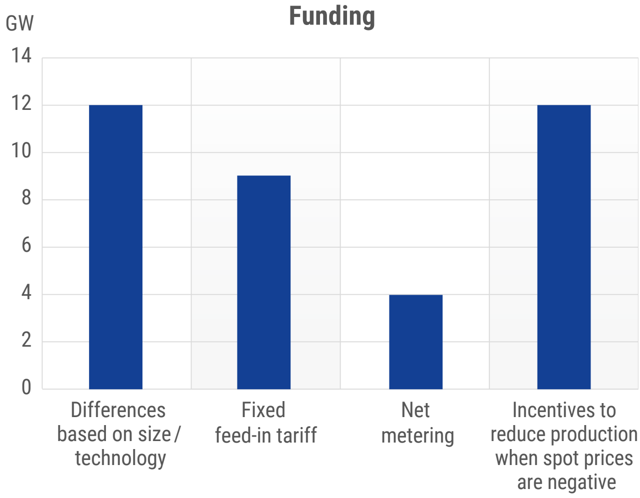


Figure 3: Survey results regarding RES funding.

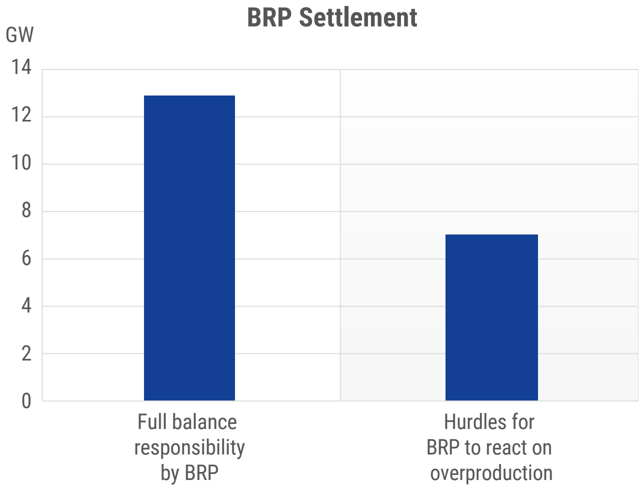


Figure 4: Survey results regarding BRP settlement.

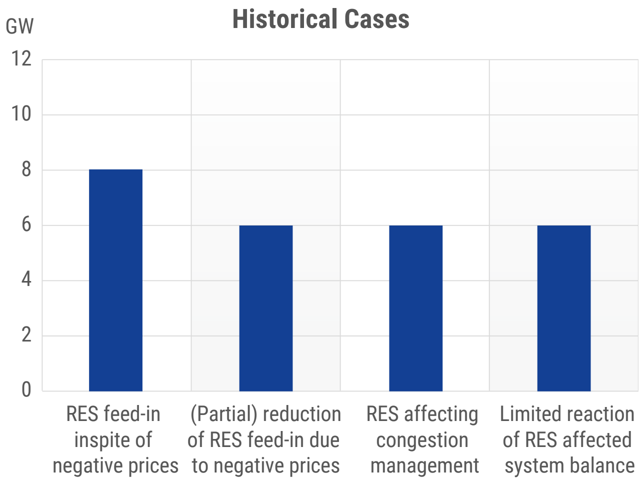


Figure 5: Survey results on historical cases of excess generation.

12 Austria, Belgium, Finland, France, Germany, Greece, Luxembourg, Poland, Netherlands, Serbia, Spain, Sweden, and Switzerland.

Historical cases of excess generation

Belgium – 07/04/2024

The day-ahead price was negative or zero for a large part of the day, reaching a minimum of −23.32 €/MWh between 1 and 2 pm for Belgium (see **Figure 6**). These prices are quite moderate and do not account for a significant amount of excess generation compared to demand, but still assume that all demand will be met with low-marginal-cost generation (mostly RES). It was a Sunday, which typically has a low electricity load. Over the course of the day, it turned out that the solar forecast was underestimated by a significant amount – around 1,700 MW (see **Figure 7**).

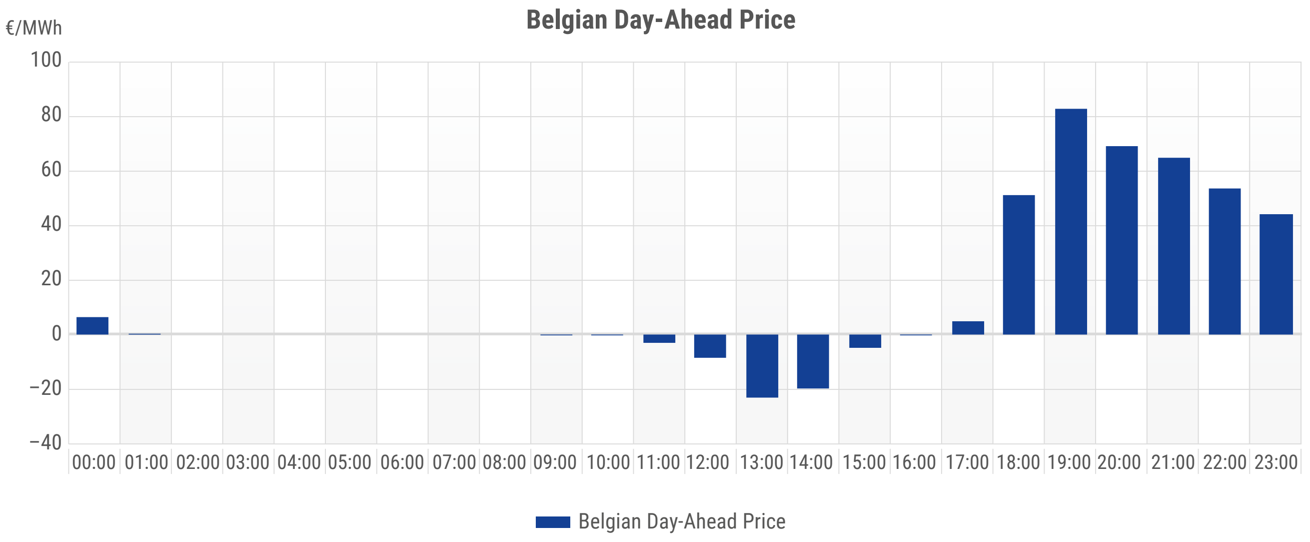


Figure 6: Belgian day-ahead prices for 07/04/2024 (Source: www.elia.be).

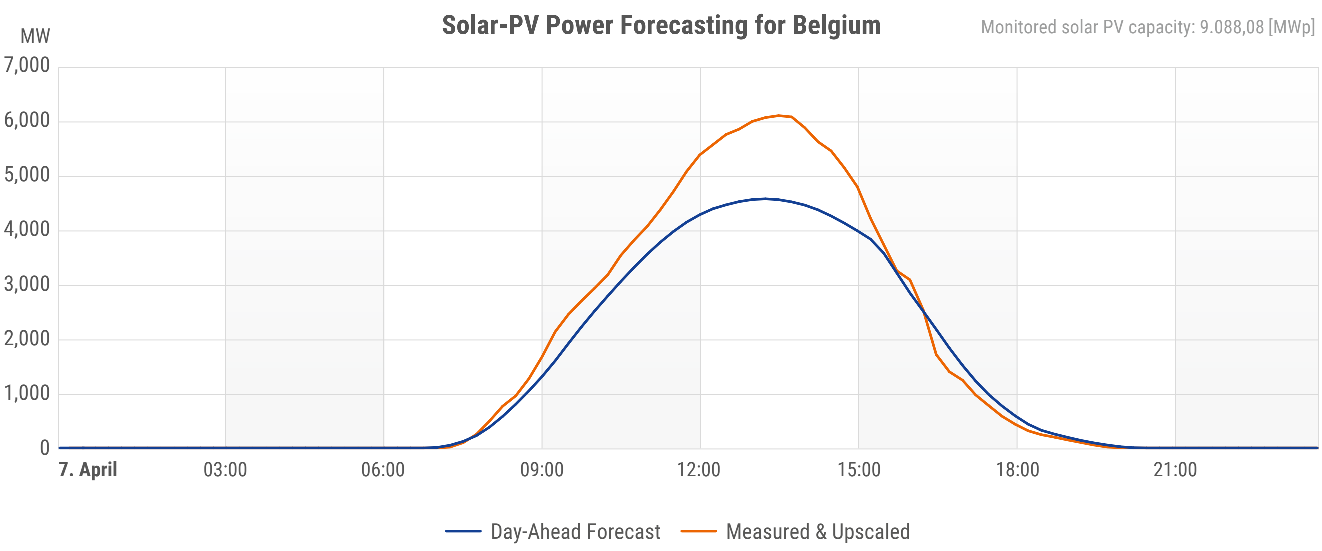


Figure 7: Solar forecast and measured production for Belgium on 07/04/2024 (Source: www.elia.be).

Overall, the system imbalance was around 2 GW (up to a maximum of 2,375 MW), of which about 1,000 MW of down reserves were activated via wind curtailment and 1 GW of reserve sharing with neighbouring TSOs. The highest imbalance price recorded was −4,574.64 €/MWh, which Belgian BRPs were liable to pay.

Despite the ability of market players, including renewable generation, to react to (negative) prices, and their ability (and even obligation, for units larger than 25 MW) to offer downwards reserve capacity to the TSO, the market was not able to resolve the excess supply on its own.

Large renewable assets (generally large wind parks but also large solar parks) are curtailed (or activated for downwards FRR) at the direction of TSOs through their participation in balancing reserves, and as such are at least technically able to reduce production. However, a significant portion of renewable assets consists of decentralised assets (in particular solar PV installations), which are not obligated to offer reserves and are generally not yet capable of being controlled for curtailment. Therefore, even if the price incentive reaches the consumer level, the technical capability to react to it is unlikely to be available in the short term.

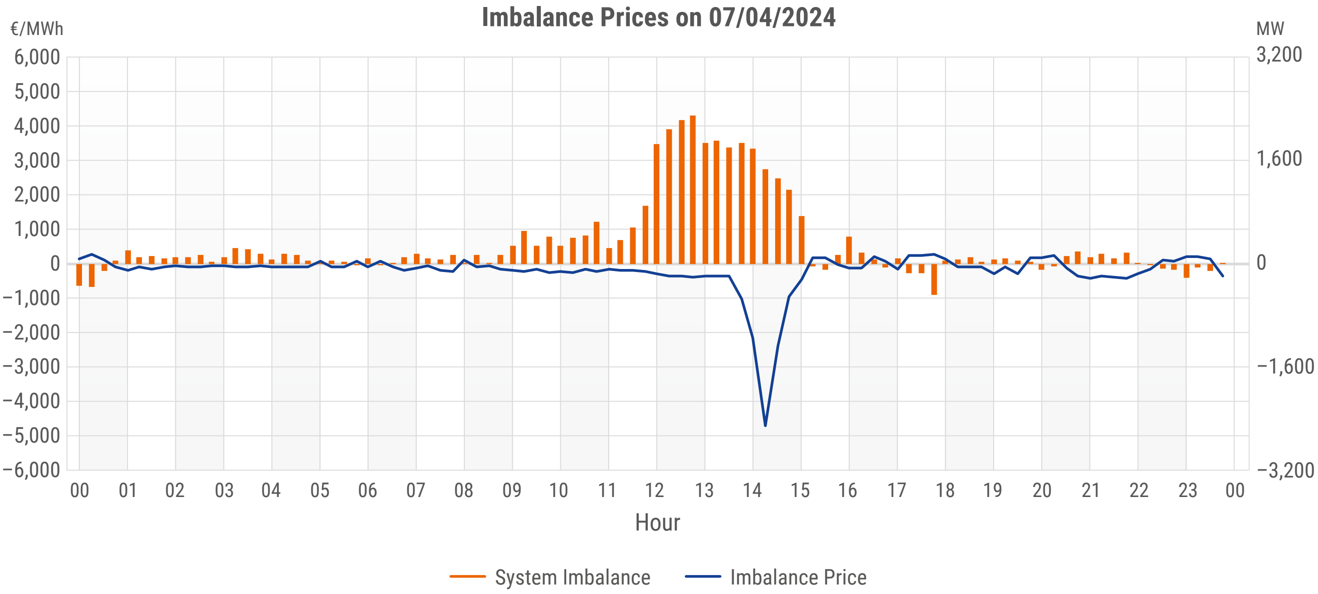


Figure 8: Belgian real-time imbalance prices and system imbalances (Source: www.elia.be).

Germany – 02/07/2023

On 02/07/2023, day-ahead prices in Germany were negative for 15 consecutive hours, even dipping below −100 EUR/MWh for 5 hours. From 2 to 3 pm, the lower price limit of −500 EUR/MWh was reached in the DA market for the first time. A look at the actual wind feed-in in this situation shows that although it was reduced compared to the possible feed-in, 40–50 % of the possible capacity was still generated (see **Figure 9**). This means that many turbines were not shut down, even though financial incentives were provided. In a survey, market players mentioned possible hurdles (see **Section 5**). An analysis of similar situations in 2024 shows initial progress, and it can be assumed that increased financial pressure will soon lead a large proportion of wind turbines to stop feeding into the grid during such hours. The PV picture is much worse. An analysis of a larger sample shows that on 02/07/2023, only about 20 % of the potential feed-in had been shut down, and the situation has only improved slightly in 2024. This must change. The target for Germany is to have 215 GW of PV installed by 2030. If these are not adequately integrated into the market and react to negative prices, the probability of excess generation is very likely.

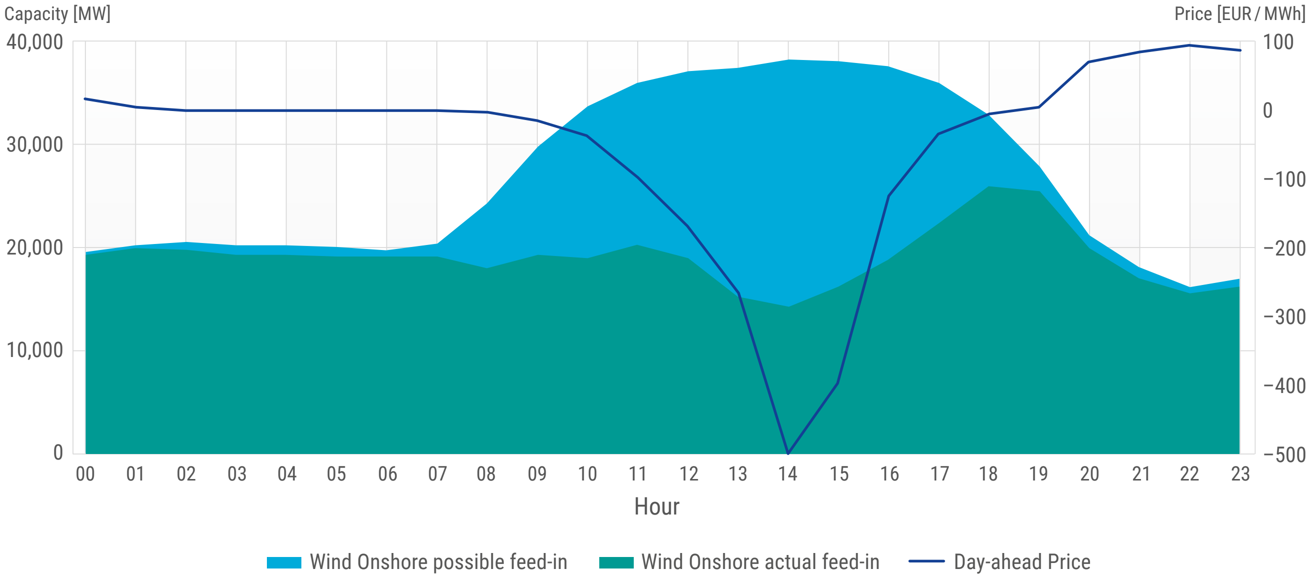


Figure 9: Possible and actual feed-in and day-ahead price for Germany on 23/07/2023 (Source: www.netztransparenz.de; www.epexspot.com).

Poland – 01/05/2024

For Poland, high renewable production necessitates the use of non-market-based redispatch. For the observed period of 1/1/2024 to 15/06/2024, it was utilised on 33 days, over 60 % of which were either during a weekend or a public holiday. The example below presents a redispatch event during a public holiday.

Redispatch usage was required from 7am to 6 pm, with an average of 936 MW of onshore wind and 3,291 MW of solar with activated redispatch. During the event, renewable generation exceeded 60 % of demand for that hour.

The imbalance price during the event remained negative for most of the event. It is important to note that due to the accumulation of weekends and public holidays, as well as weather conditions, the situation was similar throughout the week. Negative imbalance prices persisted during most days during daylight hours, requiring additional redispatch.

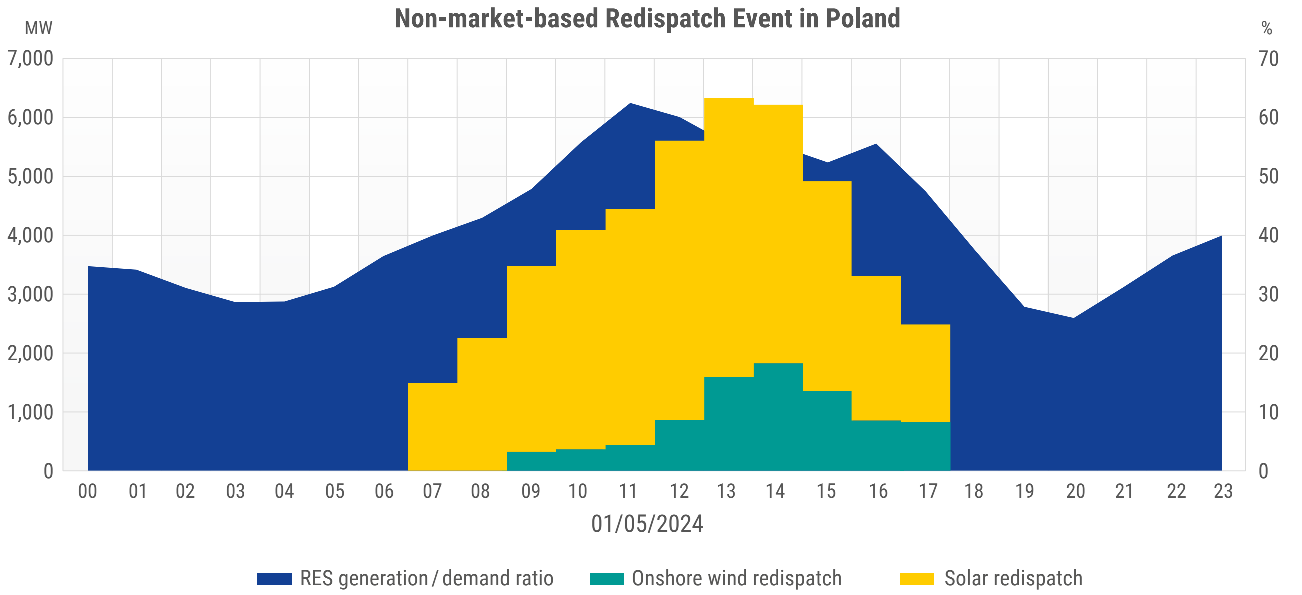


Figure 10: Non-market-based redispatch event in Poland (01/05/2024).

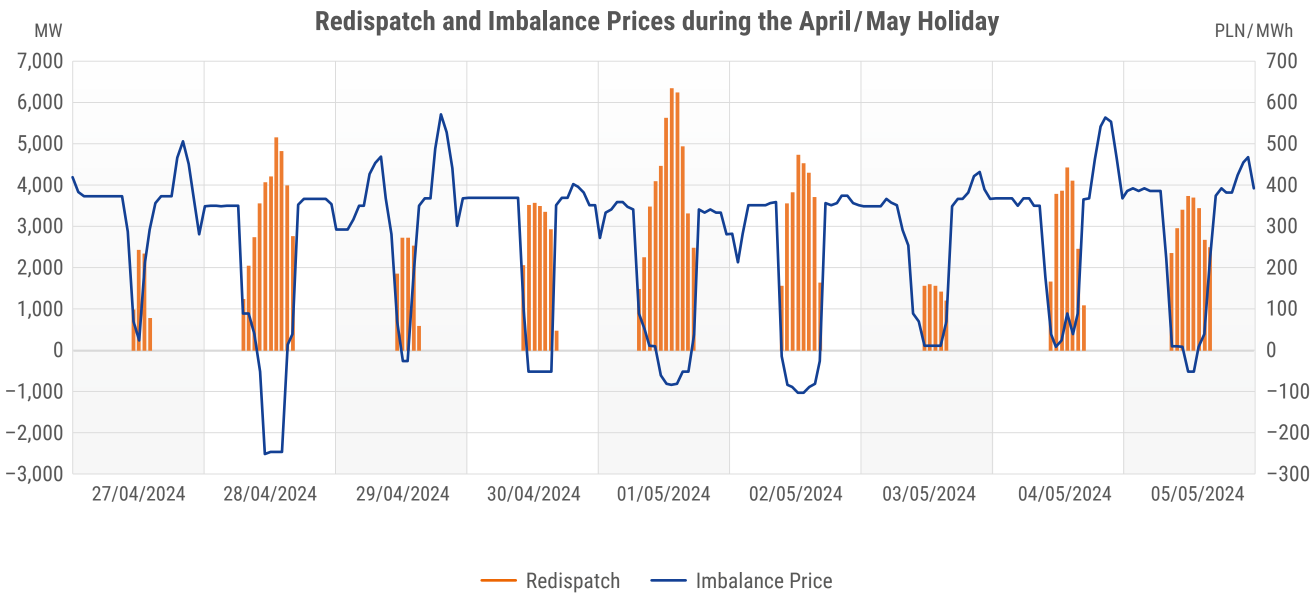


Figure 11: Redispatch and imbalance prices during April/May holiday.

Spain – 05/04/2024

Day with minimum average price in the day-ahead market: 0.44 €/MWh.

Two hours, between 2 and 4 pm, had a negative price of −0.01 €/MWh. In the intra-day market, additional hours saw negative prices, with a minimum of −15 €/MWh. Balancing reserves were also negative for much of the day, with the lowest price recorded in downwards manual FRR (mFRR) service at −1,000 €/MWh from 5 to 6 pm.

The PV and wind plants that receive support schemes in Spain are paid according to their installed capacity, encouraging them to participate in balancing services. This possibility was implemented in 2016, and 70 % of installed wind parks and 25 % of PV plants are now participating.

On 05/04/24, PV and wind parks participated in upwards and downwards balancing services following price signals, as described in the following graphs. In hours with negative prices in balancing services, awarded resources were paid for reducing their generation. Only 0.7 GWh of energy, primarily from wind parks, was technically curtailed over the entire day, representing a minimum volume given that PV and wind parks provided 24.8 GW of downwards RR and mFRR services.

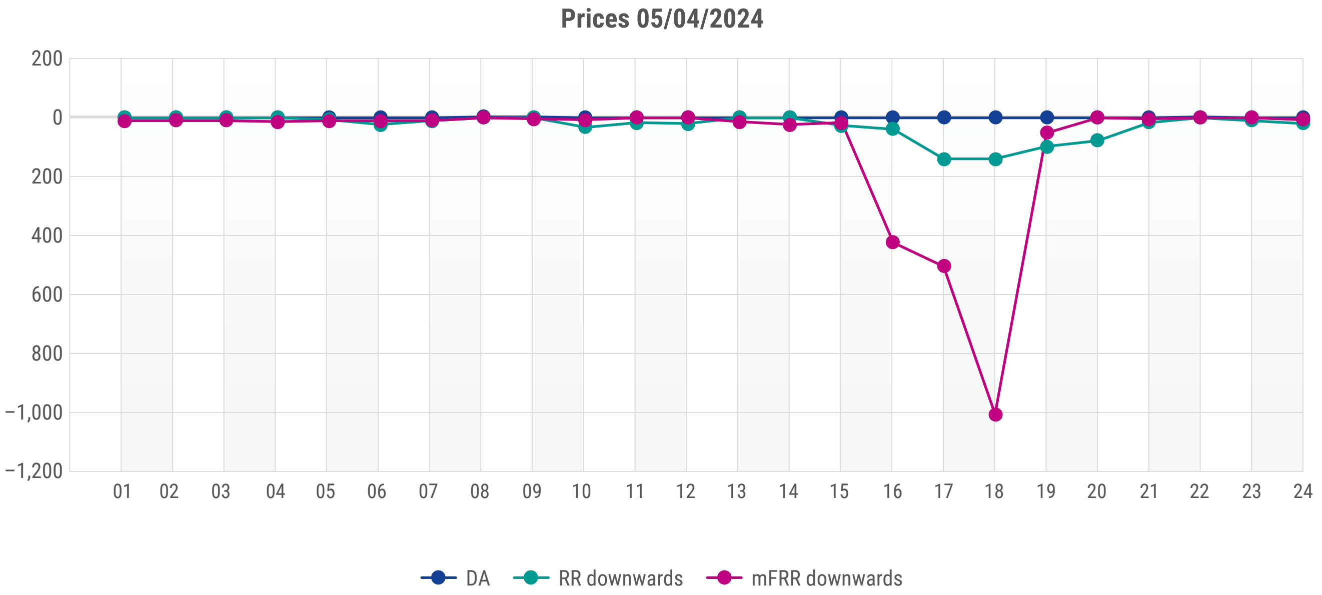


Figure 12: Hourly prices – day ahead, mFRR, and RR downwards.

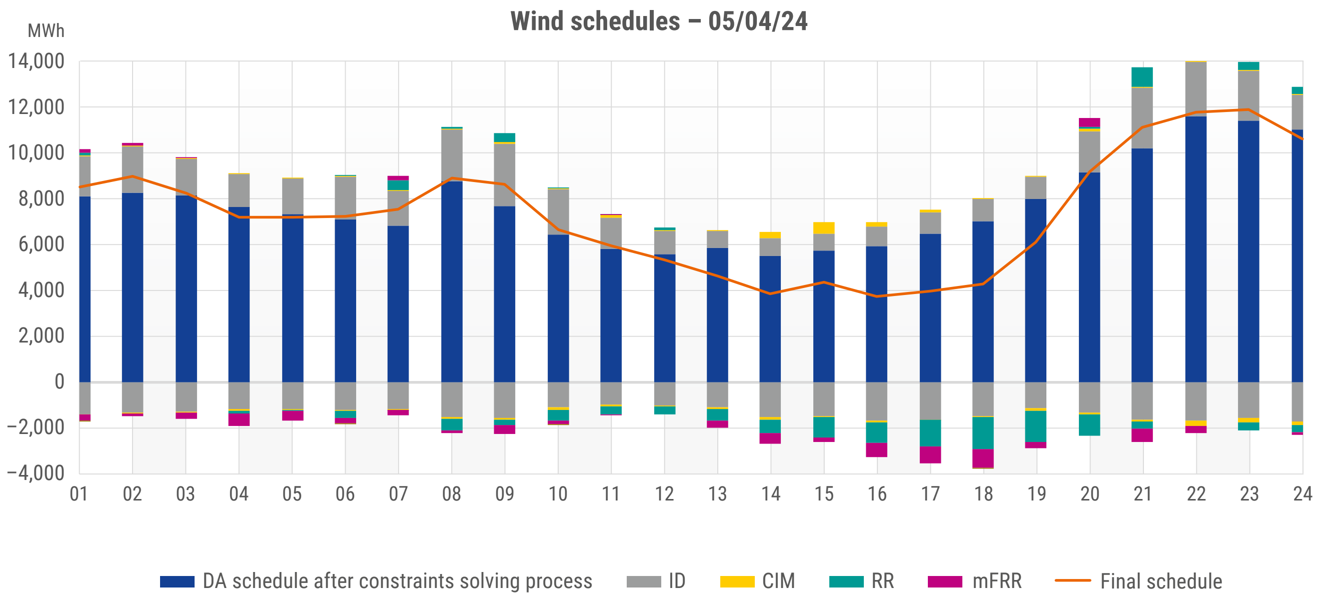


Figure 13: Hourly wind schedules (MWh) on 05/04/2024.

The described RES behaviour is enabled, among other factors, by the observability and controllability requirements for assets connected to the transmission and distribution grid. Red Eléctrica's control centre receives real-time data for all units with an installed capacity above 1 MW and also sets of units that share a connection point and have an aggregated installed capacity higher than 1 MW. Red Eléctrica's control centre can also send set points to all units above 5 MW (or even lower if they opt in voluntarily), as well as sets of units that share a connection point and have an aggregated capacity above 5 MW. Both the observability and controllability requirements are applied regardless of which grid they are connected to (transmission or distribution). More than 90 % of wind parks, PV, and thermal solar units are observable by the TSO.

The March 2022 implementation of a new Automatic Power Reduction System (APRS) was a milestone for increasing RES flexibility in Spain. This system allows the SO to reduce RES downwards redispatches, as preventive solutions are replaced by corrective solutions, meaning that curtailment is only applied if the contingency occurs. Since the system was put into service, more than 4,500 GWh have been integrated – energy that would have been curtailed if APRS did not exist.

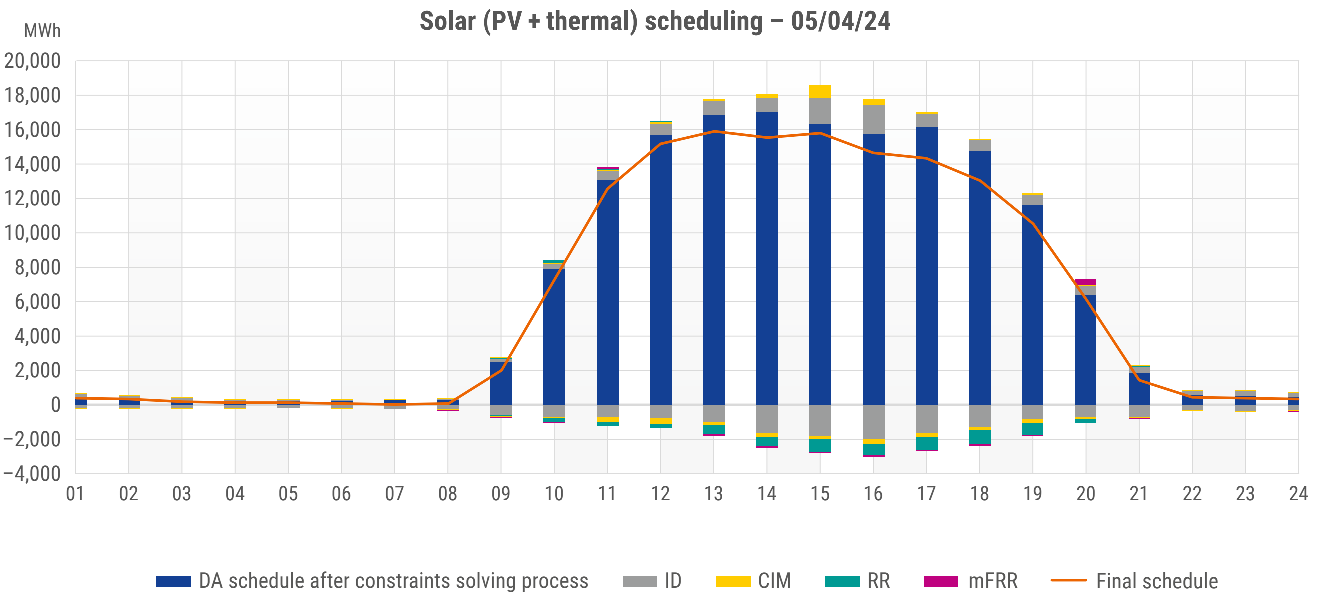
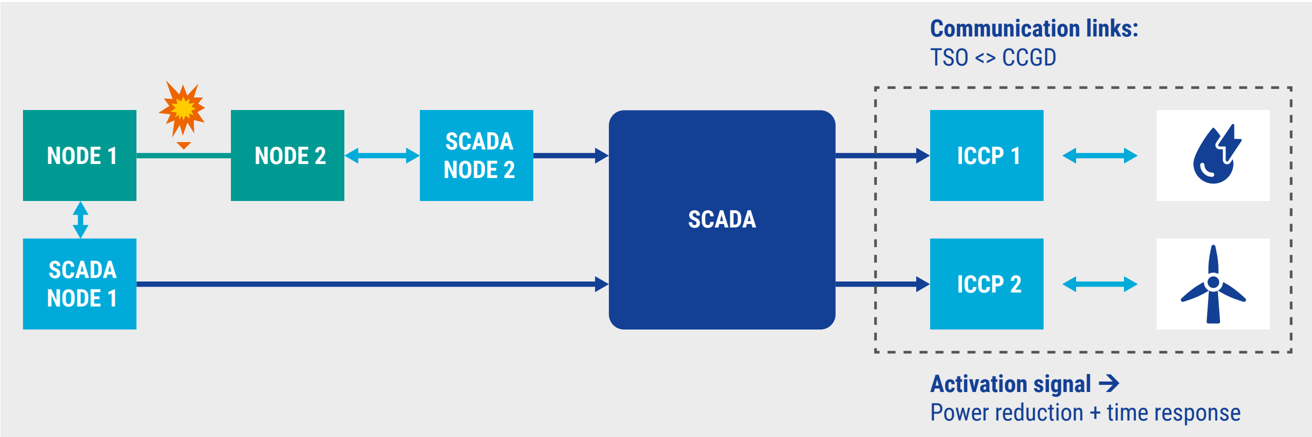


Figure 14: Hourly solar (PV and thermal) scheduling (MWh) on 05/04/2024.

› **Maximising renewable integration with a new software-based mechanism to protect the grid**

– Dynamic mechanism that allows for solving post-contingency overloads by means of corrective automatic power reductions, minimising the application of traditional preventive solutions, such as generation redispatches or topology changes.

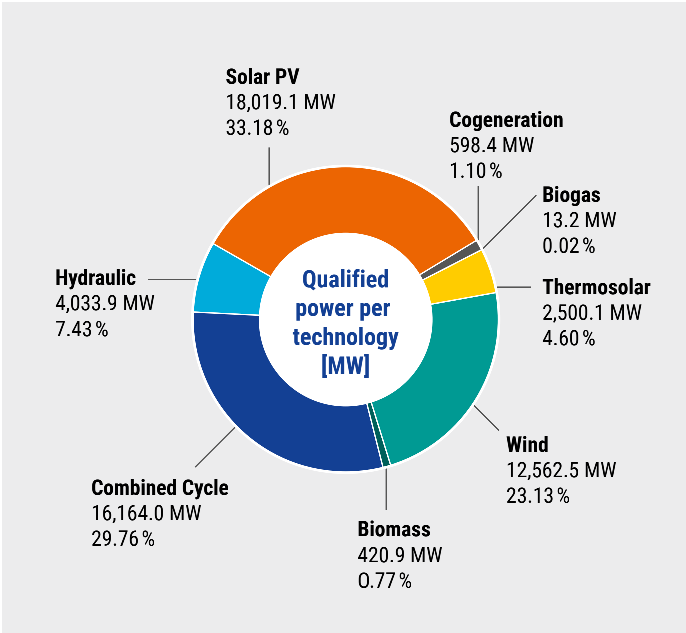


› **More flexibility to the system:**

– Power is curtailed only if the incident happens.
– Power plants avoid preventive redispatching and/or limitations.
– It allows for maximising the integration of renewable generation and the use of the grid.
– Reduces the cost of the system.

✓ Since APRS system implementation in March 2022 more than **4,600 GWh** has been **additionally integrated in the system**.

APRS in numbers:
✓ **1,217 power plants are participating (54,689 MW) → 28 CCGDs.**
✓ **85 qualification requests in progress (around 3 GW).**



(*) Data until 31/12/2024

Figure 15: Description of the Automatic Power Reduction System (APRS).

Greece – 14/04/2024

On Sunday, 14/04/2024, day-ahead market prices were negative at 14 and 15 CET (−0.01 EURO/MWh) and zero at 12 and 13 CET. At 10, 11, 16, and 17 CET, prices were observed fluctuating around zero (0.02–0.03 EURO/MWh). Despite the low prices, imports were scheduled from neighbouring bidding zones with even lower prices, as significant energy surpluses were also observed in other countries on the same day. In Greece, as prices remained close to zero between 9 and 16 CET, energy was imported at almost no cost, while at the same time, a portion of RES offered quantity was not cleared on the day-ahead market between 7 and 17 CET (RES energy surplus on the day-ahead market is shown in Figure 16).

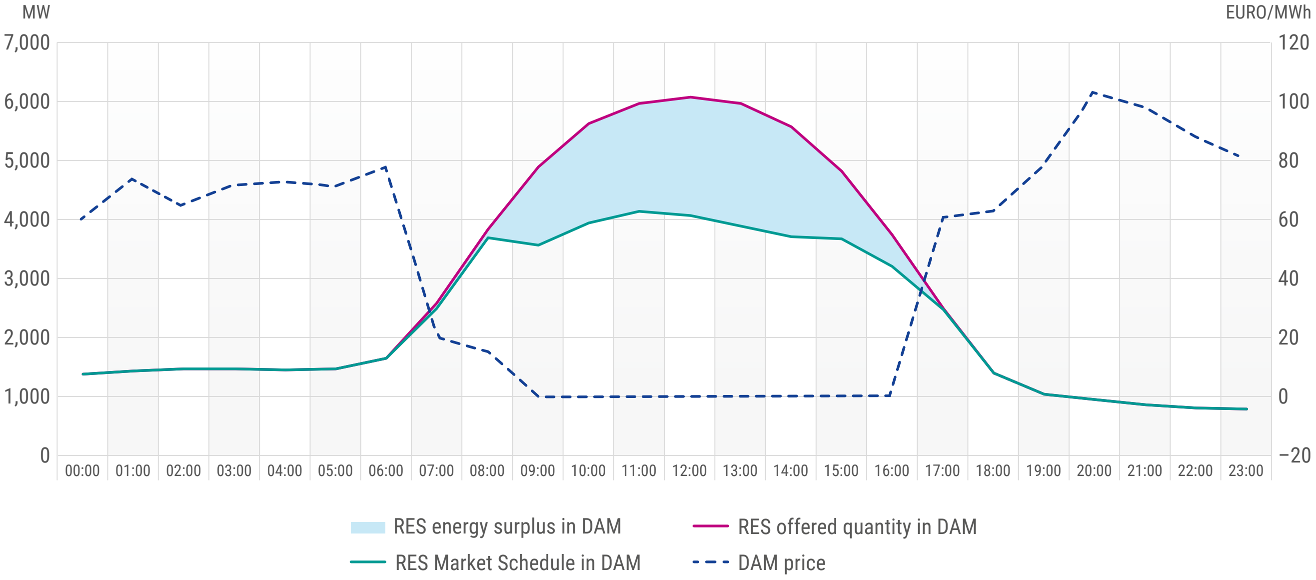


Figure 16: Day-ahead prices and RES volume on 14/04/2024.

However, the RES plants did not regulate their output according to the market generation schedule, resulting in a real-time energy surplus. IPTO, in cooperation with DSO, was forced to deal with this energy surplus, and between 8 and 17 CET, the TSO regulated the RES plants to reduce their output, resulting in the total RES injection remaining close to its market schedule (after DAM and IDM). Otherwise, based on the forecast generation, the energy surplus would have been more than 2 GW, as shown in Figure 17.

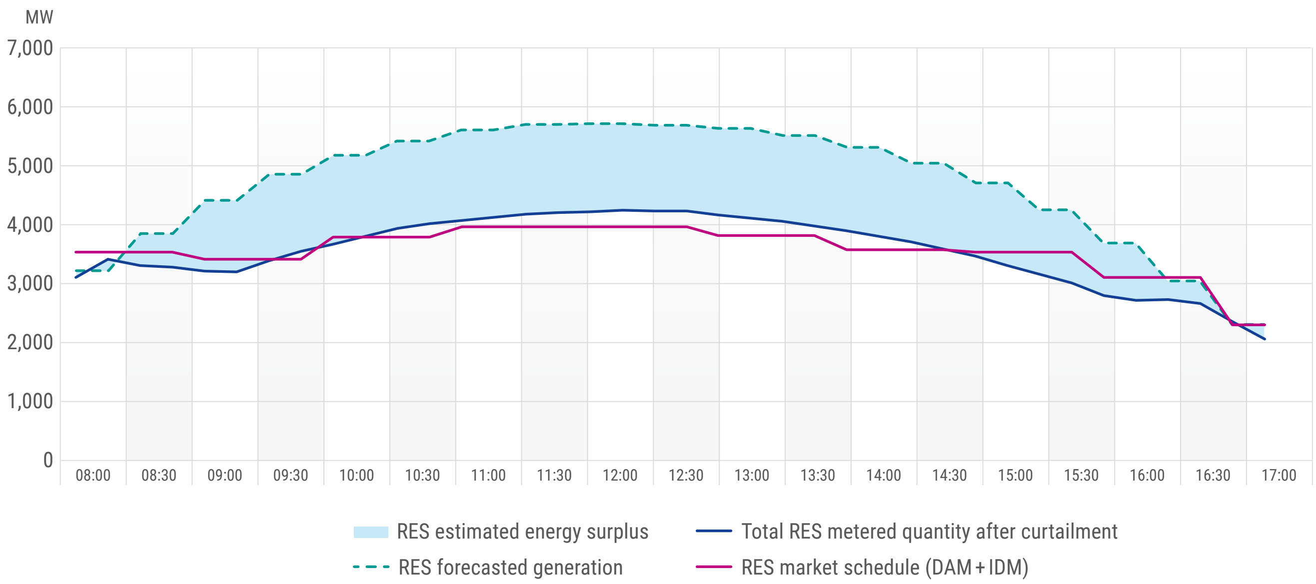


Figure 17: Curtailment time window on 14/04/2024.

Glossary

aFRR	Automatic Frequency Restoration Reserve
APRS	Automatic Power Reduction System
BRP	Balance Responsible Party
CCGD	Generation and Demand Control Center
CfD	Contracts for Difference
CHP	Combined Heat and Power
DAM	Day-Ahead Market
DSO	Distribution System Operator
DSR	Demand-Side Response
EMDR	Electricity Market Design Reform
EPBD	Energy Performance of Buildings Directive
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
EVs	Electric Vehicles
FRR	Frequency Restoration Reserve
IDM	Intraday Market
IPTO	Greek TSO
mFRR	Manual Frequency Restoration Reserve
PV	Photovoltaic
Red Eléctrica	Spanish TSO
RES	Renewable Energy Sources
SCADA	Supervisory Control and Data Acquisition
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan

Publisher

ENTSO-E AISBL
8 Rue de Spa
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Belgium

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Design

DreiDreizehn GmbH, Berlin
www.313.de

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Publishing date

November 2025

European Network of
Transmission System Operators
for Electricity