Curtailment of variable renewable energy and battery storage co-location

Energy Transition Summit Poland 2024

DENTONS AURORA

Contents

Executive summary

Curtailment occurs at times of oversupply of electricity, such as weekends, when consumption is low, and production is high due to favorable weather conditions. In March 2024, the Polish Transmission System Operator (PSE) started a regular curtailment of renewable energy generation, mainly from large-scale photovoltaic plants, which reached 15 percent of generation by May.

The implementation of the second part of the European Union's balancing market reform did not stop the curtailment but helped reduce its level. Nonetheless, it remains a serious challenge and may limit the pace of construction of new renewable energy sources as investors will fear a decrease in revenue.

Key highlights of the report:

- The main reason for curtailment in Poland is the limited flexibility of coal-fired power plants, which cannot reduce their production below a minimum. These plants must be kept within the system to ensure the replacement of renewable energy sources during periods of reduced activity.

- The second reason is the non-market revenue of renewable energy installations, which makes generators less responsive to signals from the energy market. Additionally, renewable energy generators do not participate in the balancing market, which could help them respond to such signals.

- To reduce the scale of curtailment, it is necessary to make energy demand more flexible, allowing consumers to use electricity when it is cheapest and to implement mechanisms that allow generators to earn revenue for services to the power system, minimizing the impact of negative energy prices on the profitability of renewable energy sources and storage installations.

- Investors should prepare for the new energy market conditions and adapt their strategies accordingly. The co-location of PV and battery energy storage systems is becoming pivotal. In addition, it is essential that they adopt cutting-edge technological solutions, and actively enter the balancing market.

In this report, designed by Dentons and Aurora Energy Research in cooperation with Lublin University of Technology, we provide investors, financial institutions, and other stakeholders with a better understanding of the current challenges and potential solutions.

Introduction

This is a strategic evaluation of the likelihood of increasing the – increasingly uncompensated – curtailment of variable renewable energy, mainly solar PV, in Poland in the coming years. As the penetration of variable renewable energy increases in Poland, as in many other markets, the share of curtailed solar PV and to a lesser extent wind generation is also on the rise. This is partly related to grid constraints. In recent years, investments in Poland's distribution grids were treated neglectfully. Despite unbundling obligations, allocated profits were redistributed within state-owned utility groups to facilitate capitalization of coal mines. While the new government announced plans to consistently unbundle power generation and grids, no steps have been taken so far. However, Polish transmission grids are generally in good condition. So, in other large renewable energy markets in Europe, the share of curtailed solar PV and wind generation ranges from 1.5% to 4% at most, and increasing the share of variable renewable energy does not necessarily lead to more curtailment, e.g. in case there is no geographic mismatch between renewable energy generation and consumption.

Nevertheless, in March 2024, the Polish TSO PSE and major DSOs started to regularly curtail solar PV, and by May 2024, the curtailment of utility-scale solar PV already amounted to 15% of its generation. This is not due to grid constraints or emergency situations. According to the Head of PSE, Mr Grzegorz Onichimowski, the reason for this massive amount of curtailment is the current technical environment for balancing the power system by conventional power plants. Also the implementation of the second stage of the liberalization of the balancing market from 14 June 2024 did not prevent curtailment, however, slowed curtailment down. In total, curtailment of large-scale solar PV may amount in 2024 to 7–10% of its generation.

Looking at the current technical environment for balancing the power system, the power demand in Poland amounts to 18–20 GW on working days, 17–18 GW on Saturdays and 14–16 GW on Sundays and holidays. The frequency is almost entirely balanced by the spinning reserve of conventional, mainly coal-fired power plants with an operating capacity of about 20 GW. In the spring of 2024, due to high energy generation, currently by about 18.5 GW solar PV (two-thirds of which is rooftop prosumer installations) and 10 GW onshore wind, the coal generation capacity was regularly dispatched by PSE down to a technical minimum operating capacity of 8 to 9 GW, to ramp up the capacity at sunset, while still being eligible to provide frequency services by its spinning reserve.

To understand the medium and long-term risk by curtailment of solar PV, it is necessary to identify the determinants that will shape Poland's energy mix until the end of the next decade. In the absence of actual strategic government plans for the development of Poland's energy mix, the 10-year transmission network development plan for 2025–2034 published by PSE in March 2024 is the only official energy mix scenario to provide guidance. In our opinion, as in many other markets, the cure for the medium and long-term curtailment of variable renewable energy, especially large-scale solar PV with possible curtailment even without compensation, is battery co-location. But compared to leading markets for BESS investments in Europe the regulatory environment in Poland is not (yet) fully equipped for commercial operation of such investments.

With this report, following our Energy Transition Summit Poland 2024 end of May in Warsaw, we aim to provide investors and financial institutions with a better understanding of the current challenges and an outlook for solutions.

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1 Energy mix according to the new 10YNDP

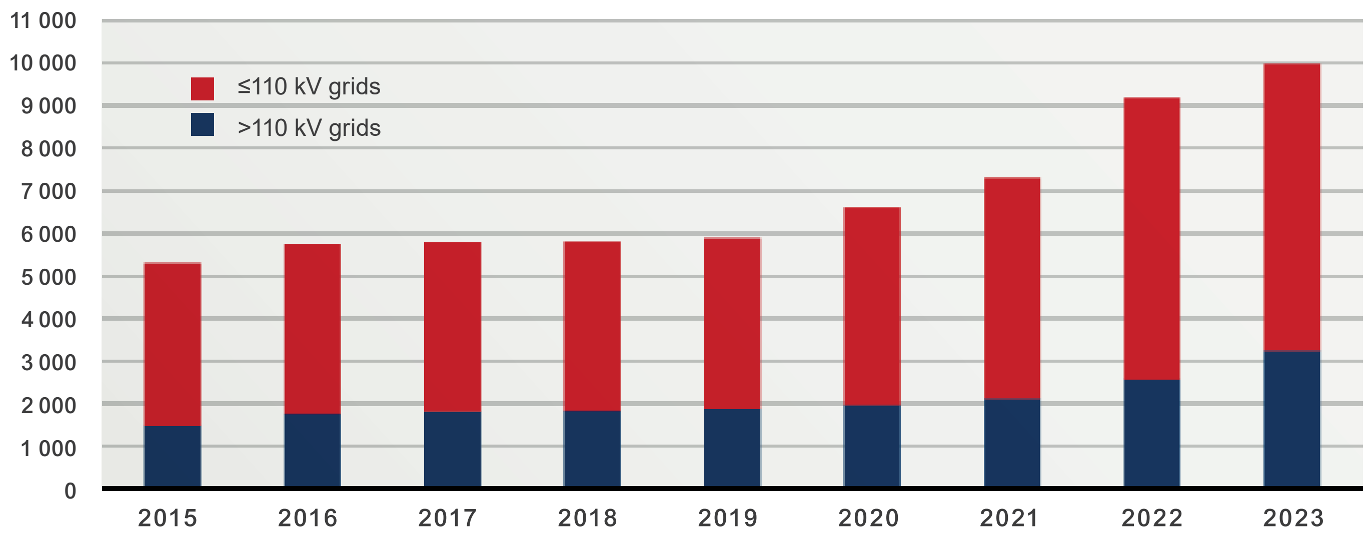
PSE 10YNDP is a generic scenario based to a limited extent on outdated government policies, but reflecting the current EU climate policy and legislation

The NDP2034 is a generic scenario published by PSE based on the current EU legislation, mainly the Clean Energy Package (CEP) adopted in 2019 and the Fit for 55 legislative package presented by the European Commission on 14 July 2021, which has so far been partially enacted. The main objectives of the NDP2034 are the climate neutrality of the energy sector by 2050, a RES share in the final energy demand of 31.5% in 2030, new energy efficiency targets by 2030 and the European deployment of supercharging infrastructure for cars and trucks by 2030. PSE aims to prepare the transmission network for an even more ambitious climate policy. According to PSE, the Polish power network should be prepared for more than 50% variable RES generation by 2034.

Rapid increase of variable RES and limited potential for redispatching of aged coal power plants leads to RES curtailment

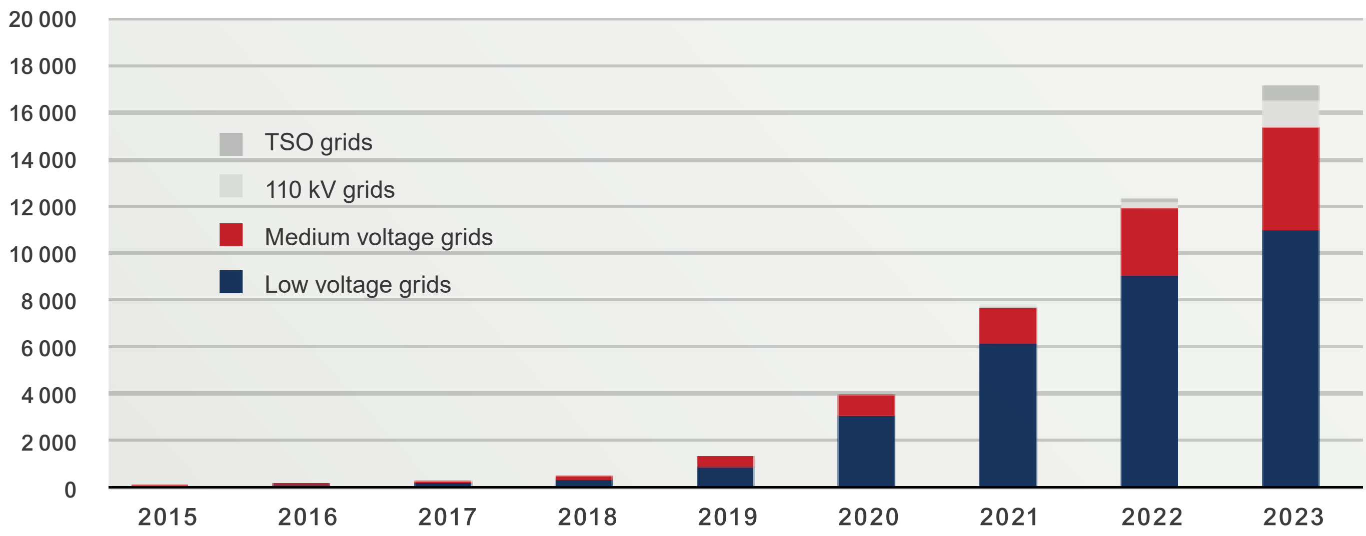
The huge increase in distributed generation in Poland has put significant stress on the distribution networks. As the penetration of variable renewables increases, the Polish transmission system operator PSE has started to curtail utility-scale solar PV and, to a lesser extent, onshore wind generation (against compensation) from 2023. As major investments in grid infrastructure at both the transmission and distribution level, as well as the deployment of battery energy storage (BESS) and the regulatory framework are not keeping pace with the deployment of variable renewables, the curtailment of zero-emission energy is PSE's latest response to maintain must-run capacity (baseload power stations, i.e. coal-fired power plants) in the Polish energy system in case of oversupply from both coal-fired power plants and variable renewable energy generators.

Drawing 1: **Installed capacity of onshore wind turbines connected to the power grid (data as at the end of 2023) [MW]**



Source: NDP2034, page 13

Drawing 2: **Installed capacity of solar plants connected to the power grid (data as at the end of 2023) [MW]**

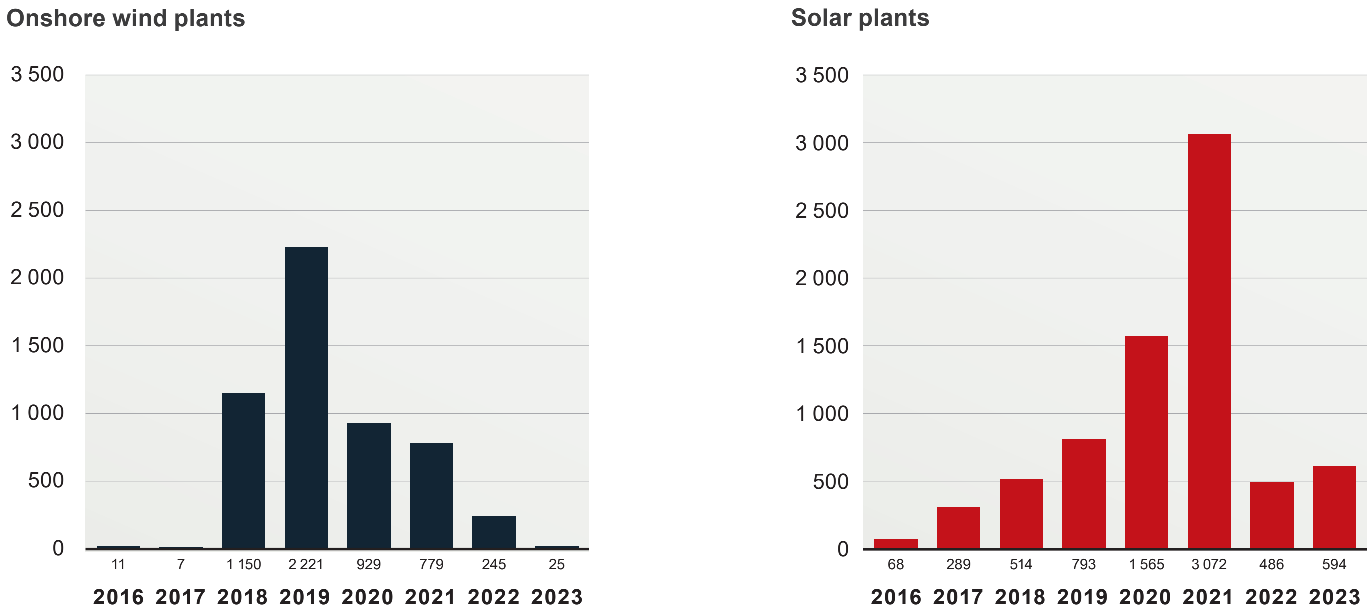


Source: NDP2034, page 13

RES auction system kicked off large scale solar PV

Until the energy crisis of 2022/2023, the further deployment of renewable energy generators connected to the medium and high voltage network depended mainly on the auction support system, which awarded investors with a 15-year double-sided and indexed contract for difference. When wholesale prices peaked, the auction system became less attractive and long-term power purchase agreements with utilities or corporate offtakers gained popularity. A major obstacle with the auction support system is its settlement against a weighted base index (TGeBase), so that RES generators suffer technology profile losses, which is particularly detrimental to solar PV generation. However, the auction system may become attractive again due to the medium-term power market forecasts of further decreasing wholesale prices.

Drawing 3: **Estimated contracted capacities at RES auctions held in consecutive years [MW]**



Source: NDP2034, page 15

PSE is currently issuing most of the new grid connection conditions

Due to the underinvested distribution grid network, the TSO has issued most of the new grid connection conditions (GCC) and concluded most of the new grid connection agreements (GCA). According to PSE's forecast, 43 GW of solar PV, 18 GW of onshore and 18 GW of offshore wind farms will be commissioned by 2034.

Drawing 4: **Grid connection agreements and grid connection conditions issued by PSE status: 31.12.2023**

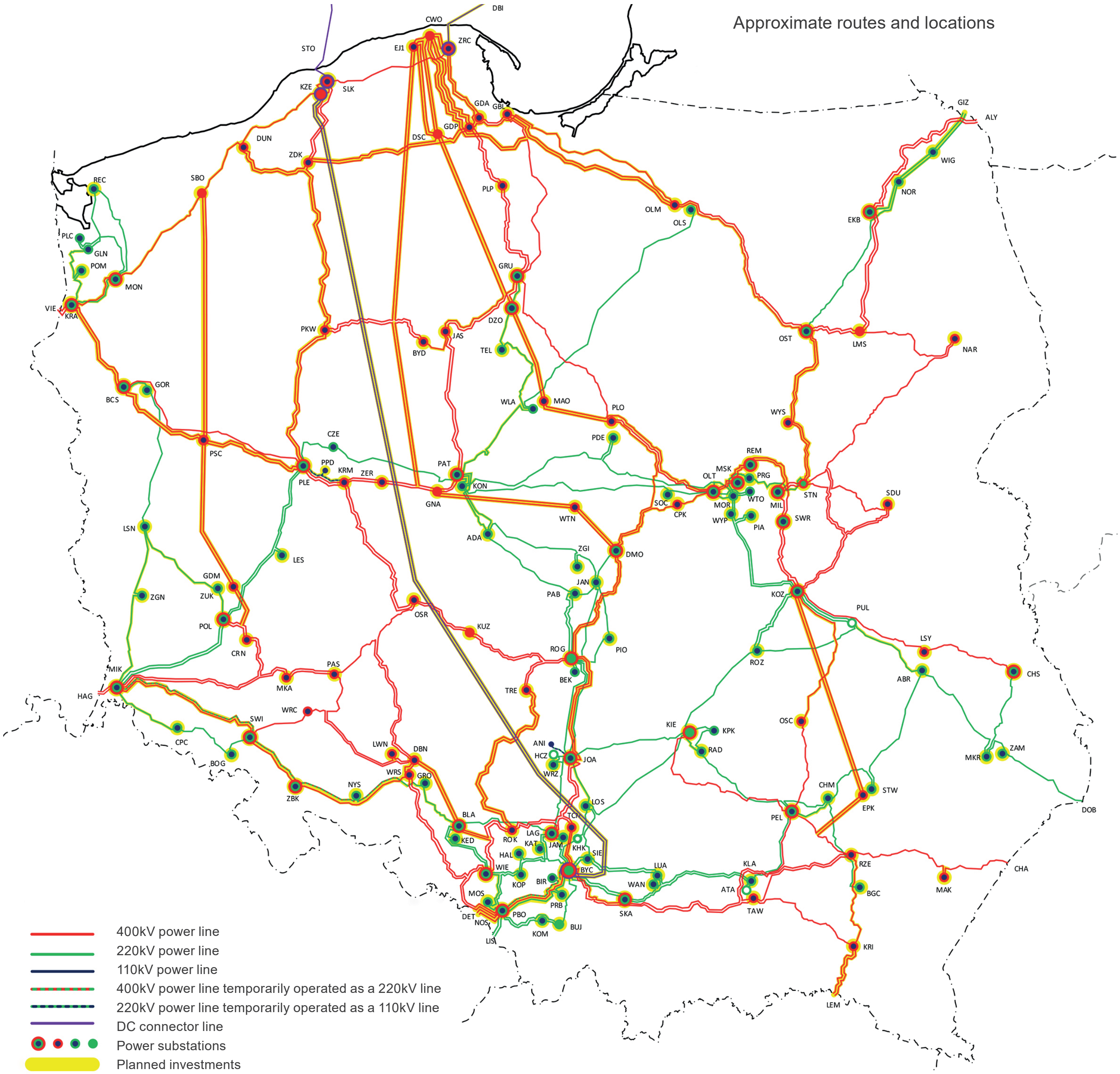
Technology	GCA (MW)	GCC (MW)
Conventional power generation	8735.8 (mainly gas power plants)	300
Offshore	8388.5	101
Nuclear	n/a	3720 (EJ1 - Choczewo)
Onshore	3067.1 (jointly)	1070.1
Solar PV		4681.2
Energy storage	1901.4	9689.8
HV transformer stations (mainly at new power plants)	n/a	1090
HV Distribution systems	595.1	3892.8

Source: NDP2034, page 15

PSE plans to construct power highways to transmit offshore wind generation to large agglomerations in the center and south of Poland by 2034

As in Germany, most of the variable renewables generation is in the northern part of the country, but energy consumption is located in the center and south of Poland. Coal-fired power plants are located close to consumers, but 18 GW of this fleet is aged and has the highest volume of replacement reserves in the EU. Only 4.5 GW of more flexible coal-fired power plants were commissioned in the second half of the last decade (Opole, Kozienice, Jaworzno, Turów). High voltage direct current (HVDC) lines, the so-called "power highways", are not yet available to transmit intermittent renewable energy to the main electricity consuming regions. According to the 10-year transmission network development plan 2025–2034 published by PSE in March 2024, the Polish TSO plans to construct a power highway with a total length of 1,440 km from several HVDC converter stations located in northern Poland, i.e. Sławoborze (new), Koszalin (new) and Choczewo (new), south to Poznań, Warsaw and Silesia. These lines will transmit power from offshore wind farms with a total capacity of 8.4 GW, for which grid connection contracts have already been signed, and from onshore wind farms located near the Baltic coast. The power highway will be able to transmit 18 GW of offshore capacity, which will be subject to CfD (Contract for Difference) support schemes under the Act on the promotion of electricity generation in offshore wind farms.

Drawing 5: **Transmission system map showing planned investments as per the dynamic SDT scenario**



Source: NDP2034, page 87

18 GW coal power plants will exit the capacity market between 2025 and 2028

For coal-fired power plants with their rotating reserves, which are still the backbone of the Polish electricity system, capacity market payments and relatively low prices of EU ETS emission allowances are crucial to cover variable costs. From mid-2025, according to Regulation (EU) 2019/943 on the internal electricity market, coal power plants commissioned before 2019 will no longer be awarded capacity market payments, which would affect half of the 18 GW old coal power plants. A derogation mechanism to extend this deadline until the end of 2028 has not yet been enacted, which would allow these units to participate in additional quarterly capacity market auctions, provided that other low-emission units do not meet the volume of the quarterly auctions. By the end of 2028, all 18 GW of coal-fired units will exit the capacity market mechanism. The chances of further successful notification of support schemes for coal-fired power generation at the EU level are negligible.

Coal power plants will be challenged by a new generation of best available emission technique standards for large combustion plants

In 2017, the integrated emission permits for coal-fired power plants that were granted the derogation were issued for an indefinite period of time, unless there is a change in the law or new BAT (best available technology) conclusions are published. New BAT conclusions for large and medium-sized combustion plants are expected to come into force in 2028 at the latest. In this context, it is worth noting that only four Member States still burn coal for power generation: Poland, Germany, Czechia and Greece. Germany has already announced its coal phase-out for 2035, but the current government is trying to bring it forward to 2030. Czechia announced in October 2023 that it will phase out coal by 2033, and Greece will phase out coal by 2025. It is almost certain that new environmental standards will most likely be very demanding – too demanding for coal generation.

The very high cost of building and exploiting wet desulphurization equipment makes it technically impossible to refit Poland's aged coal plants. But even if these units could theoretically meet the new thresholds, refitting would require substantial state aid, which the European Commission will not accept. Alternatively, as in 2016/2017, Poland could apply for a time-barred derogation mechanism with limited operating hours to avoid further investment in filters for the operation of these units after 2033. However, without capacity market payments or strategic reserve payments, which would require a new notification to the European Commission, these plants cannot be profitable. Thus, their ownership could be transferred to budget units, and the transmission system operator would use them for technical balancing. Ultimately, energy consumers would pay the allocated costs through distribution tariffs. Nevertheless, pursuant to EU policy, distribution tariffs should become more flexible and balancing markets should be further liberalized, so a fixed fee for both capacity market and strategic reserve payments contradicts this approach. To date, neither the government nor PSE has identified a sustainable way to operate these plants after the exit from the capacity market mechanism by the end of 2028 at the latest.

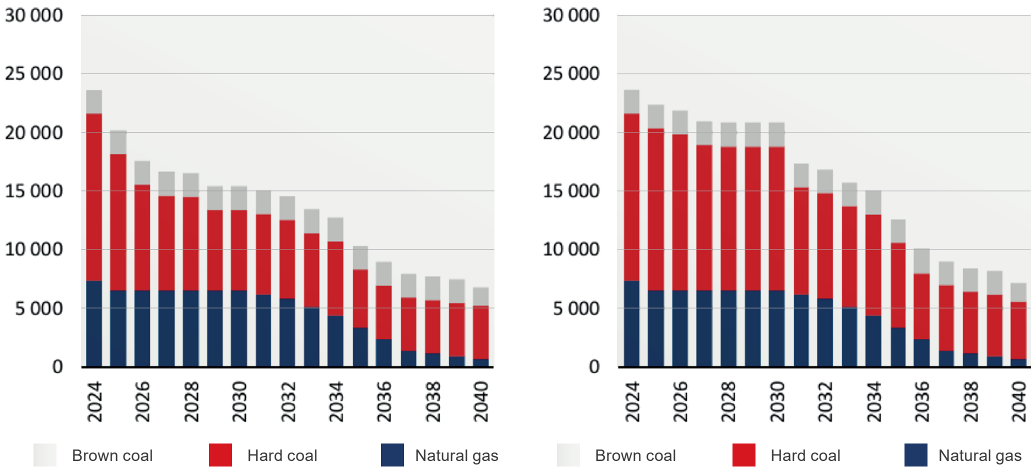
Assignment of coal power plants to a new budget entity NABE is not realistic

Another 4.5 GW of new coal power plants have been awarded capacity market payments until the end of 2034. As a result, prior to the parliamentary elections in autumn 2023, Tauron, the second largest utility in Poland, had already announced decommissioning of its last (new) coal-fired power plant in Jaworzno in 2035. The graph below presents the scenario for the closure of coal-fired power plants declared in 2022/2023 when their transfer to a new state-owned entity called NABE was planned. This would have restructured Polish utilities to avoid responsibility for the decommissioning and make them attractive again to institutional investors and banks. In the meantime, however, the transfer of coal-fired power plants to NABE has been questioned by both the EU Commission and the trade unions, and it is doubtful whether it will be implemented at all. The discussion around NABE has led to a situation where coal-fired power plants have not been modernized for years, as recently criticized by Maciej Bando, the government's representative for strategic infrastructure. However, with falling wholesale prices and a lack of public support mechanisms, it remains unclear how this modernization should be financed.

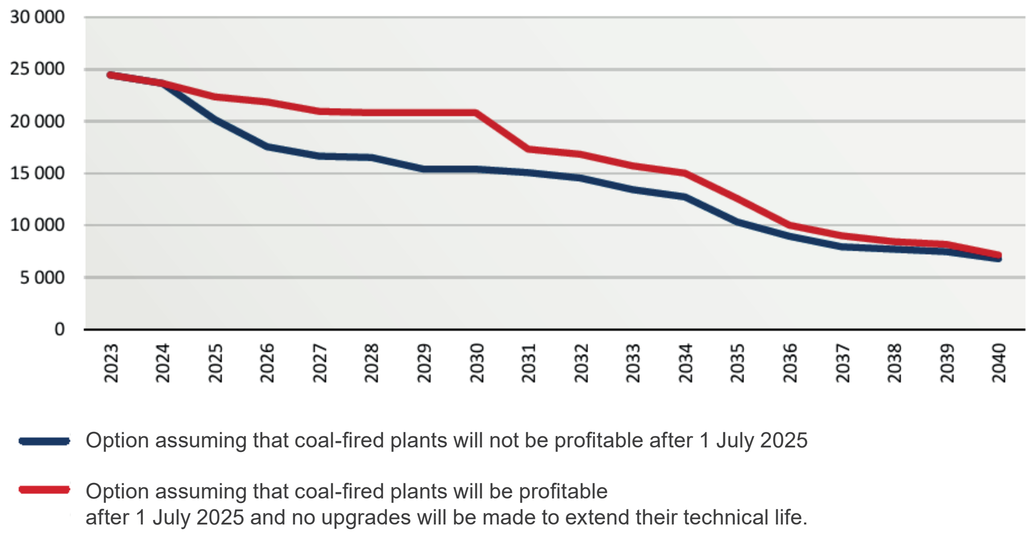
Drawing 6: **Maximum net generating capacity of conventional power plants participating in the central balancing mechanism. Status at year end [MW]**

Option assuming that coal-fired plants will not be profitable after 1 July 2025

Option assuming that coal-fired plants will be profitable after 1 July 2025 and no upgrades will be made to extend their technical life



The two options compared



Source: NDP2034, page 27

New gas power plants will regularly close the merit order in the coming years

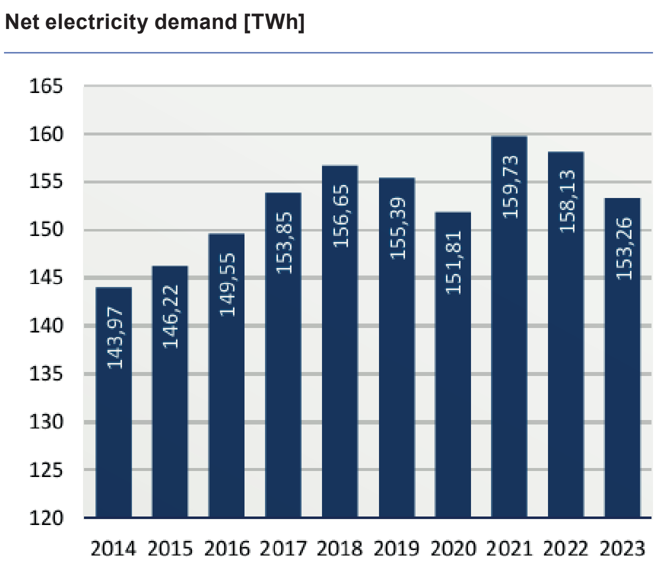
In summary, partial coal generation might survive until 2035 at the latest, with a substantial decline in generation after 2028 due to economic and technical reasons. The scenarios for a slow phase-out of coal generation presented in the NDP2034 do not seem realistic as a change in the economic and technical environment after the exit from the capacity market would lead to a sudden shutdown of most units. This happened in the UK in 2015/2016, where coal generation fell from 23% to 9% of total generation within one year, and further to 5% by 2018.

In addition, more than 6 GW of new, more flexible gas-fired (combined heat and power) power plants awarded with capacity market contracts of up to 17 years, to be commissioned by 2027, bringing the total gas capacity to 10 GW, will partially fill the generation gap and be able to provide system services. In the event of an economic recovery and (again) rising prices for EU ETS emission allowances, but still moderate LNG prices, the variable operating costs of gas-fired power plants should be lower than those of coal-fired plants and will regularly close the merit order. Moreover, this trend is likely to strengthen in the first half of the 2030s as BESS deployment increases.

Net electricity demand dropped substantially in 2023

Net electricity demand peaked in 2021, but dropped substantially afterwards, while demand in 2023 was comparable to 2017 – in parallel with GDP growth of more than 20% between 2017 and 2023 and a growing population, mainly due to Ukrainian refugee immigrants. After COVID-19, Poland experienced similar demand trends as the Western European economies. Increasing energy efficiency measures and behind-the-meter generation and storage are expected to reinforce this tendency.

Drawing 7: **Historical demand for electricity [MW]**

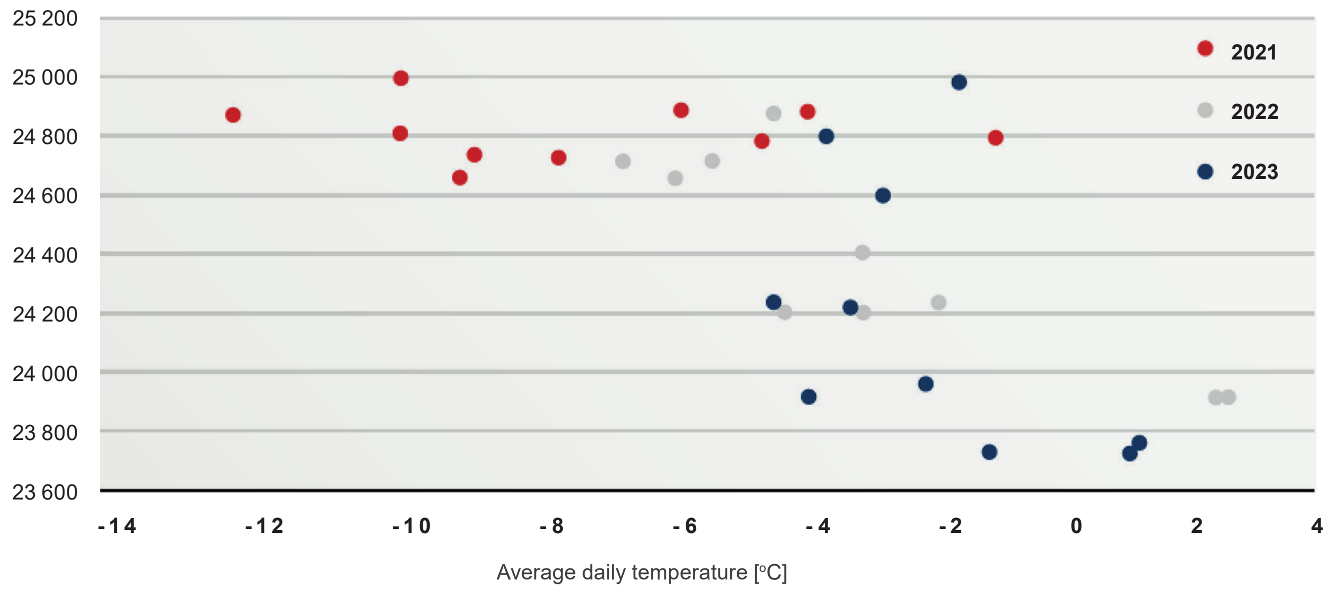


Source: NDP2034, page 29

Climate change also had a significant impact on winter peaks between 2021 and 2023, which generally did not increase due to higher average winter temperatures.

Drawing 8: **Net peak demand in 2021–2023 vs. average outdoor temperatures on these days**

Top ten days with net peak demand for electricity in a given year [MW]



Source: NDP2034, page 30

Sector coupling is a key tool for decarbonization of the industrial energy supply, but increases power demand

According to PSE, sector coupling (electrification of heating and transport), as a key tool for decarbonizing the energy sector, should lead to a significant change in electricity demand. Undoubtedly, replacing carbon-intensive fuels such as coal, natural gas, LPG, and diesel, which can account for the majority of carbon emissions in many energy-intensive industries, with electrified alternatives, is critical to progress towards the net-zero goal. However, investments in electrification through the installation of heat pumps, EV charging, or on-site solar generation face challenges related to grid constraints. The growth in electricity consumption can exceed the grid supply capacity, and PSE forecasts a substantial increase in electricity demand from sector coupling in both the dynamic (SDT) and standard (SST) transformation scenarios. Even in the standard scenario, electricity demand from sector coupling is expected to increase by nearly one-third by 2040. Based on the current mix, PSE expects new energy efficiency measures and expected economic growth to balance electricity demand.

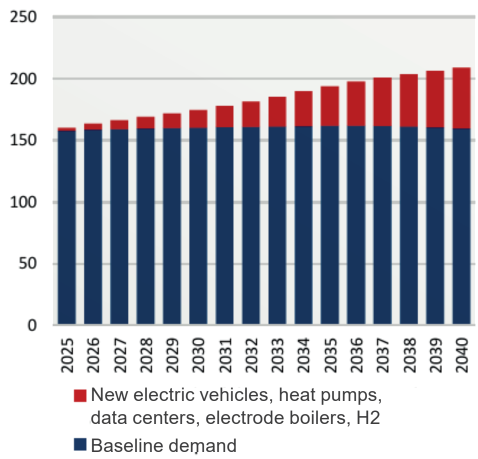
PSE's scenarios are aligned with international studies such as the sector coupling report published by Bloomberg New Energy Finance in 2020 (BNEF2020).

Electrification Action Plan required as electrification of the energy sector is stagnating

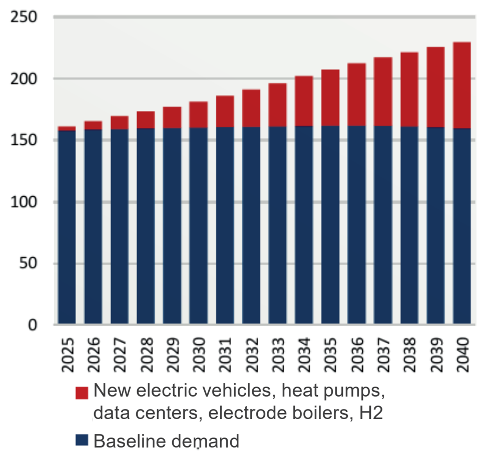
Electrification of the energy sector is currently stagnating at 23%, and the European Electrification Alliance is urging the EU to set a target in its Electrification Action Plan of at least 35% electrification of final energy use across the EU by 2030, while the European Commission itself expects this share to reach at least 50% by 2040.

Drawing 9: **Annual net electricity demand in 2025–2040 – average from climatic years 1982–2019 [TWh]**

SST scenario



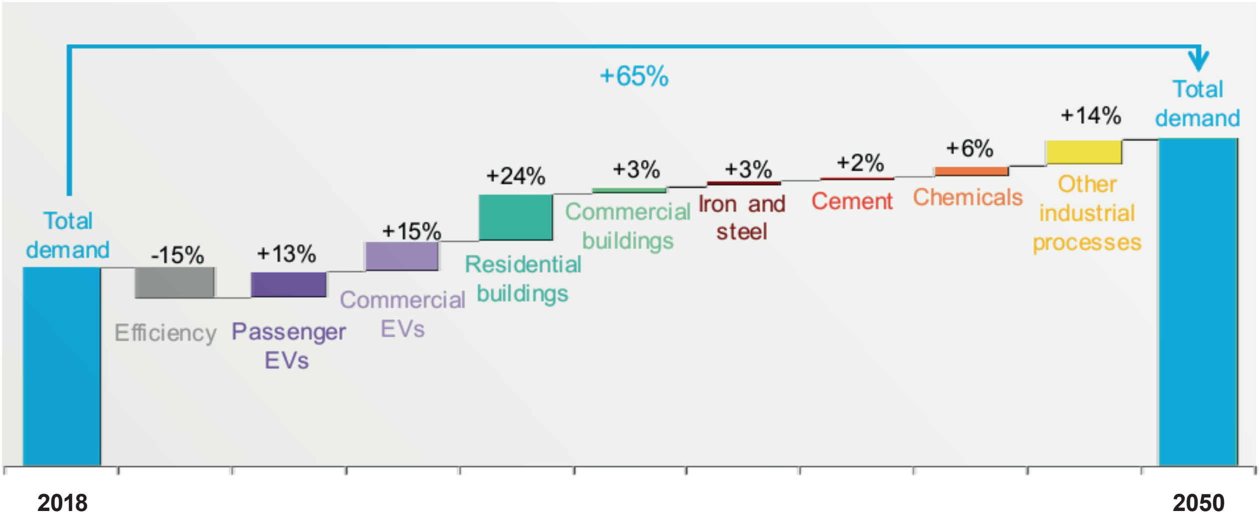
SDT scenario



**H2 - electricity demand in connection with hydrogen production*

Source: NDP2034, page 37

Drawing 10: **Forecasted increasing power demand by sector coupling by BNEF until 2050 – BNEF2020**



Source: Bloomberg NEF, "Sector Coupling in Europe. Powering Decarbonisation", 2020, page 7

Winter and summer peaks will increase, but the scenario presented by PSE is at the higher end

Based on such scenarios, PSE presents typical daily demand profiles for 2034 with an expected winter peak of 40–43 GW and an expected summer peak of 31 GW. This is a significant increase from the current net peak of 25 GW observed in 2021 and 2023.

This means that PSE expects a boom in sector coupling technologies, but without smart consumer behavior due to dynamic tariffs supported by artificial intelligence solutions, without exploiting the increasing potential of demand-side response (DSR) with both heat pumps (small and utility-scale heat storage) and EV charging (vehicle to grid technology), and also without the potential of behind-the-meter generation and storage. As these measures are already promoted by both the Clean Energy Package and the Fit for 55 legislative package and should be implemented in national law, PSE's assumptions are at the higher end. PSE justifies the much higher winter peak by the electrification of heating, i.e. the massive use of heat pumps and radiators, but this does not reflect the typical demand profile of heat pumps, which operate mainly in the winter during off-peak hours, whereas electricity peak demand typically occurs in the late afternoon. The increase in demand is also justified by additional demand from data centers and unspecified "additional take-off" assuming that large consumers would not be incentivized by DSR. In our view, a more likely scenario for the increase in daily demand was presented by BNEF.

Sector coupling may challenge demand, but flexibility is key to cap the increase of peak demand

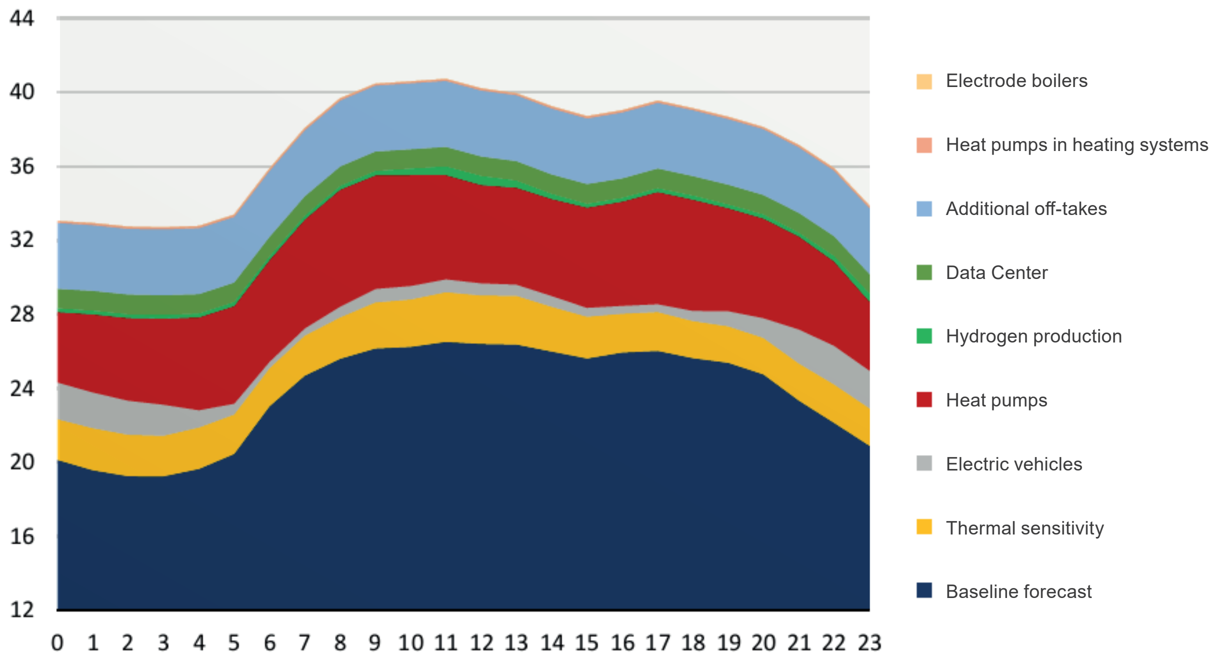
More dynamic demand means less investment in flexible capacity, lower system costs and lower power emissions. Doubtless, sector coupling will transform the demand profile by increasing and shifting the intra-day and seasonal peaks. The scale of this challenge will depend on the amount of demand-side flexibility in the system. Short-term flexibility will be needed to absorb intra-day variations in wind and solar output, using options such as demand response and other flexible new loads, as well as battery storage and other flexible generation sources. Long-term flexibility, on the other hand, requires “back-up” capacity that can provide power during the weeks of the year when wind and solar output is very low. The demand-side can also affect long-term flexibility needs: in particular, the electrification of heating is expected to increase the need for winter back-up. But sector coupling creates the potential for more demand-side flexibility, including large, concentrated loads such as data centers or EV fleets, highly distributed loads such as dynamic EV chargers and heating systems (through seasonal thermal storage), or aggregated loads such as virtual power plants that can reduce overall electricity demand by 40% (BNEF2020 page 37).

Generally, a highly flexible scenario shifts demand to hours of high solar PV and onshore wind generation to adopt peak demand to variable RES generation. Thus, although sector coupling would provide for a long-term increase in demand of 65% (including energy efficiency measures), two-thirds of this demand could be met by demand-side flexibility. This requires half of EVs to be dynamically charged, an increase in building retrofits to increase energy efficiency, heating flexibility, and the promotion of demand-side response. In such a flexibility scenario, a 65% increase in peak demand is a question mark, but a 20–25% increase by 2040 perspective is likely. Behind-the-meter generation and storage increase demand even further.

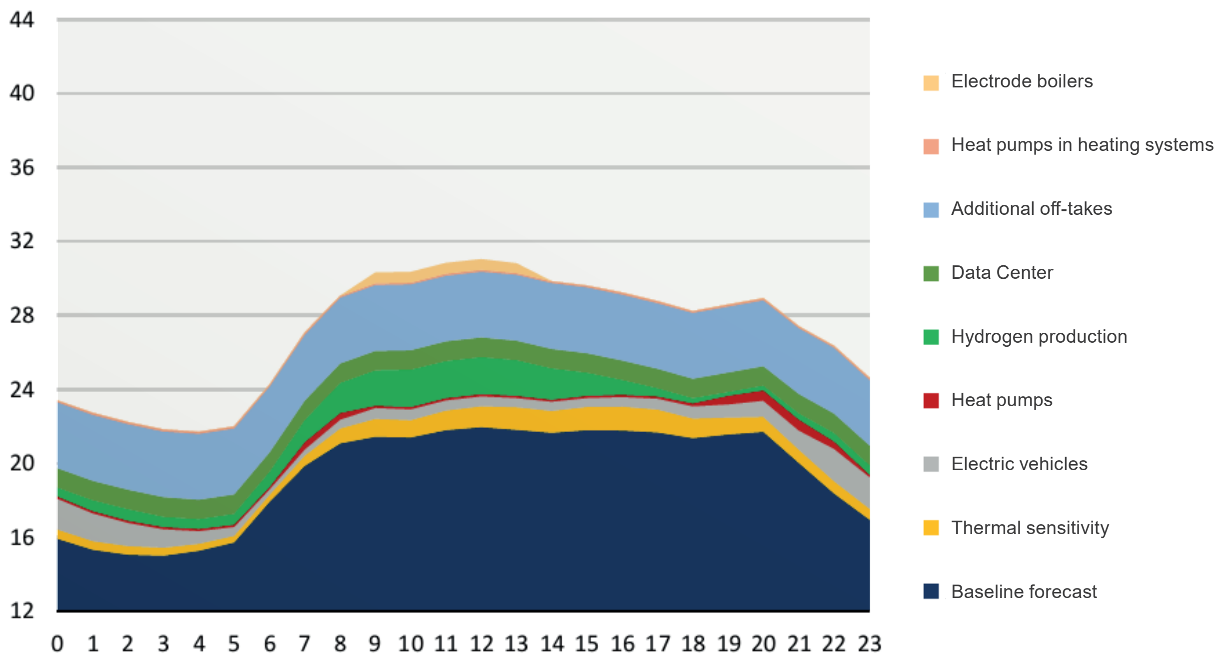
To sum up, an increase in Poland’s current net winter peak demand from 25 GW to more than 40 GW as presented by PSE, is likely only in the case of inflexible demand. This would involve serious sunk costs for back-up generation and therefore lead to an increase in electricity costs for consumers. It would have a negative impact on the competitiveness of the Polish economy. In contrast, according to the scenario outlined by BNEF, net peak demand can be capped at around 30 GW+ through highly flexible sector coupling.

Drawing 11: **Power demand curve – SDT scenario**

SDT scenario: typical daily demand curve in the winter of 2034

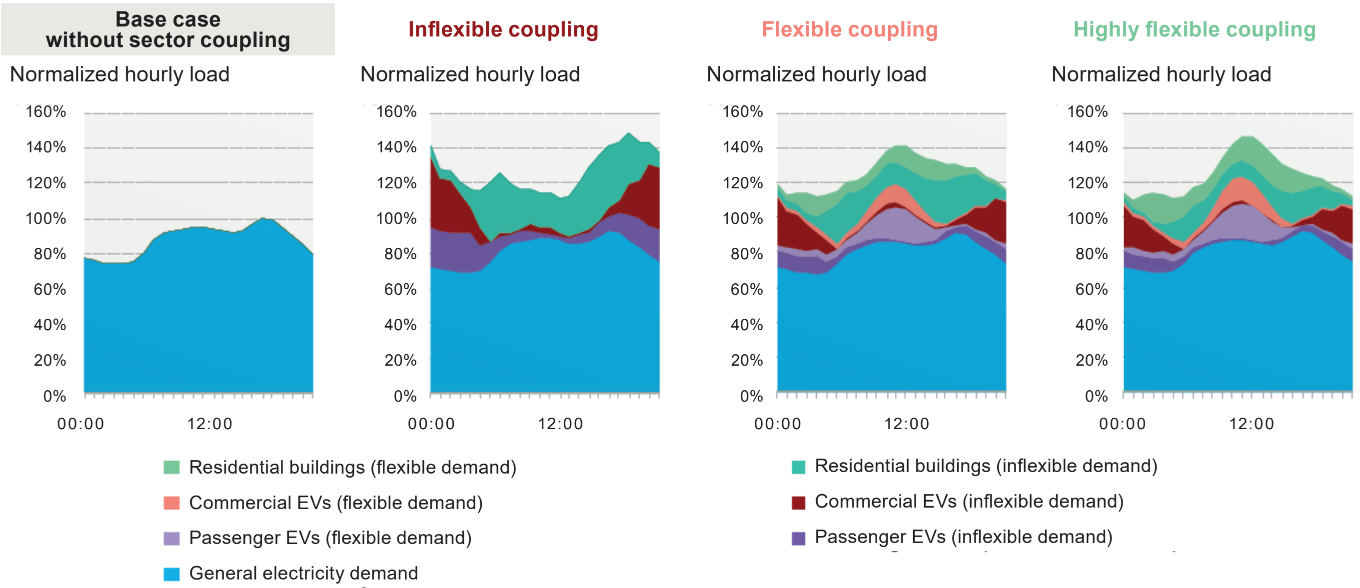


SDT scenario: typical daily demand curve in the summer of 2034



Source: NDP2034, page 37

Drawing 12: **Typical daily demand curve in winter based on flexible sector coupling**



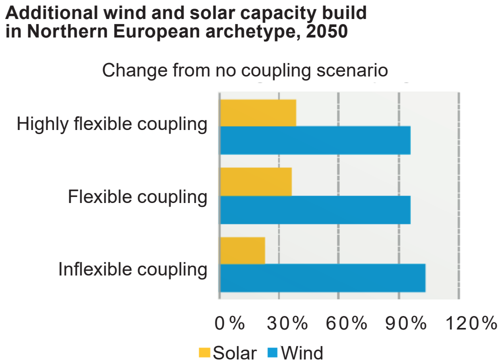
Note: Charts are normalized to the value of the peak load in the "no coupling" scenario.

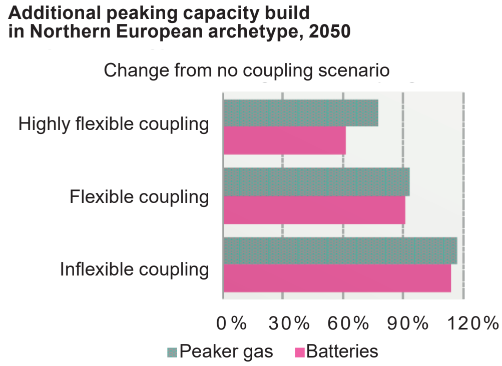
Source: Bloomberg NEF, "Sector Coupling in Europe. Powering Decarbonisation", 2020, page 40

Based on a 30 GW+ peak demand scenario in 2034, the Polish power system should be able to shut down generation from old coal power plants. Gas-fired power plants currently in operation and to be commissioned by 2027 could provide 10 to 11 GW of available capacity, with an additional 3 GW of planned capacity replacing new coal-fired power plants with 15-year capacity market contracts by the end of 2034. In our view, nuclear power is unlikely to replace 4 GW of new coal capacity in 2035, as the first Polish nuclear power plant is currently in the planning stage. Furthermore, existing, modernized and newly constructed interconnectors will be able to import around 5 GW of capacity in the early part of the next decade, however, their influence might be limited in case capacity will be mainly weather dependent. By the end of 2025, Poland will complete its transmission investment programs increasing the total AC and DC import capacity to up to 4 GW. Pumped storage hydropower plants can provide another 2.5 GW (including the new 750 MW ESP Młoty plant). The potential of DSR could double from around 2 GW at present to more than 4 GW in a highly flexible sector coupling scenario. The remaining 5 to 6 GW capacity can be secured by BESS, assuming at least doubling of the capacity to technically fill the remaining generation gap, i.e. to install around 12 GW of battery storage, which is not unlikely given the level of grid connection conditions currently issued for However, such BESS capacity could be reached only in case of a special support system, e.g. similar to the BESS and PHES dedicated capacity market MACSE currently implemented in Italy.

Thus, it is not technically impossible to balance Poland's energy system without aging coal power plants and baseload nuclear power, but it requires a coherent strategy to promote a highly flexible demand-side response that takes advantage of the cheapest hours of generation to avoid late afternoon/early evening off-take, behind-the-meter generation combined with storage to avoid distribution tariffs, and a large and transparent market for frequency regulation services capable of adequately compensating both gas peakers and BESS.

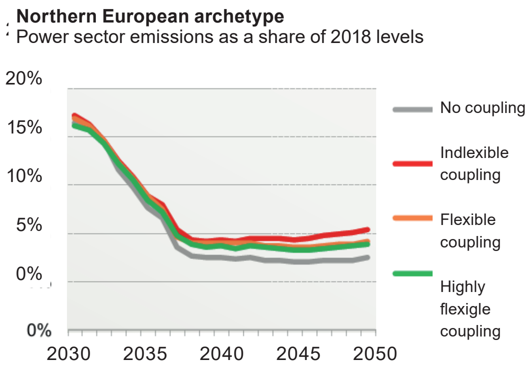
Drawing 13: **Increase of variable renewables and peaking capacity in sector coupling scenarios**

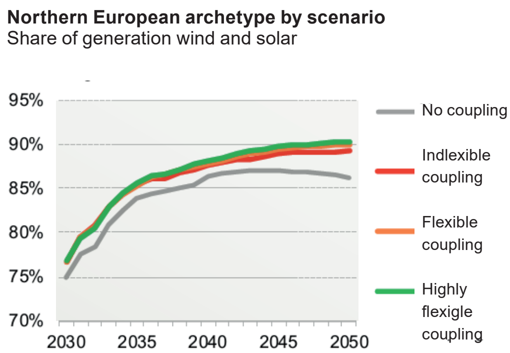




Source: Bloomberg NEF, "Sector Coupling in Europe. Powering Decarbonisation", 2020, page 42

Drawing 14: **Emissions in sector coupling scenarios and share of variable RES generation**





Source: Bloomberg NEF, "Sector Coupling in Europe. Powering Decarbonisation", 2020, page 45

The measures envisaged in the European Commission's Market Design Proposal seem not to be reflected in PSE's peak demand scenario

In this context it is worth noting that the European Commission's 2023 Market Design Proposal promotes the idea of shifting investment in storage and DSR solutions more towards forward, long-term hedging instruments and creating demand for flexibility services. The Commission is pursuing greater flexibility of intra-day markets and standardized peak-shaving system services to ensure that surplus renewable generation is used efficiently and that market access barriers are reduced. Intra-day gate-closing times will be reduced and a lowering of the minimum bid size will ensure that small-scale flexibility can participate. Dynamic network tariffs will incentivize system operators to use flexibility services by further developing innovative solutions to optimize the existing grid and by procuring flexibility services based on demand-response and storage – as also supported by EU funds. In addition, transmission system operators will be encouraged to develop standardized short-term peak-shaving products that compensate market participants for reducing electricity consumption or using stored energy during peak hours.

Further empowering active consumers by energy sharing

The Commission emphasizes that energy sharing by RES generators with a total installed capacity of up to 100 MW will be particularly encouraged. Active customers who own, lease, or rent a storage or generation facility will have the right to share excess production and enable other consumers to become active, or to share the renewable energy generated or stored by jointly leased, rented or owned facilities, either directly or through a third-party facilitator. Member States will have to put in place an appropriate IT infrastructure to allow for administrative matching of consumption with renewable energy self-generated or stored by active customers within a certain timeframe. Additionally, Member States will have to ensure that all customers are free to have more than one electricity supply contract at the same time, provided that the necessary connection and metering points have been established. To this end, customers will be entitled to have more than one metering and billing point covered by the single connection point for their premises. Active customers will be entitled to have the shared electricity netted against their total metered consumption within a time interval not exceeding the imbalance settlement period and without prejudice to applicable taxes and network charges.

Therefore, we estimate that the implementation of the new electricity market design will result in a lower increase in peak demand than projected by PSE, even in the case of dynamic deployment of sectoral coupling technologies.

2 Regulatory environment for curtailment of intermittent renewables

One of the key elements of the new electricity market structure, which consists of regulations and directives adopted in 2018 and 2019 and constitutes the so-called “Clean Energy for All Europeans” package, is Regulation (EU) 2019/943 of 5 June 2019 on the internal market for electricity (Regulation), the provisions of which entered into force on 1 January 2020. An important aspect of the Regulation is the regulation of so-called redispatch. Redispatching is understood as a measure, including curtailment of power generation, activated by one or more transmission system operators or distribution system operators (network operators) and consisting of a change in generation pattern, load pattern or both, to modify the physical flows on the transmission system and reduce physical congestion or otherwise ensure system security.

The general principle for the introduction of congestion (at the level of EU law) requires network operators to first apply market-based solutions (e.g. curtailment with compensation based on merit order and balancing offers by market participants) or non-market-based solutions, but with compensation. According to Article 13(1) of the Regulation, the redispatch of generation units and the redispatch of off-take response must be based on objective, transparent and non-discriminatory criteria. An analysis of the subsequent paragraphs of Article 13 of the Regulation dictates that the EU legislator has introduced the principle that financial compensation shall be paid for the redispatch of generation or energy storage units that is not based on market principles, except in cases where the generator has accepted a connection contract that does not guarantee a reliable energy supply.

In accordance with Article 13(7)(b) of the Regulation, the amount of compensation in the case of a RES generation unit must be at least equal to the net revenue from the sale of electricity on the day-ahead market that the generation unit would have generated if no redispatch order had been issued. If a generation unit has received financial support based on the amount of electricity generated or consumed, the financial support that would have been received if no redispatch order had been issued shall be considered as part of the net revenues.

In the light of paragraph 3 of this provision, non-market based redispatch may only be applied if:

- there is no market-based alternative;
- all market-based resources have been exhausted;
- the number of available generation, energy storage or off-take response units is too low to ensure effective competition in the area where units suitable for the service are located; or
- the current state of the network leads to such regular and foreseeable congestion that market-based redispatch would lead to regular strategic bidding, which would increase the level of internal congestion, and the Member State concerned has adopted an action plan to address the congestion or provides the minimum capacity available for inter-zonal trading.

In summary, according to the Regulation, non-market redispatch, as a measure to ensure the security of the electricity system, is to be applied in strictly defined cases and financial compensation is to be the rule, from which the EU legislator provided for an exception in the form of the generator's acceptance of the provisions of a connection contract that do not guarantee a reliable energy supply.

Legal basis for non-market redispatch in Poland

The non-market redispatch of PV, wind units and energy storage was introduced into the Polish legal order by the Act of 28 July 2023 amending the Energy Law Act (EL Amendment), the relevant provisions of which entered into force on 7 September 2023. The purpose of the EL Amendment was to implement Directive 2019/944, but also Directive 2018/2001 and to ensure the application of Regulation 2019/943. Prior to the EL Amendment, the grid connection conditions or connection agreements contained a general clause allowing redispatch due to congestion or grid failure, which allowed the TSO and DSO to reduce the output power and exempted the operator from liability for such reduction. The clause in question in the connection agreements was and is a standard clause introducing reductions "for network reasons", which is in line with the network transmission/distribution code (IRiESP/D), accepted by the Energy Regulatory Office. The risk resulting from the inclusion of this clause in the contract varies from project to project, as the risk of a network security condition depends on the location of the installation in question. It is worth noting that this clause does not allow grid operators to curtail wind farms and PV installations for "system balancing" reasons without compensation.

Thus, under the EL Amendment, paragraphs 7a–7q were added to Article 9c of the Energy Law Act concerning non-market redispatch of generation units and energy storage facilities. Pursuant to the new provisions, the transmission system operator may issue orders directly or through a distribution system operator to a generator connected to the transmission system to shut down a wind or solar generating unit or reduce the capacity generated by that unit in order to

- balance electricity supply and demand, or
- ensure the security of operation of the electricity grid.

Pursuant to Article 9c(7a) of the Energy Law Act, the execution of the order is to be subject to the financial compensation referred to in Article 13(7) of Regulation 2019/943. The financial compensation due to the generators would be paid for the failure to produce electricity in the amount that would have been produced if PSE had not issued the order, considering the principles set out in Article 13(7) of Regulation 2019/943.

The Regulatory Impact Assessment for the EL Amendment indicates that the proposed regulation of the settlement rules for generation reduction (financial compensation) is in line with EU law and that the national regulation will allow to provide legal security for potential investments in new wind farms and PV installations in terms of the right to receive full financial compensation for reduced generation.

New connection agreements and annexes, or how the exception becomes the rule

The EL Amendment introduced two provisions into the Energy Law Act, the practice of which by network operators has had the effect of limiting the ability of generators to obtain financial compensation for non-market redispatch “for balancing reasons”. First, by adding paragraph 2e to Article 7 (relating to the elements of the grid connection contract), the legislator indicated that the contract for the connection of a generating unit (or energy storage) is to contain provisions entitling the grid operator to limit the guaranteed connection capacity or to introduce operational limitations resulting in the lack of guarantees of reliable electricity supply in order to balance the electricity supply with the demand or to ensure the operational security of the power grid. Second, paragraph 7g was added to Article 9c, according to which the legislator explicitly indicated that the mechanism of financial compensation for non-market redispatch is excluded if the grid connection contract contains provisions that result in the lack of guarantee of reliable electricity supply.

The effect of the introduction of these provisions was that network operators treated the lack of compensation for “balance curtailment” as a rule that could be introduced, inter alia, by annexing it to existing connection contracts. In practice, therefore, the new provision of Article 7(2e), combined with the provision of Article 9c(7g), became the basis for network operators to try to introduce clauses into connection contracts concluded prior to the EL Amendment, allowing network operators to limit the production of PV and wind farm generators without adequate financial compensation. Annexes were often proposed to entities that had themselves applied for an amendment to the connection contract due to the need to update the connection schedule or change the location of the investment. However, as this practice is illegal, many RES generators rejected such offers and successfully pushed back.

PSE offered connection conditions to photovoltaic generators much earlier, at the beginning of 2023, i.e. before the EL Amendment came into force, which included a clause on “curtailment for balancing reasons”. However, in some cases, the provisions on the curtailment of generating capacity or the shutdown of a generating source “for balancing reasons” included a right to financial compensation for generators if the curtailed capacity was covered by electricity sales contracts or if it was covered by a balancing energy offer within the balancing market. It is worth noting that only a detailed analysis of the provisions of individual connection contracts, including those concluded prior to the EL Amendment, will make it possible to determine whether the provisions in question concerning curtailment of generation capacity may also apply to curtailment for balancing reasons and whether the network operator is liable to the generator for such curtailment.

The same applies to distribution service contracts (for the consumption of electricity). If there are provisions in the distribution contract concluded with the DSO that do not guarantee reliable energy supply and, in addition, the operator explicitly excludes its liability for the occurrence of a curtailment in the injection of the power and electricity into the network by the generating facility in accordance with the connection contract, the terms and conditions of the network transmission/distribution code (IRiESP/D) or the station’s movement cooperation (IWR), such a provision may constitute grounds for (unjustified) refusal to pay financial compensation to the generating entity. In principle, however, generators whose PV or WF installations have been redisposed for balancing reasons and whose connection contract or connection conditions do not contain provisions that do not guarantee reliable energy supply are entitled to the financial compensation referred to in Article 9c(7a) of the Energy Law Act, in accordance with the rules set out in Article 13(7) of Regulation 2019/943, in line with the principle of direct effect of the provisions of EU regulations.

Until now, the network transmission/distribution codes of the individual operators did not regulate redispatch for balancing reasons. In connection with the second phase of the balancing market reform and the entry into force of the new balancing conditions (WDB) as of 14 June 2024, the DSOs updated their network transmission/distribution codes with provisions allowing network operators to make non-market redispatch for balancing reasons, importantly with financial compensation. According to the new network transmission/distribution codes, redispatch is to be based on the principles discussed above arising from Article 13(3), (6) and (7) of Regulation 2019/943. The reform of the balancing market is intended to motivate system participants to respond to its needs. It appears that the reformed balancing market rules will reduce the curtailment of PV and wind farm installations.

Penalties for non-compliance with a power redispatch order

The Energy Law Act contains as many as three legal grounds for penalizing generator for not complying with a non-market redispatch order issued by the network operator. Such a generator may be subject to a financial penalty, imposed by the President of the ERO, under Articles 56(1)(19) and 27a of the Energy Law Act. At the same time, in the case of licensed energy companies, Article 56(1)(12) of the Energy Law Act provides that the President of the ERO may impose a financial penalty of between PLN 10,000 and 15% of the revenue generated in the previous fiscal year for failure to comply with the obligations arising from the license.

Amendment of the Act on Renewable Energy Sources

It is worth noting that the EL Amendment also resulted in amendments to the Act on Renewable Energy Sources (RES Act). As a result, pursuant to Article 93(18) of the RES Act, subject to paragraph 19, a generator is obliged to inform its network operators within 14 days from the date of the order referred to in Article 9c(7a) of the Energy Law Act whether and which part of the reduced energy should be accounted for in a given support scheme. According to the above provisions, if the generator does not provide this information within 14 days from the date of the order, the reduced energy will not be included in the calculation of the compensation in the part concerning lost revenues from the auction support system.

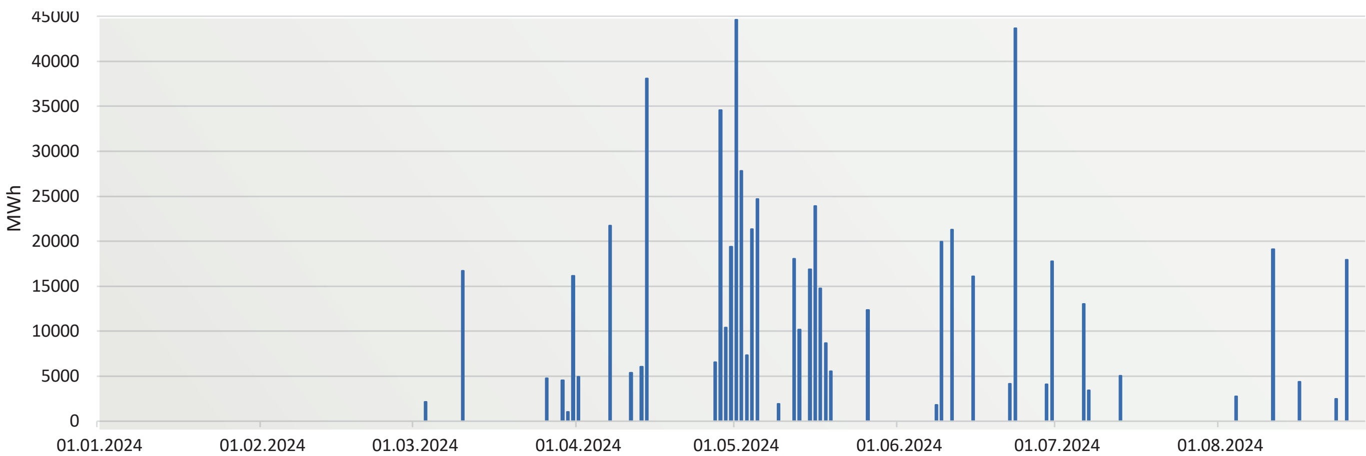
In addition, it should be noted that, in accordance with the provisions of Article 93(4) and (5) of the RES Act, support under the auction system is also not due for the quantities of electricity generated in a renewable energy source installation during the hours for which the volume-weighted average prices of electricity session transactions were lower than PLN 0 per 1 MWh for at least six consecutive hours of electricity delivery. An analogous rule applies to the support scheme for the sale of certificates of origin. In the light of the provisions of Article 46(4) and (5) of the RES Act, support is not available for electricity generated during hours in which the volume-weighted average prices of electricity in session transactions were lower than PLN 0 per 1 MWh for at least six consecutive hours of electricity supply.

3 Curtailment risk until 2040

From July 2024, the ongoing implementation of the European balancing platforms MARI (Manually Activated Reserves Initiative) and PICASSO (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation) with both manual and automated frequency services should lead to a more transparent market for frequency services also in Poland due to the aFRR and mFRR auctions being organized at the regional level. This international and competitive bidding environment for FRR services contrasts with the manual allocation of frequency services to domestic coal-fired power plants due to their spinning reserves prior to the liberalisation of the balancing market in July 2024. However, it is not yet clear how large the auctioned volumes for these services will be. Based on the current experience in the markets that went live in 2022, i.e. the four German TSOs, the Austrian TSA and the Czech TSO, the total monthly volume of the automatic Frequency Restoration Reserve (aFRR) services regularly amounted to up to 2.0 TWh, compared to a net energy demand in this network area of 50 to 60 TWh per month. The technical impact of these new European balancing platforms is therefore limited for the time being. It can be assumed that the security of the National Power System will rely on the spinning reserve of conventional power plants, while in the second half of this decade and the first half of the next, gas-fired turbines will replace coal-fired turbines.

The volume of this year's generation reduction orders issued to generators or automatically implemented (known as non-market redispatch) is 45 messages until mid of August, adding up to 0.63 TWh of renewable energy that could potentially be fed-in. Throughout 2024, this amount could reach around 0.8 TWh. Relative to the annual generating capacity of solar PV and wind farms operating in the National Power System, which can be estimated at 45 TWh, this is a small, albeit noticeable value (at a level of 2%). However, considering that more than two thirds of the restrictions apply to large-scale solar PV generation, whose installed capacity amounts to 6 GW, this figure becomes significant, as it could eventually reach up to 10% of the annual generation from this type of RES sources. Prosumers with an installed capacity of around 12 GW are not subject to the planned curtailment, although a significant proportion of them are affected by "natural reduction" due to inverter switching as a result of excessive voltage at the point of connection.

Drawing 15: **Curtailment of RES in 2024**



Source: own source

Understanding the future development of RES capacity is important for forecasting future curtailment, which is not easy. Hard facts in this respect are provided by the NDP2034, which shows the level of capacity of RES sources for which connection conditions have been issued (or connection agreements concluded), including the capacity of already installed sources.

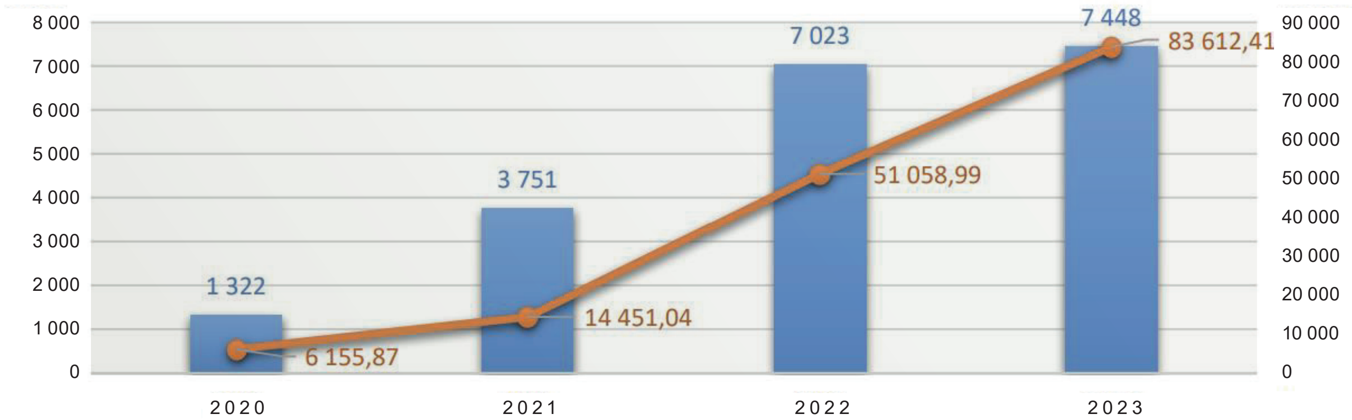
Drawing 16: **Connection conditions issued and connection agreements concluded**

	CONNECTED (as of the end of March 2024)		PLANNED, ISSUED CONNECTION CONDITIONS (with microinstallations)		POTENTIAL POWER UNTIL 2030
Onshore wind farms	10,2 GW	+	8,2 GW	→	18,4 GW
Offshore wind farms	0 MW	+	8,5 GW	→	8,5 GW
Photovoltaics	18,3 GW	+	31,8 GW	→	50,1 GW
Sum FW + PV	28,5 GW		48,5 GW		77 GW
			Potential annual electricity production		> 140 TWh > 50% consumption
Electricity storage	→		24 GW		

Source: own source

There are facilities that will not be realized for various reasons (business, environmental, administrative). In their place other RES generators are trying to enter the market, and the applicants are making efforts to obtain conditions for connection to the grid – without success so far.

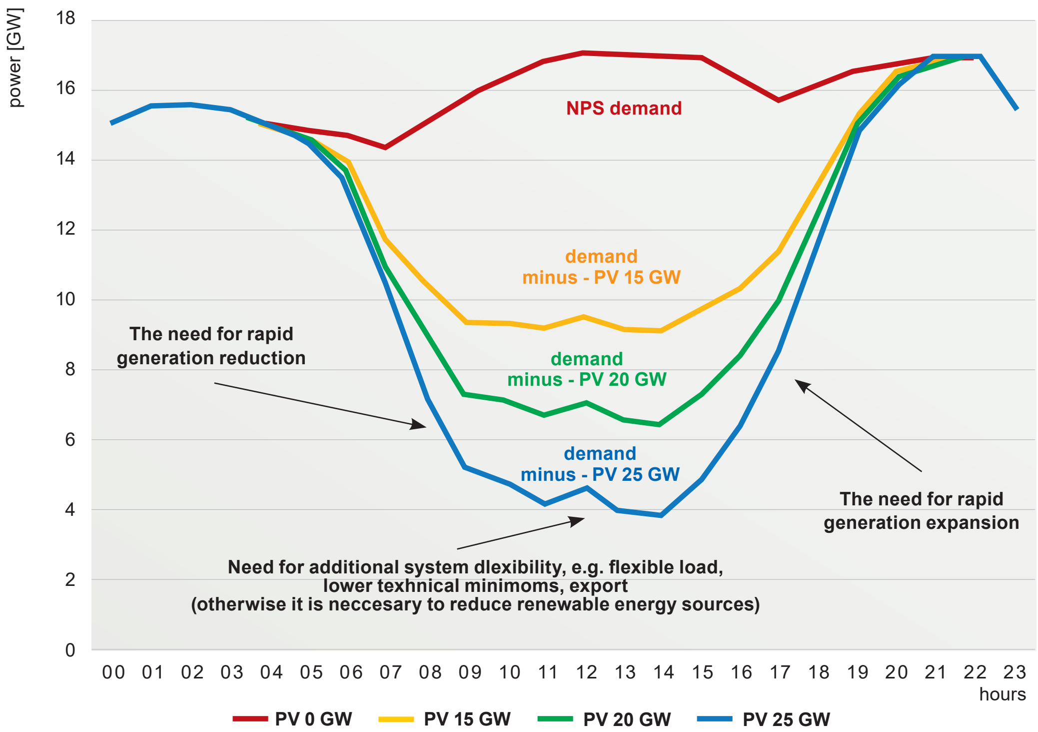
Drawing 17: **Amount and capacity (in MW) of connection conditions rejected by TSO and DSOs**



Source: Energy Regulatory Office (URE)

Theoretically, assuming that the development and modernization of electricity grids will allow 50% of these RES generators to be connected, one should expect 110 GW of installed RES capacity (and more than 130 GW if prosumers are included). Even in theory, this capacity should translate into a significant increase in demand. A positive correlation between electricity demand and installed RES capacity is evident. Stagnating demand will sooner or later lead to a reduction in the momentum of RES development for economic reasons. This can be explained by a periodic increase in energy supply due to natural factors (changes in insolation and wind speed), which periodically increases the demand for renewable energy.

Drawing 18: **The "Duck" curve: Impact of high PV capacity on reducing the accidental load on the national power system below the regulatory limits**



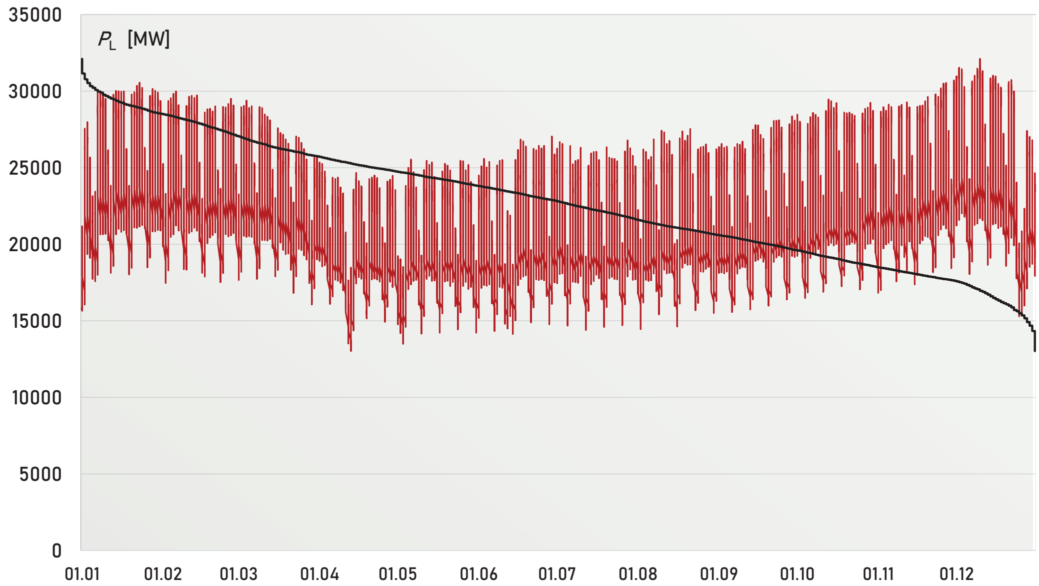
Source: own source

As can be seen in the drawing above, at a daily peak of about 17 GW (a value that is currently typical for weekend days), PV generation resulting from an installed capacity of 25 GW will lead to a reduction in power demand from conventional plants from 15 GW to 4 GW, followed by a necessary increase in generation to 17 GW as the sun sets. Currently, this is not technically possible with a reduction in conventional generation to 4 GW, so PV generation must be reduced to a level that does not reduce system demand below 9 GW. Thus, the level of 130 GW of installed capacity, resulting from the current dynamics of RES capacity growth, connection conditions issued and efforts to obtain them will not be reached by 2040. In our opinion, the following values seem entirely realistic: photovoltaic generation 45 GW, onshore wind farms 20 GW, offshore wind farms 10 GW.

The short but dynamic history of the phenomenon of curtailment of RES sources urges investors to include the risk of non-market redispatch in their calculations and to know whether the amount of curtailment of the potentially available generation. This is particularly important in the context of the TSO's prospective withdrawal of compensation for lost generation based on grid connection agreements concluded since the beginning of 2023. The following calculations are the results of a simplified analysis.

Using the original demand record for 2022 and comparing the total increase in power consumption to a value of 200 TWh and 32,100 MW (peak) in 2034 as the base year, a plausible relationship can be derived as shown in the drawing below. Certainly, electromobility and the power consumption of heat pumps and other loads resulting from sector coupling will further change the nature of this trajectory after 2034, but this issue is not included in the considerations presented here.

Drawing 19: **The variability of power demand for a projected annual consumption of 200 TWh in 2034 as base year**



Source: own calculation

The ability to balance this demand was examined by considering both renewable and conventional sources. Renewable sources are considered according to their expected installed capacity and variability depending on weather conditions and seasons. For conventional power generators, only those that provide the required level of system stability (must-run generation) are modeled. Nuclear units, which would be included in the must-run group, are not included as this technology is not expected to be commissioned before 2040.

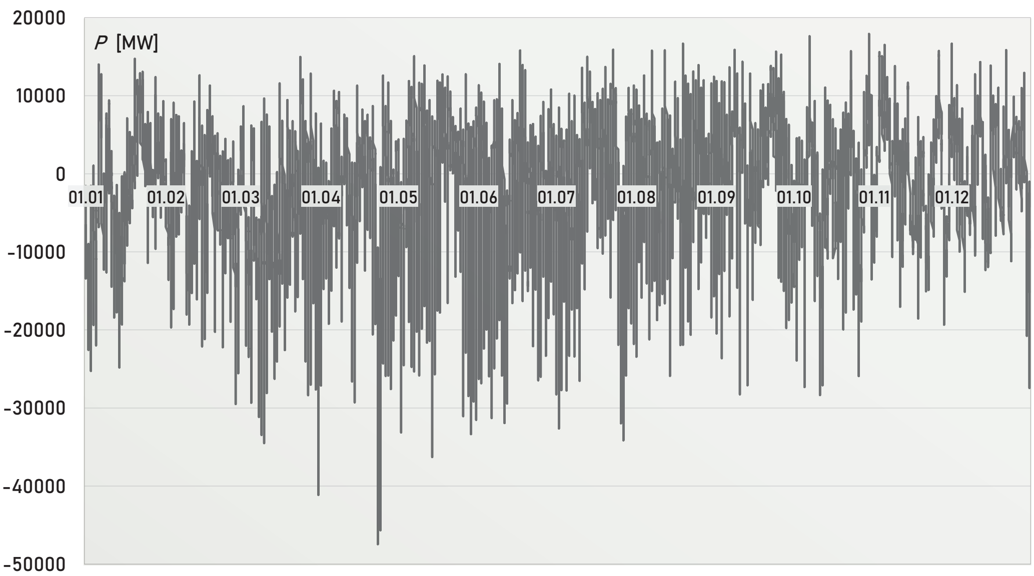
Drawing 20: **The variability of power demand for a projected annual consumption of 200 TWh in 2034 as base year**

Generation asset	Installed capacity / peak load in MW	Annual power demand (net) in TWh
Peak load/Annual Demand	**32 100**	**200**
Solar PV	45 000	49
Onshore Wind	20 000	56
Offshore Wind	10 000	46
Must-run conventional generation	9 000	67
Nuclear Power Plants	0	0
Hypothetical generation (without storage)	84 000	218
Hypothetical surplus of power	-	18

Source: own calculation

The variable distribution of RES generators, i.e. solar PV, onshore wind and offshore wind results in periods of generation surplus and periods of capacity deficit. The duration of these periods and the values of the capacities that occur during them determine the system's demand for balancing (peak) capacity, demand response services and, most importantly, energy storage.

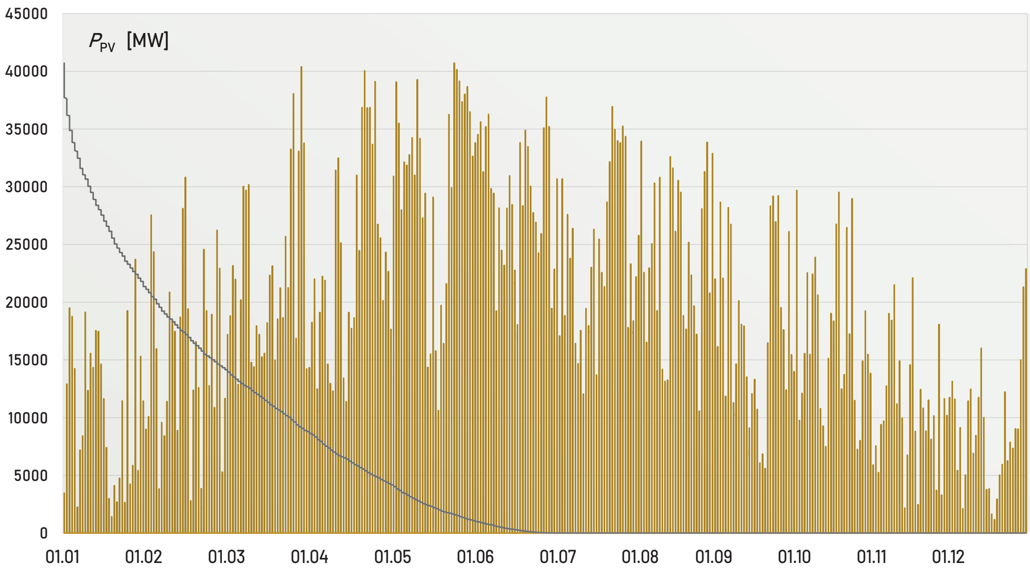
Drawing 21: **Non-balanced capacity in 2034 as base year**



Source: own calculation

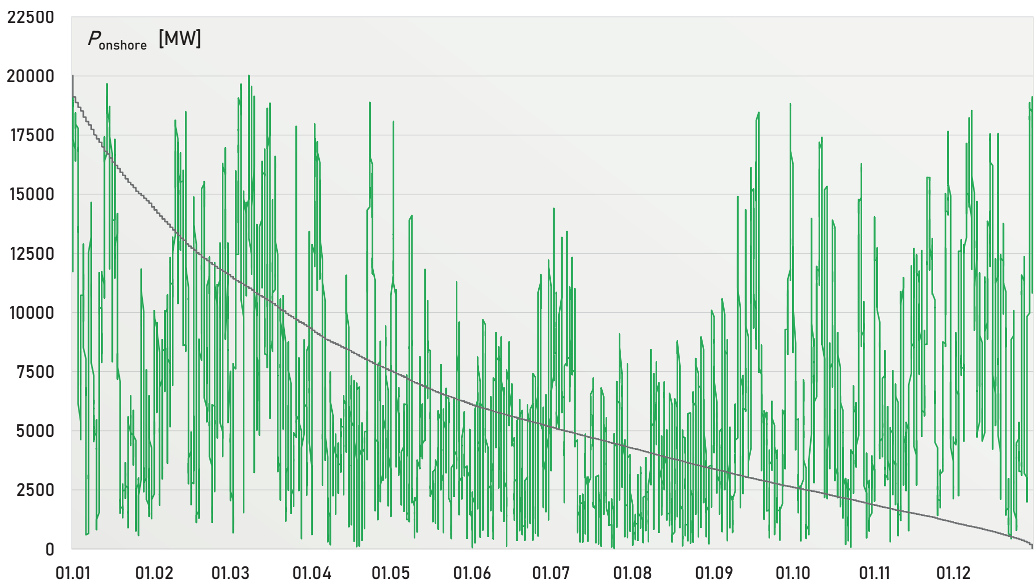
Dividing these quantities by specific technology capacity and adding up the resulting values gives the annual value of energy required to balance demand and the annual value of energy that cannot be produced from variable renewable sources.

Drawing 22: **Solar PV generation of 45 GW installed capacity with a capacity factor of 0.121**



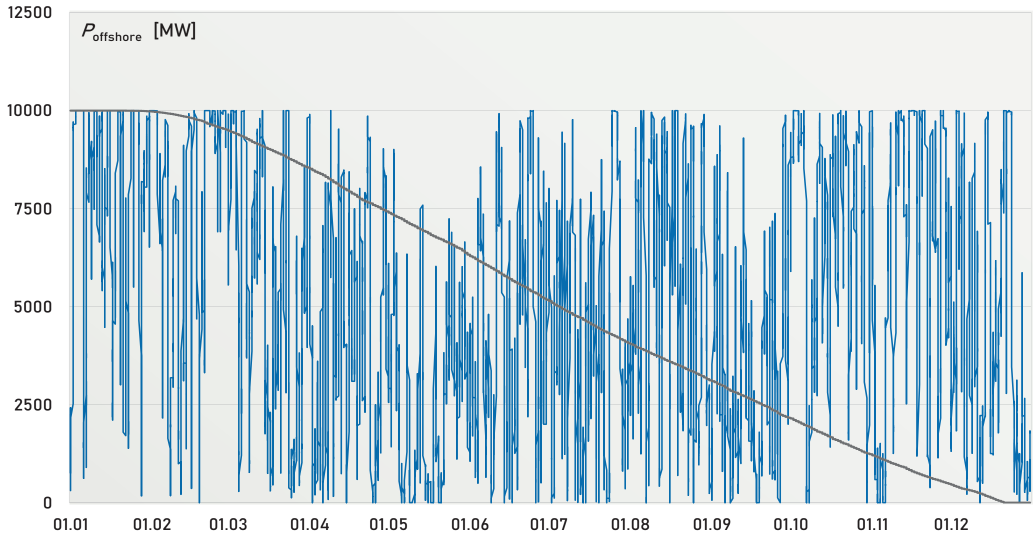
Source: own calculation

Drawing 23: **Onshore wind generation of 20 GW installed capacity with a capacity factor of 0.319**



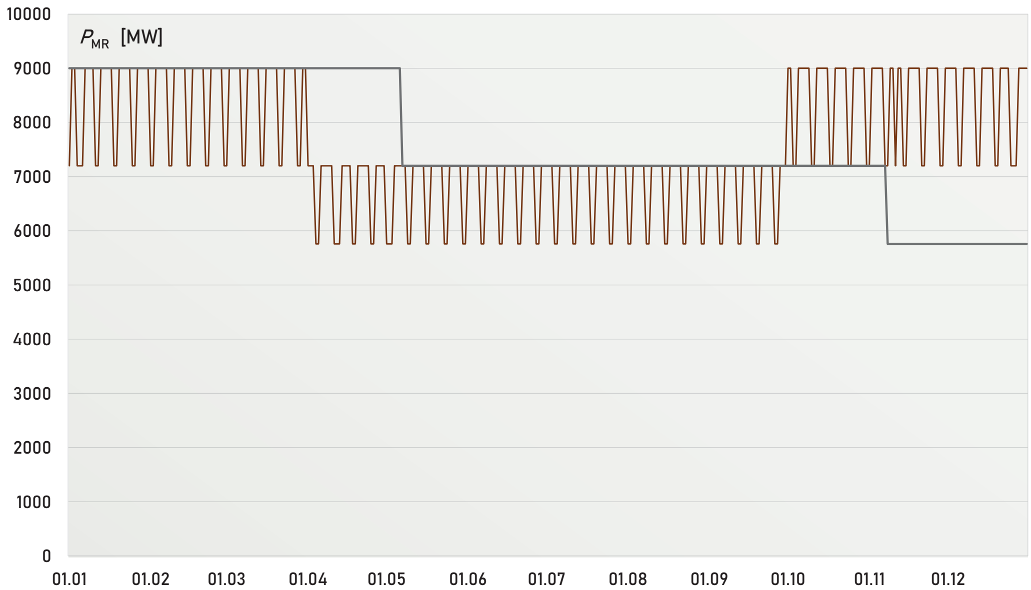
Source: own calculation

Drawing 24: **Offshore wind generation of 20 GW installed capacity with a capacity factor of 0.514**



Source: own calculation

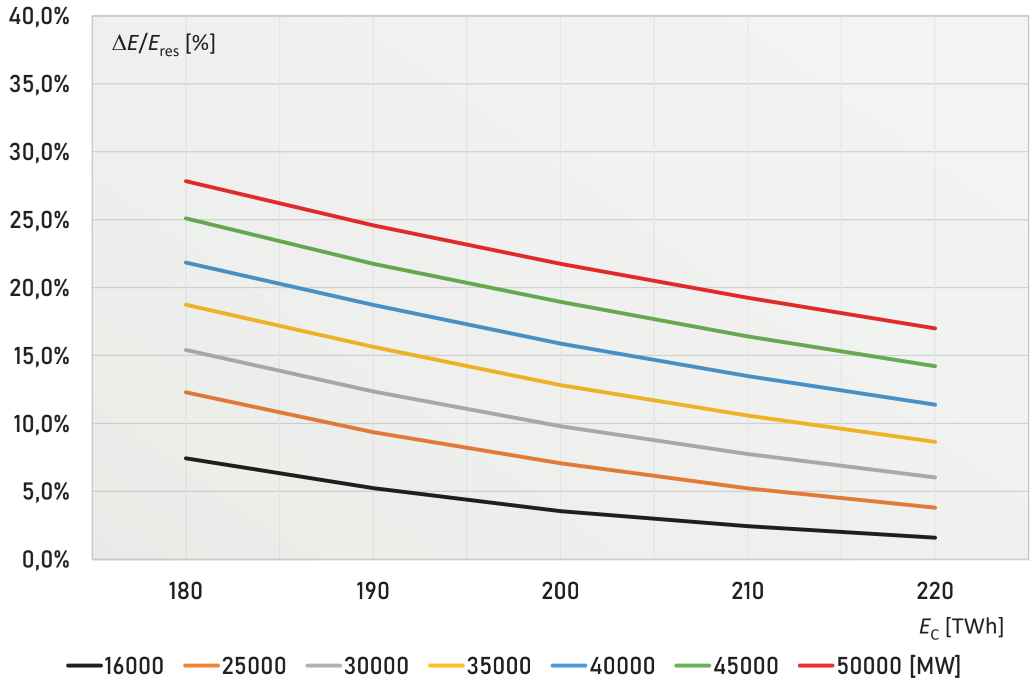
Drawing 25: **Must-run generation of 9 GW installed capacity, reduced during weekends and summer months**



Source: own calculation

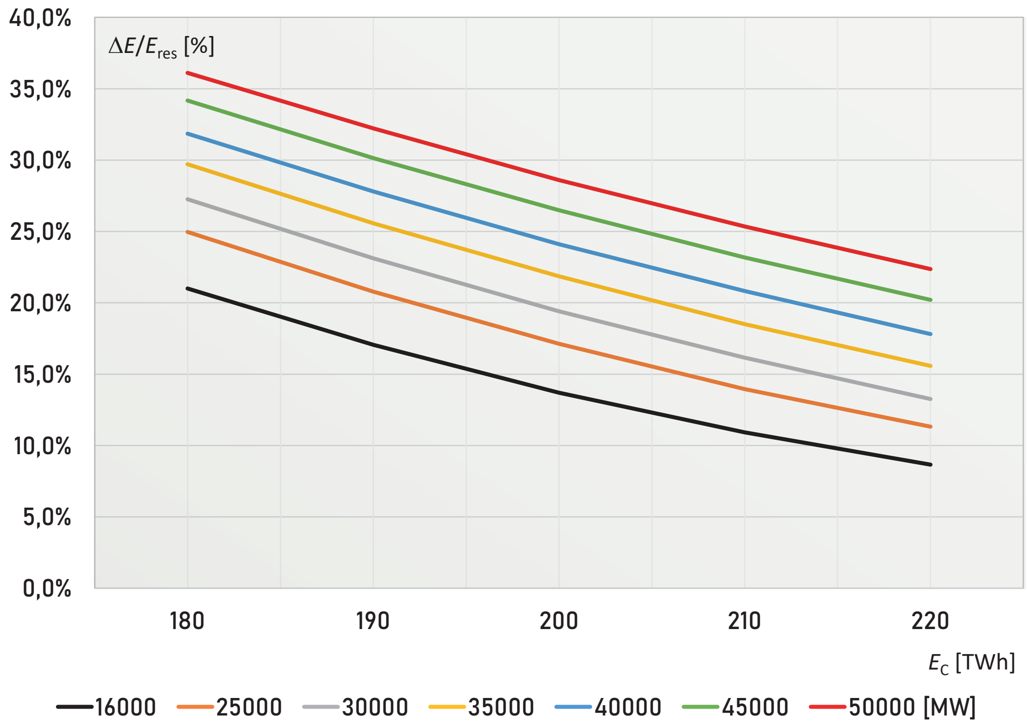
Generally, the percentage of annual solar PV curtailment will increase based on demand, installed capacity of solar PV and other variable renewable energy sources. The following figures show some calculation examples based on increasing solar PV capacity from the current level up to 50 GW, with a net energy demand of 180 up to 220 TWh. The must-run capacity is 9 GW in each case.

Drawing 26: **Curtailment of solar PV with 15 GW onshore wind and 5 GW offshore wind installed capacity**



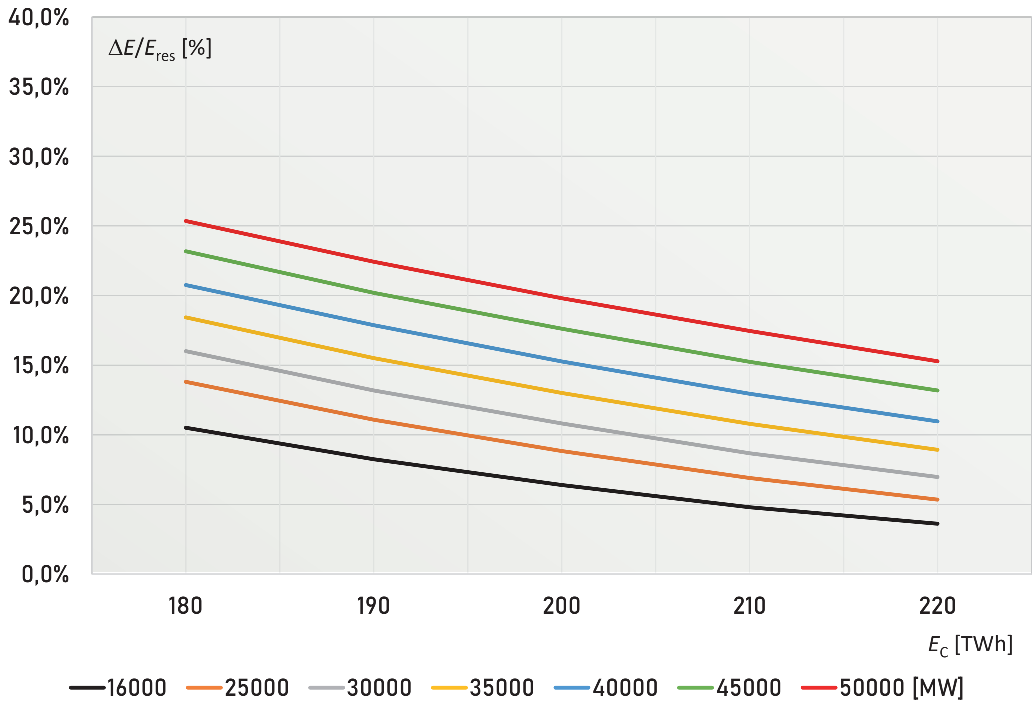
Source: own calculation

Drawing 27: **Curtailment of solar PV with 20 GW onshore wind and 10 GW offshore wind installed capacity**



In the same scenario, if the must-run capacity is reduced to 5 GW, the percentage of solar PV curtailment decreases significantly, by more than 10%, but does not disappear.

Drawing 28: **Curtailment of solar PV with 20 GW onshore wind, 10 GW offshore wind, 5 MW must-run capacity**



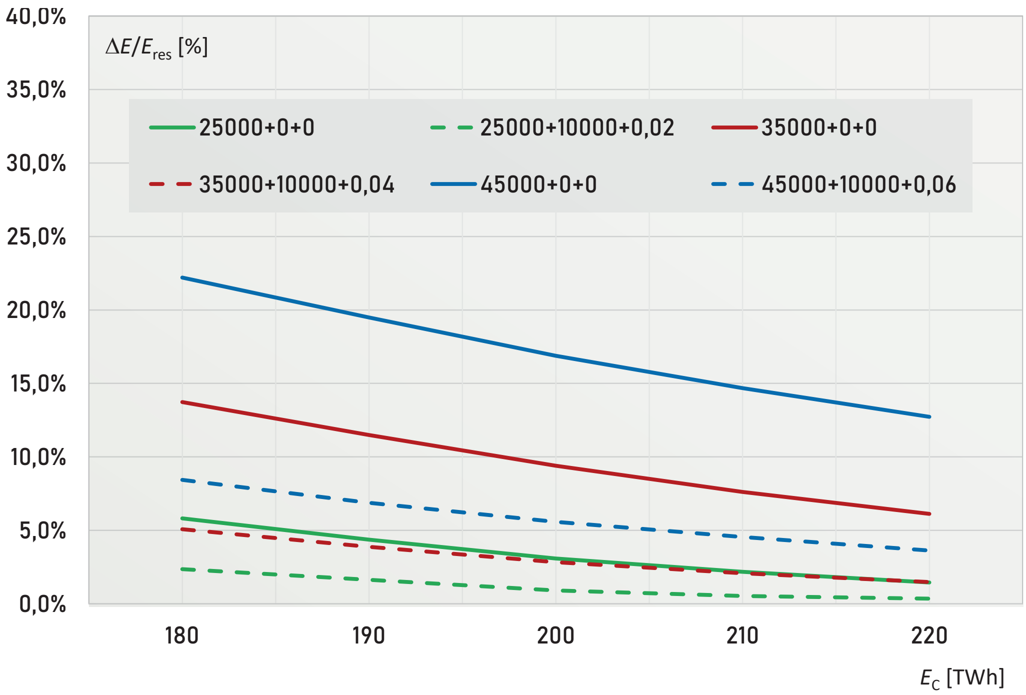
Source: own calculation

A key technology for reducing the must-run capacity is grid-forming inverters, which can be installed on variable renewable energy generators and BESS. It is worth noting that grid-forming inverters (GFMIs) face several challenges, such as the need for improved control schemes to ensure the stability and robustness of the power system, or independent control of active and reactive power transfer, which becomes challenging due to the coupling between power and voltage loops in GFMIs. Effective control strategies and coordination among GFMIs to ensure the stability and reliability of power systems is a must.

As a result of the above calculations, the need to consider energy storage becomes crucial, as its absence reduces the effectiveness of RES investments and will sooner or later bring the dynamics of their development to a halt. New BESS storage facilities will be eligible for 4h storage due to their participation in the capacity market. If all 20 GW of storage for which grid connection conditions have been issued are installed, i.e. about half of the expected installed peak capacity of solar PV, a BESS capacity of 60–80 GWh or 0.06–0.08 TWh can be expected.

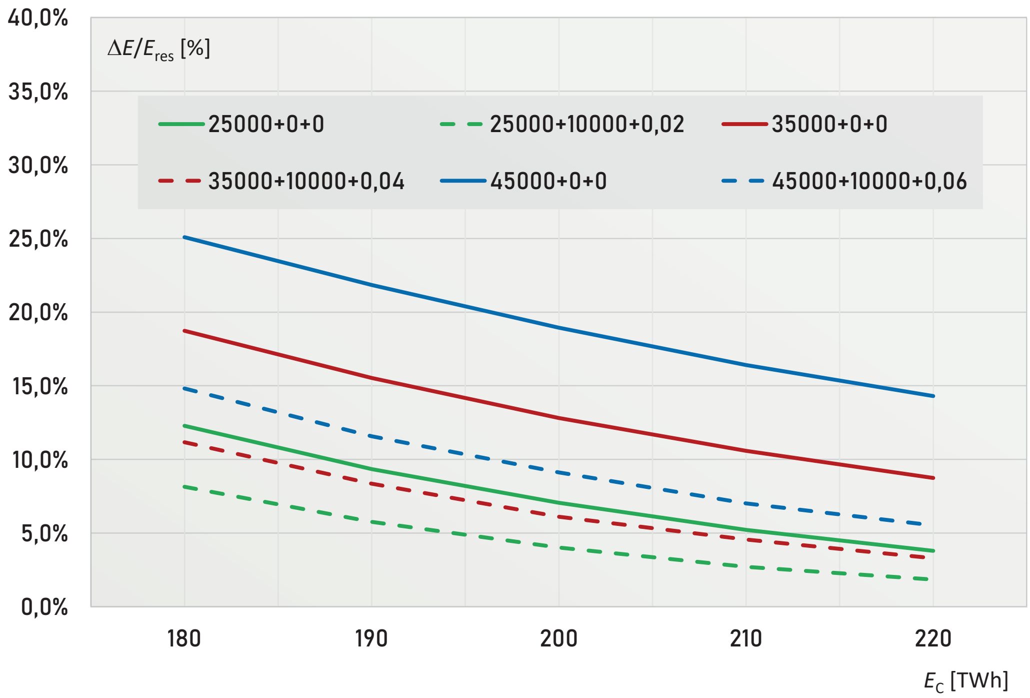
A more likely scenario is an increase in BESS capacity (assuming 10 GW capacity with increasing BESS volume per MW capacity, for calculation purposes only) in line with the increase in solar PV, i.e. 25 GW solar PV and 0.02 TWh BESS, 35 GW solar PV and 0.04 TWh BESS and 45 GW solar PV and 0.06 TWh BESS.

Drawing 29: **Curtailment of solar PV (10 GW onshore wind, 0 GW offshore wind, 9 MW must-run capacity, increasing solar PV and BESS capacity – 10 GW)**



Source: own calculation

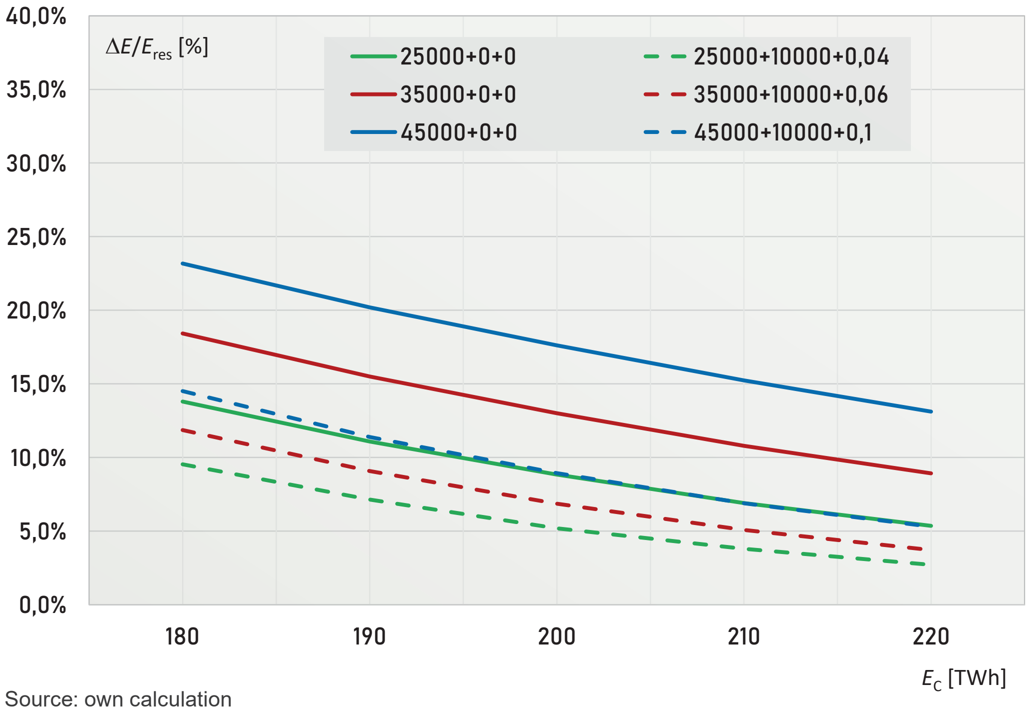
Drawing 30: **Curtailment of solar PV (15 GW onshore wind, 5 GW offshore wind, 9 MW must-run capacity, increasing solar PV and BESS capacity – 10 GW)**



Source: own calculation

In a more progressive decarbonization scenario, with more installed onshore and offshore wind capacity and less must-run capacity, the percentage of curtailment remains almost unchanged.

Drawing 31: **Curtailment of solar PV (20 GW onshore wind, 10 GW offshore wind, 5 MW must-run capacity, increasing solar PV and BESS capacity)**



Source: own calculation

4 Technical and commercial aspects of BESS co-location

Cable-pooling improves the investment case

Curtailment risk and technology profile costs make investment in large-scale solar PV less attractive. To improve the investment case, the development of hybrid projects, i.e. the joint development of solar PV and onshore wind with their overlapping production profiles, helps to optimize the costs of grid connection infrastructure. In this context, the new cable-pooling regulation, which came into force on 1 October 2023, is key to realizing the full potential of hybrid installations.

The Energy Regulatory Office issued a new interpretation of cable-pooling legislation

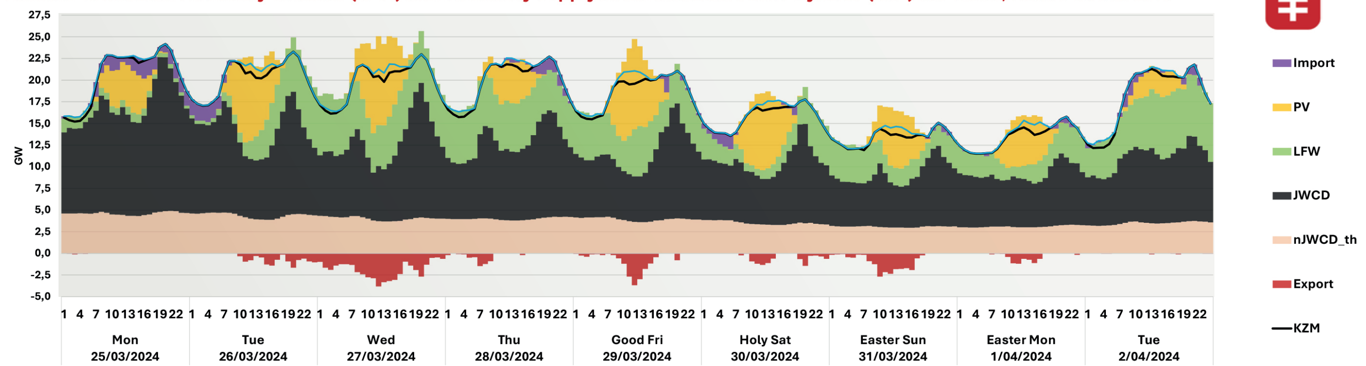
Pursuant to the new article 7 sec.1f) of the Energy Law Act, two or more renewable energy source installations belonging to one or more entities may be connected to the electricity network with a rated voltage higher than 1 kV through a single connection point. Such regulation applies only to the connection of two or more renewable energy installations and is designed in principle for the construction and connection of new installations, but is also applicable when one installation is to be connected to another one at the same connection point. Furthermore, there is no technical limitation on the type or RES installations that can be connected. All installations have a single point of connection to the grid and the metering assigned to each of these RES installations is located at the place indicated by the connected entity, before the common grid connection point, e.g. in case one or more installations make use of the auction support system.

Individually designed grid connection agreement is required

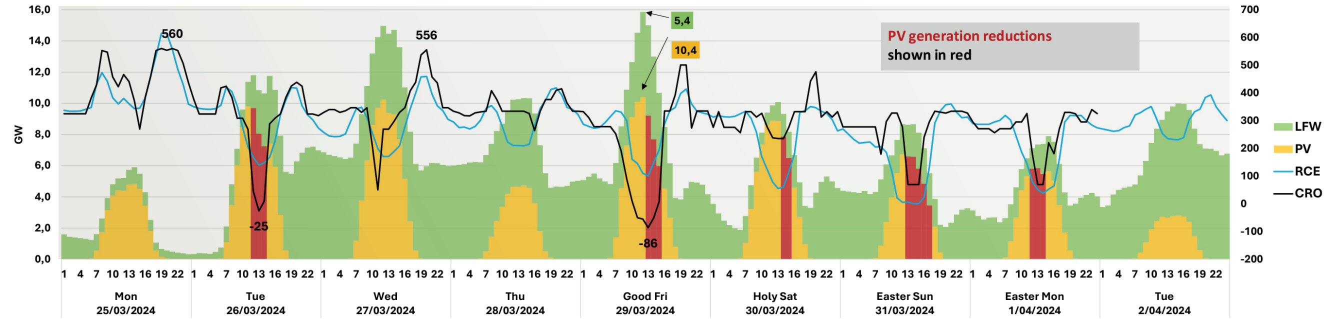
In the case of multiple entities, it is necessary to develop an individual model of cooperation of the owners of the subject RES installations as the grid operators have not yet published any template documentation. The respective entities are obliged to conclude a grid connection agreement, and subsequently a distribution or transmission agreement. In any case, if the connection capacity is lower than the sum of the installed electrical capacity of the respective RES installations, the grid connection agreement must contain a detailed description of the manner in which the technical capacity will be ensured not to exceed the connection capacity. The cost of purchasing and installing appropriate equipment shall be borne by the entities connected to the grid. In turn, the monitoring of the operation of the equipment to ensure the technical capacity not to exceed the connection capacity is carried out by the grid operator responsible, in particular, for securing the equipment in such a way that its settings cannot be changed. The requirements of the Grid Code only apply to RES installations connected to the grid after the entry into force of this EU Regulation.

Drawing 32: **Solar PV and onshore wind generation end of March 2024 in Poland**

Balance of national electricity demand (KZM) and electricity supply in the National Power System (KSE) in Poland, Easter Week 2024



Power generation by onshore wind and solar farms in Poland during the Easter Week, RCE and CRO prices and PV generation reductions



The long Easter weekend saw a significantly lower national electricity demand (KZM) compared to normal weekdays, and several other interesting phenomena.

The average daily KZM level was at 15.8 GW on Saturday and about 13.4 GW on Sunday and Monday, as compared to 18.6-20.5 GW on weekdays.

Although relatively low levels of solar and onshore wind energy were recorded in the early days of last week (especially on Monday), reductions in solar generation were necessary in order to balance the overall national electricity demand and to ensure a downward regulation capacity as windy and sunny weather patterns developed in the following days.

'Downward regulation capacity' refers to the frequency containment and restoration reserves (FCR and FRR) that allow for generation reductions during frequency spikes. At the current stage of the KRE development, these reserves are maintained by JWCD centrally dispatched generating units operating above the 'technical minimum' level (which provides room for generation reductions in the event of frequency spikes).

Solar power reductions were necessary to make room for the JWCDs providing the downward FCR/FRR reserves that are absolutely necessary to ensure the security of electric reliability.

The period under review also saw several records set on Good Friday:

* Historically highest solar power generation (10.4 GW), which — together with 5.4 GW of onshore wind generation — brought the total to 15.8 GW of weather-dependent RES;

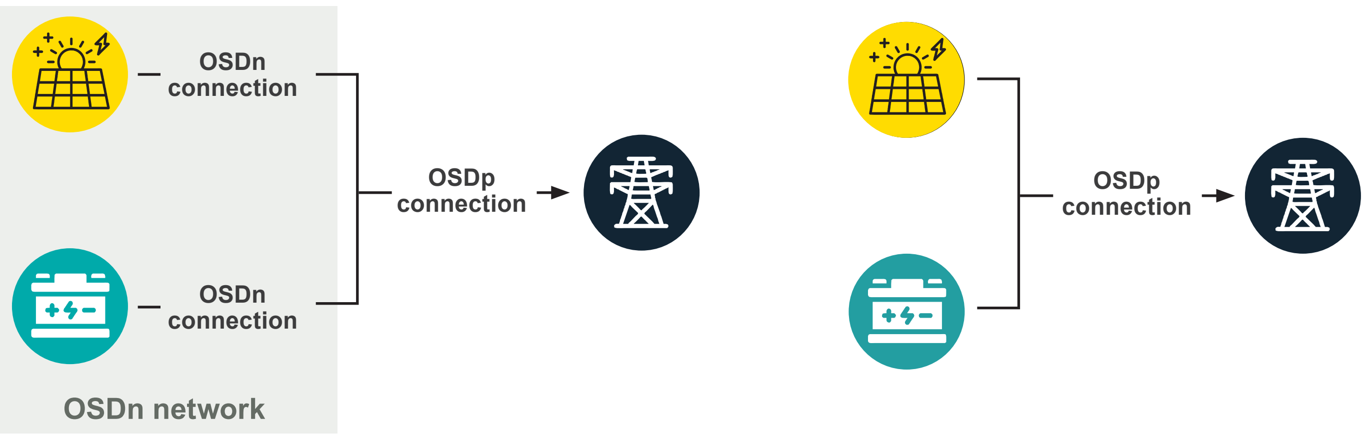
* Historically lowest prices on the Balancing Market (CRO imbalance settlement prices), which reached –PLN 86/MWh.

Source: Instytut Jagielloński

> Due to the new market design for balancing, battery storage investments have become more attractive

In general, the cable-pooling regulation does not apply to co-located battery storage, which does not qualify as a RES installation. The launch of the European balancing platforms MARI and PICASSO will ensure common principles, harmonized products and methodologies for the functioning of balancing markets in Europe, which has long been expected in Poland. These two platforms complete the implementation of the European target market design for balancing, which Poland agreed to implement along with the notification of the capacity market. With the liberalized balancing market, frequency services will also be available for battery storage.

Drawing 33: **Independent DSO network without connection to transmission grid vs cable-pooling**

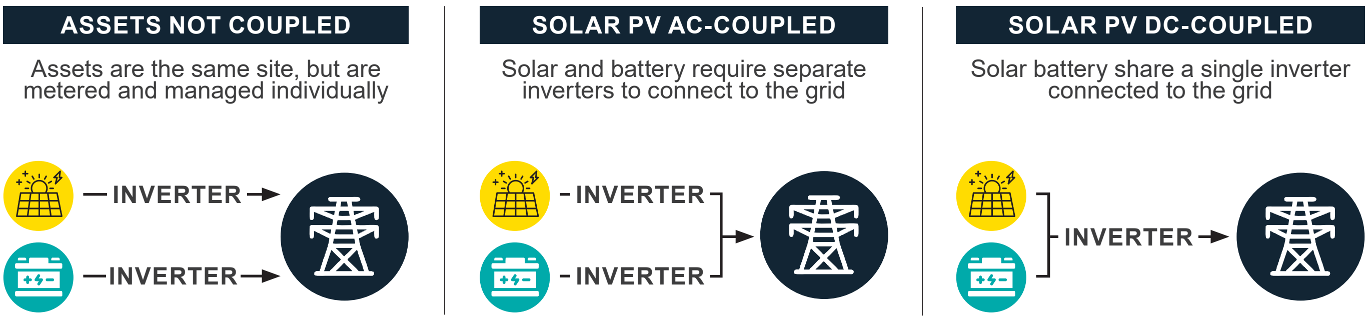


Source: Aurora Energy Research

Different models for co-location of PV and BESS

Combining variable RES with BESS, especially solar PV, can significantly improve the investment case for stand-alone solar PV. Several models for co-location of PV and BESS are possible. Co-location of solar PV generation and storage at the DC level are most advantageous in terms of cost savings by using one DC-AC inverter. However, such an investment model provides regulatory complexity.

Drawing 34: **Technical possibilities for co-location of variable RES and BESS**

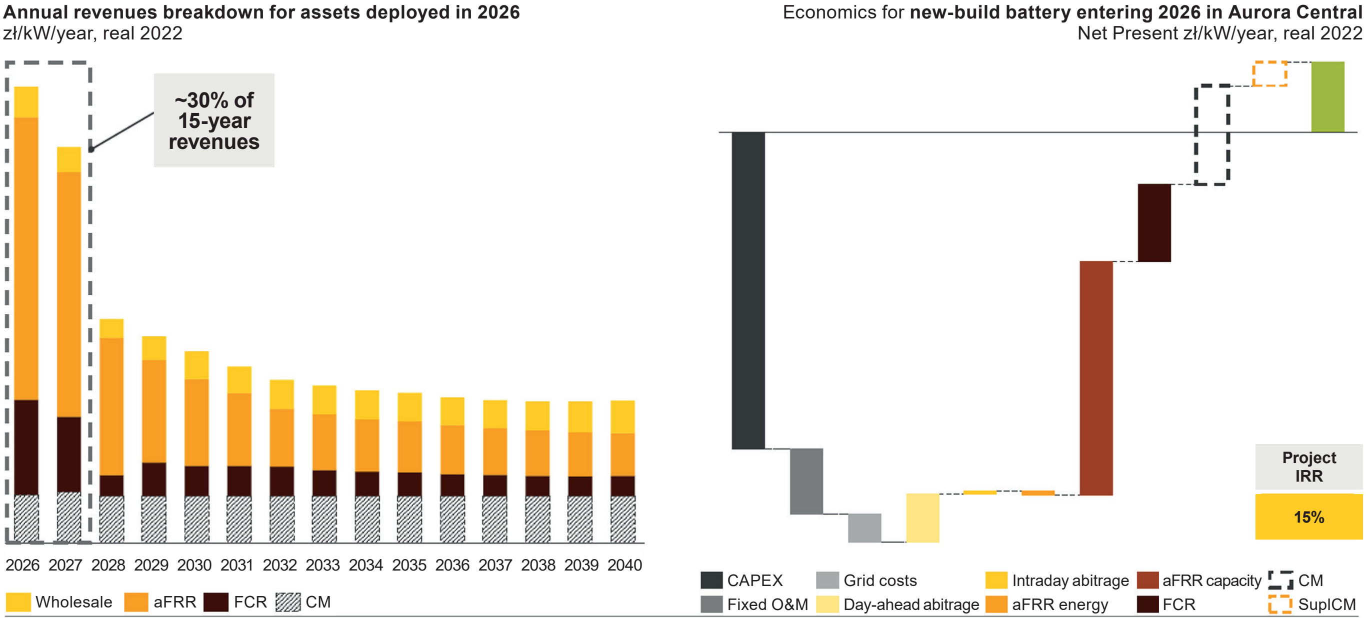


Source: Aurora Energy Research

BESS faces risk of market saturation due to dropping system costs

Like solar PV, stand-alone BESS is subject to certain economic risks. A significant revenue stream for BESS in Poland is the day-ahead arbitrage, but this represents only a small portion of the 15-year revenue. Major income is generated by the aFRR and, to a lesser extent, by the FCR. Furthermore, the main and additional capacity market auctions generate significant revenues. The investment case below, presented by Aurora Energy Research, demonstrates the importance of ancillary system services and capacity market revenues for BESS in Poland. It also illustrates the risk of market saturation due to dropping system costs, a development similar to solar PV after the COVID-19 crisis.

Drawing 35: **Revenues breakdown of stand-alone BESS and expected project IRR for BESS commissioned in 2026**

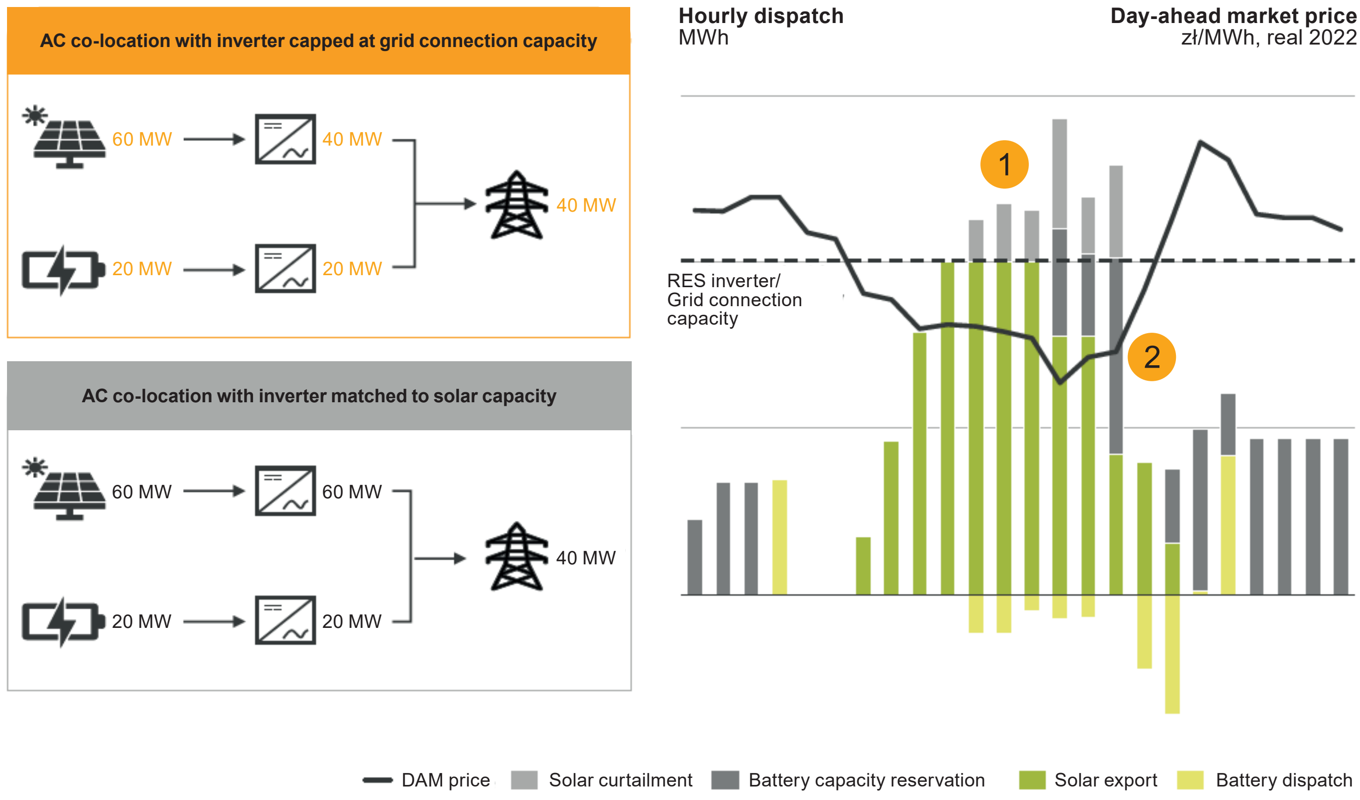


Source: Aurora Energy Research

Co-located BESS and solar PV may increase the attractiveness of stand-alone solar PV

A typical AC co-located setup ensures that the renewable inverter capacity is equal to the export capacity of the grid connection, even if the renewable asset has a larger capacity, which is typical for solar PV. Such a setup has both inverter and grid capacity constraints on dispatch. The spillover generation cannot be captured due to inverter sizing – if inverter would be sized appropriately this would require further investment. Nevertheless, such an investment usually would be NPV negative – spillover energy value is smaller than the cost of bigger inverter. Solar PV is then curtailed to allow the battery to participate in these markets. Co-location allows for reduced grid connection costs because only one connection needs to be built, and it does not need to match the combined asset capacity. In addition, some of the installation and development costs can be saved because co-located assets are built on the same site. OPEX savings for an AC coupled co-located asset are based on a reduction in operations and maintenance costs. However, self-consumption does not offer savings on grid fees in Poland, as separate metering means that assets are metered individually.

Drawing 36: **Co-location of solar PV and BESS and typical dispatch scenario**

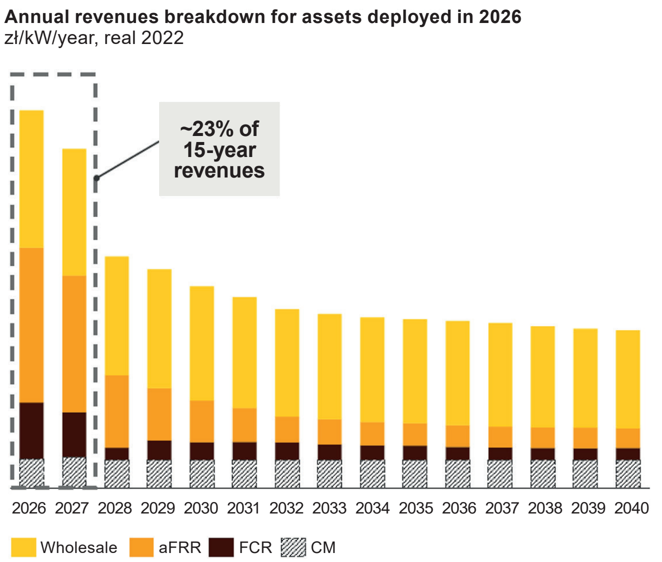


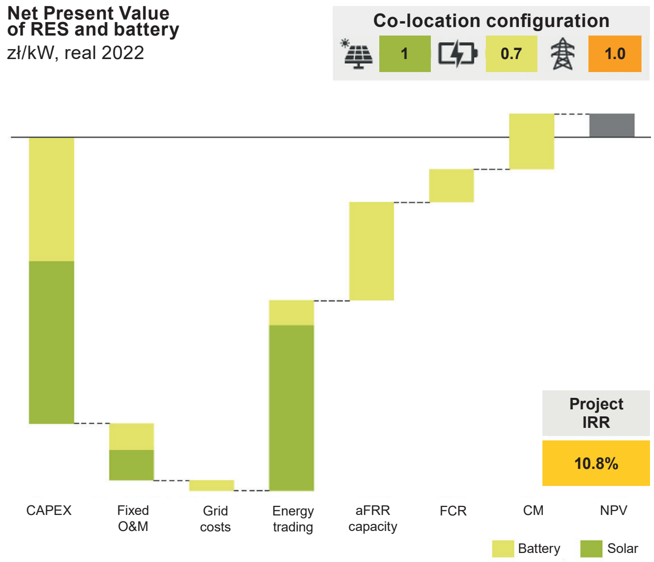
Source: Aurora Energy Research

Co-located assets require proper sizing of BESS, which is significantly different for co-location of BESS and solar PV and co-location of BESS and hybrid assets.

The recent passing of legislation allowing cable-pooling means that co-location can be an effective way to maximize limited grid connection capacity. The current requirement for separate metering points for co-located assets means that only AC-coupled co-location is possible in Poland. Full access to wholesale, balancing and capacity markets is then available. Batteries entering operation by 2026 will generate very high returns. With aFRR and FCR capacity markets saturating by 2030, the value of stand-alone battery investments declines. Stand-alone solar investments are placed on the edge of investability on a fully merchant basis. Adding a co-located battery to a stand-alone solar project entering the market in 2026 can significantly improve its IRR. According to investment models, returns are optimized when up to 0.7 kW of battery capacity is added per 1 kW of solar and grid connection capacity. If a co-located battery is added to a hybird project (onshore wind + PV + BESS), the size of the battery must be significantly smaller to avoid competition with wind generation, and then around 0.2 kW of battery capacity is added per 1 kW of hybrid and grid connected capacity. However, those ratios are very case-dependent. If hybrid ratios (onshore/PV) or any technical data (location, technology etc.) changes, an optimal case may be different. Such optimality can be defined per NPV.

Drawing 37: **Revenues breakdown of co-location solar PV and BESS and expected project IRR when commissioned in 2026**





Source: Aurora Energy Research

5 Regulatory environment for BESS co-location

The co-location of a generation source and a power storage battery system may be a response to the threat of the more frequent implementation of a non-market-based redispatch mechanism by the Transmission System Operator or Distribution Network Operators for RES generation units, in particular for generators whose grid connection/distribution contracts (temporarily) exclude the right to request compensation. In practice, co-location means either connecting an energy storage system to an existing RES generation unit or the commissioning of a unit consisting of a generation unit and a storage unit. Both cases are characterized by a common, shared grid connection point.

Energy storage is a concept defined in EU law, most notably in the wording of Article 2(59) of Directive 2019/944 on common rules for the electricity market, which considers energy storage to be the deferral of the final consumption of electricity within the energy system from the moment of its generation or its transformation into another form of energy, allowing for its storage, the storage of this energy and its subsequent transformation back into electricity or its use in the form of another energy carrier.

In turn, Article 2(60) of Directive 2019/944 defines energy storage as an installation in the energy system where energy storage takes place. These definitions have been fully implemented in the Polish Energy Law Act, where, accordingly, Article 3(59) defines the activity of energy storage, Article 3(10k) defines energy storage as an installation that enables the storage of electricity and its introduction to the electricity grid, and Article 3(10ka) defines energy storage as an installation enabling the storage of energy, including the storage of electricity.

Connection process in the co-location model for RES source and storage

The process of connecting an energy storage facility to the transmission or distribution grid does not generally differ from the process of connecting a pure generation source. An entity applying for connection of a source or energy storage facility to the electricity grid with a rated voltage higher than 1 kV shall pay an advance payment for the grid connection fee in the amount of PLN 30 for each kilowatt of connection capacity specified in the application for the determination of connection conditions. However, the amount of the advance payment may not be higher than the amount of the expected connection fee and may not exceed PLN 3,000,000.

In the case of an existing generating unit, the connection of an energy storage facility to the same connection point requires the issue of separate connection conditions for the storage facility, preceded by an expert opinion on the impact on the power grid. This obligation is based on Article 7(8e) of the Energy Law Act and, in the case of energy storage units, applies to facilities connected to the grid with a voltage of 1 kV or higher and with an installed capacity equal to or greater than 2 MW. It should be noted that a connected energy storage unit is treated as a non-renewable energy source. This has its consequences for the issuance of guarantees of origin for renewable energy, even if the BESS is (partially) sourced from a RES generator.

The co-location of a RES generation source and an energy storage unit at a single point, for which connection to the grid via a single connection point seems to be an economically and practically justified solution, reminds of the institution of cable-pooling introduced into Polish law in the Renewable Energy Sources Act and the Energy Law.

Cable-pooling as a basis for the connection of energy storage

From 1 October 2023, the Energy Law Act, based on Article 7(1f), allows for the connection of two or more renewable energy source installations belonging to one or more entities to a single connection point. According to the new regulation, it is possible to connect one RES source to a connection point to which another RES source is already connected. The sources may be characterized by the same or different energy generation technology and may be owned by different entities. Such a connection is characterized by the fact that a single connection agreement is concluded for the sources connected in this model (cable-pooling). In terms of the ability to connect via cable-pooling, either at the plant design stage or to an existing plant, a distinction can be made between parent cable-pooling and derived cable-pooling.

From the perspective of the process of connecting generating units, including energy storage, to RES generating units for which connection conditions have already been issued or which are already connected to the grid, the legal basis for connection becomes more complicated. Namely, when defining cable-pooling, the legislator overlooked the important circumstance that an energy storage facility that is not a part of a RES installation (not connected to this generation unit), which is yet to be connected to a connected RES generation unit or for which connection conditions have already been issued, is not a renewable energy source installation (RES source) within the meaning of the statutory content of the definition of this concept, as indicated in Article 2(13) of the RES Act and 3(20h) of the Energy Law Act.

For this reason, the submission of a request for connection conditions for an energy storage facility by an interested entity cannot be based on the legally formalized institution of sharing an energy connection point. This significant omission of energy storage from the legislator's cable-pooling framework significantly restricts the possibility of obtaining a connection for energy storage using the same connection point. In case of connection sharing, entities connected to the same connection point based on a single connection contract are obliged to conclude an appropriate agreement specifying all necessary conditions and rules of cooperation of the entities sharing the connection. The agreement is obligatory and its minimum scope is defined by the Act.

Sharing a connection point and covering all units with a single connection agreement means that the installed capacity of the combined units cannot exceed the connection capacity of the connection point. In this respect, the legislator introduces the obligation to install a so-called "power guardian", i.e. a device that physically limits the possibility of feeding into the grid (in the case of simultaneous feeding in of energy from a RES installation and an energy storage device) power exceeding the value of the connection power specified in the connection agreement. Another important element of the agreement between the entities connected under cable-pooling is the assumption of liability by these entities towards the grid operator based on strict liability for the breach of obligations relating to the requirements for the use of a connection caused by the act or omission of any of the generators of the installation connected at that location.

Informal cable-pooling

It should be noted that while in the case of a formalized connection based on cable-pooling, the grid operator cannot effectively refuse to issue connection conditions if the interested entities meet the legal requirements, in particular after they have concluded the necessary agreement, in the case of co-location of an energy storage facility with an existing RES generation facility, the connection of this source entails the risk of refusal to issue connection conditions, most often related to the lack of technical conditions for the connection (the grid operator assumes the simultaneous operation of both generation sources and the injection of energy into the grid).

In practice, despite the lack of a statutory basis for connecting an energy storage facility to an existing connection point based on cable-pooling, energy storage facilities are usually connected to existing RES generation facilities. In such a case, the grid operator may amend the content of the connection conditions for an existing RES generation installation and the grid connection agreement to include the new installation consisting of a RES generation unit and an energy storage unit. In the case of a unit with a capacity equal to or greater than 2 MW, the grid operator requires the submission of an expert report on the impact of the generation unit on the power grid.

A problem that may arise in the process of changing the connection conditions is the possible scope of the said expert report. Despite a valid expert report for the existing RES generation source, it cannot be ruled out that the grid operator may request an additional one for the energy storage unit to be connected within the same connection point. The question arises as to whether the expert report should cover the entire connected installation or whether it should be limited to the newly connected energy storage. These are issues that require legislative intervention, as the current legal situation does not regulate the procedure for connecting energy storage as part of the co-location of RES sources using the same connection point.

The connection of energy storage based on the so-called "informal" cable-pooling is possible only in a scenario where the holder of the title to the storage to be connected is the entity holding the title to the RES installation. In such a case, there is no need to conclude the agreement referred to in Article 7(3de) of the Energy Law Act. This is because it is reserved exclusively for the sharing of the connection point by installations, each of which is defined as a RES installation.

Special status of a generation installation

The connection of an energy storage facility to an existing RES generation facility or the connection of a new generation facility and a storage facility may, in certain cases, result in an increase in the value of the installed capacity to a level that causes the TSO to grant the generator the status of a Significant Network User (SGU).

The powers and responsibilities of the SGU are set out in the Network Code on Emergency and Restoration of Electricity Systems (NC ER). This is an operational code setting out the rules for cooperation between TSOs, DSOs, SGUs, defense providers, restoration providers, balancing providers, balancing service providers, designated electricity market operators and other entities designated to perform market functions in accordance with the Commission Regulation for the defense and restoration processes of the interconnected electricity systems.

The NC ER Code sets out the requirements for the TSO's management of emergency, blackout and system restoration, coordination of the system's operation in an emergency, blackout and system restoration, simulation and testing to ensure reliable, effective and rapid restoration of the interconnected transmission systems.

The President of the ERO, based on the decision of 7 August 2019, will determine that the status of essential generating units (generation modules) for the Reconstruction Plan or the Energy System Defense Plan, are units with a capacity of 50 MW or more.

The SGU status requires compliance with various regulatory obligations and can significantly counteract the negative effects of non-market curtailment and, in emergency situations, the threat of disconnection from the grid. In addition, projects with SGU status may be less likely to be denied connection conditions.

DENTONS

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