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2023 outlook for the Polish Energy Market

Battery storage has become a key technology for the energy transition.

- Planned structure reforms at the EU level
- Power demand
- Conventional generation
- Non-dispatchable renewable generation
- Dispatchable renewable generation
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Introduction

This strategic outlook provides you with our view on how the market will develop in the coming years by identifying the key determining factors that will shape Poland's energy markets until the end of this decade. This includes all market segments—the wholesale markets, balancing and ancillary services markets and finally the capacity market.

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Planned structure reforms at the EU level

Regulatory certainty and stability is required to facilitate a swift and economic energy transition.

The current energy crisis, accelerated by Russia's attack on Ukraine and subsequent restrictions on imports of Russian fuel carriers to Europe, has put European economies under severe strain. This has prompted national governments to intervene in their energy markets— first by imposing numerous measures on the natural gas market. Next, the EU Commission consented to electricity price caps, as transitional measures, until 30 June 2023. Consequently, the Polish government addressed the escalation in electricity prices by imposing price-cap mechanisms to support households, local governments, public institutions and small and medium businesses. While ad-hoc regulatory interventions on energy has mitigated some of the crisis effects, the haphazard way they were applied resulted in uncertainty for investors and financial institutions and ultimately risks delaying the energy transition.

The European Commission's Market Design Proposal aims to improve market resilience and protect business, industry and household consumers.

On March 14, 2023 the Commission published a proposal to improve the electricity market design ("Proposal")[1] expanding on the ongoing Fit-for-55 reform. It emphasizes amendments to the electricity market and renewable energy sources (RES) framework aimed at improving the energy market's resilience to price shocks and competitiveness of businesses and industry and securing social welfare through affordable electricity. Moreover, the proposal promises to drive investment in RES, storage and demand-side response (DSR) solutions through greater focus on forward, long-term hedging instruments and creating demand for flexibility services. Finally, certain aspects of wholesale market transparency are addressed.

No fundamental changes to electricity market design.

Generally, the Commission proposes that a faster deployment of renewable energy and clean flexible technologies constitute the most sustainable and cost-effective way to structurally reduce demand for fossil fuels for electricity generation and dependence on the currently highly volatile variable costs of electricity generation. This, paired with electrification of heating and transport, should shield markets and consumers against power price increases caused by external factors and players.

The Proposal includes very limited crisis management tools for the energy market. They focus on consumer protection, allowing member states to extend access to affordable (i.e., regulated) electricity prices to small and medium enterprises or to temporarily set supply prices for micro-enterprises and households at below cost, with compensation for suppliers.

The Commission would coordinate this crisis response–monitoring the market against sustained high prices and declaring a regional or EU-wide state of market emergency, for a period of up to one year, whenever triggering of those tools becomes necessary. Member states will need to observe several strict cumulative criteria when applying public interventions to electricity prices.

The Proposal does not support claw-back measures targeting windfall profits as a standard market design feature, concentrating instead on long-term measures to reduce price volatility, better integrate renewable supply and encourage demand response to mitigate standard market-price pressures. Nor does it clarify whether the temporary revenue caps for generators and traders (in some countries), currently applicable until June 30, 2023, might be extended. Hence, policy signals arriving from Brussels should be monitored closely. It seems, that a prolongation for six or even 12 months is still being debated, however, Poland's price cap mechanism differentiates from other measures which might be prolonged, e.g. measures in Romania, Spain or France.

1. Amendments to Regulation (EU) 2019/943, Directive (EU) 2019/944, Directive (EU) 2018/2001 (RED 2), as well as Regulation (EU) 1227/2011 (REMIT) and Regulation (EU) 2019/942 (ACER regulation)

Further strengthening short-term and forward markets.

Strengthening intraday power markets remains a key tool for the integration of renewable energy—the Commission is pursuing greater flexibility of intra-day markets and standardized peak-shaving system services. This would ensure surplus renewable generation is efficiently utilized and market access barriers are reduced. Intra-day gate closure times would be further reduced and a lowering of the minimum bid size from 500kW to 100 kW will ensure that small-scale flexibility can participate.

Forward markets should be incentivized to allow suppliers and consumers to hedge against the risk of future volatility in electricity prices. The Commission proposes to achieve that in a number of ways: fine tuning subsidy schemes (the preferred option being two-way contracts for differences), developing corporate power purchase agreement (PPA) markets by promoting guarantee schemes and increasing their availability to a larger pool of consumers, and facilitating access to forward transmission capacities for cross-zonal electricity delivery and price hedging.

Strengthening of (corporate) PPAs.

The Proposal further sets out an intention to strengthen long-term (corporate) power purchase agreements as an efficient hedge against short-term price increases. We endorse the Commission's clear message that market participants should retain the freedom of contracting choice.

Explicitly, the option to combine state-backed CfDs and PPAs is intended and could be rewarded in CfD subsidy tenders, e.g., giving preference to bidders presenting a commitment from a potential buyer to sign a PPA for part of the project's generation. Generally, member states should ensure that instruments in the framework of PPAs to reduce the financial risks associated with offtaker payment default are accessible to companies that face entry barriers to the PPA market and are not in financial difficulty. Appropriate state aid measures, like guarantee schemes, are explicitly permitted by the Proposal.

More measures to promote storage and demand response.

According to the Proposal, network tariffs should incentivize system operators to use flexibility services by further developing innovative solutions to optimize the existing grid and in procuring flexibility services, in particular based on demand-response and storage. Member states should set national objectives for demand-side response and storage, which should also be reflected in their integrated National Energy and Climate Plans. Through this link the Commission intends to allow such projects to better access funds within the Resilience and Recovery Facility, which still utilized to a limited degree by many member states.

Member states that apply a capacity mechanism would be required to promote the participation of demand-side response and storage by introducing additional criteria or features in the design. The Proposal lays out design principles for flexibility support schemes dedicated to DSR and storage.

Furthermore, transmission system operators (TSOs) would be prompted to design standardized, short-term peak-shaving products that remunerate market participants for reducing electricity consumption or use stored energy at peak hours. Interestingly, remunerated peak shaving products focus clearly on shifting the demand curve and would not include ramping up behind-the-meter generation to reduce demand for network supplier electricity.

No material changes to current RES auction support system intended.

Generally, the current RES auction support system guidelines are not expected to see substantial changes. As part of the support schemes for new generation, the Commission is promoting the implementation of two-sided contracts for difference (CfDs) with the respective state counterparty and preventing early termination of participation in the support scheme. This limits design choices—requiring generators to transfer revenue above the agreed strike price to the state counterparty—as opposed to the one-sided CfDs and sliding premium schemes implemented in some member states.

Reserving some electricity for sale through private PPAs could be promoted by beneficiary selection criteria, which the Commission believes would further contribute to the development of power purchase agreement markets. This concept was met with a somewhat cool reception by some market participants, as it would require involving the PPA counterparty, even if indirectly, in the subsidy bid and planning, complicating the overall process.

The proposal does not include amendments to the financial stability clause, protecting existing RES support schemes against changes that would impair the financial viability of projects already benefiting from public support. We therefore believe that there should be no room to impose two-sided contracts for difference on existing projects.

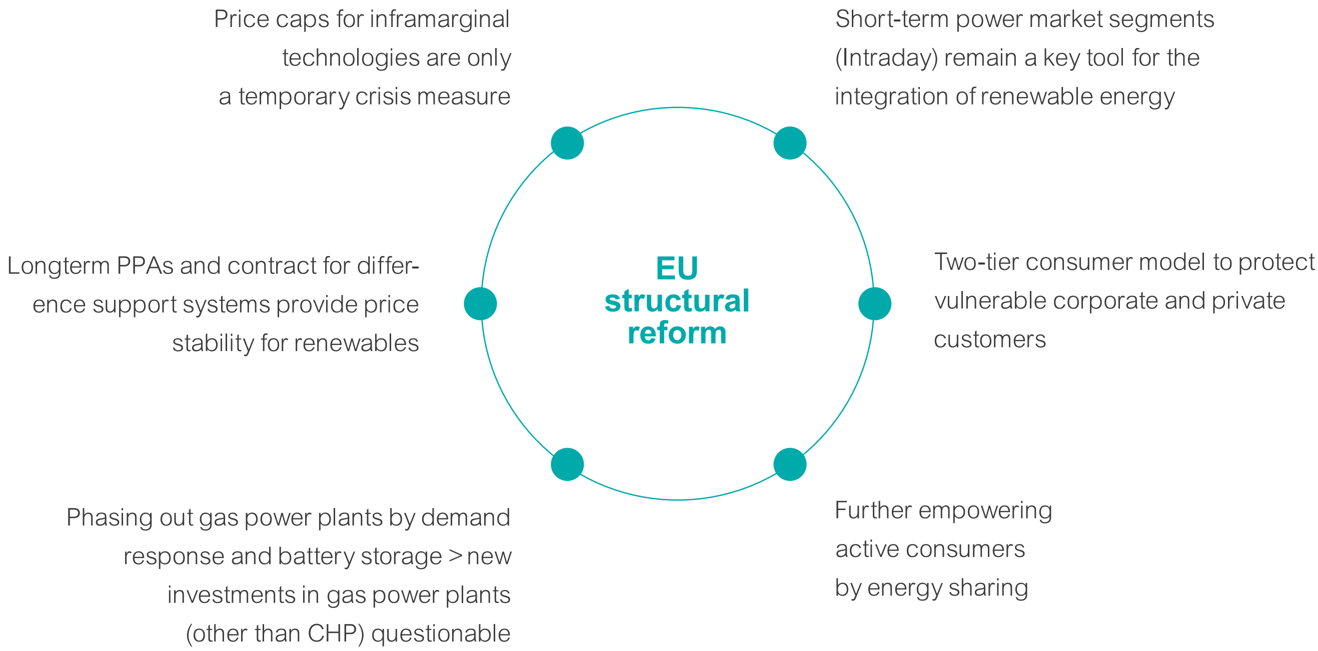
As a novelty, location criteria would need to be considered in future assessments of auction bids. This would ensure that new investments in generation take place in optimal locations and not create or worsen congestion in the grid. More generally, the Proposal highlights the need to reinforce transparency on available grid connection capacity, clarifying how network operators should share that information with the market. However, with structural congestion already giving grounds for concern in numerous jurisdictions, we believe such location criteria could become a useful tool, but only when strongly linked to other measures ensuring greater network flexibility and actual availability of connection capacity that matches the expected rollout of new RES generation investment.

Further empowering active consumers by energy sharing.

The Commission emphasizes that energy sharing will be especially promoted. Active customers that own, lease or rent a storage or generation facility will have the right to share excess production including from 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 within a certain consumption timeframe with renewable energy self-generated or stored by active customers.

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 required 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 with their total metered consumption within the applicable imbalance settlement period (currently in most cases that would be one hour) and without prejudice to applicable taxes and network charges.

GRAPHIC #1: Key elements of the EU structural reform



Implications of new EU rules for the Polish power market

Clarification of Behind-the-meter regulations to be expected soon.

Market participants in Poland will appreciate a number of clarifying rules that should strengthen their position when dealing with prevailing market hurdles, especially regarding admissibility of behind-the-meter supply by RES generators. However, legislative proposals are still pending at the governmental level.

Modification of the capacity market design.

Due to increasing concerns about dispatchable capacity, we expect the Polish capacity mechanism to soon be modified to promote the participation of storage through the introduction of additional features to the current design, mainly by shortening the requirement to deliver capacity.

Revenues from ancillary services may exceed capacity market revenue.

Furthermore, the ancillary services market will be strengthened as already envisaged in the new balancing services regulation proposal published by the Polish TSO. The ancillary services market can be divided into two types of service offerings: energy and capacity Balancing energy will help to match up demand and supply of electricity, while capacity will support various types of reserves required to maintain network parameters (FCR – Frequency Containment Reserve, FRR – Frequency Restoration Reserve, RR – Replacement Reserve) -all matching the ancillary services standards harmonized at the level of EU network codes. Finally, the TSO will procure operating reserve (activation time of up to 30 minutes).

The balancing market reform will pave the way to the future peak-shaving and flexibility services, providing a better, more transparent structure of revenue streams.

As an example, Ireland—which currently generates about 43 percent of total electricity from intermittent renewables, primarily wind—has an 80 percent target for electricity generation from intermittent renewables by 2030. According to the local TSO, the revenue pool for variable cost components of energy (ancillary services) is expected to substantially exceed capacity market revenues, to a large extent driven by less energy from conventional fossil-based power plants. Poland, which has awarded expensive capacity payments to its aging coal fleet since 2021, will soon change its approach to the capacity market once its coal fleet is decommissioned from 2026 onwards. Accordingly, operational efficiency and ancillary services will play a greater role in ensuring a stable supply of electricity to consumers.

GRAPHIC #2: Main takeaways for Poland

More RES, also from the perspective of localizations, provides higher volatility in power market prices.

Promotion of shortterm (intraday) wholesale markets.

Explicit endorsement for battery storage and DSR assets in the capacity market mechanism.

Defining a national objective for non-fossil flexibility will be reflected in the National Energy and Climate Plan.

Sector coupling and energy efficiency as key drivers for an electrified zero-emissions economy

The EU's key energy sector strategy remained unchanged during the recent energy market crisis, and good progress has been made in the gradual enactment of the Fit for 55 legislation package. The new EU Emissions Trading System (ETS) measures will further speed up the transition to a zero-carbon-emissions economy.

Sector coupling and energy efficiency measures are the two pillars of the zero-carbon economy.

The EU's zero-carbon strategy is based on two main pillars:

(1) electrification of the heat and transportation energy sectors (so-called "sector coupling") and (2) energy efficiency measures. Only a combination of both strategies can lead to a zero-carbon industry. According to the International Energy Agency (IEA), between 2021 and 2030, despite the global economy growing by nearly a third, total final energy consumption will fall by 9 percent.

E-mobility and heat pumps are more effective than production renewable hydrogen production, which will still be needed to decarbonize all industry sectors.

With sector coupling, primary measures are related to direct electrification, i.e. e-mobility and heat generation by heat pumps, whereas indirect electrification measures, such as renewable hydrogen production by electrolysis powered by renewable energy, are less effective. Therefore, renewable hydrogen is mainly required in industries where direct electrification is not a practicable approach, e.g. high temperature heat for industrial processes in the chemical sector, long-distance aviation or shipping. The main cost component for renewable hydrogen production is the cost of power generation paired with substantial volumes of required in those sectors. Therefore, utility- scale solar PV installations in Southern Europe or North Africa and large onshore or offshore wind farms in Northern Europe with surplus energy will have a competitive advantage.

Biofuels are a short term alternative fuel, but burning wood biomass is less sustainable than methanization of agricultural biomass.

Biofuels remain an alternative for renewable hydrogen. However, biofuels require proof of sustainability—wood biomass may have its problems to prove sustainability as burning wood biomass is harmful to short-term climate change and has an impact on air quality. Therefore, in the EU's main economies biomethane is favored against burning wood biomass. In Germany and France many biogas plants are currently being refurbished for producing biomethane. This could replace natural gas in existing applications without the adjustments required for hydrogen use.

ETS reform is underway: (I) the ETS will cover waste incineration, (I) member states will spend their ETS income on climate action, (iii) free ETS permits will be phased out by 2034, (iv) ETS2 will be implemented for fossil fuels used in road transportation, for heating buildings, and for vulnerable households that obtain support from Social Climate Funds for investments in zero-emission technologies.

The ultimate flagship measure to drive demand for zero-carbon energy is the European Emissions Trading System (ETS). Reforming the ETS was selected as key to achieving the goal of reducing by 55 percent the CO_2 emissions by 2030 from 1990 levels. At the end of April 2023 member states adopted five laws adjusting and expanding the carbon pricing framework.

Power generators and heavy industrial polluters covered by the ETS will have to curb their pollution by 62 percent by the end of this decade compared with 2005 levels, a significant increase on the current 43 percent target, while withdrawal of allowances from the market will accelerate towards 2030. Alongside this, free emissions certificates will be cut in half by 2030 and totally phased out by 2034.

Waste will be covered by the ETS scheme from 2028, with potential derogations until 2030. This will make waste incineration very expensive. The shipping sector will be a new sector to be covered by the ETS scheme, while a separate dedicated ETS 2 system will launch to cover heating buildings and the road transport and fuel sectors. This second scheme will cover fossil fuels used in road transportation and heating buildings from 2027 or latest in 2028 if natural gas prices remain high. In a bid to prevent social discontent and rising energy bills, this new ETS 2 carbon price will be capped at 45 per tonne.

The Carbon Border Adjustment Mechanism addresses competition between certain parts of European industry—production of cement, aluminum, fertilizers, electric energy, iron and steel—against imports and suppliers from third countries with lower environmental standards. From 2026, this EU border tariff will mirror the price on the EU's own carbon market for respective imports.

In the future, all revenues generated by the ETS will be spent on climate action. A Social Climate Fund of up to 65 billion will support vulnerable households from 2026 until 2032 to invest in zero-emission technologies and may be expanded by contributions from member states.

Clean energy technology manufacturing becomes a major industry

According to the IEA, renewables, power grids and energy storage in 2022 accounted for more than 80 percent of the nearly US$1 trillion of total power sector investment. Clean energy technology manufacturing is becoming a leading industry sector in Europe and worldwide, worth around US$650 billion a year by 2030—more than three times today's level. The IEA predicts that jobs in related clean-energy manufacturing should more than double from 6 million today to nearly 14 million by 2030, with over half of these jobs tied to electric vehicles, solar PV industry, wind energy industry and heat pumps.

The global energy crisis accelerated investments. By 2030 every US$1 spent on fossil fuels will be outmatched by US$5 on clean energy supply and another US$4 on efficiency, but international efforts are required to step up climate finance.

A new global energy economy is emerging with the rapid growth of solar, wind, electric vehicles and a range of other technologies, such as battery storage, heat pumps and electrolyzers for hydrogen. The IEA forecasts in its 2022 World Energy Outlook that the yearly investments in clean energy technology could as much as triple by 2030. The 2050 net zero emissions scenario predicts that by 2030 every US$1 spent on fossil fuels will be outmatched by US$5 spent on clean energy supply and another US$4 on efficiency. The major economies in the world are currently expanding their clean energy technology manufacturing to advance net zero transitions, to strengthen energy security and to be competitive.

The current global energy crisis has significantly accelerated these efforts, a good example is the US Inflation Reduction Act. According to the IEA, "global lowemissions hydrogen production rises from very low levels today to reach over 30 million tonnes (Mt) per year in 2030, equivalent to over 100 bcm of natural gas (although not all lowemissions hydrogen would replace natural gas)." The forecasted international renewable hydrogen production for 2030 exceeds five times the actual annual demand of Poland for natural gas. However, today's rising borrowing costs could exacerbate the financing challenges facing such projects, despite their favorable underlying costs, so international effort is needed to step up climate finance. The EU will provide appropriate programs to facilitate climate finance.

Poland urgently requires a coherent industry strategy for clean energy manufacturing.

However, for a country like Poland it is not realistic to try to compete across all parts of clean energy technology manufacturing and its supply chains. Each country will need to play to their strengths, whether that comes in the form of mineral resources, like rare earth elements; production of materials, like lithium, copper, nickel, steel, cement, aluminum and plastics; low-cost clean energy supplies, thanks to solar irradiation or wind speed; a workforce with relevant skills, or synergies with existing industries. A coherent industry strategy is required for Poland to focus on its strengths. According to the IEA, "Industrial strategies for clean energy technology manufacturing require an all-of-government approach, closely coordinating climate and energy security imperatives with economic opportunities. This will mean identifying and fostering domestic competitive advantages; carrying out comprehensive risk assessments of supply chains; reducing permitting times, including for large infrastructure projects; mobilising investment and financing for key supply chain elements; developing workforce skills in anticipation of future needs; and accelerating innovation in early-stage technologies." Innovation is key as, according to the IEA, "half of the emissions reductions in 2050 come from technologies at prototype or demonstration stages today."

New EU targets for renewable energy

At the end of March 2023, representatives of the Council of Europe and the European Parliament reached a conditional agreement on the revision of the Renewable Energy Directive (RED III)—one of the key elements of the Fit for 55 package.

The binding RES target for 2030 has been increased.

The agreement raises the binding target for the share of RES in final energy consumption to 42.5 percent from 2030, up from 32 percent in the 2018 directive (RED II). The initial draft had set a target of 40 percent, but after Russia's invasion of Ukraine, the Commission proposed raising it to 45 percent, with the European Parliament agreeing to its position. However, the conditional agreement identified 45 percent as a desirable but nonbinding target. Eurostat data indicates that in 2021 the average share of RES in final consumption in the Union was 21.8 percent and in Poland 15.6 percent. With the current high capital expenditure and financing costs, member states will have to urgently simplify permitting procedures for RES, by giving it the status of an investment in the overarching public interest, to meet the 2030 targets. Additionally, energy efficiency measures will have to speed up to substantially decrease overall energy demand, although the implementation of sector coupling generally increases power demand.

Ambitious targets have been set for renewable hydrogen production.

Hydrogen generation is a key strategy of the EU, including nuclear-generated hydrogen. However, nuclear-generated hydrogen will only count as part of the RES share once the country has reached the 42.5 percent target. Of the EU countries with nuclear power, only Sweden and Finland had hit his target in 2021. RED III is expected to implement specific targets for those industry sectors that were not addressed in previous directives; an increase of 1.6 percent per year of RES in final consumption is mandatory.

By 2030, 42 percent of hydrogen produced for industrial use is to be made up of the so-called non-biological renewable fuels (RFNBO), as further defined by delegated acts. The target for 2035 is 60 percent. However, if a country meets its contribution to the overarching EU RES target, some exceptions for member states producing its hydrogen from nuclear have been implemented.

RES targets in the transportation sector require a larger share of advanced biofuels and RFNBOs.

In terms of RES targets for transportation, each member state will be able to choose a specific transport target for 2030, i.e. to decarbonize its transportation sector by 13.0 percent or, alternatively, to increase the share of RES in the transportation sector's final consumption to 29 percent, from the 2021 EU average (EUROSTAT) of 9.1 percent. Poland's share of RES in the transportation sector amounted to 5.6 percent. The conditional agreement furthermore sets a binding combined target of 5.5 percent for the share of advanced biofuels and RFNBOs (Renewable Fuels of Non-Biological Origin) in renewable energy supplied to the sector from 2030.

The conditional agreement also sets a nonbinding target of increasing the share of RES in final consumption by building, heating and cooling to 49 percent in 2030, from the current 22.9 percent (2021 EU average EUROSTAT) and 21 percent for Poland, including a large statistical share of individual wood biomass firing. The share of RES should increase by 1.1 percent per year until 2030.

Increased targets for building, heating and cooling are realistic only if wood biomass firing figures in the RES share.

The conditional agreement also sets a nonbinding target of increasing the share of RES in final consumption by building, heating and cooling to 49 percent in 2030, from the current 22.9 percent (2021 EU average EUROSTAT) and 21 percent for Poland, including a large statistical share of individual wood biomass firing. The share of RES should increase by 1.1 percent per year until 2030.

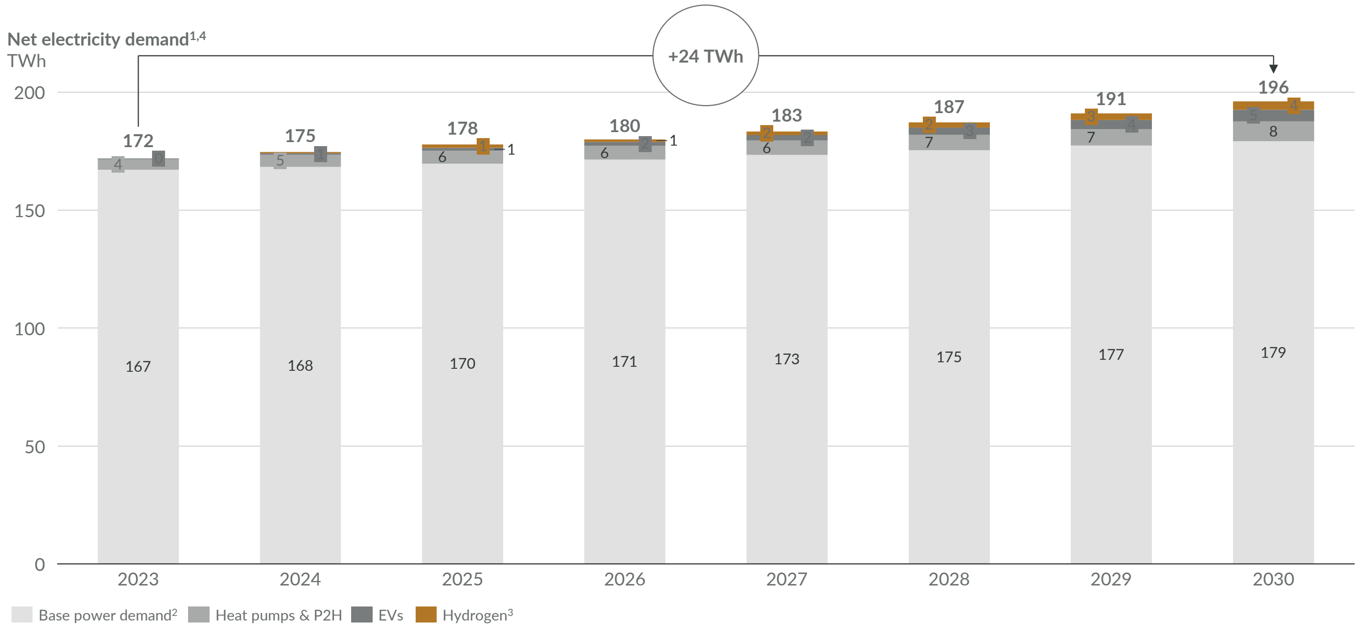
Power demand

With a net electricity demand of 169 TWh in 2022[2] (without losses), Poland is the seventh biggest consumer of electricity in the European Union. Compared with other European countries, demand from the services sector is relatively large, at the expense of residential demand. Demand growth over the last few years was almost linear at 1.45 percent p.a., except for a slight decrease due to the financial crisis in 2009 and the COVID-19 crisis. It is expected that over the coming years Poland will continue increasing its power demand at a comparable rate of 1.35 percent p.a., reaching 196 TWh by 2030. Moreover, the structure of demand will start to change as we will see new sources of demand, such as heat pumps, electric vehicles and also renewable hydrogen production.

[2] Not accounting for transmission and distribution losses.

GRAPHIC #3: Power demand over the coming decade

Power demand is expected to rise by 24 TWh by 2030 due to continued electrification of industrial activity, heat and transport.



1) Total net electricity demand includes sectoral demand as well as transmission losses, but excludes power plant self-consumption and demand from efficiency losses of storage; 2) Underlying demand excluding heat pumps and EVs; 3) Demand for hydrogen production from electrolysis; 4) GDP between 2023 and 2060 is expected to growth at the 1.47% p.a. on average (CAGR)
Sources: Aurora Energy Research

Macroeconomic assumptions

GDP growth of 2.6 percent p.a. until the end of this decade.

The main driver of increasing demand is strong GDP growth expectation over the coming decades, partially counteracted by efficiency gains that will decouple electricity demand from GDP. The IMF and Oxford Economics outlooks expect GDP growth to continue in Poland to 2050—approx. 1.6 percent p.a. on average (CAGR) in 2023–2050, with almost 2.6 percent p.a. until end of this decade.

Electrification of transportation

Combined demand of both personal and heavy electric vehicles can reach up to 5 TWh by 2030.

We expect electric vehicle (EV) sales to ramp up and dominate the market by late 2020. We predict the combined demand of both personal and heavy electric vehicles can reach as much as 5 TWh by 2030. In the long view, the EV sector is expected to develop even faster. Prioritizing the deployment of infrastructure allowing for smart EV that could charge flexibly can be of great benefit to the power system and minimize the impact of additional demand. Besides providing flexibility sought for system management it also decreases the overall cost for end-consumers for charging their vehicles. Nevertheless, to achieve a high share of smart charging, regulatory interventions are required, in the form of dedicated tariffs and improvements to the EV charging infrastructure.

The electrification of transportation may face issues related to grid congestion as deployment of chargers, especially fast utility scale ones will put a strain on distribution system operators (DSOs).

Electrification of individual heating

Individual heat pumps in 2030 would require approx. 9 TWh electricity to operate.

Most buildings in Poland were built before 1988. Those could be subject to thermo-modernization, which could be part of a bigger energy efficiency improvement effort. Poland undertook to improve its energy efficiency and achieve a reduction of 23 percent in terms of primary energy consumption relative to the EU Commission's primary energy prognosis from 2007. The Polish Energy Policy towards 2040 (PEP2040) states increasing household energy efficiency is one of the key components for improving the overall situation but sets no exact official targets.

We consider renovations and construction of new buildings to be the main driver of heat pump adoption. We expect the adoption rate to rise to 45 percent of new buildings and 27 percent of those renovated by 2030. At that rate, by 2030 heat pumps in Poland would require approx. 9 TWh of electricity to operate. On the 2030 horizon we see little to no potential for flexible heat pump operations - in the short term those will be more constrained by reacting to the actual, local heat demand. Different technical solutions allowing for increased flexibility of operation of domestic heat assets already exist. To be effectively introduced they should be recognized and addressed with appropriate policies and a support scheme.

Electrification of district heating

A 19 percent share of power for heating in district heat production is expected by 2030, but due to heat demand being covered by gas CHP; this will be followed by only incremental growth until 2040.

Around 60 TWh of heat is produced in cogeneration annually in Poland, by industrial plants and district producers. We expect this to drop by around 7.5 percent until 2030, as efficiency gains are largely balanced by the connection of new customers. The district heating system offers an effective way to centralize the decarbonization of heating but faces high demand for new investments in a challenging revenue environment with high ETS prices and strictly regulated heating tariffs.

Our assumptions are consistent with the view of the governmental Polish Strategy for District Heating, which expects district heat demand to rise from 247 PJ to 255 PJ between 2020 and 2030. The strategy sees a 19 percent share of power to heat (PtH) in district heat production by 2030, but this will be difficult to achieve given the technology maturity and investment capacity of district heating operators. Nonetheless, PtH remains one of the most viable options for the decarbonization of district heating, alongside wood biomass and coal to gas to hydrogen switching, but this is hardly bankable.

Enabling the uptake of PtH in district heating will require significant policy intervention over the next decade. High-efficiency, low-temperature systems are needed to enable the integration of heat pumps and sufficient incentives need to be provided to enable such capital-intensive investments.

Our view on large-scale heat pump demand in 2030 is rather conservative, with small uptake expected before 2040. The reason for this is twofold. First, large-scale heat pumps remain an expensive technology. Secondly, such heat pumps would form a part of larger systems with multiple heat sources connected, dispatching on a competitive basis. Low renewable penetration means wholesale prices are likely to remain high on the 2030 horizon, while ETS prices are still low enough to make dispatch against gas CHPs uncompetitive. It is therefore only later on, once more low-price hours occur and the cost of generating heat from alternative sources is higher, that heat pumps could play a significant role in the district heating system.

Renewable hydrogen

Hydrogen electrolysis needs could result in 1 TWh of additional power demand by 2030.

Published in November 2021, the National Hydrogen Strategy assumes a couple of milestones related to hydrogen production. It foresees 50 MW and 2000 MW in 2025 and 2030 respectively of low-emission hydrogen production facilities, with specific demand driven by public transport vehicles. It is not specified that those will necessarily be renewable hydrogen sources but they must qualify as low carbon ones.

We expect that development of hydrogen electrolyzers might start in the late 2020s. Achieving a total installed capacity of 1 GW of electrolyzers would require concrete policy mechanisms and long-term planning. To ensure renewable hydrogen production development, it is important to resolve barriers currently slowing down the development of RES. Hydrogen electrolyzers could benefit from cheap RES energy and, in return, compensate intermittency of those by providing much-needed flexibility to the power system. As such, hydrogen electrolysis needs could result in 1 TWh of additional power demand in 2030.

Power system

The Polish power sector will face an accelerating energy transition within the next 10 years. The dominant role of coal and lignite for power generation will diminish in the coming years and is expected to collapse after 2030. Stabilizing gas prices and high prices for emissions certificates increase the competitiveness of gas plants in the merit order, and soon new units that have been awarded in the capacity market will be commissioned. However, it will be challenging to build the full capacity of gas plants awarded by the recent capacity market auctions, mainly due to bankability issues and systemic undersupply of natural gas. Since most gas-fired projects are planned as CHP units, those problems will not allow to fully replace coal as the dominant heat supplier either, grid operators are urged to implement most effective demand-side management by digitalization and AI to use the demand-side potential of various solutions.

Nuclear as an element of the Polish energy mix will most likely come too late in the discussed timeframe to play a role in the energy mix, which should become carbon neutral between 2045 and 2050. Regular third-generation nuclear power plants face a recurring financial model challenge, and new, small modular reactors will first have to be commissioned in the EU, which arguably could extend into the 2030s. Therefore, renewables and flexibility services remain the key answer to the zero-emission scenario. Wind and solar generation will grow rapidly. Additionally, battery storage will stabilize the national energy system benefiting from capacity market auctions and revenues from ancillary services. Both, renewables and gas plants will squeeze coal out of the generation mix very soon.

Conventional generation

Coal

Historic co-dependency of the coal mining sector and the domestic power sector will soon end.

Electricity production from coal, both lignite and hard coal, is the backbone of the Polish power sector with almost three-quarters of electricity still being produced by those plants (as of 2022, data from energy research firm Agencja Rynku Energii). Moreover, coal is also broadly used in other sectors as a source of energy, mostly for heating purposes in households. This translates to 52.8 million tonnes extracted domestically (as of 2022, ARP). Historically, Poland has very much depended on the domestic coal production sector, which itself was quite electricity intensive. Starting in the 1950s, Poland started expanding its mining sector, which was then intended mainly for export. In the following years, the country became a major exporter of hard coal, with an average of 19 percent of total world exports in the 1966–1978. A power generation plant fleet was built to cover rising electricity consumption of the mining sector. During the transformation period in the 1990s, exports started to decline and reached negative values (net imports to Poland) in 2017. The legacy of that co-dependency of the coal mining sector and the domestic power sector is the dominance of coal as a fuel in Polish power generation and fierce social opposition to a coal phase-out for those who are employed in the mining sector. Domestic coal production rapidly declined due to aging reserves and years of underinvestment in the sector; by 2022 country faced coal shortages and has struggled to secure replacement from abroad, regardless of seaborne imports surging over 15 times in 2022 to more than 6.7 million tonnes.

Methane emissions will be penalized and make Polish coal mining unprofitable, at the latest from 2031.

It's worth mentioning that Poland is the largest emitter of methane gas in the EU, with 90 percent coming from coal mining. In 2021, mines officially emitted more that 426,000 tonnes of methane, an increase from 321,000 tonnes in 2011. In 2016, methane emissions hit an all-time high of 522,000 tonnes, which has been decreasing ever since.

Coal mining will soon become unprofitable, thanks to limits on uncontrolled methane emissions at the EU level, to be implemented until the early 2030s; however, a few coal mines will be still used to exploit methane commercially, e.g. the coal mine located in Brzeszcze in Lesser Poland voivodship. According to the Ministry of Climate and Environment (MKi), the revised methane regulation, which is currently in the trilogue, is a threat for the coal mining sector. It assumes that from 2027, coal mines will be allowed to emit no more than five tonnes of methane per 1,000 tonnes of extracted non-coking coal, and from 2031 a maximum of three tonnes of methane. At that time, however, the extraction of coking coal will also count towards the limit—currently, coking coal mines owned by the national giant JSW S.A. are responsible for approximately 50 percent of yearly methane gas emissions. From 2025, the burning of methane from mine demethylation stations will be banned in the EU. These requirements are currently unattainable for Polish plants (the largest Polish coal mining conglomerate PGG S.A. alone emits on average eight to 14 tonnes of methane per 1,000 tonnes mined coal), which will face penalties for exceeding them—PGG's management estimates that penalties amount to approximately 1.5 billion PLN a year.

Thermal coal quality is a challenge for both, state-of-the-art fluid boilers and emission filters and new BREF for large-combustion plans will require a shutdown by latest 2031.

For the last two decades Poland has been facing shrinking resources of good quality thermal coal. Relatively high ash and sulfur content are a challenge for state-of-the-art pulverized coal-firing boilers and also for emission filters, as the current technical issues with the new Jaworzno 910 MW coal-fired boiler shows. Polish power and heat plants recently became more dependent on good quality thermal coal imports from Russia, which peaked in 2021 at a share of 87.7 percent of all coal imports amounting to almost 6 million tonnes. Russia's attack on Ukraine and the subsequent ban of imports of Russian thermal coal forced coal importers to find other markets, but coal imports from overseas are often of different (and inferior) quality and therefore were not able to replace different sorts of Russian thermal coal to which the Polish power plant fleet has been technically adopted.

Additionally, new requirements regarding SO2, NOx and dust emissions from power plants in the EU were adopted in 2017 and implemented by member state authorities by 2021. Necessary investments in new emission filters were financed in Poland by five-year capacity market contracts for coal and lignite power plants, which expire in 2025 and 2028, respectively. By 2030, the requirements are projected to lead to emission reductions of 66 percent to 91 percent for SO2, 56 percent to 82 percent for dust and 51 percent to 79 percent for NOx, compared with 2016 reported emissions. By the early 2030s, revised BAT guidelines are expected to enter into force.

The current capacity of 27 GW might drop to 5 GW by 2030.

Coal power plants currently constitute the bulk of the Polish power system, with an installed capacity of approximately 27 GW, which translates to 68 percent of total installed capacity and around 70 percent of power generation in 2022. We expect operating capacity to drop to a little more than 5 GW by 2030, with only the newest coal plants (erected within the last few years) and a few CHP plants to remain in the power system, thereby creating a substantial capacity gap. This expected exit of 21 GW of plants from the power system is predominantly a consequence of unfavorable economics when those units cease to participate in the capacity market at the end of 2025 and 2028.

Gas plants will again push coal plants out of the merit order.

The temporary favorable situation of coal generation in the Polish energy market (and in Europe in general) is an effect of the energy crisis roaring across Europe, which has lead to a gas-to-coal switch in most markets—gas prices rose much more substantially than coal prices, leading to coal plants being the cheaper energy source. Nevertheless, we expect this situation to be short lived, with a rebalancing in commodity price, supported by additional gas market regulation. Increased investment globally in LNG infrastructure will drive prices down, and continued support for decarbonization policy will keep carbon prices high, with 100/t CO_2 or more for years to come. High variable costs for coal plants, higher than most gas plants, and subsequent low utilization of these units will lead to them dropping to the bottom of the energy market's merit order. To put it even more simply, gas units, renewables and competitive power imports are expected to become cheaper than coal plants, effectively cutting most of the revenues of these plants.

Lignite

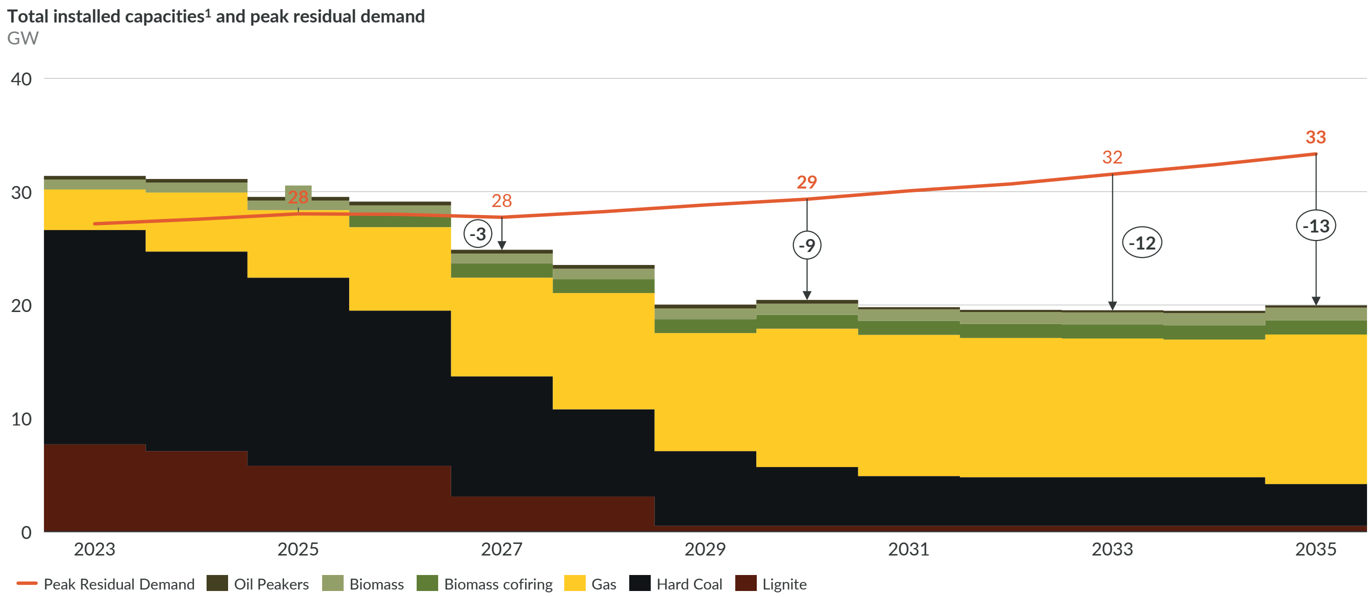
The new Dolna Odra CCGT is more competitive than the Bechatów lignite plant. The economics of existing coal and lignite plants is very challenging.

While the situation for hard coal plants is more difficult, given higher variable costs of fuel, lignite plants will also face serious issues with utilization. With gas prices dropping by 2026 to around 160 PLN/MWh and carbon prices at the level of 100/t it will be substantially cheaper to produce electricity in the new Dolna Odra gas power plant (CCGT), than in the highly emissive Bechatów lignite plant. The technical aspect also plays an important role, as the majority of this fleet was erected in the mid-'80s and are now coming to the end of their lifetimes. This necessitates refurbishment in the coming years just to be able to continue operation, not to mention a prolongation of lifetime. Upcoming BREF (BAT reference documents) requirements also add a significant challenge, most likely with more stringent conditions for generation for coal plants, forcing further investment into emission control equipment. Worth noting, the previous BREF implementation in 2016 was already a strain for the Polish power sector and one of the reasons behind the introduction of the capacity market.

All this, combined with the rules affecting the Polish capacity market— banning new contracts for units emitting more than 550 g/kWh—makes the economics of existing coal and lignite plants very challenging.

GRAPHIC #4: Installed and planned capacities and peak residual demand

Peak residual demand rises to 33 GW as demand increases; new capacities are required to ensure security of supply



1) Units that are either in operation already, or in development phase with won capacity market contracts

Sources: Aurora Energy Research

CHP and biomass

The challenges described above have a predominant impact on electricity-focused powerplants, but unfavorable economics affect older units in worse technical state even more severely. In Poland those are mostly CHP units providing heat for district systems and industrial facilities. These units have repeatedly struggled to gain any profitability over the last years, and companies other than large utilities owning major CHP plants in larger cities, such as PGE Energia Ciepa, PGNiG Termika (member of Orlen group) or Veolia, have limited financial possibilities to transform into different fuel systems. One of the ways to potentially increase the lifetime of CHP plants, and improve their economics, which we've seen in the last capacity auctions, was biomass firing, especially due to the aforementioned 550 g/kWh rule on the capacity market. Poaniec power plant (owned by ENEA) secured its first contracts for biomass co-firing for 2026, after exiting the green certificate system, and in the most recent auction for 2027 additional co-firing units in Ostroka and Biaystok secured capacity contracts. Capacity market payments might help extend the lifetime through some modernization and can alleviate (for a few years) the capacity shortage issue. Nevertheless, such payments will not solve long-term concerns around the supply of wood biomass, which is under observation at the EU level due to its carbon footprint and air pollution.

Natural gas

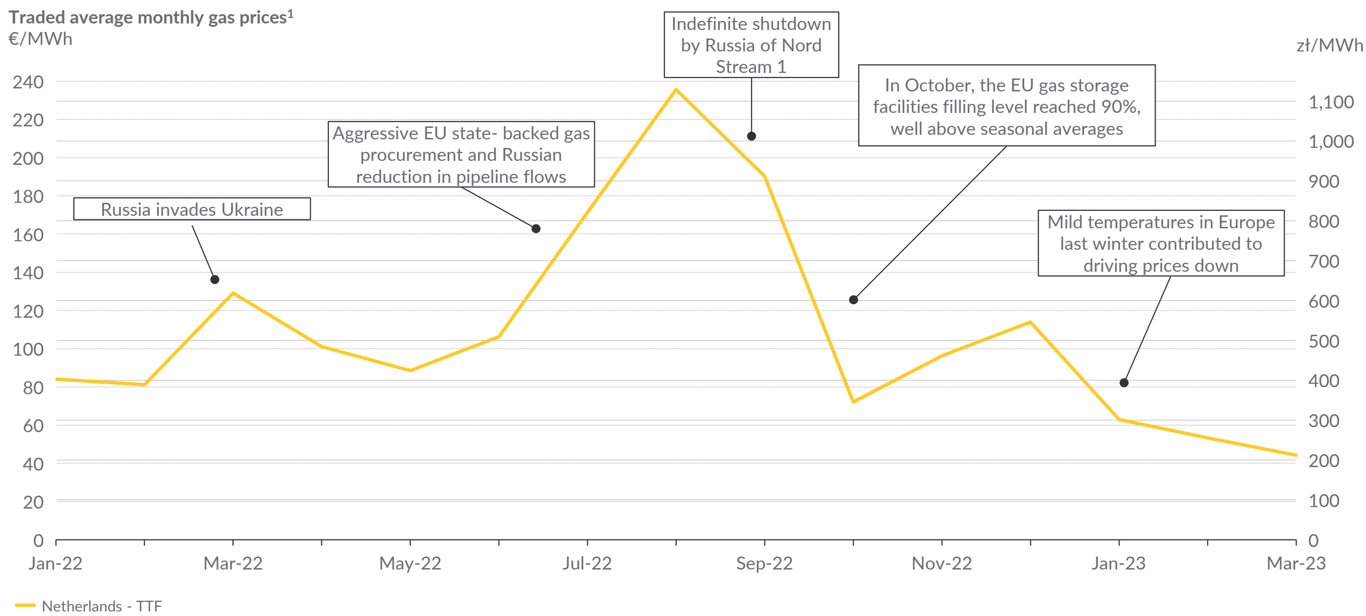
Overinvestment into gas plants is one of the reasons for the current crisis.

Over the last decades it was widely believed that natural gas would have a significant role in the decarbonization efforts across Europe as a transitional fuel on the path to carbon neutrality. In first two decades of the 21st century, we've seen significant investment across Europe into gas assets, predominantly CCGTs, seemingly the foundation of power systems, whose role was to serve as baseload capacities and to provide the flexibility needed for high renewables penetration. This approach, in the face of Russia's war against Ukraine and the pan-European energy crisis, allowed external factors to dictate power prices, driving them to historically record levels across the whole of Europe and raising concerns about the actual role of gas.

Natural gas prices, together with ETS remain the predominant drivers of power prices in Europe. As can be seen on the slide below, gas prices have been rising already as an effect of post-COVID recovery of demand, especially in Asia, but the situation worsened as a result of the escalation of the war in Ukraine.

GRAPHIC #5: Historical gas prices development in Europe

Gas prices have rebalanced from peak period in end of summer 2022 back to 50 /MWh levels.



1) Monthly average of daily day-ahead prices as of 16 March 2023.

Sources: Aurora Energy Research, Refinitiv

LNG will fully replace pipeline gas from Russia thanks to newly constructed infrastructure.

Europe sourced more then a third of its gas imports from Russia. It is now rapidly diversifying its gas supply, mostly in the form of LNG imports, while focusing on reducing demand and increasing energy efficiency. Infrastructure remains the main constraint—this supply security shift requires greater LNG import capacity, as well as export capabilities worldwide for liquefaction, not to mention gas tankers providing actual transport. We expect that in Europe these capabilities will significantly grow over the coming years from the current level of 239 bcm/a up to 384 bcm/a, based on disclosed proposals and planned capacities. Similarly, global export capacity is expected to grow from the current 639 bcm/a to 1195 bcm/a, especially with the increase in interest in projects in the US, driven by economics of these projects.

Improved supply options will lead to a decrease in gas prices in Europe. We expect that by 2026 the TTF gas price will decrease to around the level of 35/MWh; a similar trend is already visible in future contracts.

Planned gas capacity in Poland requires a significant increase of current potential for LNG imports.

Another important aspect further driving sector demand for new gas units is the CHP sector. As outlined in the Polish heating strategy, we expect a temporary increase in gas and biomass use in this sector and a gradual phase out of coal plants.

Poland currently has installed 4 GW of gas capacities (data as at December 2022, ARE) , mostly CHPs providing heat for district systems and industrial application, such as Pock and Wocawek CCGTs owned by PKN Orlen. Nevertheless, it is expected that until 2030 the capacity of gas plants will need quadruple, up to over 17 GW, predominantly in CCGTs and smaller flexible units, in order to keep up with coal closures and rising security requirements of the system.

There are serious doubts around the role of gas investments.

Such a drastic increase of gas plant capacity in the Polish power system would obviously have a great impact on actual consumption of natural gas in Poland. The total gas consumption for power needs (including co-generation) would have to increase from around 20 bcm in 2022 to above 30 bcm in 2030, significantly expanding the need for gas imports and largely depending on the ability to put supporting infrastructure in place.

Currently, Poland plans to install two FSRU units at the Gdask bay to increase LNG import capacity by 10 bcm. However, such investments pose a serious risk for the Polish government's diversification efforts, and without a clear strategy around gas investments and consumption it may lead to trapping Poland for years to come with gas assets. In addition, investments would be required in onshore infrastructure, and guarantee of supply remains an open issue, as recently demonstrated in the case of the Baltic Pipe, where reserved pipeline capacity was not immediately matched with supply orders.

Furthermore, gas investments do not match EU climate ambitions, making it challenging to finance new fossil assets. This leads to quite a dangerous dilemma for the Polish power sector—on one side faced with a capacity gap in the coming years combined with inadequate incentives for alternative sources on the other, risking the market remaining locked in with fossil assets, just of a different kind.

Waste incineration

Waste-to-energy perspectives are challenging.

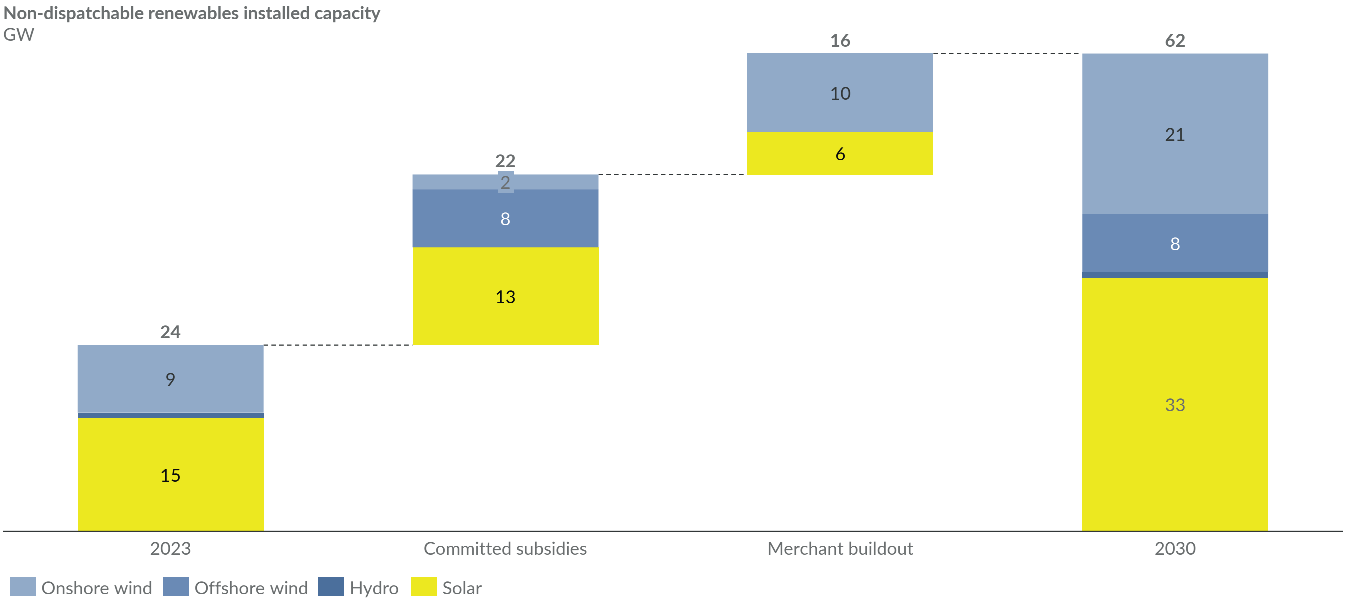
As mentioned in previous chapters, one of the crucial challenges will be in the transformation of the heating sector. Waste-to-energy (WtE) is thought to be an interesting alternative in this context and is utilized currently in some cities in Poland. Warsaw, for example, is currently constructing such a facility, which is intended to produce both electric and heat power for the city. Many local governments also looked at this idea with the promise of solving both issues at the same time too.

WtE perspectives are considerably more problematic for a variety of reasons, while offering rather minimal advantages. First, circular economic models approved at the EU level strongly discourage waste incineration and put an emphasis on the reusability and recycling of waste. Moreover, WtE-sourced CO_2 emissions will be covered by the ETS system from 2028 - a typical waste incineration plant such as, for example, in Kraków, emits a similar amount of CO_2 as a lignite plant -which will lead to a substantial increase in cost for these installations and impact their profitability.

Non-dispatchable renewable generation

GRAPHIC #6: Development of non-dispatchable renewables

Renewables capacity is forecast to increase by 38 GW by 2030, some 22 GW of which could be secured through existing subsidy systems.



Sources: Aurora Energy Research, Ministry of Climate and Environment

Offshore wind

The implementation of Poland's first 5.9 GW offshore capacity is substantially delayed and faces economic and logistical constraints.

According to PEP2040, offshore wind is, besides nuclear, the key technology to achieve Poland's emission reduction targets for 2030. Unfortunately, despite ambitious plans, the realization of the first round of projects constituting 5.9 GW capacity faces serious delays. Furthermore, the prices for wind turbine generators, towers and electric infrastructure substantially increased, and the tariffs per MWh for contract-for-differences agreed in 2021 with the Energy Regulatory Office (URE) are too low for the expected rate of return. Also, the financing costs in Polish zlotys substantially increased. This issue was partially addressed with the added flexibility of fixing CfD settlements in euros (in part or in whole).

Meanwhile, all neighboring countries investing in offshore in the Baltic Sea are farther along with their projects; investors have contracted vessels capable of erecting wind farms in the Baltic Sea, and projects regularly face lower financing costs in their respective currencies. Therefore, the commissioning of a larger fleet of offshore wind farms is not expected before 2030. It may take another few years to complete and commission all almost 6 GW capacity with obtained technical grid connection conditions to replace decommissioned lignite plants.

From 2025 to 2031 four auction rounds with a total volume of 12 GW will be announced.

Based on amendments proposed to the Offshore Wind framework, an additional 12 GW of new projects could be awarded CfD support in four auction rounds between 2025 and 2031 (originally 5 GW in two auctions in 2025 and 2027).

However, those subsidies will only be accessible to investors successful in separate competitive tenders for seabed lease locations designated by the government. These have seen strong competition, with 132 applications in total submitted for 11 development areas. The first seabed lease permits for that second batch of projects were all awarded to PGE, with objections formally submitted by other bidders. More tenders are expected to be resolved soon.

Onshore wind

Remaining onshore wind project pipelines will provide a level of installed capacity of around 11.5 GW by 2026.

The installed capacity of onshore wind in Poland is currently around 8.5 GW, mostly consisting of projects supported by the Green Certificate or CfD auction schemes. Thanks to relatively low costs and good wind conditions, onshore wind is currently a renewable energy source with the lowest levelized cost of electricity in Poland, and this is expected to remain the case until at least the mid-2030s.

The restrictions on new developments placed by the 10H distance rule (minimum distance from residential buildings amounting to 10 times the wind turbine tip height) meant that almost all projects that are operational or under development received building permits before 2016. A few small projects remain to be developed and the ones that will be constructed utilize old technology from before the passing of the 10H regulation, raising costs and reducing productivity.

The remaining project pipeline will allow to reach around 11.5 GW wind capacity by 2026, consisting largely of projects which target the CfD auction subsidy.

Liberalization of the 10H rule will pave the way for new project development, but administrative hurdles will delay the process.

Further buildout should come thanks to the recent liberalization of the 10H rule, allowing municipalities to reduce the minimum distance regulation to 700 meters from residential areas.

This development comes at the cost of an increased administrative burden, since reducing the distance will only be possible if planned wind farms get included in the Local Spatial Plans. This requires more complicated public consultations, potentially including neighboring municipalities. While it should arguably result in greater social acceptance of wind projects, it will increase the development risk and protract the time needed to deliver new projects. Nevertheless an improvement, it comes paired with additional challenges in the form of a very conservative minimum distance from neighboring high voltage overhead lines and an obligation to reserve up to 10 percent of installed capacity for the local community for a certain period after the building permit has been obtained. An optimistic assessment suggests that the first new projects would start construction in early 2026, with operation at the earliest in 2027, provided pre-existing Local Spatial Plans already allow for locating wind farms within the given area.

Beyond the 10H rule, onshore wind will face the usual challenges around grid access. Even at the current low levels of installed capacity, the Polish TSO has been forced to curtail onshore wind production at moments of particularly high generation because of grid congestion. As both new onshore wind and offshore wind capacities are added, mainly in the north of Poland, new investments will be required to bring this energy to demand centers still located in the south of the country. Measures such as cable pooling and direct line, discussed below in the solar context, will be equally important for maximizing the capacity of onshore wind that can be connected to the grid.

Photovoltaics—large-scale

CfD auctions planned until 2027 should deliver up to 9 GW of large-scale, but merchant or PPA strategies are currently more attractive.

Renewable CfD auctions are scheduled to take place until 2027. The Ministry of Climate expects to procure a total of 9 GW of newbuild utility scale solar capacity. However, low participation in the 2022 auction indicates that CfD auctions lose their attractiveness in the current market environment. In particular, the auction reference prices have failed to reflect the steep increase in supply chain, financing and inflationary pressures on project costs, making the auction business model significantly less attractive. This pushes developers towards alternative models, particularly PPAs, but the current price cap regulations mean uncertainties regarding a fair value for PPAs. As a result larger offtakers started considering acquisitions of ready-to-build projects instead of contracting long-term PPAs.

A sharp rise in the price of elements such as copper, polysilicon and steel led to solar capital expenditures being some 25 percent higher in 2022 compared with previous expectations, and supply chain tightness means this is likely to persist for the coming years. The onshoring of supply chains and manufacturing in Europe risks an increase in these costs over the long term. This may pose a challenge to solar investability, particularly in the coming decade.

Obtaining grid connection conditions is a major investment hurdle.

Obtaining a grid connection has fast become the largest challenge in developing new solar projects. Currently, grid connection conditions and agreements have been issued to 13.7 GW of installed utility-scale solar capacity but, beyond this, additional connection capacity is minimal. From 2023, PSE, the Polish TSO, and the DSOs changed their calculation method based on the most recent update to the long-term Network Development Plan of PSE; however, network operators are tempted to offer mostly non-guaranteed capacities, at least until major grid reinforcements are completed.

The "Charter for the Development of the Distribution Sector," signed near the end of 2022 between grid operators and the National Regulatory Authority (URE), is a strategic document aimed at enabling PLN 130 billion in investments into DSO networks by 2030, and many of those investments are necessary for the fulfilment of existing GCCs/GCAs. The investments considered would allow to add only 4.4 GW of additional connection capacity. While necessary, investments into grid upgrades are a slow process and do not offer a solution to the short-term problem.

Additional measures that can help relieve grid constraints are mentioned in the distribution sector development charter but have yet to see policy progress. Solutions discussed include direct lines and cable pooling.

Direct lines and cable pooling

Direct line and cable pooling could provide new capacity without investments into the public grid, but legislative measures are still under discussion.

Direct lines allow the direct connection of renewable assets to offtakers, for direct supplies of electricity, outside of the distribution system. This has the double benefit of enabling private investments connecting renewable sources to nearby demand points without burdening the distribution grid and allowing the parties involved to reduce the burden of distribution tariffs. It would also provide low-cost, decarbonized energy for industry and allow Poland's substantial demand for corporate PPAs to be fulfilled.

Cable pooling enables the co-location of multiple technologies at a single connection point without tying the maximum nameplate capacity of the installation to the capacity of the connection. It would for example allow the placement of solar installations by existing onshore wind farms, the over scaling of solar installations to maximize utilization of the connection and the co-location of batteries with renewable installations. These measures would unlock significant additional potential for connection capacities while improving the stability, both hourly and seasonally, of renewable generation delivery to the grid and therefore of wholesale energy prices.

The legislation recently reached the Parliament. While cable-pooling solutions show promise, the direct line proposal leaves much to be desired. The setup generates unnecessary regulatory hurdles, affecting bankability or requiring involving third-party electricity traders, complicating the business structure and project documentation. Direct supply is expected to generate network charges to secure the revenue base for DSOs, but at a reduced level compared with regular grid supply. Even before passed into law, we expect the direct line framework will immediately require a material revision, especially once the March 2023 Electricity market design reform proposed by the Commission enters in force.

Renewables—project finance

Temporary measures have become a popular work-around due to the unstable market environment.

In addition to the mentioned technical and regulatory challenges surrounding renewable investments, the financial side must not be forgotten. For successful and sustained growth, a stable financing environment is needed for developers—necessitating both a flexible and stable regulatory environment and support schemes.

Poland was one of the first EU countries introducing a two-sided Contracts for Difference support system. Since 2016 it provides a stable financing environment for onshore and solar investments well-recognized now by financing institutions. However, due to high power market prices as compared to prevailing, arguably low bid caps, the system has lost its attractiveness since 2021. Merchant exposure and pay-as-produced PPAs became an alternative, or often were the only economically viable option due to rapidly increasing capital expenditures.

Currently, the 2022 windfall profit regulations resulted in uncertainties impacting ongoing PPA negotiations. Additionally, terms for long-term project finance become less attractive. As market participants expect the power, finance and construction markets to stabilize from 2025/2026, temporary financing measures offered by private debt providers gain on attractiveness. The general regulatory environment for long-term PPAs is expected to improve, as the Commission recognized their importance for increasing the overall resilience of the market to price shocks and expects member states to alleviate prevailing barriers to their broader availability.

Photovoltaics—consumers

The introduction of net billing for prosumers triggered a drop in the number of new installations.

The prosumer sector can be seen as one of the first successes of the energy transition in Poland, with installed capacity of micro installations rising from under 1 GW at the start of 2020 to 9 GW at the end of 2022. Prosumer installations are an important way to mobilize capital otherwise inaccessible for energy investments, utilize urban areas and democratize the energy transition, making its benefits directly accessible to citizens. However, the sector remains heavily dependent on subsidy support and policy design.

The change from net metering to net billing for the compensation of excess generation from prosumers was largely necessary, given the impact of large, varying two-way flows on typically non-robust end sections of distribution networks. However, it had a damaging impact on the economic case for new rooftop investments. As a result, the number of new installations shrank from 150,000 in Q4 2021 to just 34,000 in Q4 2022 [source: PTPiREE]. Sufficient subsidy incentives to make investments in rooftop solar attractive are required while maintaining the signal for matching consumption to production, which net billing provides.

The second question around the continued growth of prosumer solar is the saturation size of the household market. A large share of households with the financial means to install rooftop solar have already done so, meaning larger incentives may be required to ensure lower income households can gain access. Alternative models also need to be pursued to enable participation in prosumer energy projects, such as energy cooperatives. Additionally, sectors such as commercial and industrial, public buildings and farming need to be explored to maximize the saturation potential of the micro-installation market. Support schemes already exist for these areas, but they need to be expanded and provide more long-term certainty to replicate the success of the household solar boom.

The demand for household batteries, heat pumps and electric vehicles combined with compulsory rooftop solar will again speed up investment.

Beyond rooftop solar, policy needs to steer prosumers in the direction of maximum consumption of the energy they generate. As technologies such as household batteries, heat pumps and electric vehicles develop, they will provide the potential for significant consumption flexibility from consumers. However, they are all capital-intensive investments with relatively long pay-off times and will therefore require cheap financing and, potentially, a subsidy to encourage their fast uptake. Incentivizing such investments would allow the continued development of solar micro installations while relieving pressure on low-voltage distribution networks.

Finally, the EU Solar Energy Strategy published in May 2022 establishes a set of guidelines for the further acceleration of solar deployment in Europe. One of the key focus areas is to encourage rooftop solar installations. The strategy calls for rooftop solar installations to be made compulsory for:

- All new public and commercial buildings with useful floor area larger than 250 m^2 by 2026
- All existing public and commercial buildings with useful floor area larger than 250 m^2 by 2027
- All new residential buildings by 2029

While these recommendations are currently far from being translated into law, such measures would ensure the continued fast adoption of rooftop solar in Poland.

Dispatchable renewable generation

Wood biomass

New investments in wood biomass firing are unlikely to happen.

The new Renewable Energy Directive requires wood biomass to meet sustainability criteria. The Commission has proposed a revision of the Renewable Energy Directive, which includes a further targeted strengthening of the biomass sustainability criteria and is currently finalizing an implementing act that will set out uniform conditions for implementation of the revised directive's sustainability criteria for forest biomass. The Commission is also introducing an obligation on EU countries to design their own biomass fuels and use biomass as a renewable fuel. However, the growing opposition against firing wood biomass makes it almost impossible to attract external long-term finance. Thus, new investments in wood biomass firing are unlikely to happen.

Agricultural biogas

Poland has very few biogas plants for power and heat generation, and legislative measures to support biomethane production have still not been implemented.

After decades of subsidized and energy crop-oriented development, agricultural biogas production is standing at a crossroads. It is intended, that an agricultural biogas plant becomes an integral part of the circular bioeconomy and works mainly on the base of residues. Flexibility with regard to feedstocks, digester operation, microbial communities and biogas output has to be increased. Currently, in Poland fewer than 200 agricultural biogas plants operate, all designed for power and heat generation, compared with nearly 9,000 biogas plants in Germany. But the future of biogas plants is the generation of biomethane, with France as a shining example. According to the European Biogas Association, at the end of 2021, there were 945 biogas plants and 365 biomethane plants operational in France. By the end of 2022, the number of active biomethane plants had reached 514.

Appropriate legislation to incentivize biomethane plant growth and to allow the gas generated to be fed into public gas grids has been pending for more than a year with the Ministry of Climate, but even the current natural gas shortage could not trigger a legislative breakthrough.

Hydropower—run-of-the-river

Run-of-the-river hydropower capacity in Poland is at a level of around 600 MW, with minimal capacity additions having been made in recent years.

Run-of-the-river hydropower capacity in Poland is at a level of around 600 MW, with minimal capacity additions having been made in recent years. Except for the Wocawek plant at Vistula river, most capacity consists of small-scale installations. Due to a combination of geographic, environmental and economic factors, the potential for further development of run-of-the-river capacities is very limited.

Run-of-the-river plants are feasible in situations where rivers have large flows, relying in effect on altitude differences at the plant location. Poland possesses few such locations, as the country has only a few primary rivers and its topography is relatively. Most suitable locations have already been utilized for hydropower production.

Furthermore, hydropower leads to environmental disruption and therefore typically faces strong social opposition. The European Water Framework Directive requires bodies of water to achieve a “good” ecological and chemical status classification by 2027. Under the directive, new hydropower installations are only possible if (i) there are no significantly better environmental options, (ii) the benefits of the new infrastructure outweigh the benefits of achieving the goals of the Water Framework Directive, and (iii) all practical measures are taken to mitigate the installation’s impact on the water body.

Finally, hydropower has limited economic potential in Poland. Support is available through 15-year CfDs awarded through RES auctions for installations above 0.5 MW, and through feed-in tariffs for installations below 0.5 MW. Reference prices in 2022 were set at 675 PLN/MWh for feed-in tariffs and 650 PLN/MWh for CfD auctions for assets to 1 MW. Despite these generous levels, only one installation won a contract in the auction for assets below 1 MW, with 22.5 percent of auction volume clearing. No projects won contracts in the auction for assets larger than 1 MW. This lack of investor interest reflects the difficult economic case for hydropower development in Poland.

Hydropower—pump storage

PGE’s ESP Moty pump storage project, with a 750 MW capacity, will be commissioned early in the 2030s; other projects are unlikely to enter the investment phase.

In contrast to run-of-the-river hydropower, pumped storage has been receiving an increasing amount of policy attention in recent years. It is seen as a useful mechanism for balancing increasingly volatile generation from renewables and providing longer storage than batteries are capable of.

In consequence, a report outlining the potential role of pumped storage in Poland and making recommendations for the development of the policy environment was produced by the Ministry of Climate, National Fund for the Protection of the Environment and Water Economy (NFOiGW), the Polish TSO, the Energy Regulator's Office and the state-owned utilities interested in developing pumped storage projects. The document outlines both the demand for investments into modernizing existing units and the potential for new projects. In particular, three sites—Tolkmicko, Moty and Ronów—were identified as more concrete projects, with a total potential capacity of 2.5 GW. Seven additional sites were identified with a potential of 4 GW. The government aims to bring all these capacities into operation by the mid-2030s, but does not have a clear strategy outlined for the mechanisms that would allow this.

Of these projects, the ESP Moty project, developed by PGE, is by far the most advanced, having recently received a funding commitment of PLN 2 billion from NFOiGW, covering almost half of planned investment costs. The project would have a capacity of 750 MW and is planned for commissioning in 2030.

While the legislative undertakings for the promotion of investments into pumped storage improves the legislative environment for new project developments, cost will remain a key obstacle. The substantial financing provided to the Moty project demonstrates that the technology is not cost competitive on a market basis, even with access to revenues from the wholesale, capacity and frequency control markets. Rather, hydropower will only be delivered with the support of large government strategies. Batteries may well provide a more cost-effective alternative for the regulation of renewable generation, while having the advantage of greater geographical flexibility to manage to load on individual grid segments.

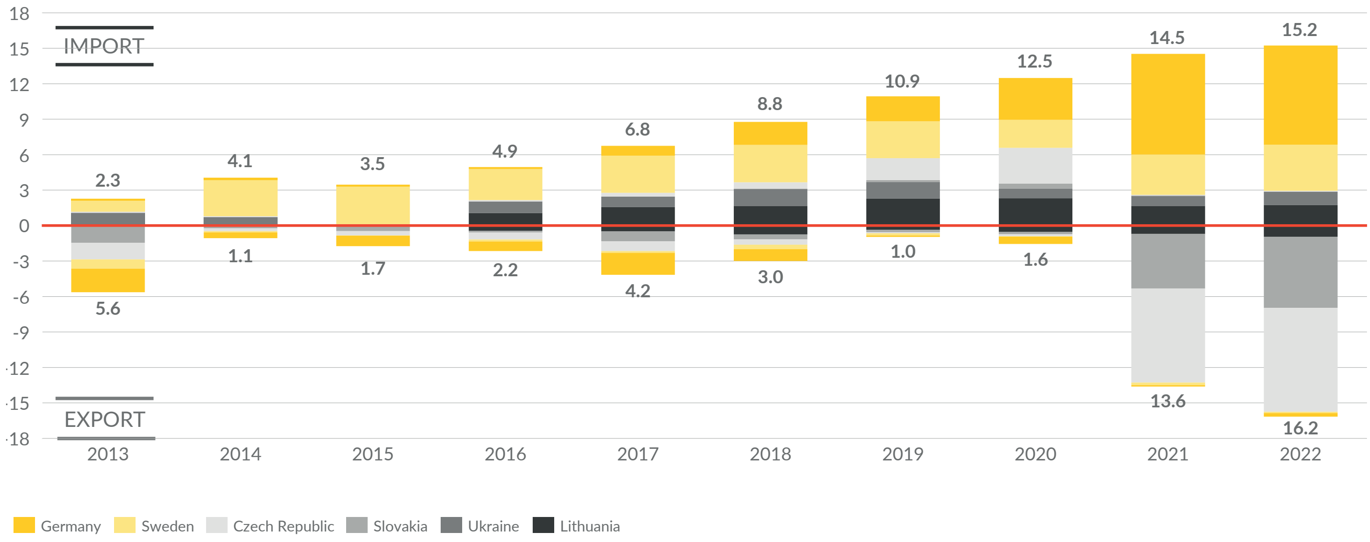
Power imports

Traditionally, power imports and exports have played a somewhat insignificant role in the Polish power system. But the situation has changed drastically. Since 2015 Poland as seen growth in the volume of flows between neighboring countries, especially from Germany. While in 2014 Poland remained balanced in terms of imports, in 2020 (a record year) total net imports reached almost 13 TWh, constituting almost 8 percent of the electricity supply. The main reasons for this shift are the economics of power generation in Poland compared with neighboring countries. Unlike its less carbon-intensive neighbors, Poland is affected more by the transition to a green economy, not to mention the rise in ETS prices. The recent energy crisis has put Poland again as a net exporter of electricity in 2023 with flows on net basis reaching 1.7 TWh, as neighboring countries with gas generation became more expensive than coal generation, despite the prevailing ETS system.

GRAPHIC #7: Historical import and export balance

With outflows to Slovakia and the Czech Republic on the increase, Poland has turned into a net exporter of power in 2022.

Yearly commercial flows by country
TWh



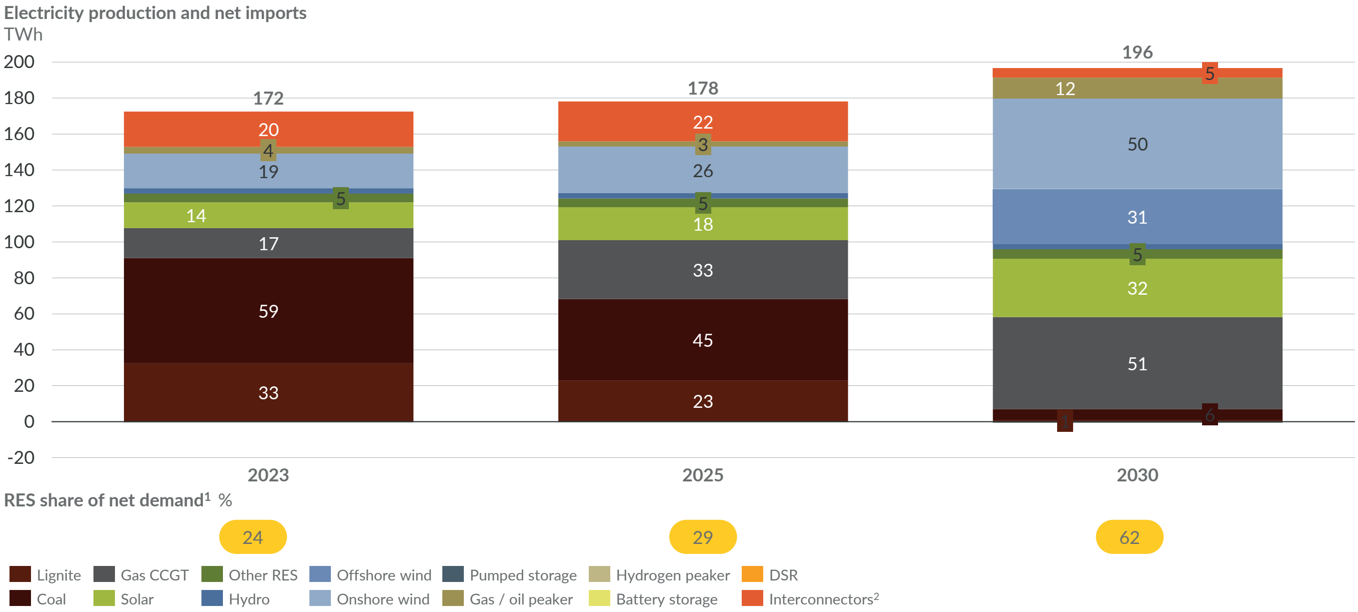
Sources: Aurora Energy Research, PSE

Poland has historically experienced rather minimal interconnection flows, but situation have changed recently.

Over coming decade, we currently expect the slightly positive net export balance to shift rapidly, with Poland becoming much more reliant on imports. With the renormalization in commodity markets, especially gas, and rising renewables penetration in neighboring countries, the overall level of imports will reach over 22 TWh in 2025. This high level will be required at that time, not only due to the favorable economics of cross-border flows, but also because of the lack of sufficient generating capacities in the Polish system. In the second half of the 2020s, with new investments in offshore, onshore and the shift from coal-fired conventional plants to lower-emission gas plants, it is expected that Poland will significantly improve its competitive position and reach a level of around 5 TWh of net imports.

GRAPHIC #8: Electricity production and net imports

Total Polish power generation is expected to rise to 196 TWh, with 62% of generation coming from renewables by 2030.



1) Calculated as the sum of nuclear, wind, solar and other renewables generation over demand. 2) Interconnectors represent the net imports or exports

Sources: Aurora Energy Research

Poland will have significant net imports of electricity in the coming decade due to competitive disadvantage.

In principle any price spread occurring between two neighboring countries will lead to electricity flows constrained by transmission technical capabilities or security of supply concerns. The EU has set an interconnection target of at least 15 percent by 2030, to encourage member states to interconnect their installed electricity production capacity. This means that each country should have in place electricity cables that allow at least 15 percent of the electricity produced on its territory to be transported cross-border to neighboring countries. To fulfil this target, Poland will have to reach 6.6 GW of available export capacity.

Moreover, while significant net flows are a sign of a country's competitive, high interconnection capacity is beneficial both from the perspective of security of supply as well as flexibility and integration of renewables into the power system. TSOs not only utilize cross-border flows in a scarcity moment, such as the outage at the Bechatów plant on 17 May 2021, but they also procure cross-border capacities with the capacity market mechanism. For example, we note the Lithuanian, Swedish and Slovak units winning the capacity market auction for deliveries in 2026 and 2027.

Flexible capacity and load

Battery energy storage

Already by 2021, the Polish regulator had recognized battery energy storage. This was followed by gradual updates of the interconnection standards for network operators. The key challenge remains the prolonged reform of the balancing market, which received a major boost at the beginning of 2023, with changes expected to take effect already at the beginning of 2024.

Development of battery energy storage systems (BESS) is currently driven mostly by revenues available through tendered capacity payments, with up to 17-year capacity contracts possible for new assets.

The December 2022 capacity market auction (for delivery of capacity services in 2027) supported battery capacity for the first time, with 165 MW power capacity representing 3 percent of total contracted 5.3 GW capacity market payments. However, 3 GW of battery storage power capacity has already been pre-registered for the 2022 auction. It is expected that this growing potential will manifest itself in the December 2023 capacity market auction (for delivery of capacity services in 2028). In 2022 the following companies were awarded contracts (in order of contract size):

1. Columbus Energy—124 MW capacity contract with a total of 133 MW power capacity and an energy capacity of 532 MWh

2. OX2—21 MW capacity contract with a total of 50 MW power capacity and 100 MWh energy capacity), Battery ESS-1 (9.2 MW power capacity and 36.8 MWh energy capacity

3. PKE Pomerania in cooperation with Hynfra Energy Storage and the Heyka Capital Markets Group fund—6.5 MW power capacity

4. Energa Wytwarzanie (part of PKN Orlen group)—3.8 MW power capacity)

In the coming 2023 auction, most likely a large BESS owned by PGE with 205–269 MW power capacity and an energy capacity of around 1,000 MWh, located close to the pump-storage facility on the Baltic Coast in arnowiec should take part as well.

Energa's bid strategy for its planned BESS serves as a good example: This system is planned with a 6 MW power capacity with an energy capacity of 27.3 MWh. This will be connected directly to the 110 kV distribution network to participate in the balancing of the National Power System (NPS). The system uses both, Li-ion batteries and lead acid batteries. The system also consists of a BESS-DCS system that allows for control of the two types of batteries and a 6 MW PCS (Power Conversion System). The storage facility cooperates with a Special Protection Scheme (SPS) which will support the management of the NPS. A seven-year capacity market contract has been concluded for a 3.79 MW power capacity, i.e. slightly more than half of the planned power capacity.

Overview—current status of battery storage in Europe

The need for flexibility in the European Power System is rising.

Rising flexibility needs and corresponding battery storage buildout is primarily driven by decarbonization. Battery storage complements intermittency of renewables by charging in periods of high-RES production and discharging in peak periods or allowing to tailor commercial profiles towards baseload. Additionally, battery storage contributes to availability of firm capacity on the system and ensuring operability of the grid.

Because of the expected 3.7-fold increase in intermittent renewables and 82 percent more demand until 2060, the need for flexibility in the European Power System is rising. The increasing share of intermittent renewables leads to a greater need for dispatchable, yet non-emitting capacity in the system.

Example: Battery storage development in Belgium

Having implemented a market-wide capacity mechanism available to storage, Belgium serves as a good example for fast development of BESS. With a base load level of approximately 10 GW, Belgium's base power demand is 40 percent lower than Poland's power demand. About 75 MW of storage power capacity will go live until the end of this year in Belgium with another 90 MW power capacity expected to commission until 2025–2026. Income from balancing and ancillary services, wholesale arbitrage and capacity markets are the key sources of revenues for BESS that optimize their dispatch based on prices.

The economics of an exemplary new-built BESS entering the market in 2025 (2-hour duration, one-to-two cycles per day, with energy capacity exceeding power capacity two-fold) indicate that batteries' investment costs can only be recovered when participating in all possible markets and opting for revenue stacking. With high prices projected for primary (FCR) and secondary (aFRR) reserve markets across the mid-2020s, batteries would make most of their profits on these markets. Several upsides, such as capacity market payments, reactive balancing or further liberalization of balancing and ancillary services would add a premium to the already profitable business case. Currently, shorter duration batteries are more profitable as increased investment costs severely affect longer storage duration batteries.

Battery storage and Poland's capacity market

Functioning of the capacity market (CM)

Battery storage is treated equally with generation units.

The Capacity Market Act was enacted in 2017, and beginning in 2018 yearly Dutch auction rounds have been successfully organized for delivery years from 2021 to 2027. The functioning of a unit in the capacity market in Poland can be generally divided into three main stages—certification of the supplier and its capacity market unit, subsequent (main and supplementary) auction rounds and performance of the capacity obligation.

BESS were awarded for the first time in a 2022 auction.

BESS has been awarded in the capacity market for the first time in 2022 regarding delivery year 2027. For the time being, energy storage systems are subject to identical capacity obligations as generation units. The amount of capacity obligation to be offered by a capacity unit in a CM auction cannot be greater than the product of the net generating capacity of this unit and the technology-specific corrective availability coefficient. For battery storage, this coefficient historically amounted to 96.11 percent, but for delivery year 2027 it was reduced to 95 percent.

Technology-specific information for general certification is required.

Entering the capacity market system starts with a general certification, which is necessary to ensure further eligibility, but does not yet result in any obligations to market participants. It allows the TSO to collect basic information about the proposed BESS—energy capacity (MWh), efficiency of a single charge and discharge cycle, maximum power capacity (MW) and maximum discharge capacity.

New generation capacity market units have to fulfil certain technical criteria to start at auction.

The next step is certification of the pre-registered BESS for the purpose of the annual auction. At this stage market participants create capacity market units consisting of specific pre-registered assets and select the type of participation (participation in the primary annual auction, yearly or long-term contracts, participation in the secondary market). Registering for the annual auction effectively means placing the first bid, at the level of the opening price. Once the auction takes place the registered asset is automatically included in the bidding pool, and bidders may only withdraw before clearing takes place. Resigning prior to the auction is not included as an option.

Eligibility requirements in the case of bidding for a long-term capacity contract include an independent expert opinion confirming planned or incurred expenditures and emission levels, valid connection terms or a connection agreement, if already signed. Submitting a building permit and environmental decision could be required as well. At this stage the ability to reach the minimum number of consecutive operational hours (duration) also needs to be confirmed. Currently, the capacity market requires a duration of four hours for all types of units, including BESS.

The annual CM auction takes place in December, five years before the capacity delivery period, whereas supplementary auctions take place in the first quarter of the year before the delivery year. A bid bond of PLN 43 per kilowatt of offered capacity is required to participate.

Capacity contracts are concluded between PSE and the entity responsible for operating the capacity market unit.

The legal basis for performance of the capacity obligation is a capacity contract concluded between the Polish TSO—PSE S.A—and the entity operating the relevant capacity market unit. The capacity contract is concluded upon the announcement of the preliminary results of the auction, subject to an announcement of the final results of the auction, as condition precedent. On the secondary capacity market, capacity contracts result from the entry of a bilateral transaction between CM participants in the CM register. The capacity contract is a model contract and is not negotiable, nor can it be terminated under normal circumstances.

Delivery of power capacity to the system during recall periods is key.

The capacity obligation price specified in the capacity contract is the closing price of either the main auction or the supplementary auction (title to the capacity payment automatically transfers with a secondary market transaction). In the case of long-term capacity contracts, the price is adjusted by the annual CPI index.

Remuneration for the performance of the capacity obligation does not depend on the energy delivered during the recall period but is paid for the readiness to deliver capacity.

The primary obligation is the delivery of capacity to the electricity system during recall periods, i.e. a full hour in which the surplus capacity available to the TSO is below technical thresholds. PSE can also announce test recall periods in order to verify the operational capability of specific units. The rules for determining the test recall period are consistent with a "true" recall period.

Performance during the recall period on the capacity market has an impact on the possible penalty or the right to a bonus (in the event of overperformance. Overall, the liability regime under the CM framework is strict and requires proper contingency planning, both by adequately managing the capacity obligation through transactions on the secondary market and through reallocation options triggered ex-post, which allow for matching the aggregate performance and obligation of multiple assets in order to avoid penalties.

Balancing market reform and liberalization of ancillary services

Poland is expected to liberalize the full range of ancillary services starting on 1 January 2024.

The most up-to-date plan from PSE for reforming balancing services was released at the end of March 2023. Liberalizing the ancillary services market is planned to launch on 1 January 2024, with much delay over the initial schedule. While risks of further delays persist, a detailed setup of the new markets has been presented.

One of the main roles of the balancing and ancillary services markets is to ensure demand and supply is met in real time, at every instance of operation of the NPS, while maintaining the required standards of supply. While wholesale markets and other OTC contracts provide a convenient way to connect supply and demand, the TSO needs to ensure that security of supply and key technical parameters of grid operation are maintained at the infrastructure level with the use of ancillary services. The TSO manages both balancing energy to match supply and demand at any instance, responding to forecasting errors or unplanned outages of plants, as well as capacity that allows to manage technical supply parameters within seconds or minutes of an unplanned event and recurring shifts in generation and offtake patterns at different grid locations. Those two types of services are complementary with each other, as the TSO ensures there is always capacity to react and dispatches it when needed.

It is important to note that ancillary services are not limited to frequency response and restoration reserves, as there exists a range of other services, such as reactive power compensation, voltage control or congestion (redispatch) management, which are required for secure operation of the NPS. Nevertheless, given their lower importance for battery revenues and highly localized nature of this services, they are not a focal point in this report.

Polish ancillary services markets will consist of renumeration for capacity, such as FCR and aFRR, mFRR and RR as well energy.

To participate in the balancing services market, a supplier has to register its operating units including the balancing location/grid connection point. Successful prior testing is required and the service provider must also demonstrate its financial capability, including providing security of PLN 500,000 for proper performance of services.

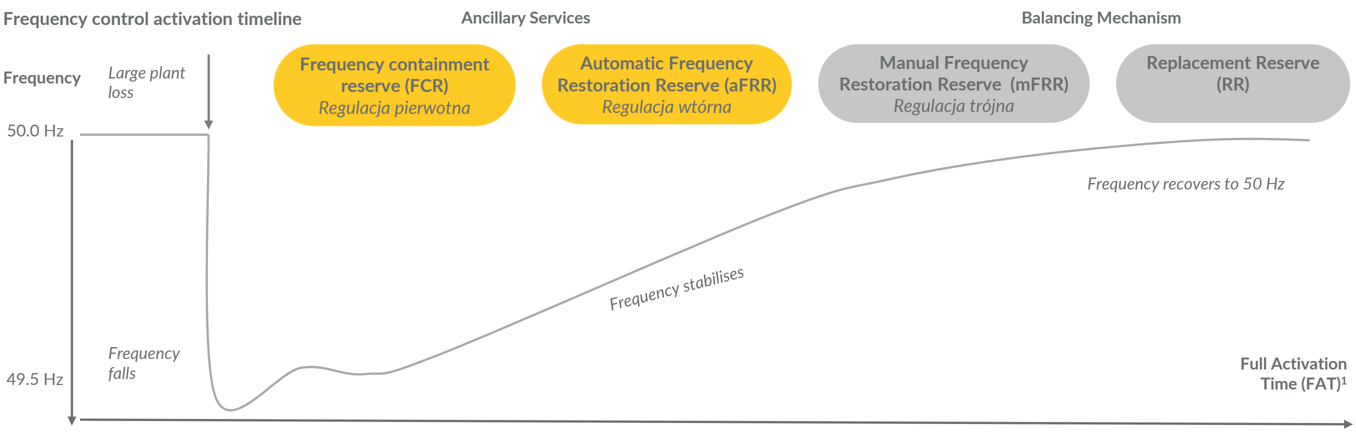
Poland's new planned ancillary services framework envisages a setup that is similar to the one already present in neighboring countries, with four main types of capacity services and one common market for balancing energy. The principle behind balancing market revenues assumes payments for a given duration for each MW committed and available to be dispatched at a critical moment of operation, noting though that the actual energy procured would be additionally renumerated under balancing electricity payments.

Frequency Containment Reserve (FCR or Primary control/ Regulacja pierwotna) will be the fastest reacting reserve to be activated within the first 30 seconds of a frequency shift in the system. For that reason only selected types of assets with advanced automation systems and technical setup can perform these services. For thermal and hydro plants this service can be performed only when such units are generating and only to the degree limited by their ramp rate (for most of coal plants, currently up to around 5 percent of their capacity). On the other hand, batteries can freely perform this service within the full range of their capacity and are limited only by the state of charge. The FCR market in Poland is expected to be around a 170 MW power capacity and can procure separately upwards and downwards, with the day-ahead auction procuring required capacity for hourly blocks.

Frequency Restoration Reserve (FRR or Secondary reserve/ Regulacja wtórna) is a reserve ensuring grid stability and replacing FCR after initial operation of the power system and providing further regulation. It is activated after 30 seconds of FCR operation and split into automatic (aFRR) and manual (mFRR) reserves, with the time required for ramp up being up to five or 15 minutes, respectively. This market is expected to be much larger than the FCR market, with upwards reserves of approximately 1100 MW and with a minimum of 500 MW procured within aFRR. Similarly to FCR, both upwards and downwards reserves will be procured separately and bidding takes place a day ahead of delivery. From the technical standpoint, given the longer time required for assets when responding to activation this market is more accessible for thermal power generation technologies, especially when it comes to mFRR, as long as not limited by GHG emission thresholds. For battery storage it is expected to be based on examples from other markets where aFRR is the main target market, given the higher prices and its estimated competitiveness.

GRAPHIC #9: New ancillary services markets

A full suite of liberalised frequency response markets is expected to be introduced by PSE in Q1 2024 to balance deviations in supply and demand.



	FCR	aFRR	mFRR	RR
Full Activation Time (FAT)[1]	<30 seconds	<5 minutes	<15 minutes	60 minutes
Purpose	Initial containment of frequency deviations	Replacement of activated FCR capacities	Supplementing or replacing activated aFRR capacity	Replacement of FRR reserves after continued activation
Activated	Automatically for frequency deviations of +/-0.01 Hz	Automatically after 30 seconds of FCR operation	Manually after 5 minutes of aFRR operation	

1) Full Activation Time is defined as the maximum allowed duration for the full activation or deactivation of an energy bid

Source: Aurora Energy Research, PSE

Revenue stacking for battery storage

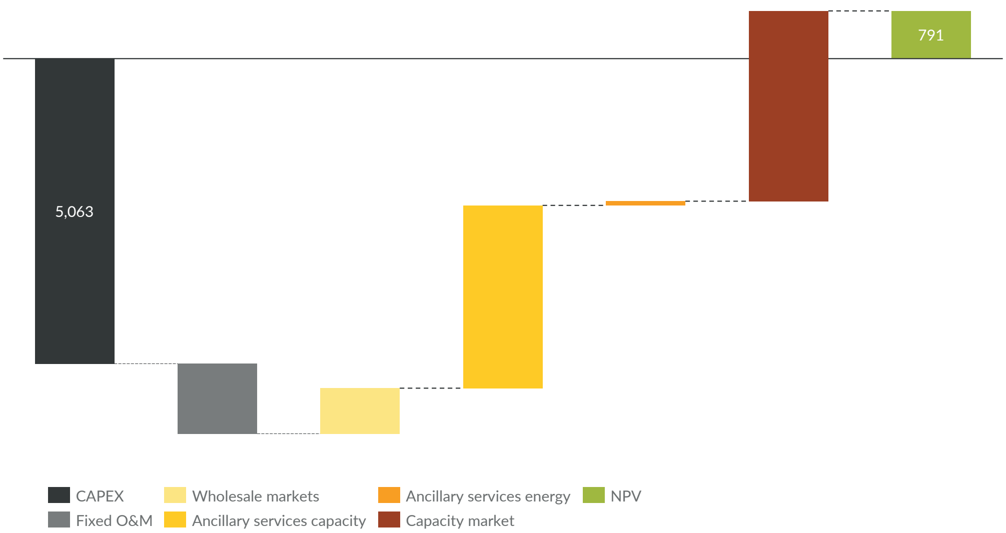
Revenue stacking across various market segments will be key for battery economics.

All ancillary services presented above are very attractive for BESS participation, as those technologies can provide quick and reliable power for the National Power System in an event of stress. Moreover, BESS can provide these services much more cheaply than thermal units, which will still drive prices in those markets in the coming years. On the other hand, we see opportunities for BESS to participate in traditional arbitrage activities in wholesale markets, trying to buy when electricity is cheap and sell when it's expensive. This can be optimized with participation in the growingly important intraday market, which could provide additional volatility not seen in other power market segments. Some regulatory issues need to be clarified in respect of combining the capacity market and ancillary services revenues, we expect those to be addressed as the balancing market reform matures.

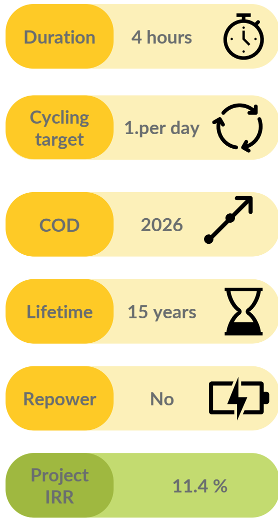
GRAPHIC #10: Electricity production and net imports

With their high derating factors, 4h batteries are highly dependent Capacity Market revenues and achieve IRRs over 11%.

Economics for new-build battery entering 2026 in Aurora Central[1]
Net Present Value[2] PLN/kW (real 2021)



Aurora's battery base case
Polish Market



1) Assuming a lifetime of 15 years, with no repowering. Cycling assumed at 1.5c for 1h battery, 1.5c for 2h battery, 1c for 4h battery. 2) NPV calculated based on discount rate of 11% for all revenue streams except the Capacity Market, which is discounted at 6% and 9% for main and supplementary auctions, respectively. Costs are discounted at 9%. 3) IRR in real terms, pre-tax
Source: Aurora Energy Research

Key consideration for maximizing returns for BESS projects is to stack different revenues and optimize them across all markets. BESS will operate in all these markets dynamically switching between different revenue streams. Such revenue stacking of typical battery projects coming into the system in 2027 is expected to achieve positive NPV with IRR exceeding 11 percent. Main revenues for such BESS projects would come from the ancillary services market, with high dependence on capacity payments, lastly from wholesale price arbitrage. Early access to the ancillary services market is important, as it is expected that this market will become saturated with the increasing number of BESS projects being commissioned.

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