

**NATIONAL RESOURCE
ADEQUACY ASSESSMENT
2025 – 2040**

November 2024



Table of Contents

1	Introduction	5
2	Generation adequacy in Poland.....	7
3	Calculation methodology.....	11
4	Key assumptions.....	15
5	Scenarios and results.....	32
6	Summary and results.....	41
7	Appendix.....	42

List of names, abbreviations and symbols

CDGU	Centrally Dispatched Generating Unit, as defined in the Transmission Network Code developed pursuant to Article 9g (1, 4, 5c, and 6) of the Act of 10 April 1997 – the Energy Law, and approved by the decisions of the President of the Energy Regulatory Office No. DRR.WRE.4320.4.2023.LK of January 19, 2024, and No. DRR.WRE.4320.4.2023.LK of February 23, 2024
DSR	Demand Side Response - the service of voluntary and temporary reduction of electricity consumption by consumers or shifting the time of consumption at the order of a TSO in exchange for expected remuneration
EENS	Expected Energy Not Supplied - the expected volume of energy not supplied due to power shortfalls in a particular period
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment - a requirement of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity
LOLE	Loss of Load Expectation - the expected total duration of power shortfalls in a particular period during which capacity resources are insufficient to meet the demand, resulting in a positive value of energy not served
nCDGU	Non-Centrally Dispatched Generating Unit, as defined in the Transmission Network Code developed pursuant to Article 9g (1, 4, 5c, and 6) of the Act of 10 April 1997 – Energy Law, and approved by the decisions of the President of the Energy Regulatory Office No. DRR.WRE.4320.4.2023.LK of January 19, 2024, and No. DRR.WRE.4320.4.2023.LK of February 23, 2024
NPS	National Power System - power system in the geographical area of the Republic of Poland
NRAA	National Resource Adequacy Assessment referred to in Article 24 of Regulation (EU) 2019/943 of the European Parliament and of the Council on the internal market for electricity
PECD	Pan-European Climate Database
Regulation (EU) 2019/943	Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (Official Journal of the EU L 158/54 of 14.6.2019)
URE	Energy Regulatory Office – the National Regulatory Office
VoLL	Value of Lost Load - the value of undelivered energy as defined in Article 2 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

1 Introduction

This document presents the National Resource Adequacy Assessment (NRAA) at the national level, as referred to in Article 15(i) of the Energy Law and Article 24 of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (L 158/54 of 14.06.2019).

The National Resource Adequacy Assessment is an element designed to support decision-makers in strategic matters to maintain the security of the power system.

Methodology and legal background

The results presented in the NRAA report have a national scope, and the method used to determine them is based on the European Resource Adequacy Assessment (ERAA) mentioned in Article 23(5) of Regulation 2019/943. Additionally, the resource adequacy assessment uses wide range of assumptions that consider the specifics of national electricity demand and supply, which are detailed further in the document. It should be noted that those assumptions aim to achieve the goals set out in various EU directives, including the Directive (EU) 2023/1791 of the European Parliament and of the Council of 13 September 2023 on energy efficiency of September 13, 2023, the revision of the Renewable Energy Directive adopted by the EU Council on October 18, 2023, and are based on the current economic growth forecasts of the National Bank of Poland and the Ministry of Finance, technical and economic information regarding individual generation units, forecasts for the development of renewable energy sources, and anticipated changes in electricity demand resulting from the ongoing energy transition. Any changes in trends or input information may require updates to the analyses conducted.

The NRAA modelling horizon is 2025 – 2040.

Results and summary

The results of the NRAA, particularly the base scenario results, indicate that during the analysed period, the reliability standard for Poland (Chapter 2.1) may not be met (tab. 1.1).

Tab. 1.1 Results of LOLE and EENS indicators for the Base Scenario

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LOLE	h/a	7,6	40,8	50,2	33,3	20,5	9,6	6,6	14,3	15,0	14,4	10,9	10,8	12,5	10,4	5,8	14,2
EENS	GWh/a	5,8	40,6	54,4	52,1	31,8	13,8	9,4	22,7	24,3	23,6	18,1	23,5	25,3	23,3	13,5	33,6

The main assumption of the base scenario (Chapter 5.1) was to demonstrate the economic viability, understood as a positive financial result, of all available centrally dispatched generation units (existing and planned). These units were subjected to economic optimization. Other generation units, such as RES, cogeneration units, and industrial units, were included in the analysis as determined, based on PSE assumptions and information obtained from generation sector entities. The calculations showed that the economic viability for the optimized units could be achieved if the average total duration of lost of load hours per year is between 10 - 20 hours or greater for some climate scenarios, assuming that during scarcity periods, electricity prices will approach the value of VoLL. The aforementioned number of scarcity hours significantly exceeds the mentioned reliability standard set at 3 hours per year.

At the same time, the NRAA report presents the results of a scenario in which it was assumed that the reliability standard is met (tab. 1.2) in each year of the analysis (Chapter 5.2).

Tab. 1.2 Results of LOLE and EENS indicators for the Scenario with Capacity Mechanism

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LOLE	h/a	2,9	3,0	3,9	2,3	3,1	2,2	2,5	3,1	2,0	3,1	2,7	3,4	4,4	2,5	4,1	2,2
EENS	GWh/a	1,8	2,1	3,2	2,4	3,6	2,2	2,9	3,8	2,1	4,3	3,8	6,4	10,2	5,1	8,7	4,0

As part of the analysis of this scenario, an economic viability of all centrally dispatched generation units necessary to achieve the reliability standard was performed. The results of this analysis indicate that in a system that ensures the reliability standard is met, a significant number of the generation units will be unprofitable, i.e., the second-degree margin will be negative. Therefore, to maintain these units in the system, it is necessary to implement a mechanism or mechanisms for generation capacity that will allow for the maintenance of existing units and investments in new dispatchable power sources, particularly gas-fired units, with the possibility of future conversion to hydrogen or biomethane-fired units, as well as electricity storage facilities.

Assumptions

The NRAA report was prepared using current data on generation units, cross-border connections, power and electricity demand, and demand response units (DSR). In terms of DSR, both the capabilities on the demand side, where consumers voluntarily adjust their energy consumption in response to price signals in the market (implicit DSR), and DSR units actively participating in the energy market were considered (explicit DSR). Current information on the generation sector, including fuel prices and CO₂ emission charges, was also considered.

2 Generation adequacy in Poland

2.1 Reliability standard for security of electricity supply to end users in Poland

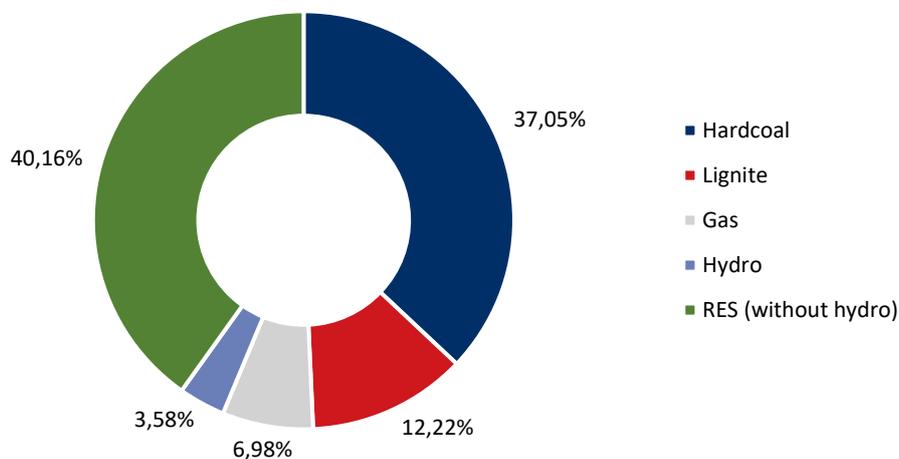
The reliability standard for security of electricity supply to end-users, understood as the acceptable expected time of undersupply of electricity to end-users determined in accordance with the methodology approved by ACER¹ was established in Poland by the Regulation of the Minister of Climate and Environment dated September 13th 2024 *on the execution of the capacity obligation, its settlement and demonstration and conclusion of transactions on the secondary market*.

In accordance with the aforementioned regulation, the reliability standard is 3 hours per year, with the hour counted as a reliability standard being the hour in which it is allowed to occur that the aggregate net generating capacity of the generating units connected to the system cannot be balanced with the demand of the grid, the minimum reserve of generating capacity and the planned balance of cross-border exchange.

2.2 Characteristic of polish power Sector

The electricity generation sector in Poland at the end of 2023 consisted of more than half of fossil fuel-fired generating units (fig. 2.1). Coal and lignite-fired units accounted for the vast majority in this group, totalling more than 49% of the total gross installed capacity. Despite this, in 2023 they were responsible for the production of nearly 68% of the electricity generated in the country. Complementing the above-mentioned conventional sources are renewable sources (wind farms, solar sources, hydroelectric, biogas and biomass plants), which accounted for nearly 44% of the gross installed capacity, while accounting for about 24% of the electricity generated.

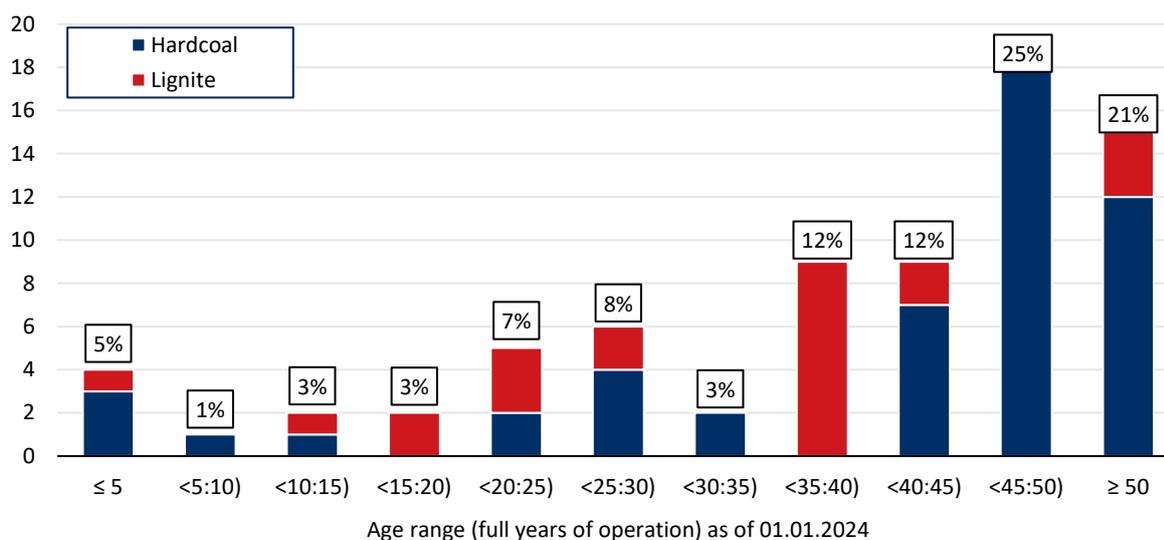
Fig. 2.1 Percentage structure of gross installed capacity in the NPS as of 31.12.2023



The structure of electricity generation in Poland described above is changing dynamically. The biggest influence on these changes is the connection of new renewable sources and, more significantly, the shutdown of old coal sources. The average age of a Centrally Dispatched Generating Unit that fired with hard coal or lignite is more than 37 years (fig. 2.2). Numerically, 88% of the units are over 20 years old, while units 40 years old and older account for nearly 60%.

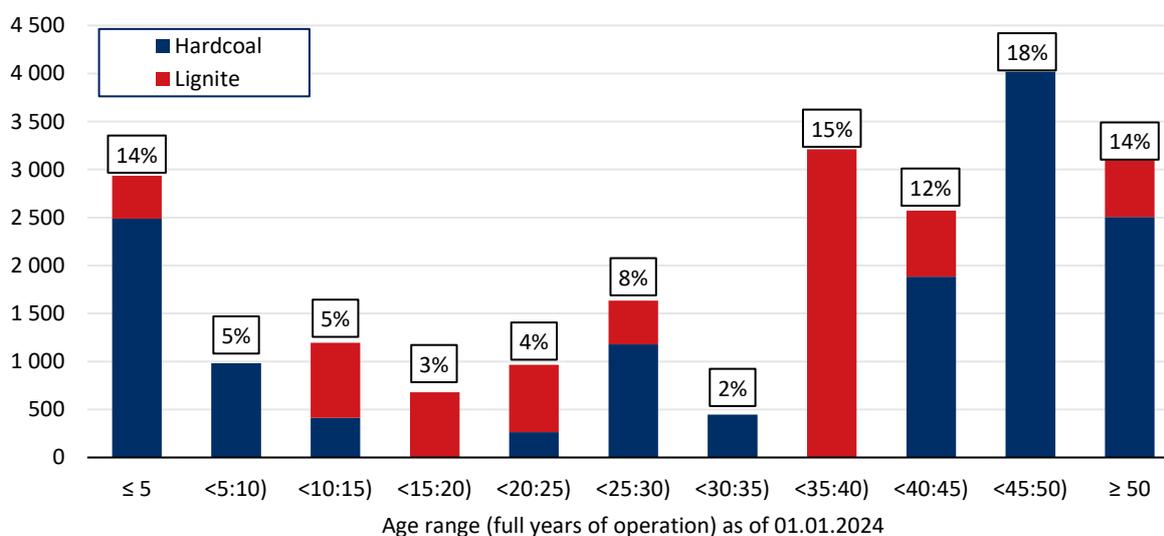
¹Decision No 23/2020 of the European Union Agency for the Cooperation of Energy Regulators of 2 October 2020 on the methodology for calculating the value of lost load, the cost of new entry, and the reliability standard

Fig. 2.2 Number of CDGU in each age range and their share in the total number of units



The above statistics are only slightly better in the context of the available capacity of individual coal units. In the capacity share, units over 20 years old account for less than 74% of the capacity, while units over 40 years old account for 45% of the capacity (fig. 2.3).

Fig. 2.3 Coal-fired Centrally Dispatched Generating Units net generating capacity by age and their share in total unit capacity [MW]



2.3 Existing capacity remuneration mechanism

The capacity market in Poland is a mechanism aimed at ensuring a stable supply of electricity by rewarding capacity suppliers for maintaining readiness to supply power to the system and for supplying capacity during the system stress events. It was introduced in Poland in 2018 under the Capacity Market Act of December 8, 2017 (Journal of Laws of 2021, item 1854, as amended). Its main objective is to ensure energy security by guaranteeing the availability of capacity resources in sufficient quantity to ensure stable operation of the National Power System, especially at times of peak demand. In addition, it is a form of incentive for investment in new generation sources and electricity storage facilities, as well as a foundation for developing and maintaining the availability of customer demand reduction services.

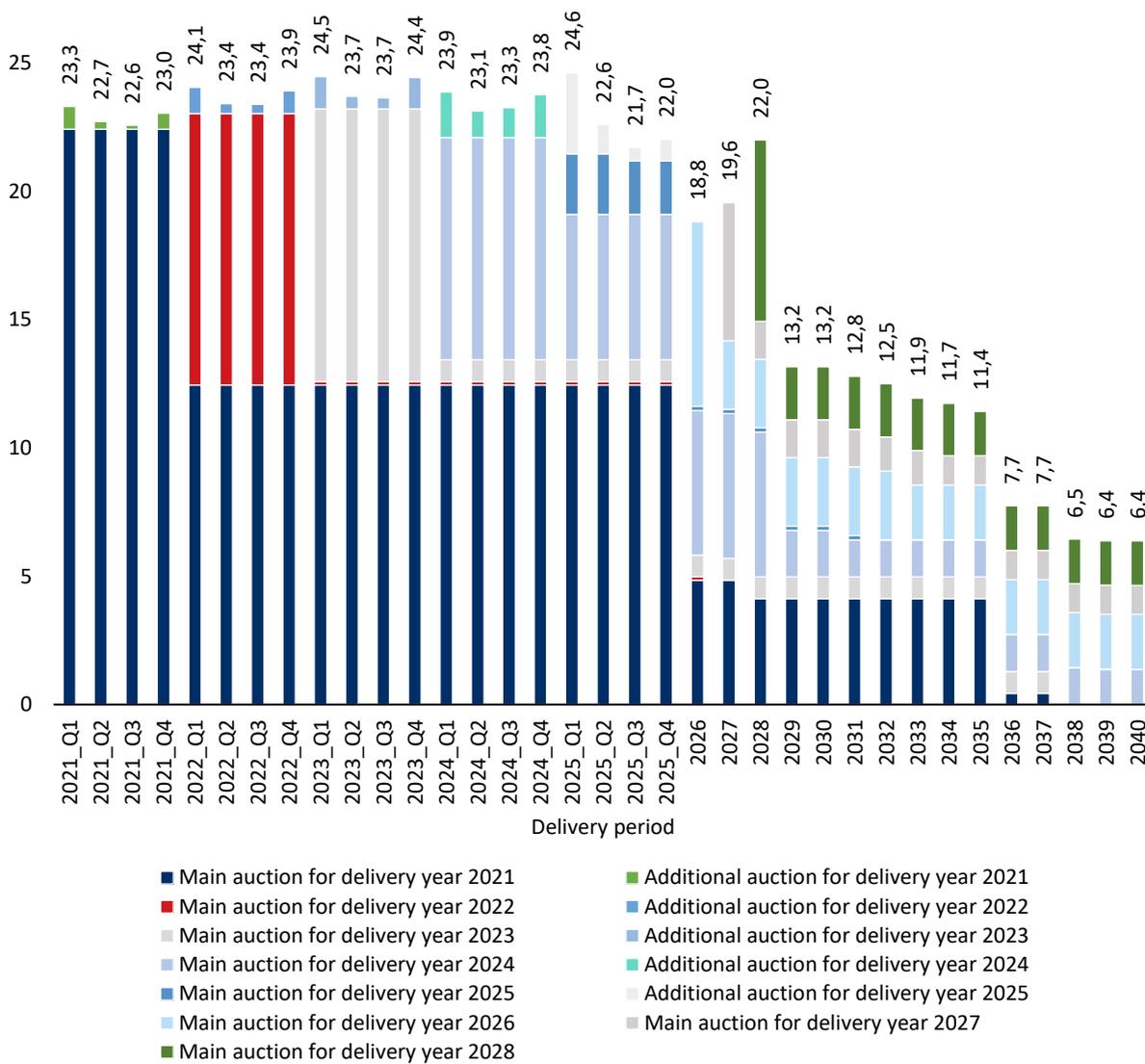
Participants of the capacity market are both generators, electricity storage units and energy consumers, who can reduce their demand at certain times.

To participate in the capacity market, capacity provider undergoes a two-stage certification process consisting of general certification and certification for auctions. Once certified, capacity providers participate in capacity auctions. The capacity market includes main auctions held in the fifth year before the delivery period, and additional auctions held in the year before the delivery period. Capacity providers that win the auctions enter into capacity agreement. In the main auctions, it is possible to conclude one-year agreement for existing units and multi-year contracts (with a maximum length of up to 17 years) if certain conditions are met regarding the type of unit and capital expenditures incurred. In additional auctions, quarterly agreements are concluded.

Based on the concluded capacity agreements, capacity market units are obliged to remain ready to supply capacity to the system and to deliver power during system stress events. Capacity market system stress events are announced when the level of reserves is lower than the specified threshold for safe operation of the NPS. For providing these services, the capacity providers receive a monthly remuneration based on the closing price of the capacity auction and the capacity obligation offered.

Fig. 2.4 shows the capacity resulting from the capacity obligations contracted in the capacity auctions held to date.

Fig. 2.4 Capacity obligations contracted in the capacity auctions held to date [GW]



So far, eight main auctions have been held for 2021 - 2028 and 20 additional auctions for individual quarters of 2021 - 2025. In 2025, the last main auction based on rules the current law (for the 2030 delivery year) will be held.

3 Calculation methodology

The national assessment of generation resource adequacy covers a period of sixteen years, from 2025 to 2040. In terms of the methods applied, the NRAA is in compliance with the provisions of Article 24 of Regulation (EU) 2019/943 of the European Parliament and Council, specifically: it has a regional character, uses probabilistic calculations, assesses the impact of extreme meteorological events on system balancing, employs a uniform modelling tool, and also takes into account assumptions that reflect the specifics of national electricity demand and supply.

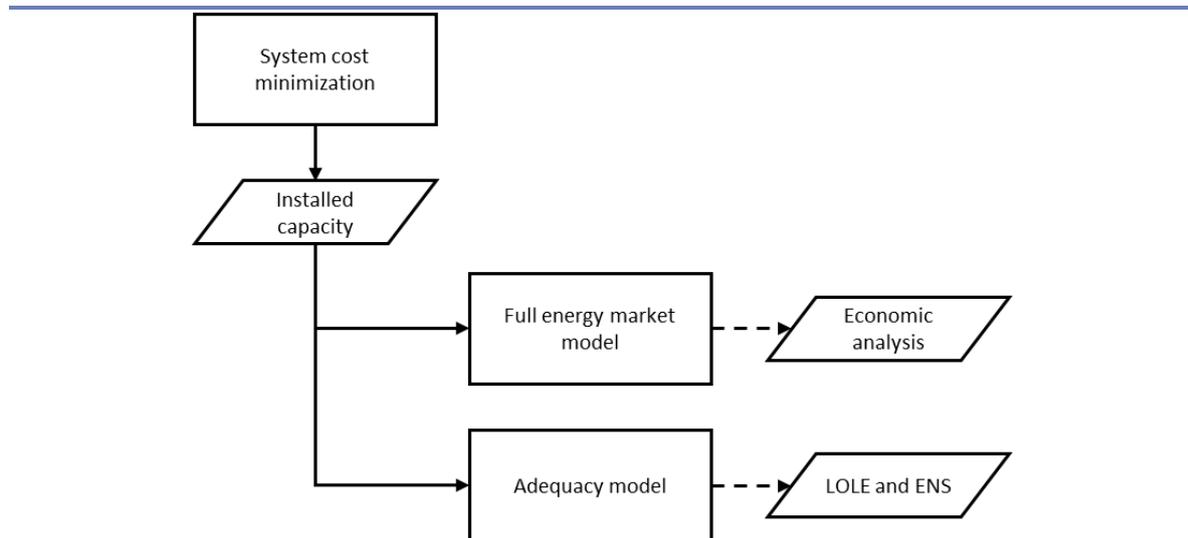
3.1 Process diagram

Calculations conducted within the NRAA were carried out using three models, namely:

1. System cost minimization model,
2. Full energy market model,
3. Adequacy model.

Fig. 3.1 presents the schematic use of the individual calculation models for scenario analysis in the NRAA

Fig. 3.1 Calculation Process Diagram for NRAA



Each NRAA calculation model was built and computed in the PLEXOS software, which is a tool for modelling, optimization, and simulation of energy systems, used among others by ENTSO-E during the preparation of the European Resource Adequacy Assessment (ERAA) and the Ten-Year Network Development Plan (TYNDP).

3.2 System cost minimization model

The system cost minimization model is an optimization task in the long-term horizon, aiming for efficient planning of the power system development. The model, using optimization algorithms, analyses key issues related to changes in the energy mix, i.e., it examines the validity of maintaining existing units in operation and investing in new generation capacities. The result is a set of optimization decisions characterized by the lowest necessary costs in the generation sector (so-called system cost minimum). In this model, there is no absolute requirement to maintain the reliability standard, i.e., the model also allows situations where part of the electricity demand is not met by the generation units. In such cases, the cost of unserved energy is assumed to be the product of the unserved energy and the maximum price defined in the VoLL value (described in Chapter 0). Additionally, it should be noted that this model does not analyse the profitability of individual generation units. It finds a solution that maintains the cost minimum from the perspective of the entire power system, but within the chosen

solution, it allows the operation of generation units that do not generate profit at the operational level, which may be at risk of being shut down for economic reasons.

To accurately reflect the system dynamics, the model includes the variability of electricity production and demand (including operational reserve) with hourly resolution throughout the considered time horizon, which has been intentionally extended to the years 2025 – 2050. This approach allows for precise modelling of fluctuations in both electricity demand and supply over short time intervals, which is particularly important in the context of reflecting the operation of electricity storage and electrolyzers and managing dynamic changes resulting from the increasing share of renewable energy sources. As a result, the modelled system can be optimally balanced even with high penetration of weather-dependent sources such as wind and solar power plants. The model results cover the 2025 – 2040 horizon, but the aforementioned extension to the year 2050 allows for better consideration of the decisions made by the model, particularly decisions regarding the construction of new units whose operating horizon extends beyond the studied time horizon, known as the lack of "end-of-the-world effect".

Simultaneously, to reflect the variability of weather conditions, despite access to a large amount of data related to climate variants, clustering of available climate data was initially carried out (Chapter 4.3.1). As a result of the clustering, three representative climatic scenarios were identified that best reflect the diversity of climate conditions during the studied period, while allowing for the assessment of system operating costs under different climatic conditions. Subsequently, for the clustering result, the optimization task of the generation sector was conducted within the described model.

To enable the model to make investment decisions in new dispatchable power sources, the possibility of optimization and decision-making regarding investments in the following technologies was allowed:

- CCGT (Combined Cycle Gas Turbine) power plants fuelled by natural gas,
- CCGT power plants fuelled by green hydrogen,
- OCGT (Open Cycle Gas Turbine) power plants fuelled by natural gas,
- battery energy storage systems based on electrochemical cells.

Optimization of the existing fleet of generation sources included CDGU fuelled by hard coal and lignite and involved making decisions regarding their retirement in operation in individual years.

The model decisions were influenced by various technical-economic parameters of the technologies:

- investment and maintenance expenditures,
- fixed and variable operational costs,
- efficiency of generation units,
- fixed costs related to the operation of lignite complexes (only for existing CDGU),
- costs resulting from the decommissioning of units (only for existing CDGU).

The techno-economic parameters applied for individual technologies are further described in Chapter 4.7 (for new entrants) and 4.6 (for existing coal-fired CDGU).

Other generation units, including RES and cogeneration units, were analysed as determined based on own assumptions and information obtained from generation sector entities, as described in detail in Chapter 0.

The analysis also considered the contribution of foreign units (see Chapter 4.4.1) and the participation of the demand side, i.e., DSR (Chapter 4.1.3), which enable flexible management of energy consumption by end-users.

It should be noted that solving the optimization task with hourly granularity over a 25-year perspective required certain simplifications, so the results of this model were treated as input data, providing a suitable basis for further analyses conducted using the full energy market and adequacy models, ensuring a higher level of detail.

3.3 Full energy market model

The full energy market model is used for UCED (Unit Commitment Economic Dispatch) type optimization analysis, aimed at determining the production level of generation units that ensures the lowest cost of meeting electricity demand, considering balance and technical constraints. Balance constraints include maintaining the balance between electricity demand and supply, considering the required operational reserves. As part of the model's operation, in the case of identifying excess supply, generation curtailments are implemented, which in extreme cases can lead to negative prices. On the other hand, a generation shortage leads to high electricity prices, which in extreme cases can reach the maximum value, i.e., the VoLL value. Technical constraints relate to the characteristic operating properties of individual types of generation sources, such as available capacity, technical minimum, efficiency, minimum run time after startup, tank/storage capacity, and the frequency and duration of repairs for forced and planned maintenance. Electricity grid constraints are not considered in the model.

Optimization is carried out based on the cost parameters of generation sources and their market environment. The first group includes startup costs and variable operational costs, while the second group includes fuel prices and CO₂ emission fees.

Operational reserve is modelled as the demand for two types of reserves, namely FCR (Frequency Containment Reserve) and FRR (Frequency Restoration Reserve). In the model, they are represented as a single value (sum). Units subject to optimization, besides participating in the modelled energy market, can simultaneously offer (with a specified limit) their capacity in the reserve market.

Calculations using this model are carried out individually for the consecutive calendar years 2025 – 2040 and three characteristic climatic scenarios selected through clustering (Chapter 4.3.1). Optimization is performed for each hour of the year on a weekly step basis. The model assumes one schedule for forced outage and one schedule for planned maintenance.

The result of the calculations performed by the market model is a set of economic parameters for a given calendar year and a given climatic scenario, determining the second-degree margin index for each generation unit expressed by the following formula:

$$M_2 = \frac{(I_{EM} + I_{RR} + I_{HM}) - (C_{FC} + C_{VOM} + C_{EC} + C_{SC} + C_{FOM} + C_{RC} + C_{MC})}{P_I} \quad (1)$$

where:

M_2	– second-degree margin;
I_{EM}	– revenue from electricity sales;
I_{RR}	– revenue from providing operational reserves;
I_{HM}	– revenue from heat sales;
C_{FC}	– fuel cost;
C_{VOM}	– variable operational costs;
C_{EC}	– CO ₂ emission cost;
C_{SC}	– startup cost;
C_{FOM}	– fixed operational costs;
C_{RC}	– maintenance costs;
C_{MC}	– mining costs for lignite-fired units;
P_I	– installed capacity.

The final second-degree margin index i.e. economic viability for individual units for a given calendar year is determined as the sum of the indices from climatic scenarios, considering the weights calculated during the clustering of climatic scenarios (see Chapter 4.3.1).

3.4 Adequacy model

The adequacy model is used for ED (Economic Dispatch) type optimization analysis, aimed at determining the production level of generation units that ensures the lowest cost of meeting electricity demand, considering balance and technical constraints. The objective of the optimization activities is to maintain the balance between electricity demand and supply, considering the required reserve. As part of the model's operation, in the case of identifying excess supply, generation curtailments are implemented, which in extreme cases can lead to negative prices. On the other hand, a generation shortage leads to high electricity prices. Technical constraints relate to the characteristic operating properties of individual types of generation sources, such as maximum capacity, efficiency, storage capacity, and the frequency and duration of repairs for emergency and planned maintenance. Compared to the full market model, the adequacy model does not consider constraints resulting from the technical minimum, minimum run time after startup, or minimum downtime after shutdown.

Optimization is carried out based on cost parameters concerning individual generation sources and their market environment. The first group includes variable operational costs, while the second group includes fuel prices and CO₂ emission fees. Compared to the full market model, in this case, startup costs of generation units do not participate in the optimization of the cost of meeting demand. They are instead determined based on optimization results and added to the system total costs.

Operational reserve is modelled as the demand for two types of reserves, namely FCR (Frequency Containment Reserve) and FRR (Frequency Restoration Reserve). In the model, they are represented as a single value (sum). Units subject to optimization, besides participating in the modelled energy market, can simultaneously offer (with a specified limit) their capacity in the reserve market.

Calculations using this model are carried out for the full set of climate scenarios covering data from the period 1982 – 2019. Optimization is performed for each hour of the year on a daily step basis. The model assumes one schedule for planned maintenance and ten schedules of forced outages.

For each climate scenario, the result of the adequacy model is the number of hours in the year in which unserved energy occurs and the total unserved energy to electricity consumers. The result of the adequacy model calculations for a given calendar year are the LOLE and EENS indicators, which are the average number of hours with unserved energy and the average total unserved energy to electricity consumers among all climate scenarios.

4 Key assumptions

Below are the key assumptions regarding individual elements of the power system, which formed the basis for conducting analyses within NRAA.

Centrally dispatched generating unit (described in more detail in Chapter 4.2)

When parameterizing the resources participating in the central dispatch mechanism, technical-economic data and schedules of planned outages were used, based on the results of a survey conducted in June 2024. Additionally, it was assumed that new generating units, which currently have valid capacity agreements, would be put into operation. Data on the availability and reliability of generating resources held by PSE was also considered.

Non - centrally dispatched generating unit (described in more detail in Chapter 4.2)

For resources not participating in the central dispatch mechanism, the available capacity in each year was determined based on the latest information obtained from their owners, provided as part of the cyclical survey process of the generation sector (data from early 2024).

Renewable energy sources (described in more detail in Chapter 4.2)

The forecasts for the development of renewable energy sources adopted for NRAA are aligned with national strategic documents. The development of offshore wind farms was assumed based on available data (including connection agreements) held by PSE. For photovoltaic sources and onshore wind farms, their dynamic development in the coming years was assumed, considering observed trends as well as existing and announced support systems.

Nuclear energy (described in more detail in Chapter 4.2)

The construction of nuclear power units was assumed according to the capacities outlined in the Polish Nuclear Power Program, with the commissioning of the first unit planned for 2036. The start of operation of following nuclear units was assumed for 2038 and 2040, respectively.

The contribution of neighbouring Member States in ensuring the resource adequacy (described in more detail in Chapter 4.4)

The participation of Member States in ensuring the resource adequacy was estimated based on the methodology used to determine *Maximum Entry Capacity*². It was assumed that exchange volumes for interconnections with Ukraine do not impact the resource adequacy.

Price assumptions, prices of commodities and CO₂ emission allowances prices (described in more detail in Chapter 0)

Forecasts of prices for individual types of fossil fuels and CO₂ emission allowances prices were used, as adopted for the preparation of the European Resource Adequacy Assessment (ERAA 2024).

Demand for power and electricity (described in more detail in Chapter 4.1)

The demand curves for power and electricity used for the NRAA were developed considering historical data on final energy consumption, GDP growth forecasts, and anticipated changes in the structure of final energy consumption resulting from the ongoing energy transition. For each calendar year, an hourly power demand

²The methodology for calculating the Maximum Entry Capacity for cross-border participation in capacity mechanisms (Maximum Entry Capacity – MEC) in accordance with the ACER decision of December 22, 2020 „ACER Decision on technical specifications for cross-border participation in capacity mechanisms”

forecast was made in 38 climate scenarios, where each climate scenario was characterized by correlated parameters defining hydrological conditions, wind, insolation, and external temperature

4.1 Power and energy forecast

The long-term forecast for net energy and power demand in the National Power System (KSE) was prepared considering historical trends and projected final energy consumption. Factors considered included those affecting the structure of energy consumption in the household, transport, industry, and services sectors, changes in energy efficiency, GDP growth forecasts in individual sectors, technological and consumer changes, and changes resulting from EU directives aimed at achieving Poland's required RES target in final energy consumption. Additionally, anticipated structural changes in final energy consumption were included, such as the increase in the number of electric vehicles and heat pumps.

The forecast for power and electricity demand was conducted as a combination of the baseline demand forecast and individual forecasts for sectors of increasing importance due to the ongoing energy transition, namely:

- heat pumps,
- electric vehicles,
- data centres,
- electrode boilers, industrial heat pumps, and
- green hydrogen production installations.

Fig. 4.1 and fig. 4.2 present, respectively, the result of the forecast for annual net electricity demand and power demand for the years 2025 - 2040 within the NRAA.

Fig. 4.1 Forecast of annual net electricity demand for the years 2025-2040 [TWh]

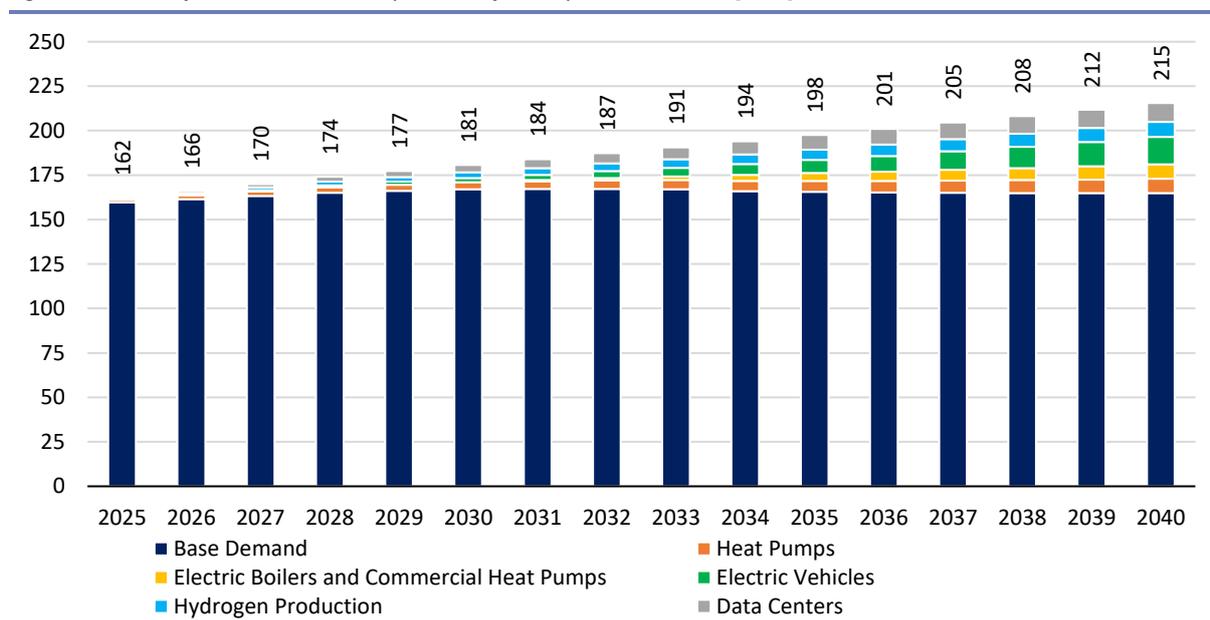
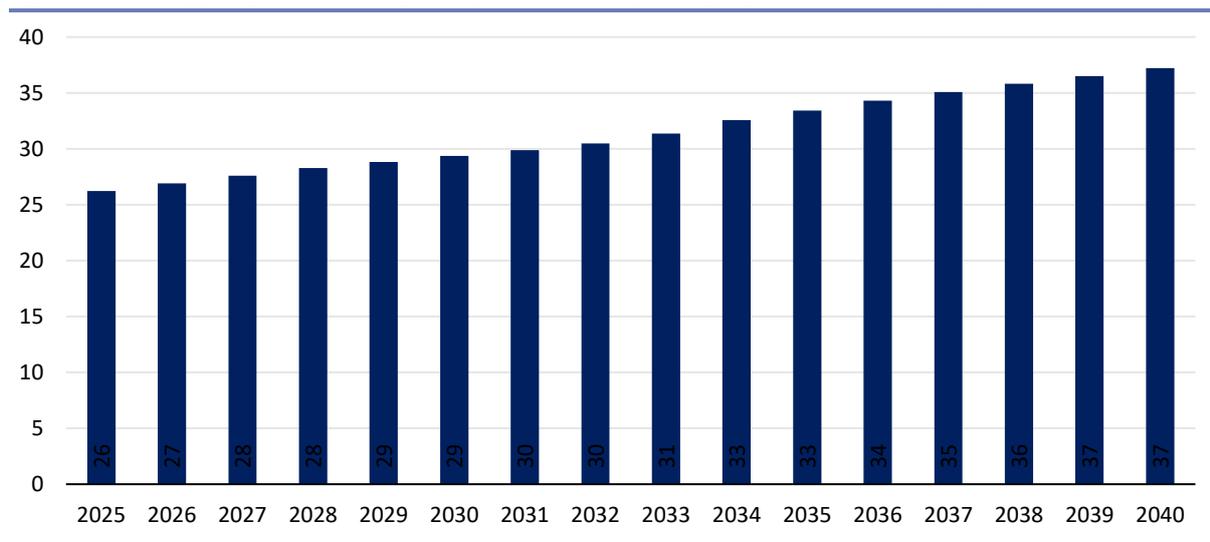


Fig. 4.2 Forecast of peak power demand for the years 2025-2040, average of climate scenarios [GW]



4.1.1 Baseline power and energy demand profile

Power demand is shaped by a wide range of factors, making it a complex issue. On one hand, it is impacted by external conditions (resulting in different demand for cooling and heating production). On the other hand, a certain portion of the demand is independent of weather and has a structural character (e.g. demand related to industrial processes). The method used considers the occurrence of both these elements. Inclusion of the seasonality of demand along with its response to external conditions enables probabilistic analysis using the concept of climate scenarios.

To illustrate, it should be noted that in Poland, the demand for electric in January exceeds the demand observed in May, even at the same ambient temperatures. This is because only part of the demand is sensitive to temperature changes (e.g. heating, air conditioning), while the rest depends on seasonal factors (e.g. the length of the day affects lighting operation). Therefore, the first step was to develop a seasonality model by eliminating trends and normalizing seasonal patterns in the data.

The next phase involved developing a temperature sensitivity model in the form of an autoregressive model that incorporates temperature to reflect weather conditions. Other weather factors were omitted due to collinearity and their secondary importance. The temperature sensitivity model uses the residuals from the seasonality model (values not accounted for by seasonal changes) and the temperature gradient, which is the difference between the actual temperature and the reference temperature, that is the average hourly temperature from all available data.

By combining seasonality and temperature sensitivity models, the demand was accurately represented under various external conditions, according to the PECD database, i.e., in different climate scenarios.

4.1.2 Baseline demand forecast

The reference point for the conducted demand analyses is the Eurostat statistical data for Poland presented in the Energy Balance³ report published in December 2022. This report, updated periodically, provides a comprehensive collection of statistical data presenting the energy balance, covering elements such as import and domestic production of primary energy through its transformation processes, up to final consumption in

³ <https://ec.europa.eu/eurostat/web/energy/database/additional-data>

European countries, including Poland. The statistical data are presented according to the consumption of various types of fuels, broken down by sectors:

- transport,
- industry,
- services,
- households,
- final non-energy consumption,
- energy sector,
- others.

The long-term baseline energy demand in the National Power System was prepared considering historical trends and projected final energy consumption. Factors impacting the structure of energy consumption in the household, transport, industry, and services sectors were considered, as well as changes in energy efficiency, GDP growth forecasts in individual sectors, consumer, and technological changes, and changes resulting from EU directives aimed at achieving Poland's required renewable energy target in final energy consumption.

4.1.3 Power and energy demand forecast

Based on the base profile and the baseline demand forecast, a power demand forecast was prepared. The forecast for the first years considers changes in the demand profile, referring to historical data under consistent environmental conditions. In the following years of the forecast, considering possible trend changes and distortions, the profile was adjusted according to the energy consumption forecast.

To better reflect the ongoing energy transition, the base forecast is supplemented with the results of individual forecasts for sectors such as:

- Forecast of demand in the electric vehicles sector.

The forecast of electric power demand for electric vehicles was developed based on the analysis of vehicle traffic profiles and the number of vehicles in the respective forecast years. The model considers daily vehicle movement patterns such as average trip length, charging hours, and average energy consumption per distance travelled.

- Forecast of demand in the individual heat pumps sector.

The forecast of electric power demand for heat pumps was developed based on the analysis of heat demand in buildings and the forecasted number of heat pumps in the respective years. The model considers the energy characteristics of buildings, average heating demand in different periods of the year (dependent on external temperature), and the efficiency of heat pumps. The forecast considers the increase in the number of heat pump installations resulting from market trends, legal regulations, and the pace of building modernization.

- Forecast of demand in the data centres sector.

The forecast of electric power demand for data centres considers a constant daily demand profile, resulting from the continuous operation of servers and cooling systems. The power capacity of data centres in the respective years was determined based on market trends, such as the development of cloud services and the increasing number of computing centres.

- Forecast of demand in the sector of electrode boilers, industrial heat pumps, and hydrogen production installations.

The forecast of demand in the sector of electrode boilers, industrial heat pumps, and hydrogen production installations was developed based on the anticipated development of these technologies, which was prepared based on internal analyses and external sectoral analyses.

Two different methods for determining electricity demand profiles for individual sectors were adopted in the analysis, as described below.

Demand in the system cost minimization model

In the system cost minimization model, i.e., the long-term model, the baseline demand forecast was prepared at an hourly resolution for each climate scenario and each calendar year of the analysis. The individual sector forecasts were prepared considering:

- To produce hydrogen in electrolyzers, for electrode boilers, and industrial heat pumps, an approach based on renewable energy production curves was applied. The electricity demand profile was correlated with the availability of energy from RES, allowing for efficient matching of energy consumption to its production. This ensures that hydrogen production, powering of electrode boilers, and industrial heat pumps are carried out in the most efficient manner, utilizing renewable energy, especially during periods of excess production. This approach allows for the determination of profiles before final calculations, significantly reducing the computational problem and enabling simulations with hourly resolution over a time horizon exceeding 15 years.
- the electricity and power demand for heat pumps, electric vehicles, and data centres was developed based on external models developed by PSE.

The final forecast for the long-term model is the sum of the baseline forecast and individual sector forecasts, performed for each climate scenario and each calendar year of the analysis.

Demand in the full energy market model and the adequacy model

In the full energy market and adequacy models, i.e., short-term models calculated individually for each calendar year, the same baseline forecast as in the cost minimization model was used. The individual sector forecasts were prepared considering:

- a dynamic approach to modelling electricity demand in the hydrogen production, electrode boilers, and industrial heat pumps sectors. Two key parameters were considered: minimum monthly energy consumption and maximum power demand. The minimum energy consumption in a month includes:
 - the minimum hydrogen demand in the industry, which must be met regardless of the availability of energy from RES, ensuring the continuity of industrial processes,
 - the demand for electrode boilers and industrial heat pumps adjusted to seasonal heating needs, which are higher in winter due to increased heating demand and lower in summer.
- The maximum power demand primarily reflects the production capabilities resulting from the projected power capacity of electrolyzers, heat pumps, and electrode boilers. This includes the potential maximum capacity of these devices to draw power during peak operational moments, which is crucial for modelling dynamic energy demand.
- Dynamic energy demand for electric vehicles, which accounted for about 10% of the total electromobility demand. This profile is mainly dependent on hourly electricity prices, allowing for the optimization of vehicle charging during periods when prices are lowest, e.g., during surplus production from RES.

In this way, the demand-side response in the NRAA was represented, where consumers voluntarily adjust their energy consumption in response to market price signals (implicit DSR).

The final forecast for short-term models is the sum of the baseline forecast and the fixed component of individual sectors, performed for each climate scenario and each calendar year of the analysis. Additionally, the models

include constraints describing the demand flexibility of electrode boilers, industrial heat pumps, green hydrogen production installations, and electric vehicles. This way, greater flexibility of the power system was reflected by shifting part of the demand to more favourable moments, allowing for cost minimization and reducing peak power demand.

4.2 Resources to cover power demand

4.2.1 Existing conventional units

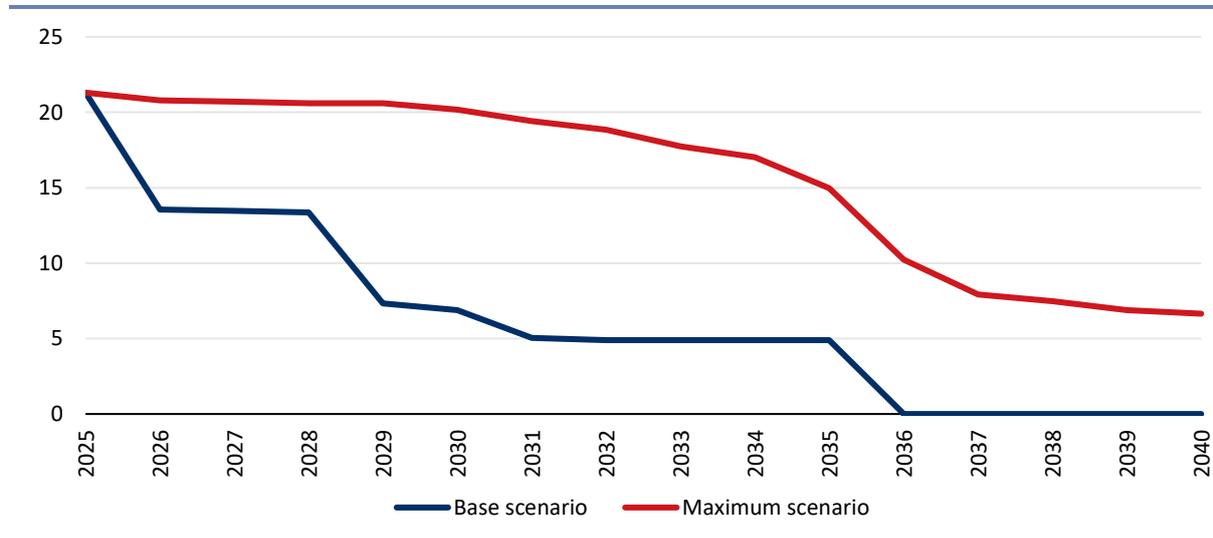
PSE conducts an annual survey of the generation sector to obtain the latest data on the operation of existing resources as well as those planned for construction in the long-term perspective. Owners of existing hard coal-fired and lignite-fired units, often provide scenario-based decommissioning dates of those units, dependent on the projected profitability, which is impacted by, among other things, applicable regulations, derogations, operational restrictions, and production costs.

For the purposes of this study, PSE conducted a survey covering techno-economic data and the planned decommissioning dates of coal-fired and lignite-fired generating units participating in the central balancing mechanism

Based on the aforementioned survey, net available capacity curves were prepared depending on the decommissioning scenarios:

- **base scenario**, resulting from technical-economic analyses under the current legal and market framework,
- **maximum scenario**, assuming profitability of generating units and possible lifetime extension actions.

Fig. 4.3 Maximum net available capacity of existing centrally dispatched coal-fired generating units [GW]

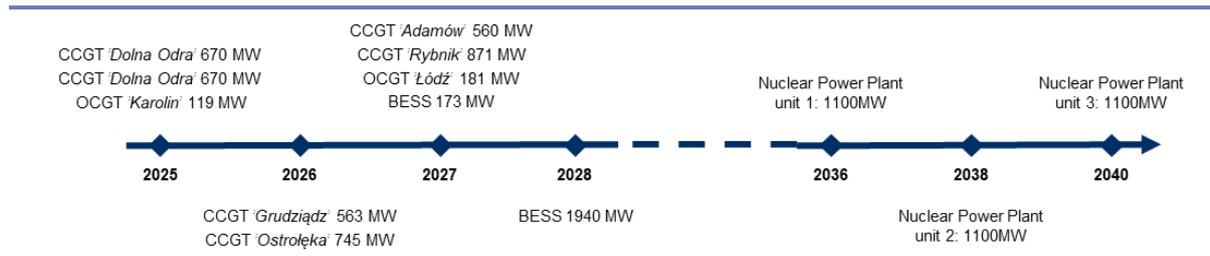


4.2.2 New centrally dispatched generating units and energy storage capacity expansion

In terms of new, determined centrally dispatched generating units, in the short-term perspective, conventional units and electricity storage facilities that are at an advanced stage of the investment process and have capacity contracts were assumed.

In the long-term perspective, the commissioning of large nuclear units was assumed in accordance with the capacities indicated in the Polish Nuclear Power Program, with the first unit expected to be commissioned in 2036. The commissioning of subsequent nuclear units is planned for 2038 and 2040, respectively.

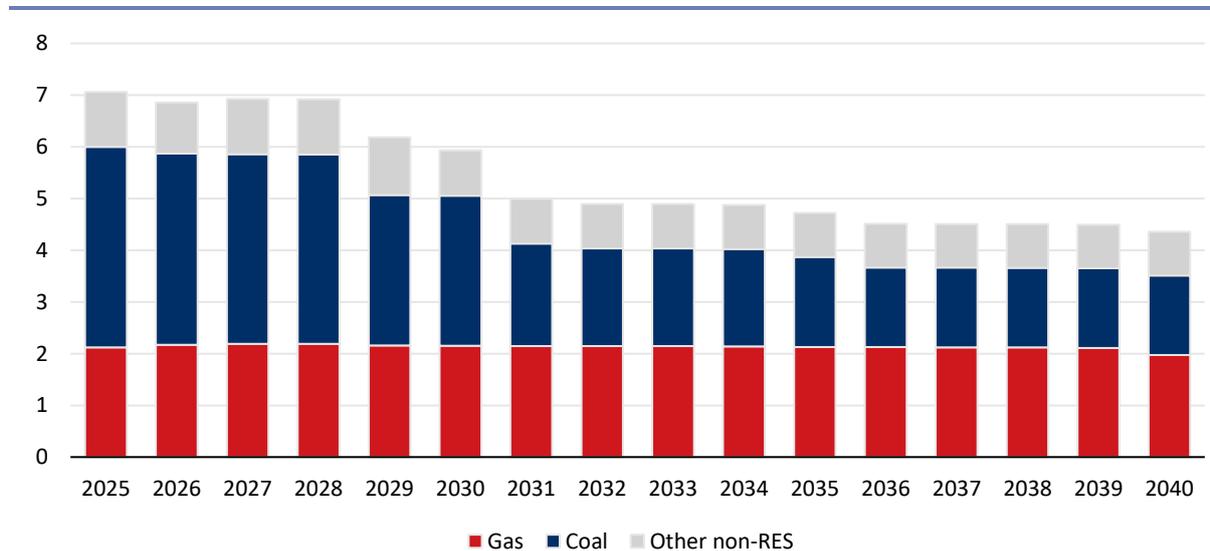
Fig. 4.4 New determined resources [MW]



4.2.3 Non-centrally dispatched generating units

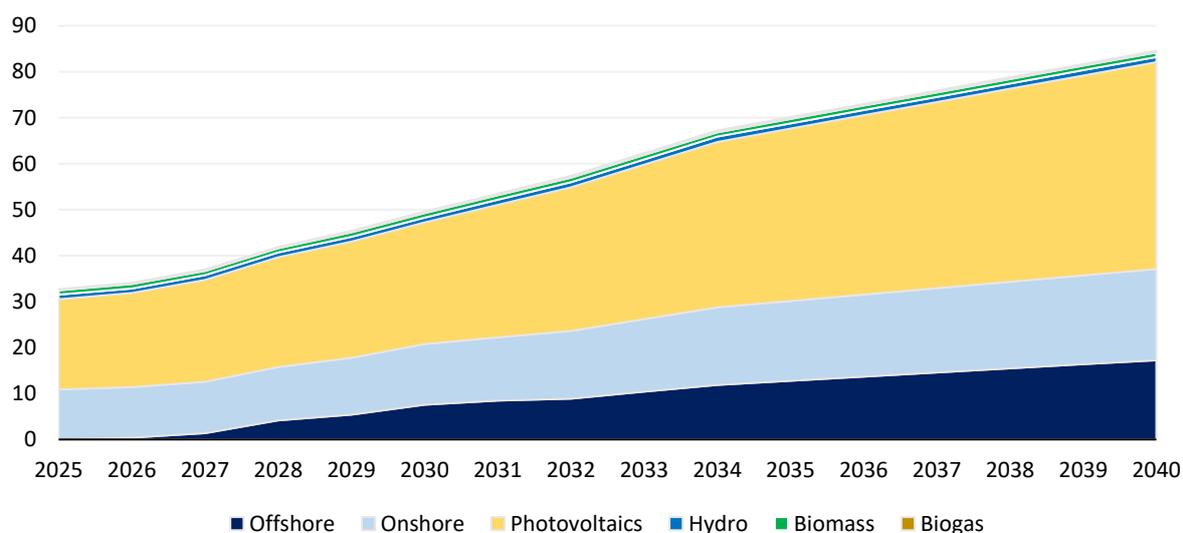
In terms of units powered by gas, hard coal or other non-renewable fuels, the results of the generation sector survey conducted at the beginning of 2024 were used. Fig. 4.5 presents a summary of these units.

Fig. 4.5 Net available capacity of non-centrally dispatched generating units powered by gas, coal or other non-renewable fuels [GW]



A further, determined development of renewable energy sources was assumed. Most of the capacity is expected in solar and wind sources, being supplemented in the coming years by offshore sources alongside onshore technologies. Fig. 4.6 presents a summary of the installed capacity of these sources.

Fig. 4.6 Renewable energy sources development [GW]



Detailed values of installed capacity of generating units that are not centrally dispatched, used in the NRAA, are presented in report's Annex Z1.

4.2.4 New entrants - generating resources capacities and energy storage facilities

In addition to the new determined capacities presented in more detail in sections 0 and 4.2.3, the model has the flexibility to make investment decisions involving the construction of other generating sources to minimize the total system costs. The analysis specifies the possible maximum annual capacity increase for two gas technologies, CCGT (Combined Cycle Gas Turbine) and OCGT (Open Cycle Gas Turbine), as well as electricity storage facilities. Assumption is, that in each year of the forecast investment period, it is possible to install up to 2 GW of capacity in CCGT units, including hydrogen-powered CCGT units, 2,5 GW of capacity in OCGT units and 2,5 GW in battery energy storage facilities with a capacity allowing for 4-hour operation at maximum load (Chapter 4.7).

4.2.5 Demand side response

In addition to included in the NRAA the so-called implicit DSR, described in section 4.1.3, the models consist also DSR that is an active participant in the energy market. To determine the volume of such service for individual years, past experiences related to DSR units were considered, including the current potential for demand side reduction contracted in the existing capacity market. The table below presents the values of available capacity in DSR used for the NRAA.

Tab. 4.1 Available capacity in DSR, which is an active participant in the energy market

		Year of analysis			
		2025	2026	2027-2028	2029 - 2040
Demand side response	MW	1 300	1 509	1 539	1 600

DSR has been divided into 5 price bands. It is assumed that this service will be activated depending on the current price in the energy market.

4.3 Climate scenarios

The National Power System is increasingly sensitive to changes in weather conditions. To accurately anticipate possible future events that may impact the power system balance, it is necessary to include data covering a wide range of possible combinations, accounting for both "normal" and "extreme" climatic conditions.

The analysis is based on the "climate year" method, which is used in ENTSO-E analyses such as the European Resource Adequacy Assessment (ERAA) and the Ten-Year Network Development Plan (TYNDP). This method allows for the simulation of variable weather conditions observed in past years as projections for the future. Each climate year is characterized by interdependent parameters defining hydrological, wind, solar, and external temperature conditions, enabling an assessment of the power system operation while considering the simultaneity of these phenomena.

The scenarios for climate years were developed using the Pan-European Climate Database (PECD), an essential component in studying the impact of climatic conditions on the adequacy of power systems. The PECD database includes climate data spanning 38 years (1982 – 2019), such as wind speed, solar radiation, cloud cover, and temperature. These data provide a broad range of climatic conditions, incorporating rare but extreme events. While precise future weather conditions cannot be predicted, using such an extensive range of historical phenomena enables the creation of a robust understanding of potential future risks.

4.3.1 Climate scenarios clusterization

Clustering of 38 climate years from the PECD was conducted to support both the cost minimization model and the full market models. The cost minimization model aims to optimize the power system from a long-term perspective. Due to the multidimensional nature of the problem, a dimensionality reduction technique was applied to reduce the number of variables while preserving essential information. The clustering concept, used in ENTSO-E studies such as the ERAA and TYNDP, was implemented here. Specifically, the PD-Gauss method—a probabilistic clustering method that extends the basic PD⁴ method—was used. The PD method itself belongs to a class of probabilistic clustering techniques that assign a likelihood of membership to a given cluster. The extended method allows the selected climate scenario to align with the cluster size using a Gaussian density-based divergence measure. This approach enabled the clustering of the entire set of climate scenarios into three representative clusters, with the most characteristic scenario selected for each cluster.

Clustering was based on the results of a simplified adequacy model, which used a system states table and the probability of occurrence, without incorporating economic optimization of unit operation. Input data for the model came from a scenario assuming maximum unit decommissioning (see section 4.2.1). The model results include EENS (Expected Energy Not Served) and LOLE (Loss of Load Expectation) metrics. The clusters were created by considering the similarity of climate scenarios based on climatic parameters, demand distributions, and probabilistic values of EENS and LOLE obtained from the analyses. Thus, the clusters were characterized as low (low LOLE and EENS, low demand, high RES share), medium, and high (high LOLE and EENS, high demand, low RES share).

Tab. 4.2 Climate years clustering results

Cluster	Number of climate scenarios assigned to a cluster	Representation with the highest probability of participation	Symbolic description of the cluster	Weight
1	21	2001	average	55,3%
2	8	2008	low	21,1%
3	9	2013	high	23,7%

⁴Tortora C., McNicholas P.D., and Palumbo F. A probabilistic distance clustering algorithm using Gaussian and Student-t multivariate density distributions. SN Computer Science, 1:65, 2020

4.3.2 Capacity factors for wind and solar power plants

For the onshore wind farms, offshore wind farms, and photovoltaic power plants, hourly operational profiles were developed. Electricity production from renewable energy sources is a process dependent on the ambient conditions at a specific location. This means that the amount of energy generated by wind turbines depends on the wind speed at the turbine's nacelle, while the energy produced by photovoltaic power plants is determined by the intensity of solar radiation and the angle of incidence on the panel surface.

Given the prevailing atmospheric conditions, the instantaneous load of a specific wind or photovoltaic power plant can be accurately assessed. The ratio of generated power at any given moment to the installed capacity is known as the capacity factor. Creating an hourly generation profile for RES units was made by using the hourly database of climate years. Generation profile established this way made it possible to determine electricity production across all scenarios of climatic conditions.

In fig. 4.7, fig. 4.8 and fig. 4.9, the full load hours for offshore wind, onshore wind, and photovoltaic power plants in Poland for the respective climate years are presented.

Fig. 4.7 Full load hours of offshore wind power plants

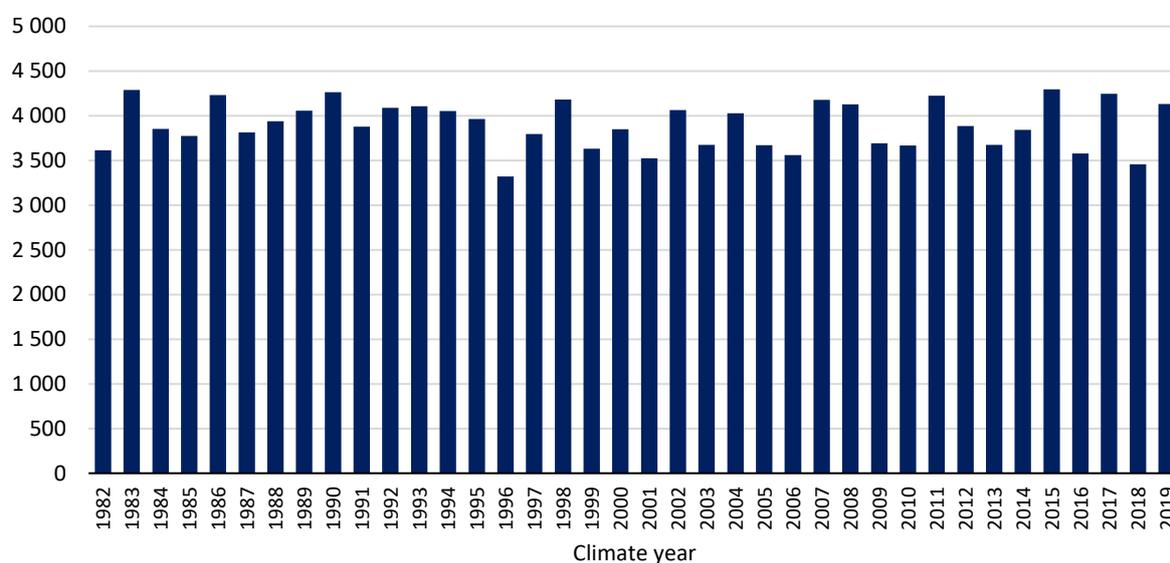


Fig. 4.8 Full load hours of onshore wind power plants

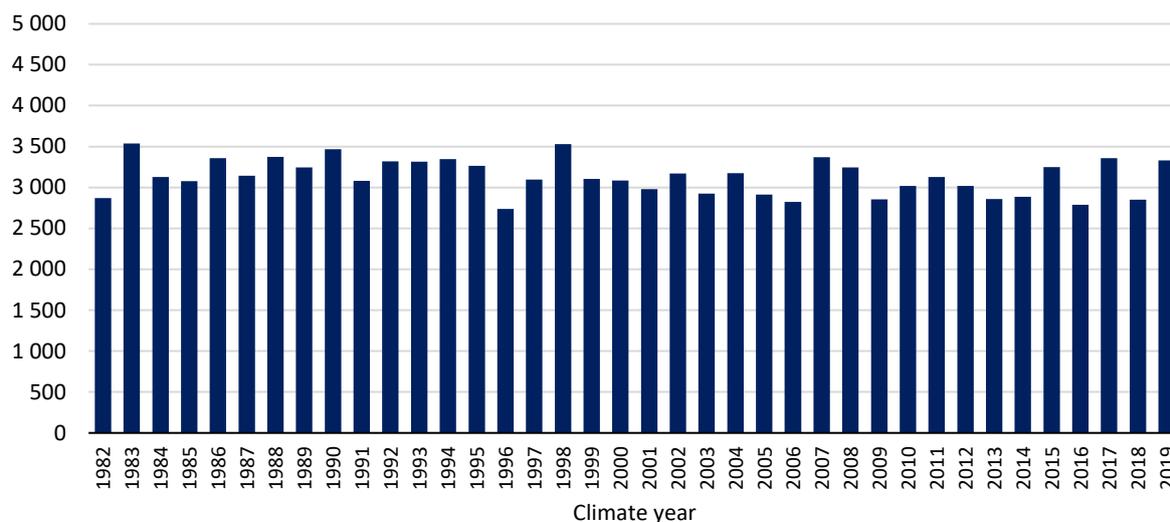
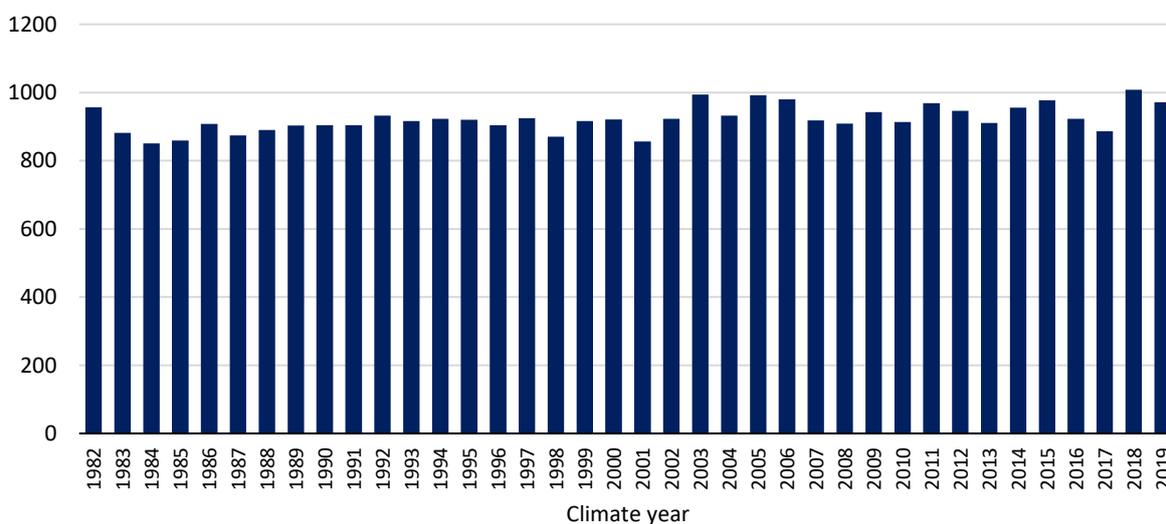


Fig. 4.9 Full load hours of solar power plants

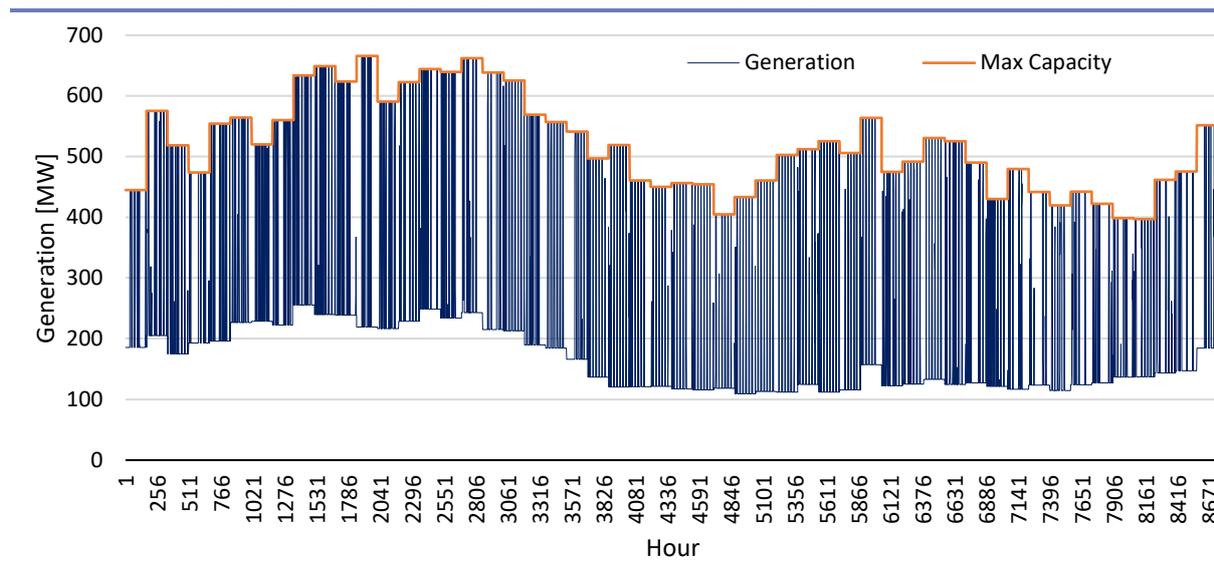


4.3.3 Capacity factors for run-of-river power plants

To incorporate the responsiveness of run-of-river hydropower plants to market electricity prices, as well as their contribution to system balancing and generation regulation, an optimization of their operation was applied. Based on historical data from 2019 to 2023, an average annual profile of minimum power—generated independently of the balance situation in the National Power System was developed, along with a maximum power profile that reflects technical generation capabilities. Additionally, an aggregated inflow profile was created on a weekly basis for the year.

Fig. 4.10 presents the generation output of run-of-river hydropower plants included in the model for one of the full market models for the year 2025.

Fig. 4.10 Generation of run-of-river hydropower plants, full market models for the year 2025



4.3.4 Capacity factors for conventional industrial and utility-scale generation units

Capacity factors for installed power in conventional industrial and utility-scale generation units classified as non-Dispatchable Generation Units were determined based on historical generation data. This approach was applied to coal-fired units, biomass, biogas plants, and Waste-to-Energy facilities.

For utility-scale combined heat and power plants, thermosensitivity curves were also developed to describe the relationship between load and ambient temperature. Each month of the year has its own thermosensitivity curve assigned.

The data are adjusted to the hourly resolution used in the model, resulting in curves that describe unit operation, accounting for both scheduled maintenance and forced outages. For utility-scale units, these curves are further differentiated according to climate scenarios.

4.4 Cross-border exchange

4.4.1 Contribution of neighbouring bidding zones to the system security

To determine the capacity of foreign capacity providers contributing to the NPS balance, a methodology that is used for determining the volumes of foreign capacity participating in capacity mechanisms was applied. The method is introduced with the ACER decision⁵ and is presented in the annex to this decision *on technical specifications for cross-border participation in capacity mechanisms: Annex I*. Essentially, in this method, the contribution of foreign capacity to the balance of the zone where the capacity market is located, is calculated based on the analysis of cross-border flows during scarcity hours in this zone, i.e., during periods of capacity deficit.

The analysis was based on forecasted values due to the changing power structure in European power systems, and consequently, the price differentiation in individual zones, as well as structural changes in the transmission

⁵ ACER Decision No 36/2020 of the European Union Agency for the cooperation of energy regulators of December 22, 2020, on technical specifications for cross-border participation in capacity mechanisms

capacity of cross-border connections. The analyses utilized the results of the European Resource Adequacy Assessment, i.e., ERAA 2023 report (in the version approved by ACER in May 2024).

Tab. 4.3 presents the values of contributions from foreign units to the NPS balance used for the NRAA report.

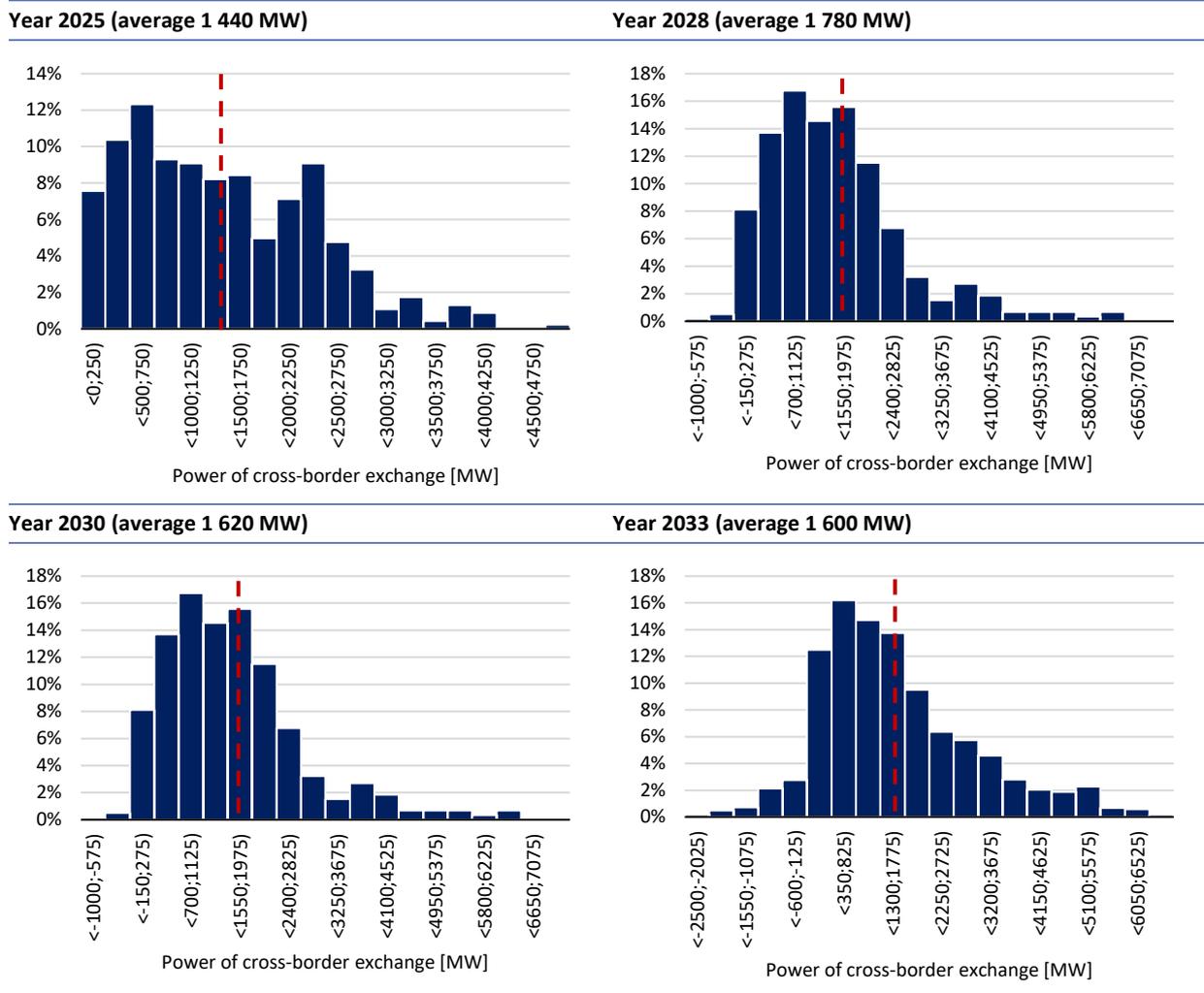
Tab. 4.3 Values of contributions from foreign units to the system balance used for the NRAA report

		Year			
		2025 - 2027	2028 - 2030	2031 – 2033	2034 - 2040
Contribution of neighbouring zones	MW	1 440	1 780	1 620	1 600

Fig. 4.11 presents the data distributions based on which the aforementioned contribution of foreign units was determined for the respective calculation years of ERAA 2023. The result is the average value of all analysed samples. However, the presented distributions show that the contribution can be significantly below the average (zero or even negative values – negative values indicate export due to simultaneous scarcity in the region and the apply of the curtailment sharing mechanism) as well as significantly above the average. Such large deviations in the analysed data set cause the contribution of foreign units to be an element introducing significant uncertainty into the NRAA analyses, requiring appropriate consideration during the result processing and conclusion drawing stages.

It should be emphasized that the primary goal of the NRAA is to assess the level of operational security of the NPS. Therefore, the lack of full modelling of cross-border exchange during periods not characterized by a tight balance situation does not affect the result of the analysis.

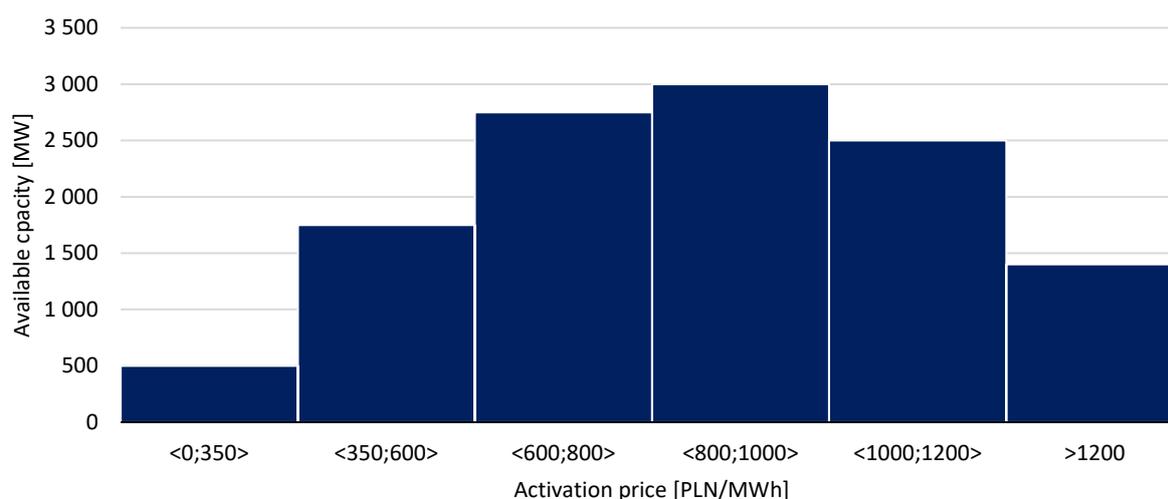
Fig. 4.11 Distribution of samples for cross-border exchange



4.4.2 Cross-border exchange – energy import and contribution

In the scope of the applied model for cross-border exchange, i.e., energy import and contribution to the capacity balance, the possibility of covering the energy demand of consumers in the NPS by foreign units was considered. These units were modelled as energy suppliers with a non-linear price profile relative to the offered capacity. This aims to simulate the variable supply of foreign units depending on the balance situation in the systems where they are located. The maximum power capacity was determined as in the contribution model described in Chapter 4.4.1. Fig. 4.12 presents the activation levels of foreign units.

Fig. 4.12 The relationship between available import capacity and the offered price of electricity



4.5 Macroeconomic assumptions

The macroeconomic assumptions include factors such as fuel prices and CO₂ emission fees. These elements are crucial for market models as they affect the operating costs of generating units and their position in the energy market, which in turn determines their optimal utilization and generated revenues.

To ensure a consistent approach with the European Resource Adequacy Assessment, the prices of fossil fuels and CO₂ emission fees are based on the assumptions used for the currently developed ERAA 2024. These assumptions were determined considering, among others, analyses conducted by Bloomberg, IEA in the documents “World Energy Outlook 2022” and “World Energy Outlook 2023”, Booz&co in the document “Understanding Lignite Generation Costs in Europe”, as well as data presented in the Danish Technology Catalogue.

Tab. 4.4 Fuels and CO₂ emission fees costs (real prices PLN'23)

		2026	2028	2030	2035	2040
Gas	PLN/GJ	33,2	30,8	28,3	27,1	25,9
Hard coal	PLN/GJ	14,4	11,8	10,7	10,1	9,5
Lignite *	PLN/GJ	3,7	3,7	3,7	3,7	3,7
CO ₂ emission fees	PLN/kg	0,3	0,5	0,6	0,7	0,8
	PLN/t	330,2	474,9	619,6	711,4	803,2
H ₂ (green) **	PLN/GJ	261,4	261,4	261,4	235,2	209,1
Biomass	PLN/GJ	50,0	62,1	75,8	84,6	93,5
Oil	PLN/GJ	68,7	71,5	74,2	70,7	67,2

* - Lignite prices were determined individually for each power plant based on data from the unit owners. The table presents the averaged values for all sources.

** - Hydrogen prices were determined based on publicly available hydrogen production cost models

For the purposes of the NRAA, the cost of unserved energy (VoLL) estimated by the President of the Energy Regulatory Office was used, as presented in the Information of the President of the Energy Regulatory Office No. 10/2023 regarding the estimated value of undelivered electrical energy in the territory of the Republic of Poland. Subsequently, to adjust the VoLL to 2023 prices, changes resulting from inflation for the period 2021 – 2023 were considered. The VoLL value used in the NRAA was set at 108 kPLN/MWh. This approach ensures the consistency of VoLL with the costs for new entry and other assumptions also adjusted to the real prices of 2023.

4.6 Existing units' costs

To developing the economic assumptions for the operation of existing coal-fired CDGU, the costs were adopted based on the survey mentioned in section 4.2.1. The model includes:

- fixed operating costs,
- variable operating costs (other than fuel and CO₂ emissions),
- investment and maintenance expenditures,
- costs of permanent decommissioning of units.

Since the above information constitutes confidential data of the entities owning the generating units, the values of the cost parameters have not been presented in the report.

4.7 Technical and economic parameters of new generating units

Tab. 4.5 presents the technical and economic parameters of new generating units that could have been selected within the system cost minimization optimization model. The parameters for OCGT and CCGT were determined based on the Information of the President of the Energy Regulatory Office of March 14, 2023, No. 12/2023 *regarding the cost of entry for new capacities and demand-side response*. The values were indexed to the real prices of 2023. The investment expenditures for CCGT H₂ were assumed to be 15% higher than the investment expenditures for CCGT. The investment expenditures for electrochemical storage were estimated based on the publicly available offer from Tesla for Megapack units. The specific cost was determined for an installation with a capacity of 100 MW and a storage capacity of 400 MWh. Due to the anticipated decrease in investment expenditures for the construction of energy storage as a developing technology, a 5% decrease over 5 years was assumed.

Tab. 4.5 Technical and economic parameters of new units depending on technology (real prices PLN'23)

		OCGT	CCGT	CCGT H ₂	BESS
CAPEX	kPLN/MW	3 349	3 638	4 184	5 035 – 4 544*
WACC	%	8%	10,39%	10,39%	10,39
Technical lifetime	years	25	25	25	15
VOM **	PLN/MWh	20	20	20	-
FOM	PLN/kW/year	248	315	315	96

* Investment expenditures for the period 2030 - 2040 according to the publicly available offer from the Tesla Megapack supplier

** The variable cost does not include fuel costs and the cost of purchasing CO₂ emission allowances

4.8 Analogies and differences between NRAA and ERAA

The reports of NRAA and ERAA should be consistent with the assumptions specified in Article 23 of Regulation 943/2019, particularly in points (b) to (m) of Article 23(5) of Regulation 943/2019. Due to the common legal requirements regarding methodology, these reports share many similarities, however, due to the regional scope of the NRAA, there are differences between the documents in terms of the scope of analysis conducted, the assumptions made, and the scenarios considered.

In both cases, the assessment of resource adequacy conducted in the ERAA and NRAA reports:

- is based on appropriate central reference scenarios of projected demand and supply including an economic assessment of the likelihood of retirement, mothballing, new build of generation assets and

- measures to reach energy efficiency and electricity interconnection targets and appropriate sensitivities on extreme weather events, hydrological conditions, wholesale prices and carbon price developments,
- considers contribution of all resources including existing and future possibilities for generation, energy storage, sectoral integration, demand response, and import and export and their contribution to flexible system operation,
 - is based on a market model using the flow-based approach, where applicable,
 - apply probabilistic calculations,
 - apply a single modelling tool,
 - includes the indicators Expected Energy Not Supplied and Loss of Load Expectation,
 - consider real network development,
 - ensure that the national characteristics of generation, demand flexibility and energy storage, the availability of primary resources and the level of interconnection are properly taken into consideration.

The presented NRAA report complements the analyses conducted in the ERAA 2023 report, which was published and approved in May 2024. The most significant difference compared to the ERAA report is the comprehensive economic viability of generating units in the National Power System. Using the terminology of this NRAA report, it can be stated that the ERAA 2023 results were developed based on the system cost minimization model and the adequacy model. The ERAA 2023 did not present a full economic analysis for existing and new generating units. In the NRAA, such an economic analysis was conducted based on the cost minimization model results. Additionally, the NRAA presents results for a scenario with a capacity mechanism, which was not included in the ERAA 2023. Besides the differences in scenarios, the ERAA 2023 and NRAA reports also differ in the assumptions for the analyses, i.e., the NRAA includes updated technical and economic data on the Polish generation sector and macroeconomic assumptions.

The results of the baseline scenario are presented in Chapter 5.1, and the scenario with the capacity mechanism is presented in Chapter 5.2.

5 Scenarios and results

The NRAA report consist results of two scenarios:

Base Scenario – assumes the inclusion of existing contracts in the capacity market and does not consider new mechanisms supporting generation capacity. It foresees the operation of centrally dispatched conventional generation units only when they generate profits at the operational level.

Scenario with Capacity Mechanism – assumes the operation of solutions supporting generation capacity. It foresees the operation of centrally dispatched generation units at a level necessary to ensure the security of electricity supply to end consumers.

5.1 Base Scenario

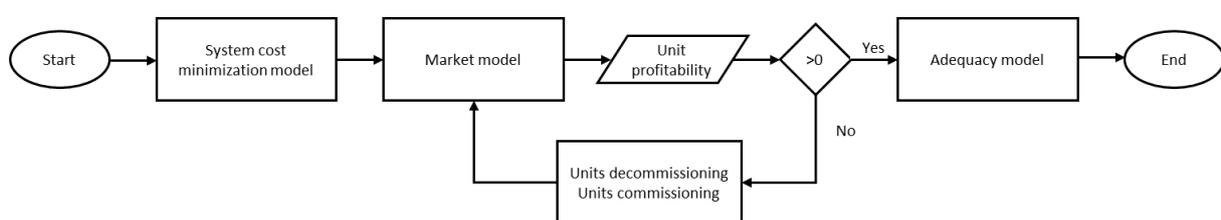
The main assumption of the base scenario is to demonstrate the economic viability of all available generation units (both existing and planned) that are centrally dispatched. These units were subjected to economic optimization. Other generation units, such as RES (Renewable Energy Sources) and cogeneration units, were analysed as predetermined based on own assumptions and information obtained from generation sector entities. The calculations showed that the economic viability for the optimized units could be achieved if the average total duration of lost of load hours per year is between 10 - 20 hours or greater for some climate scenarios, assuming that during scarcity periods, electricity prices will approach the value of VoLL. The number of scarcity hours significantly exceeds the mentioned reliability standard set at 3 hours per year.

To develop this scenario, the following were used:

- cost minimization model – the results of this model served as the starting point for the subsequent stages of this scenario. Detailed results of this model are presented in Annex Z1;
- full energy market model – the model was used for iterative analysis of the profitability (economic viability) of units;
- adequacy model – calculation of system adequacy indicators based on the results of the full energy market model.

Fig. 5.1 presents the process and models used within the base scenario. The scope of input data for the models used in the scenario is presented in Chapter 3 of the report.

Fig. 5.1 Process diagram of the Base Scenario



The main element of this scenario were the iterations performed in the full market model. For each calendar year, when unprofitable units were present in the market, part of them was withdrawn from the system during the iterations (i.e., existing units were withdrawn, and the commissioning of new units was delayed until profitability was achieved in subsequent years). Iterations end when profitability is achieved for all units i.e. all units are economically viable. In special cases, when there is a large diversity of technologies available in the system (mainly after 2035), achieving a result where all units are profitable required many time-consuming iterations. In this case, the result where a few units are on the edge of profitability was accepted as the result for the given year. The result of economic viability is the installed capacity mix in the system for the years 2025 – 2040 (Fig. 5.2 Profitability of CDGU and storage – Base Scenario [GW]fig. 5.2 and fig. 5.3).

After completing the iterations of the full market model, an adequacy analysis was conducted (as described in Chapter 3.4). Tab. 5.1 presents the results of this analysis.

The label ‘with a capacity obligation’ refers to units with a capacity obligation from the auctions of the existing capacity market conducted to date.

Fig. 5.2 Profitability of CDGU and storage – Base Scenario [GW]

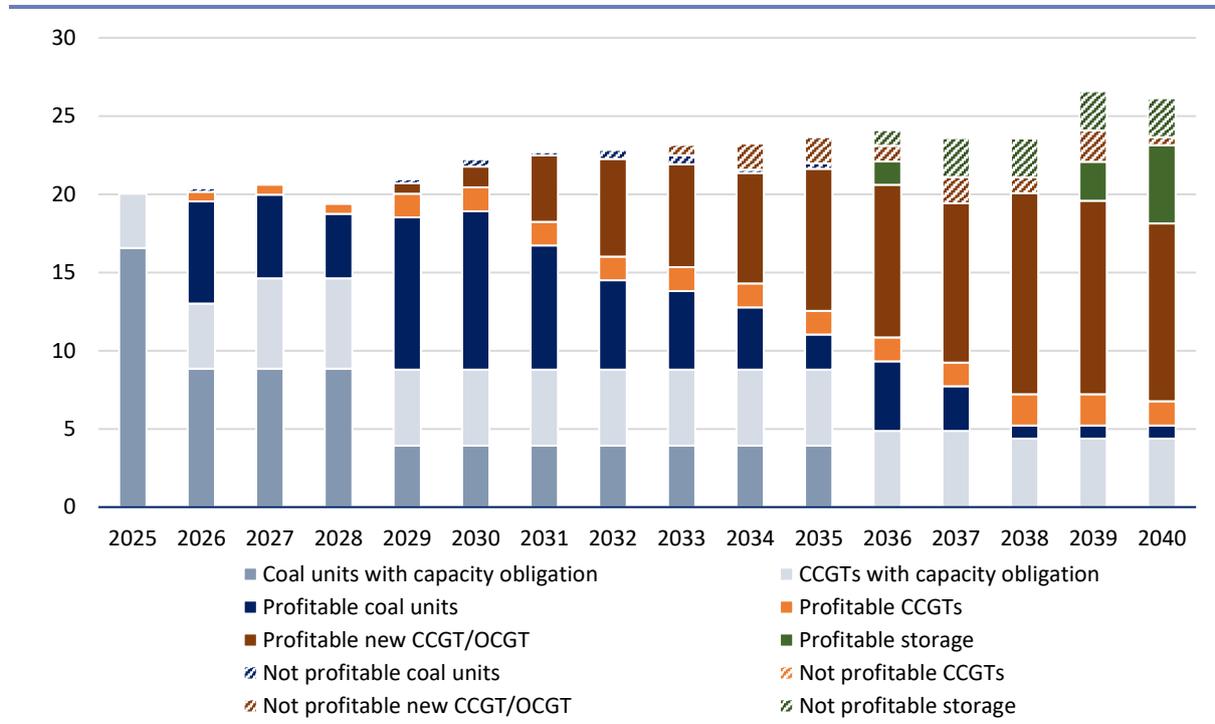
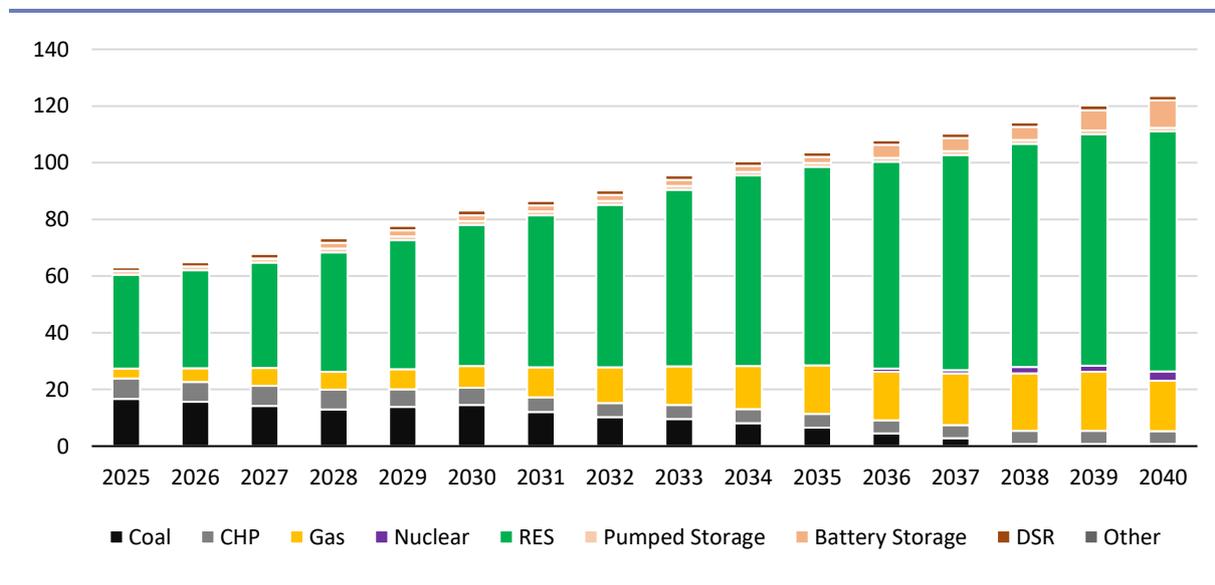


Fig. 5.3 Installed capacity of generation units – all units – Base Scenario [GW]



Tab. 5.1 Adequacy analysis results – LOLE and EENS – Base Scenario

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LOLE average	h/a	7,6	40,8	50,2	33,3	20,5	9,6	6,6	14,3	15,0	14,4	10,9	10,8	12,5	10,4	5,8	14,2
LOLE P95	h/a	21,0	79,8	82,8	68,7	45,8	25,2	21,6	36,0	39,3	35,0	28,4	32,1	30,8	30,6	22,1	42,6
EENS average	GWh/a	5,8	40,6	54,4	52,1	31,8	13,8	9,4	22,7	24,3	23,6	18,1	23,5	25,3	23,3	13,5	33,6
EENS P95	GWh/a	16,4	92,8	105,0	114,6	79,8	43,3	33,5	67,3	74,4	72,1	53,6	83,1	73,8	88,7	56,3	124,4

Detailed results of the system adequacy model are presented in Annex Z3.

The charts below present:

- the share of generation in the analysed years – fig. 5.4
- emissions from the energy generation sector – only CDGU burning fossil fuels – fig. 5.5.

Fig. 5.4 Generation share of technologies/fuels – Base Scenario

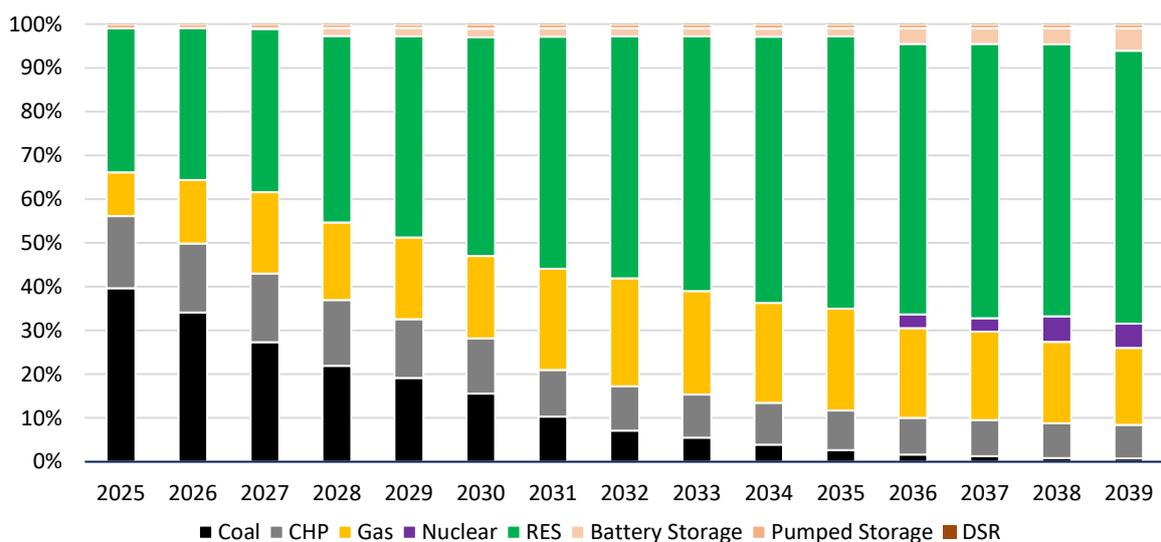
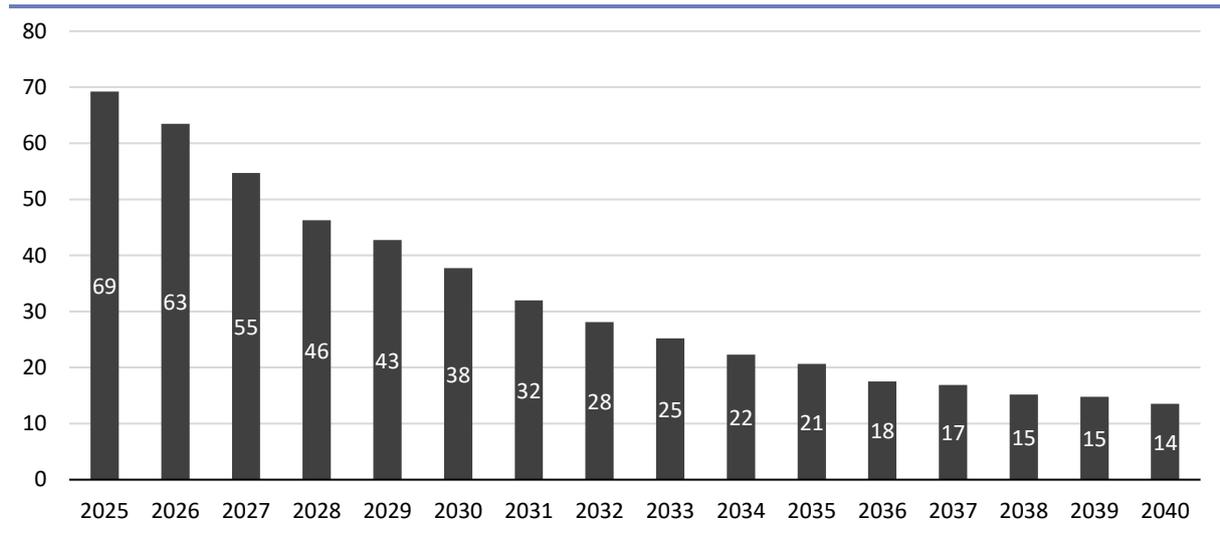


Fig. 5.5 Emissions from the energy generation sector in CDGU – Base Scenario [mln t]



5.1.1 Base scenario with energy import

As a sensitivity analyses, calculations were carried out for the base scenario, considering cross-border exchange and energy import to the National Power System (as described in 4.4.2). The purpose of presenting this sensitivity is to demonstrate the impact of energy imports on generation units. It can be stated that from the perspective of the profitability analysis of generation units, energy imports change the competitive conditions in the energy market, thereby worsening the profitability of generation units in the NPS. The calculations were carried out based on the base scenario results, and no further iterations were performed to achieve profitability for all units. Conducting further analyses and withdrawing unprofitable units would result in an additional increase in the LOLE and EENS values in the adequacy model results. The label 'with a capacity obligation' refers to units with a capacity obligation from the auctions of the existing capacity market conducted to date.

Fig. 5.6 Profitability of CDGU and storage – Base Scenario with energy imports [GW]

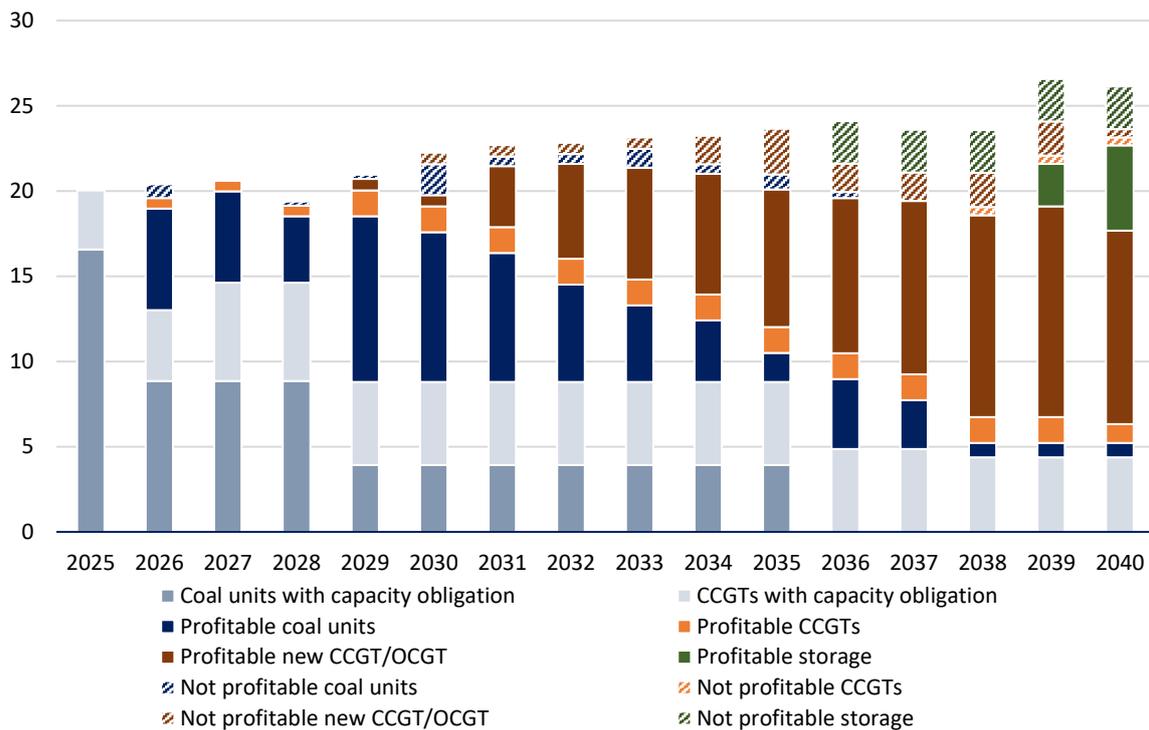
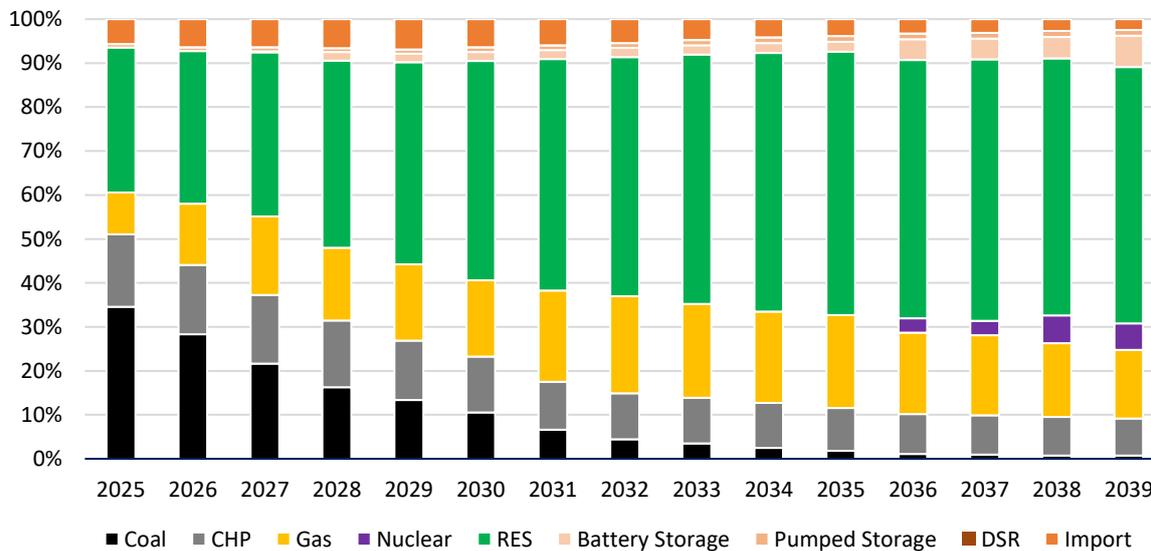


Fig. 5.1 presents the share of generation from individual sources in the analysed years.

Fig. 5.7 Generation share of technologies/fuels– Base Scenario with energy imports



5.2 Scenario with Capacity Mechanism

The main assumption of the scenario with capacity mechanism was to demonstrate the necessary dispatchable capacity installed in the system to meet the reliability standard. As part of the analysis of this scenario, an economic analysis of CDGUs necessary to meet the reliability standard was performed. The results of this analysis show that in a system that meets the reliability standard, a significant portion of generation units is unprofitable, i.e., the second-degree margin is negative. Therefore, to maintain these units in the system, it is necessary to implement a mechanism or mechanisms for generation capacity that will allow for the maintenance of existing

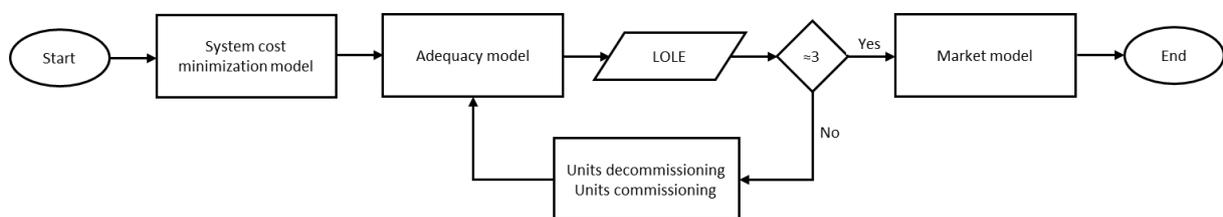
units and investments in new dispatchable power sources, particularly gas-fired units, with the possibility of future conversion to hydrogen or biomethane-fired units, as well as electricity storage facilities.

To develop this scenario, the following were used:

- cost minimization model – the results of this model served as the starting point for the subsequent stages of this scenario. Detailed results of this model are presented in Annex Z1;
- adequacy model – the model was used for iterative analysis of system adequacy indicators;
- full energy market model – analysis of the profitability of generation units based on the results of the adequacy model.

Fig. 5.8 presents the process of the analyses and models used within this scenario. The scope of input data for the models used in the scenario is presented in Chapter 3.

Fig. 5.8 Process diagram of the Scenario with Capacity Market



The main element of this scenario were the iterations performed with the adequacy model. For each individual calendar year, the LOLE result was checked, and units were added or removed from the set during the iterations. Iterations end when the LOLE indicator reaches approximately 3 hours per year. In special cases, when only high-capacity units (around 1 GW installed capacity) are available in the system, achieving a result close to 3 hours may be impossible. The impact of a single unit of such capacity on adequacy indicators is so significant that the results range from 2 to 4 hours per year. It was accepted that a result within this range is final. After completing the iterations in the adequacy model, an economic viability was conducted for the resulting mix for years 2025 – 2040 (fig. 5.9 and fig. 5.10).

Tab. 5.2 presents the results of the adequacy analysis of the scenario with capacity mechanism.

The label 'with a capacity obligation' refers to units with a capacity obligation from the auctions of the existing capacity market conducted to date.

Fig. 5.9 Profitability of CDGU and storage – Scenario with Capacity Mechanism [GW]

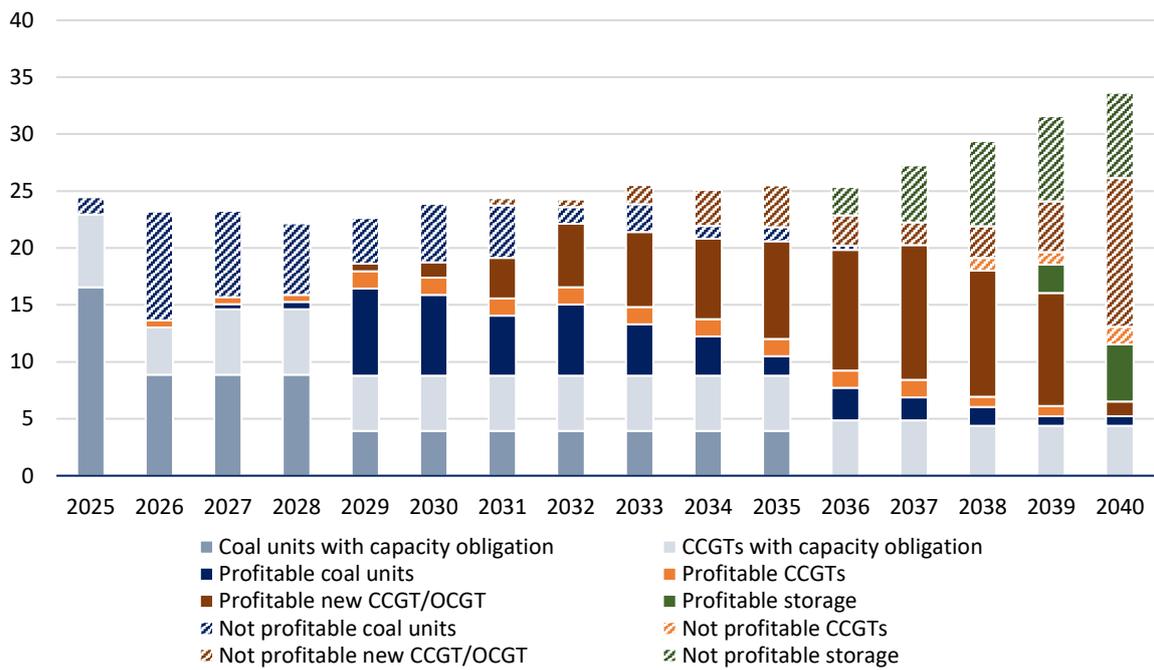
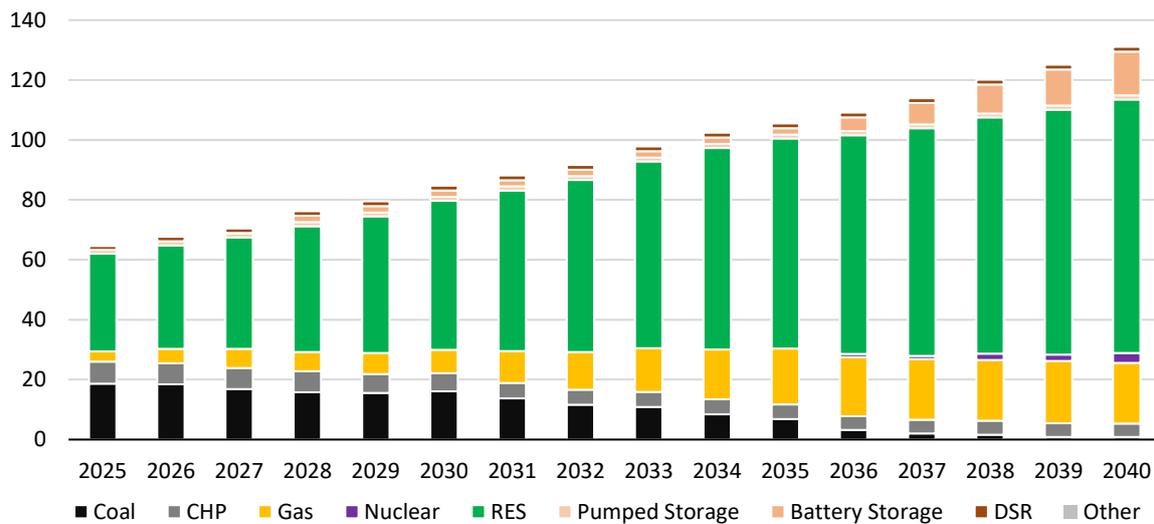


Fig. 5.10 Installed capacity of generation units – all units – Scenario with Capacity Mechanism [GW]



Tab. 5.2 Adequacy analysis results – LOLE and EENS – Scenario with Capacity Mechanism

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LOLE average	h/a	2,9	3,0	3,9	2,3	3,1	2,2	2,5	3,1	2,0	3,1	2,7	3,4	4,4	2,5	4,1	2,2
LOLE P95	h/a	7,3	8,7	10,6	7,4	9,2	7,5	9,6	10,7	8,7	12,4	9,8	11,8	12,8	12,0	16,9	9,5
EENS average	GWh/a	1,8	2,1	3,2	2,4	3,6	2,2	2,9	3,8	2,1	4,3	3,8	6,4	10,2	5,1	8,7	4,0
EENS P95	GWh/a	5,4	6,8	10,1	9,2	11,9	7,5	11,1	16,4	11,4	18,2	16,2	28,5	32,3	23,8	37,7	15,5

Detailed results of the system adequacy model are presented in Annex Z4.

The charts below show:

- the share of generation in the analysed years – fig. 5.11,
- emissions from the energy generation sector – only CDGU burning fossil fuels – fig. 5.12.

Fig. 5.11 Generation share of technologies/fuels – Scenario with Capacity Mechanism

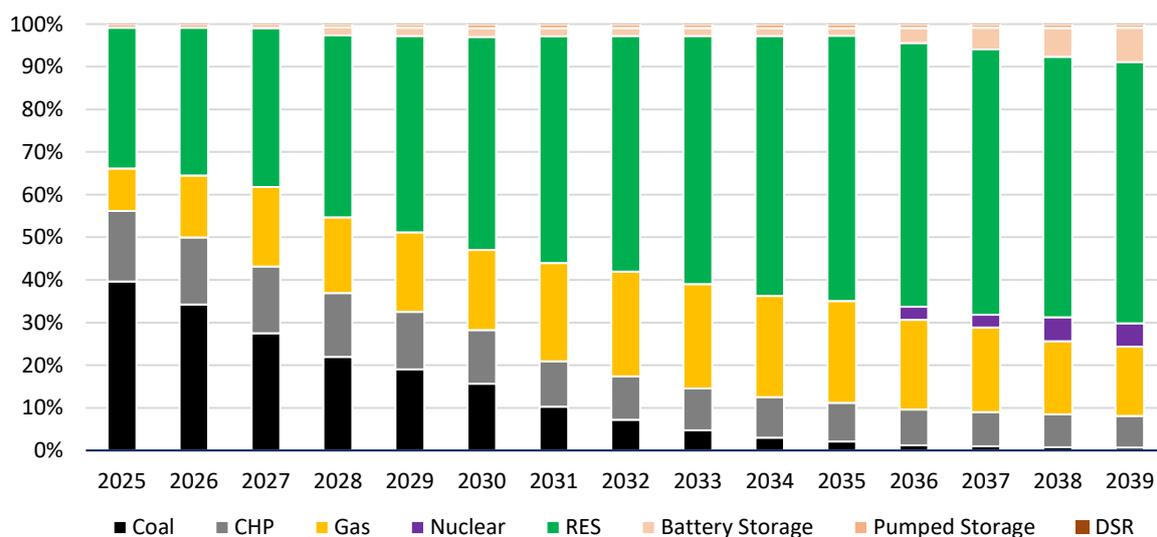
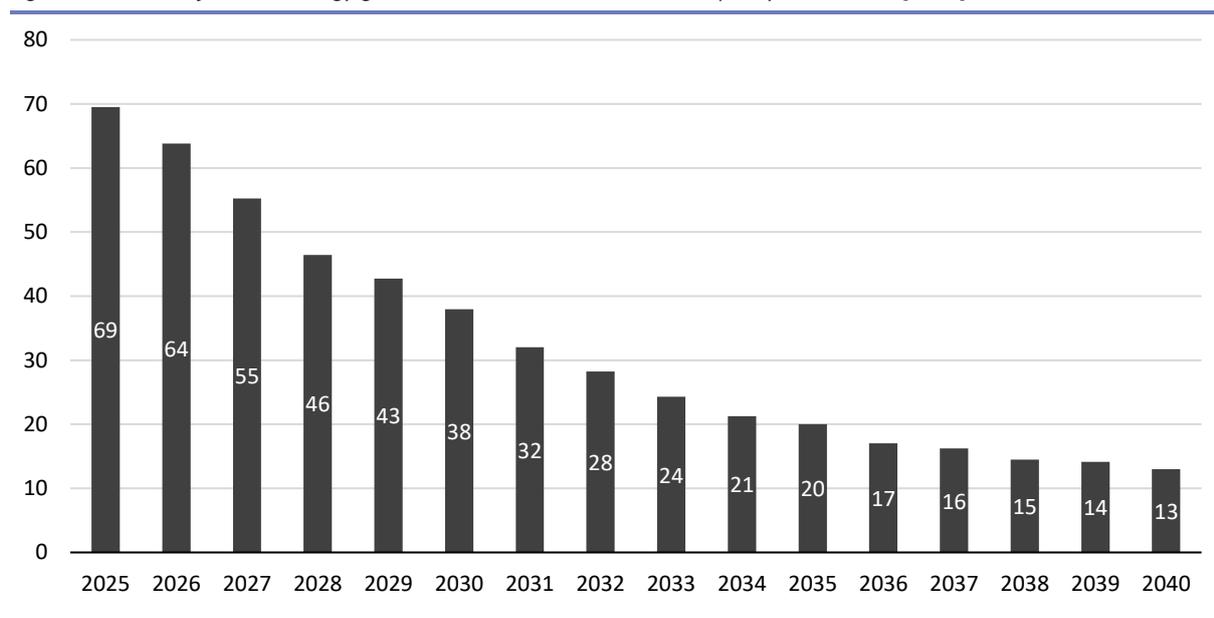


Fig. 5.12 Emissions from the energy generation sector – Scenario with Capacity Mechanism [mln t]



5.2.1 Auctions capacity to ensure compliance with the reliability standard for end consumers in the years 2025 – 2028

Based on the results of the scenario with capacity mechanism, in order to support the security of the National Power System in accordance with the provisions of Article 64(2b) of Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design the required capacity obligations were determined to ensure compliance with the reliability standard for end consumers in the years 2025 - 2028, used to determine the auction target capacity in the supplementary auctions. The result includes the minimum reserve of generation capacity referred to in §3 of the Regulation of the Minister of Climate and Environment of 13 September 2024 *on the execution of the capacity obligation, its settlement, and demonstration, as well as the conclusion of transactions in the secondary market*. Simultaneously, this result does not consider already concluded contracts during conducted and planned auctions. Tab. 5.3 presents the auction capacity to ensure compliance with the reliability standard for end consumers in the years 2025 – 2028.

Tab. 5.3 Auctions capacity to ensure compliance with the reliability standard for end consumers in the years 2025 –2028

Delivery period		Required Capacity Obligations
Second half of 2025	MW	24 122
2026	MW	24 872
2027	MW	25 323
2028	MW	25 717

6 Summary and results

The results of the NRAA base scenario show that during the analysed period, the reliability standard for Poland (Chapter 2.1) may not be met (Tab. 6.1). This is mainly due to the risk of permanent decommissioning of coal units, which are unprofitable from the first year of analysis. Additionally, there is a lack of sufficient new investments in generating sources that could offset the power losses resulting from the decommissioning of these coal resources.

Tab. 6.1 Results of LOLE and EENS indicators for the Base Scenario

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LOLE	h/a	7,6	40,8	50,2	33,3	20,5	9,6	6,6	14,3	15,0	14,4	10,9	10,8	12,5	10,4	5,8	14,2
EENS	GWh/a	5,8	40,6	54,4	52,1	31,8	13,8	9,4	22,7	24,3	23,6	18,1	23,5	25,3	23,3	13,5	33,6

The results of the NRAA base scenario significantly deviate from the goal of meeting the reliability standard. These results were achieved despite the use of tools such as imports, i.e., the contribution of foreign units to the NPS balance, and the use of demand reduction mechanisms through the activation of demand side response service providers and the flexibility of consumers sensitive to price signals.

The possibility of using these tools, i.e., imports and demand side response, is also subject to risk. As presented in this report, the contribution of foreign units to the NPS balance can vary, and for the analyses, the average value was used in accordance with European methodologies. However, if, at times of tight balance in the NPS, access to the capacity of foreign units were limited, e.g., due to simultaneous scarcity in neighbouring bidding zones caused by weather conditions, the adequacy results of the system in Poland would be even further from the assumed goal of 3 hours per year.

Moreover, the above results present average values from all climate scenarios. In extreme scenarios, the values of LOLE and EENS may be significantly higher. In extreme scenarios, the risk of unavailability of import contribution from neighbouring systems also has a higher probability of occurrence.

The NRAA report additionally presents the results of a scenario in which it is assumed that the reliability standard will not be significantly exceeded (tab. 6.2) in each year of the analysis (Chapter 5.2).

Tab. 6.2 Results of LOLE and EENS indicators for the Scenario with Capacity Mechanism

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LOLE	h/year	2,9	3,0	3,9	2,3	3,1	2,2	2,5	3,1	2,0	3,1	2,7	3,4	4,4	2,5	4,1	2,2
EENS	GWh/year	1,8	2,1	3,2	2,4	3,6	2,2	2,9	3,8	2,1	4,3	3,8	6,4	10,2	5,1	8,7	4,0

As in the base scenario, the adequacy model results for this scenario depend, among other things, on the contribution of imports and demand side response.

The above results show that to maintain the security of system operation, it is necessary to ensure mechanisms for financing dispatchable capacity resources, including generating sources, storage, and demand side response units. Otherwise, there is a significant risk that these resources will not be able to achieve a positive financial result, and consequently, the risk of decommissioning will materialize, resulting in the base scenario presented in this NRAA report

7 Appendix

Supplementary material to the NRAA report:

- Z1. Installed capacity of generation units not centrally dispatch.
- Z2. Results of the system cost minimization model.
- Z3. Detailed LOLE and EENS results – base scenario.
- Z4. Detailed LOLE and EENS results – scenario with capacity mechanism.
- Z5. Detailed LOLE and EENS results – system cost minimization model.

Z1. Installed capacity of generation units not centrally dispatched

Tab. 7.1 presents the installed capacity of generation units not centrally dispatched. The data is presented for characteristic years and the calculation years shown in the ERAA 2023 report.

Tab. 7.1 Installed capacity of nCDGU

Fuel/Technology		2025	2028	2030	2033	2035	2040
nCDGU thermal, including:	MW	7 060	6 922	5 931	4 894	4 721	4 357
Natural gas	MW	2 123	2 191	2 155	2 147	2 129	1 974
Hard coal	MW	3 875	3 663	2 902	1 887	1 743	1 540
Other non-renewable	MW	1 061	1 068	874	860	848	843
RES, including:	MW	32 727	41 907	49 604	62 286	70 129	84 600
Photovoltaics	MW	19 631	23 898	26 443	33 611	37 500	45 000
Onshore wind farms	MW	10 883	11 630	13 155	15 807	17 358	19 858
Offshore wind farms	MW	0	4 138	7 594	10 376	12 779	17 250
Biomass	MW	928	898	944	950	950	950
Biogas	MW	277	302	367	408	408	408
Run-of-river	MW	1 008	1 041	1 101	1 134	1 134	1 134

22. Results of the system cost minimization model

Fig. 7.1 and fig. 7.2 present the results of the system cost minimization model. However, it should be noted that these results do not consider the economic viability of individual generation units. Apart from optimizing the installed capacity of units participating in the central balancing mechanism and energy storage, other sources (including nuclear sources) were predetermined at the assumption stage. The assumptions and modelling method are presented in Chapters 3.2 and 4. The results of this model served for further analyses and work on the scenarios analysed in the NRAA.

Fig. 7.1 Installed capacity of generation units – System Cost Minimization Model [GW]

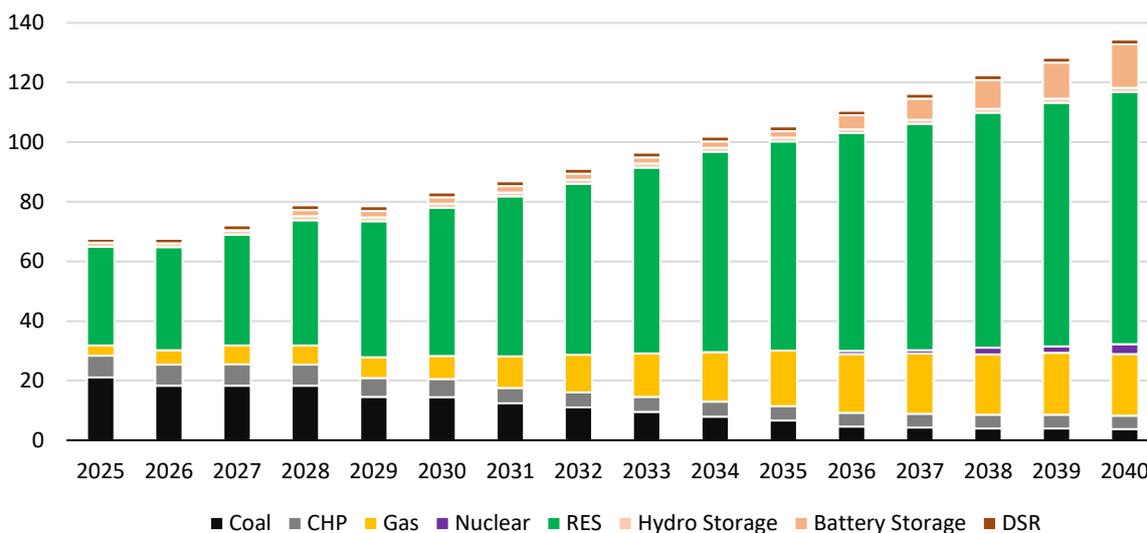
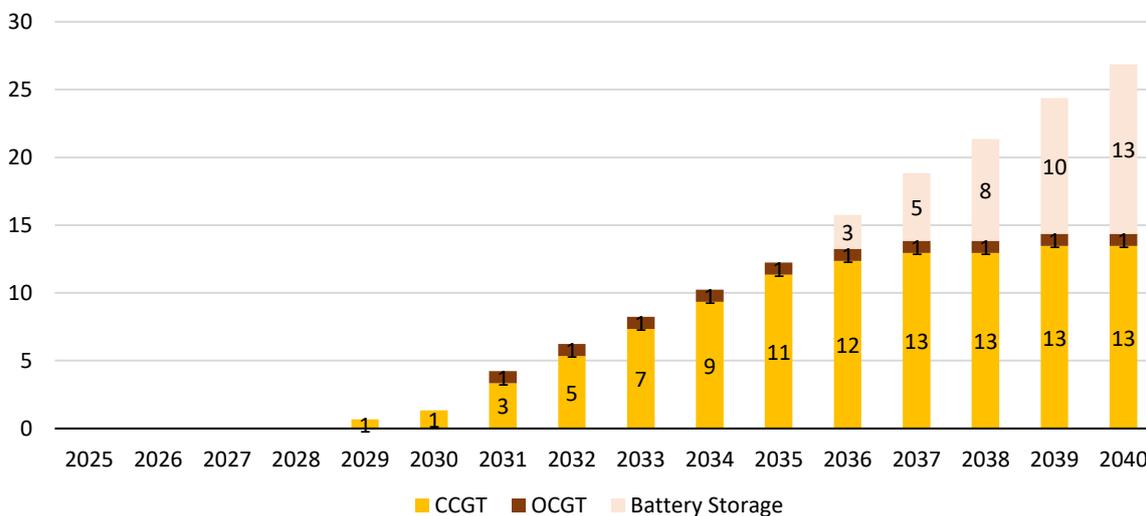


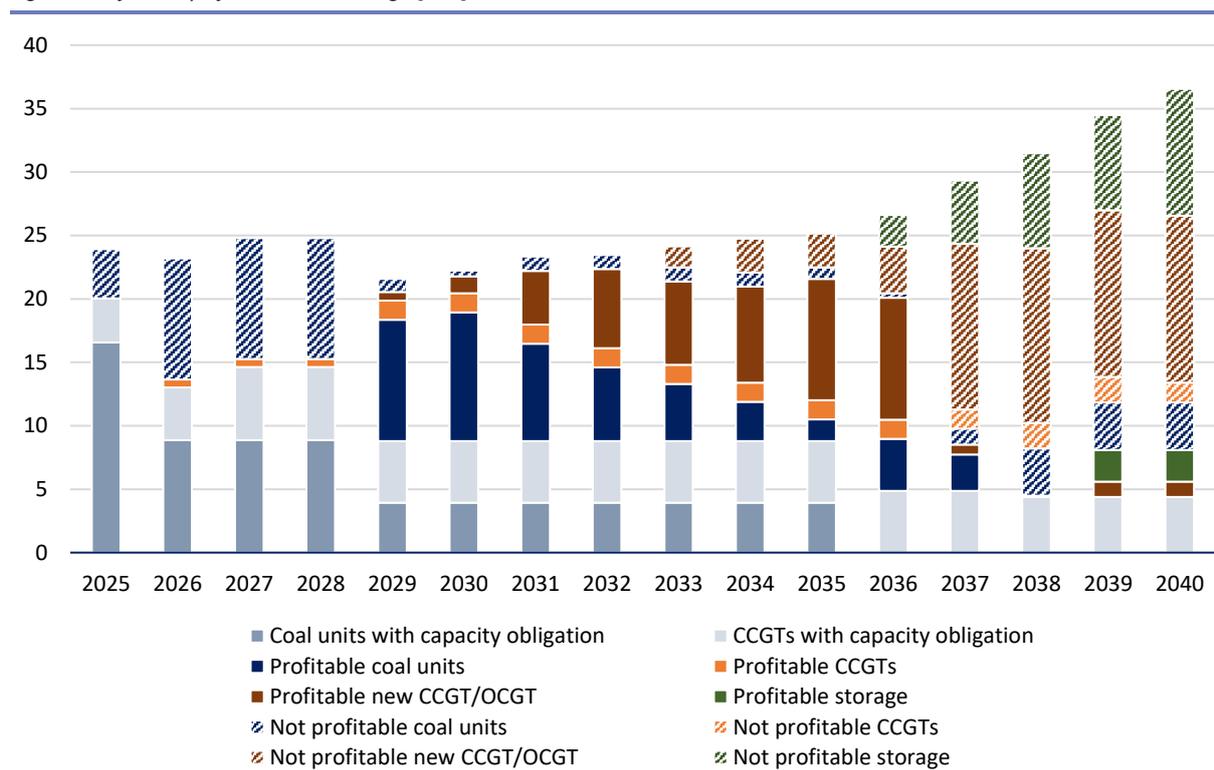
Fig. 7.2 New generation capacities – System Cost Minimization Model [GW]



The results, constituting the set of energy market participants from the system cost minimization model (presented above), were then verified in the economic model to check their profitability under market conditions (fig. 7.3). Tab. 7.2 presents the adequacy analysis results of the system cost minimization model.

The label ‘with a capacity obligation’ refers to units with a capacity obligation after the auctions of the existing capacity market conducted to date.

Fig. 7.3 Profitability of CDGU and storage [GW]



Tab. 7.2 Adequacy analysis results – LOLE and EENS – System Cost Minimization Model

Year		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
LOLE average	h/a	0,0	3,0	0,6	0,0	9,1	9,6	6,6	6,6	7,1	4,3	3,7	1,2	0,9	0,3	0,2	0,0
LOLE P95	h/a	0,1	8,7	2,4	0,0	23,0	25,2	21,6	20,6	22,3	15,5	11,5	6,2	4,2	1,5	0,8	0,1
EENS average	GWh/a	0,0	2,1	0,4	0,0	12,0	13,8	9,4	9,3	9,9	6,1	5,4	2,0	1,7	0,4	0,2	0,0
EENS P95	GWh/a	0,0	6,8	2,4	0,0	35,3	43,3	33,5	33,3	36,9	23,9	20,4	9,6	7,7	2,6	1,0	0,1

The graphs below present:

- the share of generation in each year of the analysis – fig. 7.4,
- emissions from the energy generation sector – only CDGU burning fossil fuels – fig. 7.5.

Fig. 7.4 Generation share of technologies/fuels – System Cost Minimization Model

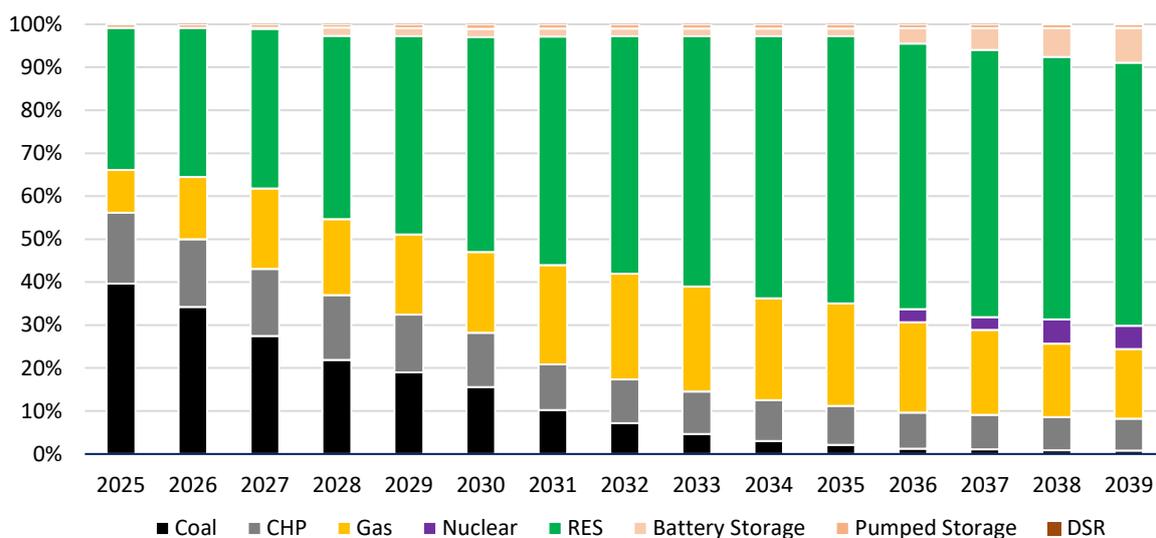
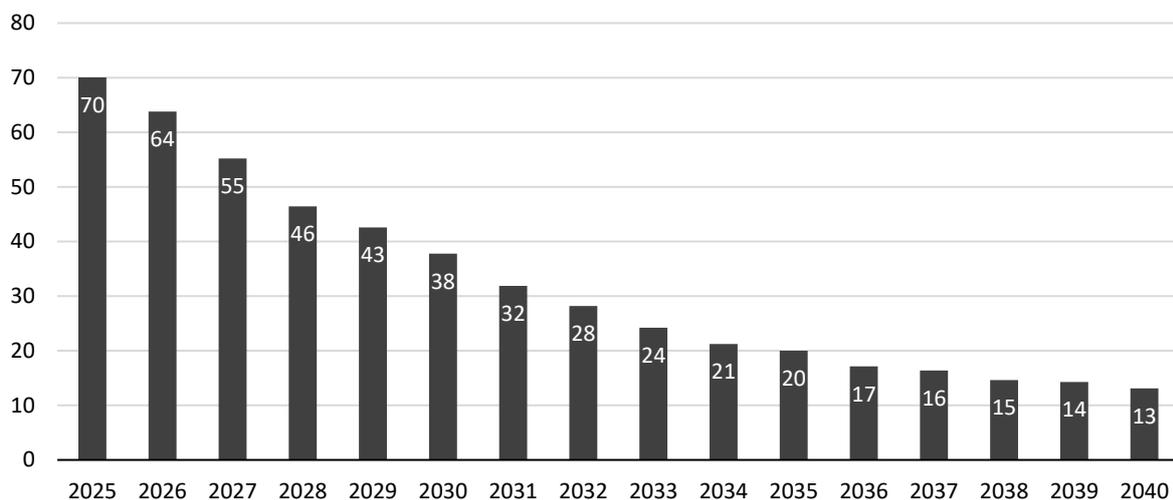


Fig. 7.5 CO₂ emissions of CDGU [mln t]



23. Detailed LOLE and EENS results – base scenario

The tables below present detailed LOLE and EENS results for the base scenario.

Tab. 7.3 System adequacy analysis – LOLE – Base Scenario [h/a]

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1982	3,2	60,1	79,0	47,9	26,8	9,8	4,6	13,1	15,8	15,9	8,0	11,2	21,8	15,8	9,4	25,4
1983	0,8	12,9	18,3	8,7	3,2	0	0	0,7	0	0,3	0,4	0	1,8	0,9	0	1,3
1984	6,6	34,1	36,0	25,3	12,9	6,1	4,6	11,7	12,3	8,9	6,3	4,0	6,2	4,9	1,3	11,1
1985	16,5	66,4	79,9	51,1	41,8	23,6	22,8	28,0	35,7	33,6	28,2	31,2	29,5	29,6	27,4	52,2
1986	2,2	14,8	30,5	23,3	16,1	2,3	1,3	8,3	5,3	2,7	10,9	11,9	22,9	16,9	8,1	14,8
1987	6,2	71,0	76,7	68,5	45,7	24,2	17,8	38,8	41,9	46,2	29,2	37,2	38,1	36,3	30,1	42,0
1988	4,4	22,9	26,2	14,7	2,7	0,1	0,1	2,6	5,7	5,6	0,8	2,3	0,5	2,1	1,8	2,3
1989	5,3	28,8	25,7	12,4	7,5	3,5	1,2	7,2	7,7	4,4	3,6	0,3	0,7	0	0	0,1
1990	4,0	19,7	19,8	20,0	13,5	6,2	4,0	10,4	7,1	4,9	3,9	3,2	5,2	1,5	1,0	3,4
1991	9,6	67,4	81,3	61,7	46,2	19,7	9,6	29,1	28,3	23,8	11,4	6,9	9,2	3,6	0,8	2,6
1992	0,9	19,2	26,8	16,2	6,3	1,8	0,7	3,3	4,5	10,0	3,7	2,4	1,3	2,3	0,6	0,8
1993	17,8	37,0	53,6	32,0	24,1	16,9	11,1	19,7	20,0	13,1	7,7	2,5	3,4	0,8	0,3	2,3
1994	1,5	16,3	31,8	23,1	10,7	6,2	2,4	4,7	3,8	1,5	3,4	3,8	9,1	4,8	0	6,7
1995	9,6	46,7	45,9	32,3	30,4	14,9	8,8	26,8	29,5	25,6	14,8	7,6	8,5	4,6	1,2	4,6
1996	9,4	59,7	75,9	58,1	40,9	18,3	12,6	32,0	25,8	31,7	21,0	29,1	22,9	26,4	19,1	29,8
1997	23,5	82,3	91,3	71,0	42,7	18,9	12,9	22,9	26,1	17,8	14,0	7,3	17,3	9,0	7,0	19,3
1998	23,0	79,3	76,1	57,4	43,7	32,2	22,9	35,3	39,1	27,8	24,2	11,5	4,1	3,5	0,5	8,8
1999	4,5	33,7	38,1	22,4	6,5	0,9	0,9	2,3	2,8	1,4	1,0	0,5	0,6	0,2	0,1	0,4
2000	1,6	19,6	22,4	14,9	9,1	2,9	1,1	2,0	1,5	3,5	1,1	0,8	4,1	7,5	0,4	8,1
2001	8,0	53,6	62,0	60,0	52,6	24,8	17,2	35,7	37,1	34,8	25,8	22,3	28,4	15,8	2,9	13,7
2002	15,6	47,1	57,8	49,1	36,2	21,2	11,7	29,1	30,2	23,7	19,8	20,4	23,0	25,1	10,1	23,3
2003	10,0	28,1	51,9	27,6	11,9	1,1	0,8	1,8	5,1	5,7	4,7	1,7	9,6	5,9	2,0	10,7
2004	5,5	25,4	38,9	24,5	14,8	6,4	2,1	20,0	17,0	19,8	10,6	16,4	15,7	13,1	7,8	17,1
2005	6,5	43,3	45,3	32,8	21,4	12,1	9,9	12,0	13,6	11,8	7,8	6,4	3,9	4,0	1,7	9,4
2006	8,0	51,2	65,8	32,1	18,7	9,2	9,2	17,0	21,5	28,4	19,5	25,0	25,3	24,4	21,1	24,8
2007	2,1	8,0	10,5	6,9	5,7	1,4	0,6	2,0	4,6	3,1	3,0	3,1	4,6	2,1	0,4	13,1
2008	1,3	5,7	13,6	3,1	1,4	0,7	0,6	0,8	0,8	1,3	1,0	0	0,4	0	0,3	0
2009	7,9	34,5	52,2	27,5	13,4	4,1	2,1	7,8	5,5	9,7	7,9	10,5	13,5	11,7	7,6	17,2
2010	20,7	87,2	97,1	70,0	43,8	27,6	21,4	37,5	34,2	36,2	40,6	44,9	48,1	40,9	21,2	45,8
2011	11,5	37,3	39,2	19,1	4,9	1,2	0,8	3,3	3,2	3,2	5,6	5,2	7,4	3,3	1,5	7,0
2012	6,9	54,3	73,8	37,4	25,0	12,2	8,9	16,6	16,4	13,8	19,6	13,9	19,4	12,6	6,9	25,1
2013	8,0	60,4	72,6	41,7	14,2	2,6	2,4	11,3	8,8	11,1	8,9	9,2	11,0	23,0	16,4	26,1
2014	11,5	73,8	71,3	57,9	35,0	20,2	17,7	30,5	40,7	27,5	27,3	19,2	24,3	13,3	1,4	23,5
2015	3,9	29,0	38,5	20,1	12,8	4,1	2,0	0,4	2,4	1,7	0	1,4	1,4	0,7	0	4,4
2016	1,3	36,3	45,5	16,9	5,6	1,0	0,7	4,0	2,6	5,9	3,1	1,9	8,6	6,3	3,2	4,8
2017	6,1	33,7	51,4	26,3	7,5	1,5	0,2	4,6	4,8	11,0	3,3	14,7	7,6	11,8	5,6	18,0
2018	4,0	33,1	60,0	39,0	19,6	4,5	1,8	7,3	8,0	5,3	8,5	9,4	14,1	4,3	0,4	12,5
2019	0,8	14,7	24,0	13,7	4,3	1,3	1,2	2,5	2,3	13,5	3,5	9,8	1,5	5,4	1,9	5,3

Tab. 7.4 System adequacy analysis – EENS – Base Scenario [GWh/a]

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1982	1,7	59,9	78,2	74,9	34,8	12,1	5,3	15,8	19,5	26,0	11,5	25,7	0	33,2	19,3	0
1983	0,3	9,0	17,5	9,5	1,9	0	0	0,2	0	0,0	0,2	0	2,0	1,4	0	2,3
1984	7,4	38,8	44,9	39,9	16,1	7,4	6,7	17,2	18,7	11,4	11,2	6,8	10,0	10,4	2,5	28,8
1985	12,3	80,5	107,3	114,4	72,5	36,0	36,5	57,8	74,1	75,4	57,4	81,5	70,9	87,7	84,4	154,3
1986	0,9	12,2	32,3	32,3	17,3	1,8	0,8	9,4	5,0	2,0	11,0	20,4	44,3	28,5	12,0	34,4
1987	4,3	84,4	100,8	115,8	77,9	35,6	23,1	56,5	65,7	96,3	44,6	92,4	83,5	94,4	83,0	125,5
1988	4,0	18,6	25,6	16,3	1,8	0,1	0,1	3,1	4,9	5,4	0,5	3,1	0,4	3,4	2,6	2,9
1989	4,6	25,2	24,3	12,9	10,6	3,8	1,6	9,0	11,0	4,1	4,0	0,4	1,9	0	0	0,1
1990	2,0	16,0	17,4	27,2	18,3	8,2	5,3	17,5	9,3	7,1	4,1	3,8	13,7	1,8	3,0	7,7
1991	5,4	69,1	85,5	84,8	60,6	22,2	11,2	35,1	35,1	25,1	13,8	8,1	14,1	3,6	0,7	3,2
1992	0,3	14,6	25,5	18,3	4,5	1,0	0,6	2,1	3,0	10,2	3,8	4,7	1,6	3,0	0,7	1,3
1993	14,1	52,8	65,9	64,6	54,0	27,8	17,0	35,2	32,8	17,8	11,1	4,3	6,7	1,1	0,4	4,8
1994	0,9	12,0	28,2	31,9	14,9	5,5	1,5	5,0	4,4	1,1	2,9	8,3	19,7	7,8	0	12,4
1995	6,5	38,9	39,5	51,4	49,5	24,2	13,0	45,2	48,0	33,3	22,4	14,8	15,6	7,7	1,9	7,5
1996	6,4	65,2	103,9	109,7	69,3	26,3	16,7	55,1	38,0	55,3	46,0	81,3	47,4	61,9	44,6	79,1
1997	21,1	92,7	103,6	111,2	62,1	21,1	15,1	31,9	35,4	22,0	17,2	11,7	33,6	15,4	13,4	42,0
1998	21,2	97,2	94,2	110,5	100,3	66,2	45,1	75,8	78,0	49,2	40,7	23,4	4,7	5,0	0,6	12,4
1999	5,3	33,2	42,0	30,4	6,6	0,7	0,3	1,9	2,7	0,8	0,7	0,6	0,4	0,1	0,2	0,2
2000	1,1	14,5	20,6	17,2	8,7	1,9	0,5	1,1	1,2	3,7	1,2	0,9	7,0	15,6	0,5	19,2
2001	4,3	63,8	73,0	92,1	90,7	43,2	27,0	72,3	76,3	71,5	52,9	43,3	72,0	38,1	5,9	39,8
2002	10,8	41,6	58,9	85,7	71,0	25,8	15,5	60,1	63,2	44,2	36,1	60,8	70,8	79,5	25,1	69,9
2003	7,3	23,8	50,4	27,7	10,1	1,3	0,3	1,0	3,2	3,6	4,2	1,6	11,6	5,9	1,0	14,7
2004	3,5	19,4	33,3	30,2	17,0	5,9	1,8	22,3	22,0	28,4	14,1	29,6	27,7	27,5	18,2	33,1
2005	6,3	47,2	52,6	53,9	41,3	19,8	19,0	19,5	30,6	19,9	19,5	14,2	7,2	9,6	3,6	30,2
2006	4,8	56,3	75,9	55,2	26,5	16,2	14,9	29,5	35,5	56,5	41,2	57,5	50,6	58,8	49,3	70,9
2007	1,5	5,2	5,9	10,0	5,3	0,6	0,3	2,6	5,6	3,5	3,9	7,1	10,9	3,9	0,6	34,0
2008	0,5	3,5	10,1	1,6	1,4	0,6	0,3	0,9	0,6	0,5	1,3	0	0,2	0	0,5	0
2009	6,2	29,3	46,2	37,5	17,4	5,2	3,1	10,3	7,3	12,9	12,2	17,8	39,2	27,7	16,4	42,9
2010	15,6	93,9	118,2	127,6	77,5	43,9	32,9	66,4	60,8	67,0	80,5	115,0	125,5	98,4	51,6	124,3
2011	9,2	29,8	36,3	20,7	3,9	1,3	0,7	2,7	2,8	2,3	4,5	5,3	9,9	4,2	0,9	8,3
2012	5,1	54,5	104,6	79,2	44,7	18,8	14,6	27,7	28,2	29,9	39,1	37,2	46,6	28,8	13,1	62,9
2013	4,1	53,4	67,7	60,4	14,8	2,9	1,8	11,4	10,4	16,3	9,8	15,8	14,4	46,3	36,2	64,2
2014	12,1	80,4	75,9	82,0	54,4	27,1	20,2	44,3	68,9	48,2	44,6	39,4	44,5	28,8	1,7	54,8
2015	2,2	20,4	31,9	23,0	13,2	2,6	0,9	0,0	1,5	1,0	0	2,1	2,2	1,3	0	8,9
2016	0,6	21,9	36,2	16,8	4,9	0,7	0,5	3,6	1,7	5,2	3,5	1,5	14,2	7,0	2,7	7,7
2017	4,9	25,3	48,6	33,1	5,7	1,1	0,3	4,1	5,0	15,3	3,0	21,4	9,4	19,0	11,8	39,0
2018	1,6	30,7	65,4	56,3	22,5	3,4	2,3	6,7	9,7	5,8	10,1	13,4	27,2	7,8	0,9	23,7
2019	0,4	8,2	19,4	13,7	3,1	0,8	0,8	2,1	1,4	17,1	3,1	18,1	0,8	11,9	5,3	9,0

24. Detailed LOLE and EENS results – scenario with capacity mechanism

The tables below present detailed LOLE and EENS results for the scenario with capacity mechanism.

Tab. 7.5 System adequacy analysis – LOLE – Scenario with Capacity Market [h/a]

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1982	1,9	0,2	1,4	3,2	3,9	1,3	1,3	0,8	0,8	0,5	0,9	5,0	6,6	2,1	6,1	2,7
1983	0,3	0	0,9	0	0	0	0	0	0	0	0	0	0	0	0	0
1984	4,1	8,0	4,0	2,9	2,0	1,3	1,9	2,6	4,7	3,7	1,5	1,3	0,1	0,6	1,1	1,7
1985	9,6	7,1	10,5	7,9	8,7	3,6	9,5	9,0	5,9	12,1	9,2	10,5	9,1	6,7	14,1	9,1
1986	0,5	0,3	2,3	1,1	1,1	0	0	0,7	0	0,3	4,7	8,2	12,0	6,3	8,8	5,3
1987	2	6,3	8,8	10,6	9,1	5,2	6,4	10,3	5,8	17,8	8,0	13,3	11,4	12,5	17,1	12,9
1988	0,1	2,7	0,4	0	0	0	0	0	0	0,1	0	0	0	0	0	0
1989	1,9	1,5	0,6	0	0,6	0,7	0,3	0,3	0,3	0	0	0,1	0	0	0	0
1990	0,7	0,8	0,9	0,5	2,4	1,8	1,3	1,5	0	0	0	0	0,4	0	0	0
1991	3,8	3,4	5,0	2,9	5,0	3,8	2,8	2,9	1,0	1,2	0,7	2,1	1,3	0,2	0,1	0,2
1992	0,1	0	1,8	0	0	0	0	0	0	0,6	0,7	0,6	1,2	0,1	0,4	0
1993	7,1	7,0	5,9	3,0	5,7	5,4	4,0	4,2	0,6	0,2	0,6	0,9	0	0	0	0
1994	0,8	0	1,2	1,4	0	0	0	0	0	0	0,2	3,1	5,2	1,1	0	0
1995	1,5	1,9	2,5	0,8	4,1	4,9	3,2	5,0	0,4	0,3	0,6	1,6	0	0,8	1,3	0
1996	3	4,2	9,9	6,1	6,9	5,5	5,4	4,9	1,5	7,9	5,4	4,1	8,8	3,7	11,7	6,2
1997	8,4	12,6	11,3	3,3	5,1	1,7	3,3	3,0	1,1	1,9	0,5	0,8	1,8	0,1	1,5	0
1998	11,9	11,5	9,4	6,6	12,5	14,9	13,9	13,2	3,7	4,0	2,9	0,8	0,3	0	1,1	0,4
1999	1,9	4,7	4,9	0	0,8	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0,4	0,3	0,3	0	0	0	0	0	0	0,5	1,4	1,1	0,3	1,0
2001	3,5	5,4	5,6	5,5	9,7	7,4	7,2	8,3	8,6	12,2	9,8	4,3	3,9	2,2	3,4	2,2
2002	3,1	0,9	1,3	1,2	4,2	1,6	2,7	7,9	3,8	7,5	5,6	3,3	10,0	7,9	11,9	2,9
2003	1,4	1,0	2,2	0	0,3	0	0	0	0	0	0,9	0,8	1,5	0	0,8	0,3
2004	0,8	0,3	0,4	0	0,5	0,5	0,5	0,7	0	1,3	0,6	6,8	4,0	4,3	5,7	0,9
2005	6,6	5,6	7,6	5,4	7,2	2,3	5,2	4,0	4,1	2,1	1,8	0,7	1,0	0,7	0,6	2,0
2006	2,2	2,3	4,7	5,5	4,4	3,5	5,4	7,9	4,1	9,9	9,8	11,5	17,0	11,9	16,9	11,8
2007	0	0	0	0	0	0	0	0	0	0	0	0,9	1,5	0	0	0,9
2008	0,2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	1,1	0,4	1,4	1,0	2,3	1,1	0,9	0,7	0	1,4	1,7	1,9	7,3	1,6	3,9	3,1
2010	5,5	5,6	9,7	7,3	8,1	7,8	10,3	15,0	9,1	13,7	18,1	22,7	32,7	15,7	18,4	8,5
2011	3,3	1,8	2,1	0,7	0,8	0,2	0	0	0	0	0	0,3	0,7	0,4	1,7	0,9
2012	3,4	2,4	11,8	5,2	5,6	4,1	4,1	6,4	4,9	6,0	8,0	5,2	7,5	1,5	3,6	1,7
2013	1,2	1,1	2,4	0,6	1,6	0,5	0,2	1,6	0	1,8	2,9	2,6	3,9	7,6	15,2	6,3
2014	7,7	8,2	5,7	3,7	3,7	3,5	5,1	4,6	12,7	11,1	7,1	6,1	5,4	1,3	0,8	3,9
2015	2,8	0,7	0,7	0	1,0	0	0	0	0	0	0	0	0	0	0	0
2016	2,2	0	0,6	0,6	0	0	0	0	0,3	0	0	0,7	1,9	0	0,6	0
2017	1,1	3,3	1,1	0	0	0	0	0	0,3	0,5	0	1,8	2,8	2,4	3,8	0
2018	3,5	2,5	7,2	0,7	1,9	0,7	0,3	0,4	0,3	0	0	3,0	4,2	0,6	0,1	0
2019	0	0	1,0	0	0	0	0	0	0,2	1,4	0,5	2,2	2,0	1,2	3,0	0

Tab. 7.6 System adequacy analysis – EENS – Scenario with Capacity Market [GWh/a]

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1982	1,2	0,1	0,2	2,6	3,7	1,2	1,2	0,3	0,7	0,2	0,6	8,2	14,6	3,3	12,3	4,8
1983	0,1	0	0,6	0	0	0	0	0	0	0	0	0	0	0	0	0
1984	2,0	6,3	2,7	1,7	1,2	0,8	1,2	2,7	5,2	3,7	1,2	0,9	0,0	1,2	1,6	3,7
1985	6,2	6,5	10,6	10,6	11,7	3,1	11,0	16,4	5,4	17,5	8,5	24,7	20,1	17,2	33,3	14,5
1986	0,3	0,1	2,0	1,1	0,5	0	0	0,3	0	0,2	4,7	11,2	23,7	10,9	13,3	6,6
1987	1,8	2,8	5,5	11,2	12,9	6,7	6,9	9,9	4,8	23,6	9,2	31,9	30,6	24,9	43,0	28,3
1988	0,0	1,0	0,2	0	0	0	0	0	0	0,1	0	0	0	0	0	0
1989	1,4	0,4	0,2	0	0,1	0,4	0,3	0,2	0,1	0	0	0,0	0	0	0	0
1990	0,2	0,9	0,8	1,0	2,4	1,5	1,7	2,0	0	0	0	0	0,9	0	0	0
1991	2,3	2,3	3,2	2,1	4,9	2,6	2,6	2,4	1,2	0,6	0,9	1,8	1,1	0,2	0,0	0,0
1992	0,1	0	1,5	0	0	0	0	0	0	0,5	0,5	1,2	0,9	0,0	0,6	0
1993	5,7	6,5	5,8	3,0	7,3	6,2	5,0	6,0	0,3	0,0	0,5	1,0	0	0	0	0
1994	0,2	0	0,7	1,1	0	0	0	0	0	0	0,0	4,7	10,4	2,0	0	0
1995	0,6	1,2	1,3	0,6	4,1	4,7	3,6	5,4	0,3	0,1	0,4	2,7	0	0,9	3,2	0
1996	2,5	4,1	10,0	7,8	8,7	5,1	5,6	6,5	2,5	7,9	6,8	7,1	20,5	6,3	23,4	13,0
1997	4,9	9,0	8,7	2,9	4,9	1,1	3,7	2,7	0,8	1,0	0,3	1,0	3,5	0,1	3,2	0
1998	8,4	9,9	7,1	7,2	16,1	18,8	19,6	17,5	3,0	3,8	2,4	0,5	0,5	0	1,5	0,1
1999	1,0	2,3	3,1	0	0,5	0	0	0	0	0	0	0	0	0	0	0
2000	0,0	0	0,1	0,1	0,1	0	0	0	0	0	0	0,4	3,2	3,4	0,4	1,7
2001	2,8	4,5	5,7	5,9	11,8	11,0	10,2	13,7	12,5	17,3	14,7	8,1	8,4	6,5	6,0	4,9
2002	1,3	0,4	0,4	0,5	3,6	1,4	3,1	9,3	3,1	10,4	6,2	7,2	30,5	23,6	37,9	8,0
2003	0,9	0,7	2,0	0	0,4	0	0	0	0	0	0,8	0,6	1,8	0	0,4	0,1
2004	0,3	0,1	0,0	0	0,3	0,4	0,2	0,6	0	1,5	0,5	5,5	5,9	8,5	12,6	0,7
2005	5,8	6,0	8,9	5,9	10,4	2,9	6,9	5,3	4,3	3,1	1,6	1,5	3,2	2,3	1,0	3,2
2006	1,5	1,7	4,2	4,9	4,8	3,1	6,2	10,0	6,3	18,0	20,4	28,0	41,6	21,8	34,9	21,2
2007	0,0	0	0	0	0	0	0	0	0	0	0	0,3	1,5	0	0	1,0
2008	0,1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0,7	0,2	0,8	1,0	1,5	0,7	0,9	0,8	0	1,9	1,7	2,6	17,1	2,8	6,9	2,8
2010	3,0	3,3	8,5	8,9	8,3	6,9	11,3	16,6	11,2	19,6	32,7	57,7	85,1	30,7	37,6	13,0
2011	1,3	0,4	2,6	0,6	0,6	0,0	0	0	0	0	0	0,1	0,6	0,2	1,6	0,7
2012	2,1	1,5	13,1	7,8	7,7	3,1	5,5	10,7	4,4	13,5	15,5	15,0	26,6	1,9	6,8	4,3
2013	0,5	0,5	0,8	0,2	1,4	0,3	0,0	1,1	0	1,1	2,6	3,0	7,5	14,4	31,7	11,3
2014	5,2	4,4	2,0	2,3	3,1	2,8	4,4	4,6	13,6	15,9	9,7	6,2	9,5	0,7	2,6	9,2
2015	1,9	0,5	0,4	0	0,4	0	0	0	0	0	0	0	0	0	0	0
2016	0,8	0	0,2	0,3	0	0	0	0	0,1	0	0	0,4	2,3	0	0,2	0
2017	0,2	1,2	0,6	0	0	0	0	0	0,1	0,3	0	2,3	4,3	5,1	8,0	0
2018	2,4	1,7	5,3	0,7	2,1	0,6	0,4	0,5	0,2	0	0	4,3	8,7	0,7	0,0	0
2019	0,0	0	0,7	0	0	0	0	0	0,0	0,9	0,5	3,1	2,6	3,5	7,1	0

25. Detailed LOLE and EENS results – system cost minimization model

The tables below present detailed LOLE and EENS results for the system cost minimization model.

Tab. 7.7 System adequacy analysis – LOLE – Scenario Cost Minimization Model [h/a]

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1982	0	0,2	0	0	10,8	9,8	4,6	4,1	7,6	3,4	1,9	0,2	0,4	0	0	0
1983	0	0	0	0	0	0	0	0	0	0	0,4	0	0	0	0	0
1984	0	8,0	0,6	0	5,5	6,1	4,6	7,0	10,1	4,9	2,4	0,7	0	0	0	0
1985	0,6	7,1	2,3	0	22,0	23,6	22,8	16,5	21,5	14,6	12,9	2,2	1,2	0,6	0,2	0
1986	0	0,3	0,5	0	3,5	2,3	1,3	1,8	2,8	0,8	5,9	2,7	4,0	1,4	0,6	0,2
1987	0	6,3	0,1	0	24,8	24,2	17,8	20,3	18,0	24,4	11,0	6,0	3,3	1,4	2,5	0,1
1988	0	2,7	0	0	0,3	0,1	0,1	0,3	2,5	0,2	0,3	0	0	0	0	0
1989	0	1,5	0	0	2,1	3,5	1,2	1,6	1,7	0,4	0	0	0	0	0	0
1990	0	0,8	0	0	6,2	6,2	4,0	4,7	1,0	0,1	0,3	0	0	0	0	0
1991	0	3,4	0,7	0	14,9	19,7	9,6	8,1	6,0	2,0	2,1	0,4	0	0	0	0
1992	0	0	0	0	2,9	1,8	0,7	1,3	1,3	0,8	1,5	0,4	0	0	0	0
1993	0	7,0	1,4	0	14,9	16,9	11,1	9,4	4,3	0,9	1,5	0,6	0	0	0	0
1994	0	0	0	0	4,9	6,2	2,4	0,9	2,9	0	0,7	0,1	0,5	0	0	0
1995	0	1,9	0	0	10,8	14,9	8,8	10,7	6,9	1,4	0,7	0,8	0	0	0	0
1996	0	4,2	2,2	0	15,8	18,3	12,6	12,7	8,7	9,8	7,7	0,6	1,5	0	0,3	0
1997	0	12,6	1,1	0	20,9	18,9	12,9	8,7	10,5	3,8	1,3	0	0,2	0	0	0
1998	0	11,5	0,6	0	26,9	32,2	22,9	22,5	18,1	6,9	4,4	0	0	0	0	0
1999	0	4,7	0,2	0	3,0	0,9	0,9	0,4	2,8	0	0	0	0	0	0	0
2000	0	0	0	0	2,4	2,9	1,1	0,7	0,4	0,1	0	0	0	0	0	0
2001	0	5,4	1,2	0	21,8	24,8	17,2	18,6	20,1	15,5	11,2	1,3	0	0,4	0	0
2002	0	0,9	0	0	15,7	21,2	11,7	14,6	12,8	10,1	7,9	1,4	1,1	1,0	0,8	0
2003	0	1,0	0,6	0	1,7	1,1	0,8	0,3	1,4	0	2,5	0	0	0	0	0
2004	0	0,3	0	0	3,8	6,4	2,1	5,9	2,6	2,3	1,0	0,3	0	0,7	0	0
2005	0,8	5,6	2,9	0,2	15,2	12,1	9,9	6,8	9,3	3,4	2,8	0,6	0,5	0	0	0
2006	0	2,3	0,7	0	9,4	9,2	9,2	12,2	9,1	10,8	10,8	7,3	5,4	2,9	0,7	1,0
2007	0	0	0	0	1,2	1,4	0,6	0,8	0,8	0,5	0	0	0	0	0	0
2008	0	0	0	0	0	0,7	0,6	0	0,8	0	0	0	0	0	0	0
2009	0	0,4	0	0	5,9	4,1	2,1	1,9	2,7	1,6	2,0	0,2	2,3	0,3	0	0
2010	0	5,6	1,8	0,1	22,7	27,6	21,4	22,2	26,6	15,1	20,7	11,8	8,7	2,3	0,9	0
2011	0	1,8	0,8	0	1,8	1,2	0,8	1,1	1,9	0,2	0,3	0	0	0	0	0
2012	0	2,4	3,5	0	11,9	12,2	8,9	9,0	10,3	7,1	10,7	4,9	3,8	0	0	0
2013	0	1,1	0	0	5,3	2,6	2,4	5,1	2,9	2,0	3,9	0	0	0,1	0,1	0
2014	0	8,2	0	0	19,4	20,2	17,7	15,6	31,7	15,7	10,5	1,3	0,4	0	0	0
2015	0	0,7	0	0	4,5	4,1	2,0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0,4	1,0	0,7	0,3	0,8	0,5	0,4	0	0	0	0	0
2017	0	3,3	0	0	1,9	1,5	0,2	0,7	3,5	1,7	0	0	0	0,3	0	0
2018	0	2,5	1,0	0	9,5	4,5	1,8	2,2	2,8	0,1	1,0	0,8	0,2	0	0	0
2019	0	0	0,1	0	1,3	1,3	1,2	1,0	1,3	1,6	0,9	0,4	0	0	0	0

Tab. 7.8 System adequacy analysis – EENS – Scenario Cost Minimization Model [GWh/a]

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1982	0	0,1	0	0	12,9	12,1	5,3	4,4	7,7	2,1	1,4	0,1	0,8	0	0	0
1983	0	0	0	0	0	0	0	0	0	0	0,1	0	0	0	0	0
1984	0	6,3	0,2	0	6,2	7,4	6,7	8,4	17,4	6,0	2,7	0,4	0	0	0	0
1985	0,2	6,5	2,4	0	36,3	36,0	36,5	33,0	28,9	23,4	13,4	4,5	2,3	1,1	0,2	0
1986	0	0,1	0,3	0	4,2	1,8	0,8	1,9	2,6	0,4	7,5	3,2	4,9	1,5	0,4	0,1
1987	0	2,8	0,0	0	35,1	35,6	23,1	26,8	25,6	34,1	14,1	8,1	7,4	2,5	4,3	0,1
1988	0	1,0	0	0	0,1	0,1	0,1	0,3	2,0	0,2	0,1	0	0	0	0	0
1989	0	0,4	0	0	1,8	3,8	1,6	1,7	1,9	0,2	0	0	0	0	0	0
1990	0	0,9	0	0	7,1	8,2	5,3	5,7	1,1	0,0	0,1	0	0	0	0	0
1991	0	2,3	0,2	0	16,8	22,2	11,2	8,3	6,8	1,2	1,8	0,3	0	0	0	0
1992	0	0	0	0	1,6	1,0	0,6	0,5	1,2	0,9	1,1	0,5	0	0	0	0
1993	0	6,5	0,9	0	20,8	27,8	17,0	14,1	5,2	0,5	1,1	0,4	0	0	0	0
1994	0	0	0	0	4,2	5,5	1,5	0,7	1,8	0	0,7	0,2	1,0	0	0	0
1995	0	1,2	0	0	13,8	24,2	13,0	13,6	7,9	0,8	0,7	0,9	0	0	0	0
1996	0	4,1	2,3	0	24,2	26,3	16,7	18,0	12,4	12,0	9,8	0,3	2,7	0	0,6	0
1997	0	9,0	1,1	0	23,5	21,1	15,1	8,5	11,6	3,2	0,7	0	0,2	0	0	0
1998	0	9,9	0,4	0	43,2	66,2	45,1	37,8	23,2	6,9	4,4	0	0	0	0	0
1999	0	2,3	0,0	0	3,4	0,7	0,3	0,3	2,3	0	0	0	0	0	0	0
2000	0	0	0	0	1,7	1,9	0,5	0,3	0,4	0,1	0	0	0	0	0	0
2001	0	4,5	0,3	0	30,8	43,2	27,0	29,3	36,3	23,6	19,0	1,9	0	0,6	0	0
2002	0	0,4	0	0	20,5	25,8	15,5	22,8	17,6	14,9	9,4	0,8	0,8	2,4	1,6	0
2003	0	0,7	0,2	0	2,1	1,3	0,3	0,1	1,1	0	2,1	0	0	0	0	0
2004	0	0,1	0	0	3,2	5,9	1,8	4,5	2,5	2,6	1,1	0,0	0	0,7	0	0
2005	0,3	6,0	2,7	0,0	26,1	19,8	19,0	11,6	15,7	5,1	3,3	1,0	1,5	0	0	0
2006	0	1,7	0,5	0	13,9	16,2	14,9	18,8	17,2	21,5	24,0	14,3	9,9	3,2	0,5	1,0
2007	0	0	0	0	0,6	0,6	0,3	0,3	0,4	0,3	0	0	0	0	0	0
2008	0	0	0	0	0	0,6	0,3	0	1,0	0	0	0	0	0	0	0
2009	0	0,2	0	0	5,8	5,2	3,1	2,4	2,3	2,3	2,3	0,1	4,0	0,4	0	0
2010	0	3,3	1,6	0,1	31,6	43,9	32,9	34,8	40,4	25,6	41,9	26,7	19,9	3,3	1,0	0
2011	0	0,4	0,4	0	1,7	1,3	0,7	0,5	1,7	0,1	0,1	0	0	0	0	0
2012	0	1,5	2,6	0	20,6	18,8	14,6	18,4	16,3	16,4	19,8	8,7	6,5	0	0	0
2013	0	0,5	0	0	5,2	2,9	1,8	5,0	2,3	2,3	4,2	0	0	0,3	0,1	0
2014	0	4,4	0	0	20,2	27,1	20,2	16,9	50,8	23,2	14,5	1,7	0,9	0	0	0
2015	0	0,5	0	0	3,5	2,6	0,9	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0,1	0,7	0,5	0,3	1,1	0,3	0,1	0	0	0	0	0
2017	0	1,2	0	0	1,2	1,1	0,3	0,6	4,5	1,4	0	0	0	0,1	0	0
2018	0	1,7	0,3	0	10,9	3,4	2,3	2,1	3,1	0,1	0,7	0,6	0,4	0	0	0
2019	0	0	0,0	0	0,5	0,8	0,8	0,5	1,5	1,8	1,0	0,6	0	0	0	0