The missing element

Energy security considerations

instrat

Instrat Policy Paper 09/2021

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- Achieving the goal. Coal phase-out in the Polish power sector.
- What's next after coal? RES potential in Poland.

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Abbreviations and definitions

ARE	Agencja Rynku Energii (Energy Market Agency)
CCGT	Combined Cycle Gas Turbine
CHP	Combined heat-and-power plants
E	Electricity
PSPP	Pumped storage power plant
GHG	Greenhouse gases
IND	Industrial generating units
CDGU	Centrally dispatched generating units
EC	European Commission
NECP	National Energy and Climate Plan for the years 2021-2030
NPS	National Power System
LDP	Local Development Plan
EIA	Environmental impact assessment
RES	Renewable energy sources
PEP2040	Polish Energy Policy until 2040
PGE	Polska Grupa Energetyczna
PNPP	Polish Nuclear Power Program
TNDP	Transmission Network Development Plan for the years 2021-2030
PSE	Polskie Sieci Elektroenergetyczne
PV	Photovoltaics
RED	Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources, Renewable Energy Directive
SRMC	ang. Short-Run Marginal Cost
EU	European Union

Summary and key recommendations

1. Further dependence of the Polish power sector on coal will result in an increase in annual electricity bills for households: PLN 264 in 2022 (despite the anti-inflation measures) and even PLN 800 in 2030–2040 as compared to 2021.

2. Raising the ambitions for RES development against the government's Polish Energy Policy until 2040 (PEP2040) as proposed by Instrat would allow these price increases to be limited. Households could save from PLN 500 to 780 per year in the years 2030–2040.

3. The ambitious pace of RES development will require increasing network infrastructure expenditures and incurring additional system costs. In the years 2021–2040, investments in distribution networks must increase from PLN 180 billion in the base case scenario (i.e. consistent with PEP2040 assumptions) to PLN 238 billion in the Instrat scenario. Investments in transmission networks are PLN 10 billion higher in the Instrat scenario than in the PEP2040 scenario. This will contribute to a significant increase in the distribution tariff, compounded also by higher system costs. In total, the distribution component of the tariff will increase in the Instrat scenario by PLN 0.1/kWh in the years 2021–2040, while it will decrease below the current level in the PEP2040 scenario.

4. The increase in system costs is offset by lower costs of energy from RES, so in the years 2030–2040 the total household tariff is lower by approx. PLN 0.2/kWh in the Instrat scenario than in the PEP2040 scenario.

5. Investments in network infrastructure are insufficiently financed from EU funds – in the recent years it was only approx. 2 percent of DSO investments and 25 percent of TSO investments. Commencement and timely implementation of many necessary network projects will therefore require a larger financing scale.

6. The National Power System faces a number of challenges related to decommissioning of outdated coal-fired power units. PEP2040 does not address the resulting gap in the power balance already present in this decade. Any delay in the Polish Nuclear Power Program and the implementation of gas units will lead to power deficiencies in 2035 and 2040. The dynamic development of RES makes it possible to fill in the generation gap, resulting in significantly higher available operating capacity during demand peaks.

7

The variability in energy production from RES does not pose a threat to the balancing of the power system. With the proposed energy mix structure, there are no moments of the total absence of production of energy from wind and sun. For more than 4000 hours per year (47 percent of the time), wind and solar energy could cover all of the electricity demand.

8

A very high share of RES in the energy mix does not lead to an increased dependence of Poland on energy imports. In 2040, the volume of imports drops to 7 TWh – by almost half of the 2020 value. Only during 44 hours per year (i.e. less than two days in total) the peak net imports are above the currently recorded maximums. The peak import in 2040 is 5.5 GW – which will represent 69 percent of cross-border connection capacity, almost exactly the same as today (67 percent).

9

The Instrat scenario, despite a 71 percent RES share in the electricity mix in 2030 and 83 percent in 2040 does not require a massive deployment of natural gas units. Only the projects currently in progress and with signed capacity contracts are expected to be delivered – Ostrołęka C and Dolna Odra. In the years 2035-2040, the necessary capacity reserve is achieved using CCGT and OCGT green hydrogen units.

The tense situation on the commodity market in the second half of 2021 has brought the topic of energy security into common discussion in Europe and Poland. For many years, experts have been warning that Poland's dependence on coal, and in the following years on gas, will have a negative impact on the security of energy supply and the electricity prices for end customers. This vision seems to be materializing faster than it was assumed by the government, and the electricity price increases planned for 2022, combined with record inflation, could have extremely severe consequences for citizens. In order to protect Poles from a long-term threat to energy security in the form of both a gap in the power balance and extremely high electricity prices, it is necessary to take countermeasures, among which we can distinguish:

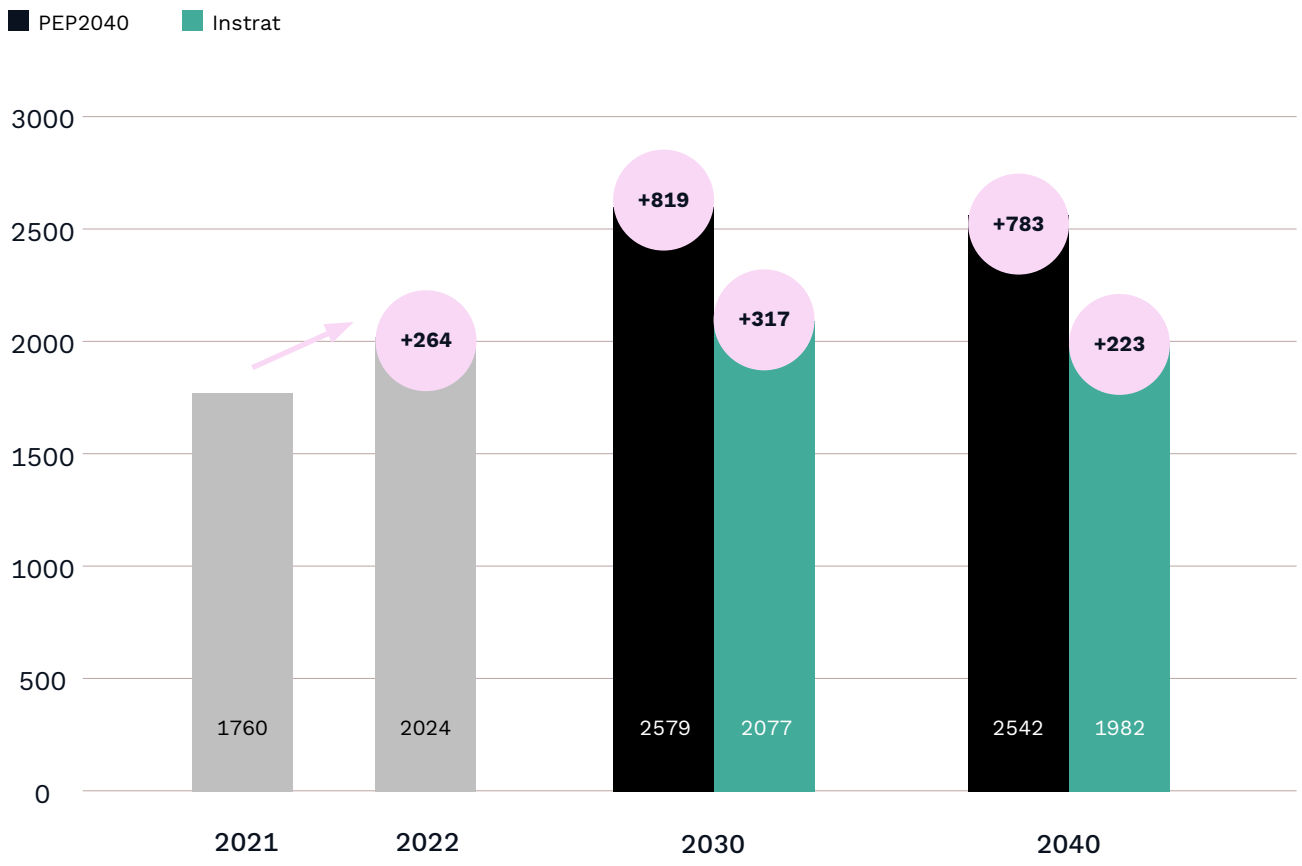
- *Immediately unlocking onshore wind power development, timely implementation of offshore wind farms, ensuring stable growth of PV capacity;*
- *Providing incentives for the development of energy storage facilities, as well as initiating discussions on the future of the capacity market or another mechanism to stimulate investments in peaker plants that have limited utilization;*
- *Announcing a plan of shutdowns of coal-fired generating units, along with preparing a reserve mechanism for the period after the expiry of current capacity contracts;*
- *Providing adequate financial support to distribution and transmission network operators, resulting in an immediate increase in available connection capacity. Some part of this goal can be achieved by increasing the number of EU-funded projects;*

- *Increasing tariff transparency, simplifying the fee structure, making sure it is clear what the various components of the tariff are spent on;*

- *Update of PEP2040 and the NECP (National Energy and Climate Plan), taking into account the current economic realities, available RES potential and market trends, as well as EU climate targets.*

Changing the direction of actions from pro-coal to ones supporting renewable energy will allow Polish households to save hundreds of zloty per year, which is particularly important in times of widespread increases in commodity prices. Otherwise, the continued dependence of the economy on fossil fuels will mean that the already high prices will keep rising. The only way to avoid it is to quickly change the structure of the energy mix to a greener one.

Figure 1. Annual electricity costs per household [PLN]



1. Introduction

This publication is the last in a series of three studies by the Instrat Foundation showing that Poland not only can, but also should take an active part in the EU's effort to decarbonize the power sector. These activities bring a number of benefits to the Polish economy and citizens and lead to an increase in energy security of the country.

Energy security, defined as the uninterrupted availability of energy sources at an affordable price, is fundamental to the smooth functioning of the world's economies. It allows to improve the welfare of citizens and to develop the country by increasing the competitiveness of industry and companies. This is why the guarantee of a stable energy supply has become one of the key points of socio-economic policies, and its role is increasing in the face of structural changes related to the need to achieve climate neutrality. Integration of green electricity leads to fundamental changes in the energy system that will require investments not only in the generating sources themselves, but also in the network infrastructure. On the other hand, it is the broad adaptation of renewable energy sources (RES) that is the best way to improve the country's energy security. Driven by the reduction in RES costs, the green energy mix in Poland will cause electricity prices to fall, as will the volume of imported energy. As a result, the competitiveness of Polish enterprises will improve, and, at the same time, numerous green jobs will be created.

In the first two publications of the series titled "Achieving the goal. Coal phase-out in the Polish power sector" (Czyżak & Wrona, 2021) and "What's next after coal? RES potential in Poland" (Czyżak, Sikorski & Wrona, 2021) we showed that it is possible to achieve more than 70 percent of renewables share in electricity generation in Poland in 2030. This level significantly exceeds the assumptions of the government's Energy Policy of Poland until 2040 (PEP2040) which are unrealistic and inconsistent with the market realities, and according to which Poland is to achieve only 32 percent of RES in the electricity mix within the next decade. Faster decarbonization of the power sector than planned by the government will be forced not only by the needs of the EU climate policy, but primarily by the need to decommission the outdated and uneconomic coal-fired generating fleet. Therefore, it is necessary to make a realistic plan for investments in network infrastructure, matching the pace of market changes already occurring, rather than inhibiting them.

This publication completes the previous two. Its purpose is to look at energy security in its two aspects – the first one, related to the balancing of the National Power System (NPS), and the second one, related to the afforda-

bility of energy for final customers, particularly households. Therefore, the report examines all components of energy tariffs, also paying attention to additional system and network costs associated with the growing share of RES in the energy mix and allowing for secure balancing of the NPS.

The results of the analysis show that despite the need for more investments in network infrastructure than in PEP2040 and the necessity to bear additional system costs, the implementation of the Instrat scenario leads to significantly lower electricity tariffs for households already in the 2030s, compared to the PEP2040 scenario. On the other hand, the attempt to stop the green transformation and the implementation of the government's energy strategy will translate into a drastic increase in electricity prices in Poland. The choice of the preferred path for the development of the Polish power sector seems clear.

It is worth noting that some of the postulates indicated in the previous Instrat reports are already being implemented. The recently adopted Polish Hydrogen Strategy proposes ambitious targets for electrolyzer deployment by 2030, which will have a positive impact on managing the green energy surplus and potentially will accelerate the decarbonization of other sectors of the economy. Following the opinions of experts, the Minister of Climate and Environment Ms. Anna Moskwa proposed to accelerate the update of PEP2040, and during the COP26 climate summit she also supported the global declaration to depart from coal. The Ministry of Climate and Environment also calls for an increased transparency of tariffs, which will make it easier for the public to control costs and revenues of the power sector.

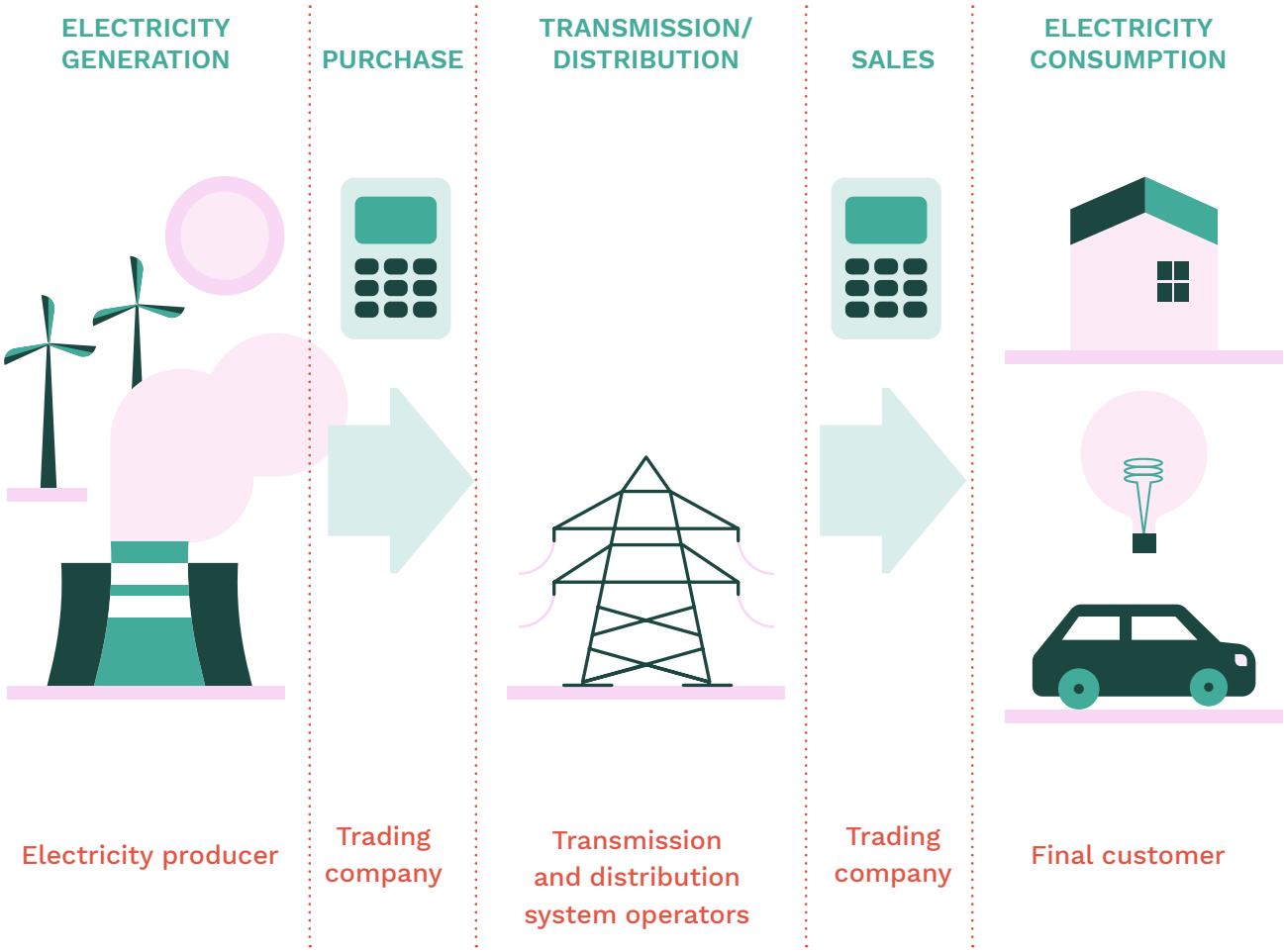
There is still a long way to go to decarbonize the Polish power sector, but the dynamics of progressing changes is enormous, and the status quo of coal is declining faster than one could have believed just a few years ago. The challenges related to rapid RES development are huge, but the benefits to citizens significantly outweigh the additional costs.

2. Shaping energy tariffs for households in the 2040 perspective

2.1. Components of energy prices

Electricity prices are shaped by the actions of each actor active on the electricity market. In the case of Poland, the main actors are: electricity producers, trading companies, transmission system operator (TSO) – Polskie Sieci Elektroenergetyczne and distribution system operators (DSO). It is thanks to them that energy is produced and reaches the final customers (Fig. 1). Energy producers – power plant owners – are responsible for producing electricity from sources such as coal and lignite or renewables. Energy producers sell energy to trading companies, which then sell it to final customers. The sale of energy to a trading company is a prerequisite for supplying electricity into the grid by the energy producer, and once this is done, it is distributed through the transmission and distribution network to final customers. Trading companies are thus responsible for selling energy to the final customer, while transmission and distribution network operators are responsible for its delivery from the producer to the consumer. The latter are also responsible for, among other things, balancing the system, ensuring security of supply or remedying power line failures, for which they are paid within the electricity bill. The above processes are regulated and supervised by the President of the Energy Regulatory Office (ERO). It is the central body of the government administration responsible for the performance of tasks in the field of fuel and energy management, and its competences include, among others, granting and revoking licenses for the sale and distribution of energy, approving the amount and duration of tariffs for households, and controlling the fulfillment of legal obligations by market participants.

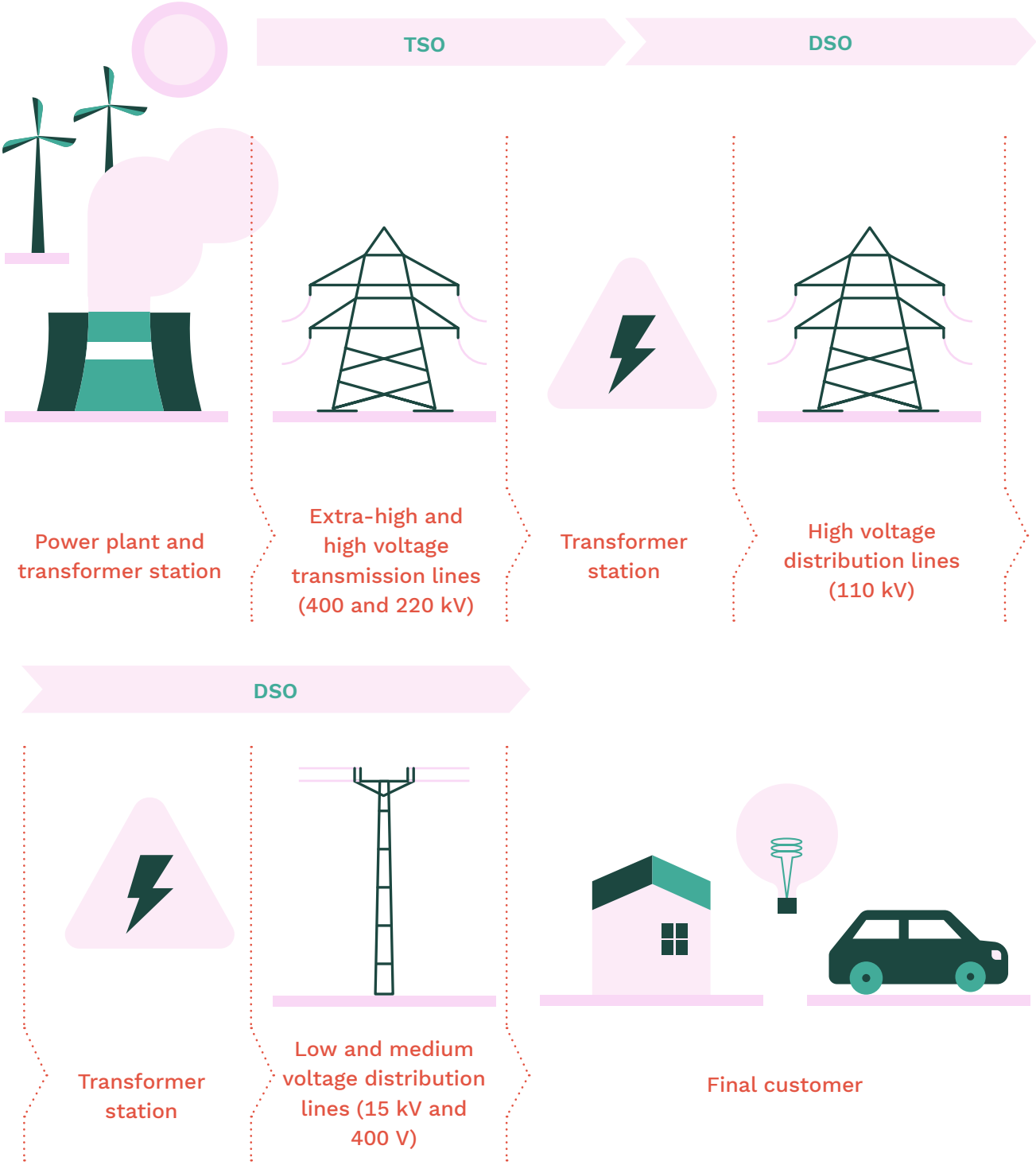
Figure 2. Process of electricity supply



Source: Instrat internal analysis.

As a rule, a grid-connected final customer uses the services of the DSO, as they are the owners of the medium and low voltage (15 kV – 400 V) networks through which electricity is supplied to final customers. However, before the energy gets there, it is transmitted through the highest voltage lines (400 and 220 kV) from the generating source to the transformer station – which is the responsibility of the TSO (in the case of Poland it is Polskie Sieci Elektroenergetyczne). At the transformer station, the voltage level changes allowing further energy distribution by the DSO, first through the high voltage distribution lines (110 kV) to the next transformer station, and then through the low and medium voltage lines (15 kV – 400V) to final customers (Fig. 3).

Figure 3. Transmission and distribution of electricity from the producer to the final customer



Source: Instrat internal analysis.

Each of the aforementioned actors incurs costs that shape the price of electricity supplied to final customers. The cost structure can be divided into the part due to the trading company and that due to the DSO, including taxes and fees.

The trading/energy sales component

This is the sum of all costs (variable and fixed) incurred by the trading company when buying and selling electricity to the end user. These are:

- *active energy charge: a charge for the generation of energy (variable charge). The purchase of energy is made at an energy exchange or from an energy producer on the basis of a bilateral agreement, and the funds go directly to the energy producer or another trading company;*

- *excise tax: a tax on the sale of electricity that depends on the amount of energy consumed (variable rate per MWh). The excise tax rate on the sale of electricity was reduced in 2019 from PLN 20/MWh to the current rate of PLN 5/MWh[1].*

- *color certificates – mainly green certificates: charges under a mechanism supporting energy production from RES – certificates of origin of electricity (a variable charge that depends on the amount of the energy produced). The RES obligation in generated electricity is currently at 19.5 percent and it is scheduled to be reduced to 18.5 percent in 2022;*

- *VAT: a 23 percent sales tax on electricity[2]*

Distribution component

A charge for supplying electricity to a customer through transmission and distribution networks (URE, 2019).

- *variable component of the network rate: related to the cost of electricity distribution. The charge depends on the amount of energy consumed by the customer (PLN/kWh). This charge also covers the purchase of additional energy by the distributor to cover network losses;*

- *fixed component of the network charge: related to the fixed costs of the maintenance and operation of the network infrastructure (PLN per month). The amount depends on the tariff type and distributor;*

- *quality charge: a charge for maintaining the parameters of electricity and the balance of the power system, depending on consumption (PLN/kWh);*

1 Temporarily reduced to PLN 0/MWh in 2022 within the anti-inflation measures.

2 Between January and March 2022 reduced to 5 percent within the anti-inflation measures.

- *cogeneration charge: a charge for ensuring availability of electricity from high-efficiency cogeneration in the national power system (PLN/MWh). Since its introduction, its amount has been marginal, in 2021 set to PLN 0 per MWh, will increase to PLN 4.06/MWh since 2022;*

- *RES charge: related to supporting mechanisms and instruments for generating electricity from RES and ensuring its availability in the power system. Variable rate – since 2018 it was PLN 0 per MWh, in 2021 it has increased to PLN 2.2/MWh (URE, 2020a), for 2022 a reduction to PLN 0.9/MWh is discussed;*

- *transition charge: related to the cost of liquidating long-term contracts. Fixed rate (PLN per month), but for households it depends on annual electricity consumption;*

- *capacity charge: a charge for the operation of the capacity market, charged since 2021. For typical households[3] in 2021 it is PLN 7.47/month and it is expected to increase to PLN 9.46/month in 2022;*

- *subscription fee: a fixed fee for operation, maintenance, etc.;*

- *VAT: a 23 percent sales tax on electricity[4]*

Each of the components listed above has a significant impact on the final price of energy for households. The trading and distribution component currently account for approx. 50 percent of the household bill each (Fig. 4). The amount of the trading component has increased over the past two years (from PLN 0.30 to 0.37 per kWh), and electricity sellers are seeking further increases in tariff prices in 2022 – by as much as 40 percent (Oksińska, 2021). This is related to the increase in energy prices on the Polish Power Exchange (the factors determining electricity generation prices are described below), threatening the profitability of trading companies. An upward trend is also observed in distribution rates. Over the period from 2019 to 2021 the distribution component increased from PLN 0.32/kWh to PLN 0.37/kWh, and this is due to, among other things, the introduction of new charges such as the RES charge and the capacity charge. Network charges are expected to stabilize in the future and the cost of electricity will play a major role in tariff changes (EC, 2020). However, before that happens, the need for costly grid investments (the Polish grids are old and not adjusted to the requirements of the energy transition, such as the dynamic development of renewable energy sources) will contribute to higher distribution prices in the short and medium term. In November this year URE initiated procedures in relation to the rates of distribution charges, and although the outcome

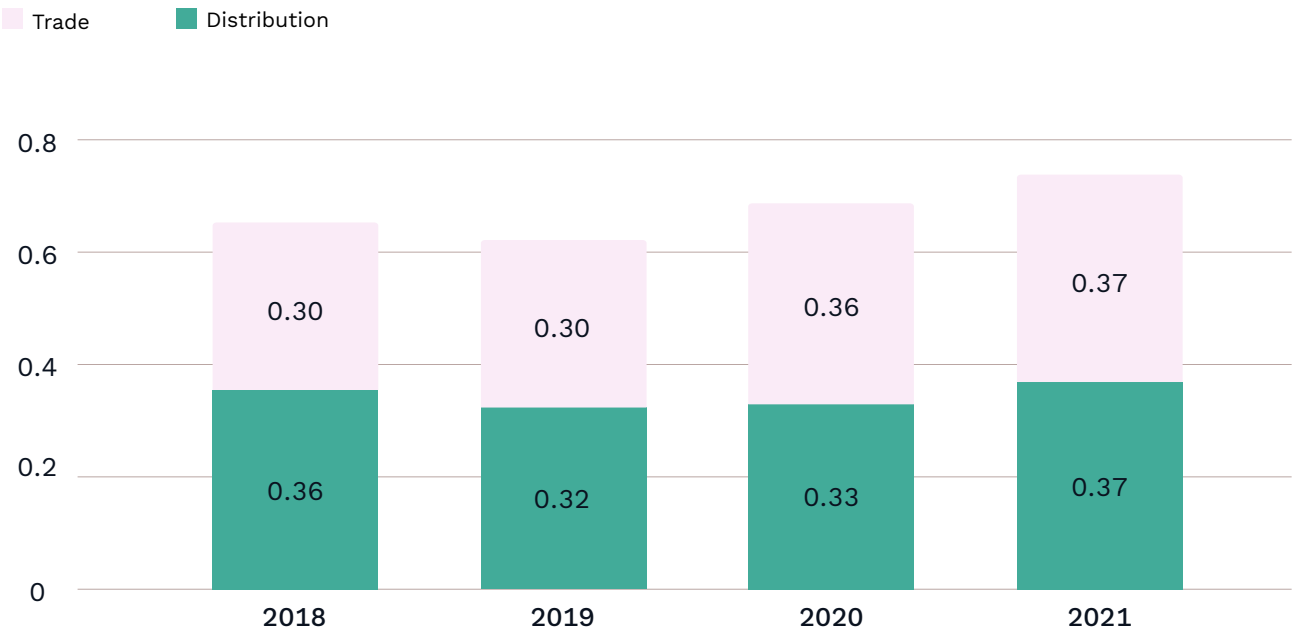
3 The average electricity consumption in households is 2375 kWh/year (CSO, 2019).

4 Between January and March 2022 reduced to 5 percent within the anti-inflation measures.

is not known at the time of writing this report, the President of the Energy Regulatory Office has already indicated that they are likely to increase significantly in 2022 (URE, 2021a).

It should be noted that the calculations do not include the planned vouchers/compensations for households suffering from energy poverty in 2022, but the decrease of VAT and excise taxes in 2022 proposed within the anti-inflation measures[5] was included in the calculations. It is important to underline that such measures are only ad hoc tools for mitigating the increase in energy costs resulting from fundamental factors (too high share of coal in the energy mix). The effectiveness of such measures is limited and only results in delaying and amplifying the adverse effects on the economy (which was fully demonstrated by the repeatedly amended Energy Price Freeze Act of late 2018 and early 2019). The energy price forecasts given in the report for the coming years are real prices, and it can be expected that, with inflation remaining extremely high, nominal energy price increases will be higher[6].

Figure 4. Level of trade and distribution components in energy prices for households [PLN/kWh]



Source: Instrat internal analysis based on PGE Branch Rzeszów tariffs from 2018–2021, for G11 tariff and a household consuming an average of 2,375 kWh of electricity per year (according to the data of the Central Statistical Office in Poland).

5 Draft act amending the act on excise duty and the act on tax on retail sales, UD 315

6 An example is the cost of investment in the development of network infrastructure, which is strongly dependent on the strongly rising cost of construction materials and services.

2.2. Factors determining tariffs for households

A number of factors – not only economic and technical, but also political and social – influence tariff formation. In particular, household tariffs are regulated by the Energy Regulatory Office, so their value does not always correspond to market conditions, which can change dynamically. The most important factors influencing tariffs for residential customers in Poland are discussed below.

Trading component

A trading company's tariff is primarily determined by the electricity generation cost (the so called Short-Run Marginal Cost, or SRMC). It is this cost that determines at what price a power plant owner can sell energy on the spot market or under a futures contract to ensure that they make a profit. This energy will then be bought by a trading company to be resold to end users – households and businesses. In addition to the margin of the generation and trading company, the tariff will also include the cost of acquiring color certificates (discussed further in the text) and excise tax.

The wholesale price formation mechanism in the energy market is referred to as merit order. At any given time, only the power plants with the aggregate capacity corresponding to the demand, ranked from the most efficient to the least (they are competing on marginal cost), are connected to the system (Figure 5). The price is set at the marginal cost of the last of the units connected – it is not profitable for less efficient units to start production, and it is not profitable for more efficient units to sell energy below the set price. This price is called the Market-Clearing Price. The *merit order* mechanism pushes expensive and inefficient units, in particular old coal-fired power plants, out of the energy market, giving preference to renewable energy sources with minimum variable costs.

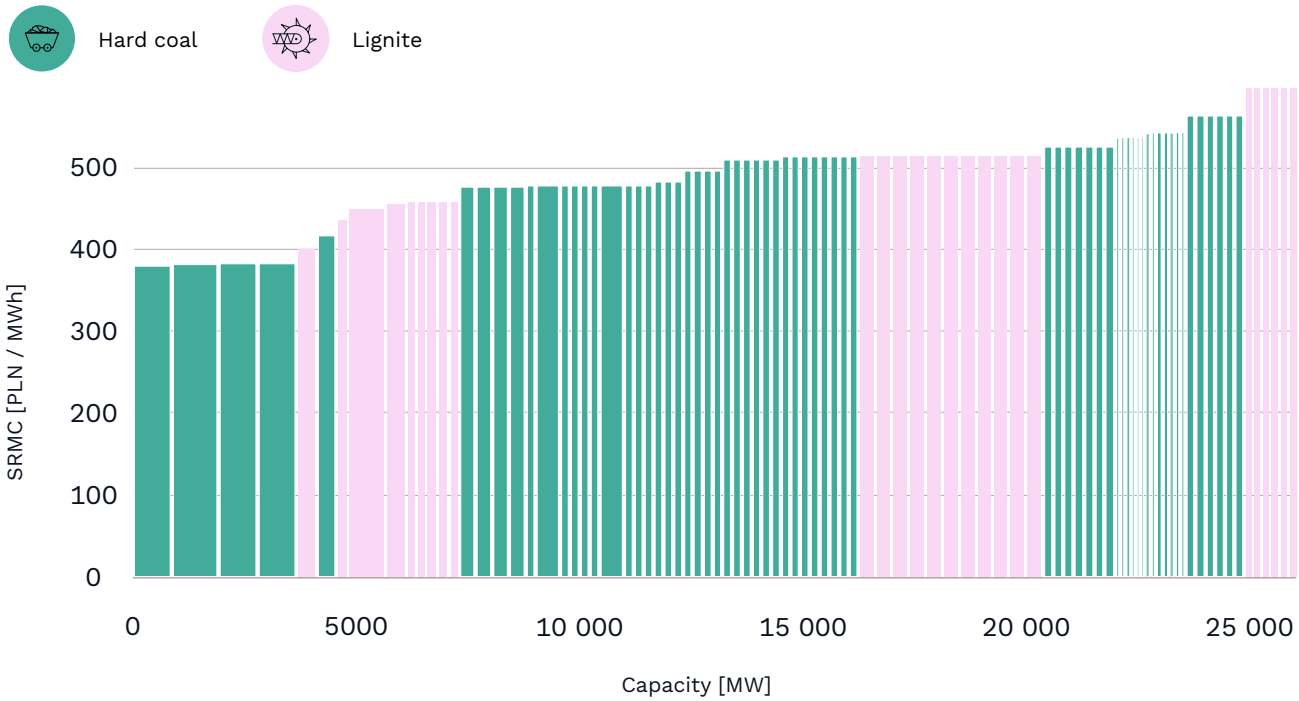
On the other hand, as long as coal units are required to meet demand, they will drive the price on the market. So it is important to remember that coal still accounts for 70 percent of energy production in Poland (Energy.instrat.pl, 2021a), and it is coal units that will most often determine the wholesale price of energy.

In practice, during the summer evening peak demand reaching 23–24 GW, with combined heat and power plants shut down and no wind, it may be necessary to start old hard coal fired units in Łaziska, Łagisza, Siersza and Stalowa Wola power plants with a low efficiency of 32 percent (Stępień, Czyżak & Hetmanski, 2021). The cost of their operation in 2021 significantly exceeds PLN 400/MWh, and very high prices are also noted on the Day-Ahead Market.

The major components of coal-fired energy production costs are:

- *the price of the raw material – hard coal or lignite (extracted near the power plant),*
- *the cost of fuel transport (negligible in lignite-fired power plants),*
- *the price of CO_2 emissions allowances,*
- *other variable costs of operating the power plant.*

Figure 5. Marginal costs of coal units [PLN/MWh]



Source: Energy.instrat.pl: https://energy.instrat.pl/power_plants

Fig. 6. shows the structure of these costs for a hard coal fired unit with efficiency of 38% and emissions of 840 gCO2/kWh[7]. Historically, the major cost component was the purchase of coal. Currently, up to 60 percent of the cost is accounted for by CO2 emission allowances, the price of which has risen from approx. EUR 30/t in January 2021 to over EUR 60/t in September and up to EUR 70/t in late November. The average for 2021 is estimated to be EUR 52/t (KOBiZE, 2021).

7 These parameters correspond to units of Ostrołęka B Power Plant and were chosen because SRMC calculated from them correlates well with energy price and average cost in the entire NPS obtained from the optimization model for 2020 and 2021.

The total cost of energy production has increased by 49 percent since January 2020 and has doubled since the beginning of 2018. The presented coal prices are taken from the PSCMI-1 index on the Polish Power Exchange (Energy.instrat.pl, 2021b), CO2 certificate prices from the EEX primary market auction (Energy.instrat.pl, 2021c), coal transportation costs were estimated based on historical PKP Cargo tariffs (PKP Cargo, 2021), and the analysis by K. Stala-Szlugaj (2021), for a coal calorific value of 22.1 MJ/kg and a distance of 200 km corresponding to the average distance of coal transportation in Poland, operating costs are taken from the Polish Energy Policy until 2040.[8] The graph shows nominal prices, prices expressed in EUR were converted to PLN based on NBP historical average exchange rates for the respective months.

The chart also highlights exchange prices on the Day-Ahead Market (DAM) and the Commodity Forward Instruments Market (CFIM). The former doubled over the past year, the latter increased by 37 percent in 2021 alone. Typically, the Day-Ahead Market (DAM) price is considered to be a representative indicator of wholesale electricity prices; however, it is the Commodity Forward Instruments Market (CFIM) where the majority of energy volume is traded – in 2019, the CFIM share in the total volume was as much as 85 percent. By far the most popular futures contract is the BASE_Y annual contract.

Historically, the futures market has almost perfectly replicated the cost of coal-fired energy production at a margin of 10–15 percent[9] In 2018, a sudden increase in CO2 prices increased marginal costs, but the producers increased prices on the futures market significantly above the values resulting from fundamental factors, achieving average margins of more than 20 percent and drawing the attention of the Energy Regulatory Office (Rzeczpospolita, 2021). This event preceded the so-called Energy Price Freeze Act of December 2018, which was intended to prevent increases in futures prices from being translated into end-user tariffs, and caused massive confusion on the market.

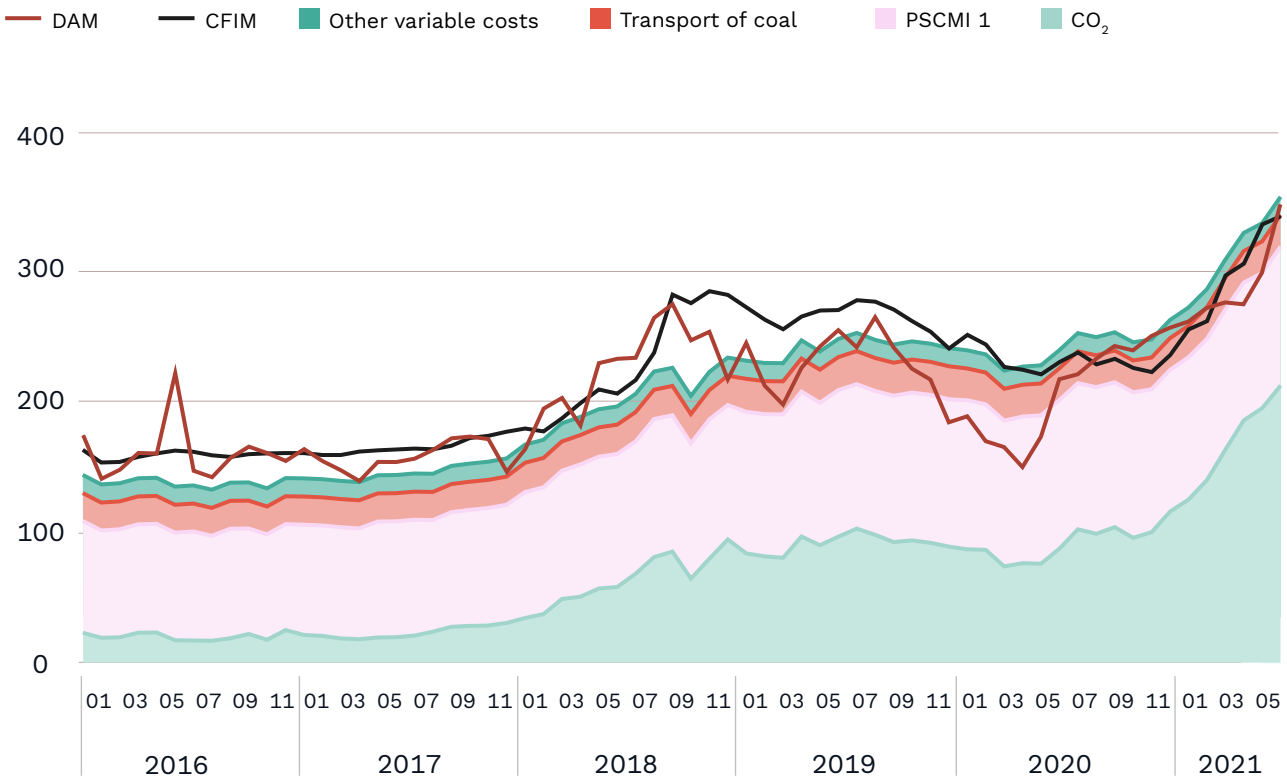
Since mid-2020, the average margins of many producers on the futures market have been negative – the cost of production for a unit with the efficiency of 38 percent and smaller exceeds the market price, and these units generate operating losses[10]. In the long term and with capacity market contracts running out, these permanently unprofitable units will have to be shut down or provided with new support.

8 Announcement of the Minister of Climate and Environment of March 2, 2021 on the state energy policy until 2040, append. 2.

9 For the aforementioned unit with the efficiency of 38 percent.

10 This calculation does not take into account other sources of revenue – e.g. the balancing market and the capacity market, but it gives a good picture of the sector's financial situation.

Figure 6. Factors determining energy production costs and exchange prices [PLN/MWh]



Source: Instrat internal analysis, data: energy.instrat.pl, TGE, EEX, ARP, PEP2040

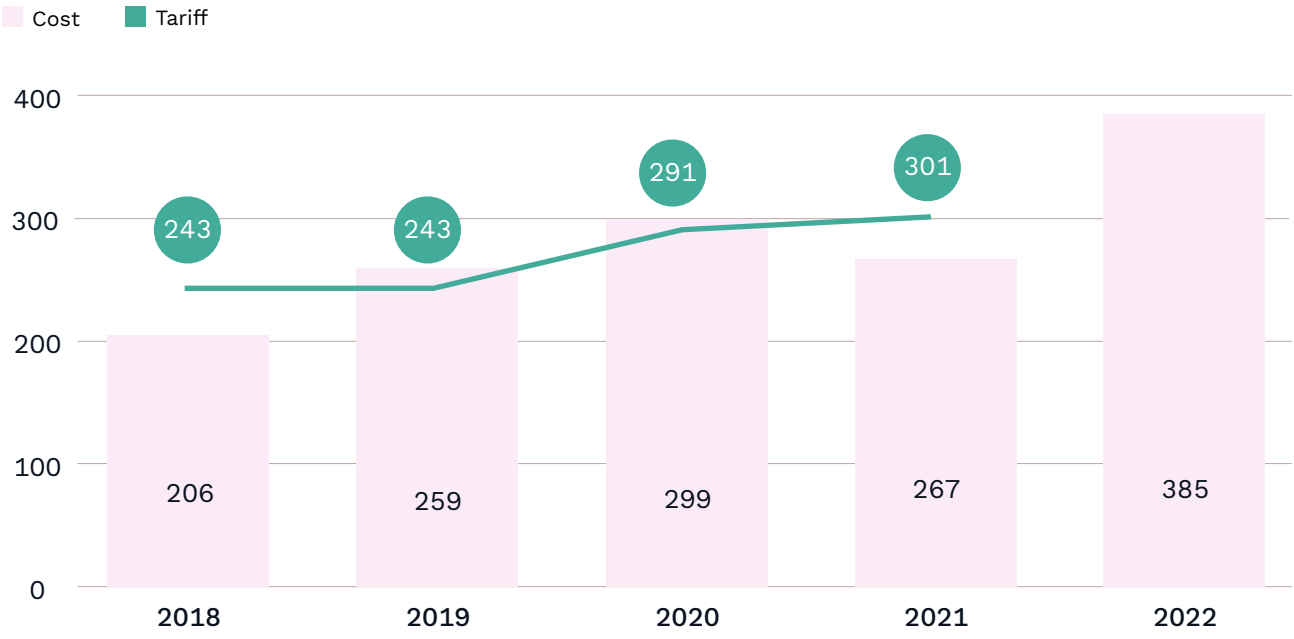
In a properly functioning market, a power plant owner sells energy at a price that reflects marginal costs. This energy is purchased by a trading company, e.g. under a contract with delivery for the following year. In the short term, changes in tariffs can therefore be forecast by looking at the prices of futures contracts – those with delivery in 2022 cost PLN 256/MWh in January 2021 and increased to PLN 442/MWh in October 2021. We know that this will be reflected in next year tariffs, and requests for price increases have already been submitted to the Energy Regulatory Office.

In addition to the cost of purchasing the energy itself, the trading company incurs other costs – e.g. the purchase of color certificates. The trading company is obliged to acquire a part of the energy from renewable sources[11] – if it is not able to physically purchase green energy, it has to supplement the missing volume by purchasing color certificates. The average price of the most important among them, i.e. PMOZE_A instrument in the first half of 2021 amounted to PLN 150/MWh. With the obligation to purchase green certificates at the level of 19.5% of the volume, the trading company bears the cost of PLN 29/MWh.

11 So far it has been 19.5 percent, for 2022 the RES obligation has been reduced to 18.5 percent.

The trading tariff also includes excise tax – currently at the rate of PLN 5/MWh. The total costs incurred by the trading companies between 2018 and 2021 are shown in Figure 7 – in 2018 it was PLN 206/MWh, in 2022 it could be up to twice as much[12]. Confronting these values with the amount of tariffs for individual customers, it can be seen that in 2019 and 2020 the costs incurred by the trading companies exceeded their revenues in the household segment. We will probably see a similar situation in 2022, because the Energy Regulatory Office will probably not agree to tariff increases of PLN 100/MWh, which is the amount that would be required to cover the growing costs of energy.

Figure 7. Relation of net tariffs to estimated costs [PLN/MWh]



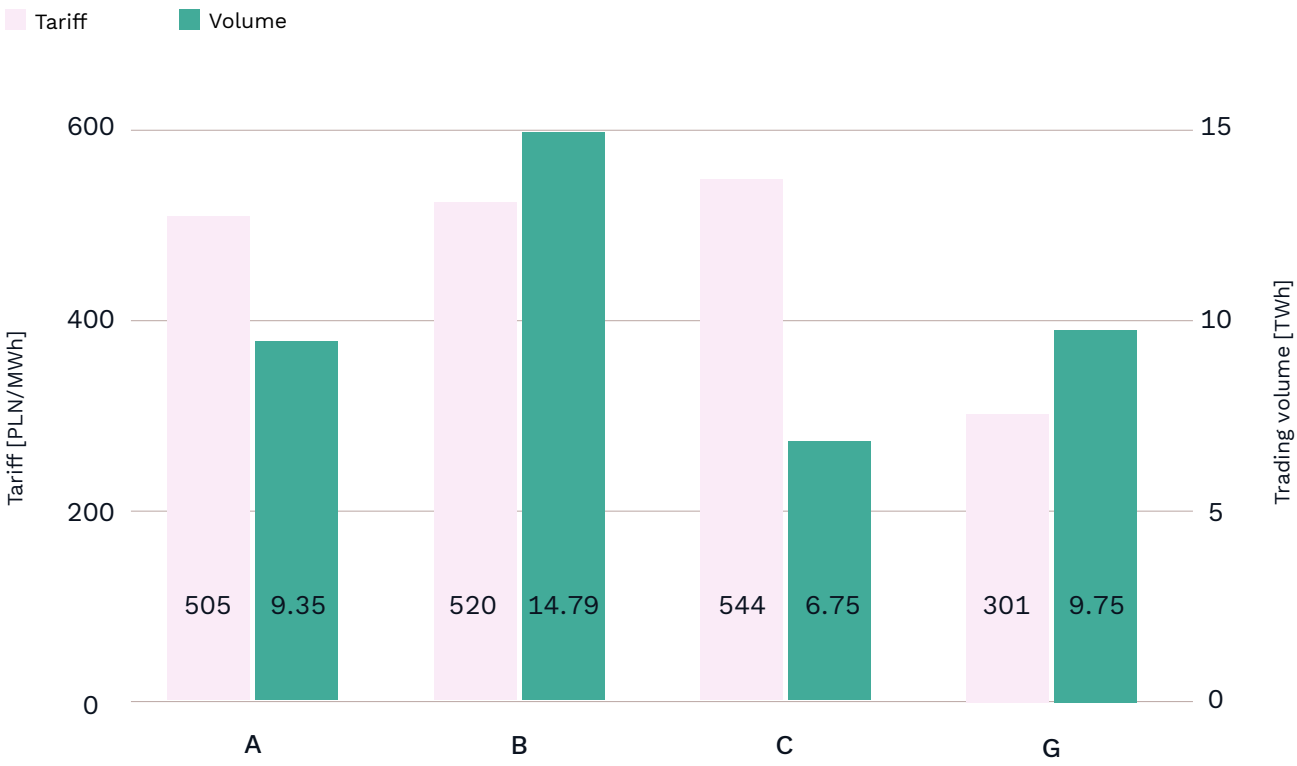
Source: Instrat internal analysis, data: TGE and DNO

This puts financial pressure on trading companies, which compensate for low margins in the household segment with revenues from institutional customers. Fig. 8 shows the tariffs for 2021 for different groups of customers of PGE Dystrybucja. Prices for businesses are not regulated and as a result are as much as 81 percent higher than those for individual customers. The largest companies can negotiate rates or enter into long-term

12 The volume-weighted average price of BASE_Y-22 contracts in the period from January to October 2021 was PLN 351/MWh, with prices exceeding PLN 450/MWh in November. Taking into account the cost of color certificates, the average total cost borne by the trading company in 2022 is likely to exceed PLN 400/MWh.

contracts, so small and medium-sized businesses are the most affected. Interestingly, PGE Dystrybucja, used as an example, sells over three times more energy to businesses than to households. Since it earns huge margins on this, it is easily able to cover any losses in the household segment.

Figure 8. Energy prices for different tariff groups in 2021 (2020 volume)



Source: Instrat's internal analysis based on the integrated reports of PGE.

Distribution component

The distribution tariff includes both fixed components[13], and variable components [14]. Each represents a different component of the full costs of the electricity distribution and transmission sector. Together, they reflect all costs incurred by the entities, related to the delivery of electricity to the customer through transmission and distribution networks.

The energy undertaking should set the tariff in such a way as to ensure that justified costs are covered and to eliminate cross-subsidization[15]. The legal

13 That is, fees independent of energy consumption and charged as a lump sum, e.g. monthly.

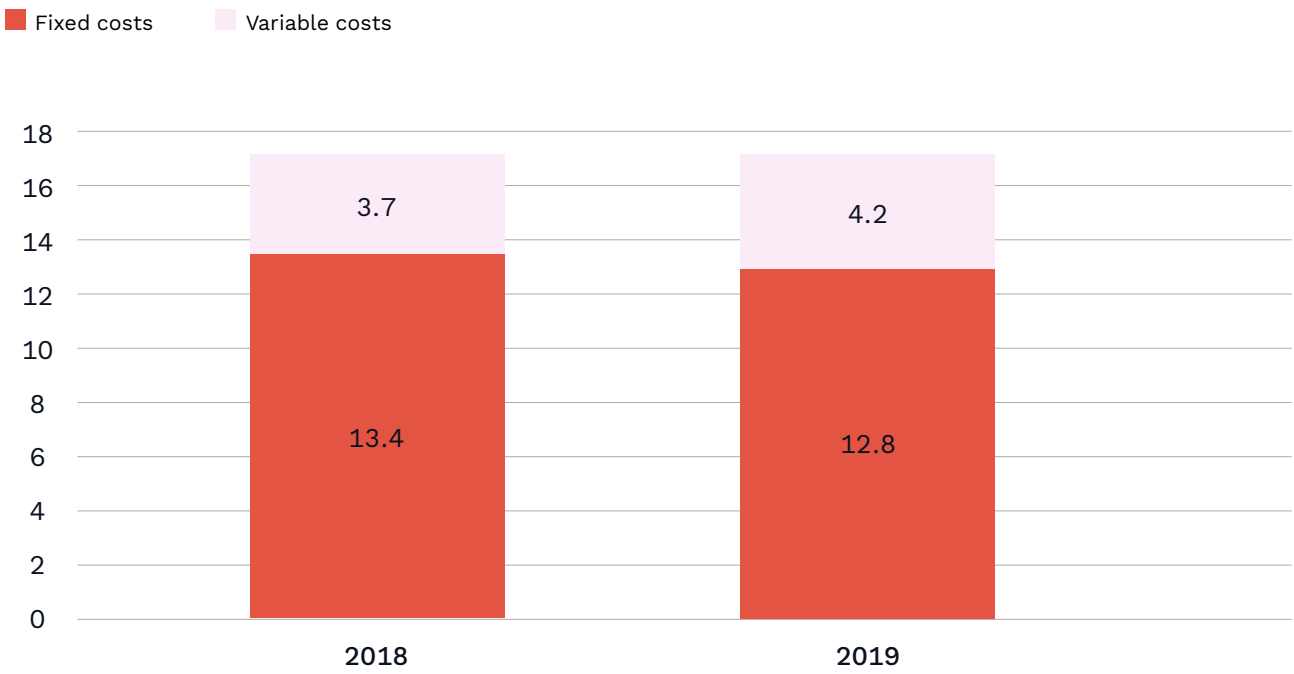
14 Dependent on energy consumption, charged per kWh.

15 Cross-subsidization, i.e., covering the costs of one type of economic activity performed or the costs concerning one group of customers with revenues from another type of economic activity performed or from another group of customers.

basis for the calculation of the individual elements of the network tariff is the Tariff Regulation (Journal of Laws of 2019, item 503).

The fixed component of the network rate is calculated based on fixed costs, which dominate the distribution costs incurred by DSOs - they account for more than 75 percent of the full costs (Figure 9). These include all taxes and similar charges, depreciation and amortization expenses, salary and other such expenses, management expenses, costs of redeemed property rights, and expenditures for network modernization and extension. Fixed costs have remained rather stable in recent years and their fluctuations are not significant.

Figure 9. Costs of electricity distribution [billion PLN]



Source: Instrat's own study based on ARE data

The variable component of the network rate is calculated based on the planned justified costs, i.e.:

- *related to purchase of such amount of electricity to cover the difference between the amount of electricity supplied to and taken from the grid by customers at a given voltage or transmitted or distributed to the grid of other voltage levels*

- *variables for the transmission or distribution of electricity through networks of other rated voltage levels and networks belonging to other operators or electricity undertakings*

- *fixed component for the transmission or distribution of electricity for the part not included in the fixed component.*

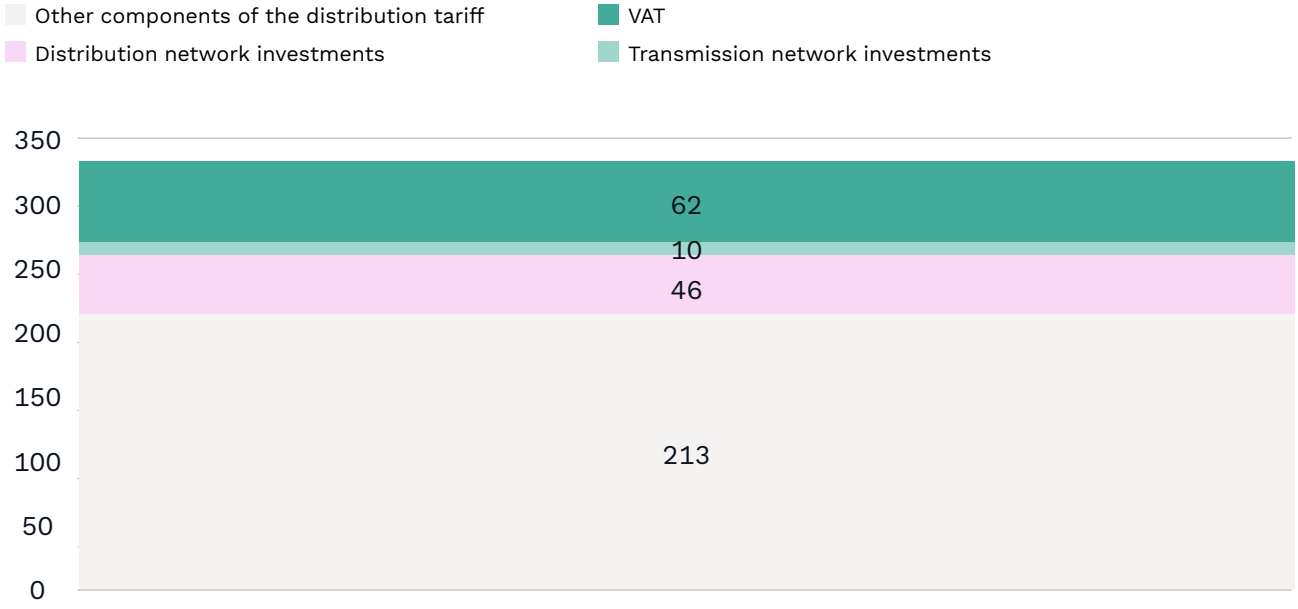
It is worth noting that the costs of network modernization and extension should be directly linked to the fixed component of the network rate and be appropriately reflected in the tariff amount. However, if modernization investments contribute to a reduction in active energy losses in the networks and reduce the volume of energy purchased to cover them by the operator, naturally they also affect the variable component of the network rate.

Historically, the fixed components of the network rate for tariff group G customers have been politically deformed (understated). This is all the more important because low-voltage customers are at the end of the physical energy supply chain, so they use the transmission, 110 kV and other energy distribution networks. Thus, their fixed component of the network rate should include the costs of all the listed network links.

It is worth realizing what portion of the household distribution tariff is currently attributed to network investments. For PGE Dystrybucja, it was only 16.9 percent of the total gross tariff in 2020 (Fig. 10)[16]. In view of the sector transformation, the changes taking place in the market and the investments required, these figures are insufficient - both in percentage terms and in absolute figures.

16 Assuming that this amount is distributed equally across all types of customers.

Figure 10. Ratio of capital expenditures to other components of the distribution tariff for households [PLN/MWh]

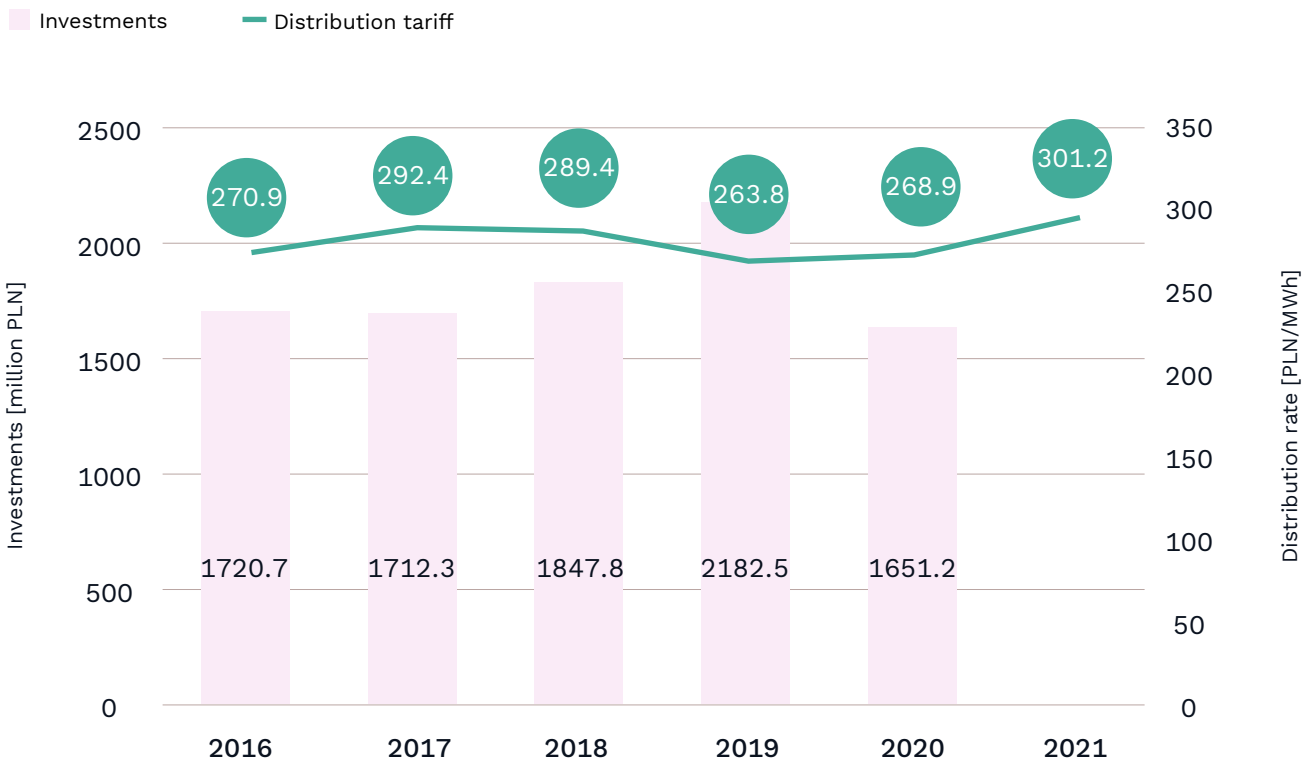


Source: Instrat's own study based on PGE Dystrybucja tariff in 2020.

Historically, the amounts of distribution tariffs for households have not been closely correlated with network capital expenditures (Figure 11). Tariffs remained about the same from 2016 to 2018, as did investments. In contrast, the same cannot be said for the following years - in 2019, investments increased significantly and the tariff amount decreased relative to previous years. In 2020, it was the exact opposite - investments decreased and the tariff increased relative to the previous year. The decrease in tariffs was related to, among others, the statutory freeze on energy prices and the decrease in the transition charge from PLN 6.5/month in 2018 to PLN 0.33/month in 2019. However, the distribution tariff rates should reflect market conditions and correspond to the plans of network operators in the context of increasing network investments. Declining capital expenditures is a definitely undesirable trend. The current obsolete distribution network will be an extremely important restraining factor for the energy transition in Poland - without investing in its extension and modernization it will be impossible to achieve the specific climate goals, as is already demonstrated by the problems experienced with connecting new photovoltaic systems to the network.

Other components of the distribution tariff include a quality charge, which reflects the cost of maintaining system quality standards and reliability of the current electricity supply. These costs are associated with ensuring continuous and correct operation of the supplied electrical equipment and loads. It is expected that they may increase in the future due to, among others, the growing share of energy sources with a variable production profile, as well as the increasing number of, for example, nonlinear loads and power electronics.

Figure 11. PGE Dystrybucja distribution tariff vs. network investments



Source: Instrat's own study based on PTPiREE data (2016-2021) and PGE Rzeszów Branch tariffs 2016-2021 - for G11 tariff and a household consuming on average 2,375 kWh of electricity per year.

Another very important component of the distribution tariff is the capacity market fee. This fee covers the costs of the capacity market which was designed to ensure a stable supply of electricity and thus energy security. The amount of the capacity fee for households is derived from their number (15.6 million) and the percentage of the total volume of energy they consume[17]. The cost of the entire capacity market was PLN 5.4 billion in 2021. By 2040, its total costs will be about PLN 50 billion. However, the total amount due for power contracted in future years will decline. In 2040 it will already be about PLN 350 million[18], which will be related to the last long--term power contracts. It should be mentioned that the capacity market has not met hopes and expectations. From July 1, 2025, it will no longer be able to support (existing) units emitting more than 550 g CO2/kWh, which effectively excludes coal-fired power plants. Meanwhile, in the auctions to date, very little of the contracted capacity comes from new investments. The capacity market has made the energy mix somewhat fixed and not diversified, so it will neither reduce CO2 emissions, nor increase the flexibility of the system, which would be highly desirable with the growing share

17 Households are estimated to pay 26 percent of the cost of the capacity market (Zasuń, 2019).

18 Assuming the current mechanism is not extended and no new contracts are concluded.

of RES in the energy mix. Finally, the price at capacity auctions has settled at a higher level than originally expected, which will improve the financial health of energy producers, but will increase consumers' bills.

When planning the shape and amount of network tariffs in the future, it is important to consider what the power system will look like a few years from now and to remember that investment processes are spread over time - so changes must take into account the vision of a system without most coal sources in 2030 and a climate-neutral system well before 2050. In this context, it will be necessary to optimize capital expenditures, a prerequisite for which is a change in the tariff model and allowing for tariff variability over time. However, such changes should be introduced gradually in order to take into account both the interest of consumers, who will partly finance the ongoing market changes and the related additional investments, as well as to ensure the stability and liquidity of DSOs and their proper functioning in the future (Gawlikowska-Fyk & Jahn, 2021).

RES component

Both the revolving and distribution tariffs have components related to support for renewable energy sources. Support for RES is applied by most of the EU countries, not only because of the necessity to meet the climate goals - it is typical of the governments to support developing industries which create new jobs or demand for services and thus, contribute to economic growth. In Poland, only part of the support mechanisms for RES is directly reflected in electricity bills. Currently, it is in the form of a RES fee added to the bill from the DSO and within the required green energy volume for trading companies. With the development of RES in the country, one should expect their increased influence also on the variable and fixed component of the distribution tariff (costs of investments in the grid), or the quality fee, due to the necessity of balancing the grid with large capacity of the sources with variable production profile. Renewable energy sources are also supported by energy consumers indirectly - e.g. through the transfer of funds from the sale of CO2 emission allowances[19].

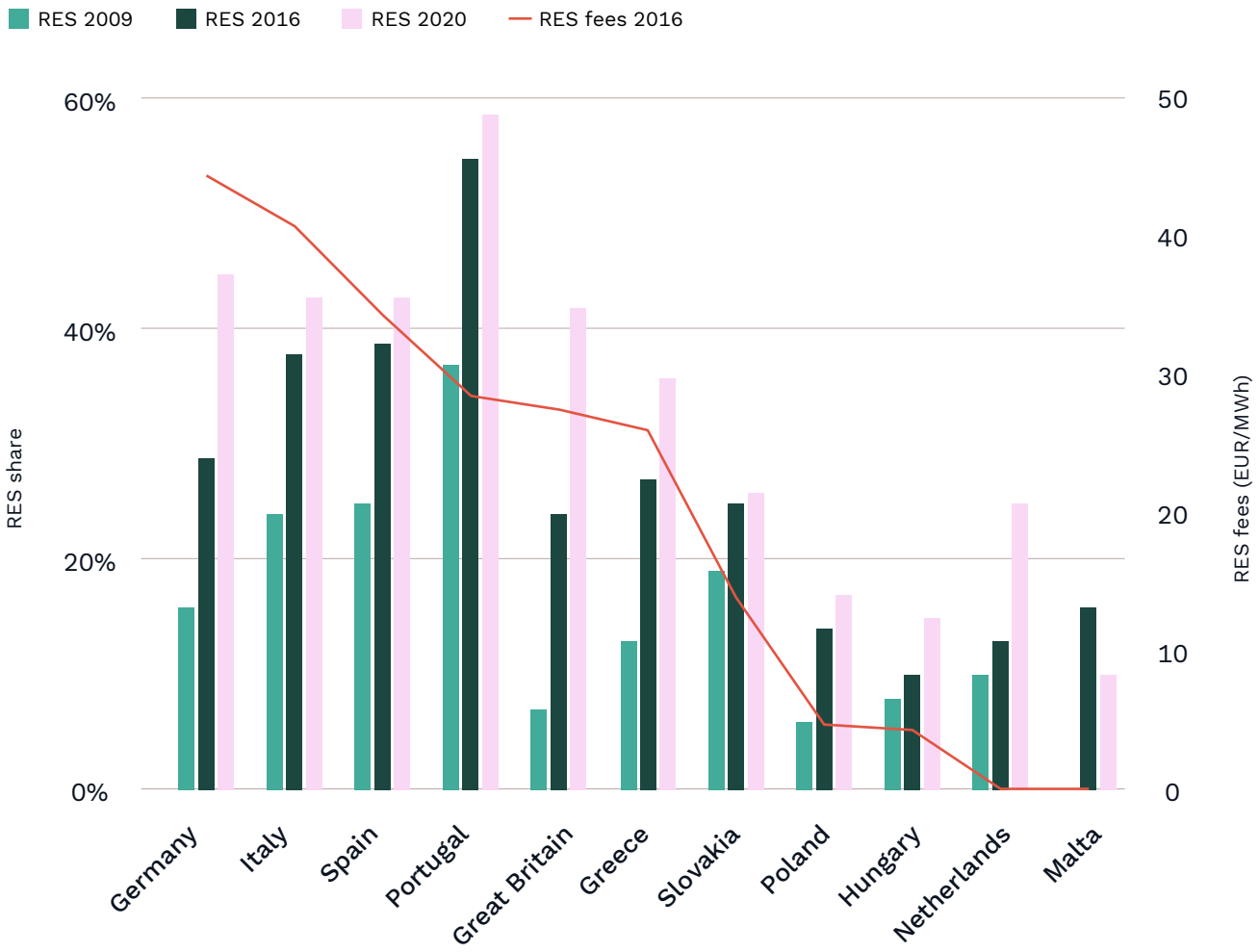
RES subsidies paid by electricity consumers in Poland[20] are low compared to many other EU countries. In 2016, the rate added to the bill was about 4.7 EUR/MWh in the country, and now it has only increased to about 7 EUR/MWh (2.2 PLN/MWh for the RES fee and about 30 PLN/MWh for green certificates). By comparison, in Italy the RES fee in 2016 was over 41 EUR/MWh and in Germany it was almost 45 EUR/MWh (Figure 12). Poland's small subsidies are reflected in the low share of RES in electricity generation and the slow development of green technologies in the country. Since 2009, the

19 Contrary to the assumptions of the ETS, the Polish government allocates only part of these funds to investments in energy transformation and decarbonization of the economy.

20 Does not include subsidies paid to generators by state governments, which are not then reflected in bills for final customers.

share of RES in the Polish power sector has increased from 6 percent to only 17 percent in 2020, while Germany saw an expansion from 16 to 45 percent over the same period. An analysis by Triconomics for DG Competition (EC, 2019) shows that, on average across the EU, the cost of RES subsidies included in tariffs increased from 6.4 EUR/MWh in 2008 to 23.9 EUR/MWh in 2016, also leading to an increase in the share of RES in electricity consumption from 17 percent in 2008 to almost 30 percent in 2016 (Figure 13). Experience of the EU shows that RES development often correlates with an increase in the RES subsidies paid by consumers. This means that in Poland, too, rate increases may be inevitable in the face of the need for faster implementation of green technologies. The largest increase related to RES is to be expected in the distribution tariff, which is related to the need to extend the network infrastructure and take into account the system costs associated with them.

Figure 12. RES fees paid by electricity consumers in selected EU states and the share of RES in electricity production in these states

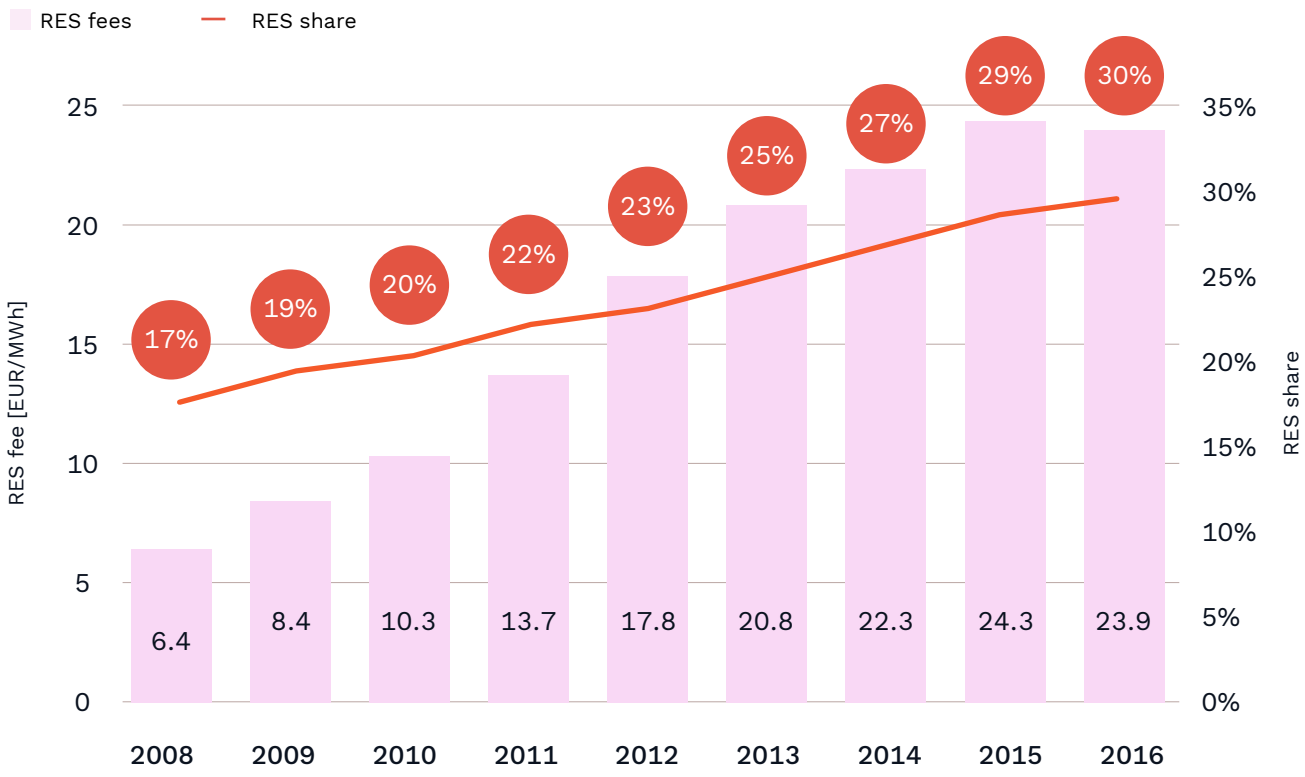


Source: Instrat's own study based on Triconomics, 2018, Study on Energy Prices, Costs and Subsidies and their Impact on Industry and Households DG ENER/Unit A4/Year 2017-Vigie No 2017-359 V2.0 and Ember.

On the other hand, renewable energy sources seem to have reached a sufficiently advanced stage of development that they can operate independently in a competitive energy market[21]. It is therefore doubtful that RES subsidies will be a significant burden on energy final customers. The phenomenon of slow withdrawal from subsidizing renewable energy sources is well illustrated by the results of RES auctions - the largest currently operating support mechanism dedicated to them.

The costs of this system are covered by a number of sources (including European funds or revenues from the sale of CO2 emission allowances) and are only marginally passed on to final customers. However, auctions have significantly contributed to the development of green technologies in Poland. As a result of the tenders concluded so far, an additional 10.15 GW of installed capacity may be generated, and the continued effective functioning of the auction mechanism will allow for the implementation of subsequent RES projects.

Figure 13. Average RES fees paid by EU electricity consumers and share of RES in EU electricity consumption



Source: Instrat's own study based on Triconomics, 2018, Study on Energy Prices, Costs and Subsidies and their Impact on Industry and Households DG ENER/Unit A4/Year 2017-Vigie No 2017-359 V2.0 and Eurostat SHARES (Renewables).

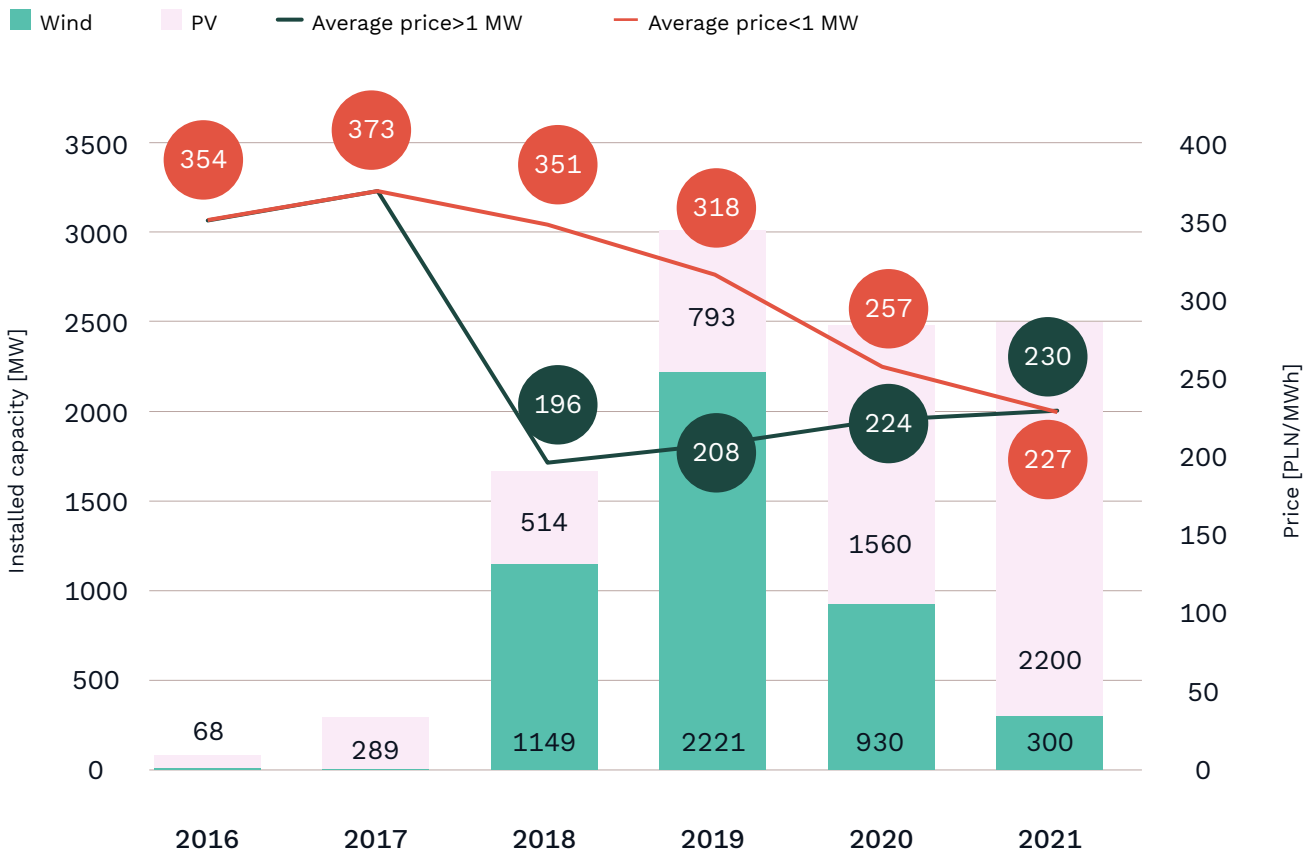
21 Another question is whether we can talk about a competitive market in Poland because of the strong political preference for fossil fuels, high degree of consolidation, dominant position of some players, strong role of the state treasury and the lack of transparency.

Between 2018 and 2019, investments in wind power stations accounted for the dominant share of projects resulting from the auctions, but the trend has been reversing in recent years in favor of PV. This is in part due to the 10H rule, which, by imposing restrictive distance requirements, has limited the number of possible onshore wind investments, and those are now running out. On the other hand, PV has become more competitive in terms of prices, so interest in it has increased.

There are two project baskets in the RES auctions - small for systems < 1 MW and large for systems > 1 MW. Wind and solar projects can compete in both baskets. The small basket has always been dominated by PV - in recent years, all the bids in it have been made by entrepreneurs investing in PV. The large basket has historically been dominated by companies interested in wind power plants, but as mentioned above, the trend is reversing there as well. In 2020, the capacities of wind and solar projects >1 MW equaled for the first time, and in 2021 there was a significant advantage of PV capacity (1.2 GW) over wind farm capacity (0.3 GW).

The prevalence of investments in PV is due, among others, to the increasing competitiveness of this technology, as reflected in the prices of contracted energy. The prices in the two baskets are converging - in the small basket they are decreasing dynamically and in the large basket they are showing an upward trend (Figure 14) . Compared to 2020, the price for <1 MW systems in 2021 decreased by about 10 percent. (from 257 to 227 PLN/MWh). On the other hand, the oversupply of bids has also decreased compared to 2020, indicating that auction prices are no longer as attractive to traders compared to current market prices, and that the auction mechanism serves as a long-term contract hedging instrument. For systems over 1 MW, the average price in 2021 increased to a level above that for small systems. This is because solar energy producers discount the risk associated with larger projects in the bid price (Energy Regulatory Office, 2021b) In the auctions held in 2020, 72 percent (54.5 TWh) of energy to be sold was indeed sold, and four of the eight auctions held in 2020 were not resolved due to insufficient number of bids (Energy Regulatory Office, 2020b). In 2021 however, only 54 percent of the energy was sold, and only three of the eight auctions were resolved (Energy Regulatory Office, 2021b). This signals that RES has become competitive enough to stand on their own in the market. However, maintaining RES auctions, which offer attractive conditions for investors, will help to increase the scale of investments, also because auctions are often used as collateral for loans and project financing.

Figure 14. Installed capacity and average energy prices in RES auctions 2016-2021



Source: Instrat's own study based on Energy Regulatory Office (URE) data

Support for offshore wind energy differs from that for onshore wind and PV, at least in the early stages of development. The first pool of projects did not have to participate in the auctions. The support price was set in the regulation on the maximum price for electricity generated at 319.6 PLN/MWh.[22] However, projects starting in the second phase will be supported by means of competitive auctions identical to those currently held for PV and onshore wind. The first offshore auction will take place in 2025, and the next in 2027. Given the scale of the investment required for offshore projects, the support period for both phases is assumed to be 25 years - i.e. longer than in the case of the current auctions.

22 Regulation of the Minister of Climate and Environment of March 30, 2021 on the maximum price for electricity generated in an offshore wind farm and introduced to the grid in PLN per 1 MWh, being the basis for the settlement of the right to cover the negative balance, Journal of Laws. 2021 item 587.

2.3. Forecast of final prices for households

Observing the ongoing discussion on the Polish power sector, experts seem to agree on one issue – electricity will become more expensive. This is not only due to high inflation, but also due to fundamental factors – the need to modernize the obsolete infrastructure, rising commodity prices, as well as high carbon intensity of the NPS which translates into rising costs of CO2 emission allowances. When analyzing the individual components of tariffs and the factors shaping them, a forecast of household electricity prices until 2040 was prepared. The assumptions and results of the study are discussed below.

Trading tariff

Forecasting the trading component of the tariff focuses primarily on the cost of power generation itself, which is what determines predominantly the final price. This cost results from the structure of the energy mix and was calculated using the PyPSA-PL optimization model according to the scenario and methodology described in the previous publication of the series entitled: "What's next after coal". In response to the rapid market changes in the recent months, as well as the publication of the „World Energy Outlook 2021" report of the International Energy Agency (2021) and the final version of the „Ten Year Network Development Plan 2020" of the Association of Transmission System Operators ENTSO-E (ENTSO-E, 2021), some assumptions have been updated (Table 1). In particular, the assumptions for commodity prices and CO2 emission allowances were revised. The year 2021 was taken as the base year using the latest available data (for gas RDNg weighted averages until October 2021, for coal PSCMI1 until September 2021) or projections (analysis of average CO2 price projections for 2021 from KOBiZE). Electricity demand for 2021 was estimated based on actual consumption for the first three quarters of 2021 and an appropriately scaled demand profile for the last quarter of 2019. The EUR/PLN exchange rate was 4.54, the USD/PLN exchange rate was 3.74.

We've also updated the cross-border connectivity scenario based on the aforementioned ENTSO-E TYNDP 2020. In 2021, the available import capacity was estimated at approximately 4.8 GW (based on PSE data on maximum physical flows), in 2030 this value increases to 7.3 GW (implementation of projects submitted to ENTSO-E and already in progress – GerPol Power Bridge I, GerPol Improvements, LitPol Link Stage 2), in 2040 to 8 GW (implementation of the Harmony Link connection with Lithuania[23]). Net energy imports in 2021 were estimated at 4.4 TWh.

23 The project is expected to be completed by 2030, but the model pessimistically assumes that it could be delayed. Naturally, the timely implementation of Harmony Link will enhance the country's energy security and improve the power balance as early as in 2030.

Table 1. Main cost parameters used in modeling

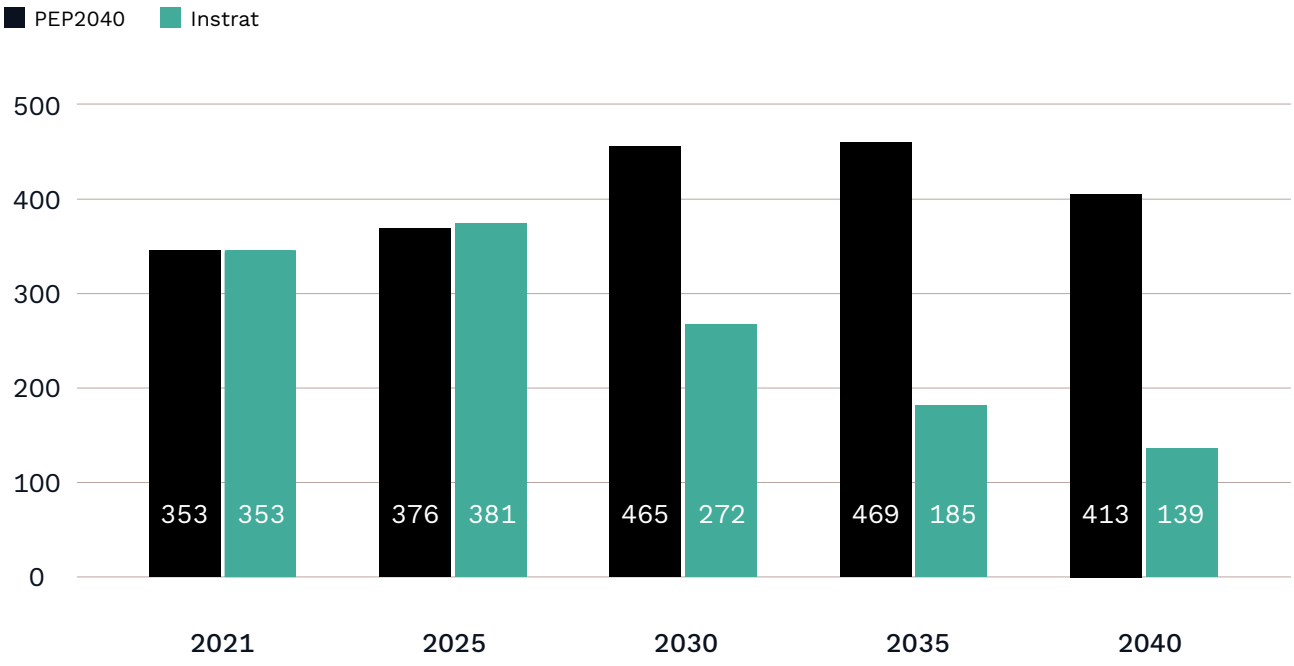
Parameter	Unit	2021	2025	2030	2035	2040	Source
Net electricity demand	TWh	157.8	170.1	181.1	191.9	204.2	(PEP2040, 2021)
Price of CO2 emissions allowances	EUR/t	52	69.1	98.9	119.5	140.0	(IEA WEO, 2021*; BNEF, 2021; KOBiZE 2021)
Hard coal price	PLN/GJ	11.4	11.4	11.9	11.9	11.9	(PEP2040, 2021)
Natural gas price	PLN/GJ	49.4	37.5	25.7	25.7	25.7	(IEA WEO 2021, 2021)*
Green hydrogen price	EUR/kg				1.5	1.1	(Renew Economy, 2021; RechargeNews, 2021 cf.: BNEF
Costs of lignite extraction – Turów	PLN/t	85.6	85.6	85.6	85.6	85.6	(Czopek & Trzaskuś, 2009), (KWB Konin, 2019)
Costs of lignite extraction – Bełchatów	PLN/t	75.2	75.2	75.2	75.2	75.2	(Czopek & Trzaskuś, 2009), (KWB Konin, 2019)
Costs of lignite extraction – ZEPAK	PLN/t	92.1	92.1	92.1	92.1	92.1	(KWB Konin, 2019)
Other variable costs – hard coal	PLN/MWh	15.14	15.14	15.14	15.14	15.14	(PEP2040, 2021)
Other variable costs – lignite	PLN/MWh	14.22	14.22	14.22	14.22	14.22	(PEP2040, 2021)
Other variable costs – natural gas and hydrogen	PLN/MWh	8.38	8.38	8.38	8.38	8.38	(PEP2040, 2021)
Increase in transport costs	%	100.00%	113.95%	127.90%	141.85%	155.80%	Instrat calculations

*For IEA WEO 2021, the Announced Pledges scenario for the European Union was used.

The updated generation costs for the Instrat and PEP2040 scenarios are shown in Figure 15. Starting in 2030, the Instrat scenario leads to a significant reduction in average SRMC. It is worth noting, however, that the values obtained in 2040 will probably not translate directly into a decrease in wholesale energy prices (or the prices of forward contracts), as this would make it difficult to achieve a return on investment in RES[24]. Taking into account the projected LCoE values[25] for wind and solar energy (PLN 112-168 per MWh in 2040, (IEA, 2021)), it is assumed that the wholesale price of energy in 2040 under the Instrat scenario will remain at the 2035 level. It is worth noting that the SRMC obtained from the model also includes the cost of energy imports[26].

According to Figure 6, the cost of power generation is largely reflected in the prices of forward contracts and day-ahead market prices. Looking at the monthly data for the period 01.2016 - 06.2021, the average margin (calculated as the difference between the contract price for the next year and the SRMC) for the said coal-fired plant with an efficiency of 38 percent

Figure 15. Forecast of energy generation costs [PLN/MWh]



Source: Instrat internal analysis.

24 For which the auctions-based support system, even if it is maintained until 2040, is not as attractive as e.g. the capacity market for new gas-fired plants which can use it to cover possible losses on the variable margin, as is currently the case for coal-fired plants.

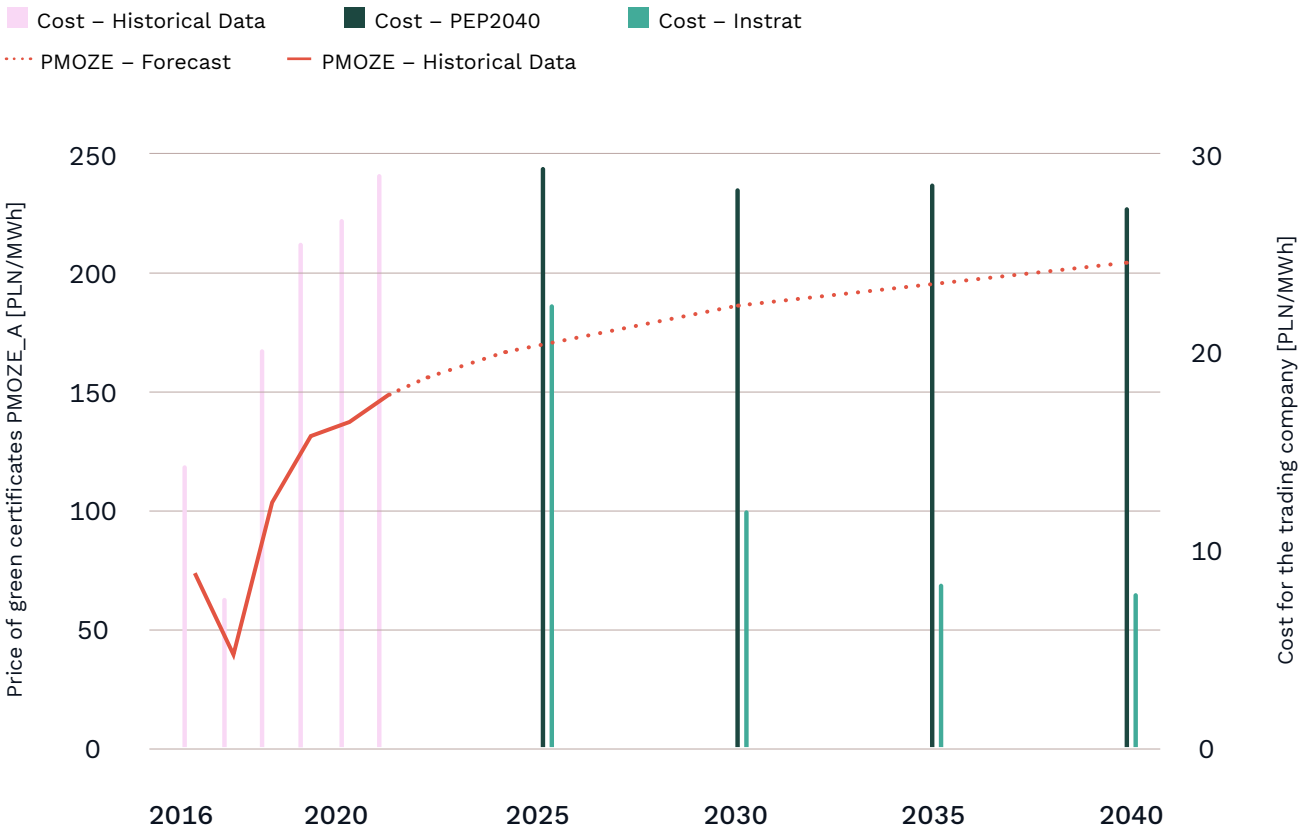
25 Average cost of energy from a given source, including also the investment, maintenance or financing costs.

26 For the Instrat scenario. In the PEP2040 scenario, imports have been artificially blocked in line with the PEP2040 assumptions.

was 6.75 percent. It was assumed that, on average, such a margin would continue in the future, and would naturally vary from one generating unit to another. Adding this margin to the SRMC from Figure 15 provided the energy purchase cost, the main cost component in the tariff charged by a trading company.

Further, the cost of purchasing the required volume of color certificates was added to the cost of the energy itself. The focus is on the green certificates alone. Their prices were assumed to increase only slightly in the future[27] – from an average of 150 PLN/MWh in the first half of 2021 to 188 PLN/MWh in 2030. (Fig. 16). At the same time, the cost estimate takes into account the increase in the share of renewables in the electricity mix – from 17% in 2020 to 32% in 2030 and 40% in 2040 for the PEP2040 scenario, and 71% in 2030 and 83% in 2040 for the Instrat scenario. Therefore, while green certificate prices will be rising, the volume of green certificate purchases will decline. As a result, we estimate, for the Instrat scenario, the cost of purchasing green certificates by trading companies at 12 PLN/MWh in 2030 and only 8 PLN/MWh in 2040, while in the PEP2040 scenario it is 28 PLN MWh in 2030 and 2040.

Figure 16. Forecast of green certificate prices and costs

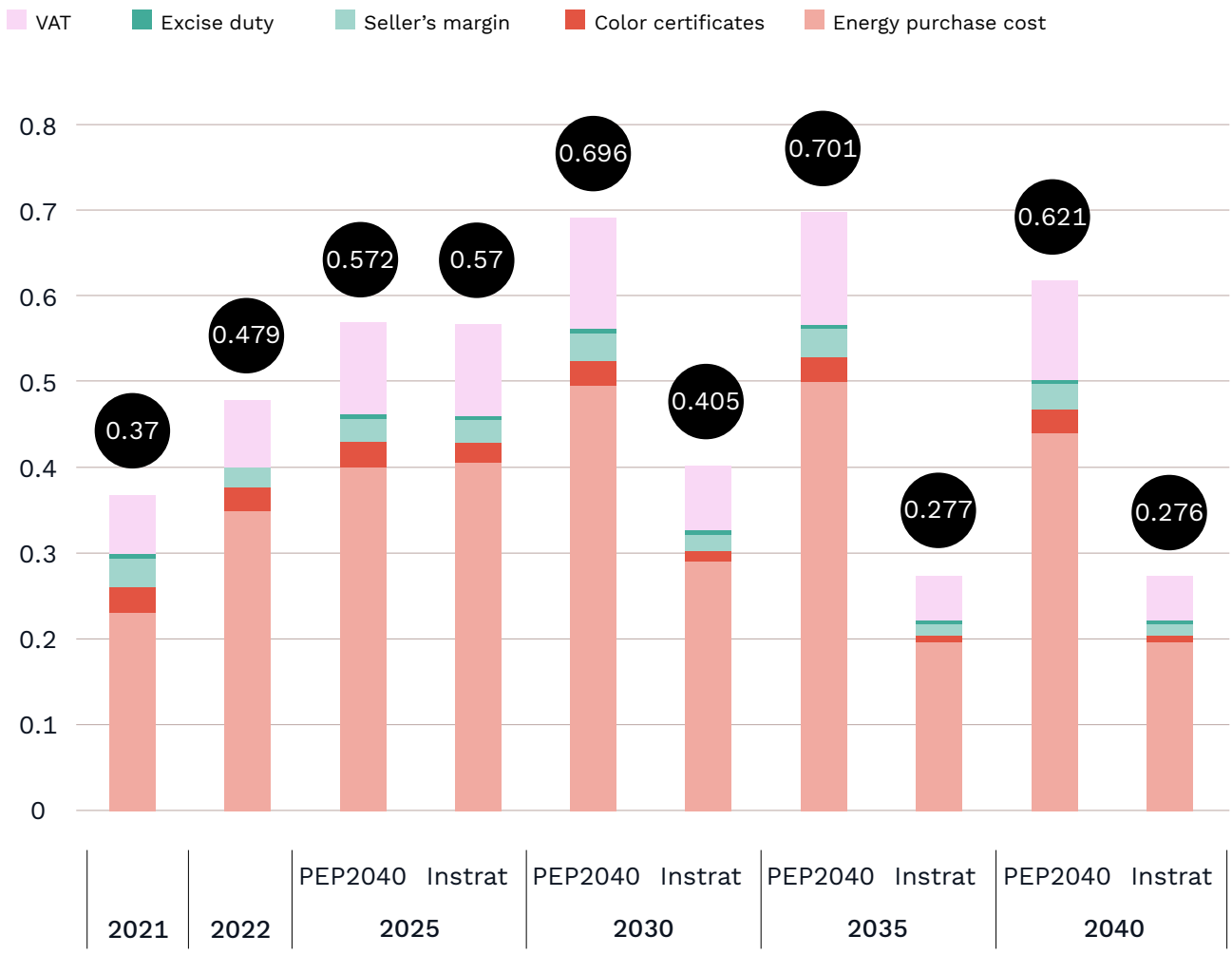


Source: Instrat internal analysis.

27 According to the forecast given by the equation 32.026*ln(x)+105.55, obtained from approximating historical data with a logarithmic curve.

The trading tariff also includes excise duty (assumed to remain at 5 PLN/MWh, in 2022 set to 0 PLN/MWh due to the anti-inflation measures) and the trading company's margin – on average estimated at 6.69 percent in 2017-2021 (based on the difference between the net tariff and energy costs plus excise duty). VAT is added to this total amount.

Figure 17. Forecast of the gross household tariff's trading component [PLN/kWh]



Source: Instrat internal analysis.

The trading tariff forecast based on the above assumptions is shown in Figure 17. In 2022, an increase from the current PLN 0.37/kWh to as much as PLN 0.48/kWh is expected, driven by an increase in futures prices – from an average of PLN 233/MWh in 2020 to PLN 351/MWh in January-October 2021. In total, the gross trading tariff may thus increase next year by 29 percent relative to the value for 2021. Further increases, comparable in both scenarios, are expected in the time horizon of 2025. In the following years, the Instrat scenario allows for a significant reduction in tariffs – to 0.4 PLN/kWh in 2030 and even to 0.28 PLN/kWh in 2040. – which is below the cur-

rent level. Under the PEP2040 scenario, huge increases are recorded – up to 0.7 PLN/kWh in 2030, an increase of 88 percent relative to 2021. In 2040, the price falls slightly, but remains well above the current price. Therefore, the high share of coal and gas in the energy mix in the PEP2040 scenario has a clearly negative impact on the trading component of energy prices.

Distribution tariff

The paradigm shift in the power sector implies changes in the approach to how network tariffs are set in the coming years. It is necessary to step up investment in grid modernization and expansion in view of the growing number of RES sources and their proper integration with the power system, as well as higher flexibility of the NPS, also through its automation and digitalization. All of this together will affect the individual components of the distribution tariff. It is to be expected that dynamic tariffs are introduced in the coming years, the amount and structure of which may differ significantly from the present ones. It is also likely that the push for greater flexibility in the NPS will result in most of the current fixed components becoming variable.

This analysis presents a forecast of how distribution tariffs will be shaped in the future, assuming no revolutionary change to their structure itself. The focus is primarily on the components of the tariff that will be changing as the share of renewables in the energy mix increases.

The increase of the fixed component of the network rate and the variable component for households will be, primarily, a consequence of a higher investment in transmission grids and distribution networks. This analysis assumes that the increase in capital expenditures will be assigned to the variable network component, with the fixed component remaining (in real terms) at 2021 levels.

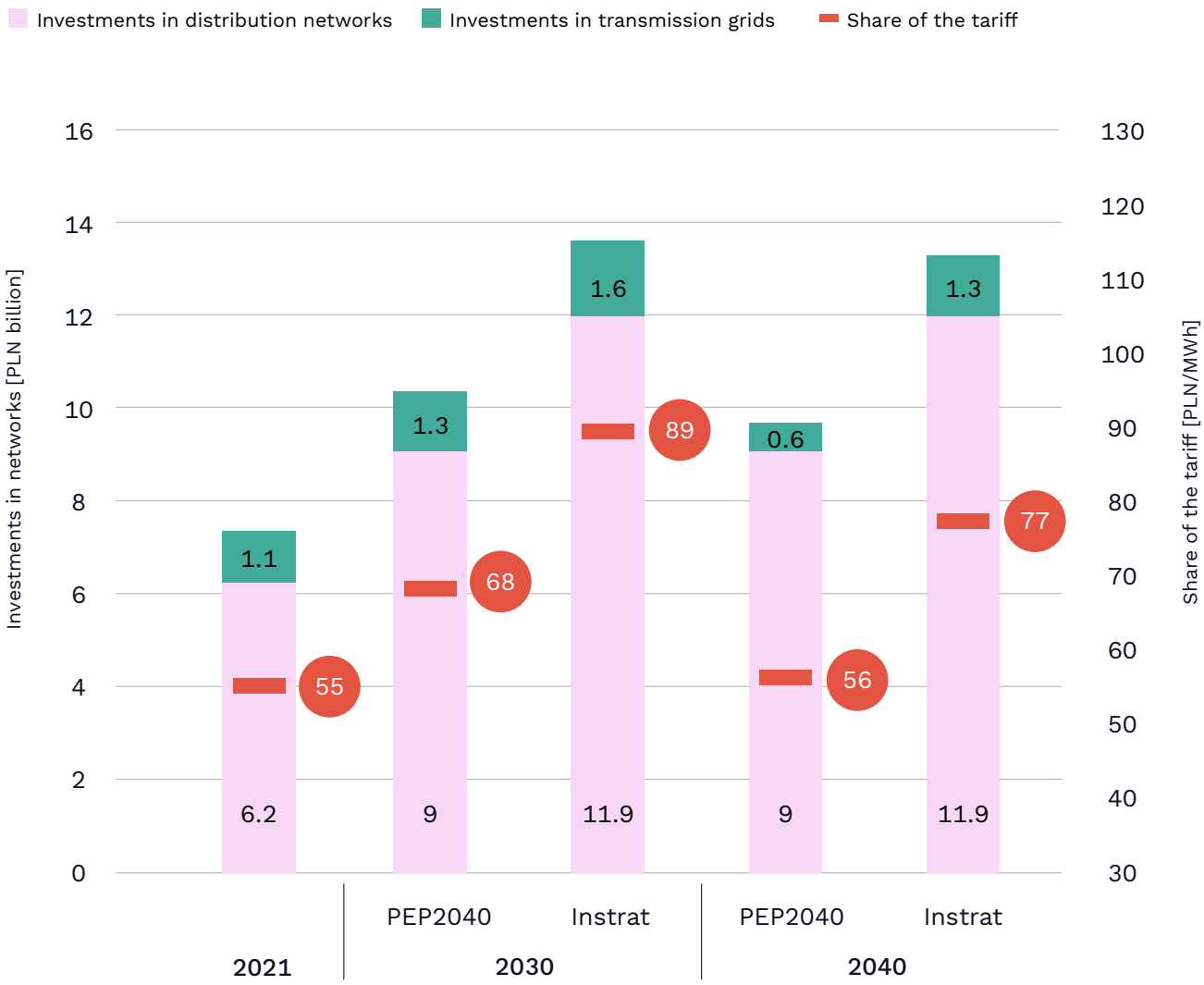
The methodology for calculating distribution networks and transmission grids expenditures alone in the PEP2040 and Instrat scenarios is discussed in detail in Chapter 3. In both scenarios, investments in distribution networks are higher than now – in PEP2040 they increase from approx. PLN 6bn in 2020 to PLN 9bn per year in 2030 and 2040.[28] In the Instrat scenario, it is even as much as PLN 12bn per year in the time horizon of 2030 and 2040. As regards transmission grids, in the 2011-2020 time horizon capital expenditures amounted to approx. PLN 1.1bn annually, while in the 2021-2030 period they will amount to PLN 1.3bn annually in the PEP2040 scenario and PLN 1.6bn annually in the Instrat scenario. In the next decade, investments in transmission grids decline – to PLN 0.6 billion per year in the PEP2040 scenario and PLN 1.3 billion in the Instrat scenario. These amounts relate to investments in new lines and modernization of existing ones in connection with RES development; additional funds may also be necessary, e.g. for installation of smart meters (CSIRE), adaptation of the network to

28 According to the DSO plans submitted to the ERO (ERO, 2020c).

the electric vehicle charging infrastructure, etc. However, it is assumed that these investments have already been provided for in the PEP2040 and in network development plans which provided the basis for the calculations, and the additional costs of the Instrat scenario have been added to the values from these documents.

The projected investment costs translate into an increase in the variable component of the distribution tariff – under the PEP2040 scenario by 13 PLN/MWh in 2030 and 1 PLN/MWh in 2040 compared to 2021. For the Instrat scenario this is an increase of 34 and 22 PLN/MWh respectively. It is worth noting that these values include an increase in distribution volume for the five largest DSOs from 133 TWh in 2021 to 152 TWh in 2030 and 172 TWh in 2040 in proportion to the rate of demand growth from PEP2040.

Figure 18. Tariff increase due to capital expenditures



Source: Instrat internal analysis.

The variable component for the Instrat scenario also includes system costs not directly related to network investments and not included in the other tariff components discussed below – including the cost of the coal reserve, as described in the "Achieving the goal" report, and the cost of managing overproduction of energy from renewable sources[29]. They increase the tariff by about 20 PLN/MWh in 2030 and even 59 PLN/MWh in 2040. The topic of system costs is described in more detail in Chapter 3. However, it is worth noting that these costs are only included in the Instrat scenario, which favors the PEP2040 scenario in this regard. Moreover, the PEP2040 scenario forecast does not include the costs of the government's power industry restructuring plan and the creation of NABE because of the uncertainty about the final shape and timing of the solutions that are adopted. As pointed out in the „Achieving the goal" report, implementing NABE alone would be several times more expensive than implementing the coal reserve under Instrat's proposed option. The creation of a monopoly in the generation market could also lead to an increase in already high energy prices in the wholesale market. Therefore, by omitting the costs of maintaining coal-fired power industry in PEP2040 and including them only in the Instrat scenario, a preference assumption was made for the government scenario.

The other components of the distribution tariff have less impact on the total amount of the tariff in the future. The cogeneration fee was assumed to be 4.06 PLN/MWh in subsequent years[30]. The RES fee and the quality fee will be increased due to the growing share of such sources in the NPS and the need to actively support them in order to meet climate targets. Taking into account the relation between RES fees and the share of renewables in electricity production in the EU (Figure 13)[31] it is assumed that, in order to achieve the shares of renewables in the power sector declared in PEP2040 at the level of 32 percent in 2030 and 40 percent in 2040, the RES fee will increase to PLN 10 and PLN 14.2/MWh, respectively[32]. In contrast, in the Instrat scenario leading to 71 percent RES in 2030 and 83 percent in 2040, the RES fee will be 30.2 and 36.6 PLN/MWh in 2030 and 2040, respectively. As mentioned, the quality fee will also increase due to the large amount of RES, non-linear loads and power electronics. It was assumed that, under the Instrat scenario, in the years 2030-2040 it will be twice as much as today, i.e. 20.4 PLN/MWh.

The transition fee and subscription fee in both scenarios are targeted at 0 PLN/MWh, due to the end of bilateral long-term contracts with power plants in 2027 and widespread implementation of remote metering by 2040,

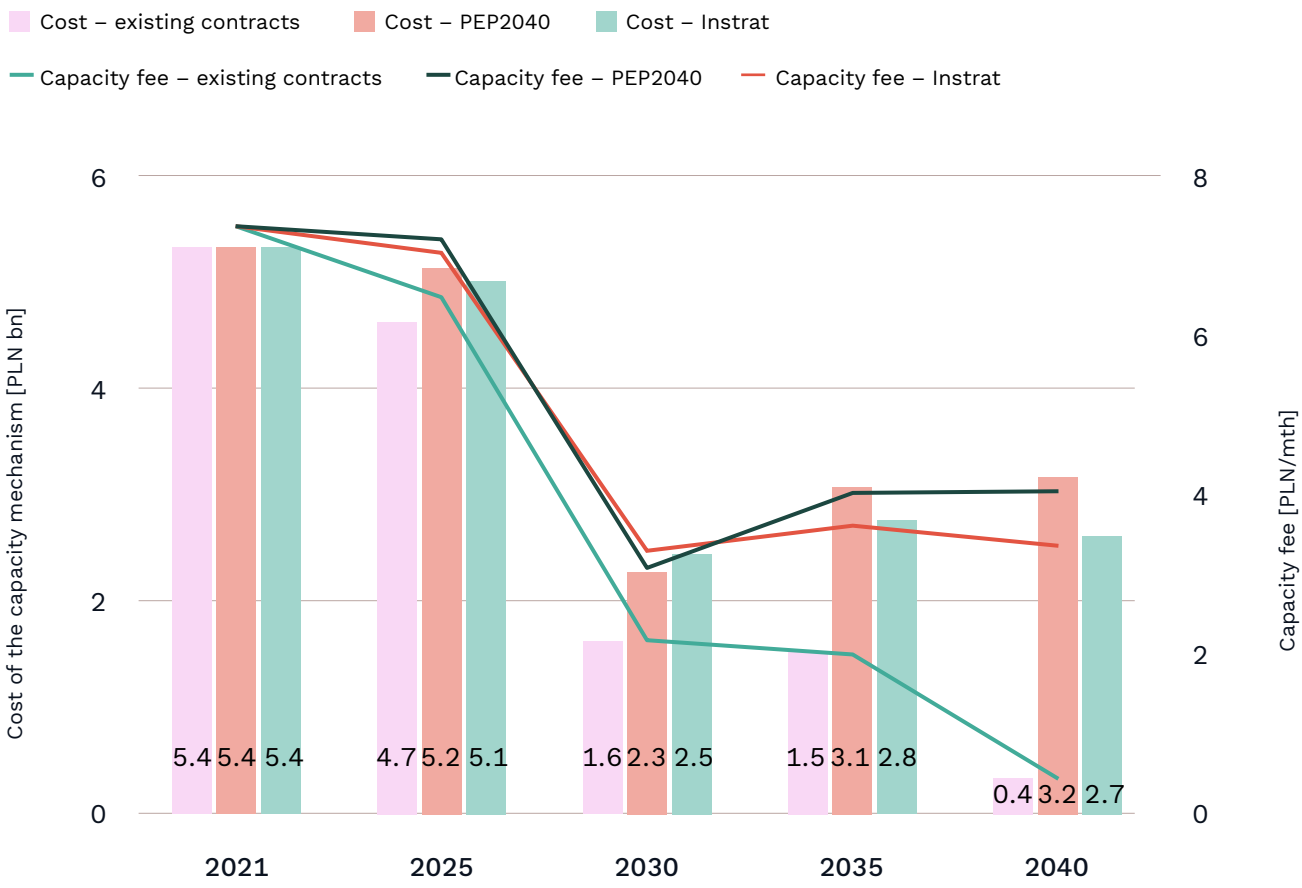
29 In a pessimistic and quite unrealistic scenario – that is, with no use of surplus energy for hydrogen production. For more about the potential for green hydrogen production see Section 3.3.

30 According to the draft regulation of the Minister of Climate and Environment on the cogeneration fee for 2022.

31 Reflected with a very high degree of accuracy (R2 = 0.9771) by the equation y=52.01*x-6.5972 which has already been scaled to the current RES fee in Poland.

32 Ironically, the government is planning to decrease the RES fee to PLN 0.9/MWh in 2022, but this should be treated as a temporary measure.

Figure 19. Forecast of the cost of the capacity mechanism



Source: Instrat internal analysis.

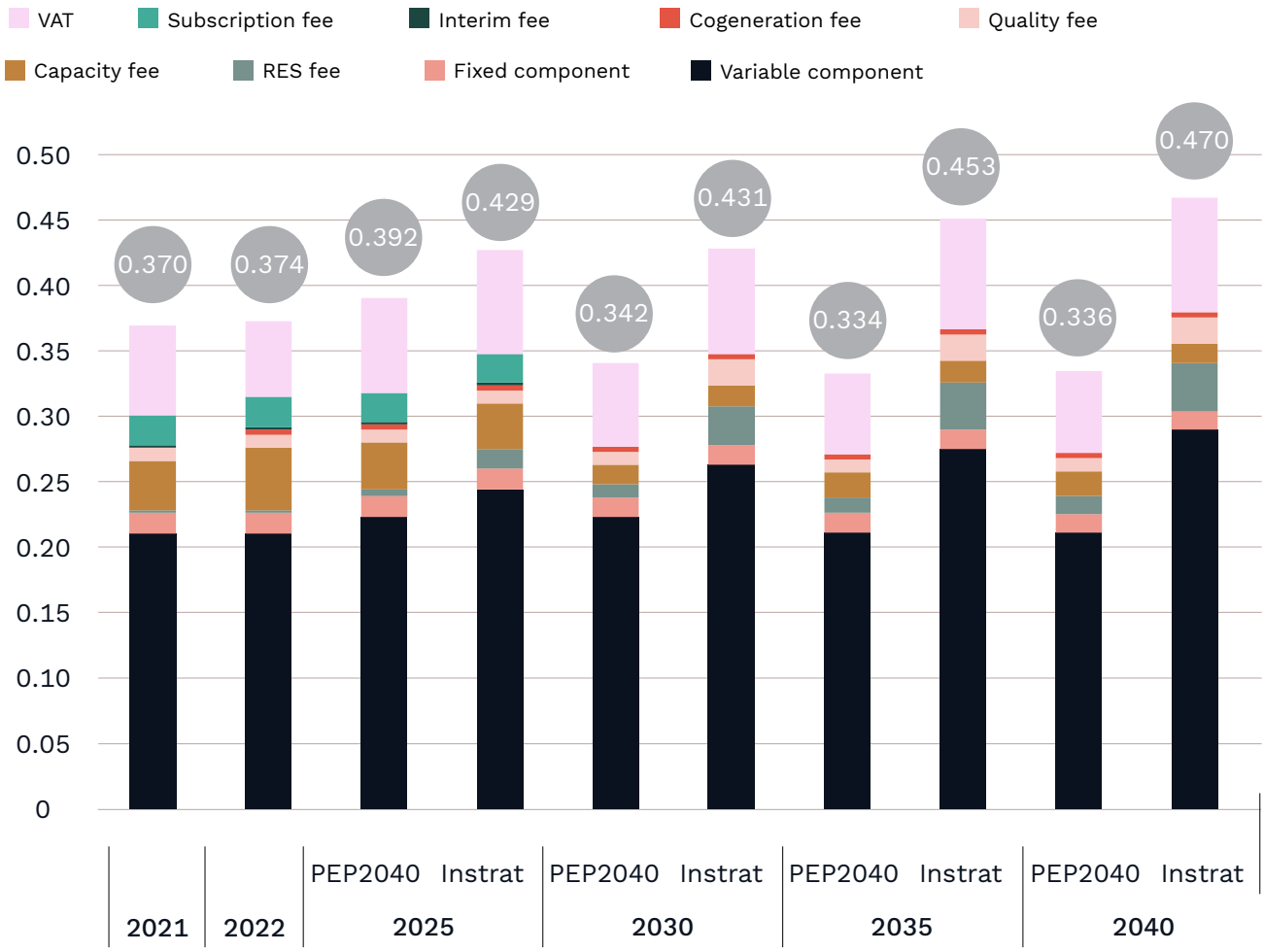
as well as the implementation of automated Central Energy Market Information System (CSIRE), which makes the work of meter readers and the old billing/invoicing system unnecessary.

As explained in Section 2.2, the amount of the capacity fee depends directly on the performance of capacity contracts in a given year. Taking into account only the contracts already concluded, the capacity fee for a typical household would fall to 2.2 PLN/mth in 2030 and 0.45 PLN/mth in 2040. Theoretically, the capacity market in its current form should not be extended after 2030. However, it was assumed that a similar type of mechanism would be maintained to allow investment in new gas units (CCGTs, OCGTs and CHPs), large-scale energy storage (battery storage and new pumped storage plants) and nuclear reactors. This mechanism would also allow for covering the fixed costs of gas units where they are used to a limited extent. There is also an intervention reduction of consumption (DSR) among the entities supported by the capacity market. Accordingly, contracts for new units built under the PEP2040 and Instrat scenarios were added to the capacity market cost resulting from current contracts. New capacity obligations were estimated on the basis of changes in the installed capacity of the technologies listed above – in the PEP2040 scenario it is 3925 MW in 2030

and 16494 MW in 2040, in the Instrat scenario it is 4860 MW in 2030 and 13365 MW in 2040. The cost of the capacity market under such assumptions is PLN 2.3bn in 2030 and PLN 3.2bn in 2040 under the PEP2040 scenario, and PLN 2.5bn and PLN 2.7bn in 2030 and 2040 under the Instrat scenario, respectively, which translates into capacity fees of households in the order of PLN 2-4 per month. (Fig. 19).

Based on the assumptions described above, a forecast of the distribution tariff for households in the year 2040 time horizon was obtained. (Figure 20). The percentage changes in this component of the tariff are lower than for the trading component. Compared to 2021, the distribution tariff falls under the PEP2040 scenario by approx. 8-9 percent in 2030 and 2040, primarily due to significantly lower fixed charges – the capacity fee and the subscription fee – with only a slightly higher burden related to network investments. In the Instrat scenario, the distribution tariff is significantly higher than in the PEP2040 scenario – by as much as PLN 0.13/kWh in 2040, and higher than in 2021 – by 16% in 2030 and 27% in 2040, respectively. This is due to higher expenditure on network investments, as well as the inclusion of system costs, including the costs of the coal reserve.

Figure 20. Forecast of the gross household tariff's distribution component [PLN/kWh]



Source: Instrat internal analysis.

It is worth remembering that the calculations of the distribution tariff for households are only an attempt to predict trends in the energy sector. Changes are so dynamic that it is impossible to tell whether all components of the distribution tariff will remain in their current form – some of them may, for example, be eliminated and be „absorbed" by the other components. For example, this may be the case with the capacity fee – a mechanism supporting the construction of new generating units to ensure stable operation of the system is needed, but its shape may evolve significantly over the next years. It should also be borne in mind that, in the long run, the individual elements of the network component will, to a large extent, be changed to variable – dynamic tariffs should be pursued that will optimize capital expenditures and ensure efficient use of the existing and new resources in the system.

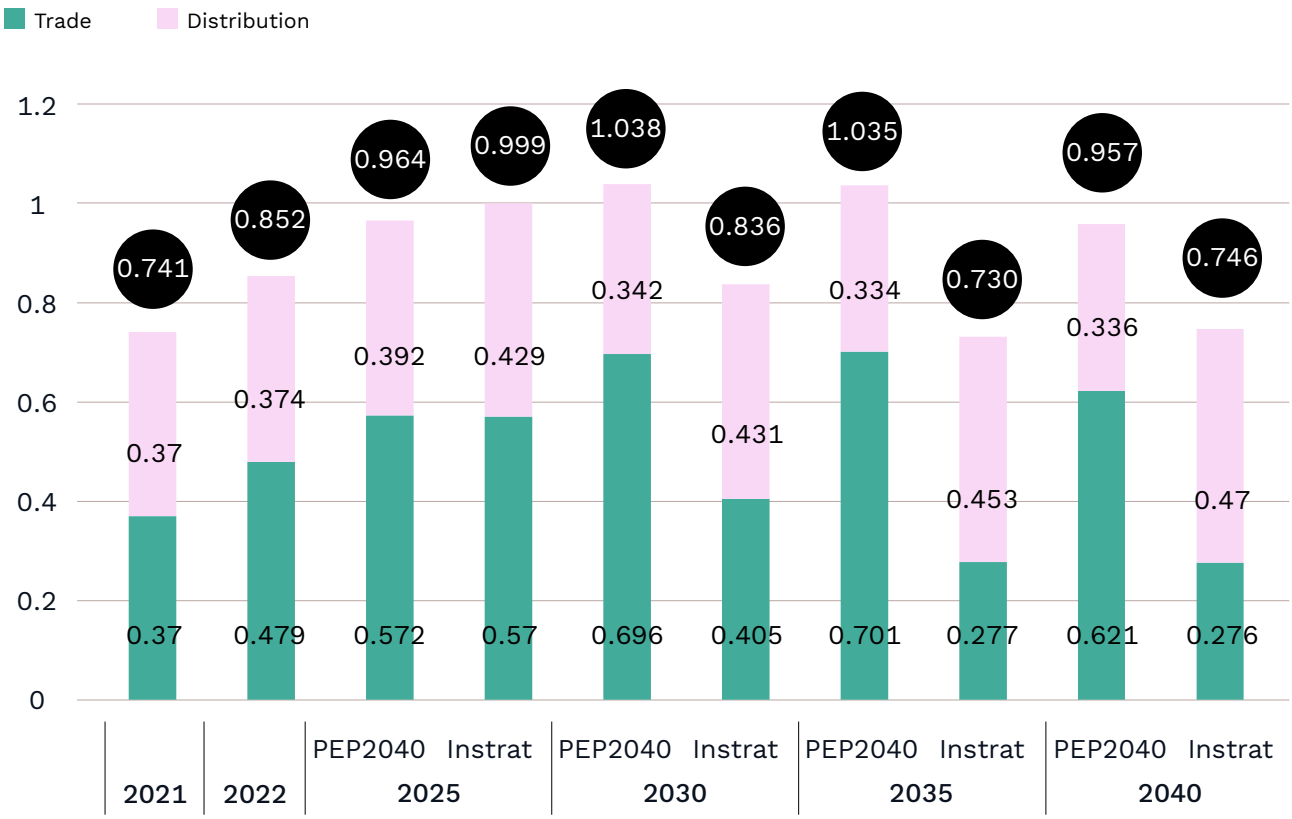
Total electricity costs for households

The final electricity price for a household with average annual consumption was obtained by summing the trading and distribution components of the tariff. The final gross amount a household will pay for one kilowatt-hour of electricity is shown in Fig. 21. It should be noted that some of the fees included in the bill are fixed fees charged monthly, independent of consumption. They were converted to "per kWh" values by multiplying by twelve months of the year and dividing by the average household energy consumption in Poland[33].

The total gross household tariff increases from the current PLN 0.74/kWh to PLN 0.85/kWh in 2022 – by as much as 15 percent. In 2030 in the PEP2040 scenario, the tariff increases by 40 percent relative to 2021, to decrease slightly in 2040. In the Instrat scenario, tariffs increase less severely – already in 2030 they fall below the 2022 level, and in the 2035–2040 perspective they are around the 2021 level. It is worth noting that in 2025 the Instrat scenario leads to temporarily higher energy prices – this is due to higher capital expenditures on networks with the still high share of expensive fossil fuels in the energy mix.

33 Total electricity consumption in the household sector was assumed to grow at a rate consistent with the growth of the NPS demand (cf.: PEP2040). The growth in the number of households is included according to the NECP, which is also growing, but at a slower rate. This means that average consumption per household increases (by approx. 12 percent between 2021 and 2040).

Figure 21. Total gross tariffs in individual scenarios [PLN/kWh]



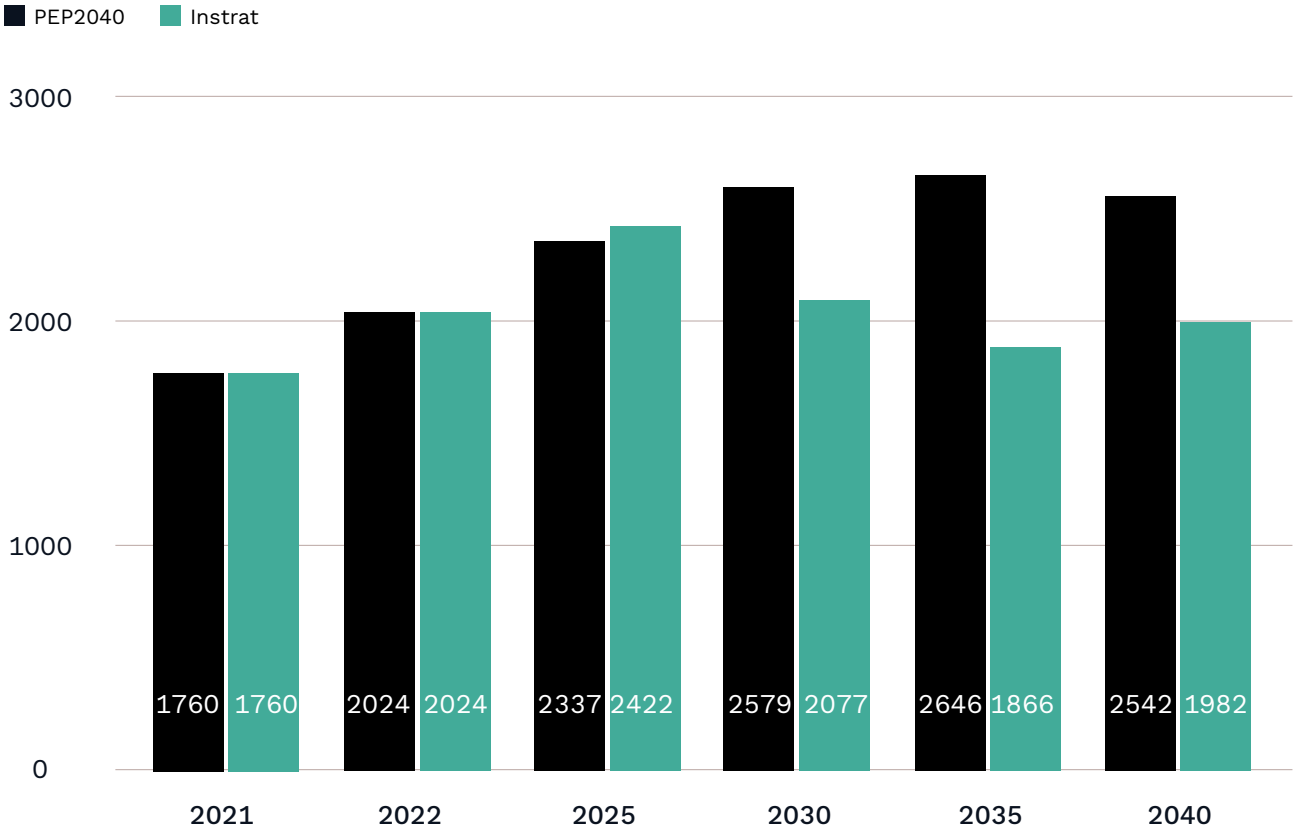
Source: Instrat internal analysis.

When the tariffs are converted to annual household expenses on electricity, the results are disturbing. The average electricity bill will increase by PLN 264 already next year. It is worth noting that in order to eliminate the negative impact of energy price increases on consumers, the government plans to introduce the anti-inflation measures[34], that temporarily reduce VAT and excise duty on electricity. However, contrary to the announcements, these reduce the price increase by only PLN 92. In the PEP2040 scenario in 2030, the increase in electricity costs will exceed PLN 800 per year and will remain at that level for the next decade. The Instrat scenario, after a temporary strong increase in bills over the next five years (PLN 85 more in 2025 than in PEP2040), will lead to spending stabilization at a level lower than in 2022. In the critical year 2035, using the Instrat scenario allows the average household to save PLN 781.

It is worth noting that although tariffs in the Instrat scenario fall to near 2021 levels in 2040, total electricity expenses are still above historical levels due to the increase in average household energy consumption.

34 Projekt ustawy o zmianie ustawy o podatku akcyzowym oraz ustawy o podatku od sprzedaży detalicznej, UD315.

Figure 22. Forecast of annual electricity bills in households with average consumption [PLN]



Source: Instrat internal analysis.

The development of RES brings numerous challenges, requiring a change in the approach to power system management. However, the positive impact of a scenario with a higher share of RES on citizens' wallets can hardly be underestimated. Savings on RES power generation costs relative to the coal- and gas-based energy mix more than cover the increased expenses on network infrastructure or system services, leading to a huge reduction in household tariffs. This is extremely important in light of the unprecedented electricity price increases planned for 2022, which are already causing public tensions. These will only grow if the government maintains its pro-coal course in the years ahead, denying the role of renewable energy sources in the country's energy mix.

3. Role of system costs in shaping energy prices

System costs play an important role in shaping energy prices, and their importance increases as the share of RES in the energy mix increases. System costs include primarily (Central Europe Energy Partners, 2020; OECD & NEA, 2018 & PNPP, 2020):

- ***Costs related to network infrastructure*** *– including modernization and expansion of distribution and transmission networks, including connection points for new generating sources;*

- ***Profile costs*** *– including the cost of maintaining a large reserve of available units and/or energy storage facilities to serve sources with a variable production profile, the cost of overproduction of energy from RES;*

- ***Balancing and system flexibility costs*** – including balancing market costs, costs of applying countermeasures (e.g. inter-operator inter-system exchange), demand management costs (DSR, dynamic tariffs), forecasting costs and possibly redispatching (changing production and/or demand profiles to change physical flows and relieve selected lines).

Expenditures on modernization and maintenance of network infrastructure and management of the NPS are reflected in tariffs for end customers, but despite their great importance, system costs are not given due attention. While there is scientific consensus on the challenges related to the development of RES and the projected increase in system costs, the methodology used in government studies to calculate these costs themselves leaves much to be desired. The Polish Nuclear Power Program[35] cites values from OECD Atomic Energy Agency (NEA) studies (2018 & 2019) –PLN 25–35 MWh, with RES share in the electricity mix at 10–20 percent and PLN 60/MWh for 30 percent and PLN 110/MWh for 50 percent, respectively. The cited NEA study also cites a value of USD 50/MWh (PLN 187/MWh) for a 75 percent RES share. However, within the content of these publications, there are several concerns regarding the methodology and the applicability of the results to particular locations[36]. On the other hand, even using the highest

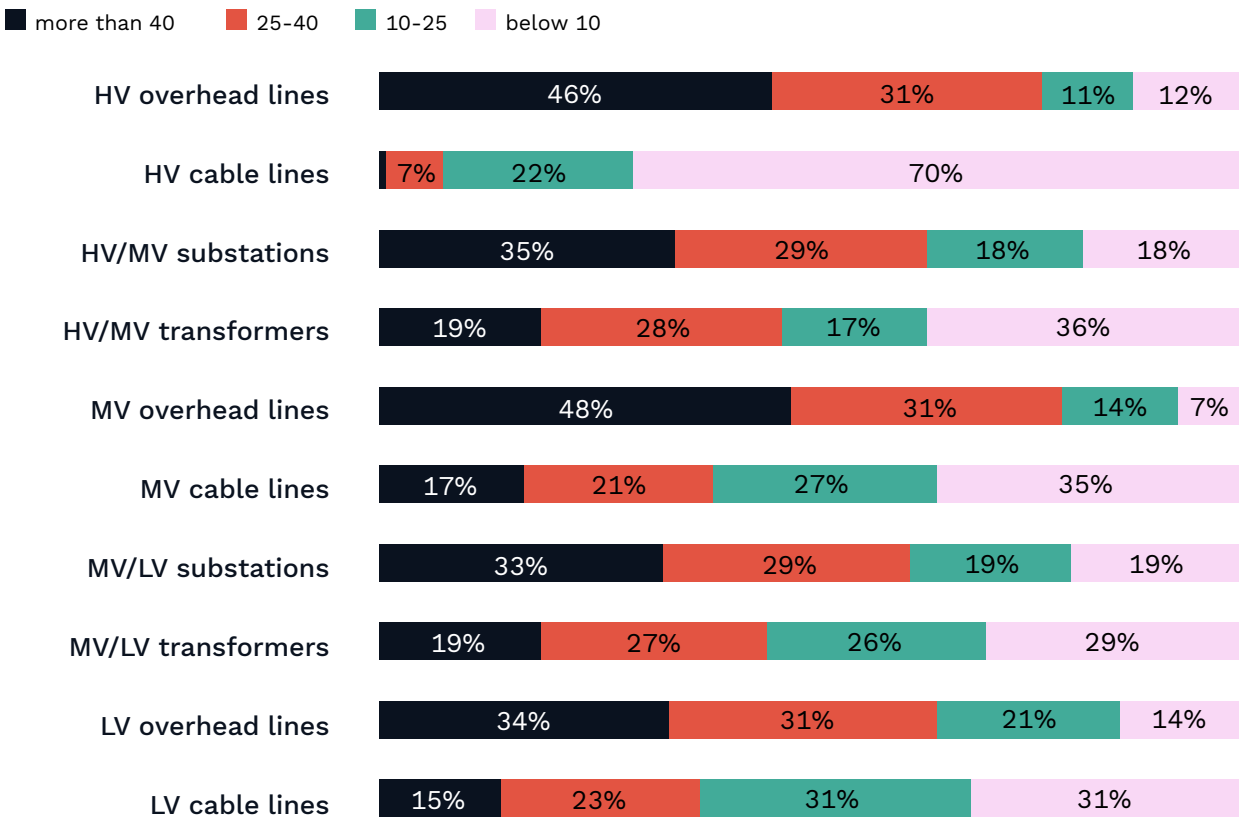
35 Uchwała nr 141 Rady Ministrów z dnia 2 października 2020 w sprawie aktualizacji programu wieloletniego pod nazwą „Program polskiej energetyki jądrowej".

36 Quoting the official translation of the second study cited in the PNPP: "The purpose of this sample chart is not to provide an estimate of the network costs of a given system, but to visualize these effects and indicate the order of magnitude. While the level of uncertainty is high, most estimates point to the resulting high system costs at the network level due to VRE integration [...]"

system cost value calculated by NEA – PLN 187/MWh in Instrat's distribution tariff forecast described in point 2.3, the implementation of the scenario with a higher RES share is more cost beneficial for energy consumers. However, to the best of the authors' knowledge, system costs in the Polish power system have not been estimated in sufficient detail, and this chapter is an attempt to fill some of that gap, with a particular focus on investments in transmission networks.

It should be remembered that an increase in the scale of capital-intensive modernization projects in the area of network infrastructure is inevitable in Poland not only due to the need to adapt the system to the dispersed nature of RES but, first and foremost, due to the poor technical condition of the networks themselves. The domestic energy infrastructure is aged and characterized by low density. Almost half of the HV (110 kV) and MV overhead lines are more than 40 years old, and 80 percent of the high and medium voltage lines were built more than 25 years ago (Fig. 23). MV overhead lines are aging more and more, while cable lines are still very few – the share of MV cable lines with an age below 10 years increased only by 5 p.p. compared to the 2016 level (PTPiREE, 2021). The investments carried out in recent years were insufficient to change the age structure of the network and lead to its expansion. As a result, the system already lacks connection capacity and there are growing problems with introducing energy from RES into the NPS.

Figure 23. Age structure of selected distribution network elements at the end of 2020



Source: Polish Power Transmission and Distribution Association (PTPiREE). (2021). Energetyka, Dystrybucja, Przesył (Power sector, Distribution, Transmission).

Availability of connection capacity defines the possibilities for development of new energy sources, so leaving this problem unresolved will further limit the potential for RES implementation, hinder the decarbonization of the power industry, and may threaten the country's energy security. An analysis of the documents of the largest DSOs and TSOs indicates that the connection capacities are currently at 10 GW and will increase to approx. 12 GW in 2026[37]. A slightly more optimistic estimate is presented by the Institute of Renewable Energy, forecasting 14.2 GW in 2025. (IEO, 2021), i.e. a maximum of 1.1 GW growth per year. However, this is still too low to meet both current[38]. and future demand for network connectivity. According to Instrat's analysis, by 2025 the total increase in onshore PV and wind capacity will reach 18 GW, exceeding by approx. 4–6 GW the available connection capacity at that time (Czyżak, Sikorski & Wrona, 2021). Even taking into account PSE's planned shutdowns of centrally dispatched generating units by 2025, an increase in connection capacity of approx. 1 GW per year may not meet the requirement for development of RES, especially since some of their place will be taken by potential new gas-fired power units (Czyżak, Sikorski & Wrona, 2021). It is therefore necessary to increase capital expenditures on the development of power networks, while ensuring that they are geographically evenly distributed. Currently, in addition to insufficient quantity, Poland is also characterized by a significant imbalance of available connection capacities across the country – the west of Poland has more than the east (IEO, 2021), in effect blocking the potential for green technology deployment in many regions of the country.

3.1. Distribution networks

Because of their complexity and diversity, it is the distribution networks that will present the greatest challenge in adapting them to future market conditions.

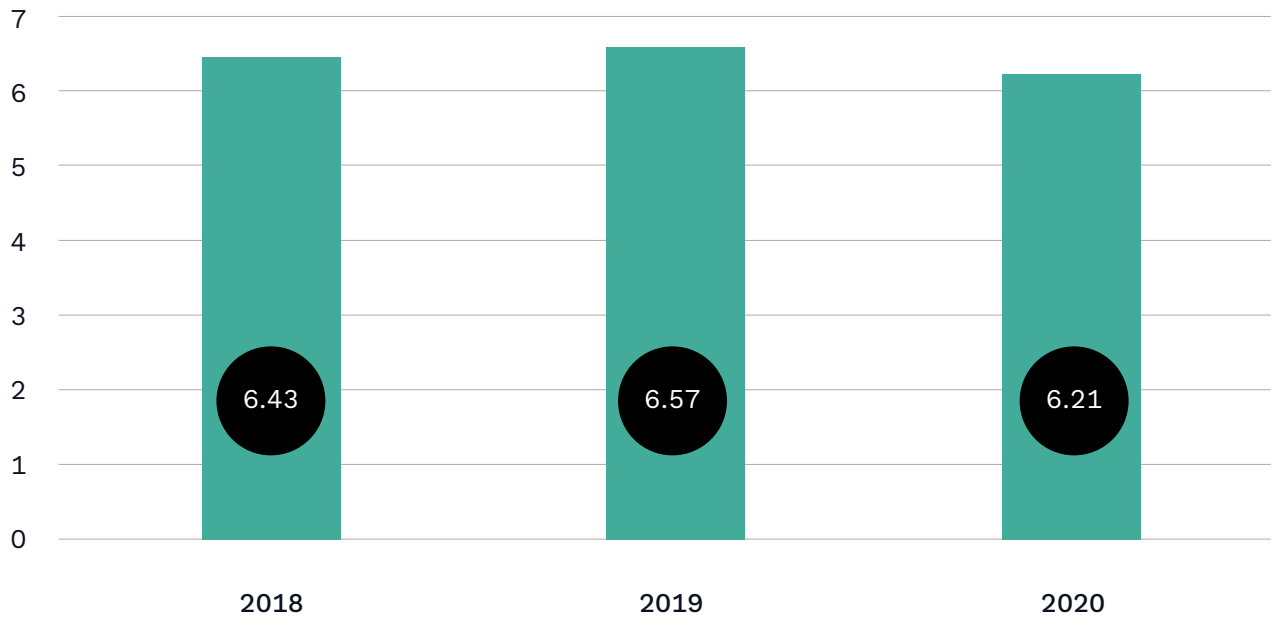
Investments in distribution networks over the past few years have oscillated at a similar level. In 2018, the total capital expenditure of DSOs amounted to PLN 6.429 billion, in 2019 it was PLN 6.571 billion (142 million more compared to the previous year), and in 2020 it decreased slightly compared to previous years and amounted to PLN 6.208 billion (Fig. 24). Only a small portion of these investments were co-financed from EU funds. In total, energy distributors received subsidies for network development of approx. PLN 1 billion under the European financial perspective 2014–2020. These

37 Data from information documents on the total value of available connection capacity for sources in the distribution networks of DSOs – Enea Operator, Energa Operator, Tauron Dystrybucja, PGE Dystrybucja and innogy Stoen Operator – and TSO – PSE, published on the companies' websites.

38 PV companies are already complaining about the lack of available connection capacities and the long waiting period for the issuance of connection conditions.

projects are carried out systematically, mostly between 2017 and 2023, which means that in annual terms it is only approx. PLN 143 million, while the companies' historical investments exceeded PLN 6 billion per year.

Figure 24. Capital expenditures of DSOs [billion PLN]



Source: Instrat internal analysis based on the ARE and PTPIREE data

If the current coal-fired generation park is replaced by RES and the energy paradigm shifts, network investments will have to be increased many times over to ensure country's energy security. This means that EU financing should also increase to effectively support the intensified scale of projects, and even enable many of them.

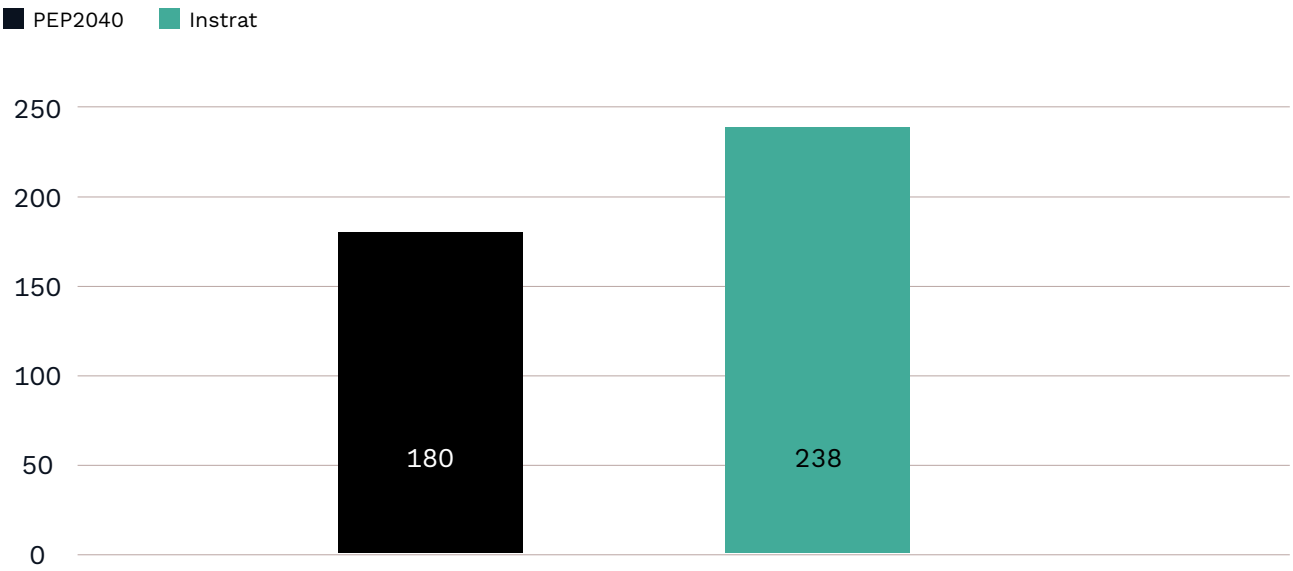
However, the distribution network development plans for 2020–2025 approved by the ERO show a change for the better. Capital expenditures have been increased compared to previous years and will total approximately PLN 45 billion (ERO, 2020c), or PLN 9 billion on average per year, which means an increase of almost half compared to previous years. According to the investment plans of DSOs, the funds are and will be allocated primarily to the development and modernization of the network, including the implementation of modern smart grid solutions, and to increasing the connectivity of renewable energy sources. Much of the investment is to prepare the network for the ever-increasing number of prosumer systems and the growth in energy demand resulting from the development of the economy and electromobility. High, medium and low voltage networks will be modernized, both in rural and highly urbanized areas. A large investment stream has been directed towards modernizing, increasing capacity and upgrading main power supply points and building new line connections, as well as cabling existing ones. All this is expected to lead to an increase in the secu-

rity and reliability of electricity supply and the possibility of connecting new customers, as well as improvement of the SAIDI and SAIFI indices, which determine the time and frequency of energy supply interruptions. In the coming years, digitalization and automation of the network will also be of great importance – equipping overhead and cable lines with remotely controlled disconnectors and short-circuit signaling devices will allow faster localization of disturbances in medium voltage networks and thus shorten interruptions in energy supply. Increased line load-carrying capacity will also enable technical services to reconfigure the network during emergency conditions, which will also affect the reliability of energy supply to consumers (PTPiREE, 2021).

In the context of investments in distribution networks until 2040, this analysis compares two scenarios – the baseline scenario, called PEP2040, and the Instrat scenario, which differ in the amount of capital expenditures. Distribution network capital expenditures on the PEP2040 scenario were taken directly from distribution network development plans by DSOs for 2020–2025. The same rate of investment and average annual expenses on the distribution network over the next 20 years was assumed. Thus, by 2030 the total will be approx. PLN 90 billion, and by 2040 twice as much, i.e. PLN 180 billion.

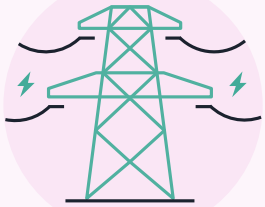
The Instrat scenario is more ambitious and relies on significantly more RES, and as a result, the distribution network expenditures will be correspondingly higher. In the 2040 perspective, we assume a total increase in installed RES capacity of approx. 41–43 GW per decade, while in PEP2040 it is a mere 7 GW in 2021–2030 and 13 GW in 2031–2040. Taking into account the distribution of individual RES technologies, we estimate that 70 percent of new RES capacity will be connected to distribution networks between 2021 and 2030, and 64 percent in the next decade.

Figure 25. Capital expenditures of DSOs between 2021 and 2040 [PLN billion]



Source: Instrat internal analysis.

How will this difference in the scale of RES development affect network investment costs? Estimates of the necessary expenditures on distribution networks are contained in a joint study by Eurelectric (a federation of European power companies), Deloitte (a global consulting firm) and E.DSO (an association of European distribution network operators). This report contains forecasts for individual EU countries, including Poland. In a scenario where the increase in installed RES capacity is 42 GW, and, as in the Instrat scenario, most new RES plants are connected to distribution networks, investments related to RES development, modernization of existing infrastructure and improvement of the quality of energy supply cost up to 2030 EUR 15.8 billion. It is worth noting that, according to Eurelectric, 47% of the total investment amount is directly or indirectly related to the development of RES; the rest of the expenditures are on network digitalization, costs related to electrification of construction and industry or development of electric vehicle charging infrastructure[39]. We assume that in the baseline scenario – consistent with the plans of the Polish DSOs, this proportion is similar – i.e. PLN 42.4 billion between 2021 and 2030 – it can therefore be described as related to the development of RES. In the Instrat scenario, these costs are PLN 29.3 billion higher and will continue to be so between 2031 and 2040. In total, in the 2040 perspective, investments in distribution networks under the Instrat scenario will amount to PLN 238.4 billion – PLN 58.6 billion more than under the PEP2040 scenario, which will be reflected in the level of distribution tariffs.



EU subsidies for the power network development in Poland

The role of EU subsidies in financing investments in the NPS is growing and will intensify in the coming years. Each of the DSOs and TSOs active on the market is implementing at least several projects for which EU funds were obtained, but the scale of support is still too small and must be expanded to enable the networks to adapt to the needs of a low-carbon economy.

During the 2014–2020 budget period, DSOs and TSOs obtained subsidies under the Operational Programme Infrastructure and Environment (OPI&E). In addition, PSE took advantage of the Connecting Europe Facility (CEF), a program available only to TSOs to support cross-border connections.

Between 2017 and 2021, PSE signed co-financing agreements for projects with a total value of more than PLN 6.5 billion, for which it received subsidies of up to PLN 1.7 billion (PSE, 2021), i.e. approx. PLN 340 million per year. Annual subsidies of this amount make it possible to cover approx. 25 percent of the cost of network investments made by PSE between 2017 and 2020*. Moreover, thanks to the CEF, the

* PSE has also secured an additional 1.4 billion in support from the CEF program.

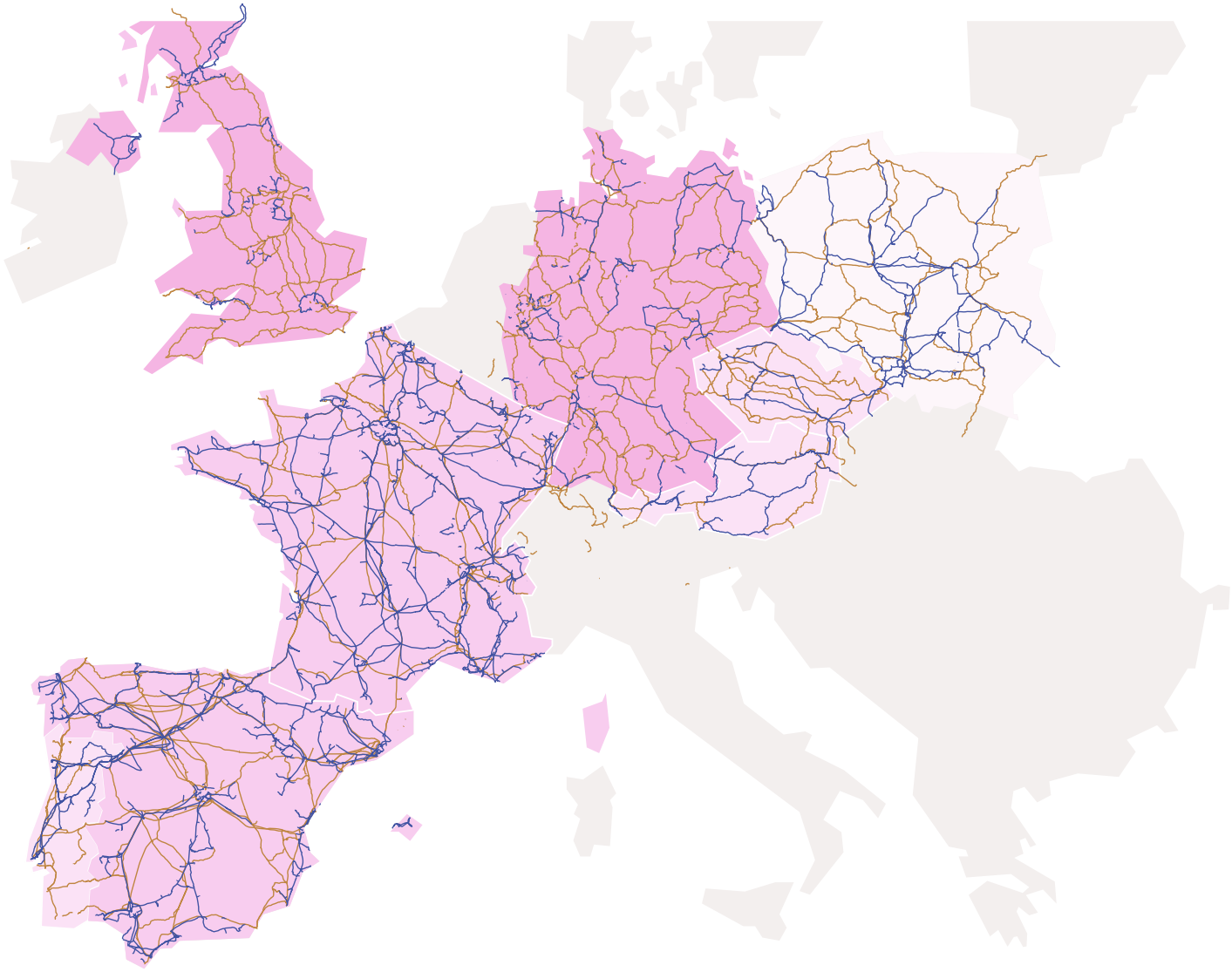
39 The proportion is similar in other countries and typically amounts to approx. 50 percent.

operator has obtained an additional PLN 1.4 billion of support. In the case of DSOs – PGE Dystrybucja, Tauron Dystrybucja, Enea Operator, Energa Operator, innogy Stoen Operator – the companies contracted the implementation of EU projects with a total value exceeding PLN 2 billion, for which they received more than PLN 1 billion of support in the form of the subsidy. Investments have been implemented systematically mostly since 2017, and the last ones are to be commissioned in 2023. The scale of EU support represents only a small fraction of the financial expenditures allocated annually by companies to network investments, especially in the case of DSOs (only approx. 2 percent). Maintaining it at current levels could delay or prevent many needed NPS modernizations, so the role of support schemes should increase significantly. Funding under the Cohesion Policy for 2021–2027, in combination with other EU programs, may come to the rescue. Apart from the European Fund for Infrastructure, Climate and Environment (the successor of OPI&E), additional funds for investments in networks will be allocated from programs such as the Reconstruction Fund – i.e. EUR 300 million (approx. PLN 1.4 billion) is to be allocated for the development of transmission networks and intelligent power infrastructure (Ministry of Funds and Regional Policy, 2021), the Modernization Fund or the Energy Transition Fund. If they are used effectively, they have a chance to significantly contribute to minimizing financial constraints on network operators and may also relieve the burden on energy final customers, to whom investment costs of DSOs and TSOs are transferred.

3.2. Transmission networks

Similarly to the distribution network, the Polish transmission network has suffered from a lack of investment over the years, one of the reasons being its low density. Per one square kilometer (km2) of the country's area, there is only 0.05 km of the extra-high voltage networks – 400 and 220 kV. This is low compared to other EU countries (Fig. 26) – in Germany and England and Wales the coefficient is 0.1, in the case of France and Spain it is 0.08, and in Portugal, the Czech Republic and Austria it is 0.07. Thus, the Polish transmission network is half as dense as, for example, the German network. This poses a number of risks that can lead to difficulties in power transmission, ultimately threatening the security of electricity supply to final customers (Dołęga, 2018). This is particularly important under circumstances of projected growth in the country's electricity demand. This means that intensive efforts to expand the network should be undertaken today, and in addition to the density of lines across the country and investments that allow for the safe power output from RES (Dołęga, 2018), it will also be important to increase the capacity of cross-border connections that will further enhance energy security and ensure the possibility of free energy trade in the domestic and international markets.

Figure 26. Density of extra-high voltage networks in Poland and selected EU countries



220/275 kV line

380/400 kV line

Network density

N/A

0.05

0.07

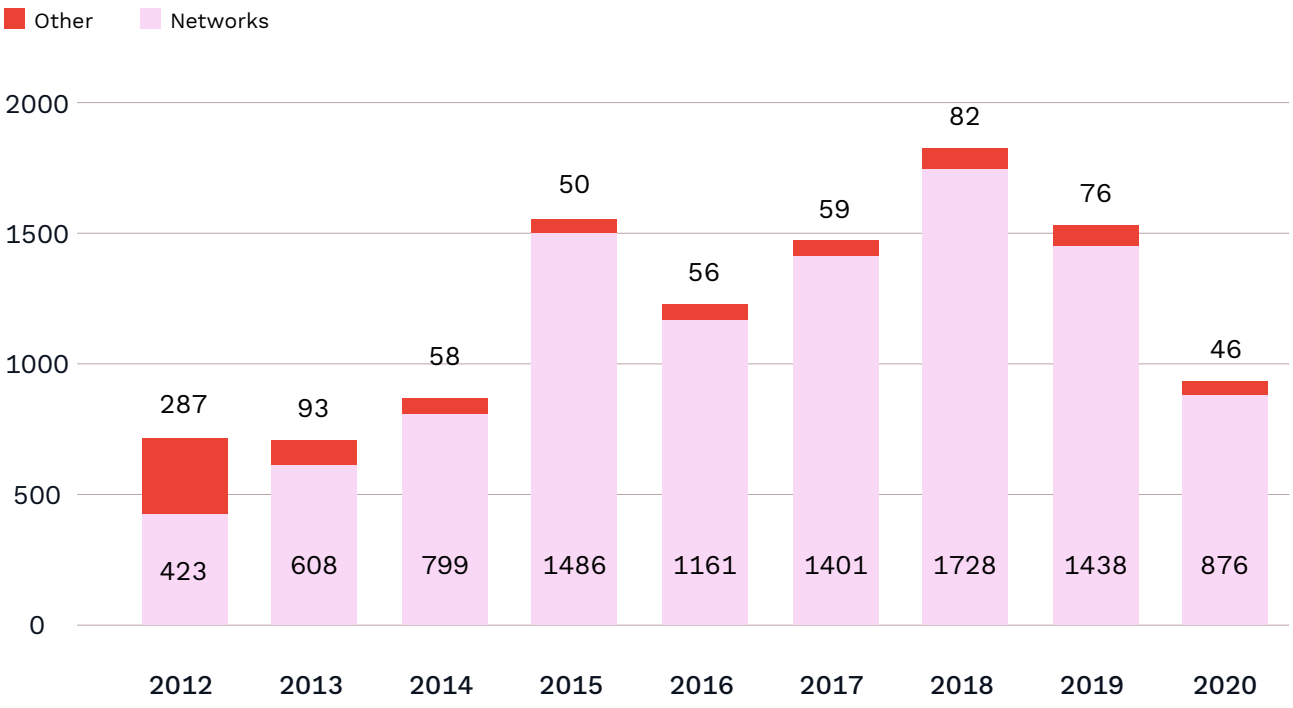
0.08

0.10

Source: Instrat internal analysis.

It should be perceived as a positive signal that PSE's investments have increased in recent years, with their value ranging from approx. PLN 1.2 to 1.8 billion annually (Fig. 27). The majority of PSE's projects (95 percent) focus on the construction, expansion and modernization of the network, with the most funds allocated in 2018 – PLN 1.73 billion. In 2019, the company's investments declined to approx. PLN 1.5 billion and the downward trend continued in 2020, most likely due to the COVID-19-induced slowdown. As with distribution, expenditures on transmission networks will also have to increase.

Figure 27. Value of investments carried out by PSE between 2012 and 2020 [PLN million]

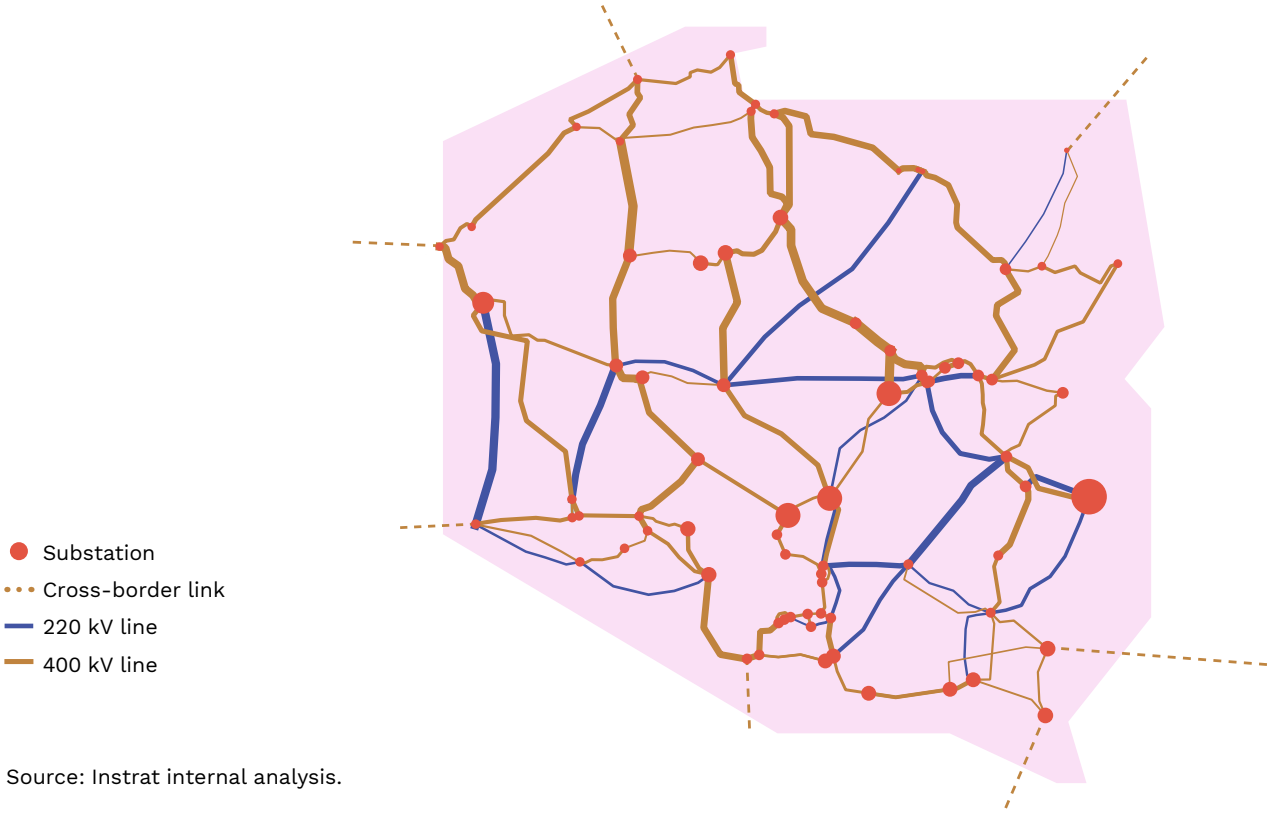


Source: Instrat internal analysis based on PSE's integrated annual reports.

In the case of future investments, the provisions of the Energy Law of April 10, 1997 require the TSO (i.e. PSE) to prepare development plans for meeting present and future electricity demand (TNDP) for a period of 10 years and to update them every 3 years. The latest TNDP, published by PSE, indicates that the total investments planned for 2021–2030 will require expenditures of up to PLN 14.16 billion (PSE, 2020), in the expansion scenario. The funds are to be used for investment in the construction, extension and modernization of substations and power lines, as well as for ICT projects, buildings and structures, the purchase of fixed investment assets and the purchase of network facilities and the regulation of the status of real property. However, the company's investment activities in the perspective until 2030 are to be focused mainly on the development of 400 kV lines – both the construction of new and the replacement of existing 200 kV networks with 400 kV lines

(PSE, 2020). If the historical trend of allocating 95 percent of investment funds to networks is maintained, the construction, expansion, and modernization of substations and lines will consume approx. PLN 13.45 billion by 2030. – i.e. approx. PLN 1.35 billion annually. The planned average annual expenditures are therefore lower than those observed historically. This means that in the context of the need to thoroughly improve the technical condition of the network, to increase its density and the availability of connection capacity, capital expenditures will have to increase.

Figure 28. Map of transmission networks and line load in the PEP2040 scenario in 2030.

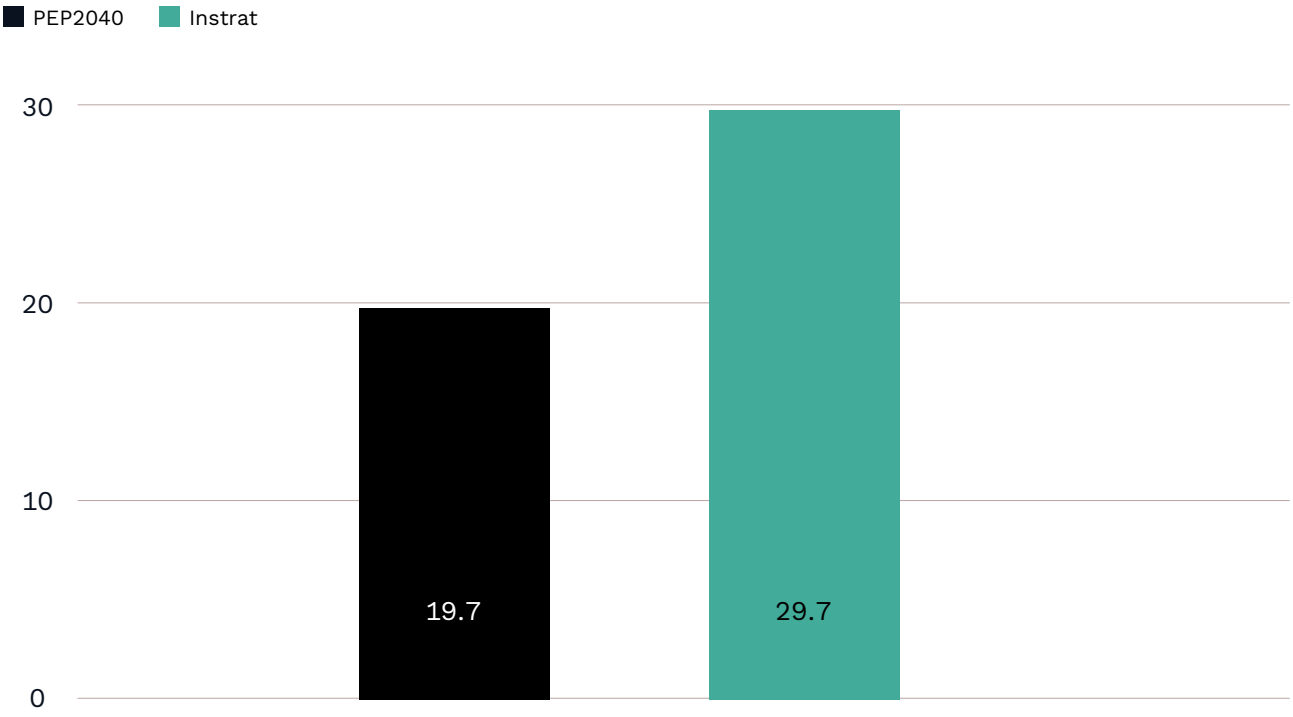


Source: Instrat internal analysis.

In order to assess the scale of necessary investments in transmission networks, the PyPSA-PL model was used to estimate the load on individual extra-high voltage lines in the PEP2040 and Instrat scenarios and to propose actions related to their modernization in the 2030 and 2040 perspective. The PyPSA-PL model contains an accurate mapping of the 400 kV network with its nodes (substations) and a simplified structure of the 220 kV network. A map of the network with the indicated load distribution for the PEP2040 scenario in 2030 is shown in Fig. 28. The model can be used to determine which lines will become overloaded due to, for example, uneven distribution of generating units or its mismatch with locations with the highest demand. Further, investments addressing these overloads have been proposed. The total costs of these investments are presented in Fig. 29 – in the PEP2040 scenario no additional investments are required by 2030 with respect to

those planned in the TNDP, while in the Instrat scenario an increase in these expenses by PLN 3 billion is necessary. In 2031–2040, in the PEP2040 scenario, capital expenditures are PLN 6.3 billion, in the Instrat scenario they amount to PLN 13.3 billion. In total, transmission network investment costs are PLN 10 billion higher in 2021–2040 in the Instrat scenario than in the PEP2040 scenario, but this has little impact on tariffs for final customers (see point 2.3.) compared to costs in the distribution network area. A detailed description of the methodology and results is described in Appendix 1.

Figure 29. Estimated capital expenditures for transmission networks between 2021 and 2040 [PLN billion]



Source: Instrat internal analysis.

3.3. Other system costs

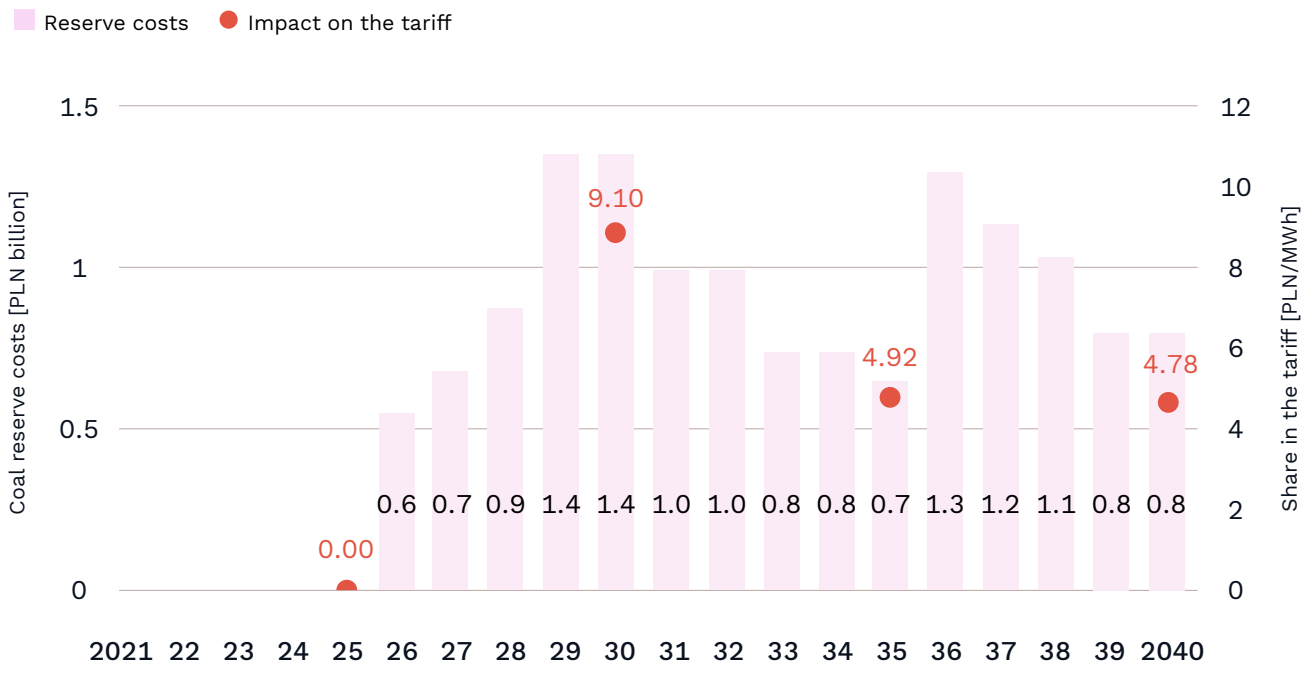
Among the system costs, in addition to investments in transmission and distribution networks, the costs of ensuring adequate capacity reserve, costs of managing variable energy production from RES, costs of balancing and system services used by the TSO should be taken into account. The most important of these are discussed below.

Ensuring the required capacity reserve

One of the key issues in designing an energy mix that relies heavily on renewable sources is providing the capacity reserve needed at times of reduced availability of energy from wind and sun. It is worth remembering that the capacity reserve is used only occasionally and therefore it should not significantly contribute to greenhouse gas emissions or influence the price of energy in the long run. Thus, this reserve can be provided by conventional power plants, provided that their production during the year is limited.

The power market was supposed to ensure an adequate amount of available operating capacity in the NPS but, as described in point 2.2, it failed to meet expectations. In particular, its design will lead to a huge gap in the power balance after 2025. A proposal to fill this gap was described in the first report of the cycle, "Achieving the goal" (Czyżak, 2021a) which advocated maintaining coal-fired units that would operate at very low utilization – of few hundred hours per year. This would be sufficient to balance the system while being in compliance with EU law (limiting the allowed emissions of subsidized units to 350 kg CO2/kW per year (EU, 2019)). The cost of such a solution was estimated at PLN 14.34 billion between 2025 and 2040, assuming that all fixed costs of the units remaining in the reserve are covered. The impact of this mechanism on household tariffs is not significant – in 2030 it would be PLN 9.1/MWh, in 2040 – PLN 4.8/MWh (Fig. 30).

Figure 30. Coal reserve costs



Source: Instrat internal analysis.

An alternative proposed by the government is the creation of the National Energy Security Agency (NABE), which would take over coal-fired power units from power companies and then maintain them for an unspecified period of time. The project also does not specify how NABE would be financed, and according to an analysis by Instrat and ClientEarth (Czyżak & Kukuła, 2020), the cost of creating and maintaining NABE in the 2040 perspective would be as much as PLN 63.3 billion – four times more than in Instrat scenario. In fact, the cost to taxpayers could be even higher because Instrat's calculations do not take into account the risk that, as a monopolist, NABE will dictate the extremely high energy prices necessary for its survival.

As the details of the project have still not been disclosed since the NABE concept was announced in April 2021, and a number of state institutions have spoken negatively about it (including the Ministry of Climate and Environment and the ERO), the PEP2040 scenario does not include NABE costs or any other costs for maintaining coal-fired units after their capacity contracts expire. Obviously, this assumption favors the PEP2040 scenario over the Instrat scenario.

In addition to coal reserve, the Instrat scenario includes other technologies to provide the required level of available operating capacities – including CCGT gas-fired power units, green hydrogen units (modeled as OCGT), large-scale energy storage facilities and pumped storage power plants. As discussed in point 2.3, these solutions are supported by the capacity market (both in the Instrat and PEP2040 scenarios), which is likely to be extended in one form or another, and its costs are included in the tariff forecast.

Management of overproduction of energy from RES

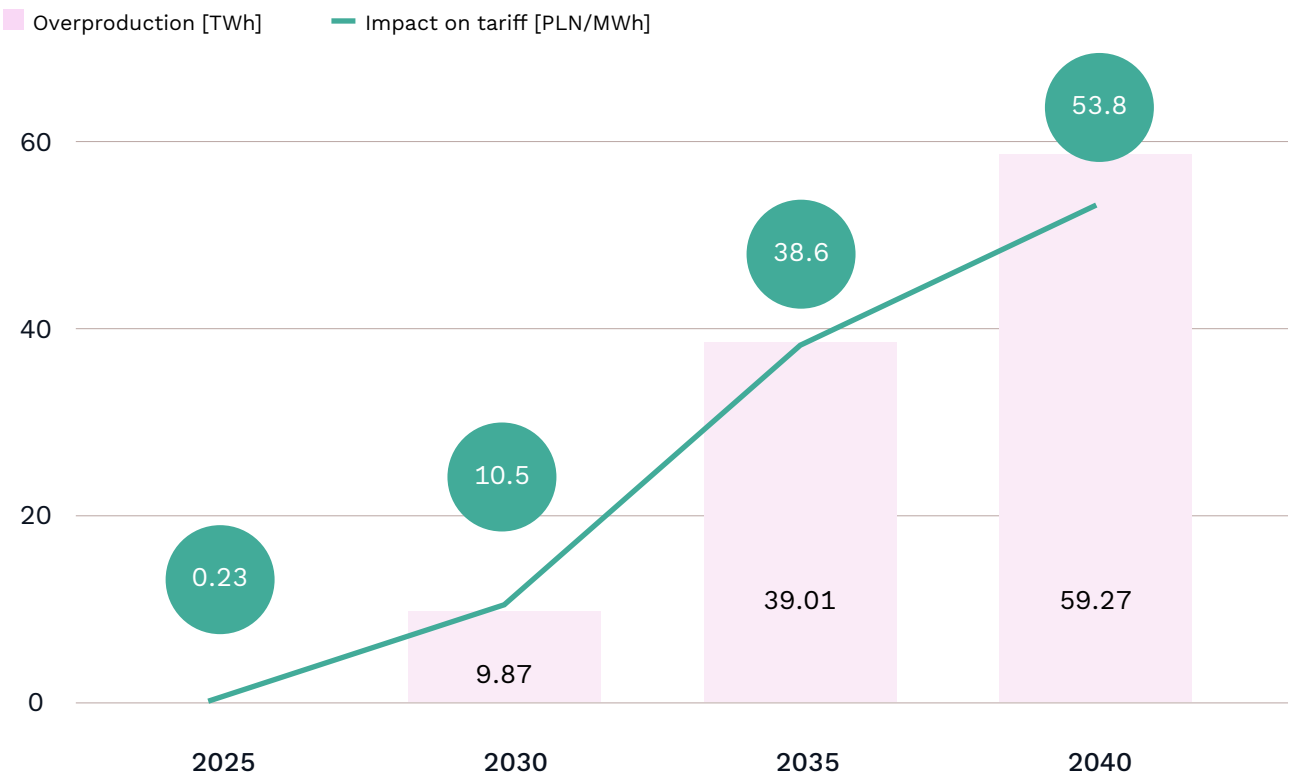
The capacity reserve described above addresses the problem of periodic RES energy shortages. The reverse situation – overproduction of renewable energy occurring, for example, at times of high wind and low demand – is also a significant challenge. While this should not be a problem for security of energy supply, it can make it difficult to achieve a return on investment for wind turbines and solar power plants – if the surplus energy cannot be received by the NPS or stored, the unit will be disconnected from the network and unable to generate revenue. The scale of this phenomenon remains marginal with the RES share in the energy mix at 40 percent (under Instrat's 2025 scenario), but with further increases in installed RES capacity needs to be addressed.

The overproduction of energy from RES can be estimated by subtracting the theoretically available operating capacity of the power plant[40] from the capacity received at any given time by the NPS. Of course, a number

40 The product of the installed capacity and the capacity utilization factor resulting from the weather conditions and technical parameters of the power plant (e.g. turbine mounting height, turbine model and its power curve, photovoltaic module or inverter efficiency, etc.).

of additional factors can affect the need to shut down a generating unit, including, for example, maintenance downtime or overhauls. Nonetheless, applying this definition and analyzing the results of the PyPSA-PL model, it can be estimated that the overproduction of energy from wind and sun will increase from approx. 10 TWh in 2030 to as much as 57–59 TWh in 2040. (Fig. 31). Such large values would pose a serious threat to the economic viability of RES and could lead to a reduction in investment dynamics and, thus, an inability to meet climate targets or a gap in the power balance.

Figure 31. Costs of overproduction of energy from RES



Source: Instrat internal analysis.

The least effective solution to the problem of overproduction of energy from RES would be to create a subsidy program for wind turbines and solar power plants that would reimburse investors for lost energy. A pessimistic costing of such a mechanism assumes compensation for the entire volume of overproduction at the generation cost level (LCoE), entirely financed by energy final customers The cost under this scenario would reach PLN 2 billion in 2030 and PLN 9 billion in 2040 and would have a huge negative impact on tariffs, adding up to PLN 10.5/MWh in 2030 and PLN 53.8/MWh in 2040, respectively. (Fig. 31). Such a scenario is unrealistic and does not take into account at least the export of surplus energy to neighboring countries, but this pessimistic variant was adopted in the tariff calculation to estimate the maximum possible values of RES system costs.

The preferred and commonly planned way to manage surplus energy from RES is to produce green hydrogen by electrolysis. The recently adopted *Polish Hydrogen Strategy until 2030 with an Outlook to 2040*[41] assumes the installation of 2 GW of electrolyzers over the next decade. These facilities would produce 0.19 million tons of hydrogen[42] with an electricity consumption of 10 TWh – more than the surplus energy from RES[43]. In 2040, 10 GW of electrolyzers could produce 0.97 million tons of hydrogen, using 50.4 TWh of electricity – again, almost all of the RES surplus that year. Among the advantages of investing in electrolyzers, it is worth mentioning that, according to estimates by Aurora Energy Research (2021), the use of electrolyzers would increase the capacity utilization factor of a potential nuclear power plant improving its profitability and making it easier to finance the project.

Among other methods of managing the profile of energy production from RES there is, of course, also the use of energy storage facilities or increasing the capacity of cross-border connections – which was taken into account in the PyPSA-PL model (see point 2.3. and the report "What's next after coal?").

The overproduction of energy from RES is undoubtedly an important issue, however, it gains a significant impact on consumer tariffs only with a very large share of RES in the energy mix. At the same time, there are already methods to mitigate the negative effects of surplus energy. Adoption of the Polish Hydrogen Strategy with ambitious targets already for 2030 allows to believe that addressing the challenges related to overproduction of energy from RES will not have a negative impact on energy end customers.

Other

The list of potential system costs is long, and this paper focuses on the most important categories. Some of the system costs were not devoted to dedicated chapters in the report, but they were included in the model itself – these include:

- ***Costs associated with energy import, inter-operator inter-system exchange, and development of cross-border connections*** *– included in the cost of power generation and in the cost of network investments. There is no provision for investment in cross-border connections other than those already planned under the TYNDP;*

41 Resolution of the Council of Ministers of November 2, 2021 on the adoption of the "Polish Hydrogen Strategy until 2030 with an Outlook until 2040"

42 Assuming 5000 operating hours per year, 70% efficiency and hydrogen calorific value of 130 MJ/kg – in accordance with the draft of the Polish Hydrogen Strategy (MKiŚ, 2021a).

43 It should be remembered that the operation profile of electrolyzers, the profile of demand for energy from the NPS, the profile of cross-border exchange, the profile of energy production from wind and sun do not have to be perfectly matched, and at times of peak overproduction of RES it may exceed the capacity of electrolyzers, which means that not all of the surplus will be able to be used. On the other hand, the surplus energy in Poland can also be exported to (or used to meet the demand of) neighboring countries that also have electrolyzers.

- ***Demand management costs*** *– included in the cost of generating power within DSR units;*

- ***Redispatching costs*** *– indirectly addressed through significant network expansion (calibrated to maximum annual line load) which should reduce overload. This means that redispatching should not be necessary significantly more often than it is now;*

- ***Other balancing costs*** *– production of energy from sun and wind in the model is based on hourly weather data for each site, and the model includes a number of balancing support solutions – including two types of battery storage energy facilities, pumped storage power plants, conventional peak load power plants, and a DSR mechanism. The model balances every hour of the year without the use of DSR and without above-standard expansion of cross-border connections. This means that the most important balancing costs (in addition to those described above such as RES overproduction, reserve, network investments) have already been addressed at the scenario development stage.*

One system cost worth exploring in a separate analysis is the cost of adapting coal-fired power units to run in reserve – that is, with limited utilization and the need for accelerated startup. However, there is already a "200+ Units" Program underway in this area (NCBiR, 2021), which is designed to adapt existing units to increasing flexibility requirements. Such actions are needed in both the Instrat and PEP2040 scenarios, and their cost will need to be included among the potential costs incurred by NABE.

4. Challenges related to Poland's energy security

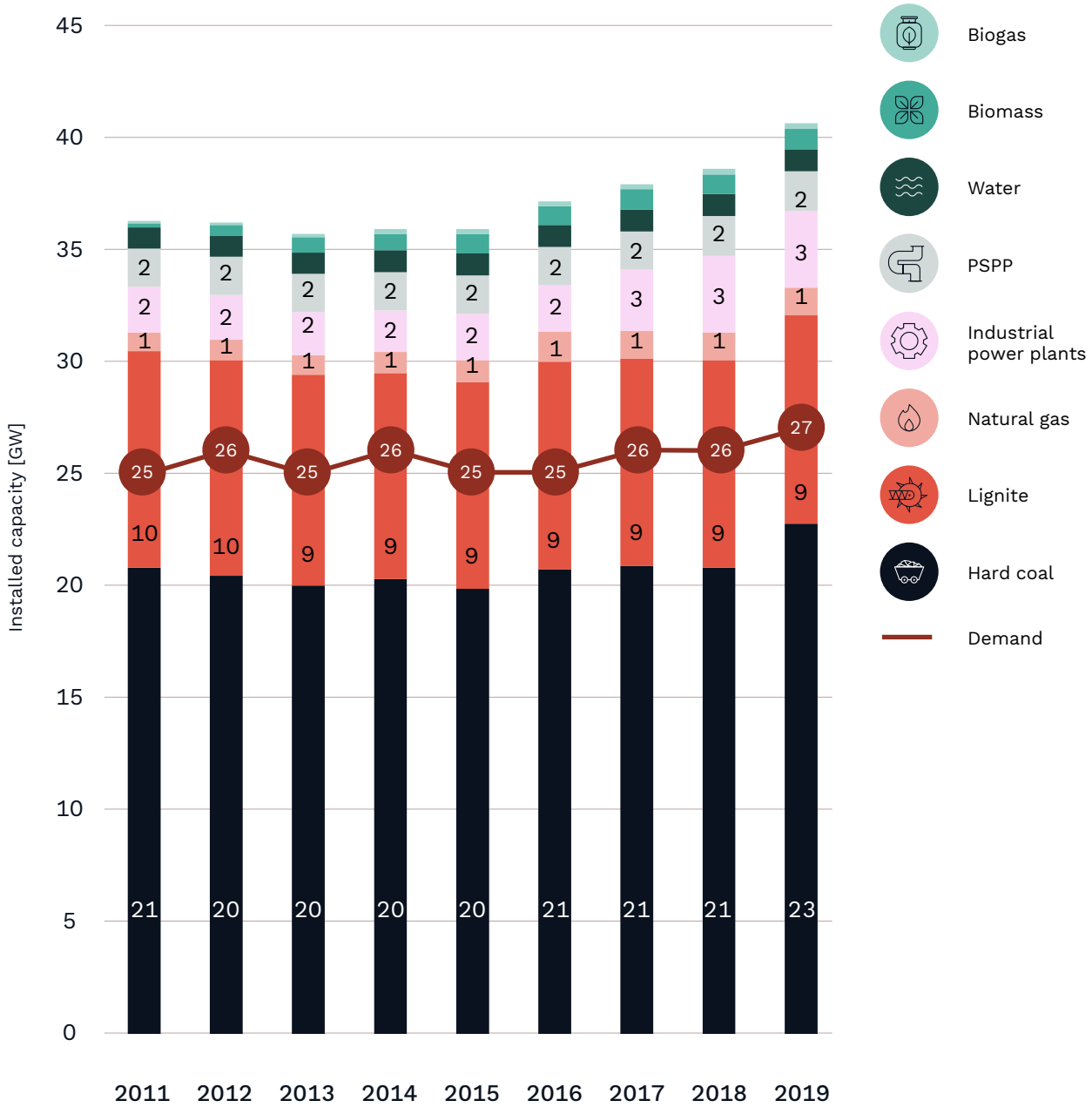
The definition of energy security focuses on two aspects – stability of energy supply and affordability. Chapter 2 focuses on the second of these factors and discusses the severe financial consequences of remaining with the coal status quo for households and the opportunity presented by renewable energy sources. Chapter 3 identifies challenges associated with the development and modernization of network infrastructure with an increasing share of RES in the electricity mix and estimates the scale of system costs necessary to ensure continuity of energy supply with weather-dependent sources. This chapter focuses on the non-financial consequences of implementation of the PEP2040 and Instrat scenarios, including the impact of both on the power balance, which directly determines the ability to provide stable electricity to final customers.

4.1. Ensuring continuity of energy supply in the status quo variant

When analyzing the possibilities of balancing the power system in the following years, it is worth drawing conclusions from the past, especially noting the situations in which mainly emergency energy imports from abroad allowed Poland to maintain continuity of power supply.

Theoretically, in previous years, the surplus capacity available to the TSO was sufficient to meet national power demand and ensure security of energy supply (Fig. 32). The trend that has become apparent over the last few years, however, is a continuous and rapid increase in demand for both electricity and power, whether in summer (mainly air conditioning equipment) or winter (electric heating). . In the years to come, ensuring the required level of capacity reserve available to TSOs during peak demand could therefore be a significant challenge.

Figure 32. Historical NPS installed capacity excluding solar power plants and wind turbines and maximum peak demand for capacity [GW]



Source: Instrat internal analysis based on ARE data.

For safe operation of the power system, it must be possible to balance the system at all times. Balancing involves mainly large CDGUs that are connected to the 110 kV transmission and coordination network and are subject to central dispatching by PSE. However, due to the increasing number of smaller RES sources in the system in recent years, they are increasingly contributing to the total power balance.

An analysis of data collected from energy producers by the ERO (ERO, 2021c) shows that available operating capacity generation potential in the national power system will decline in the 2034 perspective. A total of more than 14.2 GW of new generating capacity is planned to be commissioned, with the majority coming from offshore technology (4.8 GW), natural gas (4.4 GW) and photovoltaics (2.8 GW). At the same time, it is assumed that units with a total capacity of 18.8 GW, based mainly on hard coal (12.8 MW) and lignite (5.3 MW), will be decommissioned. It is important to note that the variability and unpredictability of weather conditions negatively affects the ability to guarantee available operating capacity from RES compared to conventional power plants. This translates into them having less impact on maintaining NPS stability. Therefore, despite a steady increase in RES capacity installed in the system, the available operating capacity will decrease – retiring and new units have different availability factors, which will result in a decrease in available operating capacity in this time horizon by up to 31 percent (10.6 GW). To avoid problems with energy supply stability, it is necessary to build new units very quickly and to continue to introduce flexible market solutions, such as DSR, energy storage facilities or increased energy import, for example (ERO, 2021c).

There have already been several incidents over the past few years that could lead to a blackout. One of these occurred in 2015, when limitations in supply and consumption of electricity were imposed during the summer period from August 10 to 31 due to insufficient generation and transmission capacity of the NPS. At that time, PSE implemented power supply levels by hour of the day. Level "20" which is the highest possible level, was in effect on August 10, 2015 from 10:00 a.m. to 5:00 p.m. (Dołęga, 2020). In 2020, PSE had to pass another stress test – on June 22, 2020, unplanned generation losses reached a historical maximum of 5.7 GW. This was due to heavy rainfall, which led to problems with the coal supply to the power units and the failure of electrical equipment, including the power output system. The crisis was also exacerbated by other random failures that occurred at the time. However, it was possible to maintain continuity of energy supply – in this case, the reduced demand of the NPS due to the pandemic, the high level of energy import, as well as the increased level of reserves in domestic conventional power plants were of great importance (MKiŚ, 2021c). An equally critical event occurred on May 17, 2021, when, due to human error and a previously undetected defect in one of the substation components, a short circuit occurred at PSE's Rogowiec substation. As a result of this event, 10 power units of the Bełchatów Power Plant were shut down. At that time, 3640 MW of power was lost, but the system was able to be quickly balanced through the activation of generation in pumped storage power plants, activation of the spinning thermal reserve in operating power plants, and inter-operator energy import from neighboring systems (PSE, 2021a).

Among significant failures of generating units, affecting the shrinking power balance in recent years, it is worth mentioning the outage of the newest power unit of Jaworzno Power Plant. This power unit was commissioned in November 2020 (six months after the deadline); however, many additional anomalies were diagnosed during the first phase of the boiler's operation, so

the unit had to be shut down. The power unit is scheduled to be re-synchronized with the power network on April 29, 2022, after a number of repair works have been completed beforehand. This represents a 2-year delay from the original assumptions (Kośka, 2021) and results in a significant 910-megawatt gap in the capacity available to TSOs during the extremely tight winter period associated with rising commodity and energy prices in nearly all European markets.

Due to the existing risk of power shortage and the length of investment processes, it is necessary to immediately begin construction of new sources of electricity generation. They will make it possible to fill the balance gap of the NPS after 2025, so that there will be no power shortage and consequently no interruption of power supply to domestic consumers. Meanwhile, the investments planned for hand over from 2024 onwards, which total approximately 9 GW, do not have secured financing, which puts a big question mark over the feasibility of their implementation at the planned scale and timing (ERO, 2021c). It is necessary to ensure proper conditions for the functioning of the market primarily for new generating sources, including RES. Existing units will be decommissioned due to their age and technical condition, failure to meet emission standards and end of their derogation period, as well as lack of economic viability (ERO, 2021c). It is worth remembering that more than 70 of 90 coal-fired power units have already exceeded the time for which they were designed, and increasingly frequent failures contributing to rising the duration and number of their overhauls, continually reducing the amount of available operating capacity in the system (Elżbieciak & Zasuń, 2021).

4.2. Balancing of NPS in the PEP2040 scenario

The problems of the Polish power system were to be addressed by the Energy Policy of Poland until 2040 published in 2021. In particular, the document was to answer the question of how to fill the gap in the power balance resulting from the shutdown of old coal-fired power units. However, the analyzis of the projected net generating capacity in PEP2040 shows some worrisome phenomena related to availability of capacity (MKiŚ, 2021b). This analysis compares the PEP2040 scenario and the Instrat scenario in this regard, using the Availability Correction Factor (KWD) for particular fuel technologies, as adopted in the Regulation of the Minister of Climate of August 6, 2020 concerning parameters of the main auction for the delivery year 2025 and parameters of additional auctions for the delivery year 2022 (Journal of Laws of 2020, item 1355). This Factor determines the ratio of net available operating capacity to net generating capacity and allows for factors such as planned and emergency outages of conventional units, or limited availability of wind and solar energy.

Table 2. Availability Correction Factor (KWD) for individual fuel technologies

Type	Availability Correction Factor [%]
Steam turbines, steam turbine system, air turbine system, fuel cells, and the organic Rankine cycle	92.58
CCGT	93.94
Simple cycle gas turbines and reciprocating engines	93.40
Onshore wind turbines	13.93
Offshore wind turbines	20.34
Once-through hydropower plants	46.81
Once-through water storage hydropower plants with reservoir with pumped storage unit and once-through water storage hydropower plants with pumped storage unit	99.37
Solar power plants	2.27
Electricity storage facilities in the form of batteries, kinetic energy storage devices and supercapacitors	96.11
Demand side response units	100.00
Cross-border exchange (net import)*	60.00
Other types of technology	90.78

*When analyzing historical data, it is evident that net import regularly reaches 50–60 percent and periodically nearly 70 percent of capacity of cross-border links./

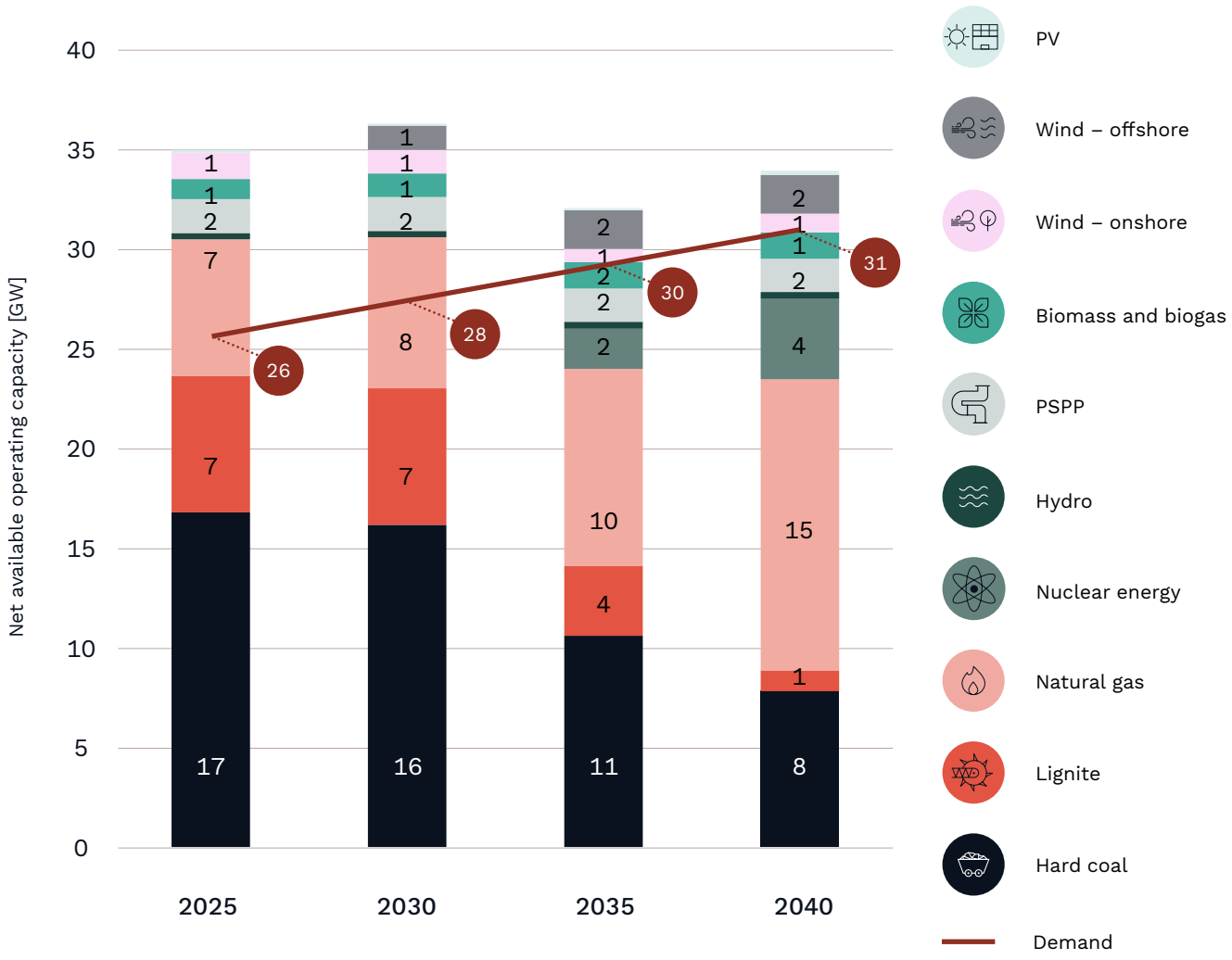
Source: The Regulation of the Minister of Climate of August 6, 2020 concerning parameters of the main auction for the delivery year 2025 and parameters of additional auctions for the delivery year 2022.

In the PEP2040 scenario, the coal-fired generation park is to be replaced mainly by gas-fired units[44] (increase in generating capacity from 7.4 GW in 2025 to 15.8 GW in 2040) and nuclear power plants (4.4 GW of generating capacity in 2040). PEP2040 does not take into account the potential of RES and locks the capacity level of these sources at values close to the current ones. The generating capacity of PV power plants is expected to increase from 5.1 GW in 2025 to only 9.8 GW in 2040 (which is already an unrealistic assumption). The generating capacity of offshore wind turbines is expected to increase to 9.6 GW in 2040, while onshore wind turbines will be slowly phased out – their generating capacity will decrease from 9.7 GW in 2025 to less than 7 GW in 2040. Figure 33 shows the power balance during the annual peak demand, after converting the available generating capacity by the corresponding Availability Correction Factors mentioned in Table 2. It turns out that in 2035, with a peak demand of 29.5 GW, there is a high risk that the available operating capacity will be too low to cover it. The surplus of available operating capacity over peak demand will only be approx. 2.5–3 GW, and for coal-fired power units, the available operating capacity often differs much more from the generating capacity than the KWD value implies. The situation will be similar in 2040, when, with peak demand of 31.3 GW, the surplus available operating capacity will also be only approx. 3 GW. It is worth noting that PEP2040 negates the role of inter-system exchange in balancing the NPS, despite the efforts of the European Union and ENTSO-E to increase the possibility of cross-border exchange, which significantly reduces the costs of energy transition and increases energy security of Member States. Therefore, import is not taken into consideration in the power balance analysis in PEP2040.

There is a great risk that in case of delays related to construction of the nuclear power plant and gas-fired power units, as well as with seasonal limitations of operation of combined heat and power plants, there may be a shortage of power which may result even in a blackout. If coal-fired power plants are phased out earlier than anticipated in the document, along with their increased failure rates and lower availability, the situation could become even more critical. Unfortunately, PEP2040 thus fails to address the challenges of ensuring an adequate power balance in the NPS. Moreover, by blocking the development of renewable energy sources, it makes it impossible to supplement the missing capacity with wind and solar energy backed by energy storage facilities. While the multiplicity of RES technologies, their ease of financing, and the pace of their construction could be the answer to the massive generation gap already emerging by the middle of this decade.

44 This term in the analysis includes gas-fired power plants and gas-fired combined heat and power plants, as well as gas peaker plants, i.e. units that operate only during peak demand.

Figure 33. Projected power balance in the annual peak in the PEP2040 scenario [GW]

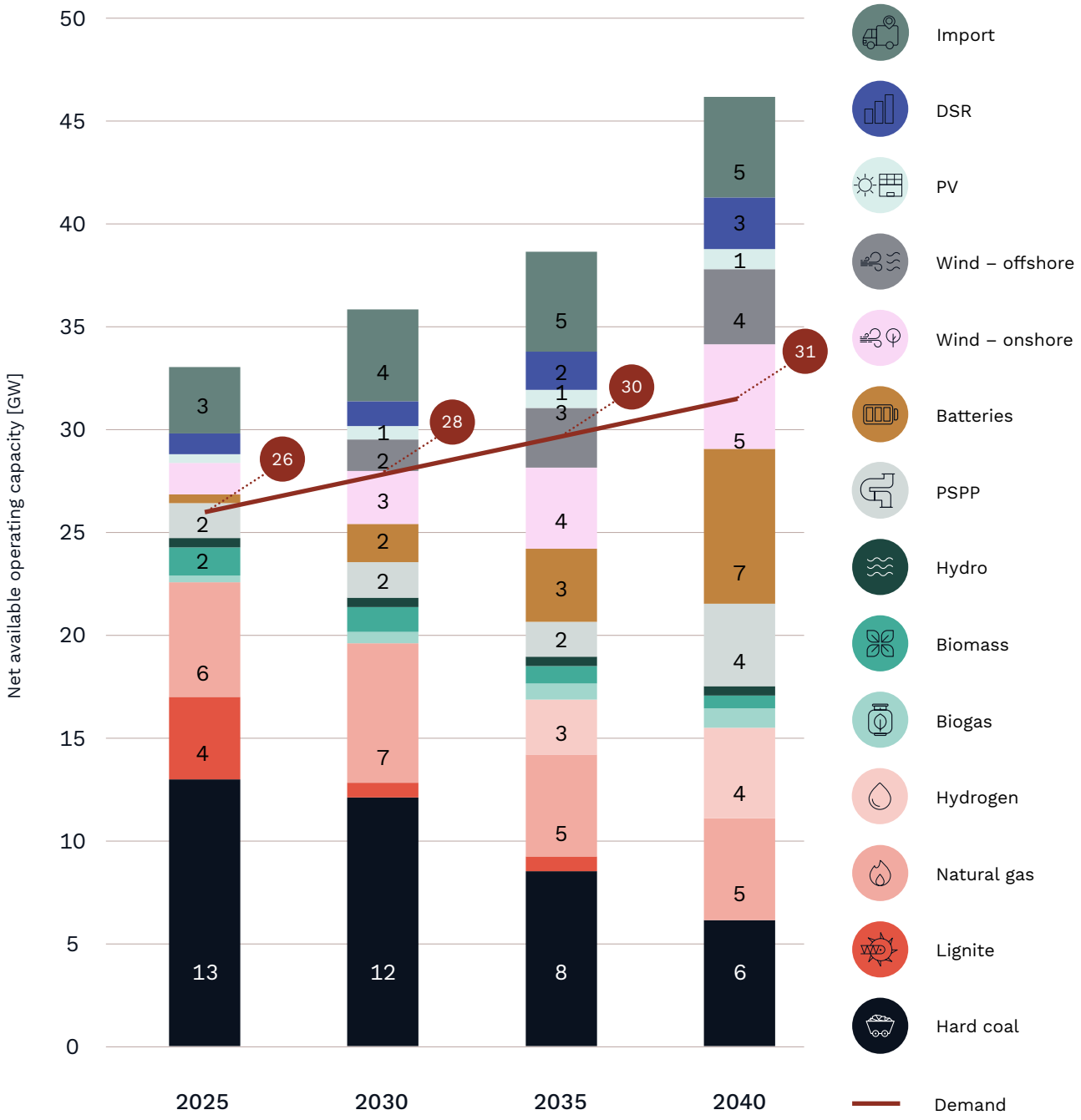


Source: Instrat internal analysis, cf.: PEP2040

4.3. Balancing the NPS with a high share of RES

With an increasing share of RES and a decreasing number of conventional generating units, providing surplus capacity in the NPS at every hour of the year creates additional challenges. In particular, to maintain a continuous supply of energy during peak demand and low wind conditions, back-up units – coal-fired, gas-fired and hydrogen\power plants – operate in the system. The operator also has at its disposal energy storage facilities and contingency reduction of consumption, as well as inter-system exchange.

Figure 34. Projected power balance in the annual peak in the Instrat scenario [GW]



Source: Instrat internal analysis.

The surplus available operating capacity at peak demand in the Instrat scenario is larger than in the PEP2040 scenario, increasing from 3.4 GW in 2030 to 9.5 GW in 2040[45] (Fig. 34). An additional 4–5 GW of capacity is provided by cross-border connections[46]. The power system proposed in the Instrat scenario is also much more diversified than in PEP2040 – both in terms of technology and geographic location of generating units. This makes it less likely that a failure at a single power plant or substation will lead to such a large loss of power, as in the case of the Rogowiec substation failure described earlier. There is also much less dependence of the country on natural gas supply constraints, causing such a severe impact now in Europe.

Examining hourly data on power surplus in the NPS in the Instrat scenario one can come to an important conclusion – despite a very high share of RES in the energy mix, Poland's dependence on energy import from neighboring countries is not increasing. In 2040, the annual import volume drops to 7 TWh – by almost half of the 2020 value. Only during 44 hours a year (i.e. less than two days in total) the level of temporary net imports is higher than the currently recorded maximums[47]. The maximum temporary net import in 2040 is 5.5 GW – which will represent 69 percent of cross-border connection capacity, almost exactly the same as today (67 percent). In 2030, the annual import volume is twice as high as in 2020 – it increases to 28 TWh. However, this is due to economic rather than energy security factors – as in 2040, maximum temporary import does not exceed 70 percent of link capacity, and only during 17 hours of the year (less than one day) is greater than the maximums recorded in 2020 and 2021. Any positive net import is needed for 158 hours in a year (less than 7 days). Of course, it would be possible to increase the capacity reserve and reduce it to zero, but this would mean incurring additional investment costs and costs for maintaining generating units with minimum utilization. Such a move also stands in opposition to the pan-European push to communitize energy markets and increase inter-system opportunities.

When discussing the possibility of balancing the NPS with a large share of RES, it is worth realizing the scale of dependence of energy production from wind and sun on weather conditions. On an annual basis, only a small number of hours are completely devoid of wind. This is even rarer if offshore wind farms and production of energy from sun are included. Fig. 35 shows the annual availability of energy from wind and sun in the Instrat scenario in 2040. The point on the graph indicates for how much of the year, the RES available operating capacity at a given time is greater than the value on the Y axis – e.g., for 90% of the year, the capacity provided by Polish wind turbines and solar power plants exceeds 8 GW.

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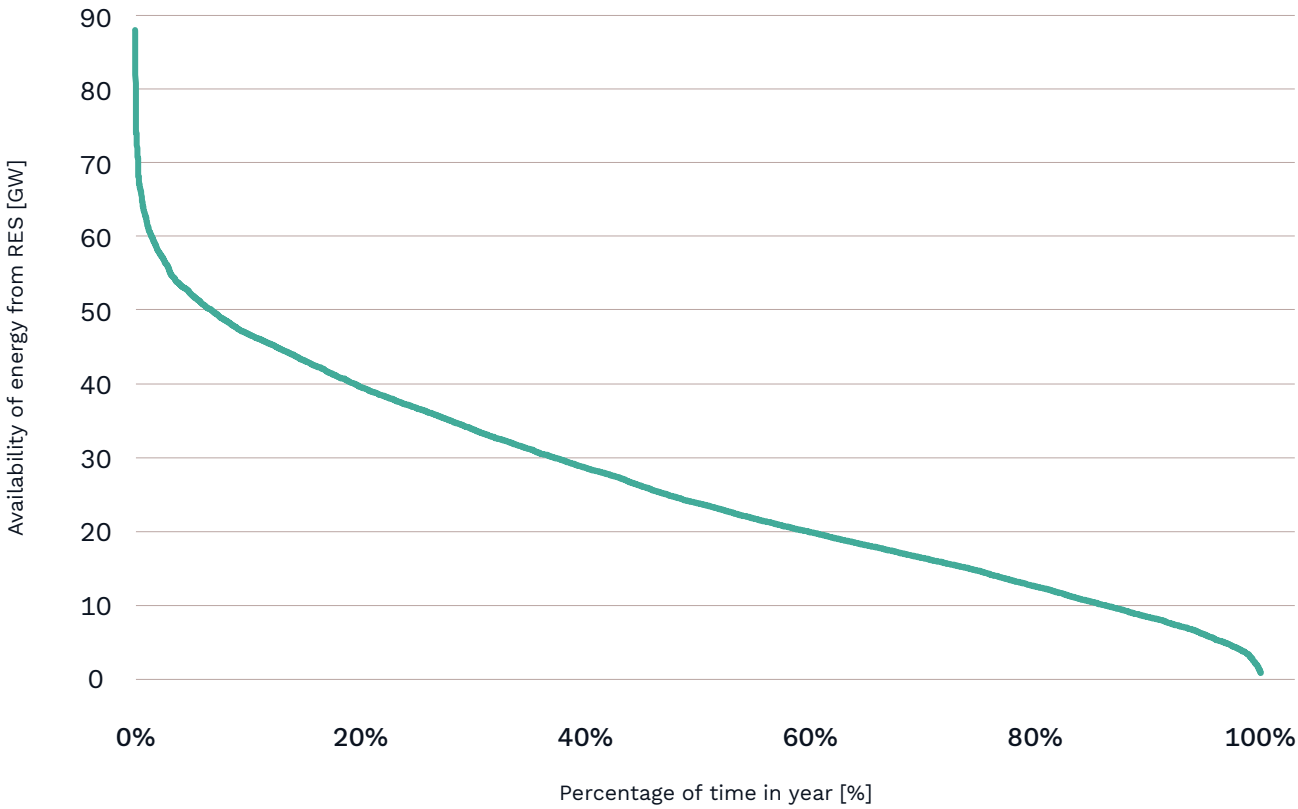
45 A detailed description of the structure of installed capacity, annual capacity increase in specific technologies, and the structure of energy production is described in the "What's next after coal" report.

46 According to Table 2, their average availability is assumed to be 60 percent; in emergency situations it could be higher.

47 In 2020, peak net imports exceeded 3.2 GW, accounting for approx. 67 percent of capacity of cross-border links.

In Fig. 35, it can be seen that there will be no moments of zero production of energy from sun and wind in Poland in 2040 – the minimum production value is 796 MW. In only 6 hours of the year do solar and wind plants produce less than 1 GW, for 83 hours of the year (3.5 days) production is less than 3 GW. On the other hand, for more than 4000 hours a year (47 percent of the time), wind and solar energy could cover all of the electricity demand.

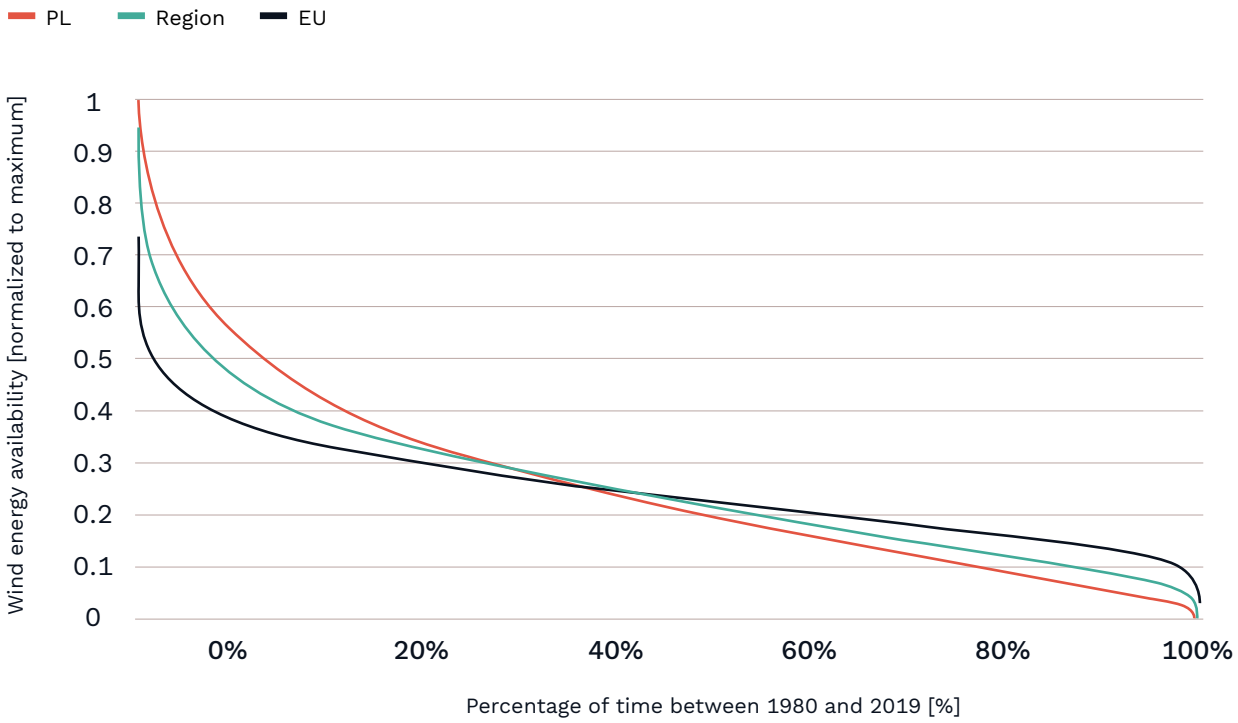
Figure 35. Production of energy from wind and sun in Poland in 2040 [GW]



Source: Instrat internal analysis, data from renewables.ninja (Staffel and Pfenninger, 2016) and EMHIRES (Energy.instrat.pl, 2021d).

It is worth remembering that the above values take into account only the wind conditions and sunlight in Poland. Seeking to increase cross-border exchange opportunities means that regions with temporarily less favorable weather conditions can import energy from countries where, for example, wind conditions are better at any given time. The benefits of such a solution are shown in Fig. 36.

Figure 36. Production of energy from wind in Poland and Europe between 1980 and 2019



Source: Instrat internal analysis, data from renewables.ninja (Staffel and Pfenninger, 2016).

Analyzing hourly wind conditions data in Poland and Europe for 1980–2019 (324,000 records), a wind energy availability profile similar to that in Fig. 35 was estimated during the analyzed period. Values on the Y axis were normalized to the hourly maximum. The key findings relate to comparing the wind condition profile in different geographic areas – the more energy markets we integrate, the fewer moments there will be where wind is inadequate. Considering the availability of wind energy in our neighbors, the minimum production could be increased from 1 percent to 3 percent of the installed capacity. Considering the rest of the European Union, 7 percent of installed capacity – or 16 of 220 GW[48] – is available 100 percent of the time. It should be noted that the data is for the historical windmill fleet and previous years, while currently installed turbines have significantly higher capacity factors and are able to produce energy with less wind[49].

Integration of energy markets is extremely important in achieving the EU's climate goals, as well as in ensuring the energy security of individual Member States. This is also recognized by the European operators of power networks associated within ENTSO-E, who emphasize in successive TYNDP documents that this will also reduce the costs of the energy transition.

48 Installed capacity of onshore and offshore wind turbines in 2020.

49 For example, the difference between the capacity factor for a Vestas V90 turbine with a tower height of 80 m and a newer Vestas V136 turbine with a tower height of 112 m located in Kopaniewo, Pomerania, is 7.1 pp. (renewables.ninja).

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Appendix 1. Analysis of investments in transmission networks

In order to assess the scale of necessary investments, the PyPSA-PL model was used to estimate the load on individual extra-high voltage lines in the PEP2040 and Instrat scenarios and to propose actions related to their modernization in the 2030 and 2040 perspective. The PyPSA-PL model contains an accurate mapping of the 400 kV network with its nodes (substations) and a simplified structure of the 220 kV network[50]. The current-carrying capacity of the first three line types was selected according to the PSE documentation (PSE, 2015), with the average value assumed for different wind conditions in the summer season. Since the recommended type of phase conductor for the 400 kV overhead line was changed in recent years to the newer 3x468/24-A1F/UHST-261 (PSE, 2017a) and its current-carrying capacity was not provided in the PSE documentation, this value was therefore taken from the supplier (Eltrim, 2020). Of course, not all 400 kV lines currently use the new conductors, which means that their load-carrying capacity may be lower. However, when calibrating the model so that the load-carrying capacity on the extra-high voltage lines in 2021 (with the energy mix consistent with the current one) does not exceed 70 percent[51], it was assumed that the average maximum load-carrying capacity of 400 kV lines is 1,737 MW (according to specification 3x408/24-A1F/UHST-261). For lines upgraded or newly constructed under the TNDP between 2021 and 2030, the allowable power is 2,166 MW (as specified in 3x468/24-A1F/UHST-261). For 220 kV lines, their maximum allowable power capacity was doubled (762 MW) to take into account the lack of mapping of 110 kV network in the model (in Poland, quite expanded and carrying a significant part of the load), and the resistance and reactance of 220 kV lines was increased to evenly distribute the load with the current network and generation structure.

Investments planned by PSE in the 2021-2030 perspective (TNDP) were implemented in the model, resulting in correct network balancing for the PEP2040 scenario in 2030, which confirms the correctness of the calibration performed. Thus, in the PEP2040 scenario, no additional investments

50 Reducing the number of network nodes from 200 (full 400 and 220 kV network) to 75 allows the model to be solved on a standard workstation with 32 GB of RAM, and this will allow other analysts, researchers, or interested parties to use the tool without additional financial outlays. In the aggregated model, 220 kV lines were connected to the nearest nodes of the 400 kV network.

51 The model operates on hourly data, for safety, the peak hourly line load during the whole year was used. A 30% buffer was required, among other things, to take reactive power into account and prevent line overloading in emergency situations (Hörsch, 2018).

Table 2. Technical parameters of extra-high voltage lines

Phase conductor	Voltage [kV]	Current-carrying capacity [A]	Resistance [Ω/km]	Maximum power [MW]
1xAFL-8 525mm2	220	1000	0.0564	381
3xAFL-8 350mm2	400	2368	0.0821	1640
3x408/24-A1F/UHST-261	400	2508	0.0709	1737
3x468/24-A1F/UHST-261	400	3126	0.0619	2166

Source: Internal analysis based on PSE specifications: (PSE, 2015) i (PSE, 2017a), Eltrim product catalog (Eltrim, 2020) and data from PTPiREE (PTPiREE, 2019).

in transmission networks beyond those defined in the TNDP are required in 2030. A heavy load is seen on north-south lines (Fig. 28), e.g. ZYD/ZDK – PKW – PLE, KRA-GOR-MIK, GDA/GBL/GDP – GRU – PLO, which, among other things, carry energy from wind farms to high demand nodes in the south of the country.

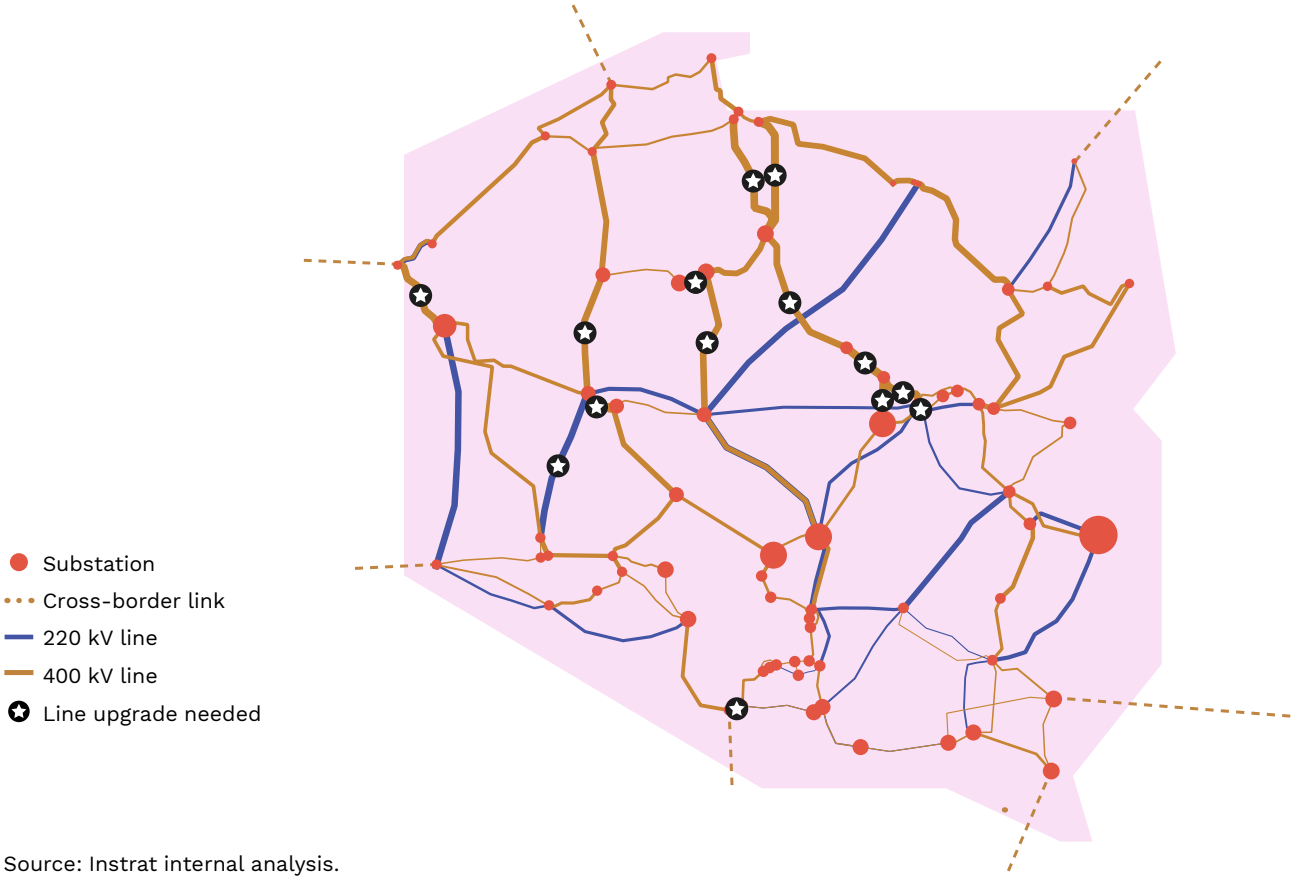
In the Instrat scenario, in 2030, it is necessary to replace one 220 kV line with a 400 kV line and to modernize[52] 12 existing 400 kV lines with a total length of 667 km. For one 119 km line currently under construction (GRU--PLO), the planned number of circuits is not sufficient - the peak load is 72 percent, despite the fact that it is a new line using the latest cable technology. It may be necessary to increase its capacity already during project implementation - e.g. by using a 3-circuit structure.

Additional investment costs in 2021-2030 resulting from the Instrat scenario were estimated at PLN 3 billion compared to the TNDP forecast. There are three types of investments:

- *220 kV line to 400 kV conversion;*
- *modernization/retrofit of an existing 400 kV without a need to increase the number of circuits;*
- *new 400 kV line or increasing the numer of circuits on an existing 400 kV line.*

52 Modernization is understood only as the replacement of conductors together with the modernization of the station, without the need to increase the number of circuits or run parallel lines.

Figure Z.1. Line loading in Instrat scenario in 2030



Source: Instrat internal analysis.

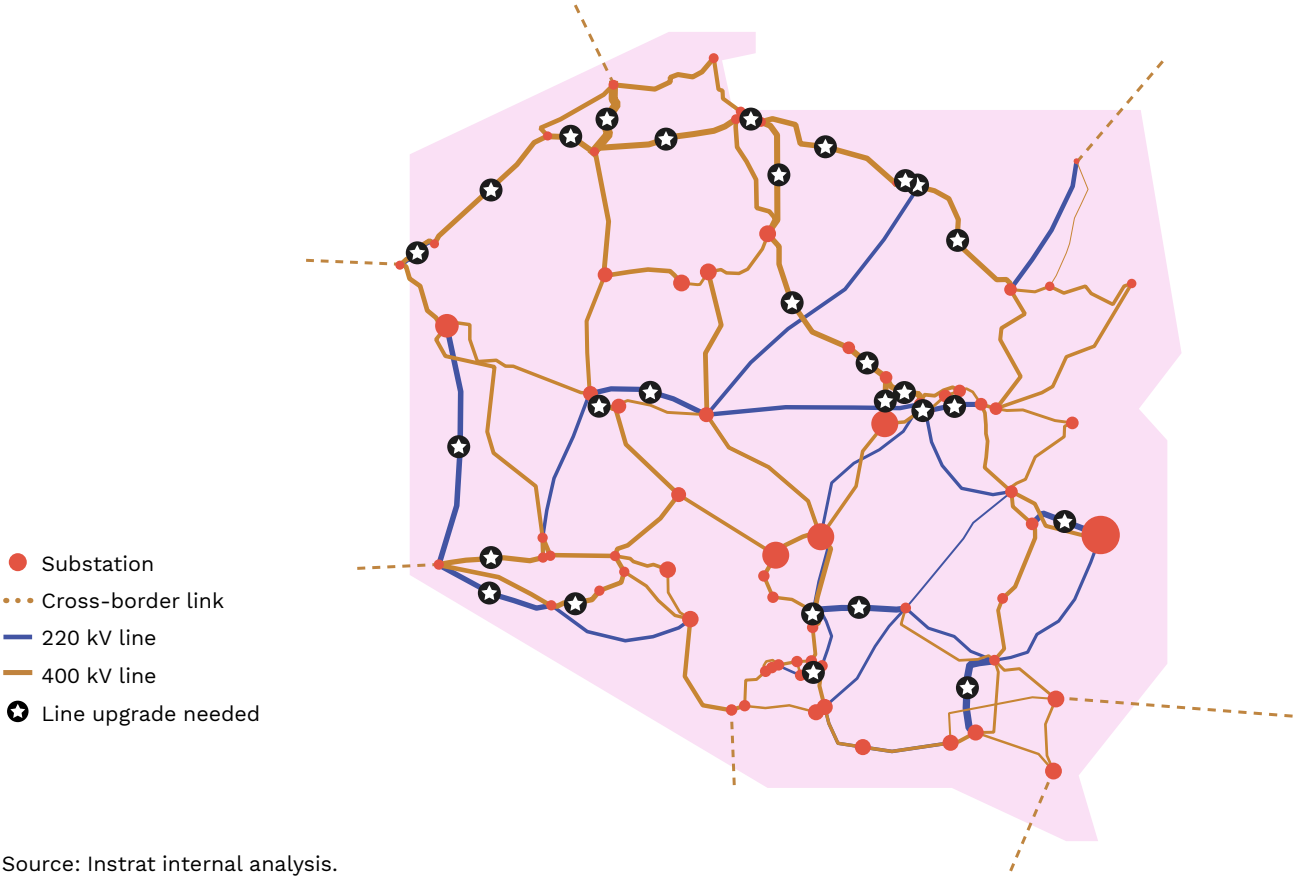
It was pessimistically assumed that in all these cases the investment costs per kilometer would correspond to the costs of building a new 2-circuit line together with the modernization of the stations - that is, the most expensive variant. Unit costs were estimated at PLN 3.32 million / km – the average for a dozen or so investments carried out or planned by PSE, for which information on the award of tenders for implementation was available[53]. As mentioned, these costs also include the cost of upgrading the station.

In the 2031-2040 perspective, investments in transmission networks are necessary in both scenarios, but in both cases their cost is lower than in 2021-2030. The PEP2040 scenario shows a further increase in the load on the north-south lines, resulting from both the development of offshore wind farms and the commissioning of a nuclear power plant[54] (Fig. Z.2). The lines around the Warsaw agglomeration are also overloaded, which may be caused by a significant increase in electricity demand compared to 2021 and

53 The information came from PSE's website (including przetargi.pse.pl), the amount of tenders for the construction of a new 2-circuit 400 kV line, including the modernization of the station, ranged from 2.5 to 5.4 million PLN / km.

54 In order to reduce the load on the grid in the north of the country, it has been assumed that only half of the nuclear power plant capacity will be built near Żarnowiec, the remaining 2.2 GW will be located in Bełchatów.

Figure Z.2. Line loading in PEP2040 scenario in 2040



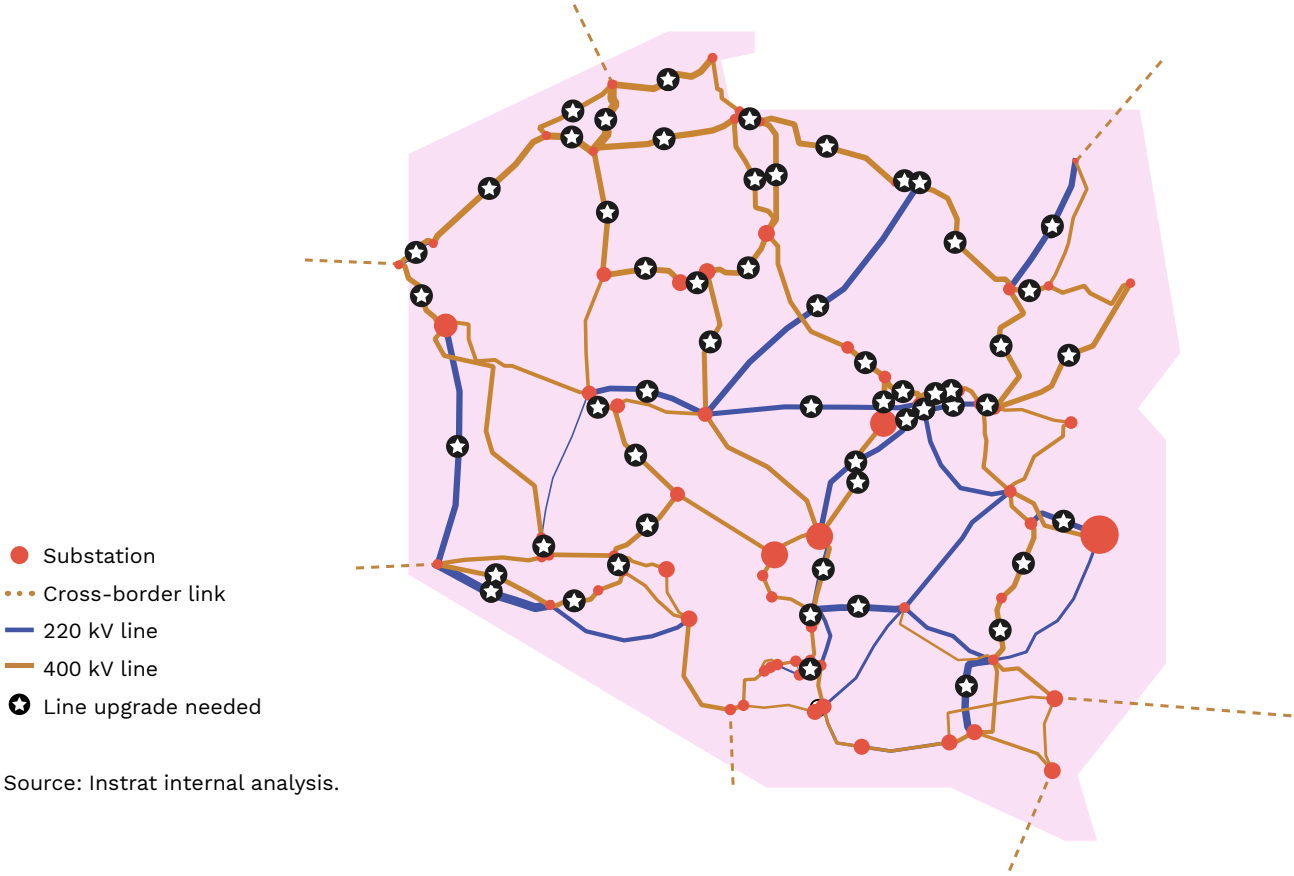
Source: Instrat internal analysis.

2030. It is necessary to increase the capacity of lines with a total length of 1,806 km. Nine of these lines (690 km) are 220 kV lines, which should be converted to 400 kV lines. 567 km of the existing 400 kV lines also require modernization, and 550 km of 400 kV lines require reconstruction (changing the number of circuits or running a parallel line). In total, in the PEP2040 scenario, investments in transmission networks in the years 2031-2040 will cost PLN 6 billion – two times less than in the 2021-2030 perspective.

It is worth noting that the proposed investments may not be the optimal solution in terms of load distribution in the network - the construction of lines along new routes was not considered, we've only accounted for the increase of the capacity of existing connections. On the other hand, laying out completely new lines is not only costly but logistically difficult, which also increases the possibility of delays in project implementation.

In the Instrat scenario for 2040, the scale of investments is significantly larger than in the PEP2040 variant (Fig. Z.3.). In total, 4003 km of lines require modernization or reconstruction (most being or planned to be 2-circuit). The largest pool of necessary investments concerns the reconstruction of the line, in particular the addition of a second circuit to the single-circuit line - 1,873 km. A modernization concerns 768 km of the existing 400 kV lines and 1,360 km of 220 kV lines (which are converted to 400 kV lines).

Figure Z.3. Line loading in Instrat scenario in 2040



Source: Instrat internal analysis.

The development of renewable energy sources requires significant investments in transmission networks, however, even taking into account the maximum load of individual lines during the year, the scale of additional network expansion is significantly smaller than it results from PSE's plans for 2021-2030 (Tab. Z.2.). This means that with adequate availability of financing (including EU funds), the costs of investment in transmission infrastructure should not constitute a barrier to the development of RES. It should be mentioned that in the Instrat scenario, the locations of large--scale energy storage facilities were not numerically optimized, because the preparation of their development plan was guided by information from prospective investors' (e.g. via press releases). Optimizing the location of battery energy storages could allow for a more even distribution of loads in the network and reduce the costs of its expansion.

Table Z.2. Necessary investments in transmission network [total line length in km]

	2021-2030	2031-2040	
	Instrat (on top of TNDP)	PEP2040	Instrat
Modernization of existing 400 kV lines	667	567	768
New 400 kV lines	119	550	1873
Modernization of 220 kV lines (including conversion to 400 kV)	120	689	1360
Total	**906**	**1806**	**4002**