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Scenario Analysis of the Development of the Polish Power System towards Achieving Climate Neutrality in 2050

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Abstract: The Polish power system has been reducing its impact on the environment for a long time, mainly through modernization and investments in new generation capacities, including renewable energy technologies. However, its starting point is still more difficult compared to other less coal-dependent power systems in the European Union. The study was conducted in the direction of optimizing the Polish energy mix of electricity generation from the perspective of 2050. Two energy scenarios for the possible transformation of the Polish power system towards achieving at least a 95% reduction in CO_2 emissions by 2050 with an increasing share of renewables were analyzed. The study was carried out with the use of the TIMES-PL model, which minimizes the total system cost over the analyzed time horizon. The model was calibrated according to data from 2018. The two scenarios show relatively similar pathways for CO_2 emission reductions by 2050. In the case of no investment in nuclear power plants, power plants equipped with CO_2 capture and storage systems are an alternative solution for achieving climate neutrality and increasing national energy security.

Keywords: power system; modeling; climate neutrality; renewables; nuclear power; CCS

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1. Introduction

Various factors are important for the functioning of power systems, depending on the considered horizon. In the short term, this is the demand for electricity and power. In the long-term, these are regulations, especially environmental regulations and prospects for price development, which, in combination, are crucial for investment decisions. Historically, the availability and prices of primary energy were the basis for the development of a rational structure of the fuel and energy sector of countries. Currently, the need to comply with European Union (EU) regulations, especially those related to climate protection, comes to the fore. Hard coal and lignite were and still are the basic carriers of primary energy in Poland. This is dominantly due to their large reserves. However, it should be expected that their use will be systematically reduced in favor of renewable energy sources (RES), mainly due to the EU energy and climate policy, whose fundamental goal is to achieve climate neutrality by 2050.

In order to strengthen actions aimed at achieving climate neutrality by 2050, a communication regarding the European Green Deal was announced by the European Commission on 11 December 2019 [1,2]. This is an EU strategy that provides guidelines and a comprehensive range of actions to enable EU countries to achieve the above goal. At the end of 2020, the European Council decided to update the greenhouse gas emissions reduction target adopted in the Paris Agreement for 2030. This target was increased from 40% to at least 55% relative to emissions from 1990 [2]. Despite the fact that Poland has been reducing the impact of its power system on the environment for a long time, mainly through modernization and investments in new generation capacities, including RES technologies, its starting point is still more difficult compared to other less coal-dependent EU countries. The energy transformation will require particularly decisive changes in the generation structure of the national power system in order to build a practically new zero-emission energy system in the period up to 2050. From the perspective of the next 20 years, we should expect significantly increased decommissioning of currently operating coal-fired units. This is largely due to the age-advanced generation structure of the national power system. More than two-thirds of the generation units currently existing in the Polish power system are more than 30 years old [3–5]. Moreover, most of these units are characterized by a significant number of hours worked. Another equally important factor determining shutdowns is the requirement to adapt coal-fired units to the increasingly stringent environmental restrictions set by EU policy. Such examples are the emission standards under (i) the Industrial Emission Directive (IED) [6] and (ii) the Best Available Techniques or Technology Conclusions (BAT) [7].

It should be highlighted that Poland actively participates in the process of shaping the European vision of energy sector development. The way to achieve climate neutrality in 2050 is to gradually shift from the use of fossil energy carriers to zero-carbon technologies. In official government documents, i.e., the "National Energy and Climate Plan for the years 2021–2030" (NECP) [8] and the "Energy Policy of Poland until 2040" (EPP 2040) [1], Poland commits to reduce the share of coal in the electricity generation mix to 56–60% by 2030 and to maintain the downward trend in the coming years. However, if the price of CO_2 emission allowances remains high, its share could be even lower, reaching a maximum of 37.5% [1]. The Polish government also plans to increase the share of RES in net electricity production to at least 32%, while in 2040 this share should not be lower than 40%. A key role in achieving RES targets will be played by offshore wind power plants, whose technological development among all currently available RES technologies is one of the fastest in the world. Therefore, the national power system is planned to have about 5.9 GW of electric capacity in the form of offshore wind energy by 2030, while in 2040, it is expected to be between 8 and 11 GW [1]. Onshore wind turbines will also be responsible for a significant part of the electricity generated from RES. In addition to the increase in the use of wind energy, we should also expect a further intensive increase in photovoltaic electric capacity. However, the assumptions made in [1] regarding an expected increase in capacity of between 5 and 7 GW by 2030 and between 10 and 16 GW by 2040 must be revised due to the partial implementation of these plans. In the case of nuclear energy, the total electric capacity of nuclear power plants in the Polish power system in 2043 is expected to be between 6 and 9 GW, with the first nuclear unit online in 2033 [1]. Nevertheless, it should be noted that despite the projected decline in coal demand, Poland's coal reserves will still be able to play an important role in maintaining the country's energy security. The future is expected to include investments in so-called clean coal technologies, such as integrated gasification combined cycle (IGCC) or fossil fuel technologies with carbon capture and storage (CCS) systems. Future demand for coal should be covered almost entirely by domestic production [8]. In connection with the above factors, the following questions arise: Is the development plan of the Polish power system presented in [1] feasible for the studied time horizon in the context of (i) the assumed CO_2 emission reduction targets and (ii) the minimum share of electricity generated from RES? Is this strategy, which assumes the use of nuclear energy (construction of at least six nuclear units by 2043) with increasing participation of RES technologies, optimal from the economic point of view, and what are the possible alternative strategies? Can fossil fuel technologies equipped with CCS systems provide an alternative option for decarbonizing the national power system? Will the captured CO_2 be able to be fully stored in Poland?

For many years, studies on energy system development have been conducted using computer-implemented mathematical models [9]. Historical trends in the development of energy system models were analyzed in [10], whereas the best practices for energy system optimization modeling were discussed in [11]. In the case of long-term planning of energy system development, the strategies developed most often concern the expansion of generation capacities. Considering a time perspective, such analyses usually cover a period of several decades. For this type of analysis, quantitative methods based on optimization modeling are usually applied for solutions, which mainly use mathematical programming [12]. A detailed overview of existing methods and techniques for comparison of energy system frameworks, models and scenario results was presented in [13]. Most studies used a quantitative approach. Taking into account the size and complexity of some problems occurring in the energy sector, a number of mathematical models have recently been developed to analyze the development of energy systems at various spatial (from local to global) and temporal scales. Depending on the approach applied to modeling of energy systems, these approaches can be used for the analysis of both individual sectors and systems covering all sectors of the economy. A recent review published in [14] examined key challenges in energy system modeling. Moreover, considering the detail of the representation of analyzed systems, we can divide them into bottom–up and top–down models. The first is an engineering approach that allows for suitable representation of a given energy system with an emphasis on its technical side of operation but without considering the links to the rest of the economy. A detailed classification of energy system models with special reference to the challenges of bottom–up models was presented in [15]. Most often, such models are partial equilibrium models [16]. This group includes PRIMES [17–19], POLES [20,21] PLEXOS [19,22], MARKAL [23,24], EFOM, MESSAGE [19,20] and TIMES [25–29], which is an integrated system of MARKAL-EFOM models developed within the framework of the Energy Technology Systems Analysis Program (ETSAP) of the International Energy Agency (IEA). These models are most frequently used to determine the optimal energy mix [30]. The second approach (top–down) is particularly used to create macroeconomic models with a more complex structure of economic relationships covering the entire economy. These types of models are computable general equilibrium (CGE) models [16]. This group includes the GEM-E3 model used by the European Commission. An example of modeling the energy mix and economic costs of deep decarbonization scenarios using CGE models was presented in [31]. The main advantages and disadvantages of top–down and bottom–up modeling were highlighted in [32].

To answer the above questions, the TIMES-PL model with a bottom–up approach was used. This model solves the issue related to the expansion of generation capacity of the Polish power system over a long time horizon, taking into account technical, economic and environmental constraints. The study was conducted in the direction of optimizing the fuel and technology structure of electricity generation from the perspective of 2050. The result of this study is the analysis of two energy scenarios for the possible transformation of the Polish power system towards achieving at least a 95% reduction in CO_2 emissions by 2050 compared to CO_2 emissions in 1990, with an increasing share of RES. The obtained results verify the development pathways for the Polish power system proposed in [33].

This paper complements previous studies on the development of the Polish power system in the context of the changing framework of the EU energy and climate policy. The first energy models for Poland were established in the 1980s [34]. In the following years, they became the basis of models used to prepare Poland's energy policy. Such an example is the model based on the EFOM methodology built in the 1990s [35]. Its usefulness was indicated not only for analyzing the problem of emissions but also for supporting strategic decisions on the development of the national power system. The current problems of transformation of the coal-intensive economy towards a high share of RES were the subject of [36–38]. Possible scenarios for the country's energy mix depending on the EU energy and climate policy were discussed in [30]. The impact of the EU Emission Trading Scheme (EU ETS) on power technology choice in modeling the long-term technological transformation of the Polish power system was studied in [24]. Optimization of the development of the Polish energy sector, taking into account air pollution and health effects, was presented in [39]. The impact of different levels of binding targets for the share of renewable energy in final energy consumption on the development of the Polish energy sector by 2050 was investigated in [40]. The inclusion of externalities in the evaluation of decarbonization scenarios for Poland was the subject of analysis in [41,42]. The combination of generation expansion and short-term planning models in one modeling system was demonstrated for the Polish power system in [43].

This paper is organized as follows. Section 2 describes the methodology, including the structure of the TIMES-PL model used in the analysis. Constraints and the objective function representing the optimization criterion are presented. The energy scenarios used in the analysis are also characterized. Section 3 illustrates the main results of the analysis, with a discussion in Section 4. Finally, Section 5 concludes the paper and mentions possible directions for future studies.

2. Materials and Methods

2.1. Methodology

The TIMES-PL model of the Polish energy system was used in this study. It was built with the use of the TIMES model generator, which has found applications in many projects around the world as a tool used to analyze energy systems at various temporal and spatial scales, from local [44] and national [26,28,45,46] to global [47,48]. Such a wide range of applications and such a well-described and verified methodology are undoubtedly its great advantages [49,50]. The authors' experience working with the TIMES model generator indicates that the obtained results are compatible with those produced by the models used by the European Union for analyses related to the introduction of new directives [27].

TIMES is a bottom–up partial equilibrium model based on dynamic linear programming. Under conditions of perfect market competition, a market equilibrium is established in the model. The model determines the flows of energy and materials, as well as their prices, in such a way that producers produce exactly the quantities that consumers are willing to buy. Producers are represented by energy technologies, while consumers are represented by demand. TIMES optimizes the operation of the system throughout the entire modeling horizon, with perfect knowledge of the future (perfect foresight approach). The task of the model is to indicate the optimal solution to meet the demand for energy services while maximizing the net total surplus (i.e., the sum of producer and consumer surplus). In general, all TIMES models have the same mathematical structure, including the objective function and equations (constraints). The objective function is defined as the discounted total system cost of the region(s) over the time horizon. This cost is minimized by the model. The main equations of the model include balances of energy, capacity, materials and pollutants. It is also possible to consider various constraints in the model, such as environmental, resource, technical and political constraints. These are also implemented in the model by equations. The main decision variables include the value of electricity and heat production in given technologies, the level of consumption of fuels and other goods in processes, new electric and thermal capacities, the amount of emissions, the level of import of goods, etc. Moreover, TIMES allows for a flexible division of the year into periods of time (time slices) [49–51].

The mathematical formulation of the objective function applied in the TIMES-PL model is described by Equation (1). The component costs included in the model's objective function cover investment costs, fixed and variable operating and maintenance (O&M) costs, fuel and CO_2 costs and decommissioning costs.

$$\mathrm{Obj} = \sum_{t \in T} \frac{1}{(1+r)^t} (\mathrm{INVCOST_t} + \mathrm{FIXCOST_t} + \mathrm{VARCOST_t} + \mathrm{DECOM_t}) \quad (1)$$

where:

Obj—discounted total system costs over the time horizon;
t—year;
T—set of years in which the costs occur;
r—discount rate;
INVCOST—investment costs;
FIXCOST—fixed operating and maintenance (O&M) costs (production-dependent);
VARCOST—variable operating and maintenance (O&M) costs (production-independent);

DECOM—decommissioning costs.

The modeling horizon in the TIMES-PL model covers the year 2050, while the base year is 2018. The temporal resolution beyond the base year and the next four-year period includes five-year periods. Results are given for the middle year of these periods (the so-called milestones year). Moreover, in TIMES-PL model, each modeling year is divided into 224 time slices considering 4 seasons (1R, spring; 2S, summer; 3F, fall; 4W, winter), 7 days of the week (1MO, Monday; . . .; 7SU, Sunday) and 8 three-hour periods of the day (1, 00:00–03:00; . . .; 8, 21:00–24:00). This division is shown schematically in Figure 1.

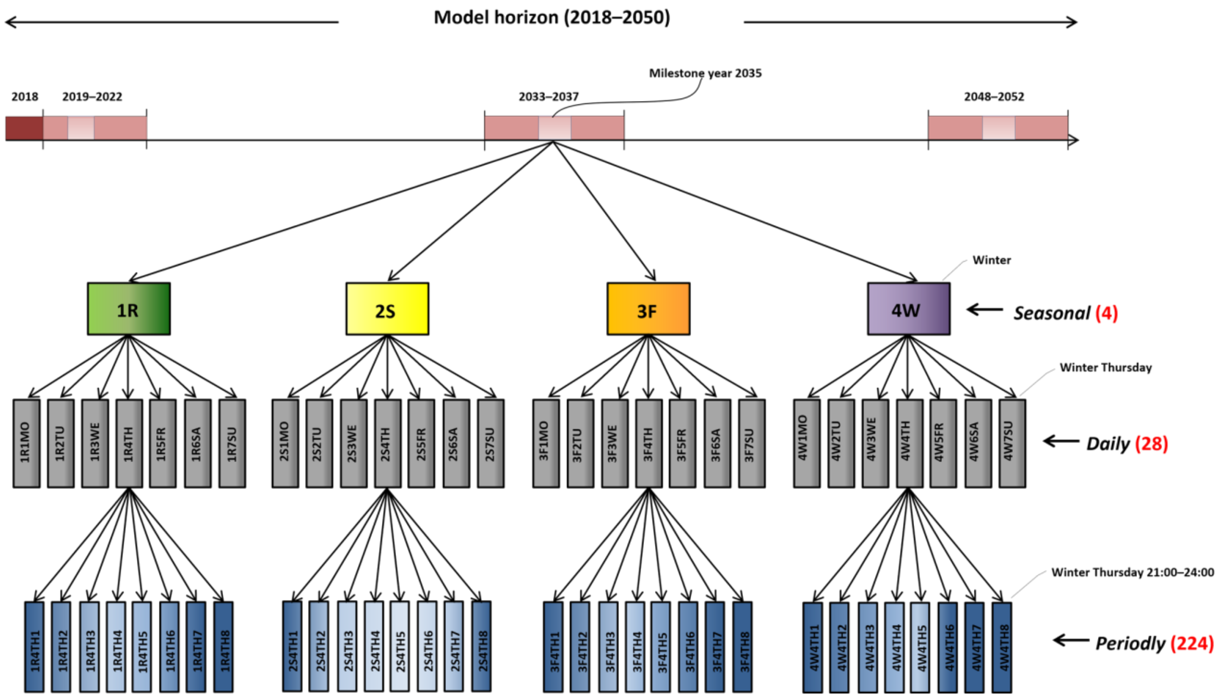

Figure 1. Visualization of the division of the modeling year into 224 time slices.

2.2. Description of the TIMES-PL Model

The current version of the TIMES-PL model consists mainly of (i) a centralized electricity and heat generation sector; (ii) other sectors, such as industrial (steel, cement and refinery), residential, transport and services and agriculture (in less detail) sectors; (iii) fuel supplies (both domestic and foreign sources are considered); and (iv) sets of new electricity and heat generation technologies and new processes for sectors (e.g., electric vehicles). The structure of the centralized electricity and heat generation sector (only existing objects) is presented in Figure 2.

The presented model structure includes all thermal power plants existing in 2018 (this year was chosen as the base year and for model calibration based on [52–54]). These are mainly hard coal and lignite power plants. Some of them are biomass-fired power plants. Each of the considered power plants was defined in the model by individual technical and economic parameters. Their total net electric capacity in 2018 was 22,671 MW. Electricity is also generated by onshore wind, solar and hydro power plants, including pumped-storage hydro power plants (used as energy storage technology in the model). These power plants are included in 'other power plants' category. The total net electric capacity of these power plants in 2018 was 9005 MW (with 1706 MW in pumped-storage hydro power plants). Existing professional and industrial combined heat and power (CHP) plants are also included in the model. They are equipped with a condensing or back pressure turbine. In both cases, they were aggregated depending on the fuel used. Their total net electric capacity in 2018 was 6806 MW and 2925 MW, respectively. In both types of CHP plants, selected natural gas and hard coal-fired CHP plants were represented individually.

Some of them have centrally dispatched generating units (in Polish, JWCDs). In addition, the model includes existing professional and non-professional heat-only plants. Their thermal capacity was aggregated according to the type of fuel used. The total thermal capacity in this group of heat producers in 2018 amounted to 22,422 MW. Moreover, the model takes into account modernizations and the commissioning of new generation units in the period of 2019–2021. The increase in electric capacity during this period, according to fuel used, was 2759 MW, 525 MW and 966 MW for hard coal, lignite and natural gas, respectively [52,55,56]. The largest hard coal-fired units were commissioned in the Opole (2 × 905 MW) and Jaworzno (910 MW) power plants, whereas 966 MW were installed in natural-gas-fired CHP plants (Stalowa Wola and Żerań).

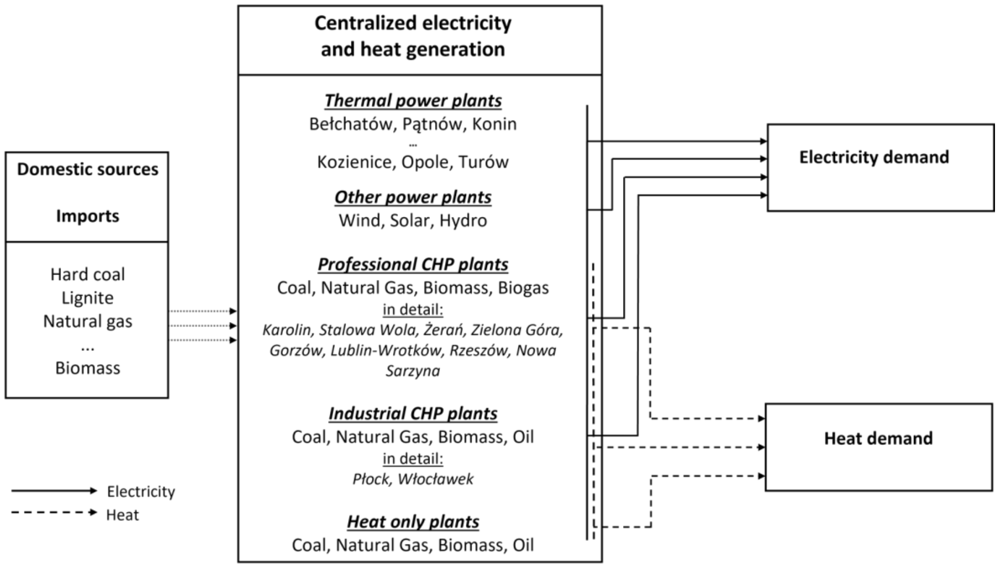

Figure 2. Simplified structure of the TIMES-PL model.

The existing generation capacities included in the model will be gradually phased out in accordance with the decommissioning schedule adopted in this paper based on information published by energy groups. Figure 3 presents both the capacity losses in MW broken down by the type of fuel used and the cumulative value of these losses in GW (grey line) from the perspective of 2050.

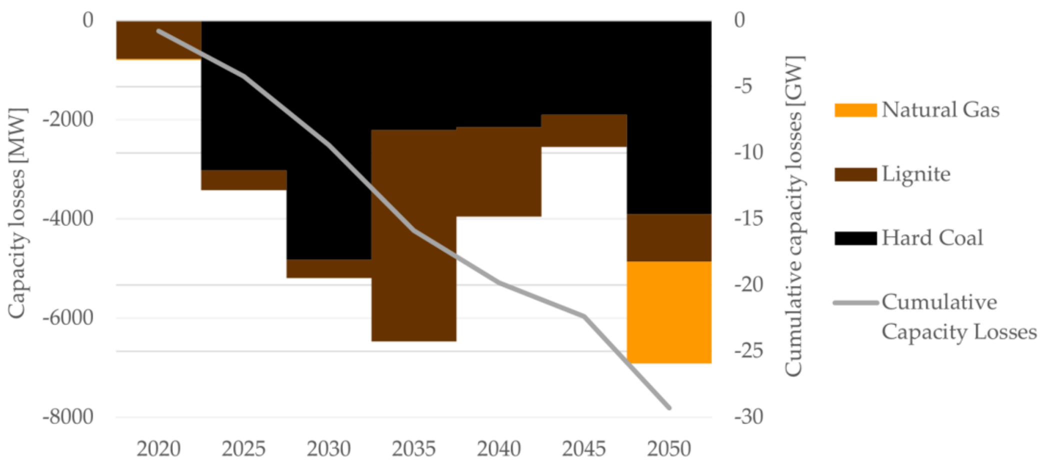

Figure 3. Planned decommissioning of the existing generation capacity by 2050.

Due to planned capacity retirements in existing power plants, the model can also apply new energy technologies. The set of new energy technologies used in this paper mostly corresponds to those presented in [33]. Moreover, generation units with a discrete size of electric capacity are included for major technology options, such as nuclear, gas and coal-fired power plants, as well as gas-fired CHP plants. Taking into account the growing share of electricity from RES, the model includes the possibility of investing in energy storage technologies. The use of this type of technology will contribute to improving the flexibility of power system operation. Energy storage will increase the balancing capacity of the power system in different time periods, as it will allow electricity to be stored during periods of increased production from RES and its reuse during periods of insufficient production. Nowadays, in the Polish power system, the function of energy storage technology is mainly conducted by pumped-storage hydro power plants. Promising prospective energy storage technologies include battery systems (used especially for short-term energy storage), compressed air energy storage (CAES) and hydrogen energy storage. However, considering the early stage of development of some of the above technologies, only one general type of new technology used for electricity storage with the parameters shown in Table A1 (see Appendix A) was included in the model.

All new energy technologies included in the model were characterized by technical and economic parameters such as unit investment costs (overnight cost is assumed), fixed and variable operating and maintenance (O&M) costs, net efficiency, CO_2 emission factor, start year and technical lifetime of the technology. A list of these technologies with their respective characteristics is presented in Table A1. O&M variable costs do not include fuel costs, as they were included separately in the analysis. It should also be emphasized that these parameters are among the most important factors determining the structure of generation capacity and electricity production. Taking into account the dynamically developing market of technologies based on the use of RES, a declining trend was assumed for the unit investment costs of this type of technology from the perspective of 2050. In the case of technologies for which generation units with a discrete size of electric capacity were specified, their costs were calibrated to Polish conditions [43]. All economic parameters are expressed in EUR. A discount rate of 7.5% was used.

2.3. Forecast of Electricity Demand

Future net electricity demand was considered an exogenous variable in the current analysis based on [33], the forecast of which covered the time horizon until 2040; hence, after this period, the net electricity demand was extrapolated to 2050. In addition, for the initial years of the analysis, i.e., 2018 (base year) and 2020, the above forecast was revised and corrected to actual data. An electricity balance (Table 1) including data on transmission and distribution losses, electricity demand in the energy conversion sector, the own consumption of power plants and the balance of cross-border electricity exchange as the difference between import and export of electricity was also developed. A positive value of this difference indicates net electricity import, while a negative value indicates net electricity export. For 2018 and 2020, the actual value of the electricity exchange balance was assumed to be 5.718 TWh and 13.224 TWh, respectively [57]. It should be noted that the current version of the model does not take into account cross-border electricity flows; hence, a value of 0 TWh for international electricity exchange was assumed for later years of the analysis. This value is in line with the forecast presented in [33]. Determining the future level of electricity import was not part of the scope of this work. Its level largely depends on the price of electricity in the various interconnected electricity markets. The development of the electricity balance was important from the point of view of the correct settlement of the obligation regarding the minimum share of electricity from RES in total electricity production.

Table 1. Electricity balance for modeling years in TWh.

	2020	2025	2030	2035	2040	2045	2050
Net final demand	132	152	165	178	192	204	217
Demand in the energy conversion sector	11	11	11	10	9	8	7
Transmission and distribution losses	8	9	10	11	11	11	12
Import–export	13	0	0	0	0	0	0
Net electricity production	138	172	186	199	212	223	236
Own consumption of power plants	14	15	14	12	12	11	10
Gross electricity production	152	187	200	211	224	234	246

Source: Own elaboration based on [33,57,58].

The current analysis assumes that the net final demand for electricity will increase from nearly 132 TWh in 2020 to approximately 217 TWh in 2050. This moderate growth in electricity demand, which was about 65% during the period, is mainly due to measures to increase energy efficiency, as well as the decreasing share of energy-intensive industries.

Taking into account the fact that each modeling year is divided into 224 time slices, it was assumed that the annual electricity demand will be distributed relative to this resolution. For 2018, it was distributed based on the actual hourly load profile provided in [59] (Figure 4, solid line). However, for 2050, the load profile presented by the European Network for Transmission System Operators Electricity (ENTSO-E) in [60] was adopted (Figure 4, dotted line). For this purpose, the sustainable transition (ST) scenario was used, which assumes a reduction in CO_2 emissions in the range of 80–95% by 2050. In addition, this scenario takes into account a moderate increase in both electric vehicles in the transport sector and heat pumps in the heating sector. As can be seen from Figure 4, there are no significant changes in the load profile between the current profile set for 2018 and the future profile set for 2050. The highest load values can be observed during the winter season.

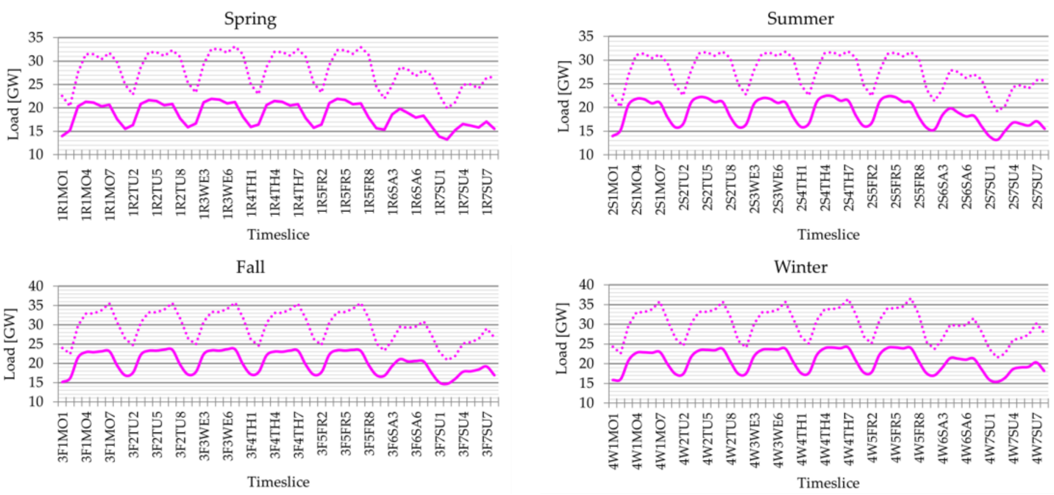

Figure 4. Load by time slice for seasons in 2018 (solid line) and 2050 (dotted line).

2.4. Forecast of Potentials of Primary Energy Sources

The present analysis assumes that there are no restrictions on the supply of hard coal and lignite. In the case of hard coal, it was assumed that its future demand will be met by domestic production; then, if necessary, it will be supplemented by import. The supply of domestic hard coal and lignite was based on the reference scenario of the research presented in [8]. This scenario for both fuels assumes a variant of increased supply. In the case of hard coal, both the increase in production in existing hard coal mines and the use of new resources not yet covered by the license were taken into account. According to these assumptions, the supply of domestic hard coal from the perspective of the analyzed time horizon will decrease from approximately 73 Mt in 2018 to 44 Mt in 2050. However, in the case of lignite, new lignite open pits were considered. Taking into account the properties of lignite, it was assumed that it will be used by power plants located near production sites. This will be particularly important for ensuring the appropriate amount of fuel in the final stage of operation of lignite-fired power plants.

In addition, the analysis assumes no limitation on import of natural gas, crude oil and uranium fuel. Achieving CO_2 reduction targets by 2050 will require increased use of RES. The RES potential assumed in this paper is mostly based on estimates presented in [33], according to which by 2040, the electric capacity estimated for onshore and offshore wind and solar power will be 10, 8 and 16 GW, respectively. After 2040, it was assumed that their growth will continue. In the case of hydropower, its potential is relatively small, and according to [33], it was estimated at about 8 TWh in terms of annual electricity production. Meeting CO_2 reduction targets also involves increasing the use of biomass and biogas. According to [33], it is expected that by 2040, the supply of solid biomass will increase by 62%. The demand for this type of fuel will be noticeable in all sectors, while the profitability of using biomass in the electricity and heat generation sector will be significantly influenced by the future price of CO_2 emission allowances.

2.5. Forecast of Fuel Prices

For the main imported energy carriers such as hard coal, natural gas and crude oil, it was determined that the level of their prices from the perspective of 2040 will be similar to the prices of fuels imported to the European Union presented in [33]. Moreover, it was assumed that the price of natural gas and crude oil will continue to increase, reaching a value of about EUR 9.4 and 16.8/GJ, respectively, in 2050. However, in the case of the price of hard coal, its further stabilization was assumed at a level of nearly EUR 2.7/GJ. This is mainly due to the policy adopted by the European Union aimed at achieving a low- and zero-emission energy transformation. It was assumed that the price of hard coal on the domestic market throughout the modeling period will be at the same level as the price of imported hard coal. In the case of lignite, the fuel price for existing and new open pits was distinguished. The extraction of lignite from new open pits involves higher costs associated with the necessary investments to start exploitation and, in some cases, with longer transport distances [8]. The remaining fuel prices were based on the information contained in [8]. The exception was uranium fuel, for which the price was assumed according to the forecast presented in [61]. The projected fuel prices used in the present analysis are included in Table 2.

Table 2. Forecast of fuel prices in EUR/GJ.

	2020	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Natural gas	5.5	6.9	7.6	8.0	8.4	8.9	9.4
Oil crude	8.0	10.7	12.1	13.3	14.3	15.6	16.8
Hard coal	2.2	2.6	2.7	2.7	2.7	2.7	2.7
Lignite	1.5	1.4	1.4	1.4	1.4	1.3	1.3
Lignite (new deposits)	1.9	1.9	1.8	1.8	1.8	1.7	1.7
Uranium fuel	0.8	0.9	0.9	0.9	1.0	1.1	1.3
Biogas	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Biomass	5.9	6.0	5.9	6.0	6.1	6.2	6.3

Source: Own elaboration based on [8,33,61].

2.6. Forecast of Price of CO_2 Emission Allowances under the EU ETS

The price of CO_2 emission allowances (European Union Allowances (EUAs)) under the EU ETS is a very important factor that has a significant impact on the shape of the future structure of electricity generation. Experience shows that the price of permits on the European Union's carbon market has a strong impact on electricity producers using fossil fuels, prompting them to undertake an energy transformation. The forecast of prices of CO_2

emission allowances under the EU ETS adopted in the paper is presented in Table 3. It is based on the projection derived from the scenario of high prices of CO_2 emission allowances included in the Energy Policy of Poland until 2040 [33]. The price of EUR 54/t in 2030 adopted in this document is consistent with the projections presented by the European Commission for the impact assessment of the 2030 Climate Target Plan, which includes a target of 55% reduction in GHG emissions by 2030. The European Commission's projections for CO_2 emission allowance prices are between EUR 32 and 65/t in 2030, depending on the scenario. The EUA price for 2020 presented in the forecast reflects the actual situation on the European Union's carbon market in this period and corresponds to an average annual price of allowances in 2020 of approximately EUR 25/t [62–64]. The sharp increase in the price of CO_2 emission allowances from EUR 17/t in 2018 to EUR 60/t in 2035 should be noted. According to the forecast presented in [33], the price is expected to stabilize at EUR 60/t until 2040, which was extended to the end of the modeling period.

Table 3. Forecast of prices of CO_2 emission allowances under EU ETS in EUR/t.

	2020	2025	2030	2035	2040	2045	2050
EUA price	25	35	54	60	60	60	60

Source: Own elaboration based on [33].

2.7. Scenarios

Two energy scenarios were considered in the current analysis. They were differentiated due to the role played by selected energy technologies. In the first scenario, i.e., the NUC scenario, a leading role was played by nuclear power plants, while in the CCS scenario, there were power plants equipped with CO_2 capture and storage (CCS) systems. These scenarios were developed using a normative approach, each with the aim of achieving at least a 95% reduction in CO_2 emissions in the public sector of electricity and heat production in Poland by 2050 compared to the level of CO_2 emissions in 1990. According to data published by the statistical office of the European Union, CO_2 emissions from fuel combustion in the Polish electricity and heat production sector in 1990 amounted to approximately 227 Mt, while in 2018, they reached a value of about 155 Mt [58]. Therefore, in all scenarios, the permissible level of CO_2 emissions was 10 Mt. The developed scenarios were also consistent in terms of achieving a minimum share of RES in net electricity production from the perspective of the analyzed time horizon. This target was set at a level of at least 40%, in line with the assumptions published in [1]. The main assumptions of these scenarios are shown in Table 4.

Table 4. Scenario characteristics.

Scenario	CO_2 Limit [1]	RES Limit [2]	Nuclear Technologies	CCS Technologies
NUC	≥95%	≥40%	Yes	No
CCS	≥95%	≥40%	No	Yes

[1] CO_2 emission reduction in the national electricity and heat production sector in 2050. [2] Net electricity production from RES in 2050. Source: own elaboration.

In addition, both scenarios assumed the same level of growth in demand for electricity and heat over the entire time horizon. Due to the considered high CO_2 reduction target, it was assumed that it is not possible to make investments in new coal technologies. The exceptions are power plants equipped with CCS (only CCS scenario) and investments to be commissioned by 2023, such as the lignite-fired unit at the Turów power plant with an electric capacity of 480 MW. It should also be mentioned that both scenarios assumed the same schedule for decommissioning of existing generation capacities. These are mainly coal-fired units. According to this plan, the last coal-fired units will be phased out in 2050 (see Figure 3).

Scenario Storylines

The NUC scenario assumed investments in nuclear power plants but without the possibility of building power plants equipped with CO_2 capture and storage systems. Nuclear power plants in this scenario were the only controllable conventional generation sources allowing the supply of CO_2-free electricity. Following the assumptions outlined in [33], it was assumed that the first unit of a nuclear power plant in Poland will be commissioned in 2033. Despite the remaining uncertainties related to the size of investment costs and the numerous opponents of nuclear power, this scenario did not assume delays in the commissioning of the first unit of a nuclear power plant. In the current analysis, the net electric capacity of a single unit of a nuclear power plant was assumed at a level of 1.3 GW. Moreover, it was assumed that in 2035, two such units will be included in the national power system. After 2035, further intensive capacity growth in nuclear power plants was considered. It was assumed that from the perspective of 2050, the total net electric capacity in nuclear power plants may amount to 10.4 GW, including 6.5 GW until 2045. The stage of commissioning of individual nuclear units and their total net electric capacity in the national power system by 2045 are similar to the assumptions presented in [1,33]. The price of uranium fuel adopted in the model additionally includes the cost of radioactive waste disposal. It was assumed that the uranium fuel will be obtained entirely from foreign resources. In this scenario, the prospective use of the potential of RES is consistent with that presented for the CCS scenario (Table 5). The total electric capacity in onshore and offshore wind farms, as well as in photovoltaic cells, by 2050 cannot exceed 16, 14 and 24 GW, respectively. Gas technologies also support the CO_2 emission reduction realized in this scenario.

Table 5. Cumulative maximum net electric capacity of new RES generation units in GW.

Technology	2030	2040	2050
Onshore wind	4.2	10.0	16.0
Offshore wind	6.0	10.0	14.0
Photovoltaics	6.0	12.5	24.0

Source: Own elaboration based on [1,33,65–69].

In contrast, the CCS scenario assumed no investment in nuclear power plants. Therefore, in this scenario, the only option to achieve the adopted CO_2 reduction target is power plants equipped with CCS systems and RES technologies. The use of power plants with CCS systems, on the one hand, allows for a smoother reduction in coal production and, on the other hand, allows the country to strengthen its independence from imported fuels during the first period of the energy transformation, i.e., until 2040. This scenario considered investments in classic coal technologies equipped with CCS systems, as well as those based on hard coal integrated gasification combined cycle (IGCC) with CCS systems. In addition, in the collection of available technologies with CCS systems, there were also natural gas-fired power plants based on combined cycle gas turbine (CCGT) technology. Two classes of power plants were distinguished due to the net electric capacity for IGCC technology, i.e., 175 MW and 350 MW, as well as for CCGT technology, i.e., 280 MW and 490 MW. The main technical and economic parameters of the above technologies are presented in Table A1. The current analysis takes into account that the first power plants equipped with CCS system in the Polish power system can be used in 2035. It was assumed that the CO_2 captured in this way will be fully stored in underground geological structures located in Poland. The estimated CO_2 storage potential presented in [8,70,71] allows for the above assumption. The cost parameters of fossil fuel technologies with CCS systems presented in Table A1 take into account the additional costs associated with transporting and storing the captured CO_2. Additionally, it should be noted that the increase in electric capacity in photovoltaic by 2040 will be achievable for the values presented in Table 5 [10]. The investments involve photovoltaic cells installed both on the ground and on the roof surfaces of buildings. Moreover, in the case of wind energy, no delays in the implementation of the investment program for the construction of offshore wind farms are expected. However, it was assumed that the trend of their development until 2040 will follow the capacity implied by the above forecast. After 2040, a further intensive increase in the use of these technologies is assumed (Table 5). The total electric capacity installed in wind and solar power plants in this scenario from the perspective of 2050 could be 54 GW.

3. Results

To provide some insights into the questions posed in the Introduction, simulations based on two energy scenarios (NUC and CCS) were carried out using the TIMES-PL model for the period from 2018 to 2050. The implementation of these scenarios required that total CO_2 emissions in the centralized electricity and heat generation sector not exceed 10 Mt in 2050. The most important results, such as electric capacity, electricity production, investment costs, fuel consumption and CO_2 emissions, are illustrated and discussed below.

3.1. Electric Capacity and Electricity Production

The results indicate significant changes in the capacity and electricity generation structure of the Polish power system from the perspective of 2050. These changes are evident in both scenarios included in the analysis, as shown in Figures 5 and 6.

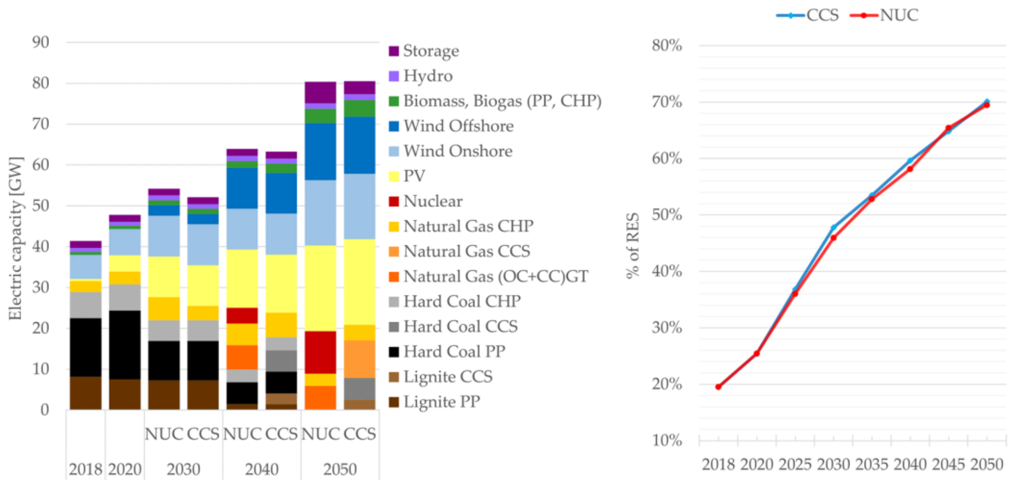

Figure 5. Capacity generation expansion (**left**) and share of renewable capacity (**right**) by 2050.

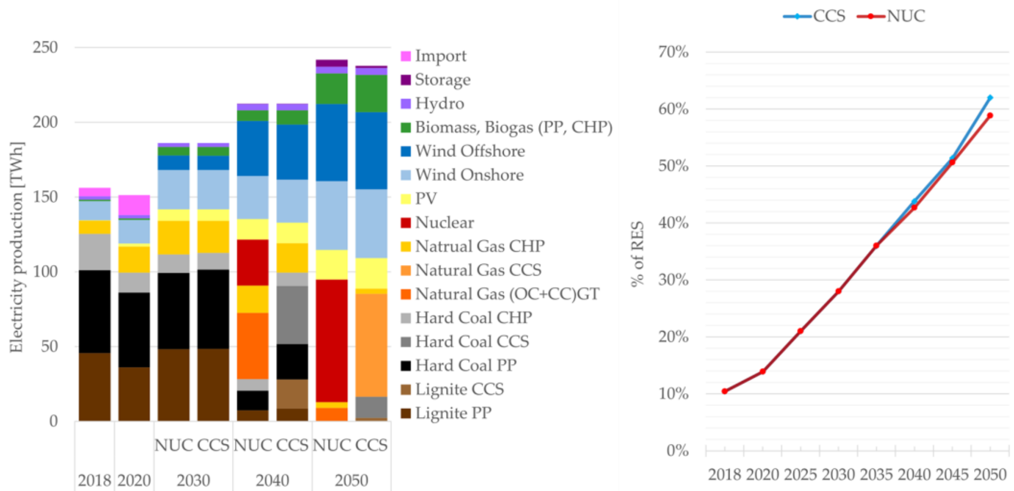

Figure 6. Electricity production (**left**) and share of renewable energy (**right**) by 2050.

The total net electric capacity in the entire modeling period increases from 41.4 GW in 2018 to about 80.3 and 80.5 GW in the NUC and CCS scenarios, respectively (Figure 5, left).

According to the NUC scenario, the first two generation units of nuclear power plants will be built by 2035. All nuclear units in 2050 will be responsible for 10.4 GW of net electric capacity (Figure 5, left). The amount of net electricity produced by nuclear power plants increases from 20.5 TWh in 2035 to nearly 82 TWh in 2050 (Figure 6, left). In the future, a decreasing share of coal-fired units in the electricity generation structure will be noticeable. In the case of lignite, a significant decrease in electric capacity takes place after 2030, when the capacity is reduced by more than 50% relative to 2025. By 2050, the share of coal-fired units drops to zero. However, it should be emphasized that the share of electricity from coal initially decreases gradually from about 66% in 2020 to approximately 60% (112 TWh) in 2030 (a trend similar to that shown in [33]); then, it drops considerably to about 13% (28 TWh) in 2040 and 0% in 2050. Part of this energy is generated in hard coal-fired CHP plants. It should be noted that in the generation structure in 2050, fossil-fuel-based technologies are exclusively gas-fired power plants. They will play a key role in balancing the power system due to their higher flexibility of operation. The total share of gas capacity in 2050 will be more than 11%. A significant part of this capacity (nearly 6 GW) will remain in CCGT and OCGT power plants. The share of gas technologies in net electricity generation will be particularly noticeable between 2035 and 2045 (the average for this period will be about 33%). By 2050, it declines because of a sharp increase in net electric capacity in nuclear power plants (an increase of about 60% compared to the capacity level in 2045). Energy storage technologies will also be used to a greater extent during this time (an increase in capacity of over 3.5 GW relative the capacity level of 2045). Simultaneously, the use of RES is growing. Their share in total capacity increases from 20% in 2018 to about 58% in 2040 and to about 69% in 2050 (Figure 5, right). This situation is particularly influenced by investments in wind power plants and solar power plants. The former will achieve 16 and 14 GW in onshore and offshore wind turbines, respectively. They will produce 46 and 52 TWh of electricity in 2050, respectively. The latter will reach 21 GW of electric capacity in 2050 (45 times more than the capacity in 2018). In contrast, as illustrated in Figure 6 (left), solar power plants will produce about 2.5 times less electricity compared to wind turbines, with nearly 30% and 50% more capacity in photovoltaic cells than in onshore and offshore wind turbines, respectively.

The implementation of the CCS scenario is an opportunity to extend the use of coal in the national power system, with fossil fuel technologies equipped with CCS systems (Figure 5, left). The largest number of investments in coal-fired power plants equipped with CCS system will occur between 2035 and 2040. By 2050, their total electric capacity will be about 7.8 GW, including 5.2 GW on hard coal and 2.6 GW on lignite. Natural gas will total about 9.2 GW in gas-fired power plants equipped with CCS systems and almost 3.8 GW without such systems. It is worth noting that the share of electricity from coal decreases to about 47% in 2040 instead of 13% as in the NUC scenario. After 2040, the implementation of the CCS scenario means an increase in the use of natural gas for electricity production, mainly in gas-fired power plants equipped with CCS systems. The share of natural gas in the electricity generation structure increases from about 9% in 2040 to about 17% in 2045 and to about 30% in 2050. Meanwhile, the share of RES technologies in the capacity structure of the CCS scenario remains at a similar level to that presented in the NUC scenario. The total share of electricity generated from renewables in 2050 will reach 62% (compared to 59% in the NUC scenario).

3.2. Investment Cost

According to the model results, the highest total investment costs are associated with meeting the assumptions of the NUC scenario. The costs related to capacity expansion in the period of 2025–2050 will amount to approximately EUR 145 billion (Figure 7) and EUR 129 billion (Figure 8) for the NUC and CCS scenarios, respectively. In the case of the NUC scenario, the highest annual investment costs occur in 2050, and they are mainly linked to investments in nuclear power plants. They account for about 50% of all costs incurred in this year (Figure 7, left). In contrast, the CCS scenario will require the highest annual investment costs in 2035, when the national power system adds the capacity of coal-fired power plants equipped with CCS systems (Figure 8, left). These costs will constitute about 50% of all investment expenditures incurred during this time and about 60% of those in power plants.

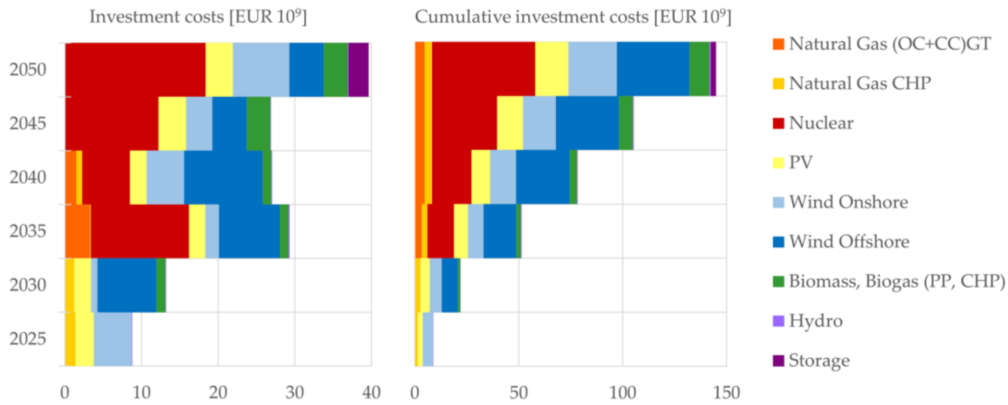

Figure 7. Investment costs in the NUC scenario.

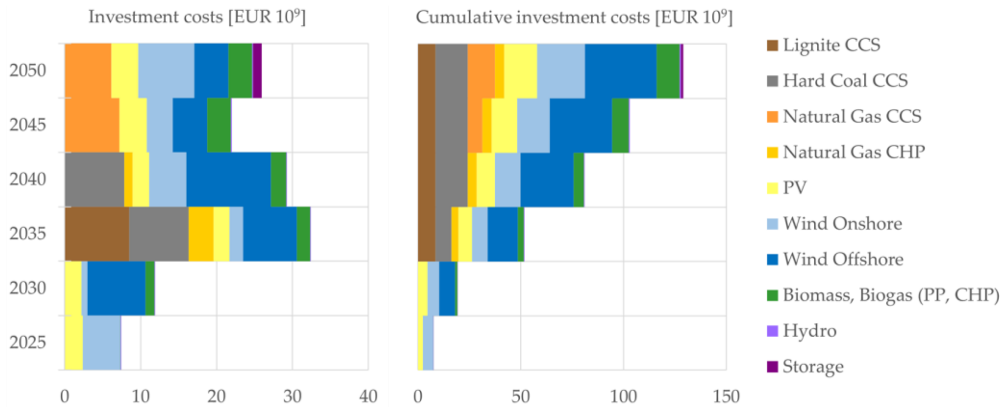

Figure 8. Investment costs in the CCS scenario.

The largest number of investments related to replacement and expansion of generation capacity is found in the power plant group (see Figures 9 and 10) in both energy scenarios. This is primarily due to the age-advanced generation structure of the national power system and the increasing requirements for reduced emissions. They account for approximately 89% and 87% of total investment costs in the NUC and CCS scenarios, respectively.

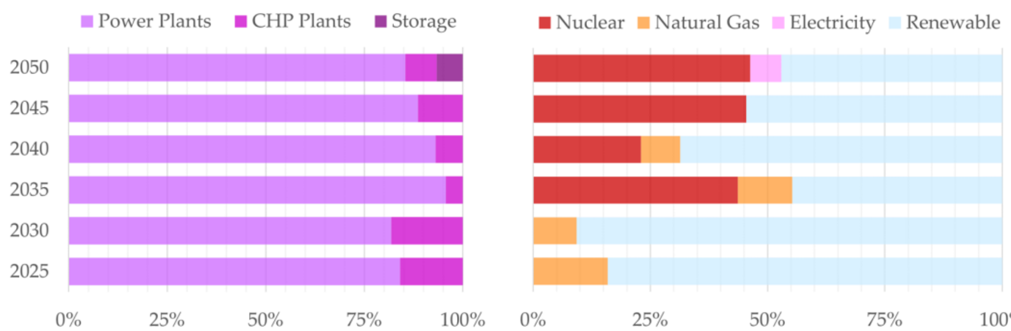

Figure 9. Investment costs by place of investment (**left**) and by fuel (**right**) in the NUC scenario.

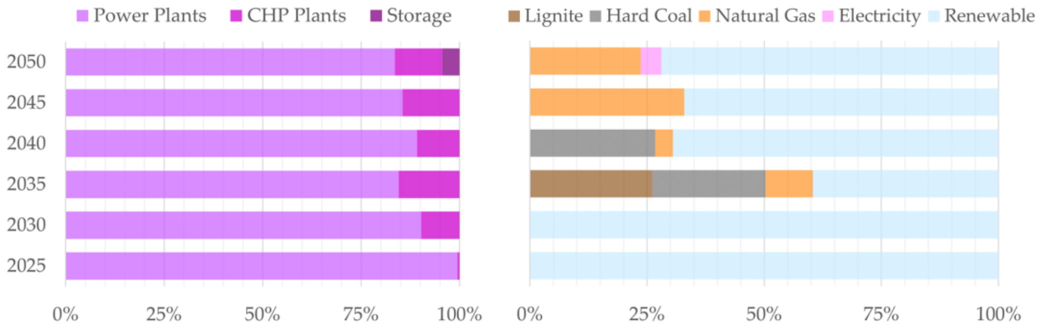

Figure 10. Investment costs by place of investment (**left**) and by fuel (**right**) in the CCS scenario.

3.3. CO_2 Emissions

In both scenarios, at least a 95% reduction in CO_2 emissions is achieved in 2050 compared to the level of CO_2 emissions from 1990. This target allows for total emissions in the electricity and heat production sector of about 10 Mt CO_2 in 2050. The CO_2 emission reduction pathways under the considered scenarios are presented in Figure 11. These results are compared with the CO_2 reduction pathway published in [33] (EPP 2040 scenario).

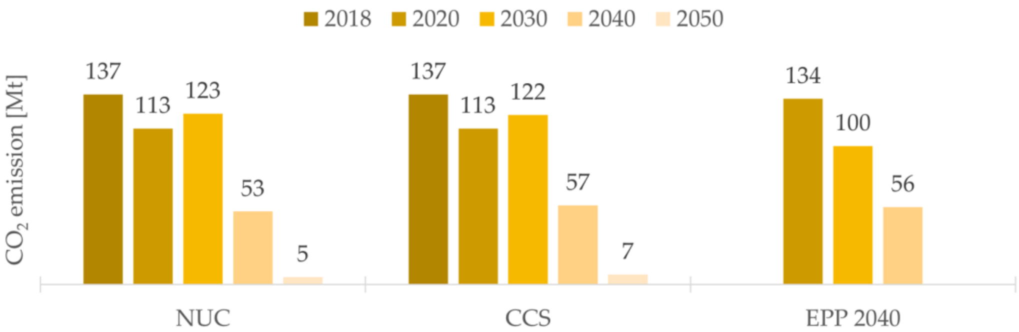

Figure 11. CO_2 emissions in the electricity and heat production sector.

The results show relatively similar pathways to the required maximum level of CO_2 emissions from the perspective of the analyzed time horizon. In both scenarios, CO_2 emissions are reduced equally by 2030. This is mainly due to almost identical generation structures during this period. In addition, due to the assumptions made in the scenarios, some low- and zero-carbon technologies, such as fossil fuel technologies equipped with CCS systems and nuclear energy technologies are not yet available for this period. The lower CO_2 emissions in 2020 compared to those presented in [33] (EPP 2040 scenario) are due to lower electricity demand caused by the COVID-19 pandemic. Differences in CO_2 emissions between NUC and CCS scenarios are visible from 2030. Then, the decommissioning of coal-fired units and the use of low- and zero-carbon technologies have a particular impact on reducing emissions. Therefore, the CO_2 emission reduction pathways shown in Figure 11 strongly depend on the electricity generation structures achieved in each scenario. In the case of the NUC and CCS scenarios, the key elements in achieving the CO_2 reduction target, besides the use of RES, are investments in nuclear power plants and fossil-fired power plants with CCS systems, respectively. The largest decrease in CO_2 emissions will occur between 2030 and 2040, when the decommissioning of coal power plants is greatest (about 6.5 GW of electric capacity will be retired in 2035). The average amount of CO_2 emissions reduced during this time will be approximately 60 Mt. It is worth mentioning that due to the increasing marginal costs of reducing emissions, removing each additional ton of CO_2 is becoming more and more expensive. Total CO_2 emissions fall from about 137 Mt in 2018 to some 53 and 57 Mt in 2040 and to about 5 and 7 Mt in 2050 in the NUC and CCS scenarios, respectively.

The largest reduction in CO_2 emissions in the considered time horizon is achieved in the NUC scenario (about 97.5% of reduced CO_2 emissions in 2050 compared to CO_2

emissions in 1990). The use of nuclear power is a factor that has a significant impact on the amount of CO_2 emission reduction achieved (the largest decreases are achieved during periods of commissioning of new units of nuclear power plants). In the case of the CCS scenario, the level of CO_2 emission reduction by 2050 will amount to approximately 96.8%.

The use of power plants equipped with CCS systems in the period of 2035–2050 will avoid a total of about 754 Mt of CO_2 emissions (Figure 12, right). This result fits exactly into the CO_2 storage capacity available in domestic hydrocarbon deposits published in [70], which was estimated at 764 Mt (assumed volumetric replacement of hydrocarbons with supercritical CO_2 at a ratio of 1:1). It should be added that this estimate does not take into account the CO_2 storage potential available in deep aquifers of geological structures.

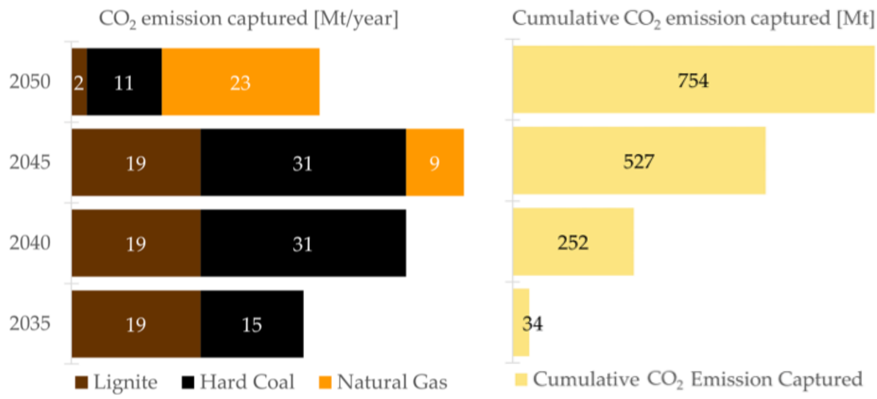

Figure 12. CO_2 emissions captured by fossil fuel technologies with CCS systems.

The implementation of low- and zero-carbon technologies in the national power system reduces the average CO_2 emission factor for power plants and CHP plants (Figure 13). Taking into account the CO_2 emission reduction pathways and electricity generation structures obtained in both scenarios, the calculated CO_2 emission factor decreases from 878 kgCO_2/MWh in 2018 to 662 and 657 kgCO_2/MWh in 2030 and to 248 and 269 kgCO_2/MWh in 2040 for the NUC and CCS scenarios, respectively. In 2050, the average value from the obtained CO_2 emission factors for power plants and CHP plants will be about 27 kgCO_2/MWh, with the lowest emission factor achieved in the NUC scenario (about 22 kgCO_2/MWh).

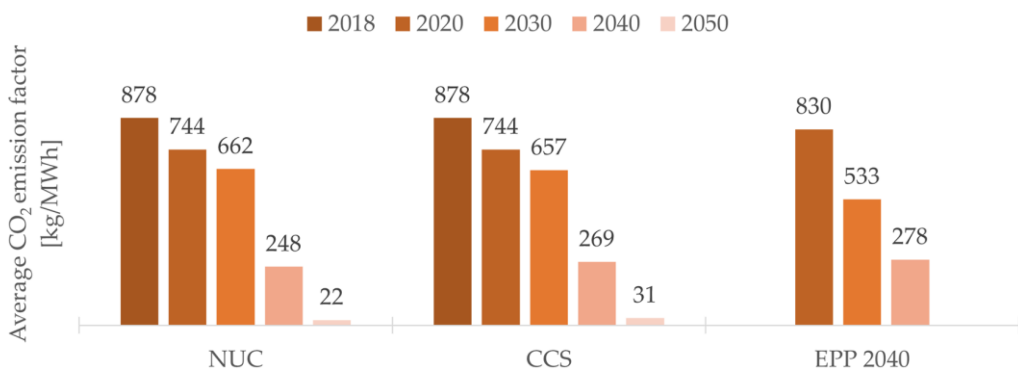

Figure 13. The average CO_2 emission factor for power plants and CHP plants.

3.4. Fuel Consumption

The transformation of the Polish power system from the perspective of 2050 based on the implementation of both scenarios leads to a transition from high-carbon fuels such as hard coal and lignite to lower-carbon fuels such as natural gas and zero-carbon fuels such as uranium fuel or RES (Figure 14).

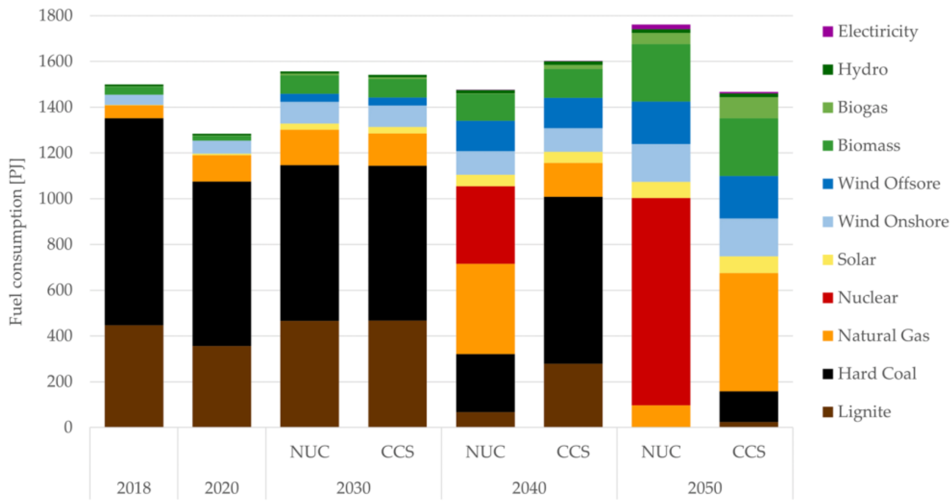

Figure 14. Fuel consumption for 2018–2050 for both scenarios.

The plan adopted in the analysis for the decommissioning of coal-fired units and the lack of investment opportunities in new generation units based on the use of hard coal and lignite cause a definite decline in demand for the above fuels from the perspective of 2050 (Figures 15 and 16). Additional factors that are not favorable to electricity generation from coal include the rising price of CO_2 emission allowances and increasingly stringent emission restrictions.

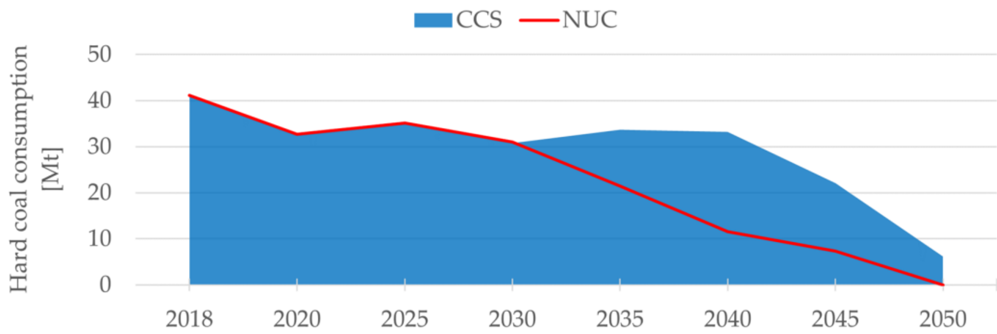

Figure 15. Hard coal consumption for 2018–2050 for both scenarios.

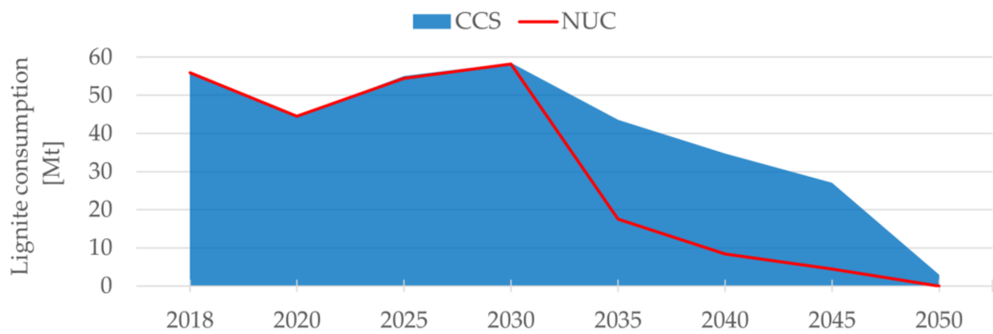

Figure 16. Lignite consumption for 2018–2050 for both scenarios.

The exception is the CCS scenario, where the possibility of investing in coal technologies equipped with CCS systems was considered (blue area above the red line in Figures 15 and 16). The use of this type of technology will help mitigate the reduction in hard coal and lignite production and extend the period of use of these fuels in the national power system. In addition, their use will have a positive impact on energy security by increasing the country's independence from imported fuels. This will be particularly noticeable in the period up to 2040, when there is a significant decommissioning of coal-fired units (see Figure 3) and when they are replaced with new energy technologies. It is worth noting that during this time, demand for hard coal will gradually increase, reaching 33.2 Mt in 2040. In the case of lignite, the use of power plants equipped with CCS systems will help soften the decline in consumption of this fuel, reaching consumption of 34.8 Mt in 2040. The total consumption of hard coal and lignite in 2050 will amount to 6.1 and 2.9 Mt, respectively. The situation is different in the NUC scenario, where in the period up to 2040, decreasing electricity production from hard coal and lignite will be substituted by generation based on natural gas (Figure 14). According to the results of the NUC scenario, demand for hard coal and lignite will drop from about 31 and 58.2 Mt in 2030 to 11.5 and 8.4 Mt in 2040, respectively, then to 0 Mt in 2050 for both scenarios.

Decarbonization of the national power system under both scenarios requires increased use of natural gas (Figure 17). This is affected not only by the aforementioned retirements of existing generation units but also by the increase in the use of RES technologies.

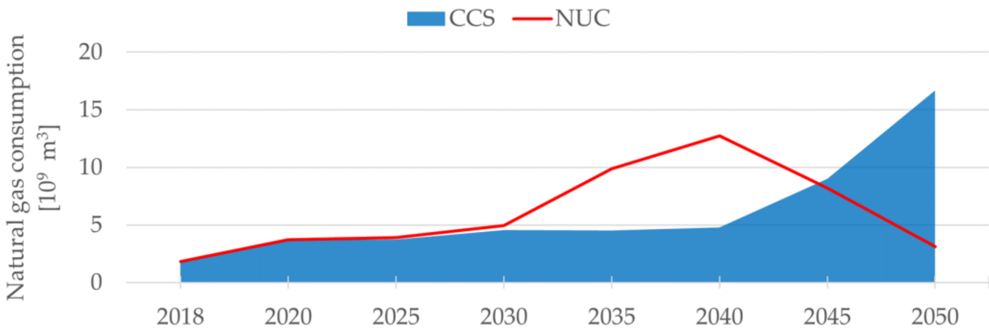

Figure 17. Natural gas consumption for 2018–2050 for both scenarios.

In the NUC scenario, natural gas consumption will peak in 2040, when nuclear power is at an early stage of use. This consumption in 2040 will be 12.7 billion m^3 (an increase of nearly 3.5 times compared to gas consumption in 2020). Thereafter, demand for natural gas diminishes due to a sharp increase in electricity production in nuclear power plants. In 2050, natural gas will be consumed only in CHP plants and in CCGT and OCGT power plants, which will additionally provide a backup for the operation of the power system. The total consumption of natural gas in 2050 will be about 3.1 billion m^3. In contrast, the implementation of the CCS scenario in the period up to 2040 will not be conducive to increasing the use of natural gas due to the significant development of coal technologies with CCS systems. Natural gas will be used more in CHP plants, while retired coal-fired units will be replaced by new units equipped with CCS systems. In the meantime, natural gas consumption will gradually increase from 3.7 billion m^3 in 2020 to about 4.6 billion m^3 between 2030 and 2040. An increased use of natural gas occurs after 2040 in a situation of increases in both CO_2 emission allowance prices and CO_2 emission limits. During the last ten years of the modeling period, there will be a significant increase in net electric capacity in gas technologies equipped with CCS systems (an increase from 0 GW in 2040 to 4.76 GW in 2045 and 9.24 GW in 2050). The demand for natural gas in 2050 will be almost two times higher than gas consumption in 2045, reaching 16.7 billion m^3 (the highest value in both scenarios in the modeling period).

4. Discussion

The changes in the capacity structure of the national power system presented above are clearly reflected in the structure of electricity production. They are particularly evident after 2030, when coal-fired units increasingly begin to be decommissioned from the system (this includes both permanent retirements and reductions in their operating hours). These changes are primarily the result of the growing requirements of the European Union regarding the reduction in CO_2 emissions. The ambitious CO_2 reduction plan adopted in the analysis, combined with the projected increase in the price of CO_2 emission allowances, leads to increased use of low- and zero-carbon electricity generation technologies. Their degree of use depends largely on the assumptions of the considered scenarios. In the case of the NUC scenario, the use of nuclear power becomes an important element in the development of the national power system. This includes both securing the operation of the system (replacement of aging coal-fired units operating in the load base of the system) and achieving the required reduction in CO_2 emissions. By 2050, more than 10 GW of net electric capacity will be built in nuclear power plants, with the first two units commissioned by 2035 (assumptions consistent with [33]). This translates into a total of eight high-capacity nuclear reactors integrated into the power system with a large share of RES technology. It should be added that the calculated capacity factor of nuclear power plants exceeds 90%. Such a series of reactor orders spread over a twenty-year period provides an opportunity to increase the competitiveness of the supply chain. The use of large units thanks to economies of scale allows for minimization of the cost of electricity generation. The NUC scenario is characterized by the highest reduction in CO_2 emissions (about a 97.5% reduction in CO_2 emissions in 2050 compared to CO_2 emissions in 1990).

An alternative to the implementation of nuclear power plants in the national power system is the CCS scenario, which involves fossil fuel technologies equipped with CCS systems. The use of technologies equipped with CCS systems is also an important option for further, less limited use of fossil fuels (especially hard coal and lignite) in the Polish power system despite the prospect of increasing CO_2 emission allowance prices. In this way, it is possible to postpone the moment of abandoning the use of coal in the power system. The use of coal-fired power plants with CCS systems is particularly important in the period up to 2040 (the first period of the energy transition), leading to less dependence of the national power system on imported fuels during this time, thus strengthening the country's energy security. The total consumption of hard coal and lignite in 2040 is about three and four times greater, respectively, than the consumption of these fuels in the NUC scenario. It is worth mentioning that the capital costs of a new power plant with CCS systems assumed in the analysis are within the range of costs given in [72]. The only important issue for the degree of use of these technologies in the power system is the national capacity to store captured CO_2. According to the results of the CCS scenario, the cumulative amount of CO_2 captured in the period between 2035 and 2050 will be about 754 Mt. Thus, on average, about 50 Mt of CO_2 would have to be stored/utilized annually. In accordance with [70] and the opinions of experts implementing the project entitled "Strategy for the development of CO_2 capture, transport, utilization and storage technologies in Poland and the Piloting of the Polish CCUS Cluster", this is feasible. In this scenario, the level of CO_2 emission reduction in 2050 is 96.8%.

It should be noted that balancing the future growing demand for electricity would not be possible without increasing the capacity available in RES technologies. In all scenarios considered, there is a significant increase in the use of RES technologies in the generation structure of the national power system. The development of offshore wind energy and solar energy is particularly visible. In contrast, a gradual increase in the use of onshore wind energy is seen by 2025. Then, in the period up to 2040, due to the retirement of existing generation capacities and the construction of new wind turbines in their place, a constant level of their total capacity is maintained. Only after 2040 is there a significant increase in electric capacity in onshore wind farms, reaching 16 GW in 2050 in both scenarios. The share of electricity from RES (solar, wind, biomass, biogas and hydro) from the perspective of 2050 will be about 59% and 62% for the NUC and CCS scenarios, respectively.

Achieving a minimum of 40% of net electricity produced from RES in 2050 is possible if the national power system is expanded with gas technologies and energy storage, which has the advantage of being able to operate in generation and demand modes. Depending on the technology applied, energy storage can be used during frequency and power regulation, as well as in daily (short-term operation) and seasonal balancing of the power system. The use of gas technologies, particularly CCGT and OCGT gas-fired power plants, increases the flexibility of power system operation. Their main role will be to ensure adequate regulatory and reserve capacities. The exception is the CCS scenario, where the CCS equipment allows these power plants to operate longer during the year. Natural gas consumption in power plants and CHP plants in this scenario increases to about 17 billion m^3 in 2050. In this context, it is important to implement the investment plans outlined in [1] concerning the development of both national network infrastructure and new cross-border connections. Therefore, it was assumed that the planned diversification of gas supplies (LNG terminal in Świnoujście, Baltic Pipe and Polish natural gas deposits in part of the Norwegian Sea) will first allow the country to become independent of natural gas supplies from the eastern direction and, secondly, together with its own capabilities, ensure that the forecasted demand is covered. In addition, it should be noted that natural gas will also be used to a greater extent in CHP plants (replacing carbon-intensive hard coal-fired units).

From the perspective of several years, the nature of the operation of many hard coal-fired units (mainly those with a capacity of 200 MW and 300 MW) will change from electricity supply to readiness to supply power to the system [73]. This will be mainly due to broad technical considerations such as advanced age and the need for modernization in the context of tightening environmental emission standards (BAT conclusions). The decrease in electricity production in these units will be compensated for by the generation of electricity by high-capacity generation units (current and under construction). In total, about 4.5 GW of net electric capacity in all hard coal-fired units is planned to be retired by 2030. In the case of lignite-fired units, their use will also decrease, but this will only become noticeable after 2030. Nevertheless, it is worth pointing out that the price of CO_2 emission allowances, which has been rising at a very fast pace recently, may lead to a situation where the phase-out plans for coal-fired units adopted in the analysis may accelerate further. According to the decommissioning schedule adopted here, the total net electric capacity in hard coal and lignite power plants in 2040 is expected to be about 5.3 and 1.5 GW, respectively. The CCS scenario shows that the first coal-fired power plants equipped with CCS systems can be used in 2035 in the case of gas supply constraints and no investment in nuclear power plants.

5. Conclusions

This paper presents the results of a study on the long-term development of the power system in Poland. For this purpose, the TIMES-PL model was used to develop two scenarios for the possible transformation of the Polish power system towards achieving climate neutrality in 2050. Their main goal was to achieve at least a 95% reduction in CO_2 emissions in the electricity and heat production sector in 2050 compared to CO_2 emissions in 1990. They were differentiated due to the role played by selected energy technologies. In the NUC scenario, nuclear power plants played the leading role, while in the CCS scenario, fossil fuel power plants equipped with CCS systems were predominant. In both scenarios, it was assumed that a minimum of 40% of net electricity should be produced from RES. The TIMES-PL model solves the problem of generation capacity expansion from the perspective of 2050 by taking into account a number of technical, economic and environmental constraints. Optimization of the energy mix is carried out in terms of developing the structure of generation capacity and electricity production. The model takes into account new energy technologies, which are described by a number of technical and economic parameters. The objective function (decision criterion), which is minimized by the model, in this case corresponds to the sum of the long-term marginal costs of electricity generation.

The results of the analysis lead to the conclusion that the assumed CO_2 emission reduction target imposed by the European Union's decarbonization policy will cause significant changes in the fuel and technological structure of the Polish power system by 2050. These changes deepen as EUA prices increase, which is shown in the results obtained for the NUC and CCS scenarios. Achieving the required CO_2 emission limit would not be possible without increasing the use of renewable technologies (in both scenarios considered). The share of electricity from RES in 2050 is at a similar level of about 60% in both scenarios. Wind power plants play a major role in this production. In the NUC scenario, nuclear power plants are used at maximum capacity for electricity generation, while gas-fired plants serve only as backup capacity. These results remain consistent with the insights presented in the Energy Policy of Poland until 2040 [33]. Reaching the imposed CO_2 limit in 2050 is possible without nuclear power plants, as presented in the CCS scenario. The use of coal-fired power plants with CCS systems allows for the postponement of the reduction in the use of hard coal and lignite for electricity generation. Their use is particularly evident in the period between 2040 and 2045; later, due to the high CO_2 reduction target in 2050, gas technologies equipped with CCS systems are used more. They will serve not only as reserve capacity in the power system in 2050 but will be primarily responsible for meeting the demand for electricity. This will require increased gas consumption, which will have to be covered mainly by foreign sources. Of course, assuming the mentioned diversification of gas supplies, there should not be any difficulties in providing adequate quantities of natural gas. The advantage of the CCS scenario is the lower cumulative investment expenditures incurred in the period of 2025–2050 for the expansion of the generation capacity of the national power system (EUR 129 billion compared to EUR 145 billion in the NUC scenario). However, it should be noted that the highest investment expenditures in the CCS scenario are in 2035 (decreasing trend until 2050), whereas in the NUC scenario, they occur in 2050.

Future work will be related to conducting an analysis on the impact of the European Union's single electricity market, which is currently being created, on the operation of the national power system. The integration of cross-border exchanges in the model will support the balancing of the power system, particularly during periods of capacity shortages. However, in the situation of a surplus of electricity in the system, this surplus can provide important support to balance other areas of the EU market.

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Appendix A

Table A1. Characteristics of new energy technologies.

Fuel/Technology [1]	Start Year	OVN Cost	O&M Fixed Cost	O&M Variable Cost	Net Electric Efficiency/Total	Technical Lifetime	CO_2 Emission Factor
		EUR/kW$_{net}$	EUR/kW$_{net}$	EUR/GJ [2]	%	Years	kg/GJ [3]
Hard coal/PC	2025	1650	44	0.89	46	40	94
Hard coal/PC + CCS	2035	3000	75	1.43 [4]	38	40	12
Hard coal/IGCC + CCS (350 MW$_{net}$)	2035	3250	79	2.02 [4]	40	40	12
Hard coal/IGCC + CCS (175 MW$_{net}$)	2035	4000	78	2.00 [4]	40	40	12
Hard coal/CHP	2025	2250	48	0.89	30/80	40	94
Hard coal/CHP + CCS	2035	3500	76	2.78 [4]	22/75	40	12

Table A1. *Cont.*

Fuel/Technology [1]	Start Year	OVN Cost	O&M Fixed Cost	O&M Variable Cost	Net Electric Efficiency/Total	Technical Lifetime	CO_2 Emission Factor
		EUR/kW$_{net}$	EUR/kW$_{net}$	EUR/GJ [2]	%	Years	kg/GJ [3]
Lignite/FBC	2025	2050	50	0.94	40	40	109
Lignite/PL + CCS	2035	3250	72	2.39 [4]	35	40	13
Natural gas/CCGT (680 MW$_{net}$)	2025	750	18	0.51	58–62	30	56
Natural gas/CCGT (390 MW$_{net}$)	2025	840	18	0.50	58–62	30	56
Natural gas/CCGT + CCS (490 MW$_{net}$)	2035	1350	38	1.12 [4]	50–52	30	7
Natural gas/CCGT + CCS (280 MW$_{net}$)	2035	1510	38	1.11 [4]	50–52	30	7
Natural gas/OCGT (680 MW$_{net}$)	2025	500	16	0.39	40	30	56
Natural gas/OCGT (390 MW$_{net}$)	2025	560	16	0.39	40	30	56
Natural gas/CHP (370 MW$_{net}$)	2025	1010	25	0.36	34/80	30	56
Natural gas/CHP (47 MW$_{net}$)	2025	1245	24	0.35	34/80	30	56
Nuclear/PWR (1300 MW$_{net}$)	2035	4840–4700	87	1.70	33	60	0
Onshore wind	2025	1380–1120	35–31	0.00	–	25	0
Offshore wind	2025	3150–2260	81–49	0.00	–	25	0
Photovoltaics/ground	2025	830–655	10–8	0.00	–	25	0
Photovoltaics/roof	2025	770–600	16	0.00	–	25	0
Hydro	2025	2000	75	0.00	–	60	0
Biomass/CHP (43 MW$_{net}$)	2025	2950–2750	120	0.89	30/80	30	0
Biogas/CHP (4.5 MW$_{net}$)	2025	2650	108	0.57	37/85	25	0
Electricity/storage	2025	1085–715	3	0.00	80	30	0

[1] PC—pulverized coal, PL—pulverized lignite, FBC—fluidized bed combustion, CHP—combined heat and power, IGCC—integrated gasification combined cycle, CCGT—combined cycle gas turbine, OCGT—open cycle gas turbine, CCS—carbon capture and storage, PWR—pressurized water reactor. [2] O&M variable cost per 1 GJ of electricity. [3] CO_2 emission factor per 1 GJ of fuel consumed. [4] Including CO_2 transport and storage. Source: Own elaboration based on [8,33,43,74,75].

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