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Coal Demand and Environmental Regulations: A Case Study of the Polish Power Sector

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Abstract: The impact of environmental regulations implemented in the power industry that affect the consumption of solid fuels is of key importance to coal-based power generation systems, such as that in Poland. In this context, the main purpose of the paper was to determine the future demand for hard coal and brown coal in the Polish power sector by 2050 with reference to the environmental regulations implemented in the power sector. To achieve these goals, a mathematical model was developed using the linear programming approach, which reflected the key relationships between the hard and brown coal mining sector and the power sector in the context of the environmental regulations discussed. The environmental regulations selected had a great influence on the future demand for hard and brown coal in the power generation sector. The scope of this influence depended on particular regulations. The prices of CO_2 emission allowances and stricter emissions standards stemming from the Industrial Emissions Directive and the BAT (Best Available Techniques) conclusions had the largest influence on the reduction of hard coal demand. In the case of brown coal, no new power generating units would be deployed; hence, brown coal consumption would drop practically to zero in 2050 under all the scenarios considered.

Keywords: mathematical modeling; linear programming; power generation; environmental regulations; coal consumption

1. Introduction

The demand for fuels in the power industry depends on a number of factors. Recent years have shown that environmental regulations, which result from the implementation of climate and energy policy instruments, are gaining particular relevance. Nilsson [1] analyzed the impact of EU energy efficiency regulations on European electricity markets. Fouquet and Johansson [2] examined the implications of implementing instruments to support the development of renewable energy sources, in particular, feed-in tariffs and tradable green certificates system. Various mechanisms to support the development of renewable energy sources in the context of legal, political, fiscal, technological, and environmental conditions have also been the main scope of Abdmouleh et al. [3]. Gorecki et al. [4] analyzed the interactions of two greenhouse gas emission reduction mechanisms (mainly carbon dioxide) introduced by the Kyoto Protocol Clean Development Mechanism and the European emissions trading system. Ruester et al. [5] focused on the future paths of the EU energy technology policy development by taking into account the impact of the EU climate policy, which aims at decarbonizing the economies of several Member States. Heidrich et al. [6] addressed the problem of the impact of EU climate policy adaptation on the policies and strategies of Member States at the local level. The European Commission has consistently pursued a policy aimed at the decarbonization of Member States' economies [7–11], which, in a situation of the strong dependence of the Polish power sector on coal [12–14], gives rise to serious consequences and challenges. Currently, the power sector's environmental issues are one of the most important factors, determining the development and future structure of the sector in the EU Member States. Such a state of affairs is also important in the context of the prospects for coal demand in the Member States since the power industry is an important consumer of coal in several European countries, including Poland. Gurgul et al. [15] analyzed the links between hard and brown coal consumption and Polish economic growth. Similarly, the Polish coal sector and its economic and social aspects in the context of EU energy policy have also been investigated by Manowska et al. [16]. Antosiewicz et al. [17] took a broader approach by assessing the impact of the transition process of the Polish power sector (decarbonization and increase share of renewables) on the socio-economic aspects with the use of an optimization model.

The consumption of hard coal in the Polish power industry amounts to 58 Mt and brown coal to 63 Mt (as of 2017) [18]. In the case of hard coal, the demand from power plants and CHP (Combined Heat and Power) plants producing electricity constitutes around 50% of the total coal consumption in Poland (51.8% in 2017). In the case of brown coal, on the other hand, the situation is even more unambiguous—practically, the entire production (around 98%) is consumed in the public power sector. In the light of the above, the analysis of the impact of environmental regulations in the power industry is of real and decisive significance for the assessment of the demand for hard and brown coal, especially in the long-run.

Environmental regulations are mostly the tools of the European Commission's policy to prevent climate change and reduce the negative impact of industrial activity on the environment and human life and health. Their impact on the power sector and, consequently, on the sector of fuel suppliers can be described as both direct and indirect. Direct action is related to, among other factors, the implementation of the provisions of the Industrial Emissions Directive [19] in national law, which tightens the standards of pollutant emissions from fuel combustion installations. If specific standards (included in BAT conclusions for large combustion plants (LCP), [20]) are not met, the generating units will have to be refurbished; otherwise, they will not be allowed to continue their operations and, as a consequence, will be closed down, and the demand for the fuel they use will be reduced.

The indirect impacts of environmental regulations may take various forms. These include the additional costs of electricity generation due to carbon dioxide emissions, which is related to the functioning of the European Union Emissions Trading System (EU ETS) [21,22] and the promotion of energy from renewable energy sources (RES) [23,24]. The former changes the competitiveness of electricity production from individual primary energy carriers. The latter determines that part of the demand for electricity that will be satisfied by production from RES-based units, thus reducing the production of electricity from conventional coal units and, at the same time, the level of fuel demand.

The amount of demand for coal from the public power sector depends to a large extent on the long-term development of the electricity generation sub-sector. Taking into account current conditions, the future of the Polish mining and power sectors will closely depend on the solutions adopted at the international level with respect to environmental regulations, which will, directly and indirectly, affect both sectors. In particular, this refers to policies aimed at the decarbonization of the economy. From the point of view of the long-term effects on the aforementioned sectors, the following regulations may have the greatest impact on the demand for coal:

- Directive 2003/87/EC of the European Parliament and of the Council [21], establishing a scheme for greenhouse gas emission allowance trading within the Community (the so-called ETS Directive), and Directive 2009/29/EC of the European Parliament and of the Council [25], improving and extending the emission allowance trading scheme of the Community;
- Directive 2010/75/EU of the European Parliament and of the Council [19] on industrial emissions (the so-called IED), which replaced, inter alia, Directive 2008/1/EC of the European Parliament and of the Council [26], concerning integrated pollution prevention and control (the so-called IPPC Directive), and Directive 2001/80/EC of the European Parliament and of the Council [27] on the limitation of emissions of certain pollutants into the air from large combustion plants (the so-called LCP Directive);

- Directive (EU) 2018/2001 of the European Parliament and of the Council [28], replacing Directive 2009/28/EC of the European Parliament and of the Council on the promotion of the use of energy from renewable sources (the so-called RES Directive);
- Directive (EU) 2018/2002 of the European Parliament and of the Council [29], amending Directive 2012/27/EU on energy efficiency.

However, the impact of environmental regulations on demand for coal in the public power sector cannot be considered as an isolated problem, without reference to, and consideration of, a whole range of other technical, economic, and environmental factors [30,31]. A sound assessment of this impact should take into account the realities of the domestic electricity generation sector with all its most important relationships and elements. In this context, for example, the demand for electricity, the decommissioning of existing generation capacities and the construction of new ones, the efficiency of electricity generation, and the emission factors or unit costs of generation achieved are of great importance.

In this context, this article attempted to determine the future demand for hard and brown coal in the Polish power sector by 2050, with reference to the environmental regulations applied in the power sector. For the purpose of solving this research problem, a mathematical model was developed using the linear programming approach, which reflected the key relationships between the hard and brown coal mining sectors and the power sector in the context of the environmental regulations discussed. The mathematical model was then implemented in the general algebraic modeling system (GAMS).

The remainder of this paper is organized as follows. A relevant literature review is provided in Section 2. Section 3 presents the methodology applied in this study (a computable model of the Polish power generation system). The results are presented and discussed in Section 4. The paper ends with conclusions (Section 5).

2. Literature Review

The impact of the environmental regulations governing the power industry on the broadly understood demand for coal has already been the subject of a number of publications. However, these publications discuss the assessment of the effects of tougher emission standards and limits imposed on the reduction of emissions generated by the power sector—both gaseous pollutants (SO_2, NO_X, PM) and greenhouse gases (primarily CO_2) [32–34]. The European perspective also often refers to an analysis of the impact of the increasing use of renewable energy sources (see [35] for an extended overview). Moreover, there is an increasing number of studies in which the authors (i.e., Lund and Mathiesen [36]; Child and Breyer [37]; Jacobson et al. [38]; Child et al. [39]) state that future transformation of the power sectors towards the use of 100% renewable energy sources is possible. The analysis of world literature also points to the existence of work on the assessment of the effects of the environmental regulations in force on demand for primary fuels. The impact of reduced emissions from the processing of primary energy sources on the directions in which the Finnish energy sector was developing has been the subject of research by Lehtilä and Pirilä [40], based on the EFOM (the Energy Flow Optimization Model) model [41,42]. The long-term development of the Egyptian fuel and power sector, including environmental aspects, has been presented by Khella [43]. A bottom-up approach to modeling the development of the power sector at the regional level (Italy) by taking environmental constraints into account has also been used by Cormio et al. [44]. The aim of the research was to check what should be the generation structure of the power sector in the event that specific environmental policies are adopted—increasing the share of renewable energy sources, including external costs, and reducing pollutant emissions. Böhringer et al. [45] analyzed what would be the global impact of climate policy mechanisms to be implemented in the European Union by 2020 on the economy. A multiregional and multisectoral computable general equilibrium (CGE) model has been used to achieve this objective, which includes the reduction of greenhouse gas emissions and the increased use of renewable energy resources. A similar assessment of the effects and detailed solutions related to the introduction of the climate and energy package at the level of the European Union has been carried out by Capros et al. [46]. For this purpose, the PRIMES (Price-Induced Market Equilibrium System) model [47,48] has been used. In order to examine the effects of the implementation of carbon dioxide reduction limits in the electricity generation sector (Ontario, Canada), Mirzaesmaeeli et al. [49] built a model for optimizing the development of the power generation sector using a mathematical mixed integer programming approach. Oliveira and Antunes [50] developed a multi-objective multi-sectoral economy–energy–environment model, using a mathematical linear programming approach combined with input-output analysis. The assessment of the long-term impact of Europe's climate policy on the power system, but limited to only one country, has also been the subject of a study by Chiodi et al. [51]. The work mainly focused on the analysis of the structural and economic effects of reducing greenhouse gas emissions in Ireland by 2050. The methodology of the study included the application of a mathematical model adapted to the conditions of the Irish fuel and power system, based on the TIMES (The Integrated MARKAL-EFOM System) model generator ([52,53]). A similar thematic scope of analysis and research methodology, but for a shorter time horizon, has been used in work presented by Chiodi et al. [54].

There are also few papers that have indirectly analyzed the impact of the application of environmental regulations in the power sector in Poland. Suwała [55] addressed the issue of adapting the coal industry to sustainability conditions. Kamiński [56] analyzed long-term changes in the demand for fossil fuels in Poland in the context of electricity market liberalization. Kamiński and Kudełko [13] assessed the prospects for hard coal demand in the power sector in the context of increased demand for electricity. Kamiński [57] and Kamiński [58] discussed the problem of market power in the Polish fuel and power sector, emphasizing the impact of increased prices for CO_2 emission allowances. The issue of long-term EU targets, concerning RES and influencing the structure of electricity production in Poland, has been discussed in [59].

The summary of the review concludes that the publications have not so far sufficiently focused on the need to assess hard coal and brown coal demand and to take into account the specific character of the power sectors in Central Eastern European (CEE) countries. Domestic papers [60–66] have filled this gap only partially, but notice should be taken of the fact that there is no comprehensive research whose scope would cover most of the relevant current environmental regulations. Neither has the impact of applying particular environmental regulations in the power sector to such a large extent yet been analyzed. Therefore, the article contributed to world literature on the methodological side (development of a mathematical model specific for CEE countries, implementation of environmental regulations in the model) as well as on the empirical side (possibility of using the tool and results obtained to develop Polish energy policy). Our research also contributed to the on-going discussion on transitions in the fuel and energy sectors resulting from the EU's introduction of strategic climate and energy policies. The novelty of the research that we carried out was related to a quantitative assessment of the impact of environmental regulations on the energy and fuel sectors of countries characterized by a high dependence on solid fossil fuels. It is important to emphasize that the most important environmental regulations (i.e., the EU's ETS Directive, the RES Directive, the Industrial Emissions Directive and BAT conclusions, the Energy Efficiency Directive) were considered independently in order to capture their impact on the Polish fuel and energy sector.

3. Methodology and Data

Developing a model for the long-term assessment of the impact of environmental regulations on demand for hard coal and brown coal for electricity generation in Poland required the application of mathematical programming methodology (operational research), in particular when developing mathematical models and their computer implementation [67–70]. The method for developing this kind of model has been described in the relevant literature (e.g., [71–78]). Due to the time horizon, the verification of research theses needed the development of a long-term model. Based on the analysis of relevant literature (e.g., [13,40,43,77,79–81]), a decision was made to apply a mathematical linear programming approach.

3.1. The Concept of Mathematical Model

The concept of the tool that was built assumed that we reflected the national electric power generation system and implemented the most important elements and relations, influencing the interaction of this sector with the mining sector (see Figure 1). Conducting analyses and simulations, with the use of both the model constructed and research scenarios outlined (described in Section 3.3), allowed the future generation and production structure of the national power system, and hence the structure of demand for individual fossil fuels for the production of electricity to be determined.

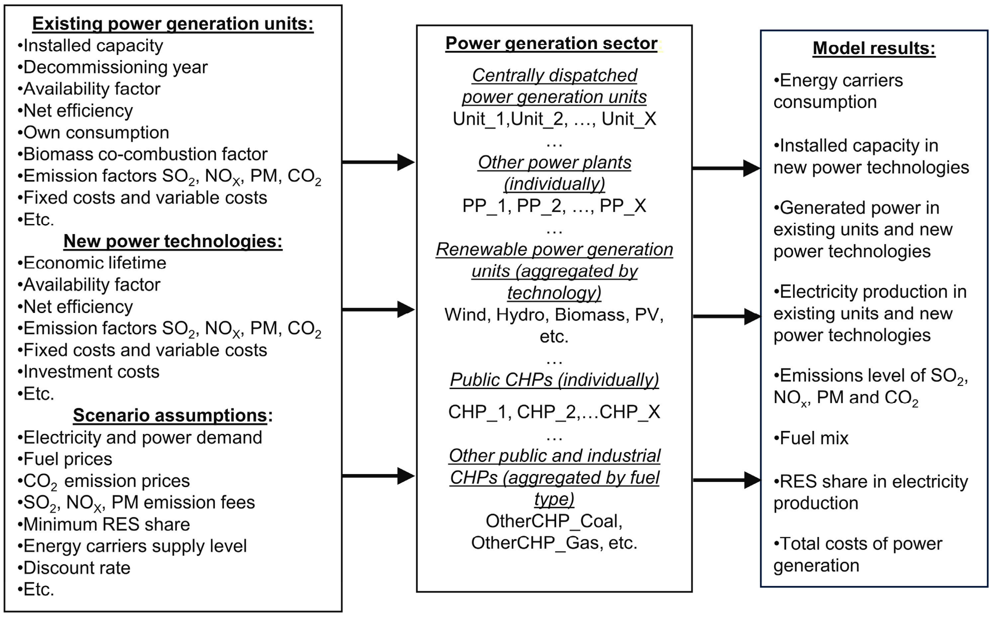

Figure 1. Simplified structure of the optimization model.

It was assumed that the objective function of the model was to minimize the total discounted system costs of electricity generation over the entire time horizon of the analysis. This was a typical approach for long-term fuel and energy system development models. It was assumed that in case of a lack of existing capacities in the system, a unit would be built whose total operating costs, i.e., fuel, fixed, and variable operating costs, as well as incurred investment outlays and related costs, would be the lowest in the whole period under analysis.

Public power plants fired with hard coal, brown coal, and biomass, which operate in the power system, were reflected as individual generating units, which allowed them to be aggregated to appropriate classes of the power unit, entire power plants, as well as to power companies, which own the installations. This flexible approach allowed for a smooth transition from a high degree of detail when it was most required to a more general level in areas of lesser importance or where input data was not available. The largest cogeneration units (above 100 MWe) and all public gas-fired units were mapped at the level of individual CHPs, with the possibility of being aggregated to larger, homogeneous sets. The remaining CHP units were aggregated to groups of CHP plants fired with the same fuel.

The same applied to RES units implemented as aggregates of particular energy technologies using renewable energy resources (wind, hydro, photovoltaic, biomass, biogas power plants).

A very important element taken into account in the model was the group of new generating units, which would join the system as a result of the need to cover the demand for power and to restore generation capacity due to the decommissioning of power units in currently operating power plants and CHP plants. These units were implemented as (i) individual generating units—for units under construction and (ii) a collection of conventional and renewable energy technologies for newly built units.

The first units had a pre-defined installed capacity level and an assigned year to be put into operation, while the second units were selected in the process of optimizing the objective function. Only the results of the model indicated which values were assigned to the appropriate variable, i.e., how much capacity was installed in the system in a given technology in a given year.

The above-mentioned generating units, both existing and new, constituting the actual and future structure of the power generation system in Poland, were described by means of technical and economic parameters in order to simulate their behavior; this would allow the demand for primary energy carriers, including, in particular, hard coal and brown coal, to be estimated.

The demand for electric power was implemented in the model in a determined manner as a structured load duration curve (more on the methods of how to take account of the demand for electric power and capacity in mathematical models in [82]). Based on the authors' own research [83], two six-month load duration curves were adopted, separately for autumn and winter, and spring and summer months. The curves were then divided into reference levels of the power demand of a specified duration, forming the so-called time zones. In total, 22 reference load levels were implemented in the model with account taken of the peak demand for power in winter and summer.

A significant group of assumptions, affecting the costs of electricity generation from a given primary energy carrier and, consequently, the level of demand for it, were fuel price paths and CO_2 emission allowance price paths. In the first case, it was possible to determine prices for the years 2017–2050 for the following carriers: hard coal (steam coal), brown coal, natural gas, heating oil, biomass and biogas, and nuclear fuel.

The same went for CO_2 emission allowance prices and environmental fees for air pollution emissions, where appropriate values for the years 2017–2050 could be adopted.

New generating units with a given energy technology would be able to start production as early as the year indicated (year of technology availability). Due to the long-term nature of the model, it was complemented with so-called learning curves. In case a specific technology develops, its technical and economic parameters may undergo changes [84–86]. By means of learning curves, potential and time-specific reductions in capital expenditure costs were described, as well as possible increases in electricity generation efficiency (conventional units) and in the coefficient of installed capacity utilization (RES units). More on the effects of improving technologies in the context of long-term fuel and power sector modeling could be found in [87–90].

3.2. Data Assumptions

The basis used for developing the structured load curves to be implemented in the model was a long-term forecast of electricity demand for the entire time horizon of the analysis (until 2050), as well as peak power demand growth forecasts. Electricity demand forecasts are illustrated in Figure 2.

The reference scenario used the moderate forecast with an additional assumption that the impact of the development of the dispersed prosumer energy sector on the reduction of demand, as well as the development of electromobility on its growth, would be mutually suppressing (more on electromobility development in Poland could be found in [91]). Two other alternatives could be used in respective research scenarios, assuming (i) lower demand due to, among other possible scenarios, an increased share of prosumers in the energy market and more dynamic improvement in energy efficiency (Forecast–Low), and (ii) increased demand through the development of electric vehicles and a lower rate of energy efficiency reduction (Forecast–High).

Based on the analyses performed, as well as on the other available forecasts of peak power demand (Figure 3), the PSE S.A.'s (Polskie Sieci Elektroenergetyczne S.A.-Polish Transmission Network Operator) low forecast was selected (PSE–low) and implemented in a long-term model, as the most similar to the Ministry of Energy's estimates and the historical trend.

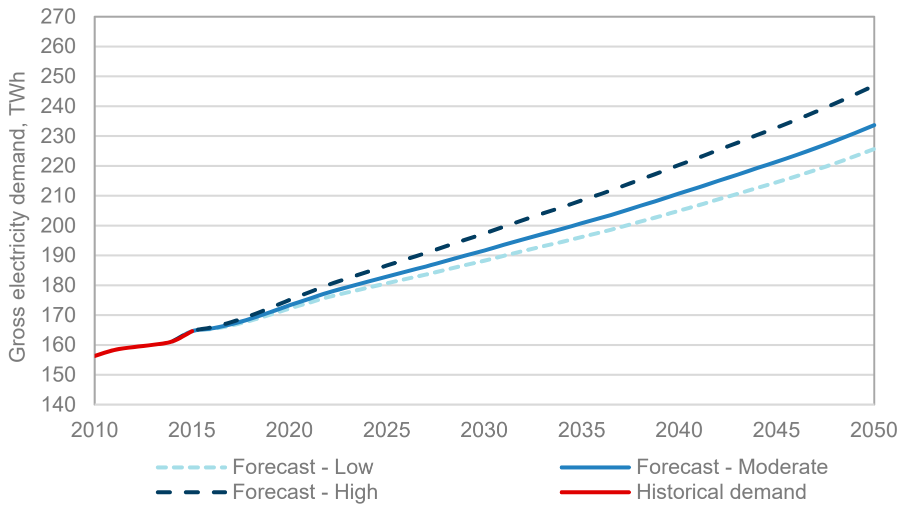

Figure 2. Gross electricity demand forecast until 2050.

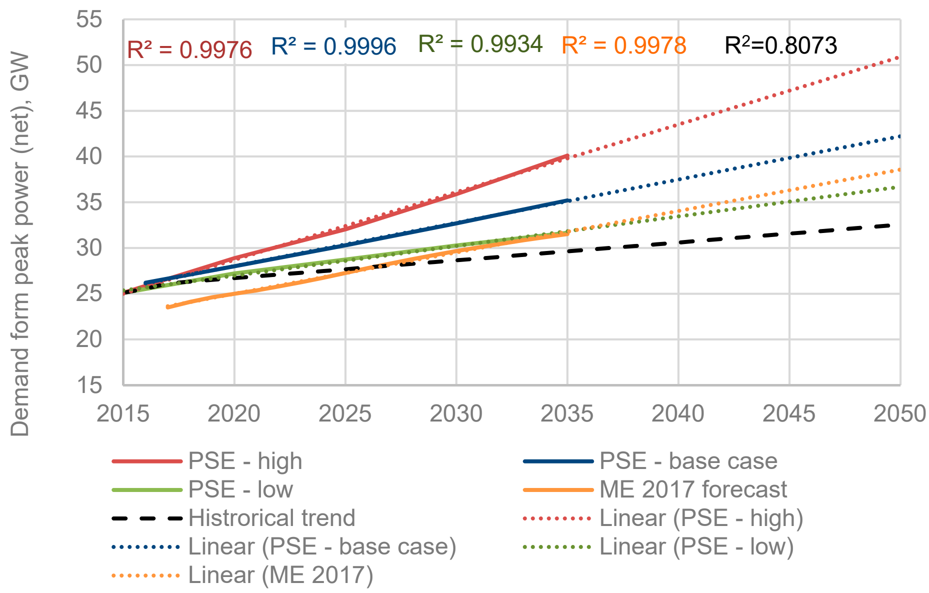

Figure 3. Peak power demand forecast until 2050 (Source: Own elaboration based on [92,93]).

Our own price paths were estimated, on the basis of (i) historical data on the unit costs of fuels consumed in the Polish public power industry [94], (ii) mutual relations between these values, and (iii) trends based on the forecasts presented in the World Energy Outlook [95], in the Current Policies Scenario concerning the development of energy sectors in the countries of the world. The model assumed price paths for the basic fuels used in the national power industry, in accordance with the data presented in Figure 4.

In the model, supply limits were only imposed on brown coal supplies. Due to its specific features associated with the operation of mine-power plant facilities, as well as the conditions for long-distance transport, the model assumed a supply path in line with the forecasts presented in the program for the brown coal sector for 2017–2030 with a view to 2050 [96] (Figure 5).

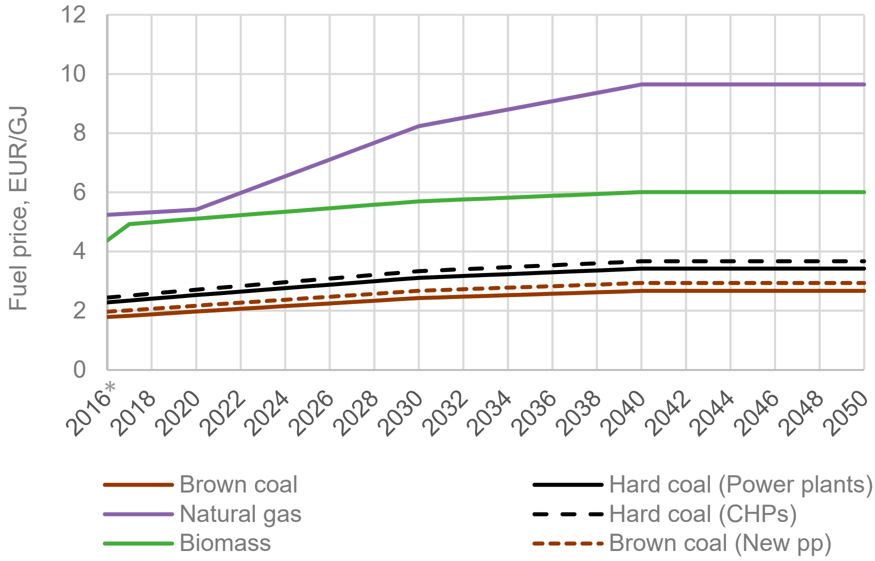

Figure 4. Energy carrier price forecasts until 2050 (Source: Own estimates based on [94,95]).

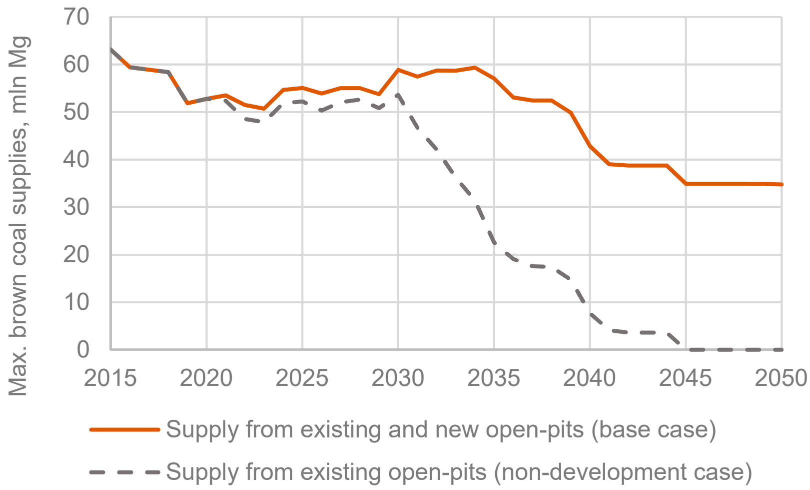

Figure 5. Maximum brown coal supply forecast until 2050 (Source: Own estimates based on [96]).

In the case of natural gas—as was the case for hard coal—a decision was made not to introduce supply limits due to the global nature of gas trading and additional expansion of import capacities through the construction of a gas terminal in Świnoujście.

A different approach was applied to the potential for producing electricity through the use of renewable energy resources in Poland, i.e., from wind, solar, water, biomass, and biogas. According to estimates and analyses presented in the works [97–99]), the model assumed the maximum levels of energy potential (expressed in PJ) of RES illustrated in Figure 6. It was important to stress that the renewable energy limits, estimated by Polish institutions and presented below, were referring to potential available for electricity production purposes. For example, the total technical potential of solar energy was estimated to be approximately 170 PJ, and only 30 PJ in terms of electricity production.

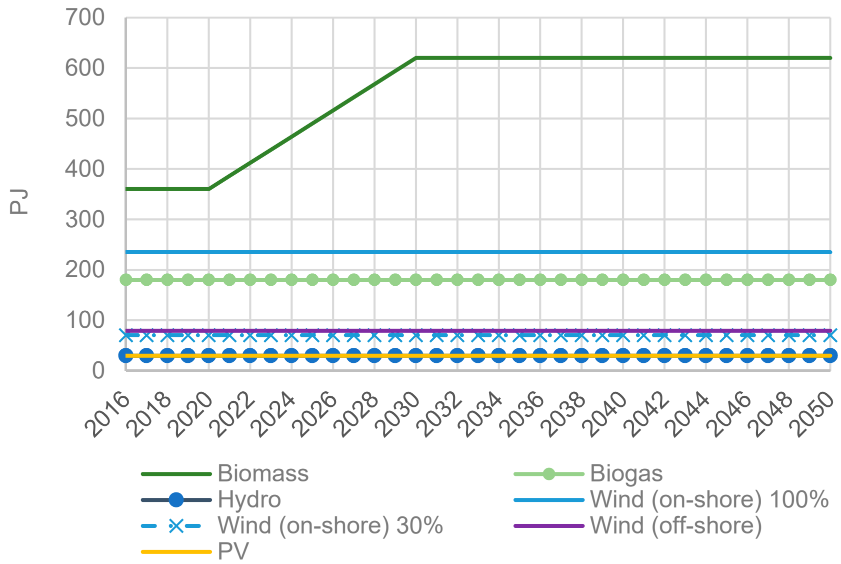

Figure 6. Maximum renewable energy sources (RES) primary energy supply potential until 2050 (Source: Own estimates based on [97–99]).

Due to regulations concerning wind power investments [100], which introduced a rule that restricts new wind power units from being built closer than a distance of 10 times the total height of the wind turbine (including the blades) from any buildings or protected area borders, a decision was made to prepare two alternative forecasts for available wind energy potential. The 100% alternative assumed that the entire estimated potential of wind energy would be available for use in the model. The second alternative assumed that only a specific part of this potential would be taken into account in the model calculations—the level was set at 30%.

The model used carbon price pathways published in the World Energy Outlook [95]—Current Policies Scenario (CPS) and New Policies Scenario (NPS) (Figure 7). To be consistent with the assumptions made for fuel price projections, a path for the CPS was adopted as the baseline, while the price level achieved in 2030 was maintained until 2050 (CPS 30–50). The option of high prices of CO_2 emission allowances assumed the implementation of the NPS; the 2040 price level was adopted for the 2040–2050 period (last year of the World Energy Outlook 2016 forecast). In addition, an alternative of low emission allowance prices was also assumed; for this purpose, a modified path for the CPS was used, maintaining the 2020 price until the end of the model's time horizon (CPS 20–50).

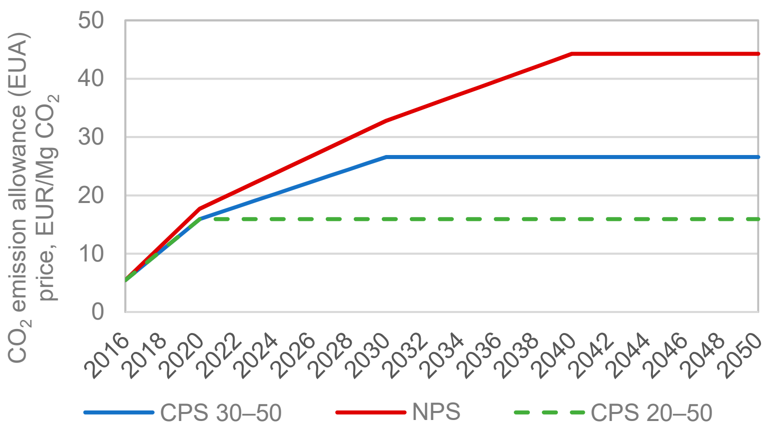

Figure 7. CO_2 emission allowance price forecasts until 2050 (Source: Estimates based on [95]).

3.3. Research Scenarios

Six main research scenarios were prepared, including a reference scenario to which the results from other scenarios would be compared.

An assumption was made that in each scenario, only one parameter/factor would change in relation to the reference scenario. This approach would make it possible to quantify the impact of individually considered environmental regulations on-demand for individual fossil fuels without considering the impact of other factors.

In addition, two other scenarios were prepared—minimum and maximum environmental regulations—in the context of the prospects for coal demand for electricity generation. They would allow the assessment of the impact of extreme approaches to the implementation of environmental regulations on demand for fossil fuels.

The following are the research scenarios developed with a description of the most important assumptions. A summary comparison of the scenarios is presented in Tables 1 and 2, with differential factors being highlighted.

Table 1. Comparison of research scenarios developed (REF, HighEUA, RES-30% and WindPot-100%).

Scenario	REF [1]	HighEUA [2]	RES-30% [3]	WindPot-100% [4]
Energy efficiency/demand for electricity	Moderate electricity demand forecast	**REF ***	**REF**	**REF**
CO_2 emission allowance prices	Reference path (CPS 30–50)	High prices path–NPS	**REF**	**REF**
National RES target	Maintaining 20% RES share in electricity prod. 2021–2050	**REF**	Increase in the minimum RES share in electricity generation to 30% in 2030 (to be maintained by 2050)	**REF**
Wind energy potential	Available wind energy potential limited to 30%	**REF**	**REF**	100% of available wind energy potential
Pollutant emission standards (IED+BAT)/ decommissioning of generating units	Adjustment of the existing 200 MW, 360 MW, 500 MW, and 1000 MW units to the requirements of the IED and BAT conclusions-reference level of decommissioning	**REF**	**REF**	**REF**

[1] Reference scenario (REF); [2] Higher CO_2 emission allowances prices scenario (HighEUA); [3] Higher renewables share in electricity generation scenario (RES-30%); [4] 100% wind energy potential scenario (WindPot-100%). * Assumption as for the REF scenario.

Table 2. Comparison of research scenarios developed (REF, Decom-BAT, HighEnEff, MaxEnvReg and MinEnvReg).

Scenario	REF	Decom-BAT [1]	HighEnEff [2]	MaxEnvReg [3]	MinEnvReg [4]
Energy efficiency/demand for electricity	Moderate electricity demand forecast	**REF ***	A faster pace in improving energy efficiency-low electricity demand forecast	High electricity demand forecast	Low electricity demand forecast
CO_2 emission allowance prices	Reference path (CPS 30–50)	**REF**	**REF**	Low prices path–CPS 20–50	High prices path–NPS
National RES target	Maintaining 20% RES share in electricity prod. 2021–2050	**REF**	**REF**	Lack of min. RES share after 2020	Increase in the minimum RES share in electricity generation to 30% in 2030 (to be maintained by 2050)
Wind energy potential	Available wind energy potential limited to 30%	**REF**	**REF**	**REF**	100% of available wind energy potential
Pollutant emission standards (IED+BAT)/ decommissioning of generating units	Adjustment of the existing 200 MW, 360 MW, 500 MW, and 1000 MW units to the requirements of the IED and BAT conclusions-reference level of decommissioning	High level of decommissioning in the system (200 MW units); only available units are those with CCS/CCU	**REF**	**REF**	High level of decommissioning in the system (200 MW units); only available units are those with CCS/CCU

[1] Higher level of decommissioning due to BAT conclusions scenario (Decom-BAT); [2] A faster pace of energy efficiency improving scenario (HighEnEff); [3] Maximum environmental regulations scenario (MaxEnvReg); [4] Minimum environmental regulations scenario (MinEnvReg). * Assumption as for the REF scenario.

4. Results and Discussion

The basic scenarios discussed in the paper and compared to the reference condition (REF) were RES-30%, HighEUA, Decom-BAT, WindPot-100%, and HighEnEff scenarios. The two additional scenarios—maximum and minimum environmental regulations (MaxEnvReg and MinEnvReg)—provided an additional framework to illustrate extremely favorable or unfavorable situations in the context of prospects for coal demand in public power generation.

4.1. Fuel Mix in Electricity Production

Table 3 illustrates the level of electricity production (in TWh) in generating units, using hard coal and brown coal as fuel, for the reference scenario (REF) in selected years (2020, 2030, 2040, and 2050). The results of the other scenarios represented an absolute difference compared to the REF scenario. The last column contains total electricity production for 2017–2050 and the percentage deviations from this figure. The comparison of the total share of electricity production from hard and brown coal over the whole time horizon of the analysis for all the research scenarios developed is presented in Figure 8. Figure 9, in turn, illustrates the electricity production fuel mix, including all primary energy carriers for the six basic research scenarios. When analyzing data and charts, it should be noted that the HighEnEff scenario was characterized by a lower level of electricity demand, the same applied to the MaxEnvReg scenario. The high demand path was adopted in the MinEnvReg scenario.

In the reference scenario (REF), hard coal-based electricity production increased after its slight decrease in 2020, reaching its highest dynamics between 2030 and 2040. In the whole period analyzed, total production based on this fuel amounted to approximately 3927 TWh (Figure 9), which was the highest result among the baseline scenarios—more (by 22.6%) electricity was only produced in the hard coal-fired units in the MinEnvReg scenario. The RES-30%, WindPot-100%, and HighEnEff scenarios achieved a similar result to the REF scenario growth trend in hard coal-based production, but the total generation volume was lower by 11.8%, 1.8%, and 3.2%, respectively. In the scenarios in which nuclear power was developing after 2030 (HighEUA and Decom-BAT), the production of electricity based on hard coal was stable until that year and gradually decreased in subsequent years as the production from nuclear power plants increased.

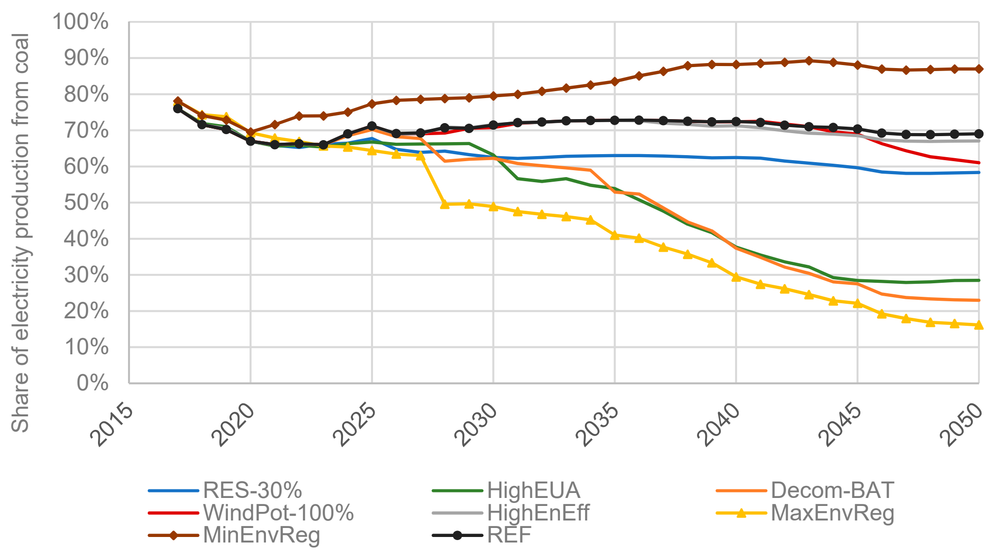

Figure 8. The total share of electricity production from coal (hard coal and brown coal) for the research scenarios until 2050, %.

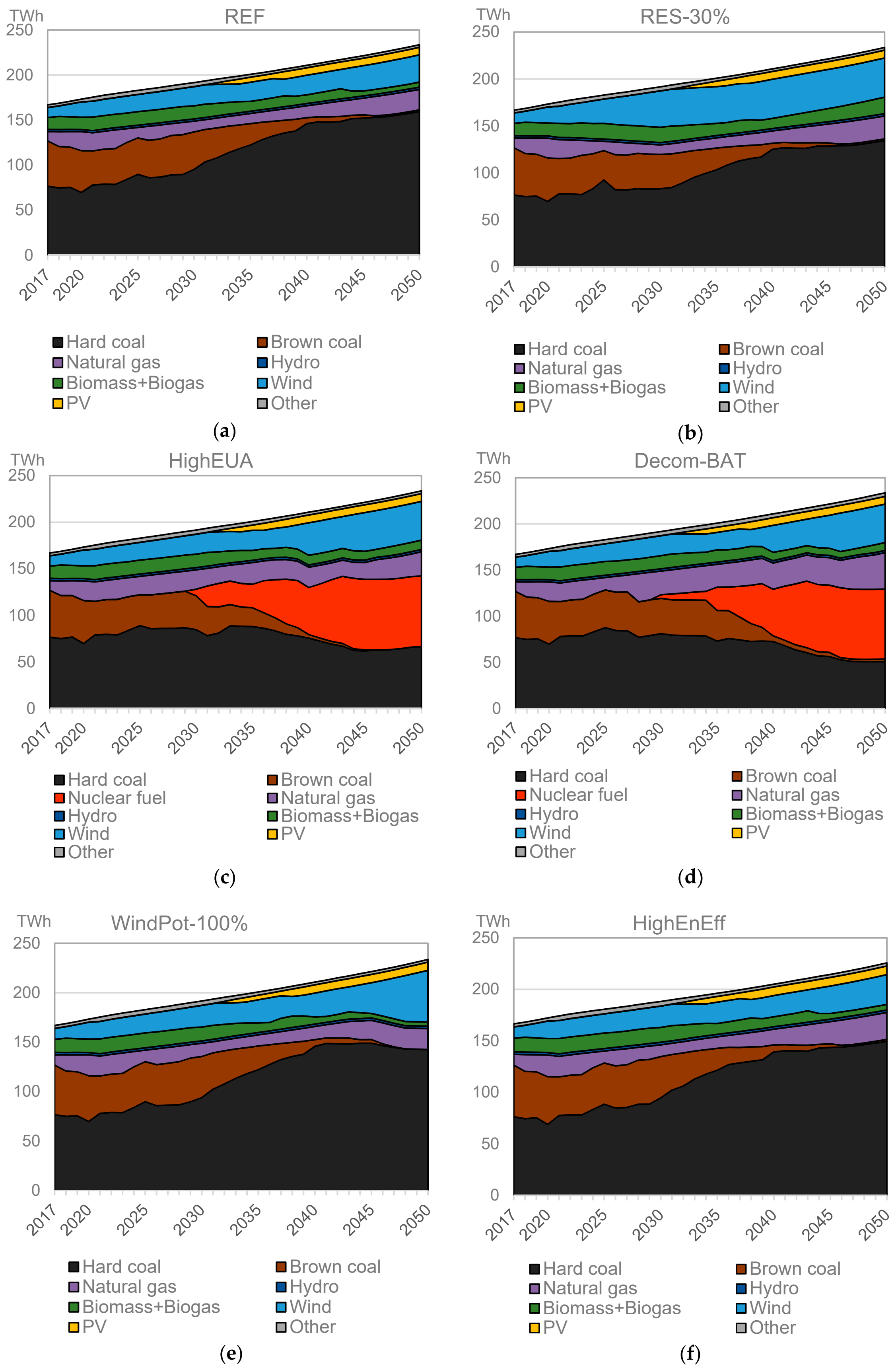

Figure 9. Fuel mix in electricity generation in 2017–2050 for the research scenarios analyzed: (**a**) REF, (**b**) RES-30%, (**c**) HighEUA, (**d**) Decom-BAT, (**e**) WindPot-100%, (**f**) HighEnEff, TWh.

Table 3. Comparison of electricity production from hard and brown coal for research scenarios in selected years with respect to the REF scenario, TWh.

Scenario	Fuel	2020	2030	2040	2050	Sum 2017–2050
REF	Hard Coal	69.8	95.4	146.1	159.5	3926.6
	Brown Coal	46.3	41.6	6.5	1.8	850.1
RES-30%	Hard Coal	0	−12.1	−21.0	−25.0	−11.8%
	Brown Coal	0	−5.1	0	0.1	−5.1%
HighEUA	Hard Coal	0	−10.8	−70.6	−92.9	−33.3%
	Brown Coal	0	−5.1	−2.6	−1.8	−12.2%
Decom-BAT	Hard Coal	0	−14.2	−73.4	−108.6	−38.1%
	Brown Coal	0	−3.4	−0.5	1.0	6.5%
WindPot-100%	Hard Coal	0	−1.4	−0.3	−16.9	−1.8%
	Brown Coal	0	0.1	0.2	−1.8	−0.5%
HighEnEff	Hard Coal	−0.9	−0.8	−6.8	−10.0	−3.2%
	Brown Coal	0	−1.5	0.3	0	−2.6%
MaxEnvReg	Hard Coal	3.3	−20.7	−87.8	−123.0	−43.4%
	Brown Coal	0	−24.1	−4.5	−1.8	−27.8%
MinEnvReg	Hard Coal	5.6	15.8	41.4	53.7	22.6%
	Brown Coal	0	4.2	0.3	−0.2	12.9%

Due to the lack of construction of new capacity using brown coal (apart from the new unit in the Turów power plant included in the model input data) along with the decommissioning of existing generating units, electricity production in brown coal-fired power plants followed a similar pattern in all scenarios, and the importance of this carrier in the fuel mix was marginalized after 2040. It was worth noting, however, that in the Decom-BAT scenario, the total level of brown coal-based generation was 6.5% higher than in the REF scenario (850 TWh—2017–2050); this was associated with increased production of hard coal-based capacity during the decommissioning period.

4.2. Demand for Hard Coal

Demand for hard coal for electricity generation in public power plants and CHP plants remained at a level very close to all basic research scenarios until around 2025. It is true that in that period, the demand fell from 30.2 million Mg in 2017 to 24.4 million Mg in 2020 due to the operation of the Transitional National Plan (TNP) and the decommissioning of units under a natural derogation, but in subsequent years—in connection with the commissioning of newly built coal units—the demand for hard coal increased to reach 29.3–31.6 million Mg in 2025 (Figure 10). After that year, the differences between the different scenarios became more and more pronounced. In the reference scenario, the demand for hard coal increased from 28.7 million Mg in 2026 to reach 51.4 million Mg in 2050. A similar trend was observed in WindPot-100% and HighEnEff scenarios.

In the first case, the unblocking of available onshore wind energy potential translated into reduced demand for hard coal after 2040, and the volume of demand in 2050 amounted to 45.7 million Mg (5.7 million Mg less than in the REF scenario). This was related to a greater increase in wind power capacities in this scenario due to decreasing investment outlays in subsequent years and the possible use of the entire estimated wind energy potential—with the assumption that there is no law on wind power investments (the so-called Distance Act) [100].

In the second case—the HighEnEff scenario, which assumed a faster pace of energy efficiency improvement and, therefore, lower demand for electricity—the hard coal demand curve remained slightly below the reference level and, in 2050, reached 48 million Mg. The difference with the REF scenario of that year amounted to 3.4 million Mg and was caused by around 6% (13.3 TWh) lower demand for electricity at the end of the period analyzed.

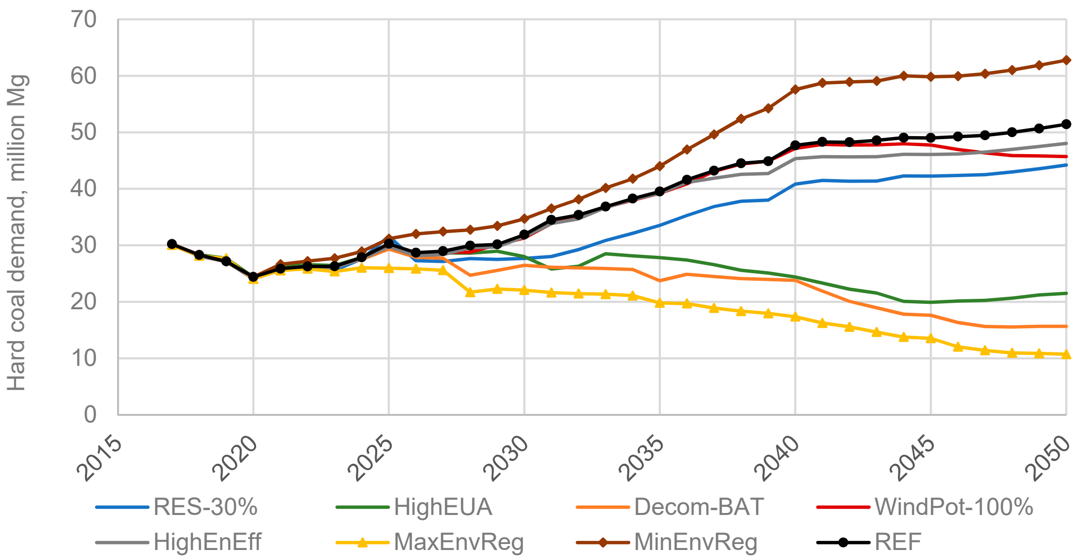

Figure 10. Hard coal demand for electricity generation in the public power sector until 2050 for research scenarios, mln Mg.

The RES-30% scenario, which assumed an increase in the minimum share of renewables generation to 30% in 2030 and the maintenance of this target in the following years, deviated much more from the resulting level of demand for the REF scenario while maintaining a similar trend. From 2031 to the end of the period analyzed, the difference in the demand for hard coal persisted in the range of 6.0–7.2 million Mg, and, in 2050, the level of this demand in the RES-30% scenario amounted to 44.2 million Mg (Figure 10). This meant that the aforementioned environmental regulation—the required minimum share of RES in the total gross electricity production—did not affect the demand trend for hard coal itself but caused a reduction in its volume, especially between 2026 and 2050.

The results for the two remaining basic research scenarios—HighEUA and Decom-BAT—indicated a reversal of the trend in demand for hard coal in relation to the REF scenario. Both scenarios showed a decrease in demand but due to various environmental regulations. The HighEUA scenario assumed higher prices of carbon dioxide emission allowances, which increased the operating costs of high-emission generating units, primarily hard coal- and brown coal-fired. In that scenario, the 2050 demand amounted to 21.5 million Mg (29.9 million Mg less than in the REF scenario). The functioning of the European Emissions Trading System (EU ETS), with the assumption of high allowance prices (about 34% above the reference level in 2050), changed the trend and significantly reduced hard coal demand after 2030 compared to the REF scenario. In the Decom-BAT scenario, where a higher level of decommissioning of the existing coal-fired capacities (200 MW class units) was assumed in 2023–2028, and there was no possibility of building new hard coal-fired units without CCS/CCU installations, the demand for hard coal started to decrease earlier and deeper compared to the HighEUA scenario. In 2050, the demand in the Decom-BAT scenario amounted to 15.6 million Mg—over 35.8 million Mg less than in the reference scenario (Figure 10). Therefore, it should be stated that the tightening of environmental regulations on the standards for pollutant emissions from the combustion of fossil fuels (introduced by the IED) together with the BAT conclusions subject to periodic verification and updating, in the event of the occurrence of the effects specified in the Decom-BAT scenario, might cause the largest decrease in hard coal demand among all the research scenarios considered.

The research scenarios cumulating the most favorable and unfavorable assumptions—in terms of prospects for coal demand—constituted the upper and lower limit of hard coal demand in each year. In the MinEnvReg scenario, this figure was 62.8 million Mg in 2050—11.3 million Mg more compared to the REF scenario; for the MaxEnvReg scenario, it was 40.7 million Mg less, i.e., 10.7 million Mg in 2050.

In order to compare the total quantity of hard coal needed by public power plants and combined heat and power plants to produce electricity, a summary of total demand for hard coal in 2017–2050 was prepared for individual research scenarios, specifying the percentage differences in relation to the reference scenario (Table 4). In addition, Figure 10 shows the differences in this level—ordered from the smallest to the largest—in relation to the REF scenario, which was expressed in absolute values (million Mg). Figure 11, in turn, shows the percentage ratio of total hard coal demand in a given research scenario in relation to the reference value (REF = 100%).

Table 4. Total hard coal demand until 2050 for the research scenarios analyzed, mln Mg.

Scenario, *mln Mg*	**2017–2020**	**2021–2025**	**2026–2030**	**2031–2035**	**2036–2040**	**2041–2045**	**2046–2050**	**Total**	**Difference%**
REF	**110.0**	**136.5**	**149.6**	**184.5**	**221.9**	**243.1**	**250.7**	**1296.3**	**100%**
RES-30%	110.0	136.4	137.3	153.8	188.8	208.7	215.6	**1150.6**	−11.2%
HighEUA	110.6	137.0	142.7	136.6	129.1	107.1	103.7	**866.8**	−33.1%
Decom-BAT	110.0	135.2	132.3	127.5	121.2	96.4	78.8	**801.4**	−38.2%
WindPot-100%	110.0	136.5	147.5	183.1	220.4	239.1	230.7	**1267.4**	−2.2%
HighEnEff	109.2	135.0	147.3	182.5	213.6	229.2	235.1	**1252.0**	−3.4%
MaxEnvReg	109.9	128.7	117.5	105.3	92.3	73.8	56.0	**683.4**	−47.3%
MinEnvReg	110.0	141.6	165.3	200.5	260.7	296.5	305.9	**1480.5**	14.2%

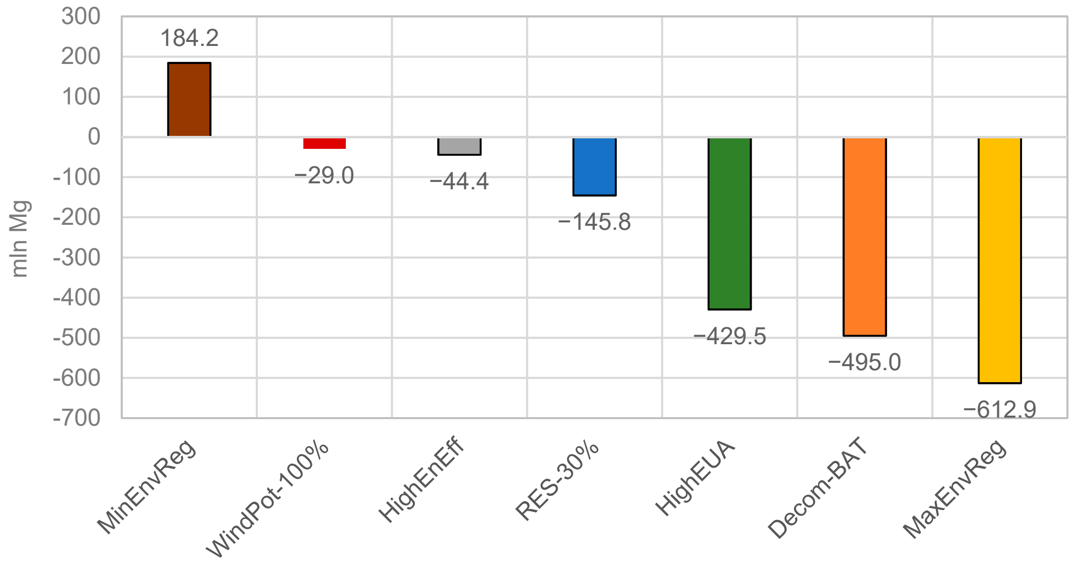

Figure 11. Differences in total hard coal demand for electricity generation until 2050 in relation to the REF scenario, mln Mg.

The total level of demand for hard coal in the REF scenario amounted to 1296.3 million Mg (Table 4). The lowest demand for this fuel and hence the largest differences occurred in the case of implementing the environmental regulations adopted in the Decom-BAT scenario—−495.0 mln Mg, and MaxEnvReg—−612.9 mln Mg, which represented 61.8% and 52.7% of the reference value, respectively (Figure 11, Figure 12). A slightly smaller difference, but at a comparable level, was observed under the assumption of higher carbon prices (HighEUA scenario)—−429.5 mln Mg. The values obtained for the RES-30%, HighEnEff, and WindPot-100% scenarios were much closer to the resulting figures of the REF scenario. This meant that environmental regulations reflected in each of the above scenarios would have less importance for the prospects for hard coal demand for electricity generation, although the total level of demand for this fuel would be lower compared to the reference scenario by 145.8 million Mg, 44.4 million Mg, and 29.0 million Mg over the entire time horizon of the analysis.

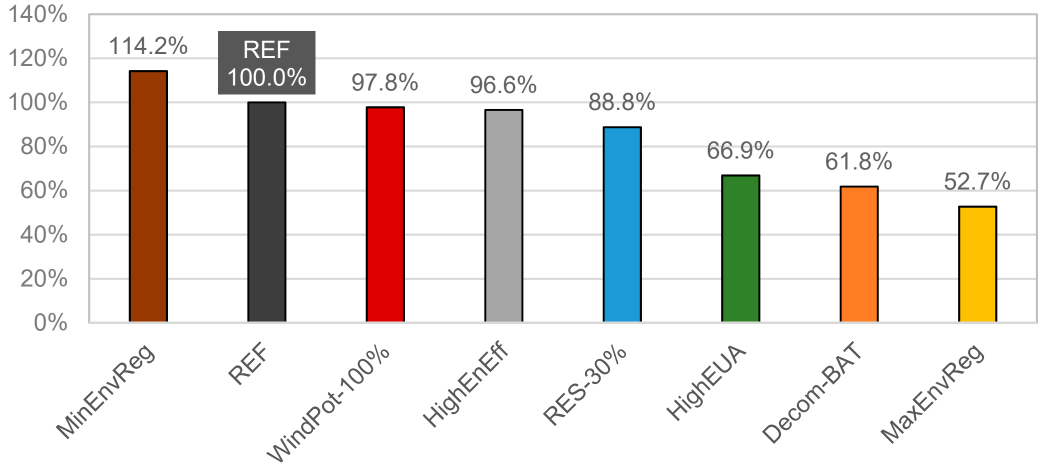

Figure 12. Percentage comparison of total hard coal demand until 2050 with the REF = 100% scenario.

The most favorable scenario for hard coal demand was the MinEnvReg scenario; it was only in this scenario that the total level of demand was higher than in the REF scenario—an increase of 14.2%.

4.3. Demand for Brown Coal

The demand for brown coal in the initial years dropped from around 58.2 million Mg to around 42.5 million Mg (2021) due to the shutdown of Adamów power plant, increasing CO_2 emission allowance prices, and greater competition from new high-efficiency hard coal-fired units (Figure 13). In subsequent years, the demand gradually increased, which was related to the start of full operations of a new generating unit in Turów, reaching 49.8 million Mg in 2029. After 2030, due to carbon prices and successive decommissioning of most brown coal-fired power units (including the largest Bełchatów power plant), demand for this fuel dynamically decreased to a level between 0 and 3 million Mg in 2050.

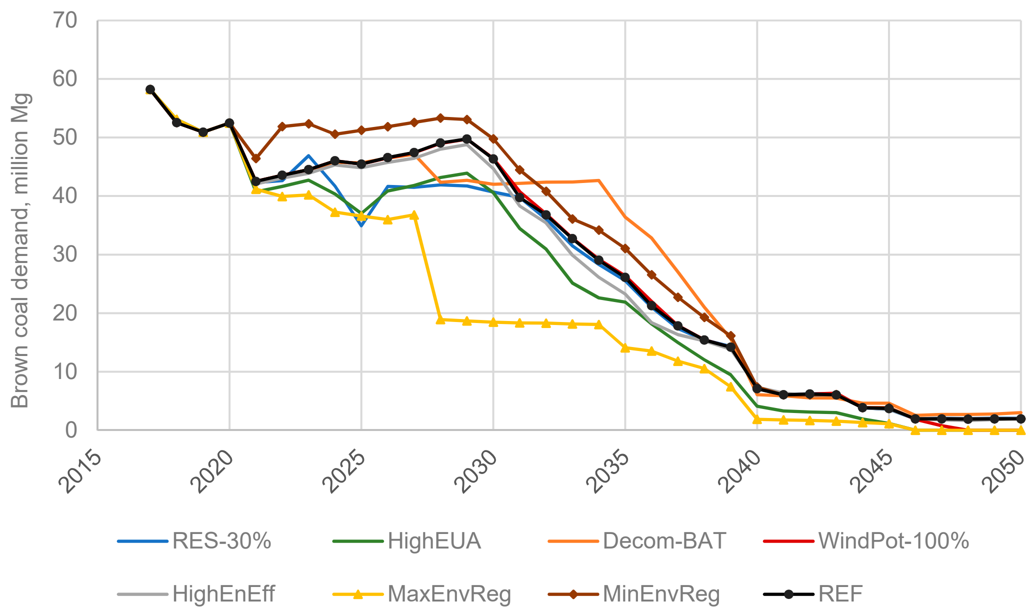

Figure 13. Brown coal demand for electricity generation in the public power sector until 2050 for research scenarios, mln Mg.

The differences showing the quantitative impact of each environmental regulation (reflected in the basic research scenarios) on demand for brown coal for electricity generation in comparison with the reference scenario are illustrated in Table 5, Figure 14, and Figure 15.

Table 5. Total demand for brown coal until 2050 for the research scenarios investigated, mln Mg.

Scenario, *mln Mg*	2017–2020	2021–2025	2026–2030	2031–2035	2036–2040	2041–2045	2046–2050	Total	Difference%
REF	**214.1**	**222.0**	**239.2**	**164.4**	**75.8**	**25.8**	**9.6**	**950.9**	**100%**
RES-30%	214.1	208.5	207.5	161.2	75.2	25.9	10.0	**902.4**	−5.1%
HighEUA	214.7	202.5	210.3	135.0	58.8	12.5	0	**833.7**	−12.3%
Decom-BAT	214.1	222.0	220.7	206.0	102.6	26.1	13.7	**1005.2**	5.7%
WindPot-100%	214.1	222.0	239.1	166.1	76.7	26.2	2.7	**947.0**	−0.4%
HighEnEff	214.1	219.2	233.7	153.0	71.1	25.7	9.2	**926.0**	−2.6%
MaxEnvReg	214.7	195.2	128.8	86.9	45.2	7.4	0	**678.2**	−28.7%
MinEnvReg	214.1	252.4	260.6	186.6	92.0	25.8	9.6	**1041.2**	9.5%

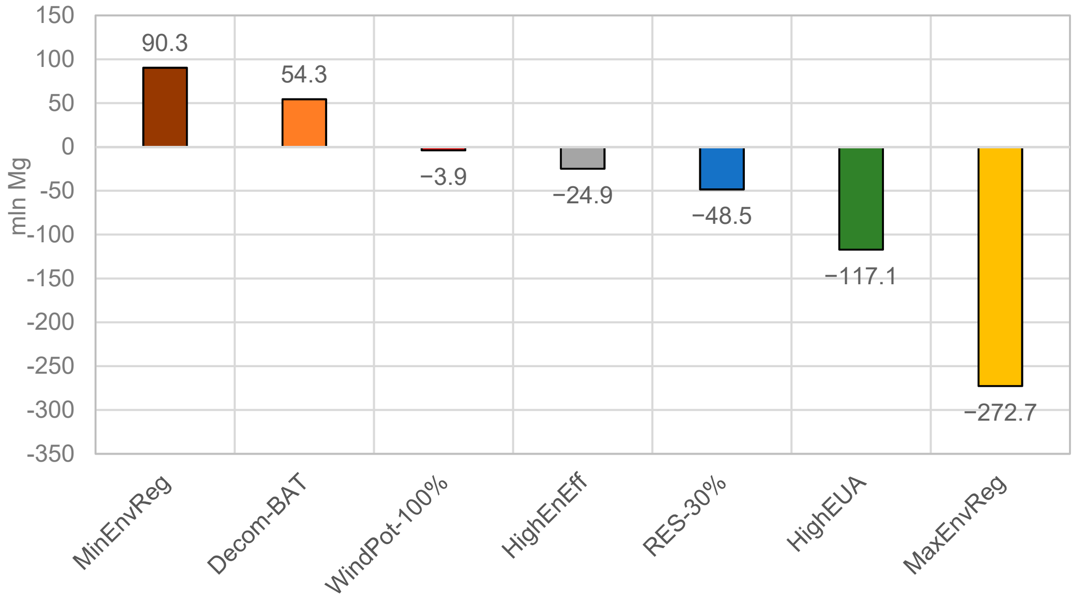

Figure 14. Differences in relation to the REF scenario in total brown coal demand for electricity generation, mln Mg.

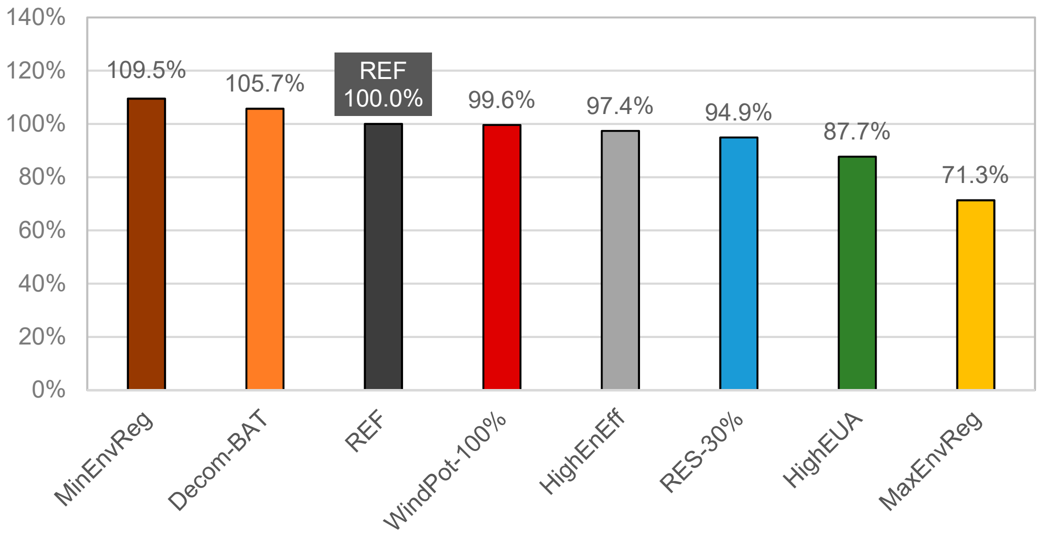

Figure 15. Percentage comparison of total brown coal demand with the REF = 100% scenario.

The least favorable scenario for brown coal (except for the additional MaxEnvReg scenario) was HighEUA, for which the total demand was 12.3% lower, which translated into 117.1 million Mg (Table 5, Figure 14). Accordingly, as in the case of hard coal, in the event of a high pathway of carbon prices, the functioning of the CO_2 emission allowance trading scheme resulted in a significant reduction in demand for this fuel. Contrary to the situation with hard coal, following the Decom-BAT scenario might be beneficial for brown coal since, in this scenario, the total demand level was 5.7% higher than in the REF scenario. The increased decommissioning of 200 MW units (mainly hard coal-based) as a result of more stringent emission standards for fuel combustion and, at the same time, the inability to build new units without CCS/CCU installations resulted in increased electricity production from existing brown coal-fired power plants and, consequently, in an increased demand for this fuel.

As in the case of the prospects for hard coal demand, additional MinEnvReg and MaxEnvReg scenarios represented extreme solutions for brown coal. In the MaxEnvReg scenario, the total demand for brown coal was 272.7 million Mg (28.7%) lower than in the REF scenario, while, in the MinEnvReg scenario, it was 90.3 million Mg (9.5%) higher.

5. Conclusions and Recommendations

The assessment of the prospects for hard coal and brown coal demand in the public power sector in the light of selected environmental regulations, especially when they are considered in the long term, is of significant importance for the future of the national fuel and power sector and, accordingly, for the entire Polish economy. Both closely related sectors of (i) suppliers of fossil primary energy sources and (ii) public power generation are currently facing the challenge of adapting to the existing and planned environmental regulations. This task is complex, mainly due to the specific nature of the Polish power sector, which is highly dependent on hard coal-fueled generating units. Proper interpretation of the effects and their long-term quantitative assessment are of crucial importance for the planning of the development of the fuel and power sector, as well as for strategic investment decision-making.

The results obtained from the aforementioned research scenarios permit the formulation of the following policy recommendations:

- The largest quantitative impact on the demand for hard coal in the public power sector is observed in the case of implementing environmental regulations reflected in the HighEUA scenario (high prices of carbon dioxide emission allowances), the Decom-BAT scenario (high level of decommissioning of existing generating units due to more stringent emission standards and the inability to build new capacities not equipped with CCS/CCU installations), and the MaxEnvReg scenario. In the first case, the demand for hard coal in the entire time horizon of the analysis (2017–2050) is lower than in the REF scenario by 429.5 million Mg, in the second case by 495.0 million Mg, while, in the MaxEnvReg scenario, the decrease is 612.9 million Mg. In all of the above scenarios, there is a significant technological change in the power system, namely, the development of nuclear power. The consequence of the scenario assumptions is also a small (HighEUA) or zero (Decom-BAT, MaxEnvReg) increase in new hard coal-based capacities.
- The functioning of individually considered environmental regulations assumed in the other research scenarios (RES-30%, WindPot-100%, and HighEnEff) does not result in a drastic technological change, and thus the demand for hard coal is closer to the level achieved in the reference scenario. Nevertheless, over the whole of the time horizon, the volume of this demand is lower by 145.8 million Mg (RES-30%), 44.4 million Mg (HighEnEff), and 29.0 million Mg (WindPot-100%). The only scenario in which the demand for hard coal is higher than in the REF scenario (by about 14.2%–184.2 million Mg) is the MinEnvReg scenario, which assumes minimal co-existence of environmental regulations.
- The long-term prospects for brown coal demand are similar in all scenarios. In the absence of new brown coal-based capacities, brown coal consumption drops practically to zero in 2050. However, the intensity of the use of existing power plants varies, which affects the overall level of demand. The biggest differences with respect to the REF scenario (without taking into account the

MinEnvReg and MaxEnvReg extreme scenarios) occur, like with hard coal, in the HighEUA and Decom-BAT scenarios. However, the operation of the greenhouse gas emission trading system in a situation of high carbon prices results in a demand reduced by 117.1 million Mg, while the extensive decommissioning of generation capacity (mainly 200 MW hard coal-fired units) translates into increased demand for brown coal by 54.3 million Mg.

- Over the entire period covered by the analysis, the share of coal utilization in the electricity production fuel mix changes. The largest changes take place in the HighEUA and Decom-BAT scenarios, where the share of hard and brown coal falls to 28.5% and 23.5% in 2050, respectively. In other scenarios (RES-30%, HighEnEff, and WindPot-100%), the share of coal is much larger and ranges from 58.6% to 69.5% in 2050, and this share of electricity is generated almost entirely from hard coal since brown coal has a maximum share of 0.8%.

The undertaken research and analyses carried out in this article have confirmed that environmental regulations significantly influence the prospective demand for hard and brown coal in the power industry. However, depending on each of the regulations considered, the scale of this impact varies. The greatest quantitative impact—both in terms of demand for hard coal and that for brown coal—has been observed in the case of high prices for CO_2 emission allowances (under the EU ETS) and more stringent standards for emissions from the combustion of fuels related to the implementation of the Industrial Emissions Directive (IED) and BAT conclusions. A lower impact on demand for coal, although significant in the entire time horizon of the analysis (2017–2050 period), is shown to result from regulations related to the promotion of energy from renewable sources (taking into account the minimum share of 30% for this energy in the total gross electricity production in 2030), assuming an increase in energy efficiency and, consequently, a low path of demand for electricity and adopting regulations concerning the unblocking of the onshore wind energy potential available in Poland (abandoning some of the provisions of the Act on wind energy investments).

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