



Polish energy sector 2050

4 scenarios

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Introduction

We present to you a study that - we hope - will be of value and support to the discussion on the national energy policy in the 2050 perspective.

The energy landscape is changing faster than ever. With a high level of unpredictability, the analysis of megatrends is key, as they determine the sustainable direction of energy development. It is important to adapt to existing conditions, but also to plan a few steps ahead. The aim of our publication is to evaluate four different scenarios for the development of the Polish energy sector over the next 30 years. We have analyzed the economic, social and environmental implications of their implementation.

Extensive modernization lies ahead of the Polish power industry. In the coming years, more than half of the power generating units will be decommissioned for ecological and environmental reasons. The dilemma on filling the generation gap, which without doubt will appear in the coming years, will have to be resolved.

This is undoubtedly an intricate jigsaw - when making decisions it is necessary to take into account the costs and the possibility of raising capital for investments, ensuring jobs in Poland, as well as reducing the environmental and health impact. International obligations and EU common market regulations are vital. But stable supplies of electricity are crucial.

We hear voices that, in the face of unpredictability, preparing long-term analyses is useless, and a reactive approach is more

suitable. We think it is quite the opposite. Without a long-term energy policy until 2050, the Polish energy industry will drift and risk unprofitable investments. High investment uncertainty will discourage action. In the face of capital-intensive decisions within the energy sector, an action plan is important. Without it, it will be difficult to maintain energy security, not to mention the development of domestic business, the creation of jobs in Poland, and the improvement of innovation.

According to our analysis, maintaining the status quo within the power industry will be impossible - the market will impose changes. Poland should seek to diversify its energy production sources. Even if our analysis shows that, with the current fuel cost estimates and the declining costs of some technologies, the cost difference between the scenarios is insignificant.

We have analyzed the potential of national energy sources, the possibility for Poland to meet its EU commitments by 2030 and 2050. Despite the complexity of the matter and the difficulties in forecasting over a 30-year period, we have made every effort to show how significant the impact of the decisions (not) taken will be.

We hope that this analysis will be a valuable contribution to the discussion on the strategy for development of the Polish energy sector.

Yours faithfully

Joanna Maćkowiak Pandera, PhD
President, Forum Energii

2. Executive Summary

1. Introduction

The objective of this study is to analyze economic and environmental effects of four scenarios for domestic energy sector development as well as their impact on the national economy.

- **“Coal scenario”** - is based mainly on coal-fired units. The scenario assumes construction of new hard coal and brown coal mines. In 2050, the RES share will amount to 17%.
- **“Diversified scenario with nuclear power”** - introduces a diversified mix of energy technologies, along with a nuclear power plant, instead of a brown coal-fired power plant. In 2050, the RES share will amount to 38%.
- **“Diversified scenario without nuclear power”** - it is similar to the previous one, however, energy generation in a nuclear power plant is replaced by increased generation from natural gas and RES, whose share in 2050 will amount to 50%.
- **“Renewable scenario”** - assumes gradual withdrawal of carbon-based energy. RES - based energy generation share increases up to 73%. Gas cogeneration units complete generation balance.

The scenarios along with the common input assumptions were adopted after an expert debate that initiated the project.

The most important conclusions

- **Total system costs of each of the analyzed scenarios are similar for the period between 2016 and 2050.** The difference does not exceed 6%. They amount to approx. EUR 529 - 556 bn (CAPEX and OPEX in the period 2016-2050). The renewable scenario means lower electricity prices in comparison with the coal scenario - within the range from EUR 2/MWh to EUR 9/MWh.
- **Individual scenarios differ significantly in terms of CO₂ emission level reduction (2050 compared with 2005).** The coal scenario implies reduction by 7%, 65%-68% in case of the diversified scenarios and by 84% in case of RES. The renewable scenario will allow achieving the reduction targets of the European Union, provided that energy efficiency policy is implemented simultaneously.

- **Diversification of the energy mix will improve energy security.** The renewable scenario provides the highest level of energy independence (only 30% of imported fuels), due to the use of primary energy local resources. In the coal scenario there is a risk of rapid increase of imported fuels. In 2050, it is estimated that between 45% and 70% of the coal necessary for electricity generation might be imported.

2. Assumptions for a scenario analysis

The demand for energy and power in the National Power System

The assumed increase in demand for energy amounts to **1.4%** per year. In 2050, net energy generation will amount to approx. **220 TWh**.

This is a resultant of growth factors, such as development of electric transport and heating sector electrification, as well as factors reducing demand: energy efficiency improvement, development of passive housing and demographic changes in Poland.

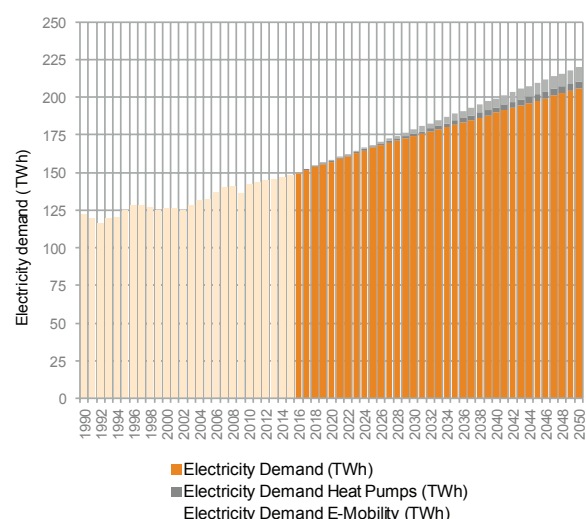


Table 1 Installed power of the National Power System

Installed power of the groups of generating units (GWe)	Coal scenario		Diversified scenario with a nuclear power plant		Diversified scenario without a nuclear power plant		Renewable scenario	
	2030	2050	2030	2050	2030	2050	2030	2050
	GWe	GWe	GWe	GWe	GWe	GWe	GWe	GWe
Nuclear power plants	0,0	0,0	1,5	6,0	0,0	0,0	0,0	0,0
Coal-fired power plants	25,3	22,6	19,1	6,7	18,4	5,5	18,4	0,0
Coal-fired CHPP	7,3	5,9	4,4	2,8	4,4	2,8	4,0	0,0
CHPP, CCGT and gas turbines	3,4	11,5	6,9	19,3	7,6	26,1	9,7	30,0
RES	13,1	15,3	18,8	37,0	20,8	47,7	28,8	68,6
Cold reserve in coal units	1,0	1,0	1,0	1,0	1,0	1,0	1,4	4,5
Reserve in gas units	0,0	3,8	2,0	5,5	3,5	6,5	0,7	5,1
Total	50	60	54	78	56	90	63	108

Increasing demand for energy will be accompanied by an increase of peak power demand (from 25 GWe, currently, to approx. **40 GWe** in 2050). The peak power demand in winter periods will increase (year to year) faster than in summer periods, due to the use of electricity for heating purposes.

Scenarios for domestic energy sector development

The assumed four scenarios for reorganization of the domestic generation base differ in terms of diversified technologies and the share of energy generation from renewable sources (Tab.1 and Fig. 2) The assumed 9% of domestic power reserve imposes the necessity of constructing units, whose share in the domestic

energy generation is either minimum or insignificant. A solution to this problem would be a better cross-border coordination to maintain the required reserve levels, through the division of costs between all countries involved.

Modernization of the selected hard coal-fired power plants (along with the completion of currently executed energy investment projects), improvement of energy efficiency and the use of the potential of cogeneration development will allow for approx. a 10-year break in the construction of new generating units in the coal scenario. After this period, the withdrawal of decapitalised units will force new investment projects.

The share of individual generation technologies

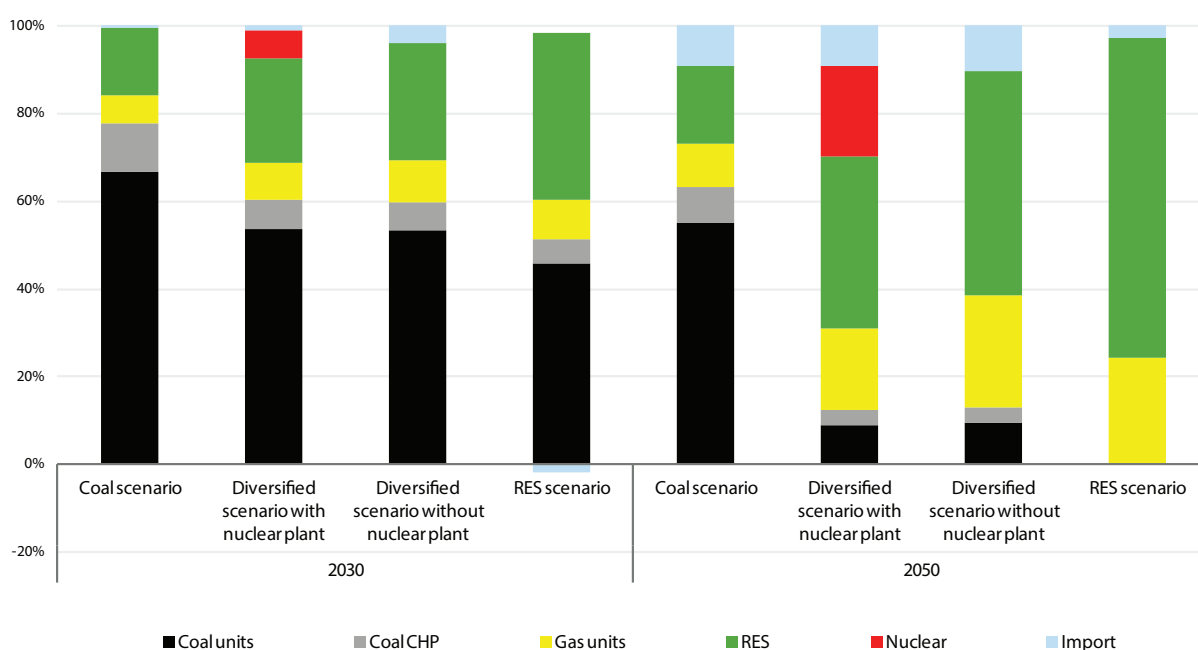


Fig. 2 The share of domestic generation and import in covering domestic demand for energy in the perspective of 2030 and 2050.

Nuclear power

We have adopted cautious assumptions regarding the capital expenditures on construction of a nuclear power plant in Poland (5 million EUR/MWe). There is a high probability that the costs will increase above the assumed levels. In all European countries, what appears are the risks related to timely completion of the construction works, maintenance of the design costs at the planned level or acquisition of investment project financing on favorable terms. As a consequence, economic results of these investment projects are much worse than expected.

Furthermore, the conducted analysis of investment project profitability indicates that after 2040, the nuclear power plants will cease to be competitive in comparison to wind farms and photovoltaics, assuming even a very moderate decrease of the prices of energy from renewable sources.

Cogeneration development strategy

The individual scenarios assume different levels of installed power output of combined heat and power plants. The largest power level is predicted in the RES scenario, assuming the possibility of using the development potential of cogeneration in coal-fired heating plants and combined heat and power plants, in which, until 2030, it is planned to replace decapitalized units with a power output of approx. 1800 MWe. In the renewable scenario, power output of the combined heat and power plants amount to approx. 19 GWe, which constitutes almost half of the peak power demand (the second half of the power demand is covered by gas power plants - CCGT). It is expected that in combined heat and power plants the cogeneration units will be operated in accordance with the needs of electricity market, rather than those of heat market, therefore it will be necessary to adjust the plants to new operating principles in terms of technical solutions.

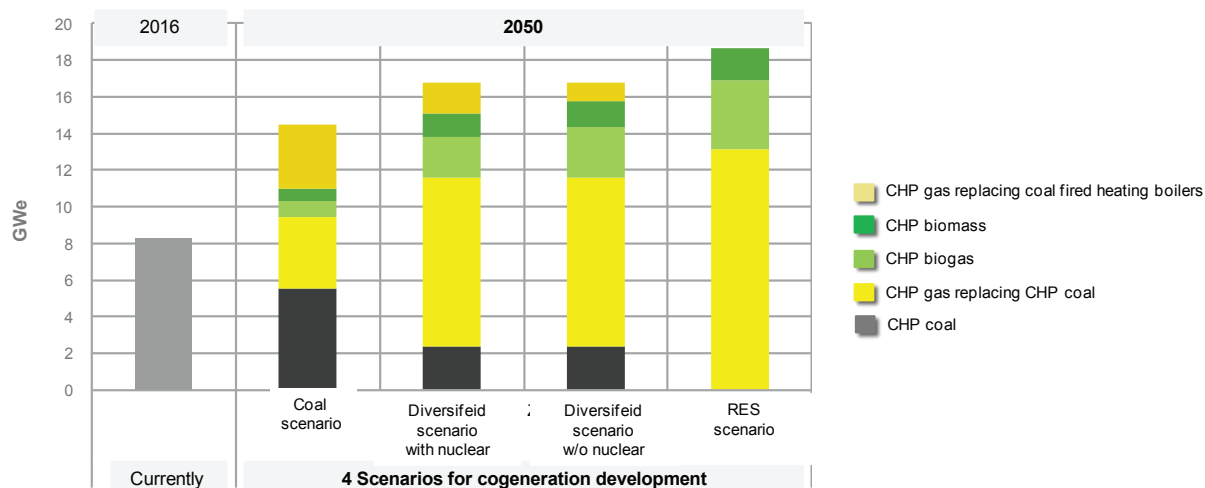


Fig. 3 Installed power output of cogeneration units, currently and in 2050

Integration of the National Power System (NPS) with the heating sectors and electric transport sectors (energy accumulation), along with demand side response (DSR) can reduce the costs of peak power reservation. Particularly high potential lies in the existing heating systems, which can both consume or supply electricity. Due to the large power output of the heating systems, their impact on stabilization of the NPS operation may be significant.

Annual investment expenditures

Subsequent scenarios (from the coal scenario, diversified scenario to the RES scenario) are characterized by successively higher CAPEX with successively lower generation costs (OPEX). The coal scenario (Fig. 4) assumes modernization of a part of the generation fleet increasing the operational life time of the existing units. However, from 2030 a need for intense renewal of assets can be observed.

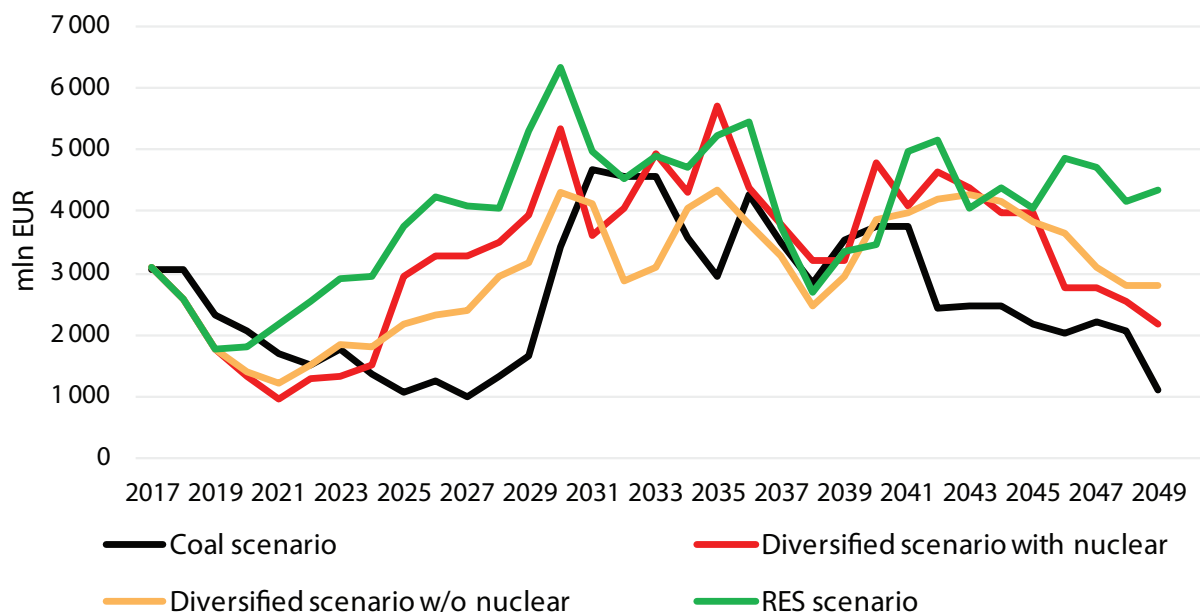


Fig. 4 Annual investment expenditures in the domestic energy sector

3. Generation costs borne by wan energy consumer

Total cost

The total cost is the sum of OPEX, CAPEX, fuel and CO₂ associated with energy generation. Figure 5 shows the costs which will have to be incurred by the customers in the period from 2016 to 2050. The level of costs in particular scenarios is quite similar, while the distribution of components changes. The coal scenario is characterized by the lowest level of capital expenditures, but, at the same time, high fuel costs, regulatory risk and the highest environmental costs. In turn, the diversified scenarios have the highest costs of electricity import, being a consequence of the specific nature of the mix of the generating units and the resulting wholesale electricity price.

In addition to the total cost incurred throughout the period, the trend analysis of annual costs is also of high importance (Fig. 6). This analysis indicates that following 2030, the coal scenario will be more expensive than the other scenarios due to CAPEX

related to the necessity of intensive construction of new power outputs and environmental costs (mainly the purchase costs of the rights to CO₂ emission and additional costs of CAPEX and OPEX resulting from BAT conclusions),

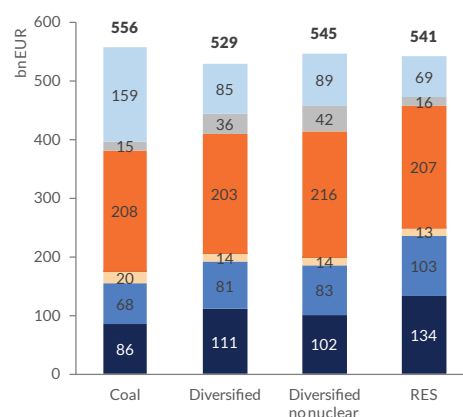


Fig. 5 Total costs of energy generation in the period from 2016 to 2050

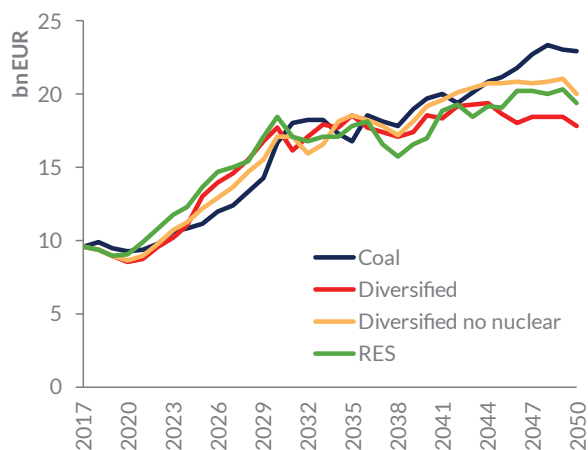


Fig. 6 Annual costs of energy generation

Fuel costs

As it can be seen in Fig. 5, the fuel costs in the period between 2016 and 2050 are similar. What has changed is their structure (Fig. 7) - decrease of the share of coal costs and increase of gas and biodegradable fuel costs. The renewable scenario assumes the use of gas for two purposes: about half of gas for generation of heat and electricity, and the rest for balancing the variable RES.

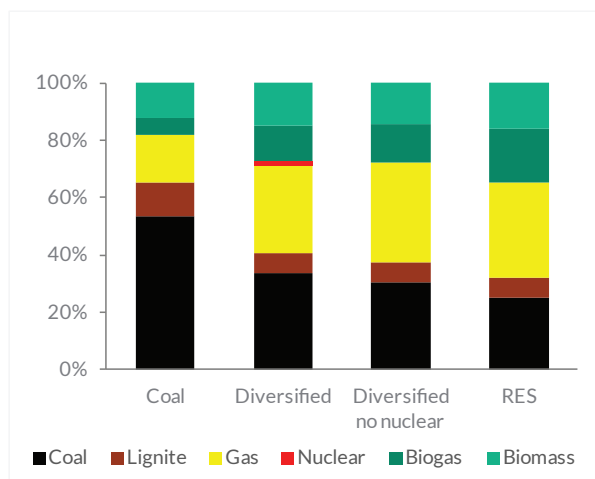


Fig. 7 The structure of fuel costs in the period between 2016 and 2050

Energy price

As opposed to the total generation costs, consisting of equity components, the wholesale energy price is mainly a derivative of variable costs, i.e. fuel prices. Figure 8 shows the average wholesale prices until 2050. Due to a large share of RES with a low (zero) variable cost, the renewable scenario ensures the lowest

level of the prices in the medium and long term perspective. This feature of the renewable scenario allows it to generate the lowest demand for energy import to Poland from the neighboring markets. A conducted additional sensitivity analysis assuming zero power of cross-border connections, showed an increase in electricity prices within the range of EUR 5/MWh - EUR 10/MWh depending on the scenario. However, it should be noted that in the future the price of energy raw materials may be subject to significant fluctuations. Furthermore, the process of gas market liberalization, if conducted effectively, may reduce the price of this raw material.

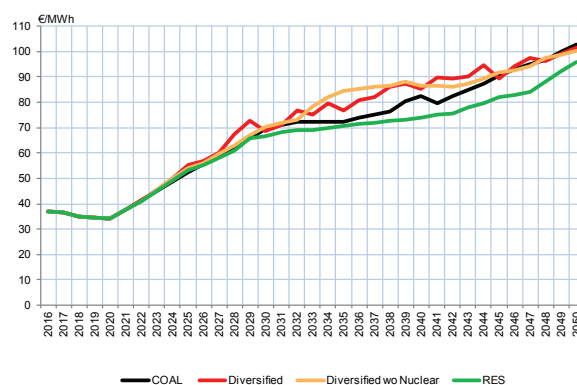


Fig. 8 Wholesale electricity prices

The impact of the wholesale prices on cross-border exchange balance

In connection with the planned reduction of coal-based generation and decommissioning of nuclear power plants in Germany in 2022, resulting in the need for the increased use of gas units, it is assumed that the wholesale electric power prices in the German market will increase. As a consequence, energy export from Poland will be increasing until 2030 (Fig. 9).

Along with a further increase, from the beginning of 2030s, of electricity generation from RES in neighboring countries, especially in Germany, Poland will become a net importer of electric energy.

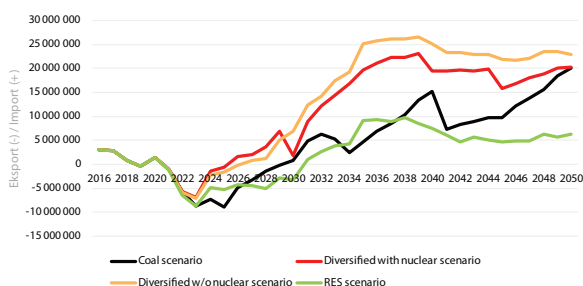


Fig. 9 National balance of trade (export [-] / import +)

The renewable scenario is characterized by the lowest import needs, due to the high share of RES units with low costs of generation, which effectively lower the wholesale energy price. Small import needs in this scenario result from a slightly higher cost of power reservation in gas units in Poland (due to the assumption of higher gas prices in Poland than in the European market). In connection with a large share of gas power plants in diversified scenarios the wholesale electricity price in Poland increases. This causes an increase of import of cheaper energy from the neighboring markets having more and more RES units with “zero” variable costs.

Risk of lack of return on the capital invested

The wholesale electricity price is a price of instantaneous balance between demand for energy and its supply. This price is determined by the so-called marginal short-term variable costs. Usually, the price does not reflect a level that would serve as a guarantor for covering not only the costs of generation, but also of the capital expenditures and capital costs.

An indicator of an energy price that would cover all the costs incurred by the investor is the so-called Levelised Cost of Electricity (LCOE). A diagram in Figure 10 shows how LCOE will evolve, along with a change of the CAPEX/OPEX in the subsequent years.

The LCOE is a measure of market attractiveness of individual technologies from the point of view of an entity constructing a generating unit. As the diagram shows, in the perspective of 2030 all key low-emission technologies will become more profitable than the hard coal- and brown coal-fired power plants. Wind onshore farms and photovoltaics will reach the profitability threshold much faster than the coal-fired units. In 2050, the hard coal-fired power plants, even those operating under base load, will provide energy up to approx. 50% more expensive (converted into MWh) than the wind farms and photovoltaics. From the economic point of view, construction of the coal-fired power plants, with focus on operation under base load, is risky. Increase of the share of the variable RES will result in the need to reduce their operation time.

The capital cost has a huge impact on the expected energy price. LCOE calculations for a nuclear power plant or an offshore wind farm for 2030 indicate that the change of the capital cost by 3 % will result in LCOE change by 15% - 20%. This is the cost that the energy consumer has to borne due to investment uncertainty being a consequence of a lack of regulatory stability. Under stable economic and legal environment, the capital cost decreases, which translates into cost savings for the energy consumers.

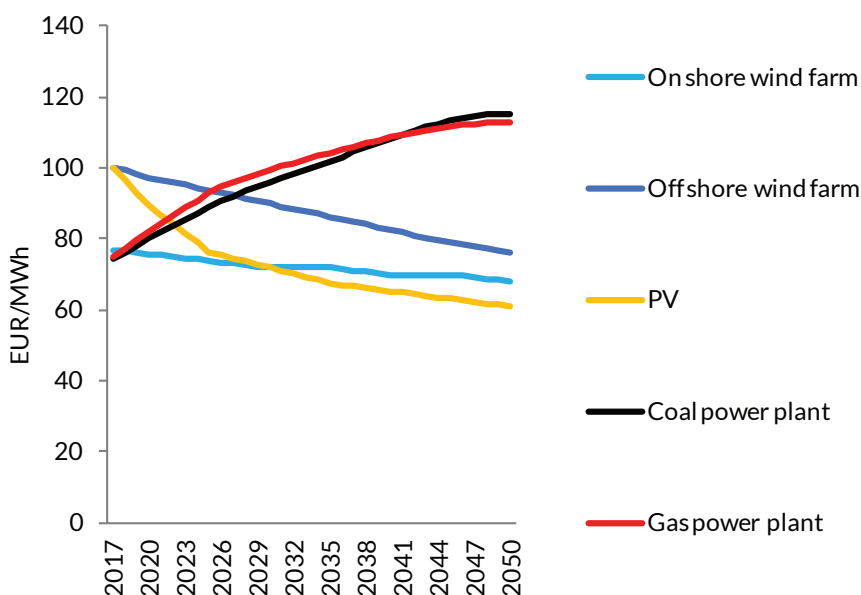


Fig. 10 LCOE of the variable RSE and a coal-fired power plant operating under base load (R=7%)

4. Energy security and dependence on fuel import

Energy security may be defined as the ability of reliable energy supply at acceptable prices, along with free access to the necessary energy raw materials.

Demand for coal

Figure 11 shows the total energy demand of an energy sector for hard and brown coal in different scenarios (converted into coal with a calorific value of $W_u = 23 \text{ GJ/t}$). The coal scenario is characterized by constant demand for coal, while the other scenarios gradually decrease coal demand, up to almost complete suppression in the renewable scenario, in 2050. In the diversified scenarios, in 2050, demand for coal will originate from the domestic power units currently under construction.

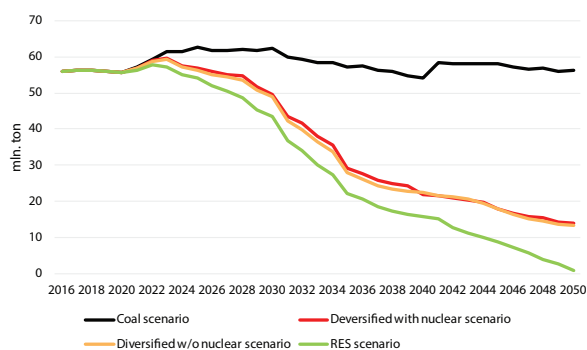


Fig. 11 Total demand of the energy sector for hard and brown coal (recalculated into coal $W_u = 23 \text{ GJ/t}$)

Hard coal supply in Poland

Taking into account factors, such as:

- geological conditions and increasingly difficult availability of hard coal deposits,
- necessity of modernization of the existing coal mines in order to improve their competitiveness,
- no new staff in the mining industry due to the development of the alternative branches of industry and services,
- rising public opposition to the construction of new mines,

it can be stated that domestic hard coal supply will be gradually decreasing (Fig.12).

As a result of the conducted analysis, it was found that coal generation in the existing coal mines will be halted by 2050. Only new mines in the Silesia region and, more probable, in the Lubelskie region, will cover a part of demand of the domestic energy sector. Until 2050, hard coal mining in Poland will not maintain competitive advantage in the domestic market, even assuming that the its production effectiveness will increase significantly.

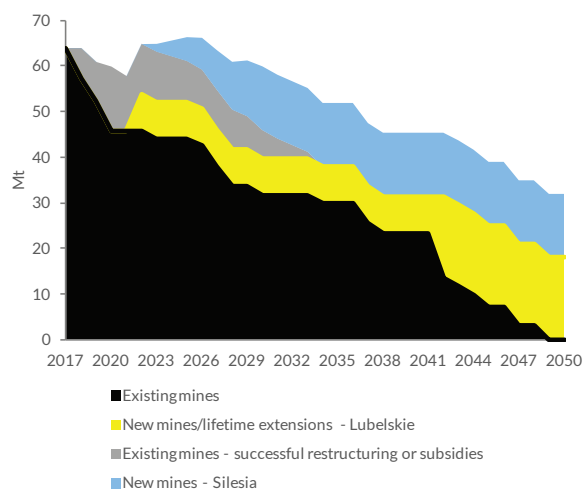


Fig. 12 Forecast of domestic hard coal mining

Lignite (brown coal) supply in Poland

Taking into account factors, such as:

- high expenditures on construction of an open-pit mining along with a cooperating power plant with a power output of 3 GWe (approx. PLN 20 billion),
- the requirement for power plant operation under base load over the period of approx 20 years, to cover high capital costs of the mine and the power plant,
- decreasing competitiveness of electricity generated from brown coal, due to increasing environmental costs,
- public opposition to construction of new open-pit mines,

it should be assumed that the chances for brown coal mines along with power plants in new locations are insignificant. Supply of this raw material will drastically decrease from the beginning of 2030s due to depletion of the currently operated deposits. Figure 13 presents forecast supply of brown coal from the existing deposits and the potential supply from new open pits.

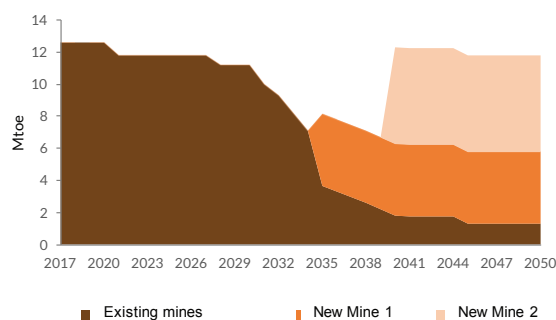


Fig. 13. Forecast of brown coal mining in Poland

This study assumes two options of the domestic coal policy:

1. Intense investment in mining development through construction of two lignite mines and hard coal mines (Silesia region, Lubelskie region).
2. Moderate investments through construction of a mine in the Lubelskie region, that is in the area with better geological conditions and higher social acceptance for this type of projects.

Comparison of the domestic energy sector demand for coal with the forecast supply indicates that in the coal scenario only import will enable balancing the demand. In the first option, hard coal import will amount to approx. 12 Mtoe in 2050. In the second option, import will increase to 23 Mtoe (Fig. 14).

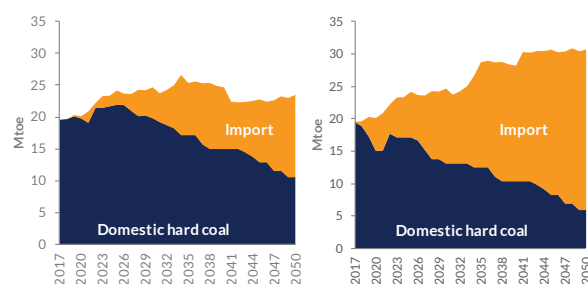


Fig. 14 The coal scenario - demand for coal.

Diagram on the left: option 1 - construction of all planned mines
Diagram on the right: option 2 - construction of a mine in the Lubelskie region only

In case of other scenarios, one may observe a balance of domestic coal supply with energy sector demand due to the diversification of generation mix and increasing share of the RES.

RES potential

A diagram in Figure 15 shows generation volume in individual categories of the RES and installed power in 2030 and 2050, which was assumed in the renewable scenario. In consultation with experts, we analyzed the actual available potential of energy from renewable sources and the possibility for construction of a plant in the perspective until 2030 and 2050.

Thanks to the use of domestic renewable energy potential, in 2050, 160 TWh of electricity will be generated, i.e. approx. 73% of the domestic demand (Fig. 16). The remaining 27% of energy will be generated by half in gas units that at the same time supply heating systems, and in units intended for power system balancing. The renewable sources reduce the negative impact of the energy sector on the environment and climate, as well as improve energy security thanks to the use of primary energy local resources. Increase of generation in the variable RES also poses a challenge for the entire power system. Increase in the dynamics of load fluctuations in the power system imposes flexible response of the entire system (generators - transmission / distribution - consumers). Therefore, the increase of the RES share entails the need to improve flexibility through adaptation in the area of generation and reorganization of the energy market.

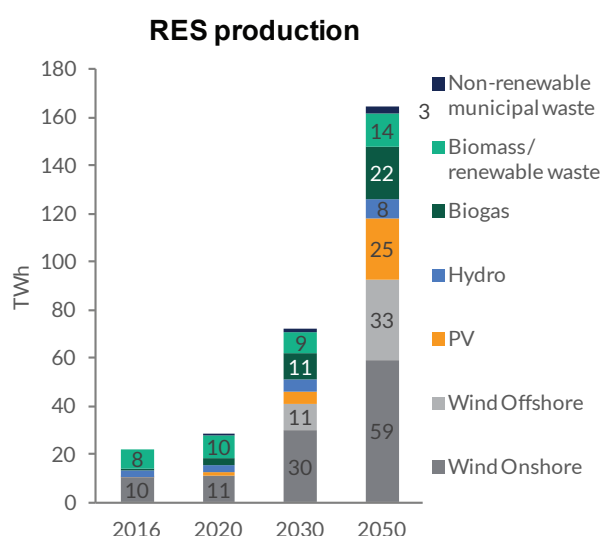


Fig. 15 The RES scenario - electricity generation and installed power

RES installed capacity (GW)

	2030	2050
Waste	0.2	0.5
Biomass	2	3
Biogas	2	4
Hydro	1.5	2
PV	5	24
Wind offshore	3	9
Wind onshore	14	25

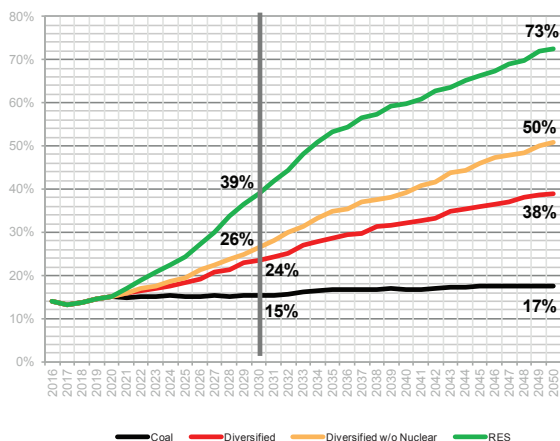


Fig. 16 The share of energy generation from the RES in domestic energy consumption

Development of the variable RES and energy sector dependence on gas import

In the scenario based on the RES, additional demand for gas in relation to the coal scenario will increase by approx. 5 billion m³ in 2050 (Fig. 17). This is approximately equal to the current import capacity of the LNG Terminal in Świnoujście. It should be noted that a part of the increased demand for gas will result from inevitable transformation of the heating sector, forced by increasingly demanding environmental regulations. In the renewable scenario, gas is used for two purposes, the first one being reservation of the variable RES, and generation of electricity and heat in a cogeneration mode as the second one.

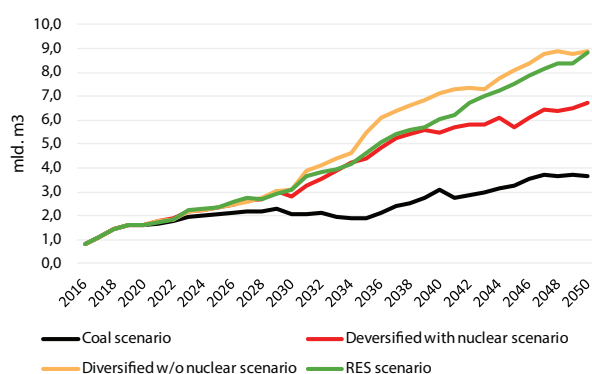


Fig. 17 Gas demand in the scenarios

To obtain a complete overview of energy supply security, it is required to evaluate the costs of imported fuels in the analyzed scenarios for the period between 2016 and 2050. In the coal scenario, successful construction of hard coal and brown coal mines entails achievement of the lowest level of fuel import

costs. However, if the domestic mining development program will be completed only with construction of a mine in the Lubelskie region, then the fuel import costs in the coal scenario will be much higher than in other scenarios (Fig. 18).

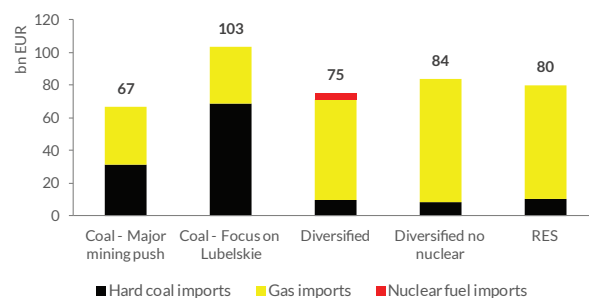


Fig. 18 Fuel import cost in the period between 2016 and 2050.

Dependence of the domestic energy sector on fuel import

In the coal scenario, the share of electricity generated from imported fuel is between 45% and 70%, depending on efficiency in implementing new mines policy. Whereas, the renewable scenario allows for the reduction of the dependence on fuel import to approx. 30%, by using local RES energy, whose domestic resources are sufficient to meet almost the entire demand for electricity.

The diversification of the generation fleet, dispersion of generation sources and maximization of the use of the RES resources translates into:

- increase of import independence of the energy sector,
- higher resistance to disturbances in operation of a transmission system of (due to dispersion of generating units),
- the possibility of improving efficiency of fuel use due to the increase of electricity generation in cogeneration units,
- professional activation through development of local energy clusters.

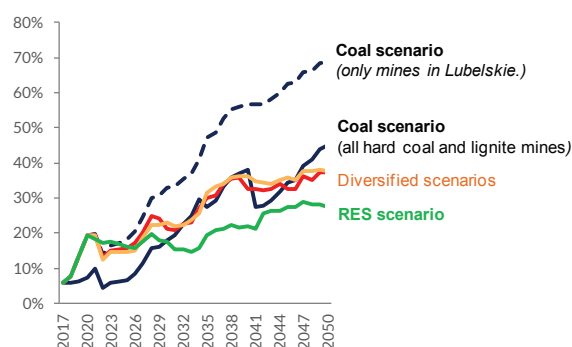


Fig. 19 Electricity generated from imported fuels (including net energy import) in relation to energy demand in Poland

5. Reducing the impact of the energy sector on climate and environment

The EU targets in the scope of CO2 reduction

The scenarios fit in the European climate policy to a various degree (Fig. 20). Only the diversified and RES scenarios provide an opportunity to meet the emission reduction targets of the European Union. In 2050 the coal scenario amounts to only 7% reduction in comparison to 2005. Increase in emissions in all scenarios at the beginning of 2020s is a consequence of the increased energy export from Poland and the adopted principles that emissions (impurities) remain in the country of an emitter.

Particularly noticeable increase in emission may be observed in the coal scenario, since additional generation for export is executed in coal-fired units. In the renewable scenario, despite similar export of energy, such a large increase due to the use of low-emission sources has not been identified.

The sensitivity analysis shows that the lack of brown coal in the future energy mix can reduce the system costs by approx. 1.5%, mainly due to savings on the costs of CO2 emissions. The domestic power industry may reach the limits determined by the Winter Package and ETS Directive (550-450 kg CO2/MWh) in the period of 10 to 15 years. However, it requires intensive transformation of the sector. The conservative variant with the coal energy sector being a dominant one does not provide prospects of achieving the targets of the European Union (Fig. 21).

The efficient reduction of CO2 emission decreases costs at the international level. In the renewable scenario, the domestic energy sector follows the path in accordance with the long-term European climate targets.

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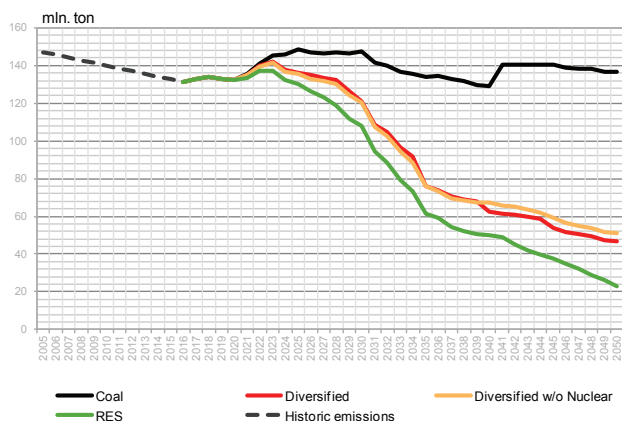


Fig. 20 CO2 emission and reduction vs 2005

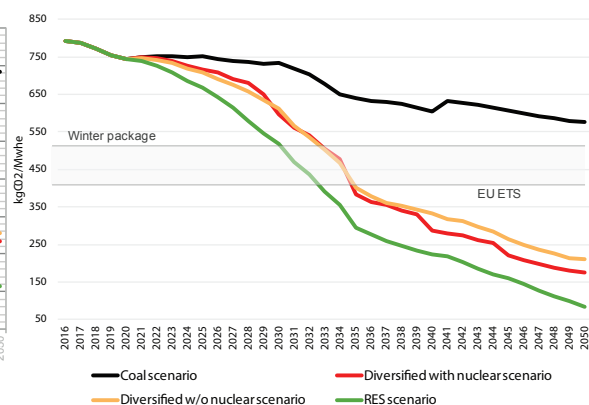
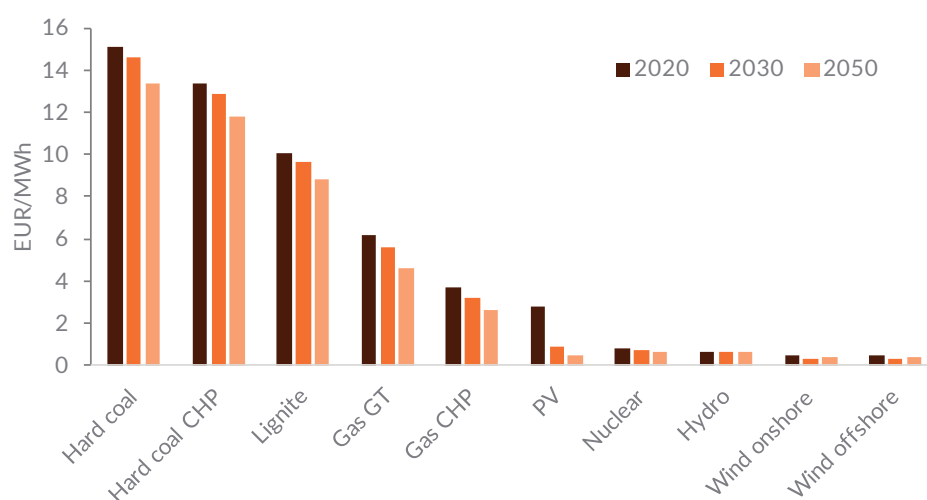


Fig. 21 Unitary CO2 emission of the energy sector vs limits of Winter Package and EU ETS

External costs

External costs are the costs incurred by the public in connection with electricity generation, which are not reflected in its price. These costs are covered in a form of taxes or charges, which seems unrelated to the energy sector. Fig. 22 shows an economic evaluation of the external costs of individual energy technologies, including the impact on human health and environment. The most important is the impact on health, mainly due to air pollution. It includes Poland and the neighboring countries. It also covers impact on the environment (losses in the area of biodiversity and in crop harvest) and damage in construction materials exposed to air pollution. This analysis does not include impact on climate changes, because calculations already include the CO₂ emission costs in the EU ETS system. The decreasing in time external cost values result from implementation of environmental protection standards, among others, introduced by the BAT conclusions.



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Fig. 22 Unitary external costs of energy generation in new

Until 2020, the external costs will be at a similar level in all scenarios due to the similarity of energy mix in the initial period of the analysis. In a long-term perspective, the external costs of the coal scenario will be maintained at the level of EUR 2 billion per year, while in the remaining scenarios they will decrease even four times.

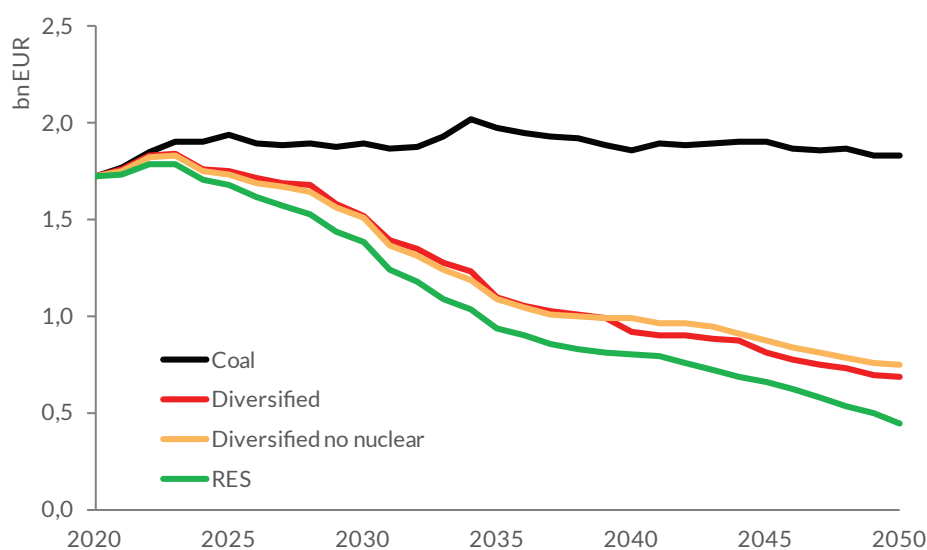


Fig. 23 Dynamic of changes of the annual external costs in individual scenarios

6. The influence of the energy sector on economic growth

GDP

From a macroeconomic point of view, increased expenditures on diversification of the energy sector in 2020s can be considered to be a reasonable investment. It will increase the long term productivity

of Polish economy and lead to the increase in social prosperity, while the demand of Polish households for energy is satisfied to the same extent as in the coal scenario; and the amount of money that can be spent on goods and services increases in a long run. Figure 24 shows GDP changes in comparison to the coal scenario, which is treated as a base scenario.

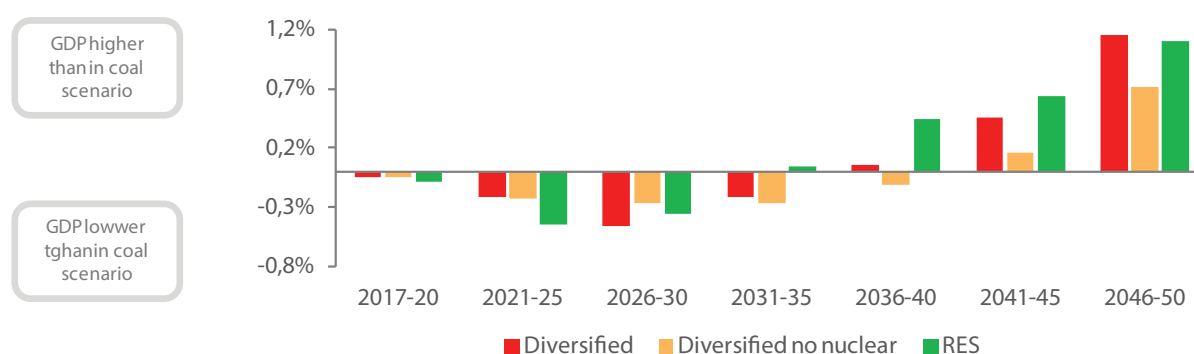


Fig. 24 GDP changes in the diversified and renewable scenarios in comparison to the coal scenario

Labor market

With the support of the mining sector and significant investments in mines (including construction of new ones), in the first years of the examined period, it will be possible to maintain employment in the coal scenario for the next 10 years. However, the perspective changes already in 2030s (Fig. 25). Necessary increase of work productivity leads to the reduction of employment in the coal mining in all scenarios. In the coal scenario, the sector provides approx. 20 thousand work places in 2050. In other scenarios, the index reaches a maximum of several thousand, or even zero. Such a trend is compliant with long-term trends in Europe and in the OECD countries. The decrease of employment in the mining sector is accompanied by an increase of employment in other sectors. In the alternative scenarios, a lot of work places appear, e.g. in agriculture (bioenergy), and in the sector associated with the RES. Employment increases also in processing industry, which provides solutions necessary for reorganization of the domestic energy mix towards more capital-intensive, low-emission generation technologies. High positive impact on employment in the services results from the changes in consumer spendings. In the cost area, better results of the diversified and renewable scenarios in a long term run mean that the Polish consumers will have increased means for non-energy goods and services. Increased consumption expenditures will translate into higher absolute profits in the service sector.

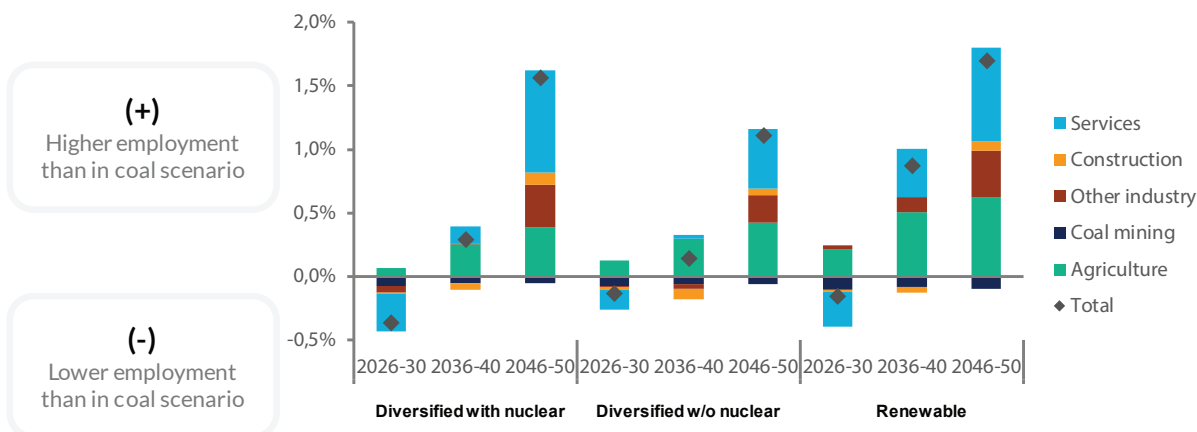


Fig. 25. Changes in the labor market in the diversified and renewable scenarios in relation to the coal scenario (coal scenario = 0%).

3. Scope of analysis

The Polish fleet consists in 70% of plants older than 30 years. Prolonging the status quo is therefore not a viable long-term option.

New opportunities emerge for power system modernization over the next 15 years and they should be utilized carefully. Therefore the Polish energy sector is facing major challenges that need to be addressed with a consistent energy strategy.

Whereas the situation is clear, the future is, by definition, not. We have seen that geopolitical assumptions as well as energy economic frameworks change faster than ever and in a more and more unpredictable manner. Let us draw the first conclusion here:

Facing high levels of unpredictability, resilience is of key importance and is, to a certain extent, based on the diversification of the power sector and energy supply in general.

Does unpredictability render predictions useless? We think not. Firstly, facing capital intensive decisions the only alternative to predictions is inaction, which against the backdrop of the status quo is clearly not a viable option. Secondly, we think predictions can provide value given the right analytical framework. Some megatrends are empirically evident already and can be extrapolated with a high level of confidence. These are the trends on which decision making should be based and which can be highlighted by scenarios. Decreasing costs of renewables relative to fossil power generation, for example, define one important megatrend which might shape the Polish energy sector. Other mega trends can be identified. Energy policy is faced with the task to identify these mega trends and define consistent policies based on them. Forum Energii addressed megatrends on the Polish power system already in 2016.¹

The Polish energy sector is therefore facing the need for thorough transformation and adaptation to future megatrends. Against this backdrop, Forum Energii (FE) has requested enervis energy advisors GmbH (enervis) and WiseEuropa – Fundacja Warszawski Instytut Studiów Ekonomicznych i Europejskich (WiseEuropa) to provide a study that examines social and economic impacts of selected scenarios of the Energy Production Mix in Poland until the year 2050. This study shall support the discussion concerning the Polish Energy Policy until 2050.

It's important to note though that, while model-based predictions can support strategic decision making they should not be a substitute. Therefore, this study doesn't try to deliver a "point-forecast" of how the future will unravel; instead we look at a broad range of different developments to see how mega trends will impact them.

This study models and analyzes energy economic as well as macroeconomic effects intervened with energy policy. Additionally, costs and potentials of domestic energy sources are assessed. We look, among others, at the following effects: system costs, external costs, GDP impacts, growth effects, employment, CO₂-emissions and import dependency. The study therefore supplies a broad range of different criteria to discuss energy policy from different perspectives and rank energy policy options. This allows for a nuanced view on technologies and scenarios.

Given the complexity of the questions addressed in this report, some limitations were in order. Therefore the scope of this project excludes grid modelling and the project focus on the power market, excluding other energy sectors.

4. Structure of this report

This report is structured in six main parts.

The diversification of the generation fleet, dispersion of generation sources and maximization of the use of the RES resources translates into:

1. The first part of this report (Chapter 5) introduces the four main scenarios that will be analyzed. This chapter answers the following question: What energy futures can we foresee for Poland?
2. Chapter 6 looks into technology costs as one of the main drivers of overall cost / benefit analysis. One focus of this chapter is: How fast are RES costs forecasted to drop?
3. Chapter 7 assesses the power market impact of different scenarios. The main question is: How is Security of Supply developing and what measures will secure SoS on a high level?
4. Chapter 8 looks at energy import dependency from different perspectives. One focus of this chapter is: Which technologies can effectively contribute to Polish import independence?
5. Chapter 9: Costs and economic impacts associated with the different scenarios. This chapter answers the following question: What is the economic and social 'price-tag' associated with the scenarios?
6. Chapter 10 broadens the scope of the scenarios and discusses the results of sensitivity modelling for some key drivers. This chapter answers the following question: How resilient are the scenarios and what are their

¹FE, 2016, „Polska Energetyka na fali megatrendów”, Deloitte, <http://forum-energii.eu/pl/tematy/polska-energetyka-na-fali-megatrendow.html>

5. Scenario definitions

This chapter challenges our imagination: What energy futures can we imagine for Poland until 2050? Which technologies can play an important role? What are the underlying challenges for the power system that impact all the scenarios?

5.1 Overview of scenarios

The Polish discussion in regards to technological pathways is especially broad, compared to other countries. The portfolio of potential technologies spans hard coal, lignite, nuclear, natural gas and different renewables. On top of these storage technologies, DSM and CHP could play an important role. Since each of these technologies objectively has specific benefits as well downsides this adds to the complexity of the discussion in Poland.

This study aims to add to the discussion of the merits associated with different technology choices. Since there is a broad set of relevant technologies, this study includes a wide range of scenarios to allow for an equally broad discussion of their effects.

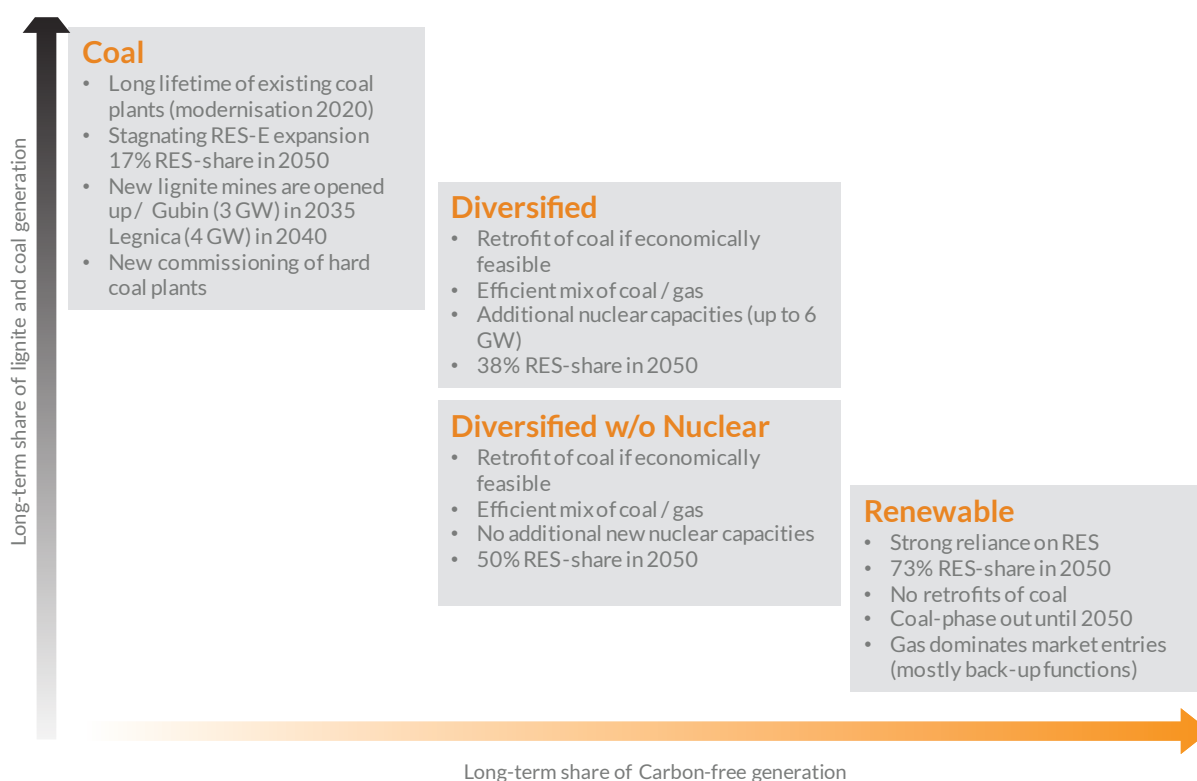


Figure 1: Overview of scenarios / Polish Energy Mix until 2050: General scenario designs

The Polish energy sector is facing the need for thorough transformation. This corresponds with a need for new investments. Due to the long construction period and lifetime of generation assets of any kind, power plants are prone to the risk of becoming stranded investments.

Therefore care must be taken to ensure that investments targeted at the elimination of the risk of capacity shortages in the perspective of 2030 do not become stranded in the long-term perspective.

Of key importance in preventing stranded investments is the choice of a suitable portfolio of generation technologies that is resilient towards short-term shocks and in line with future megatrends.

The scenario includes different energy futures with a focus on generation technology, without prejudging which development is more likely or more favourable. Instead, we define and model scenarios and put the results to the test.

It is also important to note that these scenarios represent technology scenarios, and behind each scenario we could imagine different policies and market designs fostering the specific development. Specific policies and market design decision are not in the main focus of this study, though we will of course discuss implications in regards to market design where relevant.

Figure 1 shows an overview of the scenarios defined for this study. The graph qualitatively compares the scenarios based on their long-term share of carbon-free generation (X-axis) and their share of coal/lignite-based generation (Y-Axis). Following, the scenarios are briefly described.

Coal scenario

The first scenario we analyze in this study is the Coal scenario. It prolongs the status quo of the Polish power generation mix up until 2050 by relying heavily on hard coal as well as lignite. In line with this narrative we assume new lignite mines and plants and we also, by default, commission additional new hard coal fired power plants, independently of their economic feasibility.

Diversified scenario

The so called “Diversified scenario” relies more strongly on renewable energy generation than the Coal scenario. It also substitutes the lignite-based generation of the Coal scenario with nuclear generation and therefore reaches relatively high shares of low carbon generation. On top we model a cost minimizing mix of natural gas and hard coal to supply for the residual generation and cover the peak load.

Diversified w/o nuclear scenario

The second diversified scenario is similar to the first one, but partially substitutes nuclear generation with additional RES. On top of that we again model a cost minimizing mix of natural gas and hard coal to supply for the residual generation and cover the peak load.

RES scenario

In addition we define a renewable scenario. Here, the option to commission new coal-fired plants is excluded from the model. Instead, the scenario introduces a phase-out of coal-based generation from 2040 to 2050, where we transfer all remaining coal assets into a strategic reserve. The scenario is also built on a strong expansion of RES generation. All non-RES generation is covered by gas-based generation, mostly in CHP. Overall this study looks at four quite different technology-scenarios spanning a “coal world” as well as a renewable oriented scenario.

It is important to note that this study does not include an “optimal” scenario which represents a development Forum for Energy or the authors would propose. Nonetheless, there are of course findings from the different scenarios in regards to which characteristics such a development should have.

5.2 Overview of scenarios

	Coal	Diversified	Diversified w/o nuclear	Renewable
Growth & Power consumption	Overall growth rate of +1.4% p.a. compared to 2016 levels Long term (from 2030 on) this is based on the assumption, that additional demand from e-mobility and P2H balances out with the demographic effects			
RES-E share of electricity consumption	Increases slowly to 24% in 2050	Increases to 40 % in 2050	Increases to 50% in 2050	Strong increase to 78 % in 2050
Existing coal and lignite units	Assumed modernization (+ 10 a lifetime) of existing power plants (2021)	Lifetime of 50 years for coal and lignite		
Retrofit of coal units	Life-time extension by 10 years if economically feasible (only one additional modernization per unit possible).			No retrofits assumed, long-term coal phase-out (2050)
Additional market entry	Forced entry of new coal to keep coal share relatively stable	Economic modelling of new market entry (coal vs. gas)		Economic modelling, no new coal units
New lignite units	New mines are opened up / Gubin (3 GW) in 2035 Legnica (4 GW) in 2040	No new lignite mines or plants		
New nuclear units	No new build nuclear capacity	Capacity of 6 GW in the beginning of 2030s years	No new build nuclear capacity	
Market Design / Security of Supply	Energy Only Market is backed-up by a strategic reserve that guarantees hourly, national reserve margin will not drop under 9% surplus			
Source of fuel and CO ₂ prices	World Energy Outlook 2016 – New Policies Scenario Prices until 2050: 84 €/TCE (coal) / 39 €/MWh (gas) / 80 €/t (CO ₂)			
Interconnection capacities	Development of NTC along entso-e Ten Year Network Development Plan 2017			
CHP	Existing CHP sites will be continued. Centralized CHP-Heat capacity stays constant over time. Decreasing heat capacity of existing units is compensated by a mix of coal and gas-based units. In existing boiler-only systems new biogas, biomass /waste and gas-fired units are commissioned.			
Hard-coal mining	Domestic supply: Major coal push	Focus on most efficient mines	Focus on most efficient mines (Lubelskie)	No New mines

Table 1: Overview of assumptions: All cells that are colored in grey (from light to dark grey) represent predetermined assumptions. Cells in blue highlight where the model optimizes outcomes.

To better understand the results it is beneficial to comprehend the assumptions of the scenarios and the modelling. The assumptions were chosen based on discussions with stakeholders.

Table 1 describes the underlying assumptions of the four scenarios in more detail.

One key characteristic of these scenarios needs to be highlighted at this point because it is of major importance. Our scenarios are determined by a set of predetermined assumptions. These are parameters, where we assume that political decisions, without presuming the measure to reach them, will be of key influence for the future development. Therefore market-based decision making is of little influence in regards to the development of the technology portfolio.

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Since we do not model the decision making process of political agents, all political parameters are predetermined and cannot be influenced by our models (grey cells). For example, the development of renewables, nuclear, lignite and CHP is predetermined by assumptions.

This implies that in most scenarios our models have quite little degrees of freedom when it comes to commissioning new power plants.

So what degrees of freedom do remain with our models? Our power market model is tasked with finding an optimized technological answer to the assumptions set up. This point addresses all cells that are highlighted in blue.

In the Coal, the Diversified and the Diversified w/o nuclear scenarios our models are tasked with optimizing retrofit decision based on economic feasibility. In the two diversified scenarios our models can also optimize new commissioning of power plants. Here the model is tasked with finding an efficient mix of new hard coal- and gas-fired plants.

On top of that our models assess the economic effects of different scenarios and their assumptions, especially in regards to power plant dispatch.

5.3 Important assumptions in detail

Some main assumptions will be discussed in more detail in the following chapters.

5.3.1. GDP and power productivity

An important driver of power consumption is economic growth. For estimating the development of power demand we chose a “top-down” approach in this study. We assume developments of economic activity (“Gross domestic product” short GDP) and power productivity based on a literature review to derive power demand. Therefore the assumptions in regards to GDP and power productivity are important for power demand and therefore for the overall results.

The following graph illustrates our assumptions for economic growth. Here we go with recent forecasts of the ministry of finance² for the period 2018-2045 and extrapolate the trend until 2050. For the future we assume a stable and slowly declining real growth rate in the range of 4% - 1.8% p.a. According to these numbers, Poland experiences stable growth for the next decades and closes the gap separating it from other economically more developed countries in Europe that have lower results. Our assumptions imply a strong growth of GDP which also has to be taken into account when discussing the relevance of certain costs for the overall economy (see Chapter 9).

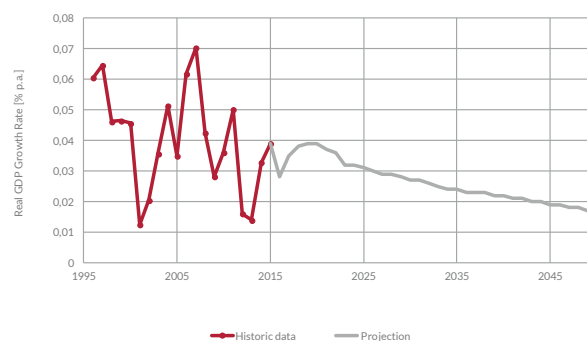


Figure 2: Development of real growth rates

The following graph illustrates the assumed development of Polish power productivity. For comparison we also included the EU 28 power productivity based on the European reference scenario³. Power productivity is a measure representing how much economic activity can be generated relative to power demand. It is therefore a measure closely related to power efficiency. The higher efficiency of the system, the higher the power productivity.

The grey line represents the assumptions of this study in regards to the development of power productivity. Clearly Poland is, even though starting from a lower level of power productivity, closing in on the European average. We are more ambitious in our estimates of future developments of power productivity than the UE reference scenario (blue line).

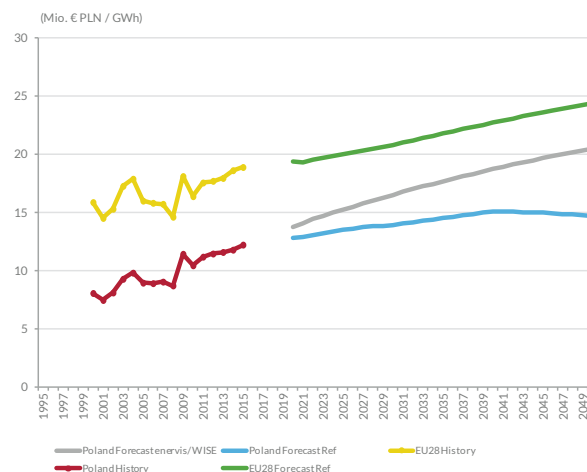


Figure 3: Development of power productivity in Poland

²GDP: 1995-2015 - GUS, 2016 - most recent estimates, 2017 - EC estimates, 2018-2045 - Ministry of Finance estimates, 2046-2050 - extrapolation of MF projections

³E3M Lab (2016): EU28: Reference scenario (REF2016)

5.3.2 Demand and peak load

Polish GDP growth is as major driver for the future development of electricity demand. Even though GDP growth and increases in power productivity balance out to a certain extent, overall GDP growth dominates and we assume the following development of power demand.

Taking into account an increasing share of e-mobility of up to 20% until 2050 (~ 9TWh) as well as additional demand from heat pumps around ~20% of electrification of domestic heating demand in 2050 (incl. efficiency increase of 1.1% p.a. in heating demand) we altogether assume an annual growth of total electricity demand by 1.4% p.a. (compared to 2015 levels).

Overall we go with conservative assumptions regarding the development of the power demand from the heat and mobility sector. Even though some stakeholders argued a stronger increase of demand from those sectors, overall the upsides (higher efficiency, lower growth) and downsides (faster sectoral integration) balance out. Also, the resulting development is in line with most other studies, which increases comparability.

Net demand grows from 148 TWh to around 220 TWh in 2050. This growing demand defines a key challenge that all scenarios have to cope with. This implies that an additional 70 TWh of power demand and the corresponding peak load increase need to be covered by new power generation. Already here we can see that additional increase in power productivity would be a welcome measure to reduce power demand and strain on the system. In case an additional energy efficiency measure can be successfully implemented, the growth of electricity demand would be lower.

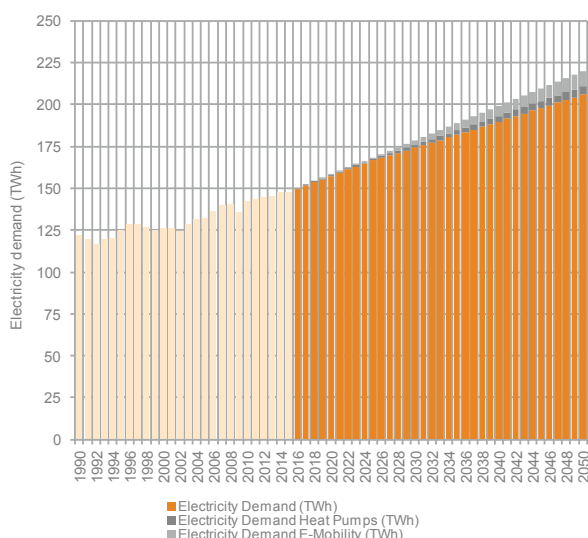


Figure 4: Development of electricity demand excl. own consumption of power plants, incl. grid losses (Source: Own assumptions based on ARE and European Commission)

If we compare our results with other recent forecast we see the following picture. Until 2030 our assumption (grey line) lies centrally within the peer group.

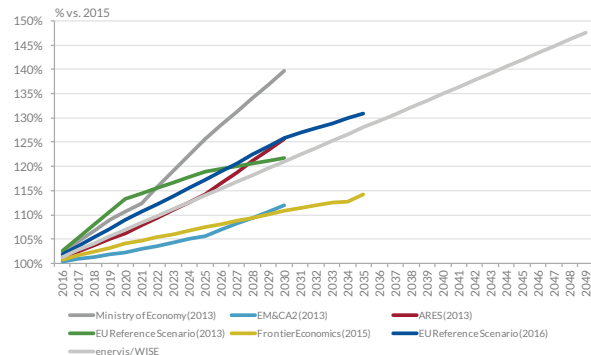


Figure 5: Comparison with literature / relative increase of gross or net demands (depending on study) vs. 2015

Next to the development of power demand the underlying structure is relevant, especially in regards to the peak load (i.e. the highest demand in the year). Here, we assume the historic structure as of 2016 and explicitly model changes of demand structure due to e-mobility and electrical heating.

It comes as no surprise that alongside growing demand the peak load also increases. Peak electricity demand is growing even faster than the total electricity demand. Overall winter peak load grows by 1.8 % on average. The summer peak load also grows, but a bit more slowly and in line with the overall demand by 1.4% p.a. This is pre-activation of flexibility. After dispatching flexibility (DSM, e-mobility) the effect on the peak load will be lower. Here we go with the assumption that prospectively 50% of e-mobility demand can be flexibilized as long as the demand for transportation services is still served (given sufficiently high power prices). Altogether we see a strong increase in the peak load. Figure 6 shows the resulting development. As a result, the peak load grows to roughly 40 GW in 2050 through the utilization of demand-side flexibilities.

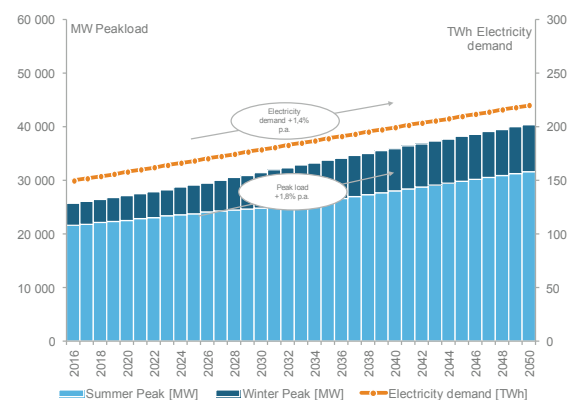


Figure 6: Development of peak electricity demand

5.3.3 Net Transfer Capacities

After having addressed two challenges to the Polish power system in the prior chapters (growth of demand and peak load), in this chapter we address a key enabler: Our assumptions regarding Net Transfer Capacities (NTC) development.

We assume a strong expansion of NTC-capacities based on TYNDP 2016⁴ projects and matching EC draft guidelines.

Import capacities increase by 300 %, though starting out on a quite low level, while export capacities increase by 115 %. Overall, NTC are assumed to increase, setting the stage for a stronger role of the import / export balance.



Figure 7: Development of cross-border capacities

5.3.4 Development of CHP-capacities

Traditionally CHP-based power generation plays an important role in the Polish power system. How will that role develop in the future?

In all our scenarios CHP remains a cornerstone of the Polish energy system. We assume in all the scenarios that existing CHP sites will be continued and additional new CHP sites are developed in existing boiler only heat grids.

This is modelled as follows: The heat capacity of existing CHP plants stays constant over time. If existing CHP units are decommissioned, their heat capacity is compensated by new units. In substituting those units we apply a mix of coal and gas-based CHP plants.

The following graph shows the composition of electrical capacity of CHP plants in the scenarios in 2050. There are CHP plants with ca. 8 GW of installed capacity in Poland as of 2016 (grey bar on the left). All of them are substituted for by 2050. The mix substituting the existing plants is coal heavy in the Coal scenario and more gas heavy in the diversified scenarios. In the RES scenario all existing CHP plants are substituted by gas based CHP units. In effect the electrical capacity of CHP plants in existing sites increase vs. 2016, even though the underlying heat capacity of these plants stays constant. This is due to a more

power-oriented design of the plants.

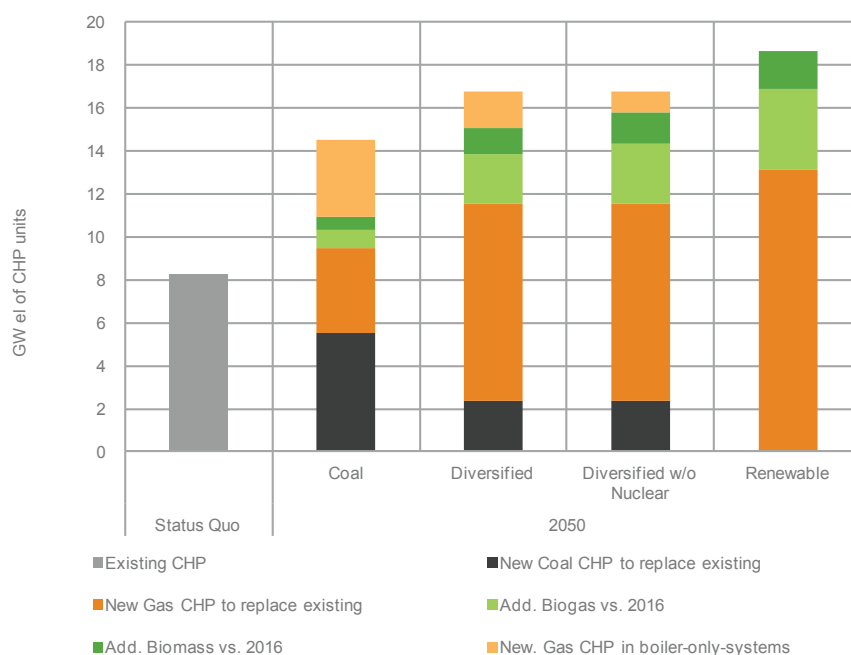
On top of existing CHP sites we assume that plants at new sites can be developed. On top of that, heat generation of boilers can be substituted by additional CHP generation. In all scenarios additional heat demand is addressed by new plants, though the mix differs: Here new biogas, biomass/waste and gas-fired units are commissioned. While in the RES scenario all new projects are renewable by nature, in the Diversified and Coal scenarios natural gas plays a stronger role.

For all new units it is assumed that power generation of CHP plants can be decoupled from heat demand by back-up boilers to prevent must-run generation. Since dispatch of CHP units is determined by our power market models (i.e. electricity price) their effective heat outputs can therefore differ in between scenarios.

In effect we assume an installed electrical capacity of CHP units between 14 and almost 19 GW in 2050. Compared with the domestic peak load of Poland, which increases to roughly 40 GW in 2050 in all the scenarios, this goes to show: CHP plants, especially if gas-based, can provide almost half of the peak demand. This is conditional on the plants' design, which allows them to be operated in condensing mode and as independently as possible of heat demand. CHP needs to be designed with flexibility in mind.

⁴ENTSO-E (2016): Ten Year Network Development Plan 2016 (ENT2016)

Figure 8: Electrical capacity of CHP plants in 2016 and 2050



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6. Development of costs of generation technologies

This chapter looks into technology costs as one of the main drivers of overall cost / benefit analysis. One focus of this chapter is: How fast are RES costs forecasted to drop? When will they break even with other technologies?

6.1 Fuel and CO₂ cost assumptions

The competitiveness of technologies relative to each other depends to a large extent on fuel costs and CO₂-price assumptions. Therefore assumptions of fuel and CO₂ prices are important in shaping overall outcomes.

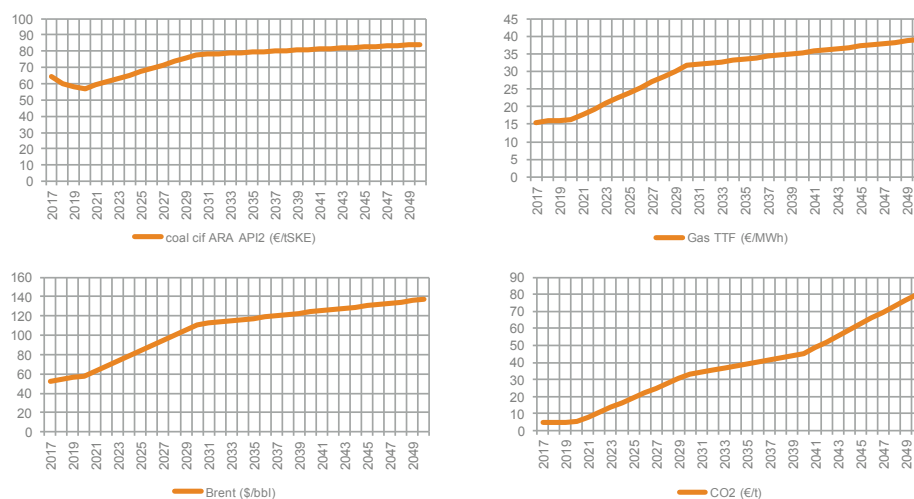


Figure 9: Overview of fuel price assumptions

Our fuel price assumptions are based on the long-term global energy market study World Energy Outlook 2016 - New Policies Scenario of the International Energy Agency. The World Energy Outlook⁵ (WEO) is a widely recognized global energy market study that explores three different scenarios of possible energy futures. Thereby, the New Policies Scenario serves as a baseline scenario. It takes account of broad policy commitments and plans that have been announced by countries, including national pledges to reduce greenhouse-gas emissions. Due to its publishing date the WEO only considers all announced policies until mid-2016. Therefore, the ratification of the Paris Agreement could not be incorporated.

For the short- and mid-term outlook futures price quotations from the 4th quarter of 2016 for the front years until 2020 were used. Price assumptions for 2021 – 2030 were derived from interpolation between future quotations and the long-term study. After 2040 a price increase was extrapolated. For CO₂-prices a long-term equilibrium of 80 €/t was assumed to reflect increasing marginal CO₂-abatement costs with rising worldwide efforts in emission reduction.

Fuel price assumptions lead to a minor fuel switch in the last decade between lignite and modern coal-fired power plants as well as between modern Combined-Cycle-Gas-Turbines (CCGTs) and old coal power plants.

6.2 Investment Costs

Next to fuel costs, CAPEX is a strong driver of overall competitiveness of technologies and therefore outcomes of this study. Key assumptions regarding investment costs of generation technologies are presented in Table 2. The long-term cost trends are diverging, with wind and solar continuing to improve their cost efficiency, while fossil fuel plants see gradual cost escalation which is driven, among other factors, by an expected tightening of environmental standards. For nuclear power plants we conservatively assume comparably high levels of investment costs, with neither improvements nor cost escalation by 2050.

	2020	2030	2050
Gas Turbine	510	530	570
CCGT	820	860	940
Hard coal	1 575	1 625	1 725
Lignite	1 825	1 875	1 975
Nuclear	5 000	5 000	5 000
Wind Onshore	1 400	1 300	1 200
Wind Offshore	2 800	2 500	1 950
Photovoltaic	800	600	475
Hydro RoR	3 600	3 600	3 600
Biogas	3 200	3 100	2 900
Biomass/waste	3 100	3 100	3 100

Table 2: Investment costs of generation technologies (EUR/kWe)

6.3 Development of LCOE of technologies

The cost efficiency of generation technologies can be compared using a simple, synthetic measure: Levelised Cost of Energy (LCOE). LCOE measures average lifetime costs of producing electricity using a given technology. LCOE in a given year represents average generation costs of a plant commissioned in that year over its full lifetime, including the effects of expected changes in fuel costs. The most striking conclusion arising from LCOE comparison is that the key RES technologies are not only characterised by favourable cost dynamics, but also become competitive with new coal-based power plants already within the next 10 years, with onshore wind farm already at or near cost parity. Such outcome is a combination of two key drivers: 1) significant and ongoing technology improvements for RES, 2) changing lifetime costs of new coal power plants.

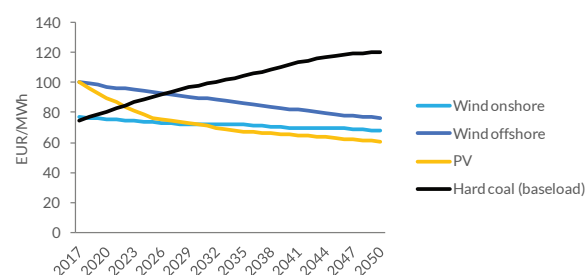


Figure 10: LCOE of variable RES and baseload hard coal power plants under base case assumptions (Note: for all technologies, $r = 7\%$)

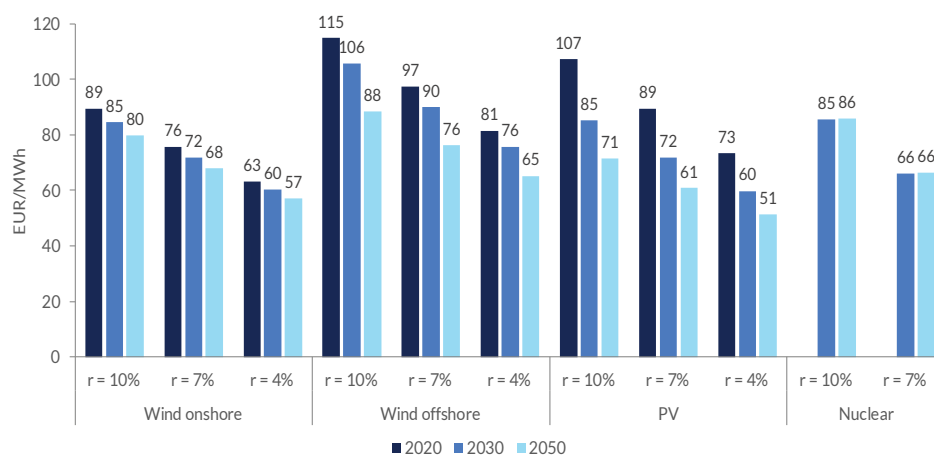
It is important to note that from the perspective of lifetime cost-competitiveness of new coal power plants to be commissioned in the 2020s, CO₂ cost developments in the 2030s, 2040s, and even 2050s or 2060s should be considered. Thus, even a gradual tightening of European climate policy in the long term has significant impacts on the LCOE of coal power plants to be commissioned in the near future.

Further conclusions may be drawn from a more detailed comparison of LCOE indicators for different technologies under different assumptions. Two important drivers of LCOE are cost of capital and capacity factor. Capital-intensive technologies are highly dependent on cost of capital (in the following “ r ”) – this includes especially key low-emission technologies: wind, PV, and nuclear. Dependence on cost of capital is further increased by a long lifecycle in case of nuclear. Capacity factors are also crucial for capital-intensive technologies. In practice, this is the most problematic issue for coal plants, which are characterised by comparatively high CAPEX and significant variable costs (especially fuel costs), which places them at risks of low utilization due to merit order effects. For mid-merit and peaking plants, low CAPEX of gas technologies may offset their high variable costs, leading to their better cost performance against new coal power plants. On the other hand, wind, solar, and nuclear plants face a lower risk of underutilization thanks to their low

⁵IEA (2016): World Energy Outlook (WEO)

variable costs. Here the main risks are curtailment in the case of RES (i.e. limiting the production of variable RES when it is too high to be safely fed into the electricity system), and decreased operating time in case of nuclear power plants functioning in very high variable RES environment. Both effects are limited in the assessed scenarios, with RES curtailment not rising beyond 2.5% even in a high RES scenario, and nuclear capacities utilized close to their technical limits in the Diversified scenario.

Taking the above into account, we can compare LCOE developments for two groups of generation technologies: low-emission technologies dependent primarily on the cost of capital (variable RES and nuclear power plants) and fossil fuel-based technologies, whose costs are driven mainly by capacity utilization rates.



Note: cost of capital range is consistent with the values currently observed in the EU for RES and nuclear
Figure 11: LCOE of different low-emission generation technologies under different assumptions on cost of capital

Figure 11: LCOE of different low-emission generation technologies under different assumptions on cost of capital; Note: cost of capital range is consistent with the values currently observed in the EU for RES and nuclear

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The cost of capital is crucial for both RES and nuclear competitiveness. While low financing costs make the nuclear power plants a most cost-efficient option, recent European experience suggests that it is easier to lower the cost of capital for RES by providing a predictable stream of revenues via auctions or feed-in-tariffs. In case of nuclear, observed high costs (e.g. in the Hinkley Point case) may be explained by both technical and long-term political risks associated with these projects. In turn, recent renewable auctions in several European markets are establishing record low levels of generation costs for solar and wind technologies⁶. These outcomes are in line with our assumptions for Poland once differences in the cost of capital and capacity factors are taken into account. For instance, electricity production costs at the Kriegers Flak offshore wind

farm in Denmark (including grid costs), which is to be launched in 2021, are estimated at ca. 64 EUR/MWh. Our LCOE estimate for Polish offshore wind is 81 EUR/MWh at low capital cost comparable to the Danish case⁷, with the remaining difference explained primarily by a higher capacity factor achievable in the North Sea (ca. 50%) compared to the Baltic Sea (ca. 42%, according to our assumptions). Furthermore, taking into account that recent studies indicate potential for further decreases in RES costs beyond what we assume in the base case, additional sensitivity analysis was conducted with a 20% lower RES costs trajectory (see Chapter 10). The results demonstrate that the scenarios with a higher RES share become substantially more competitive, with the strongest beneficiary of lower RES costs naturally being the RES scenario.

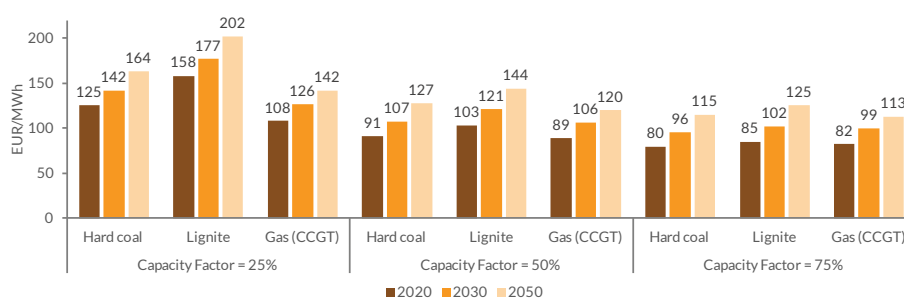


Figure 12: LCOE of different generation technologies based on fossil fuels under different assumptions on capacity factor (Note: for all technologies, r = 7%)

⁶Agora Energiewende (2017), The cost of renewable energy: A critical assessment of the Impact Assessments underlying the Clean Energy for All Europeans-Package

⁷E.g. Agora Energiewende (2017), Future Cost of Onshore Wind; Fraunhofer ISE (2015), Current and Future Cost of Photovoltaics. Long-term Scenarios for Market Development, System Prices and LCOE of Utility-Scale PV Systems.

Turning to comparison between fossil fuel-based power plants, it becomes apparent that there is a permanent cost advantage of hard coal over lignite, regardless of the time horizon or the assessed place in the system (baseload vs mid-merit or peaking plants). This is driven by the fact that LCOE measures average lifetime costs and not current variable costs: the future projections on developments of fuel and carbon costs are already embedded in LCOE for any given year. Thus, new lignite power plants face strong a cost disadvantage due to high emission-intensity.

The comparison also suggests that gas plants are more cost competitive in the long run compared to hard coal plants, despite relatively unfavourable fuel price developments assumed here. For baseload power plants, the two fuel options break even in the mid2030s, while for mid-merit and peaking plants, natural gas is already the cheapest option. There are two additional points to consider when comparing LCOE for hard coal and gas technologies. First, increasing cost-competitiveness of variable RES will put economic pressure on shrinking baseload. Second, differences in lifetime should be taken into account: while gas plants built in the 2020s will not operate long enough to face the

prospect of high CO₂ costs in the second half of the century, this should be included in the assessment of hard coal investments, together with the risk of baseload disappearance in the long run.

Thus, regardless of energy mix choices, there are two points which can be highlighted already based on LCOE analyses:

- It is crucial to provide a clear and stable framework for the development of low-emission technologies. In the Polish case, where the cost of financing for such investments is among the highest in Europe (e.g. the cost of capital for onshore wind farms was 8.7-10% in 2014, compared to 3.5-4.5% in Germany⁸), ensuring a stable domestic framework for the energy sector development is as important for lowering energy production costs as ongoing technological improvements driving down RES costs.
- It is important to ensure that investments in the perspective of 2030 do not create stranded assets in the long-term perspective. Given the trend of decreasing RES costs, combined with increasing fuel and CO₂ costs, care should be taken to optimise investment in fossil fuel power plants, avoiding oversized and non-flexible capacities.

7. Techno-economic evaluation of scenarios for the development of the energy sector

In the upcoming years Poland's power plant fleet faces a crossroad between modernization and replacement of existing power plants. 70% of the power plants of the Polish fleet are older than 30 years. We assume that until 2021 around 3.8 GW of coal and lignite capacity will be decommissioned due to non-compliance with updated EU-wide emissions standards (BREF LCP)⁹. This is based on a first assessment based on available information as of end of 2016. While some units were retrofitted in the last years, the future of further 6 GW is still pending. Here it is unclear if they will be modernized or if they will be decommissioned in the mid-term. On the other hand, 6 GW of new build power plants, of which 70% is coal or lignite-fired, is currently under construction and will be commissioned in the following years until 2019. Our scenarios explore four possible pathways how the Polish electricity system can modernize its fleet to cope with a rising electricity demand and updated EU-regulations.

This chapter looks closer at the techno-economic implications for the electricity sector of each scenario. Thereby, the following questions will be addressed:

- How can the decapitalized Polish power plant fleet be modernized to cope with rising electricity demand in the near future?
- How can the issue of long-term security of supply be addressed?
- How do the different technology choices affect Polish electricity imports?
- How can the Polish electricity sector contribute to long-term targets for emission reduction?
- What role has RES deployment to play in reaching these targets?
- How do different technology-mixes affect power prices?

⁸ Diacore (2016), The impact of risks in renewable energy investments and the role of smart policies.

⁹ Own estimates, based on analysis of BREF LCP derogation lists and announcements of utilities.

7.1 Development of Capacity

The issue of how to modernize the Polish power plant fleet and how to keep a reasonable level of security of supply is among the most pressing concerns in the current discussion. This paragraph will explore this critical issue.

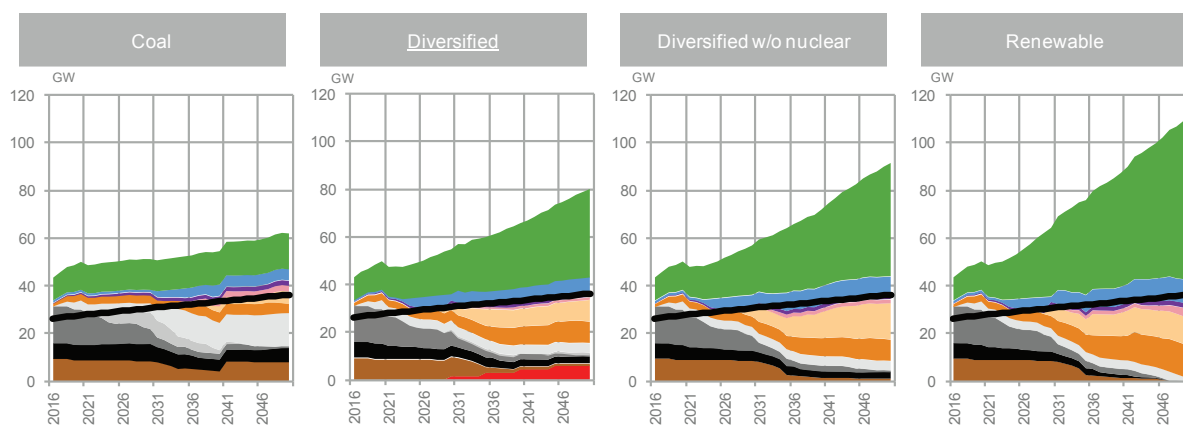


Figure 13: Capacity structure in the scenarios in GW

It is important to highlight the following assumptions that were made for all scenarios and are therefore not a model output. For each of the scenarios a renewable trajectory path was determined that fits the assumptions of the respective scenario. In all scenarios the security of supply is assured by a newly built capacity, modernization of existing units and a back-up reserve to reach a margin of 9% on top of the national peak load (excl. interconnectors). In all our scenarios CHP remains a cornerstone of the Polish energy system. Therefore we assume in all scenarios that existing CHP sites will be continued and additional CHP generation substitutes heat generation of boiler-systems. It is also important to note that from a capacity point of view all scenarios are able to cover the national peak load at any given time and SoS is on the same overall level in all scenarios, per default. An important indicator of SoS is therefore not the overall capacity margin (since, by default, all the scenarios reach the same overall capacity margin) but the level of capacity being commissioned by the model to reach that level. Here it needs to be discussed if these results seem feasible. Let us have a look at our four different scenarios: Figure 13 shows the development of net capacities by fuel for each scenario until 2050, whereas the black line represents the development of the annual peak load according to the overall electricity demand. In the following subchapter we discuss the scenarios separately and in more detail, and afterwards we draw some conclusions.

7.1.1. Coal scenario

One possible strategy that is nowadays discussed widely is to tackle the aforementioned issues by extensive retrofitting of existing power plants. The following graph (Figure 14) shows the yearly commissioned (positive) and decommission capacity (negative) by fuel type as well as the cumulative development of additionally commissioned capacity compared to 2017 (blue line).

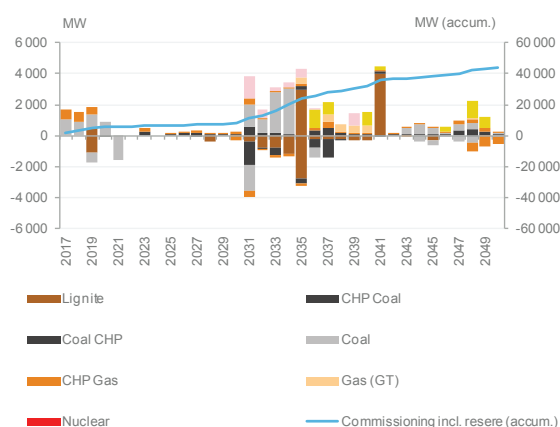


Figure 14: Commissioning and Decommissioning of Conventional Power Plants – Coal scenario

Against that backdrop, the coal scenario models an energy future heavily relying on hard coal and lignite.

The assumptions of the Coal scenario result in an increasing reserve margin until 2021 because newly commissioned capacity exceeds decommissioning. Due to extensive retrofit efforts of up to 6.9 GW of coal-fired capacity until 2030, Poland is able to keep a 9% national reserve margin. Until then no significant newly built capacity is needed to cope with rising electricity demand.

7.1.2. Diversified scenario

In the Diversified scenario the future electricity mix is more versatile compared to the Coal scenario.

Coal-fired power plants will only be newly built or modernized if economically viable. It is important to note, therefore, that no new coal capacities beyond the current project pipeline are commissioned. There is a small amount of economically feasible retrofitting going on, indicating that in such a scenario (before nuclear is commissioned and before much RES enters the market), there might be an economic role for limited amount of life-time extensions for existing coal plants.

Decreasing lignite capacities are partially compensated by newly built nuclear power plants from the beginning of the 2030s. Nuclear capacities rise gradually to up to 6 GW until 2050.

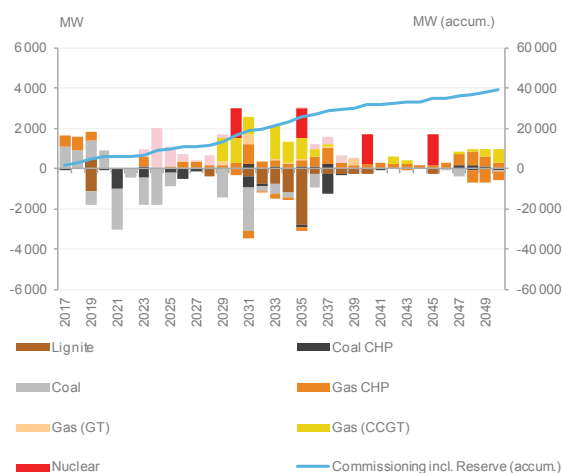


Figure 15: Commissioning and Decommissioning of Conventional Power Plants – Diversified scenario

CHP heat capacity is replaced by gas (70%) and coal-fired CHP. Renewable shares rise up to 38% until 2050. In the Diversified scenario the future electricity mix is more versatile compared to the Coal scenario.

Coal-fired power plants will only be newly built or modernized if economically viable. It is important to note, therefore, that no new coal capacities beyond the current project pipeline are commissioned. There is a small amount of economically feasible retrofitting going on, indicating that in such a scenario (before nuclear is commissioned and before much RES enters the market), there might be an economic role for limited amount of life-time extensions for existing coal plants.

Decreasing lignite capacities are partially compensated by newly built nuclear power plants from the beginning of the 2030s. Nuclear capacities rise gradually to up to 6 GW until 2050.

CHP heat capacity is replaced by gas (70%) and coal-fired CHP. Renewable shares rise up to 38% until 2050.

Even though total coal and lignite capacities decrease to around 25 GW until 2025, the first economic commissioning of CCGT power plants takes place not before 2028. Until then, 3.7 GW of additional reserve capacity needs to be commissioned to keep a 9% national reserve margin. In the long run, 5.4 GW of additional back-up capacity is needed.

7.1.3. Diversified w/o Nuclear

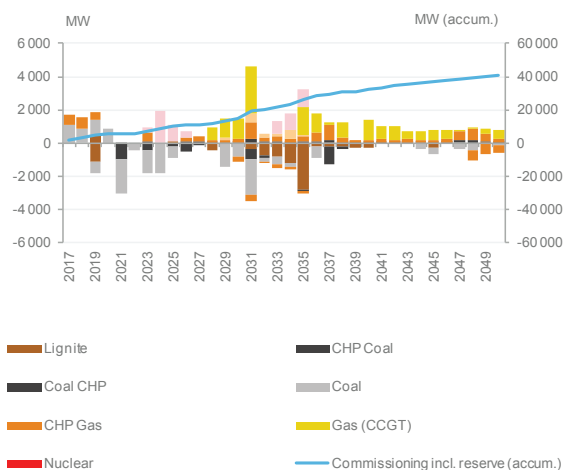


Figure 16: Commissioning and Decommissioning of Conventional Power Plants – Diversified w/o Nuclear scenario

In the Diversified w/o Nuclear scenario, nuclear capacities are substituted by additional deployment of renewables and additional gas. Coal and gas-fired power plants will only be built if economically feasible.

It is important to note that due to the economic situation no new coal capacities are commissioned beyond the current project pipeline..

The Diversified w/o Nuclear scenario follows the development of the Diversified scenario in the mid-term. In the long run 6.4 GW of additional CCGT capacity and 2.8 GW of additional back-up capacities are needed to compensate for the missing nuclear capacity.

The share of renewable energies of total demand rises to 50% until 2050.

7.1.4. Renewable scenario

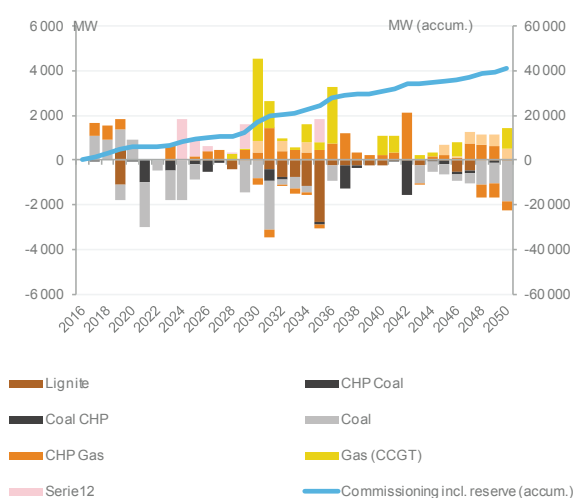


Figure 17: Commissioning and Decommissioning of Conventional Power Plants – Renewable scenario

The renewable scenario explores a widely decarbonised electricity mix until 2050. A gradual coal phase-out in between 2040 and 2050 is assumed. Modernization and new commissioning of coal power plants is excluded from the model. Decommissioned CHP capacity is replaced by gas-fired CHP and additional biogas and biomass in CHP enters the market. A balanced mix of renewables lifts Poland's RES-share to 73% until 2050.

In the Renewable scenario the modernization of existing coal fired power plants as well as the construction of newly built ones beyond the current project pipeline is excluded. Newly built CCGTs are constructed in 2028 onwards and partially replace the existing coal-fired power plants. Due to the high share of renewables until 2050 more gas turbines and less CCGTs are built compared to the diversified scenarios. The need for additional back-up capacity arises earlier in 2024.

7.1.5. Conclusions

So what can we learn from these developments?

Due to a rising electricity demand, caused by future GDP growth as well as additional electrification of heat and mobility, the national peak demand effectively rises in all scenarios. Due to the assumed flexibility of additional demand, our modelling indicates that the national peak-load can be reduced by around 4 GW until 2050 so that the peak load effectively rises by around 10 GW to 36.2 GW until 2050.

Security of supply remains a key challenge in all scenarios against the backdrop of an aging Polish power plant fleet in combination with a further increase in power demand and peak load. In all the scenarios, and if no additional measures are implemented, around 40 GW of conventional plants (coal, gas, nuclear) are commissioned up until 2050, equalling more than 1 GW of additional capacity per year.

Scenarios deal differently with this task but all reach the same level of SoS in line with the set assumptions. It is assumed that securing back-up capacities within the national borders is politically favoured, even though it creates the necessity to commission costly reserve capacities that contribute little to no generation. In all scenarios we assumed a relatively high capacity margin to be covered domestically (9%) on top of the annual peak load. Cross-border coordination of capacity requirement could help to effectively counter these issues and can be, given a sensible structure, beneficial for all countries involved.

In the two diversified as well as in the RES-scenario we see the need to commission in excess of 35 GW of capacity from 2020 onwards - additionally to the current project pipeline. The coal scenario remedies this challenge partially with an increase in retrofit activity in between 2020 and 2030. But this only buys time; after 10 years retrofitted units need to be decommissioned and an even stronger need for new investments arises. Over the full time horizon of this study, all scenarios demonstrate a similar need for reinvestment in conventional plants.

CHP plants, especially if gas-based, can provide relevant capacity to serve peak load demand. This is conditional on a plant design, which allows them to be operated in condensing mode and as independently as possible of heat demand, which also prevents must-run generation. Back-up boilers, heat storage units and heat accumulators are important options for allowing a more flexible dispatch. The more gas heavy the mix, the better CHP capacities can respond to a volatile residual load. In effect almost half of the peak load can be covered by CHP plants in the Renewable scenario.

The two diversified scenarios allowed for economic newly built coal capacities as well as retrofitting. But only the Diversified scenario w/o Nuclear showed a minor use of coal retrofits. In both scenarios, no new coal capacity is commissioned. This is in line with findings in regards to LCOE development.

But what are the options regarding short- to mid-term security of supply?

The short-term need for measures to contribute reliable capacity to stabilize the SoS situation should therefore be addressed by no-regret measures first. Within this study we look at the following measures: Replacing the decommissioning of coal-based CHP plants with gas-based CHP units, tapping into DSM and energy efficiency potentials and renewing initiatives for cross-border provision of peak capacity, which can go far in providing SoS and reducing the short-term need for new plants. Given a broad mix of technologies (biomass waste) RES can also add to SoS.

An additional sensitivity conducted with a lower growth of demand and relaxing the need for a national provision of peak load, does not see any newly built plants up to 2030. This implies that if no-regret SoS measures can be fully implemented, there seems to be little need for new power plants up until 2030 to secure the peak load. Since we did not conduct grid-modelling, we cannot rule out regional or local needs for additional capacity. Independently of the scenario, there is a clear need for new investments around 2030. Given that renewables have their breakthrough vs. coal in regards to full cost at 2030 at the latest, it would make little economic sense to invest in coal-based capacities after 2030.

If these no-regret measures cannot be implemented, however, Poland needs alternative SoS measures before 2030. Given the options on the table, a certain amount of retrofitting of the existing coal-based plants is likely to happen and seems necessary, if not prevented by no-regret measures. This is of course also conditional on being able to make the retrofitted projects compliant with EU regulations. In the scenarios where lifetime extensions are assessed on an economic basis, there is a limited amount of retrofitting that is triggered economically. When judging economic feasibility, it is important to take increasing CAPEX for new environmental equipment and deteriorating efficiency into consideration.

7.2. Generation and trade-balance

After looking deeper into the issue of security of supply under different technology mixes from a capacity perspective, this chapter explores the generation mix arising from capacity development in the scenarios. From a national point of view, the issue of energy independence is often discussed. This raises the following question: How do the different technology choices affect Polish electricity imports?

Figure 18 shows the development of national generation by fuel type for each scenario. The black line represents the national net generation incl. grid losses and demand from pumped storages.

Figure 19 shows the development of net-imports (positive) for each scenario. In the following subchapter we discuss the scenarios separately and in more detail, and afterwards we draw some conclusions.

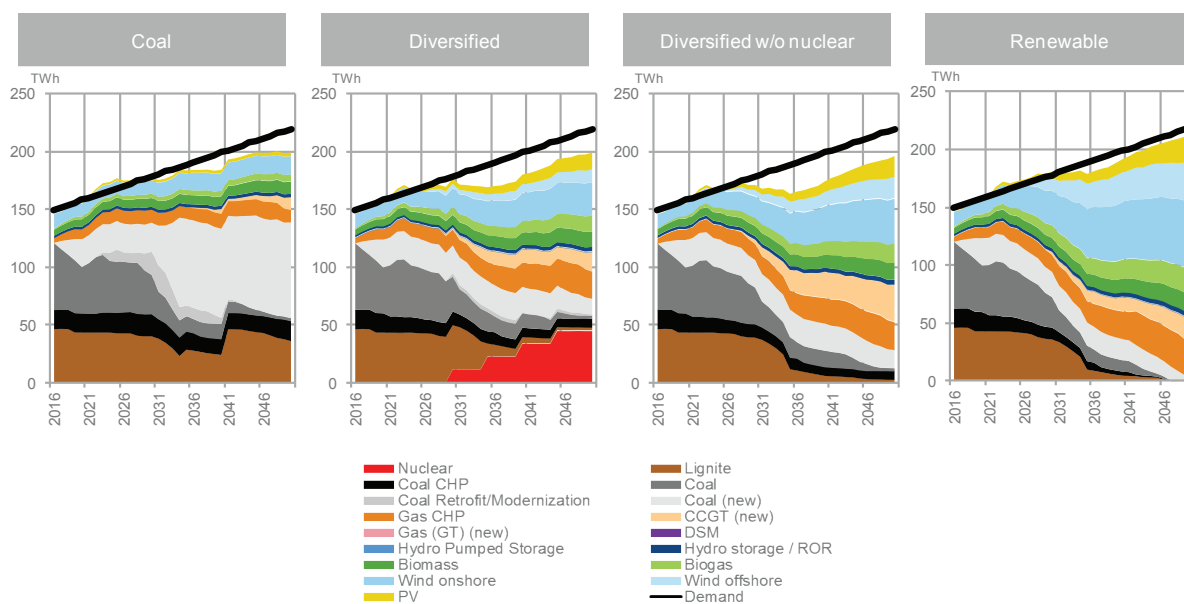


Figure 18: Generation structure in the scenarios in TWh

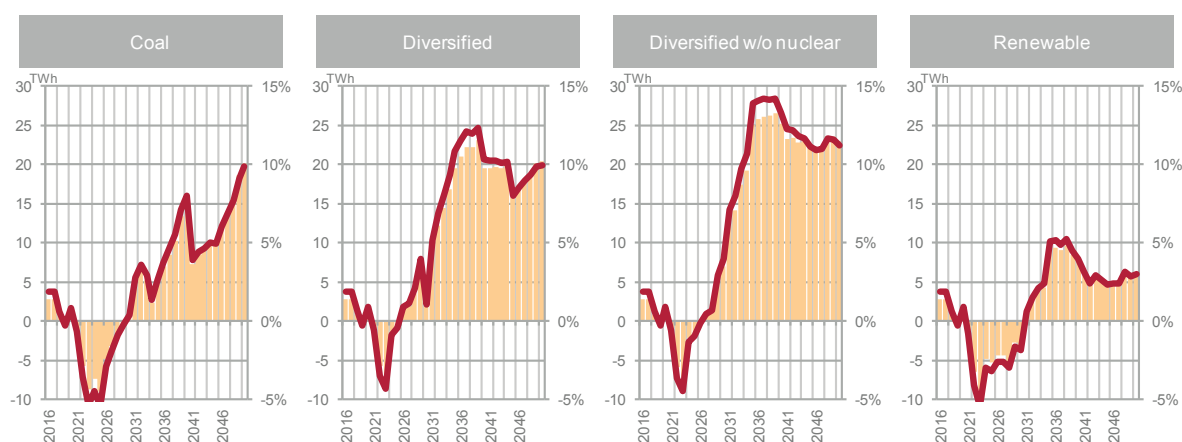


Figure 19: Import / Export Balance

7.2.1. Coal scenario

The Coal scenario shows a high share of coal and lignite generation until 2050. Modernized coal units contribute to the generation mix from the 2020's until the end of the 2030's with low utilization hours of on average 2,150 full load hours and no economic viability. Despite their significantly higher utilization of 6,400 full load hours, the earnings of newly built coal power plants do not exceed their full costs, including a reasonable return on assets. Due to a steady reduction of coal and nuclear generation in neighbouring markets, Polish coal capacities also generate for electricity exports. On the other hand, renewable generation rises steadily in the surrounding countries, especially in Germany, causing Poland to be a long-term electricity net-importer.

The Coal scenario shows a lower increase in net-imports compared to the two diversified scenarios. The high share of coal generation and decreasing capacities with low variable costs (nuclear phase-out as well as an assumed decrease in coal and lignite-based generation) in the neighboring markets leads to more export situations. It is very important to note, however, that coal plants in these scenarios are commissioned by default, not based on economic merit. This implies that these plants, once commissioned, are competitive based on marginal costs, but their overall level of competitiveness in regress of full costs is low, especially after 2040.

7.2.2. Diversified scenario

The generation mix of the Diversified scenario changes significantly from the mid-2020 years onwards due to decommissioned coal capacities that get partially replaced by gas fired capacity. Nuclear generation with high utilization of 7,500 full load hours replaces decreasing lignite-fired

generation. Net-imports of electricity rise to 28 TWh and are the highest compared to the remaining two scenarios. This is caused by a lower share of generation with low variable cost and a relatively high share of gas units in the electricity mix of the diversified scenarios compared to neighbouring markets with higher renewable shares in 2050. Additionally we assume a slightly higher gas price in Poland than in more western markets due to transport costs, which adds to this effect, since other gas units are slightly more competitive in regards to marginal costs.

7.2.3. Diversified w/o Nuclear scenario

In the Diversified w/o Nuclear scenario a higher commissioning of new CCGT capacity partly compensates for the decreasing coal generation in the coal scenario as well as nuclear generation in the diversified scenario. A higher share of renewable generation lifts total domestic generation to a comparable level to the Diversified scenario.

This scenario shows a development of net-imports comparable to the Diversified scenario. The Diversified w/o Nuclear scenario has the highest net-imports because of the (in comparison to the other scenarios) low share of generation with low or no variable costs.

7.2.4. Renewable scenario

In the Renewable scenario, a steep deployment path of renewable capacity mostly driven by wind on- and offshore generation as well as PV replaces coal generation over time. Newly built gas generation shows the lowest utilization rates compared to the other scenarios. Due to the high share of variable renewable generation, conventional generation from CHP, CCGTs and gas turbines needs to respond flexibly to a volatile residual load. The high share of generation with low variable cost leads to the lowest net-imports in the Renewable

scenario. Curtailment of variable RES feed-in (Wind, PV) stays relatively low and does not increase beyond 2.5% of Wind and PV generation even when their output matches half of Polish electricity demand in 2050. The Renewable scenario shows the lowest net-imports in the long-run. This is caused by a higher fit to generation mixes in surrounding markets with high shares of renewable generation until 2050.

7.2.5. Conclusions

So what can we learn from these developments?

In the short run, newly built coal capacities can slightly overcompensate decreasing generation from decommissioned units until the beginning of the 2020's in all the scenarios. In the course of the German phase-out plan for nuclear power plants until 2023 and a mid-term expansion of interconnectors between Poland and Germany, utilization of existing coal-fired power plants rises and Poland becomes a net-exporter of electricity for several years in all scenarios.

When looking at the power sector as well as overall import-dependency, RES provide the best solution for increasing import independence. In regards to dependency on power imports from other countries the RES scenario performs best. In the RES scenario the Polish energy mix aligns with the European energy mix respectively RES-share and therefore power imports are the lowest among all the scenarios. Even the Coal scenario, which assumes additional coal independently of economic feasibility, does not reach the same level of import independence.

In all the scenarios a strong increase in import / export capacities is assumed. As indicated by additional sensitivity modelling, cross-border trade has the potential to decrease system costs.

If countries apply domestic capacity requirements high enough to be able to domestically serve their respective peak load, the potential benefits of these import/export capacities are limited though. Cross-border trade adds most to cost-efficiency in the RES scenario, as it allows to efficiently utilize domestic renewable resources and decrease the costly use of gas for back-up generation.

7.3 Power plant dispatch

The differentiation of scenarios gets even clearer when looking at hourly generation patterns. The following graphs show an exemplary winter week in the year 2050 for each of the four

scenarios. It represents the hourly generation as well as the export and import pattern by fuel in relation to the respective demand.

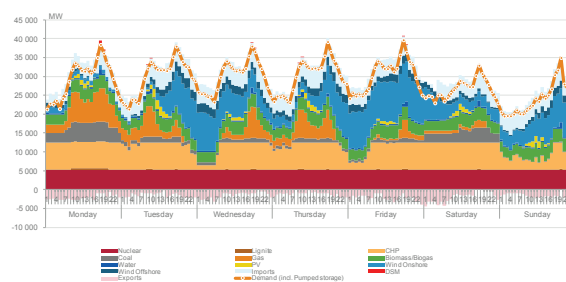


Figure 20: Coal: Exemplary Week Jan 2050

In the **Coal scenario** the fuel mix is clearly dominated by coal and lignite generation. Coal generation responds flexibly to the changing electricity demand and wind energy feed-in. CHP as well as lignite capacities slightly react to market prices, but generally operate in base load. Gas generation is only dispatched to cover the peak demand in times of low renewable generation. Electricity trading with neighbouring countries tends to be very stable, also showing Poland to be a transit country for electricity with imports and exports in the same hours.

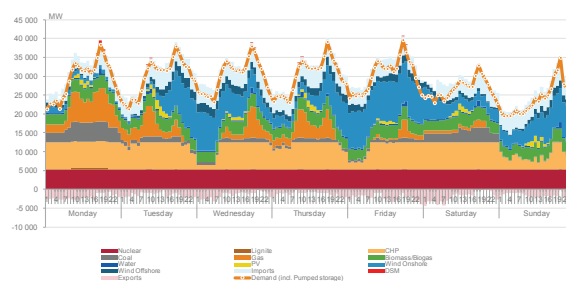


Figure 21: Diversified: Exemplary Week Jan 2050

The **Diversified scenario** shows a more versatile generation mix compared to the Coal scenario. Gas and coal capacities must respond to fluctuating renewable generation. Especially wind onshore shows days with high generation shares leaving no residual load to coal and gas generation. In some hours even CHP generation is reduced to a minimum. As a price taker with low variable generation cost nuclear generation operates in base-load mode.

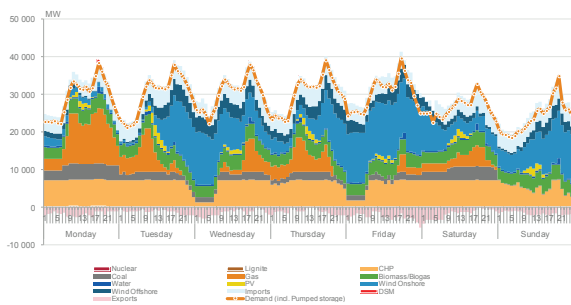


Figure 22: Diversified w/o Nuclear: Exemplary Week Jan 2050

Also in the **Diversified w/o Nuclear** scenario CHP generation needs to respond flexibly to high wind feed-in. In times of low RES-generation gas generation is ramped up to fill in.

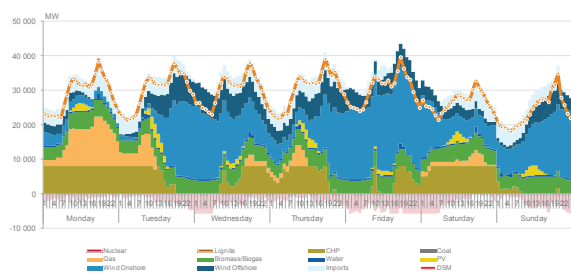


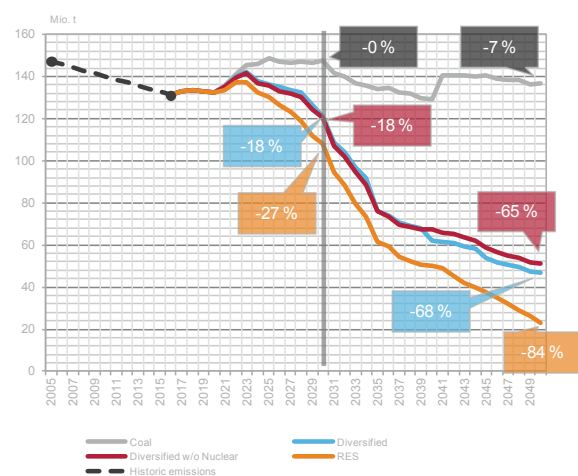
Figure 23: RES: Exemplary Week Jan 2050

The **Renewable** scenario shows hours where domestic generation of renewable energies exceeds national electricity demand. During these hours renewables all transfer capacities which are used to export electricity to neighbouring markets. Wind and PV generation that cannot be integrated domestically or abroad will be curtailed (up to 2.5% in 2050). In days of low variable RES-generation CHP and gas-fired capacities provide the needed capacities to the market. CHP capacities do not longer operate in base load. In some consecutive hours CHP power plants do not produce electricity at all. During these hours, heat-storages and heat-only-boilers need to fill in to cover heat demand.

This is conditional on further efforts to make conventional power generation more flexible. This especially applies to CHP-based generation. Power generation of CHP-plants needs to be decoupled of heat demand via heat-storages, back-up boilers and eventually electrical heating devices to prevent must-run generation. Back-up problems of RES can be mitigated via gas plants with low investment costs. Deep CO2 emission reduction via high shares of RES is therefore technically a feasible option.

7.4. Contributing to climate protection

The respective electricity mixes affect the development of CO₂-emissions. The question therefore is: How can the Polish electricity sector contribute to long-term European emission targets?

Figure 24: CO₂-Emissions and Reductions Compared to 2005 (mln. T. CO₂)

In the **Coal** scenario CO₂ emissions rise until 2030 by approximately 10 million tons of CO₂ annually due to increasing electricity exports caused by newly built power plants. Compared to 2005 levels the Polish electricity sector does not see a reduction in CO₂ emissions in 2030. Due to the commissioning of new lignite power plants as well as a steadily high share of coal generation CO₂-emissions decrease only by 7% until 2050.

Both the **diversified scenarios** show a comparable reduction of CO₂-emissions. Decommissioned coal-fired capacity is replaced by generation with lower to no specific emissions. This leads to a mid-term reduction of -18% until 2030. Main drivers here are a stronger use of natural gas in power generation and more RES as well as nuclear.

Missing nuclear generation in the **Diversified w/o Nuclear** scenario is compensated by additional renewable generation compared to the diversified scenario. Thus, significant CO₂ reductions of -65% to -68% until 2050 can be reached.

The **Renewable scenario** shows the broadest reduction in CO₂-emissions in the mid- and long-term, not only by strongly fostering renewables but also by a long-term coal phase-out until 2050. Due to the steep deployment path CO₂-emissions can be reduced by 27% until 2030 and 84% until 2050. Thus, the Renewable scenario is the only pathway in which long-term CO₂-reductions compared to the EU-ETS targets are reached. Deep CO₂ emission reduction via high shares of RES is therefore a technically feasible option. Another point must be highlighted: The ongoing reductions in emissions after 2040 are to a relevant degree caused by a coal phase-out, which we model by taking coal plants into a reserve, from 2040 to 2050.

CO₂ emissions can be reduced substantially by diversification via less coal, more or less independently of the technology used to diversify. This reduces the exposure of Poland to climate policy risks and potential costs on a European and pan-European level. In the RES scenario the power sector roughly complies with the overall European climate target trajectory in the long run, depending on how the reductions are spread in the different sectors.

This is an important issue also from the European perspective. The European Union has set itself ambitious CO₂-reduction targets of at least 40% until 2030, 60% until 2040 and 80-95% until 2050 compared to 1990 levels. Even though for the mid-term targets effort sharing regulations for non-EU-ETS sectors are agreed, each member state has to contribute significant emission reductions until 2050 to reach long-term targets.

This study does not explore CO₂ emissions of the whole economy, but conclusions can be drawn by looking at the development of emissions arising from electricity generation and CHP heat and comparing it to ETS targets. Since it is a sector with a significant share of emissions and comparably low CO₂ abatement costs it should at least follow ETS reduction targets in the long run. Likely the power sector would have to outperform those trajectories if EU targets ought to be met on an economy wide scale. For ETS-sectors the current legislation ("the linear reduction factor") implies a 43% reduction until 2030 and around 90% until 2050 compared to 2005 levels.

Overall, no scenario performs close to the European emission reductions envisioned until 2030. This implies that to align the Polish emissions with European trends' respective targets additional action before 2030 will be necessary, even compared to the measures already assumed to happen in the RES scenario.

Overall, only the RES scenario is close to the level of emission reduction envisioned by European targets for 2050. This has interesting implications, since this scenario has no remaining coal generation in 2050 and already a very relevant share of RES generation. In line with other studies, this goes to highlight

that emission reductions close to 90 % are increasingly difficult to deliver. Additional sensitivity modelling built on the RES scenario indicates that a lower demand growth is almost in line with a reduction of 90% vs. 2005 (see Chapter 10). Additionally, one would need further careful analysis of storage technologies in combination with more RES to assess other options to reach a further reduction in CO₂ emissions.

7.5. Development of RES-share

Closely linked to the CO₂-emissions is the possible RES pathway for the Polish electricity mix. But renewable deployment is not the only option to further decarbonise the Polish electricity sector.

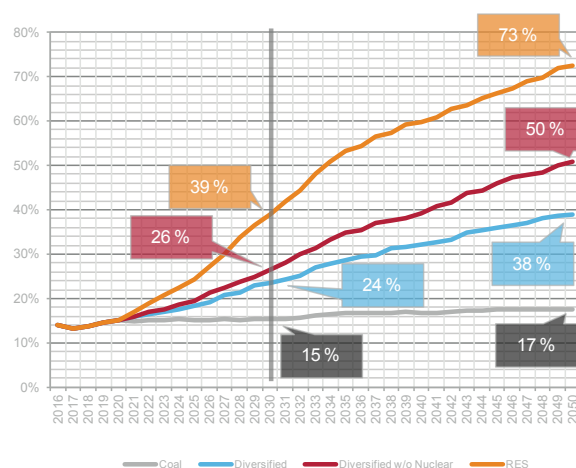


Figure 25: RES-share of Demand

What role takes RES deployment to reaching long-term emission targets?

In the Coal scenario the future renewable share does not rise significantly compared to current levels. Further deployment is needed to keep the share constant with the rising electricity demand.

The diversified scenarios show a different level of RES-deployment. In the Diversified w/o Nuclear scenario missing additional nuclear generation is compensated by a higher renewable share. Therefore, RES-shares rise to 24% - 26% until 2030 and 38% - 50% until 2050. Despite different RES-shares, CO₂emissions follow a more or less the same reduction path. Nuclear generation in the Diversified scenario contributes in the same way to CO₂-reduction as additional renewable deployment in the Diversified w/o Nuclear scenario.

The Renewable scenario shows a steep increase of renewable share until the mid-2030's reaching 39% in 2030 and 73% in 2050.

Reducing emissions in the electricity sector requires a well thought-out decarbonisation strategy. Applying a high share of renewables to an electricity system does not automatically reduce emissions significantly. High shares of renewables require an electricity system that can respond flexibly to a highly volatile residual load. In a diversified mix, nuclear energy can contribute to reducing emissions. But the residual mix does not reach sufficient emission reductions in the diversified scenarios.

A mostly coal-based electricity system is not capable of coping with ambitious EU emission targets. Even a significant increase of renewables while keeping a high share of coal-based generation does not necessarily lead to an extensive reduction in emissions. This shows the case of Germany with a high share of renewables (34% in 2016) but no significant CO₂ reduction in the electricity sector.

7.6. Power prices

After discussing different capacity and generation developments and their implications for CO₂ emissions this paragraph focuses on implications for power prices: How do different technology mixes affect wholesale power prices?

Due to its high share of renewable generation, the Renewable scenario is least affected by rising fuel prices. The number of hours with renewables supplying 100% of domestic demand rises and puts pressure on base prices compared to the other scenarios. In effect, power prices are on average lowest in the RES scenario.

It is important to note, though, that wholesale power prices are not a good indicator of overall economic costs of a scenario. They are most relevant for distribution issues, which are not in the focus of this study. Instead, it is better to look at system costs, which will be in the focus of the Chapter 9.

Another finding is that all technologies in all scenarios need financial support and are not able to recover fixed costs from power market revenues alone. There is no strict division of technologies into ones that need public support and ones that do not. The analyses in this study did not aim to rigorously “prove” that energy only markets cannot work efficiently, they are certainly an indicator of a need to deeply look into capacity mechanism of different kinds to make sure that necessary investments are triggered in time and on a sufficiently high level.

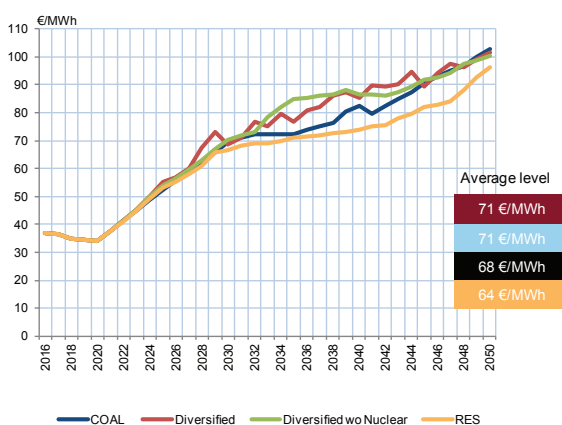


Figure 26: Base Price (real 2016)

In all scenarios average wholesale prices rise according to fuel price assumptions, mostly driven by coal and CO₂-price development. In the mid-to long run, wholesale prices rise faster in the two diversified scenarios. This is caused by a change of the price setting technology: from coal to gas.

Hard coal remains the price setting technology in the Coal scenario. Thereby, the Coal scenario shows on average 7.5 €/MWh lower base prices from the beginning of the 2030's until the mid-2040's in comparison to the two diversified scenarios. After that period, prices tend to converge again. This is caused by rising CO₂ prices that level out variable electricity production cost between coal and gas-fired generation.

8. Energy security and import dependency

This chapter looks into energy security and import dependency from different perspectives. One focus of this chapter is: Which scenarios can effectively contribute to Polish import independency? What is the role of domestic coal in that regard?

The development of domestic coal mining and possibilities of utilizing Polish renewable energy sources are two central issues driving energy security and import dependency in the future. That is why we start this chapter with a detailed look at the perspectives of hard coal and lignite mining in Poland and renewable potential development. Over the course of our analysis, we apply conservative assumptions regarding the shift of Polish domestic energy potential from coal to renewables. Firstly, we do not assume a scenario in which Polish hard coal mining collapses due to restructuring failure. Secondly, our estimates concerning RES potential are based on broadly accepted reference studies, without assuming breakthroughs in electricity storage technologies.

We do not assume a development of domestic natural gas supply beyond current levels. With a significant demand from other sectors and a relatively low domestic potential, the energy sector would almost certainly (barring shale gas revolution) be completely import dependent. At the same time, it should be noted that none of the assessed scenarios face gas infrastructure bottlenecks or significant security of supply risks, as demand for natural gas has increased gradually over several decades.

While statistical convention treats nuclear generation as a domestic source, we classify nuclear power plants as import dependent, representing the fact that the fuel will have to be sourced outside of Poland.

Thus, all our assumptions are on the conservative side, regarding potential benefits of energy security diversification as well as investment in low-emission sources of energy.

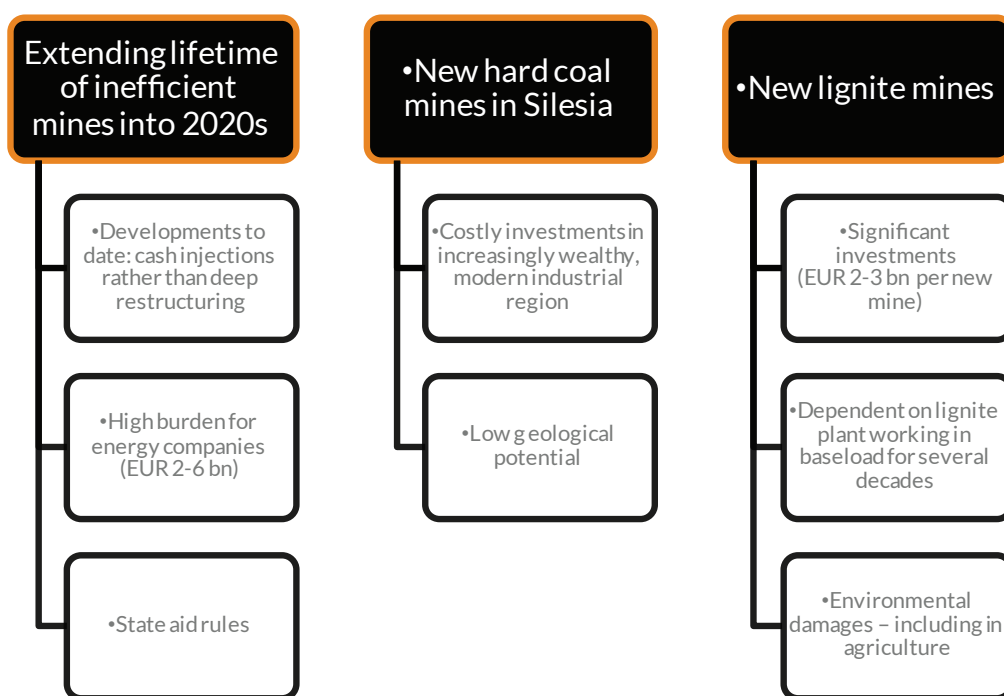


Figure 27: Socio-economic challenges of major mining push

8.1. Domestic hard coal and lignite mining potential

Historically, the Polish energy sector was based on the most abundant and cheapest available resources, i.e. hard coal and lignite, which were extracted in domestic mines. This allowed Poland to retain a high level of energy self-sufficiency for several decades. Based on this paradigm, coal was the cornerstone of energy security.

Long-term trends are not favourable, however, as domestic hard coal mining struggles to remain competitiveness stemming from low productivity and gradually increasing labour costs. This has led to deep crises in periods of low global coal prices, forcing mining companies to gradually phase out the least productive mines. Hard coal production (excluding coking coal) decreased from nearly 120 m. tonnes in 1990 to less than 60 m. tonnes in 2015. During this time, Poland gradually transformed from a major coal exporter to a country with coal trade balance close to zero.

The downward trend in domestic coal extraction is present despite direct and indirect subsidies for the sector. Recent report from the Polish Supreme Audit Office (NIK) found that in the years 2007 – 2015 Polish taxpayers supported hard coal mining industry with 65 bn PLN, mainly through a heavily subsidized social security system for miners¹⁰. It should be noted that without preferential pension rules, Polish mines would most likely face even higher labour costs pressure, as they would have to attract and retain workers without being able to provide state-subsidised social security benefits.

The latest crisis led to major restructuring in Polish mining sector and emergence of new entity – Polska Grupa Górnicza (PGG) – made possible through major cash injections from state-controlled companies. While its businessplan aims to improve productivity and ensure stable coal production, recent developments raise question whether its successful realization is feasible. While PGG has achieved net profit in late 2016, it remains well below profitability level ensuring resilience in the event of another downturn on global coal markets. Furthermore, the company has missed its extraction plans. Taking into account the necessity of high investment to maintain extraction levels and increase productivity in the coming years, a further decline in production in existing mines is a likely scenario. In such case, new mines are required to maintain the domestic extraction levels. However, major new investments

in the Silesia region are unlikely for economic reasons: the region sees robust development of other economic sectors, in particular a growth of its manufacturing base, which leads to wage pressures, as well as raises costs of mining damages as ever more expensive infrastructure and machines operate on the surface. In contrast, the Lubelskie region provides much more favourable conditions for hard coal mining. Both existing and potential new mining operations may benefit from relatively good geological conditions, lower labour cost pressures and lower risks of damaging expensive infrastructure on the surface.

Lignite mining in Poland faces its own set of challenges. Overall, lignite mines utilize highly productive, non-labour-intensive methods of extraction and do not face structural problems with competitiveness similar to hard coal mining. The significant risk for existing mines comes from the demand, not supply side: a significant increase in CO₂ costs and development of low-emission electricity production may decrease the capacity factors of lignite power plants. Taking into account high fixed costs for operating the lignite mine, any drop in demand will lead to a further increase in its unit costs and deterioration of its competitiveness. Barring such a scenario in the near future, the key problem is the depletion of resources in existing mines. The biggest drop in lignite extraction is expected to occur in the 2030s, when the largest mine – Bełchatów – will be phased out.

Maintaining a significant presence of lignite in the Polish energy mix requires investments in new lignite mines. Currently, two major projects are considered: Legnica and Gubin. Combined, they may offset the phase-out of the Bełchatów mine. These new projects, however, face challenges that are not applicable to existing mines, which have no capital costs to pay off anymore. High investment costs and long payback time, combined with reliance on power plants staying in the baseload well into the second half of the 21st century. The latter is going to be challenging, taking into account the increasing stringency of climate policy and RES development trends. Furthermore, both projects face strong public opposition, both from local communities and from the agricultural sector concerned with environmental risk, in particular in terms of water resources.

While its economic fundamentals weaken, domestic coal extraction remains an essential part of debate on the future of the Polish energy sector, with mining and energy sector developments closely interlinked. Recent years have demonstrated that there is significant political will to maintain support for coal extraction and limit job losses among miners.

¹⁰ NIK (2017), Informacja o wynikach kontroli. Funkcjonowanie górnictwa węgla kamiennego w latach 2007–2015 na tle założeń programu rządowego

Among others, social security privileges for miners were maintained, hard coal mining restructuring was supported with capital injections from state-controlled companies, and government representatives signal intentions to invest in new mines. Nevertheless, there are limits in regards to continuing support: EU state aid rules have to be taken into account in designing restructuring schemes (direct state subsidies for ongoing operations of coal mines are to be avoided) and the least productive mines are being closed, combined with state-financed compensations for laid-off miners.

Both lignite and hard coal developments depend to a significant extent on the political will to carry on investments in new mines (facing opposition from other stakeholders) and to maintain extraction levels in the Silesia region (either through further contentious and challenging deep restructuring measures or ongoing subsidies, which in turn create risks associated with breaching of EU state aid rules). The only comparably realistic option for further development of hard coal mining remains focusing on the Lubelskie region. However, the extraction potential there is significantly below current production from the Silesian mines. It is also clear that mining and energy mix strategies are correlated: maintaining a high share of coal generation increases chances of push for new investments, while diversification scenarios are in line with accepting the limits of domestic coal extraction scenarios (or, alternatively, coal supply gap driving diversification efforts).

Thus, we develop three scenarios for the Polish mining sector which illustrate different commitment to the development of the sector from public policy: from a strong bet on coal, with likely high economic and political costs, through a mixed strategy focusing only on most viable mining options concentrated in the Lubelskie region, to the acceptance of a complete phase-out. We build on an analytical framework developed in previous work of WiseEuropa on long-term projections of coal mining potential in Poland¹¹, updating assumptions on prices and mines' productivity. The key assumptions for each domestic coal extraction scenario are presented below.

Major mining push scenario:

- successful restructuring in the short run: extraction in the productive mines offsets reduced extraction in the ones to be closed (alternatively, significant subsidies from energy sector);
- gradual increase of productivity after 2020, but no more than 2000 t/miner/year for best mines (around three times higher than current levels in Silesia);

- new mines – full potential in line with the industry's estimates, depending on new investments in Silesia;
- new lignite mines: Gubin (3 GW power plant, 2035), Legnica (4 GW power plant, 2040).

Focus on Lubelskie scenario:

- in the short run, increased extraction in the productive mines does not fully offset; reduced extraction in the ones to be closed
- post 2020 assumptions for existing mines as in Major mining push scenario;
- new extraction is developed only in Lubelskie region, no new mines in Silesia;
- no new lignite mines, existing mines are phased out after depletion.

No new mines scenario:

- no new mines or lifetime extensions (e.g. the Bogdanka case);
- assumptions for existing mines similar to the Focus on Lubelskie scenario.

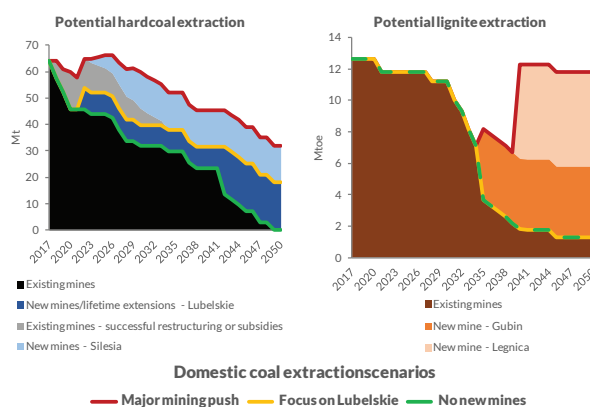


Figure 28: Overview of domestic coal extraction scenarios

¹¹ WISE Institute (2015), Whither are you headed, Polish coal? Perspectives of development of hard coal mining in Poland.

In this analysis, we omit “sudden stop” scenarios (e.g. sharp drop after 2018 due to major restructuring failure). Nevertheless, even under most optimistic assumptions, the total coal extraction in Poland faces a long-term decline: hard coal potential declines even after taking into account unlikely investments in new mines in Silesia, while Gubin and Legnica projects – if realized – may only offset the decline of other lignite mines. In more realistic scenarios, both hard coal and lignite extraction in Poland face a steep decline in the coming decades.

Based on the hard coal and lignite extraction projections, we also estimate total potential electricity generation from domestic coal by applying the following assumptions: for hard coal, up to 60% of total domestic extraction is used by power and CHP plants, with the rest going to other sectors (industry, heating, households), which is close to the current levels. It should be noted that calculations based on marginal import needs would provide lower self-sufficiency indicators. For both hard coal and lignite, power plant efficiency is increasing steadily up to 45% in 2050.

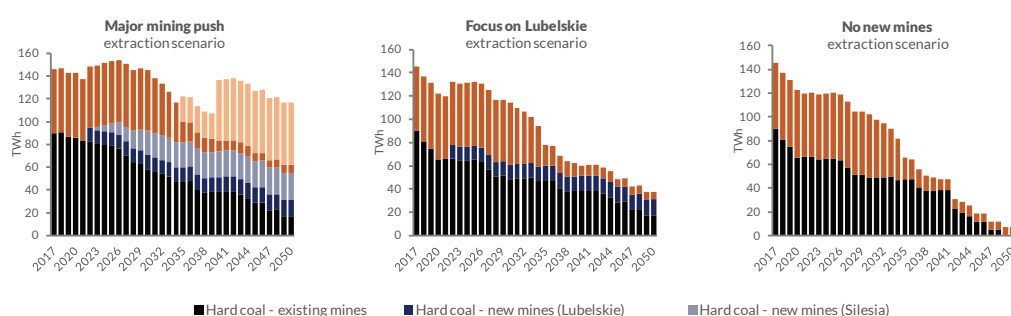


Figure 29: Potential electricity generation based on domestic coal

The results indicate that even under most optimistic assumptions, the potential for electricity generation based on domestic coal resources gradually declines. In more realistic coal supply scenarios no more than 40 TWh of electricity may be generated in 2050 with domestic fuel. If no new mines are opened, the phase-out of the last hard coal mines occurs in the 2040s, and lignite-based generation becomes marginal by the 2050s. At the same time, it should be reiterated that even for “No new mines” scenario, significant improvements in mining productivity are assumed. If these do not occur or materialize only partially, the decline will be even more rapid.

8.2. Renewables potential

Declining potential of the socio-economically viable extraction of coal leads to the question whether emerging renewable technologies may become the key for capturing new sources

of abundant domestic primary energy in Poland. Currently, RES electricity generation is based mainly on biomass and wind, with hydro generation holding third place. These three types of renewables: variable wind (and, increasingly, solar), hydro-based, and bio-based technologies are characterized by different potential and roles in the Polish energy system.

Based on technical potential, wind and solar energy represent the most abundant source of energy for Poland. For instance, EEA¹² estimates technical wind power potential at more than 3000 TWh – an order of magnitude above most optimistic projections of electricity demand in Poland by 2050. Actual potential is, however, constrained by both economic and non-economic barriers, such as costly and challenging major upgrade of networks, or securing acceptance for a large-scale roll-out of wind farms. The question also remains about the pace of

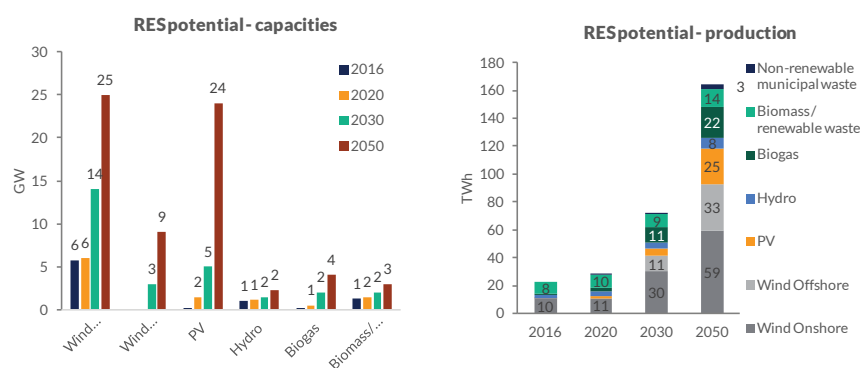


Figure 30: Estimated RES deployment potential in Poland

¹²EEA (2009), Europe's onshore and offshore wind energy potential.

technological progress in the area of energy storage and grid management, which enable integration of higher levels of renewables. In line with the conservative approach to comparing RES and coal potentials, we assume total wind potential which is consistent with estimates applied in the governmental study on energy mix up to 2060¹³ as well as recent IRENA study up to 2030¹⁴, and significantly below the potential presented in IEO “Energy (r)evolution” report¹⁵. For solar generation, taking into account recent technological improvements, we assume long-term deployment potential which is higher than in governmental study (but lower than in IEO report).

Assuming potential for onshore wind and PV on the level ca. 24-25 GW and potential for offshore wind of 9 GW, and applying capacity factors typical for efficient new technologies in the Polish climate (2370 h for wind onshore, 3720 for wind offshore, 1050 h for PVs), we arrive at a total estimate of more than 120 TWh energy from variable renewables which represent about half of the projected electricity demand for 2050. It is worth noting that by 2050, currently used, low-efficient installations (especially wind farms) will be retrofitted or replaced by new ones, improving system-level average capacity factors. While these estimates do not include curtailment needs, the modelling results show that even with such high levels of RES generation they remain limited, below 2.5% of potential generation.

While wind and solar are the most abundant sources for energy in Poland in the long run, they are not the only renewable options which currently remain underutilized. Another source which can see rapid growth in the coming years is biogas, which currently accounts for less than 1% of electricity production in Poland. Furthermore, biomass which in recent years was utilized for co-firing, may be utilized more efficiently in dedicated installations. For both biomass and biogas, maximising the overall amount of energy produced from renewable sources requires taking into account not only electricity production, but also heat demand. Furthermore, in case of biomass sustainability issues and alternative uses in other sectors should be considered. Thus, high estimates of a combined potential of bioenergy technologies should be treated with caution. We put our estimates closer to these of IRENA and IEO studies, rather than higher ones provided by governmental studies. Another assumption is that bioenergy will be used primarily in CHP installations, which maximizes the amount of RES-based energy available for final use. We have also taken into account waste streams as potential sources of both renewable and non-renewable sources of energy. In general, while these may be significant in local contexts, we do not assume major shift towards energy recovery from waste, especially taking into account emerging priorities related to circular economy.

Finally, we take into account the underutilized potential of hydropower. Here, we assume that its further development will be based primarily on small-scale installations. This may potentially lead to a doubling of capacities. While not becoming a major source of RES energy, an increased amount of hydro power further contributes to an increase in the total RES share in energy mix. This highlights the key for achieving very high shares of renewables of Poland: all options should be utilized, which is possible when remaining elements of the energy system are sufficiently flexible.

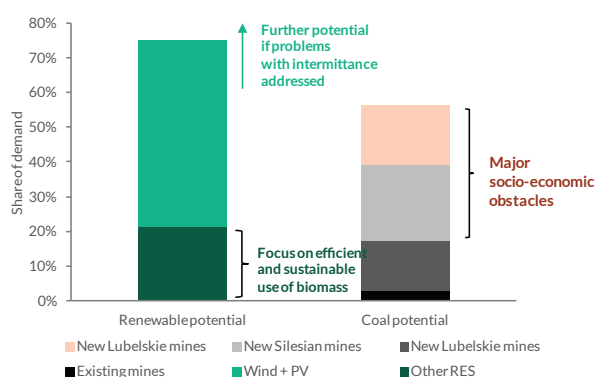


Figure 31: Potential electricity production from RES and domestic coal compared to projected demand in Poland in 2050

Comparison of long-term potential of RES and domestic coal in Poland confirms that both economic and technological trends will result in deep shift in structure of available domestic energy sources. Even under most optimistic assumptions, Polish mines will not be able to meet growing energy sector demand. At best, a major – and problematic – coal mining push can meet less than 60% of energy sector demand in 2050. More likely scenarios see domestic coal meeting less than 20% of energy sector demand. On the other hand, the RES share can reach 3/4 by 2050 without major breakthroughs: the key is combining different technological options. A major role of variable RES means that achieving high RES share requires system-level flexibility. Thus, maintaining high energy independence requires a shift towards a new paradigm: large-scale deployment of low-emission technologies, a gradual shift of coal plants to reserve, developing interconnections and exploring storage options.

8.3. Energy security and import dependence in the scenarios

Declining potential of the socio-economically viable extraction of coal leads to the question whether emerging renewable technologies may become the key for capturing new sources of abundant domestic primary energy in Poland.

¹³DAS KPRM (2013), Model optymalnego miks energetycznego dla Polski do roku 2060

¹⁴IRENA (2015), REmap 2030: Renewable Energy Prospects for Poland. IEO (2013),

¹⁵[R]ewolucja energetyczna dla Polski. Scenariusz zaopatrzenia Polski w czyste nośniki energii w perspektywie długookresowej

8.3.1. Energy security and import dependence in the scenarios

For the Coal scenario, the sustained push towards coal generation in the energy sector is likely to be combined with attempts to provide as much domestic coal extraction as possible. Here, we assess two cases: complete (Major mining push scenario) and partial (Focus on Lubelskie scenario, including no new lignite mines) success of these attempts. The latter takes into account significant difficulties associated with the opening of new mines beyond the Lubelskie region as well as sustaining long-term support for hard coal mining in Silesia. For diversified scenarios, we assume that the government chooses to focus only on the most promising coal mines in the long-term, while at the same time pursuing investments in other types of generation. Finally, for the Renewable scenario it is assumed that there are no investment in new mines (or prolonging the lifetime of existing ones) even in Lubelskie region.

The result of such matching reveals that the Coal scenario leads to a significant structural deficit in domestic coal supply, which has to be closed by increasing imports. This is the case even assuming the major mining push – in 2050, 55% of hard coal used by the energy sector (electricity and CHP plants) has to be imported. For a more realistic coal supply scenario without new mines beyond the Lubelskie region, the figures are even less favorable. Assuming that without new lignite mines the resulting generation gap in Coal scenario is filled with hard coal plants, the total import dependence for hard coal reaches 80%.

There are no structural coal supply gaps in diversified and RES scenarios. While significant amounts of hard coal have to be imported in the 2020s, in the long-run switching towards other technologies in energy mix leads to closely matching dynamics of domestic supply and demand. Therefore a gradual coal phase-out of coal generation is in line with realistic supply potential of domestic mining.

Table 3: Matching of energy mix and domestic coal extraction scenarios

		Domestic coal extraction scenario		
		Major mining push	Focus on Lubelskie	No new mines
Energy mix scenario	Coal	+	+(sensitivity)	
	Diversified		+	
	Diversified no nuclear		+	
	RES			+

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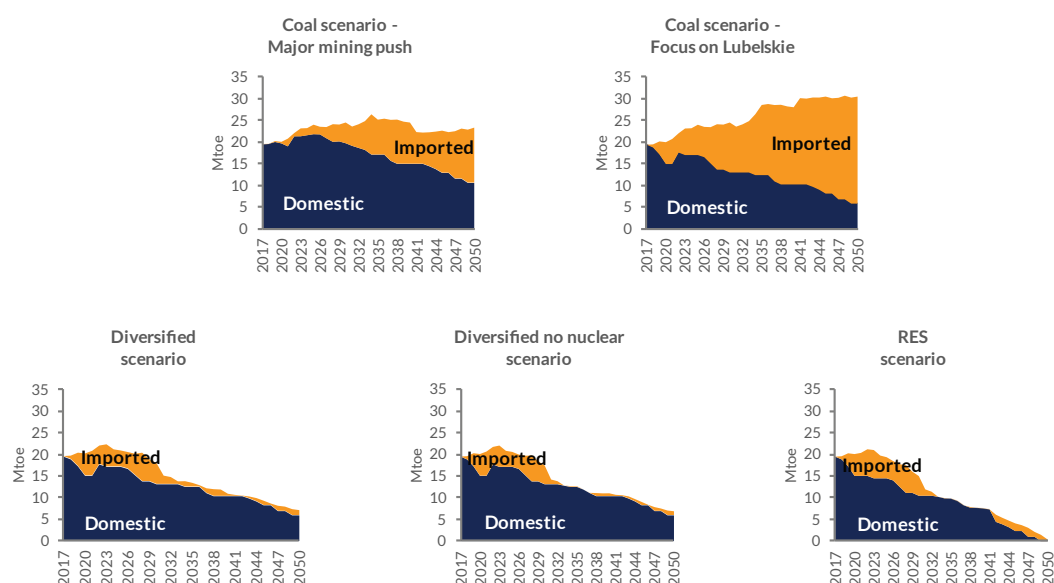


Figure 32: Domestic and imported hard coal used in Polish energy sector, by scenario

There are no structural coal supply gaps in diversified and RES scenarios. While significant amounts of hard coal have to be imported in the 2020s, in the long-run switching towards other technologies in energy mix leads to closely matching dynamics of domestic supply and demand. Therefore a gradual coal phase-out of coal generation is in line with realistic supply potential of domestic mining.

How does this translate to import dependency?

In the next subchapters we look at import dependency from three different perspectives: 1) physical import dependency of the power system (i.e. based on units of energy), 2) its economic dependence on fuel imports and 3) general economic import dependence (incl. all other goods and services used for energy production).

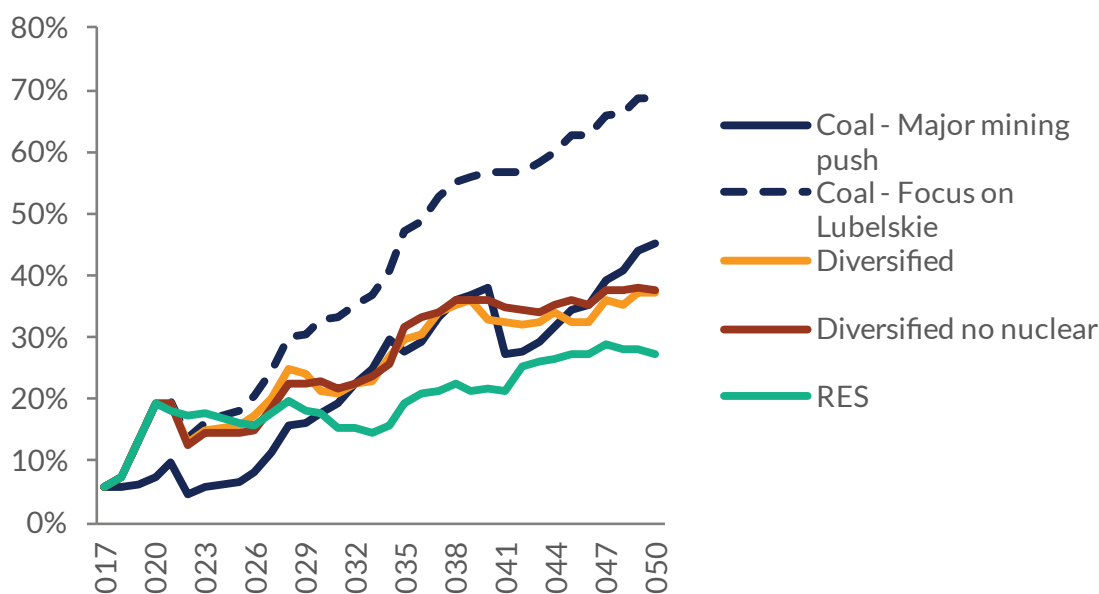


Figure 33: Electricity produced from imported fuels (including net electricity imports) as % of domestic demand in Poland

8.3.2. Physical import dependency of the power sector

Does diversification mean that Poland will substitute one import-dependent energy mix option with another? Broad measure of import dependency of the energy sector (Figure 33) reveals that it is not the case. While the Coal scenario may provide higher self-sufficiency in the 2020s, this depends entirely on maintaining support for unprofitable mines (or assuming complete success of coal mining restructuring). Without this assumption, Coal scenario delivers the worst performance over the entire assessed period. Without low-probability developments such as opening new lignite mines and new mining investments in the Silesia region, maintaining the

current share of coal generation in the mix leads to near-70% energy dependence in 2050 (see Figure 33). Even with a major mining push, the Coal scenario does not outperform diversified scenarios in the long run, and significantly underperforms the RES scenario. Therefore, the RES scenario provides a high, sustainable level of self-sufficiency. This results from the combination of a high level of domestic renewables share in the energy mix and close to zero energy trade balance (for other scenarios, there is a long-run deficit in cross-border electricity trade).

8.3.3. Economic dependency of the power sector – fuel imports

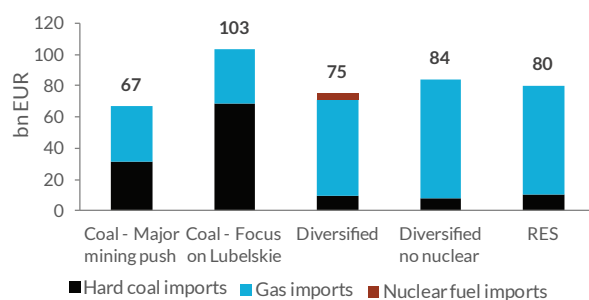


Figure 34: Fuel import bill for energy sector, 2017-2050

While import dependence expressed in physical units provides clear evidence that the Coal scenario does not deliver energy self-sufficiency, another question is whether it may minimize the costs of required fuel imports. In fact, this is not the case: while under assumed price projections for coal and gas, it costs thrice as much to import a unit of energy in the form of natural gas than hard coal, this does not translate into a clear advantage for the Coal scenario. Only a major mining push allows to limit the import bill over the whole assessed period. For more realistic supply assumptions, the fuel import bill is significantly higher in coal scenarios than in their alternatives, even despite high gas prices assumed.

We may conclude that the question is not whether Poland will face higher fuel import bills, but rather what amount and type of fuel will be imported. From the perspective of energy security, it may matter if there are infrastructure bottlenecks leading to a risk of supply disruptions. Historically, this was the case for natural gas infrastructure. However, in recent years the supply routes have been significantly diversified, with further gas infrastructure projects foreseen in the coming years (ENTSO-G 2017). Energy system modelling indicates that the gas imports difference between the Coal and diversified scenarios is gradually increasing to ca. 5 bcm in 2050. This is equivalent of import capacity of the Świnoujście LNG terminal. Therefore, projected increase in gas imports stays well within the limits guaranteeing diversified and stable supplies. It is also worth noting that a significant amount of coal-to-gas switch occurs in CHP installations, with peak plants playing a limited role in the energy mix. For example, in the RES scenario gas CHP plants meet 13% of electricity demand in 2050, while CCGT/GT plants – only 11%. Therefore, using gas plants for back-up needs is not fuel-intensive when the broader system perspective is taken into account (e.g. potential of cross-border trade).

While prolonged episodes of low wind and solar generation may happen, they represent only a share of the total time of the system operation.

8.3.4. Economic dependency of the power sector – fuel imports

While assessing import dependence in economic terms, it is useful to look at the broader picture, taking into account the whole structure of energy system costs – including CAPEX, OPEX, electricity imports, and ETS costs. Here, even assuming low domestic content of key elements of low-emission technologies (i.e. no significant development of domestic suppliers for RES and nuclear), we see that the Coal scenario compares unfavourably to its alternatives (Figure 35: Total value of imports associated with energy system costs, 2017-2050). There are several reasons for this. First, coal technologies are also only partly provided by Polish suppliers. Recent examples show that the investments are realized by consortia of Polish and international companies, with the market is dominated by international supply chains and key elements often coming from abroad. Secondly, machinery and electronics are not the only parts of CAPEX; other elements, such as construction, have significant domestic content. A similar observation applies to OPEX. Thirdly, the discussed above, coal-based technologies generate significant fuel import costs in the long run. Finally, from the system point of view, all CO₂ costs should be treated as imports. This is because they contribute to a worsening balance of Polish participation in the EU ETS system. As allocation of allowances to be sold on auctions by a given country depends on historic rather than current emission levels, increasing emission from Polish power plants does not lead to increased revenues for Poland from EU ETS auctions. Combined, these factors lead to a significant increase in import dependence of the energy sector, not only in terms of units of energy, but also monetary values.

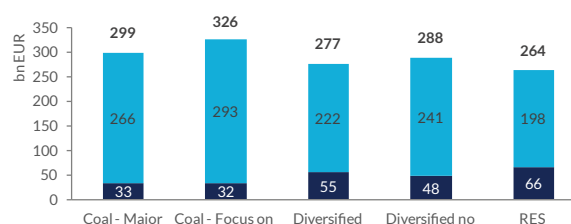


Figure 35: Total value of imports associated with energy system costs, 2017-2050

9. The impact of scenarios on economy and society

This chapter looks into costs and economic impacts associated with the different scenarios. This chapter answers the following question: What is the economic and social 'price-tag' associated with the scenarios?

9.1 Total costs of energy production

How do different energy mix scenarios perform in terms of costs? To answer this question, we compare the cost of different scenarios, taking into account the following components of energy production costs: CAPEX, OPEX (fixed and variable, i.e. independent and dependent on the actual volume of electricity produced by the given power plant), Fuel, CO₂ emissions (EU ETS costs), DSM, Net imports. Fuel and CO₂ costs include expenditures stemming from fuel used for heat generation in CHPs. These costs are together defined as "system costs". The costs of network development are not included in the calculation as we assume that they are dominated by the investments present in all scenarios.

Total costs of energy production up to 2050 are similar in all considered scenarios, with the Coal scenario being 2-6% more expensive than its alternatives. The scenarios differ in terms of cost composition: non-coal mixes need larger CAPEX and OPEX expenditures, as alternatives to coal plants are more capital intensive (except for gas plants) and are associated with higher fixed maintenance costs (except for gas plants and PV). However, this is more than offset by the decreased costs of CO₂ allowances. At the same time all scenarios demand similar outlays on fuel, as in the non-coal scenarios the increase in gas, biomass and biogas consumption is balanced by the coal savings. Overall, the total bill for fossil fuel is slightly lower in the Diversified and RES scenarios, even despite the shift from coal and lignite to more expensive natural gas. The reason is increased use of low-emission technologies which reduce the overall demand for fossil-fuels.

A closer look at the cost dynamics reveals that all scenarios see rapid increase of total expenditures required for meeting domestic energy demand in 2020s. The increase is driven mainly by the projected rebound in fuel prices and CO₂ costs.

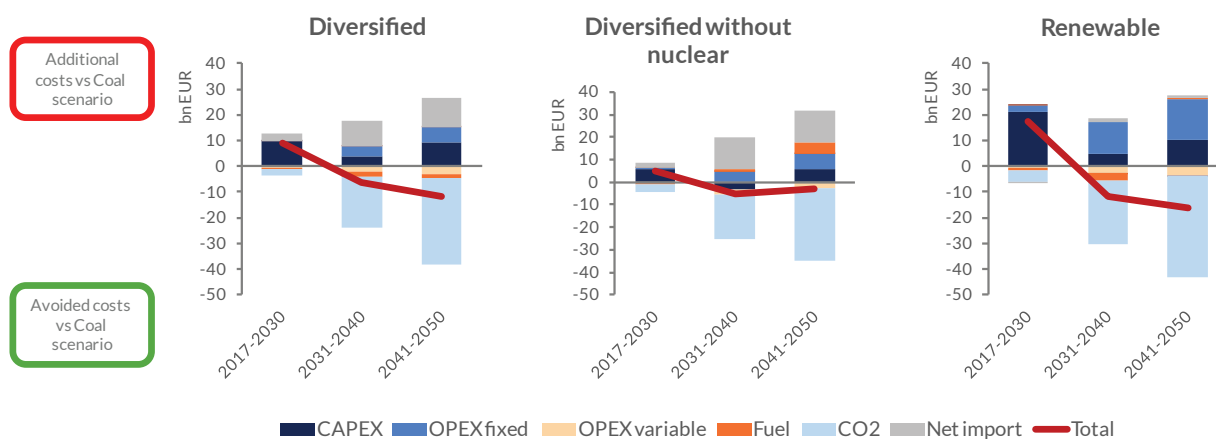


Figure 36: Cost of diversified and RES scenarios compared to Coal scenario

Furthermore, the low-carbon alternatives need larger investments in capital-intensive, low-emission options. This results in a less rapid cost escalation in the Coal scenario, which is, however, more costly in the long run, as investments in

alternative scenarios start to bring net benefits, mainly in terms of reduced import and CO₂ expenditures. Thus, an increased share of low-emission sources allows to avoid the risk of cost escalation due to the stricter climate policy in the future.

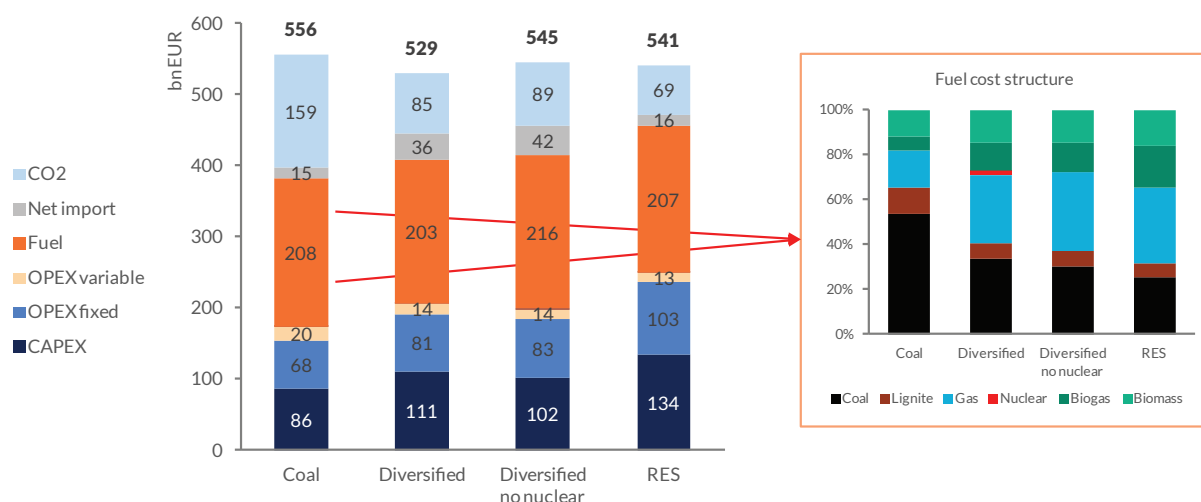


Figure 37: Total costs of energy production up to 2050

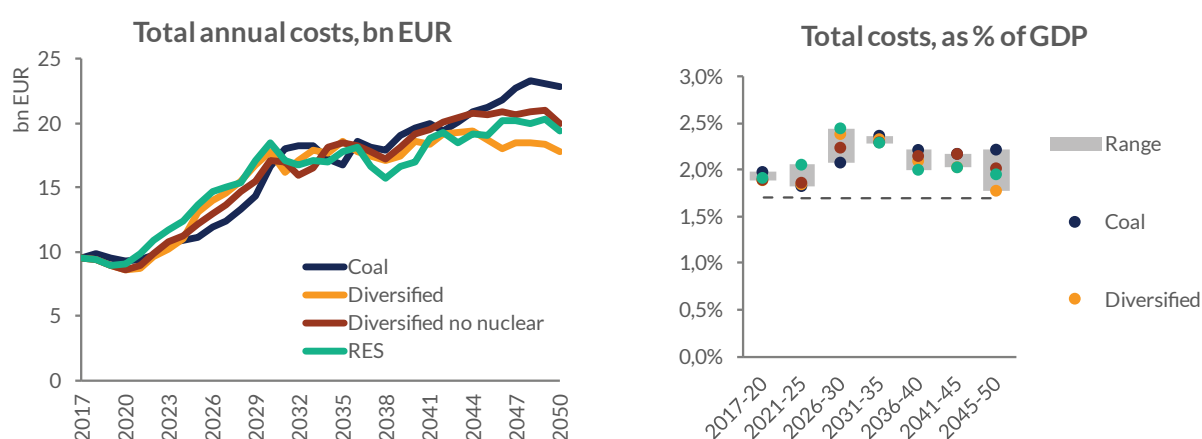


Figure 38: Dynamics of total costs of energy production – scenario comparison

While significantly increasing in absolute terms, total costs of energy production in all the scenarios remain within a rather narrow range of 1.8-2.5% of GDP, with inter-scenario differences never exceeding 0.4% of GDP. After a projected surge in the 2020s, a relative share of costs of energy production in GDP stabilizes in the Coal scenario and decreases in the Diversified and RES scenarios. In the long run, the rate of growth of economy overtakes escalation of energy production costs, especially if investments in low-emission technologies are undertaken. The increased investment effort in the 2020s pays back in the 2030s-50s in a similar way as electrification of the 1950s-70s paid back in subsequent decades.

It should be noted that the higher the initial investment level, the higher the payback in the next years in terms of CO2 and fuel costs as well as net import dependence. Decisions taken in the 2020s set the path for system cost developments up to the 2050s (and beyond). Avoiding additional capital investments required to start energy mix diversification in the 2020s (6-9 bn EUR in diversified scenarios and 21 bn EUR in RES scenario) leads to a high system cost lock-in afterwards. The Coal scenario becomes the most expensive already in the 2030s, and the costs of maintaining status quo increase further in the 2040s. Thus, it is crucial to look beyond 2030 when assessing strategic directions of Polish energy mix developments.

9.2. Development of external costs

The economic assessment of energy mix external costs takes into account health and environmental (non-climate) impacts. The main driver is health impacts, mostly due to the air pollution. Health impacts manifest in Poland and its neighbouring countries. Others comprise of environmental impacts (biodiversity and crop yield loss) as well as damage to building materials exposed to air pollution. Climate change impacts are not included in this analysis, as we already calculate CO₂ costs within the EU ETS system.

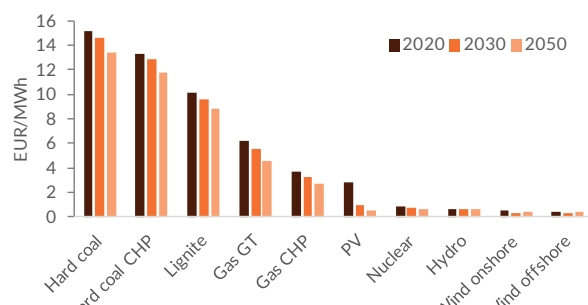


Figure 39: External cost per unit of electricity produced in new and retrofitted power plants

Our estimates of external costs per MWh are based on the NEEDS project, complemented by CASES database and cross-checked with the Ecofys (2014) study. This includes the lifecycle costs of energy sources, meaning that emissions associated with the production and liquidation of individual installations are taken into account. All costs are expressed in per MWh terms and apply to new and retrofitted plants. Therefore, they take into account technical progress (including indirect emissions from PV production) and environmental norms. This also explains the differences between the assessment of current unit external costs (e.g. in the Ecofys study) and projections such as in the NEEDS or CASES project. Some broad patterns are still present in all the studies: coal-based generation generates the largest costs, with hard coal causing more health damage than lignite (contrary to climate impacts, which are higher for lignite), with the external costs for wind and hydro energy being among the lowest. Low figures for nuclear plants are consistently reported across all the major studies, which is explained by a large amount of energy produced from the unit of fuel compared against very low risk of high-cost accidents. As for biomass and biogas, available estimates differ to a significant extent, depending on sources and technologies used

for energy production. In line with our assumptions on limited and sustainable use of bioenergy sources, we assume the values closer to the lower range of available estimates. As the expected generation mix is similar across all scenarios up to the 2020, we focus on post-2020 developments. Assuming the introduction of new environmental standards and technological progress, external costs stay around EUR 1.8-2 bn in the Coal scenario up to 2050. In the long run, they are however 2-4x lower in alternative scenarios falling almost to zero in the middle of the century. In total, the externalities improve cost performance of alternative scenarios, albeit their impact is limited in absolute terms (see Figure 40). This is due to the increasingly stringent air pollution regulations that ensure that new and retrofitted coal power plants will be much less harmful to health and the environment compared to the current standard. Still, even after accounting for these improvements, annual external costs stay at around EUR 1.8-2 bn in the Coal scenario up to 2050. Alternative scenarios decrease this number by 2-4 times in the long run, with greatest declines seen in the RES scenario (see Figure 41).

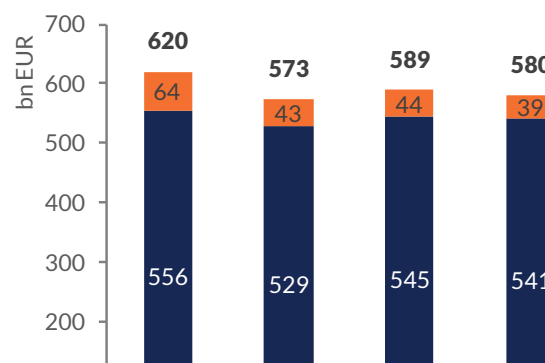


Figure 40: Total direct and external costs of energy production up to 2050

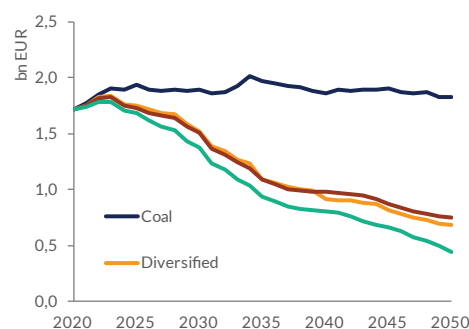


Figure 41: Dynamics of external costs – scenario comparison

9.3. Macroeconomic impacts: GDP and labour market

Based on projected differences in the direct costs of energy we can assess macroeconomic outcomes of individual mixes. In order to do this, we set the Coal scenario as our baseline and explore the impact of shifting towards alternative scenarios. We take into account not only direct shifts in the fuel demand generated by the power sector (i.e. different structure, dynamics, and import-intensity of costs incurred by it), but also shifts in the consumer demand (i.e. higher/lower household spending for non-energy goods and services resulting from lower/higher energy bills). We also consider indirect impacts occurring throughout the entire value chain. These calculations are based on the macroeconomic input-output model calibrated on the latest available data from the Polish Central Statistical Office.

This perspective has two benefits. First, we avoid narrow focus on demand originating only in the power sector by taking into account also developments on the consumer's side. Second, we further broaden our assessment by capturing spillovers from the initial shifts in the demand structure. Limitation of this approach is the partial equilibrium setting of the applied model that may, to a certain extent, underestimate the changes of fuel prices and exchange rates and overestimate the labour market impacts on employment and wages combined. This should not however change the final results more than a few percent as the relative price adjustment work on the margin.

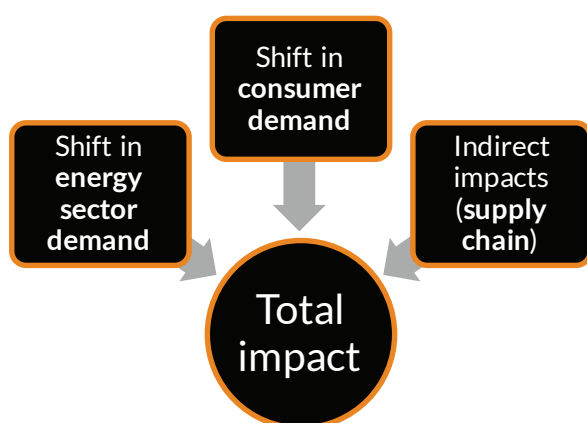


Figure 42: Scope of assessed macroeconomic impacts

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First, we assess the differences in the GDP levels between the presented scenarios. We observe the limited transitional cost of moving away from the Coal scenario in the 2020s. This is due to the reallocation of resources from consumption to investment goods necessary for the shift towards more capital-intensive energy generation technologies. Investment push in the power sector depresses the demand for other goods more than it increases the demand for capital goods. This effect is however small and temporary: by the mid-2020s the GDP path falls below the baseline scenario no more than 0.5%. To put things in perspective, in the same period Polish GDP should grow by 40% or more. Increased capital needs of the Diversified and RES scenarios are therefore macroeconomically negligible, especially than, in the long-run, they result in lower energy bills allowing consumers to spend more and generate a positive impulse for the economy that should increase GDP by 0.8%-1.1% above the baseline. This is also due to the higher import of fuels in the Coal scenario that directly or indirectly (through the real exchange rate) reduces the demand for domestically produced goods and services. Thus, increased expenditure on the energy sector diversification in the 2020s may be seen as a sound investment from the macroeconomic perspective. It increases long-run productivity of the Polish economy and leads to higher social welfare: while energy needs of Polish households are met to the same extent as in the Coal scenario, the amount of money which they may spend on other goods and services increases in the long run.

Based on GDP figures and projected labour productivity trends, our model provides estimates of employment / wage consequences of different energy choices. These numbers should be interpreted as the changes to the total wage bill, i.e. wage and employment changes combined. The exact split between the net number of jobs created and wage deviations are hard to assess without the general equilibrium modelling, as they depend not only on the future features of the labour market but also on the macroeconomic clearing mechanisms such as the exchange rate channel. In general, the wage bill dynamics are similar to the expected GDP path. In the 2020s we observe

a slightly inferior performance of all alternative (to Coal) scenarios, which is subsequently replaced by the neutral impact in the 2030s and positive in the 2040s and 2050s. Changes to the labour market created by the decarbonization of the power sector should be seen however in the context of the “normal” reallocation of employment that occurs in the economy on an every-day basis with several order of magnitude larger intensity. Temporal wage bill shock below 0.5% over a decade will likely be indistinguishable from the economic cycles and typical 2.5-3.5% annual wage increases. Therefore, the impact will likely materialize as a slight – unobservable – slowdown in the real wage growth. Nevertheless, in the long run, the overall labour market performance of the diversified and RES scenarios are superior to the Coal scenario. This materializes already in the 2030s, while by the end of the 2040s the wage bill is expected to be slightly higher than in the baseline, with highest benefits seen in the RES scenario. In the long-term benefits – manifesting primarily in increased wages – should be greater than the transitional cost, and not fade with time. The cumulative difference in the labour market performance between the presented scenarios will be however small when compared to the large macroeconomic trends that should more than double the wage bill till the 2050s. Therefore, it might be useful to think about the energy transition as largely neutral for the labour market in the long run.

Due to required labour productivity improvements, employment in coal mining decreases in all the scenarios. Even in the Coal scenario it accounts for 20 thousand jobs in 2050 and falls to several thousand or even zero in the other scenarios. This is in line with the long-term trends in the mining sector not only in Europe but also in other OECD countries. In order to retain the ability to pay competitive wages for miners the mining sector must improve the average efficiency of coal extraction. This means constant ability of employment restructuring due to the unsolvable incompatibility between the productivity growth and labour-intensive technologies that in the long run are unsustainable due to the strong wage pressure. In other words, either the mining sector will be able to reduce employment through productivity improvements or it will disappear altogether.

The decline of employment in mining is however accompanied by the rise of employment in other sectors. In alternative scenarios, a significant amount of jobs is created in agriculture that supplies the energy sector with biomass and bioenergy to a much larger extent than it is expected in the Coal scenario. Employment also increases in manufacturing, as it participates in the supplies of solutions required for the shifting of the energy mix towards more capital-intensive, low-emission generation technologies.

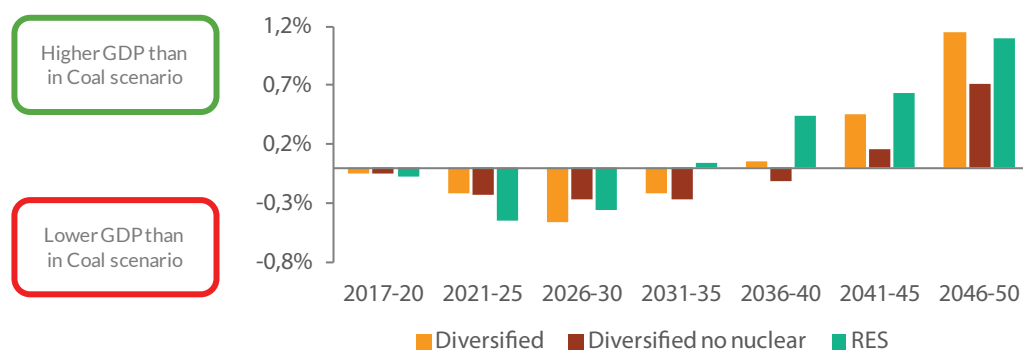


Figure 43: GDP outcomes in diversified and RES scenarios compared to Coal scenario

High positive impact on employment in services is the result of shifts in consumer spending. Superior cost performance of the Diversified and the Renewable scenario in the long run means that Polish consumers will have more money for non-energy-related goods and services. As services are the main element

of consumption basket and the most important employer (especially in the long run, when productivity improvements will shrink employment in manufacturing and mining), increased consumer spending will translate into highest absolute gains in the service sector.

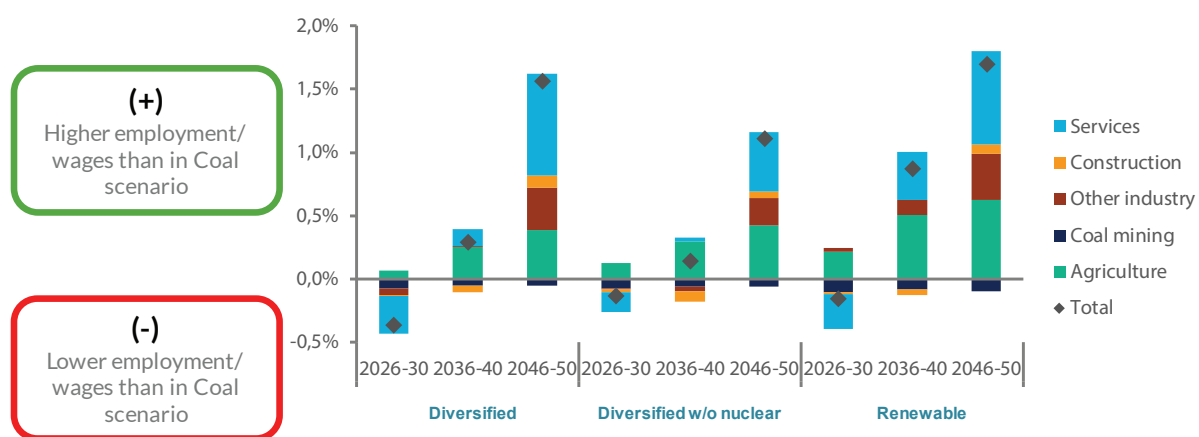


Figure 44: Labour market outcomes in diversified and RES scenarios compared to Coal scenario

10. Sensitivity modelling

This chapter broadens the scenarios setup and discusses results from sensitivity modeling for some key drivers. Thereby this chapter answers the following question: How resilient are the scenarios and what are some of their key upsides or downsides?

10.1. Overview of sensitivities

The sensitivities were designed to test out the resilience of the scenarios to certain fundamental changes of the electricity market. In this chapter, general implications will be discussed.

Lower Demand

The Lower Demand sensitivity illustrates the implication of energy efficiency on the main results. Therefore, an increase in electricity demand was modelled with 0.6 % p.a. instead of 1.4 %. This decreases peak-load by 4.5 GW in 2050 and is of key importance to mitigate SoS challenges. Thereby, the need for additional back-up capacity is decreased in all scenarios.

Also the decrease in CO₂-emissions is quite impressive. On average 12 MM t will be additionally mitigated per year in the Coal scenario.

The decrease in demand shows a low effect on average wholesale prices since marginal production costs do not change in this sensitivity.

No cross-border trade

This sensitivity explores the benefit of cross-border interconnection of Poland with neighbouring markets.

Power prices are mostly affected by this sensitivity. Average wholesale prices rise by 5 €/MWh compared to the main scenarios.

The need for additional back-up capacity does not change since this study already applied a 9% national reserve margin in all the scenarios. Though the utilization of peaking plant capacity increases in the sensitivity and underlies the value of import capacities during peak load hours.

Lower RES costs

The latest results from renewable auctions in Europe show the likely possibility of higher learning curves of renewables than assumed in the main scenarios.

Therefore, a lower RES costs sensitivity explores the change of scenarios, with wind and solar CAPEX following a trajectory

which is 20% lower than shown in Chapter 7.2.

The varied RES costs do not have influence on capacity and generation development of RES. This is because capacity is settled in advance and is not commissioned by the model.

Coal scenario without Lignite

In a sensitivity of the Coal scenario the newly commissioned lignite capacities are replaced by additional coal commissioning (6 GW).

Our sensitivity modelling indicates that omitting lignite from the mix can decrease system costs by around 1.5%, which is driven mostly by CO₂ cost savings. However, this also increases the costs of fuel imports by 14 bn EUR (+22%) up to 2050.

10.2. System costs of sensitivities

In this chapter we focus on system cost implications of sensitivities.

Table 4 presents the comparison of the total cost of energy production across the sensitivities for each of the assessed scenarios. Relative cost performance of the scenarios is not affected by sensitivities, with one exception: faster improvements for wind and solar make the RES scenario comparable to the Diversified scenario (assuming no cost overruns for nuclear power plants in the latter).

The Coal scenario remains the most expensive in each sensitivity, even for the "No lignite" case which improves its overall performance (as hard coal is more cost efficient energy mix option than lignite). Sensitivity modelling therefore indicates that omitting lignite from the mix can decrease system costs by around 1.5 % vs. our reference.

Cost savings related to lower electricity demand growth are comparable across the scenarios. It should be noted that their impacts at the end of the assessed period are significantly higher (-14-19% in the 2040s) than on average during 2017-2050 (-11-12%). It is important to note, however, that we did not take additional costs of efficiency measures into consideration.

The lack of cross-border trade leads to an increase in total costs of energy production. The resulting cost increase seems modest relative to total costs (+0.8-1.1%), though the underlying changes can be quite substantial. For example: The sensitivity

“No cross-border trade” avoids net import costs of 15 bn EUR in the Coal scenario and on the other hand increases costs of domestic power generation by 19 bn EUR. Therefore, an overall modest increase in system cost of 4 bn EUR remains. This means that for every euro of avoided net imports in the Coal scenario, Polish consumers will have to pay on average 1.3 euros for

domestically generated electricity.

Cross-border trade is most cost-efficient in the RES scenario, as it allows to efficiently utilize domestic renewable resources and decrease the use of gas for back-up generation.

Table 4: Total costs of energy production up to 2050 – sensitivities compared to base case

		Total costs of energy production up to 2050 by energy mix scenario, bn EUR			
			Diversified	Diversified no nuclear	RES
Base case		556	529	545	541
Sensitivity	Low demand	491 (-12%)	464 (-12%)	477 (-13%)	485 (-11%)
	No cross-border trade	560 (+0.8%)	534 (+0.9%)	550 (+0.9%)	547 (+1.1%)
	Niższe koszty odnawialnych źródeł energii	554 (-0.3%)	523 (-1.2%)	536 (-1.6%)	526 (-2.7%)
	No lignite	548 (-1.5%)	-	-	-

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10.3. CO₂-emissions of sensitivities

In this chapter we focus on emission implications of sensitivities.

Table 5 presents a comparison of the total emissions across the sensitivities for each of the assessed scenarios. The numbers represent the emissions in 2050.

Table 5: CO₂-Emissions in 2050 (mln. T. CO₂) and Reductions Compared to 2005 (% vs. 2005)

		CO ₂ -emissions in 2050, mln. t and reduction compared to 2005, % by energy mix scenario			
		Coal	Diversified	Diversified no nuclear	RES
Base case		137 (-7%)	47 (-68%)	51 (-65%)	23 (-84%)
Wrażliwość	Low demand	113 (-23%)	34 (-77%)	37 (-75%)	17 (-89%)
	No cross-border trade	151 (+3%)	58 (-60%)	62 (-58%)	30 (-80%)
	Lower RES costs	137 (-7%)	47 (-68%)	51 (-65%)	23 (-84%)
	No lignite	132 (-10%)	-	-	-

The sensitivities allow us to highlight some key effects.

Our low-demand sensitivities allow for a reduction in emissions compared to the Base Case in 2050. This is therefore a sensitivity where benefits in the form of lower costs and lower emissions align. This illustrates the strong effect of tapping into energy efficiency potentials on overall emissions. The effect is strongest in the scenarios which have an overall high carbon power generation mix. The low demand sensitivity for the RES scenario is almost in line with a reduction of 90% vs. 2005. A further increase of energy efficiency is as such a no-regret option.

The sensitivity without cross-border power trade shows an increase in emissions in 2050 compared to the base-case because all scenarios need to compensate missing net imports. This effect is highest in the Coal scenario, because here coal generation replaces the decrease in imports.

The sensitivity without lignite shows a strong decrease in CO₂ (-10%, vs 2005), at the same time having lower system costs. This is also a sensitivity where benefits in the form of lower costs and lower emissions align.

11. Conclusions

So what have we learned from this modelling exercise?

In this chapter we first briefly summarize the main results of our modeling, and then we expand some additional policy recommendations, beyond what we already have addressed. For a full summary of the finding please be referred to the executive summary.

Naturally, the question can be raised which scenario is “best”.

The focus of this study was not to model an optimal scenario but to point out positive and negative aspects of different technology scenarios. Therefore, the optimal pathway is likely a mix of the scenarios we have defined here, combining elements of multiple scenarios.

The following table summarizes the main quantitative results of our modelling:

	Coal	Diversified + Nuclear	Diversified w/o Nuclear	Renewable
Sum. System costs	556 bn€ (100%)	529 bn€ (95%)	545 bn€ (98%)	541 bn€ (97%)
Sum. External Costs	100 %	68 %	69 %	61 %
Sum. CO ₂ emissions	100 %	69 %	70 %	60 %
Av. Employment effect	0 %	+0.3 %	+0.2 %	+0.5 %
Overall GDP effects	0 %	+0.1 %	0 %	+0.2 %
To be commissioned add. capacity (conventional)	43 GW (100%)	39 GW (85 %)	41 GW (85 %)	41 GW (90 %)
Avg. Power price	68€/MWh	71€/MWh	71€/MWh	64€/MWh
Avg. Overall Import-dependency	22%-39%	25 %	25 %	19 %

Figure 45: Summary of main modelling results / Sums and averages are over the time period 2017-2050

Clearly, when judged over the full horizon of this study, prolonging the status quo (Coal scenario) is dominated by more diversified strategies, meaning that all scenarios with larger shares of CO₂-free generation and natural gas perform better in most (both diversified scenarios) or even all criteria (RES scenario).

So what can we learn from this regarding the different technologies?

The Coal scenario outperforms the other scenarios in the short run. This implies that coal has an important transitional role to play in regards to managing SoS and cost issues.

One important step for the future of the coal generation in Poland is to work out a transition plan which will indicate which power plants are of key importance for the system, which need to be refurbished and which should be moved to the cold contingency reserve outside the market or be phased out. Here care should be taken to develop a transparent method for identifying retrofit candidates. Beyond a transitional phase a diversification with more renewables and gas, the latter in CHP and back-up function, is clearly a no-regret pathway. Beyond CHP generation and back-up the role of natural gas needs a nuanced discussion.

Within RES the role of wind-onshore needs to be stressed. Wind onshore already outperforms all other technologies based on average generation costs. The role of nuclear seems less clear, and here a discussion of risk and potentials seems necessary.

Given the complexity of the choices ahead, the analyses laid out in this study can only be a starting point for further analysis of energy system pathways. Therefore it seems to implement a public stakeholder process with additional energy system modelling to further broaden and deepen the analysis conducted here.

In regards to impact assessments, further work might be necessary in regard to power grid implications of the different scenarios, which were not in the focus of this study. In regards to the scenario setting more work on sector integration and its impact on the power market would be advisable. This specifically applies to the electrification of the heat and power sector.

Polish energy sector 2050
4 scenarios

