POWER SYSTEM EXPANSION POLAND

A study by Quantified Carbon for
Clean Air Task Force

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About this publication: *This report has been prepared by Quantified Carbon (QC) for Clean Air Task Force (CATF) to simulate Poland's power sector decarbonization and inform recommendations for Polish policymaking.*

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Executive summary

Poland faces a pivotal moment in reshaping its energy landscape, transitioning away from a coal-dependent power system to meet ambitious decarbonization targets. The historical dominance of coal in Poland's energy sector presents unique challenges as the country strives for a sustainable and low-carbon future. The frequent changes introduced between governments further complicate the energy landscape, introducing uncertainties in market conditions and regulatory consistency. To foster investor confidence and ensure a resilient energy transition, Poland requires a stable and enduring regulatory framework and energy policy that transcends political changes, providing a foundation for sustainable investments and successful decarbonization efforts.

This study explores diverse pathways to attain a *fully decarbonized Polish power system by 2050*, targeting a 99% reduction in emissions compared to 1990 levels. Utilizing carefully crafted scenarios, including custom geospatial analysis for wind and solar potential, the analysis showcases varying projections related to crucial technology developments. These scenarios encompass optimistic and conservative viewpoints on parameters such as investment costs, commodity prices, maximum expansion potential, and build rates. Employing a dedicated multi-year capacity expansion optimization framework, the study outlines scenarios from 2030 with five-year increments until 2050. This methodology integrates investment and dispatch optimization, relying on a comprehensive set of 35 historical weather years to ensure the construction of reliable power systems with realistic dispatch schedules and electricity prices. Ultimately, the study seeks to establish a foundation for identifying the most sustainable and competitive power system for the future of the Polish energy landscape.

The results highlight a rapid and thorough phase-out of economically and environmentally burdensome coal power by 2035, a departure from the current trajectory of Polish energy policy, which leans towards a more delayed transition. Fossil-free onshore wind takes centre stage in driving decarbonization efforts, emerging as the dominant generation source in the Polish power system. Figure 1, reflecting the central 'base' scenario in this study, underscores the constituents of the decarbonized Polish power system in 2050. Rooted in a technology-neutral perspective and best-estimate input assumptions, this scenario necessitates a sustained, long-term build rate of approximately 3 GW/year for onshore wind, doubling the observed rate in Poland in 2022, and peaking in the early 2040s at a challenging7 GW/year. Offshore wind and solar PV exhibit limited cost competitiveness, assuming modest roles in the overall energy landscape.

Nuclear power, reaching an installed capacity of approximately 8 GW, plays a substantial role, contributing over 15% to the annual Polish power production. This is predominantly complemented by gas power plants, amounting to an installed capacity of around 23 GW and a 10% share of the annual generation mix. The majority of this capacity is derived from open-cycle power plants, both natural gas and biogas fuelled, selected for their relatively low investment cost and high dispatchability—a crucial factor in maintaining a stable power system during extreme weather conditions and contingencies. Additionally, combined-cycle natural gas power plants equipped with carbon capture and storage contribute a noteworthy 7% to dispatchable power generation. Finally, short-term battery storage and long-duration hydrogen storage (~ 2TWh of energy storage capacity), complementing the substantial onshore wind generation in the system, contribute a discharge capacity of approximately 2 GW and 4 GW, respectively.

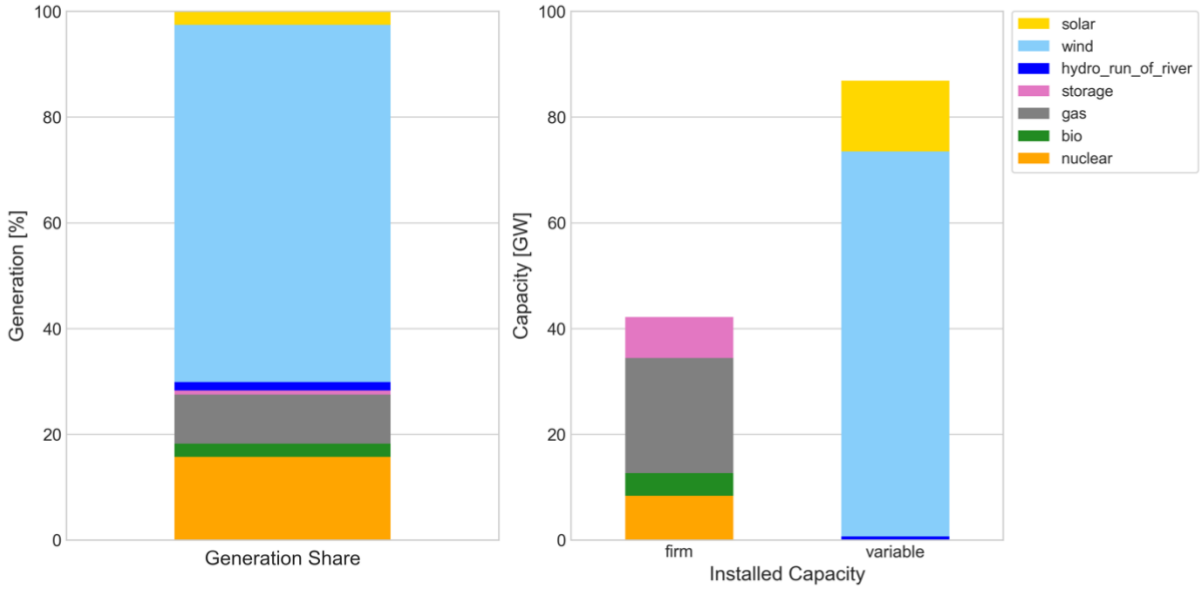


Figure 1. Generation share (left panel) and capacity mix (right panel), split with respect to firm and variable type, of the decarbonized Polish power system in 2050 in the 'base' scenario.

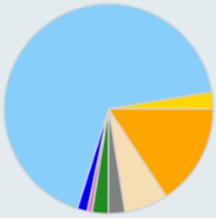
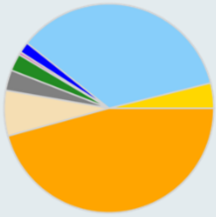
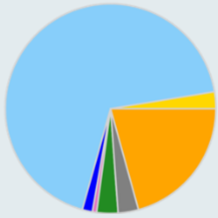
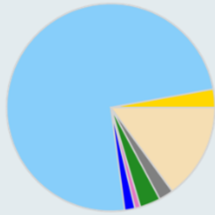
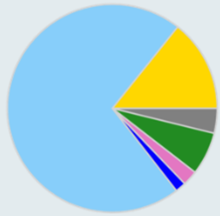
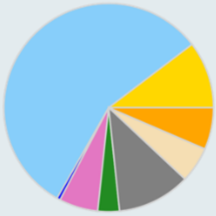
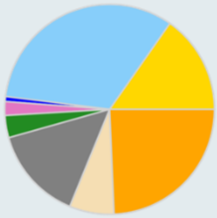
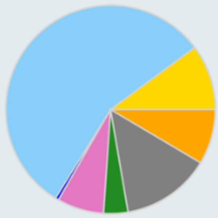
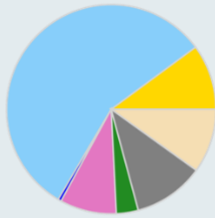
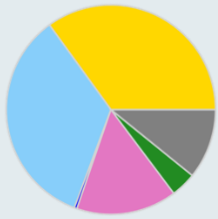
The 'base' scenario envisions notable progress across various technologies, with sustained cost reductions for renewables until 2050 and a land-availability-based cap of 74 GW on onshore wind expansion, not accounting for potential local opposition. Simultaneously, the introduction of new nuclear power aligns with expectations of rather successful and minimally delayed projects. Further, the scenario assumes the establishment of CO_2 transport and storage infrastructure by 2035 and nearly 100% carbon capture efficiency for CCS-equipped power plants by 2050. Finally, the 'base' scenario presupposes groundwork, including regulatory frameworks, for the expansion of *all technologies*.

Deviations from the above-described 'base' scenario assumptions are explored with a set of sensitivity scenarios. In case the anticipated technological developments do not materialize, or the necessary groundwork is not established for all technologies, the study explores conservative scenarios. These scenarios simulate a less optimistic development for different technologies:

- Denoted **'VRE --'**: Development of costs for wind and solar stagnates whilst simultaneously facing significant public opposition enabling a significantly lower maximum expansion potential.
- Denoted **'nucl. --'**: Initial nuclear projects don't obtain strong governmental support, starting off expensive.
- Denoted **'CCS --'**: Costs experienced for transport and storage of CO_2 becomes higher than expected.
- Denoted **'VRE -- no nucl. no CCS'**: The decarbonization strategy heavily relies on wind and solar technologies; however, their cost decrease stagnates, and they struggle with negative public opinion.

These scenarios represent distinctly different decarbonized systems and capacity mixes, making them ideal for a deeper comparison. Table 1 offers this comparative analysis, illustrating their generation mixes and shedding light on competitiveness and sustainability in these conservative scenarios, providing valuable insights into diverse decarbonization pathways.

Table 1. Summarized results comparing main parameters of the power systems for the base and conservative scenarios.

<table>
<tr><th rowspan="2">Parameter</th><th colspan="5">Scenario</th></tr>
<tr><th>Base</th><th>VRE --</th><th>CCS €€€</th><th>nucl. --</th><th>VRE --
no nucl.
no CCS</th></tr>
<tr><td>Generation mix:
</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Capacity mix:</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Security of supply</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td></tr>
<tr><td>Average electricity price (€/MWh)</td><td>53</td><td>61</td><td>55</td><td>60</td><td>141</td></tr>
<tr><td>Total system cost</td><td colspan="4">Similar</td><td>+~50%</td></tr>
<tr><td>Relative dependency on transmission infrastructure for power, hydrogen and CO2</td><td>Moderate</td><td>Lowest</td><td>Moderate</td><td>Higher</td><td>Highest</td></tr>
<tr><td>Relative greenhouse gas emissions</td><td>Moderate</td><td>Moderate</td><td>Lowest</td><td>Highest</td><td>Higher</td></tr>
<tr><td>Relative land use and use of critical minerals</td><td>Moderate</td><td>Lowest</td><td>Moderate</td><td>Higher</td><td>Higher</td></tr>
</table>

The modelling guarantees compliance with current Polish regulations by maintaining a 9% capacity reserve margin across all scenarios. This ensures that all scenarios qualify to meet security of supply, signifying the preparedness of Polish power systems to navigate challenging conditions, including extended periods of low wind production or unexpected contingencies.

In terms of competitiveness, scenarios including of diverse set of technologies demonstrate comparable electricity prices and system costs. This suggests that a policy embracing and facilitating the development of a broad set of technologies is well-equipped to handle uncertainties, such as unexpected hindrances in development, resistance to onshore wind expansion, and challenges with larger and more complex nuclear and CCS projects. In stark contrast, the scenario excluding both nuclear and CCS technologies, 'VRE -- no nucl. no CCS', coupled with an assumption of stagnation in renewables' cost reduction and negative public opinion on onshore wind, emerges as highly non-competitive due to both significantly larger electricity prices and system costs. Arguably, this points towards technology inclusiveness being a prerequisite for achieving decarbonization of the Polish power system.

Notably, the power systems with a high degree of installed nuclear power emerge as the one with least reliance to transmission infrastructure as well as minimal use of land and critical minerals. This underscores that nuclear power in the Polish system has the potential to free up land to use in other purposes and reduce reliance on an expanded transmission infrastructure, a prospect further enhanced by the possibility of repurposing coal sites for nuclear power. To further facilitate rapid deployment of fossil free energy enabling drastic emissions reductions following the coal phase-out.

Ultimately, this study has given rise to the policy recommendations listed below.

Policy recommendations

Concluding policy recommendations derived from the current study for fostering a competitive and sustainable decarbonization of the Polish power system include:

1. Establish Technology-Inclusive Foundational Groundwork:

- Develop regulatory frameworks and permitting processes to support the expansion of *all* technologies.
- Focus on reducing costs, eliminating barriers, and resolving conflicts of interest to facilitate cost-effective and scalable deployment.

2. Promote Onshore Wind Expansion:

- Maximise the deployment of onshore wind power within the limitations of conflicts of interest. This corresponds to approximately 70 GW in this study, a sevenfold increase from the current capacity.
- Maximise the build rate to expedite the phase-out of costly and environmentally detrimental coal power, thereby limiting CO_2 emissions.

3. Advance Nuclear Power:

- Target the establishment of a nuclear fleet surpassing a total capacity of 8 GW in the long term.
- Investigate measures to facilitate the repurposing and repowering of coal power plant sites with nuclear reactors.
- Nuclear power reduces reliance on transmission infrastructure, fossil-based generation, reserve capacity as well as it provides fossil-free firm capacity to the Polish grid.

4. Facilitate Natural Gas Power Plants with Carbon Capture:

- Facilitate the implementation of natural gas power plants equipped with carbon capture capabilities.
- Establish infrastructure for the transport and storage of captured CO_2, providing dispatchable capacity to complement weather-dependent wind power.

5. Swift Transition away from Coal:

- In the short term, replace coal power with more cost-effective natural gas combined-cycle and open-cycle gas turbine power plants.
- Promote CCS retrofitting of these power plants.

6. Encourage Demand-Side Flexibility:

- Promote initiatives to increase demand-side flexibility, particularly in electric vehicles and industrial hydrogen demand as well as household heating with accumulator tanks. Significant demand-side flexibility is an important ingredient in all modelled scenarios.

7. Reinforce Transmission Grids:

- Reinvest and make new investments to strengthen local, regional, and national transmission grids. Significant grid reinforcement is a prerequisite for the extensive deployment of cost-effective onshore wind capacity.

1 Introduction

Poland stands at a critical juncture in its energy landscape, grappling with the challenge of transitioning from a power system heavily dependent on hard and brown/lignite coal[1] to one that aligns with ambitious decarbonization goals. The **dominance of coal**, historically ingrained in Poland's energy sector, poses unique challenges[2] as the nation endeavours to meet its commitment to a sustainable and low-carbon future.

The regular changes in government[3] within Poland introduce a layer of complexity to the energy landscape, posing challenges to the establishment of stable market conditions and consistent regulations[4]. The shifting political tides can lead to **fluctuations in energy policies**, creating an environment where investors face uncertainties about the longevity and firmness of regulatory frameworks – where a prominent example is the unfamous *anti-wind turbines law*[5] that literally stopped energy sector development for several years.

This volatility in regulatory stability complicates strategic investments in the energy sector, hindering the development of **long-term projects** (e.g., nuclear power) valuable for the nation's decarbonization goals. Investors may be hesitant to commit resources to initiatives that could be subject to abrupt policy changes with each new administration. As a result, the need for a **cohesive and enduring regulatory framework and energy policy** becomes paramount to foster investor confidence, attract sustainable investments, and ensure the successful implementation of a robust and resilient energy transition strategy in Poland.

The Polish power system faces both challenges and opportunities in the transition towards decarbonisation:

- The ongoing **phase-out of 'coal'** is marked by a dynamic interplay of factors, including shifts in government, evolving energy policies, and a competitive landscape driven by numerous bids for energy policy dominance characterized *inter alia* by an advent of nuclear power, aggressive investment in renewables supported by natural gas or a combination of all options.
- Poland, like many regions, is dealing with challenges in balancing its electricity supply and demand. The **increasing use of weather-dependent**, low-cost generators and the need for expanding electricity generation and demand highlight the importance of addressing issues such as inflexible demand[6] and having a strong grid that can handle power fluctuations.
- The ongoing shift towards electrifying industries in Poland provides opportunities to improve **grid flexibility**. Exploring technologies like hydrogen[7] as a storage medium and their role in adjusting consumption based on grid conditions will be crucial for optimizing the power system.
- The changes in Poland's energy market structure, moving from historical regulations to a more liberalized framework, come with both opportunities and challenges. It is relevant to explore the need to adjust the current market design to support a smooth transition to cleaner energy while ensuring a **secure and affordable power supply**. Resolving conflicts of interest and simplifying permitting processes will be important for timely infrastructure development.

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[1] Share of Coal in the Polish Power System
[2] Miners Protesting Against the EU Policy
[3] Different Parties Various Visions of the Energy System
[4] Unstable Regulations Threaten the Energy System
[5] Wind Power Regulations
[6] Demand Side Response
[7] Polish Hydrogen Strategy

- Volatility in electricity prices, combined with limited grid infrastructure and long-term energy storage, presents challenges to Poland's power system. The assessment of strategies to stabilize prices, address **transmission infrastructure gaps**, and stress the importance of long-term energy storage for a reliable and efficient power supply, should be pursued.
- The pursuit of a clean energy transition in Poland raises questions about **new supply dependencies** and the phasing out of existing ones. It is important to examine the impacts of these transitions on the electricity market, emphasizing the need for diversification and resilience in the face of potential disruptions.
- Ensuring a skilled workforce is a crucial aspect of Poland's clean energy transition, with a focus on addressing potential shortages in critical sectors. High on the agenda is the value of a balanced approach to **technology neutrality**, considering the unique challenges and strengths of different generation technologies in the Polish context.

In the light of the challenges and opportunities described above, the current study employs a *power system optimisation* methodology with the aim to establish a foundation for identifying a sustainable and competitive power system for the future of the Polish energy landscape.

The study explores pathways to achieve a **fully decarbonized** Polish power system by 2050, targeting a 99% emissions reduction from 1990 levels. Using diverse scenarios and custom GIS analysis for wind and solar potential, the modelling examines projections for key technology developments. The scenarios encompass optimistic and conservative views on investment costs, commodity prices, expansion potential, and build rates. With a dedicated multi-year capacity expansion optimization framework, the study outlines scenarios from 2030 in five-year increments until 2050. Integrating investment and dispatch optimization, it relies on 35 historical weather years to construct reliable power systems with realistic dispatch schedules and electricity prices.

In addition to the economic aspects of the cost-optimal power system in diverse scenarios, measures of **environmental ramifications, land requirements and use of critical materials** are addressed to further probe the power systems' performance with respect to sustainability.

The report is structured to provide a comprehensive understanding of the study's objectives, methodologies, and findings. Beginning with an introduction that outlines the purpose and scope of the research, the subsequent sections delve into the study's design, base scenario, and various sensitivities considered. The modelling approach, tools utilized, and their limitations and exogenous assumptions are thoroughly discussed in Section 3. Input assumptions, ranging from CO_2 emissions and demand scenarios to wind and solar expansion potential and thermal power plants, are detailed in Section 4. Results, scenario comparisons, and the pathway to decarbonization are presented in Section 5, offering valuable insights into the dynamic evolution of the Polish power system. The report concludes with discussions, a summary of key findings, policy recommendations, and three appendices providing additional details on input assumptions, GIS analysis, and the methodology for emissions, land use, and critical minerals.

2 Study

2.1 Design

The overarching objective for the current work has been to answer the following question:

Question: "What does an optimal power system look like that enables Poland to transition to a *competitive & fully decarbonized* economy until 2050?"

To provide answers to the question the following method has been applied:

Method

1. Build a Polish power systems that meet power demand and capacity reserve requirements every hour of the year whilst ensuring profitability for producers based on the following:

- Pathway towards a fully decarbonised economy in 2050 starting from a present-day power system and touching down in 2030 and then in steps of 5 years.
- A base scenario is formed from a technology neutral setting with best estimates on input assumptions:
  - Investment and operational costs
  - Commodity and CO_2 prices
  - Maximum build rates
  - Development of power systems in neighbouring bidding zones along with grid reinforcements
  - Land-use constraints
  - Demand growth & flexibility
- Sensitivities are created based on technology parameter variations with respect to the base scenario investigating optimistic and conservative projections of costs and fuel prices as well as technology restrictions.

2. Evaluate the built power systems based on their *total system investment & operational costs* and through comprehensive electricity market modelling:

- Each power system is confronted with a set of 35 different weather years.
- Security of supply, average electricity prices and electricity price volatility are determined which together with total system costs provide key insights on sustainability and competitiveness.

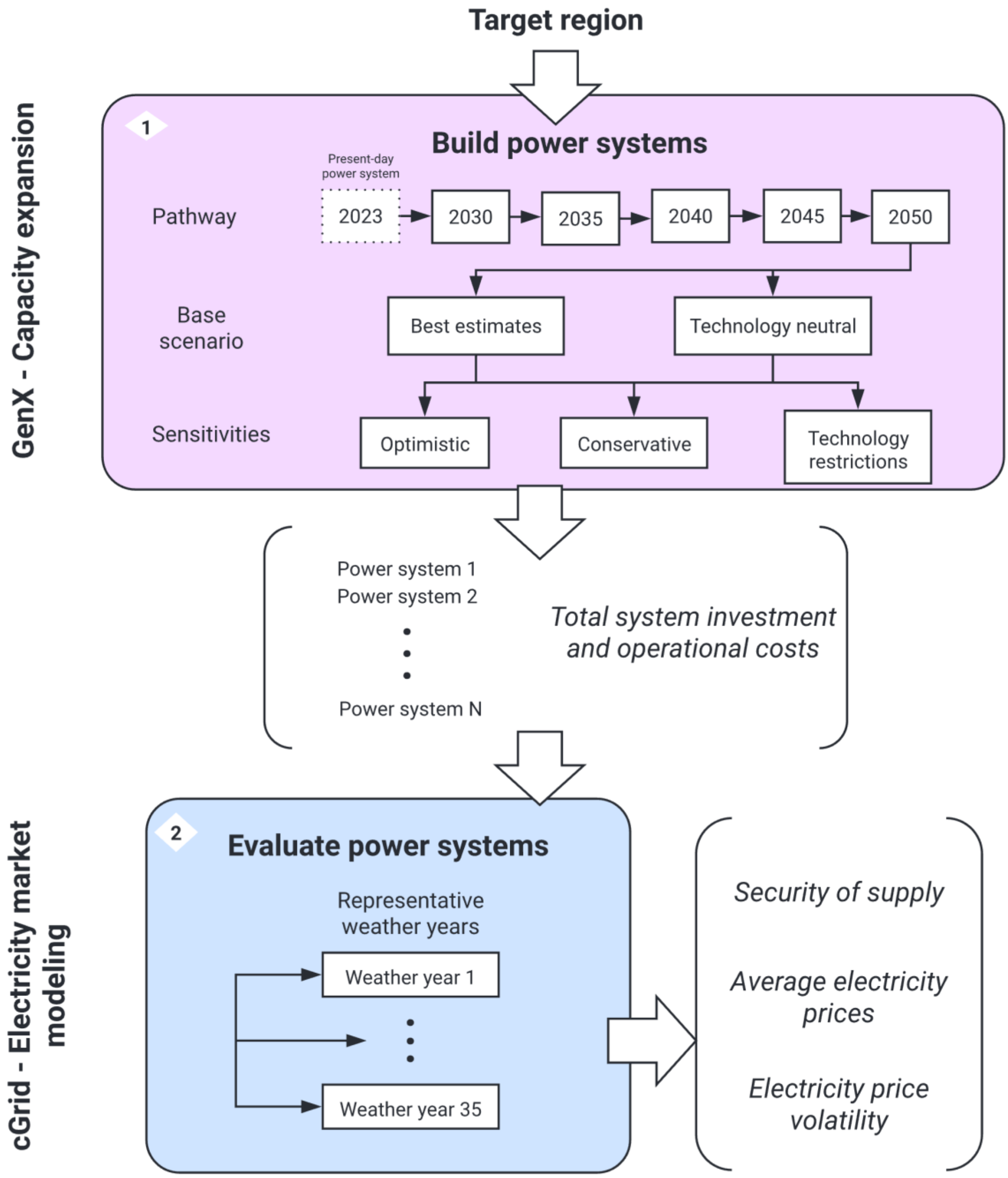

Figure 2. Flow chart illustrating study design and methodology.

The study design and methodology are illustrated in Figure 2. The foundation of the approach is two modelling steps: (1) Power system optimization, performed with the open-source tool GenX and (2) Electricity market modelling, performed with the QC-developed tool cGrid.

The methodology combines the best of different types of modelling tools. The power system optimization identifies cost-optimal power systems across a multi-year pathway including retirement and retrofitting of resources whilst ensuring that all production resources being profitable and capacity reserve requirements are fulfilled. The electricity market modelling achieves highly detailed dispatch profiles for the power systems obtained in the optimization step and can determine realistic electricity price series. Valuable is also the feasibility to confront power systems to a comprehensive set of weather years to thoroughly assess how robust they are. Together, the modelling methodology delivers credible values of system costs, security of supply, electricity prices and electricity price volatility, thereby providing firm insights into competitiveness and sustainability.

Further details on modelling strategy and tools are presented in Section 3.

2.2 Base scenario and sensitivities

The *base* scenario, which was briefly introduced in Section 2.1, is modified parameter-by-parameter to create sensitivities. The sensitivities along with the *base* scenario together create the set of scenarios that the current study ultimately investigates. A technology-neutral setting and an assumed weighted average cost of capital (WACC) of 7% are two underlying assumptions for the *base* scenario. The *base* scenario is further based on best estimate input assumptions on parameters including investment and operational costs, commodity and CO_2 prices, maximum build rates, development of power systems in neighbouring bidding zones along with grid reinforcements, land-use constraints, demand growth and demand-side flexibility. These assumptions are described in more detail in Section 4.

Sensitivities are created based on technology parameter variations with respect to the *base* scenario investigating optimistic and conservative projections of costs and fuel prices as well as technology restrictions. Sensitivity definitions considered in the current study are presented in Table 2. The sensitivities aim to probe the potential variations in resulting power systems with respect to the best-estimate assumptions of the base scenario.

Table 2. Sensitivities to different technology developments is performed for the following scenarios.

Sensitivity	Scenario	Long – short name	Definition
	Base	*base – 'base'*	WACC=0.07, base cost forecast, land availability, commodity and CO_2 prices, maximum build rates, demand growth and flexibility.
Renewables	Optimistic	*renewables_optimistic – 'VRE ++'*	Onshore and offshore wind, and solar with low WACC=0.05 and optimistic cost forecast and land availability.
	Conservative	*renewables_conservative – 'VRE --'*	Onshore and offshore wind, and solar with high WACC=0.09 and conservative cost forecast and land availability.
	Fast	*wind_fast – 'wind fast'*	Allowed build rate for wind power is almost doubled.
Fuel prices	Optimistic	*fuel_prices_optimistic – 'fuel prices €'*	Prices for natural gas approaching EU pre-energy crisis levels by mid 2030s. Coal price development coupled to natural gas.

	Conservative	*fuel_prices_conservative – 'fuel prices €€€'*	Prices for natural gas approaching Asia-LNG pre-energy crisis levels by mid 2030s. Coal price development coupled to natural gas.
CCS	No	*no_CCS*	Carbon capture and storage not allowed for fossil fuel power plant resources.
	Expensive	*CCS_expensive – 'CCS €€€'*	Cost of CO2 transport and storage doubled.
	Retrofit	*CCS_retro – 'CCS retro'*	Coal and gas CC retrofit with CCS allowed.
Nuclear	Optimistic	*nuclear_optimistic – 'nucl. ++'*	Nuclear with low WACC=0.05 and optimistic cost forecast.
	Conservative	*nuclear_conservative – 'nucl. --'*	Nuclear with high WACC=0.09 and conservative cost forecast.
	Slow	*nuclear_slow – 'nucl. slow'*	Allowed build rate for new nuclear is halved in the 2030s.
	Retrofit	*nuclear_retrofit – 'nucl. retro'*	Coal to nuclear retrofit allowed.
	No	*no_nuclear – 'no nucl.'*	Nuclear expansion not allowed.
Coal	Slow phase-out	*coal_slow_phaseout – 'coal slow phaseout'*	According to PEP 2040 Scenario 3[8] and free onwards from 2040.

Behind each sensitivity lies a potential background story, i.e. a description which lays out a narrative given the scenario materializes. It is of interest to further explore scenarios in which multiple sensitivities materialize simultaneously, and as such merged sensitivities were also investigated. The complete set of simulated scenarios are presented in Table 3 along with descriptions, i.e. background stories which lay the foundation for the discussion later in the report.

[8] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.

Table 3. Simulated scenarios in the current study accompanied with descriptions.

Scenario name	**Description**
'base'	Best estimate technology neutral baseline. No local opposition and NIMBY are taken into account.
'VRE ++'	Development of costs for wind and solar follow very optimistic trends along with a strong public acceptance enabling an essentially no upper limit on expansion potential.
'VRE --'	Development of costs for wind and solar stagnates whilst simultaneously facing significant public opposition enabling a significantly lower maximum expansion potential of 28 GW in total.
'wind fast'	Current wind power supply chain challenges are overcome enabling a faster build rate of onshore and offshore wind power.
'fuel prices €'	Fossil fuel prices rebound to EU pre-energy crisis levels by mid 2030s, facilitated by re-established pipeline network.
'fuel prices €€€'	Fossil fuel prices don't fully recover following present-day's energy crisis and instead relies on LNG.
'no CCS'	Groundwork for CCS is not made reflecting a non-existent infrastructure.
'CCS €€€'	Costs experienced for transport and storage of CO2 becomes higher than expected.
'CCS retro'	The potential value of CCS retrofitting of fossil-fuelled power plants is investigated.
'nucl. ++'	Initial nuclear projects gain good governmental support and become successful. Following projects sees a learning rate owing to serial construction.
'nucl. --'	Initial nuclear projects don't obtain a strong governmental support and starts off expensive and following projects learning. Following projects sees a learning rate owing to serial construction.
'nucl. retro'	Site repurposing and partial repowering of coal plants with nuclear power is allowed.
'nucl. slow'	Construction for initial nuclear projects is delayed due to lack of regulation framework.
'coal slow phaseout'	Coal power plants are considered vital for the power system functioning and not phased out until the 2040s.
Merged sensitivities	
'status quo'	Combining slow phase-out of coal and no CCS, this scenario aims to reflect the most likely development of the Polish power system given current policies and regulations and their probable development as well as the defined decarbonisation path for the Polish economy.
'no nucl. no CCS'	Neither nuclear nor CCS technologies are part of energy policy.
'nucl. -- no CCS'	Nuclear projects become expensive in combination with no development of CCS.
'nucl. -- no CCS nucl. retro'	Value of coal to nuclear retrofit is allowed given conservative outlook for greenfield nuclear projects and no CCS allowed.
'VRE -- no nucl. no CCS'	The decarbonization strategy heavily relies on wind and solar technologies; however, their cost decrease stagnates, and they struggle with negative public opinion (NIMBY).

2.3 Comparison energy system studies in Poland

Power system optimization studies, particularly those centred on the Polish power system, manifest a spectrum of methodologies and assumptions, yielding divergent outcomes and conclusions. In the context of this variability, Table 4 serves as a tool to elucidate the methods and inputs employed in the current study, offering a comparative perspective with other pertinent studies influencing the development of the Polish power system. Notably, three distinct organizations are spotlighted: Instrat, with a Polish-centric focus, Ember, which adopts a broader European perspective while providing insights specific to Poland[9] and Carbon-Free Europe a technology-inclusive modelling initiative covering entire Europe.

By juxtaposing the strengths and weaknesses of these examples in Table 4, the present study seeks to augment existing knowledge. It accomplishes this by combining detailed and comprehensive power system optimization, placing a particular emphasis on realistic electricity market modelling, resilience to diverse weather scenarios as well as a pathway to full decarbonisation. Furthermore, the study employs transparent inputs firmly rooted in Polish-specific conditions. This synthesis aims to complement the approaches of other studies by offering a nuanced set of scenarios, including varying costs for technologies, and robust contributions to the ongoing discourse on optimizing the Polish power system.

[9] Ember (2023), PEP2040: Progress or disappointment?

Table 4. Non-exclusive review of studies relevant for the development of the Polish power system with their strengths and weaknesses from the perspective of the current study. Primary geographical focus is indicated along with the organizing institution in the first column.

Study & Geographical focus	Strengths	Weaknesses
QC_CATF (current study) **Focus: Poland**	• Technology inclusive multi-year investment optimization with hourly temporal granularity and bidding-zone trading in long-term model future horizon accounting for retirements and retrofits. • Emphasis on realistic electricity market modelling – prices, volatility & security of supply – through inclusion of capacity reserve market and power systems examined on full set of weather years and commodity price scenarios. • Tailored and transparent technology cost scenarios and inputs well founded in Polish-specific conditions. • Thorough custom GIS analysis for wind and solar expansion potential.	• Limited coupling to other sectors, such as heat and hydrogen. However, includes endogenous optimization and realistic market modelling of hydrogen production for regeneration of electricity. • Limited accounting for granular grid aspects and considerations for zone-intrinsic network reinforcement. • Limited geographical focus.
Instrat[10,11,12,13] **Focus: Poland**	• Investment optimization and detailed electricity market modelling with granular representation of network grid and generating units as well as neighbouring market trade. • In-depth emphasis on several important power-system aspects, e.g., security of supply, consumer electricity prices, CO_2 emissions, capacity reserve and system cost components. • Deep Poland-specific knowledge, e.g., tailored methodology of coal phase-out and electricity tariffs.	• Not fully technology inclusive, e.g., disregarding nuclear and CCS. • Ends in 2040 and does not comprehend full net-zero pathway. • Limited emphasis on demand inputs and set of scenarios as well as hydrogen-sector model integration. • Lacks emphasis of technology profitability.

[10] Instrat (2021), Achieving the goal. Coal phase-out in the Polish power sector.
[11] Instrat(2021), The missing element.
[12] Instrat (2023), Poland cannot afford medium ambitions.
[13] Very recently (12.12.2023) Instrat released an updated study towards 2040 that includes a stronger sector coupling as well as a scenario that couples ambitious renewables development with new nuclear power. The scenario that considers only nuclear power (strongly constrained renewables) is not available. Carbon capture and storage is not included in the modelling.

Table 5. Table continued.

Study & Geographical focus	Strengths	Weaknesses
Ember[14] **Focus: Europe**	• Holistic multi-year European power system dispatch and investment optimization with country-level spatial and hourly temporal resolution based on three varying weather years. • Well-founded carbon-budget methodology which forms the basis for scenarios all with the long-term 2050 net-zero perspective and main focus least system cost pathways. • Technology inclusive and accounts for different energy demand scenarios. • Strongly connected and based on European electricity infrastructure plans and boundary conditions e.g., on technology build rates, resulting in realistic capacity expansion paths.	• Limited coupling to other sectors, such as heat and hydrogen. However, the hydrogen production for the power sector is endogenously optimised. • Limited accounting for granular grid aspects and consideration for zone-intrinsic network reinforcement. • Limitations imposed by current European plans and the prevailing political landscape entail the risk of an overly restricted infrastructure expansion or the exclusion of certain possibilities. • Limited emphasis on electricity market modelling aspects: electricity prices, volatility, security of supply and capacity reserve.
Carbon-Free Europe[15] **Focus: Europe**	• Advanced multi-year optimization in a single objective allowing for the development of coherent multi-decadal infrastructure plans including optimized resource retirements, repowers, retrofits, as well as deployment of new infrastructure. • Holistic technology inclusive European energy system optimization, strongly sector coupled with e.g., advanced flexible nuclear active on both power and heat markets. • Automated day-sampling approach allowing for a representation of characteristic energy system conditions. • Comprehensive set of technology build and demand scenarios including coverage of hydrogen, CCUS, refined liquid fuels and electricity. • Thorough custom GIS analysis for wind and solar expansion potential.	• Limited consideration for technology build rate and network transmission expansion constraints, especially relevant for the near-term. • Limited insights into country-specific conditions. • Limited emphasis on electricity market modelling aspects: electricity prices, volatility, security of supply and capacity reserve. • Limited high-temporal resolution of full continuous years and electricity market bidding zone spatial resolution.

[14] Ember (2022), New Generation - Building a clean European electricity system by 2035.
[15] Carbon-Free Europe (2023), Annual Decarbonization Perspective 2023.

3 Modelling

This section describes the details on the modelling framework introduced in Section 2.

3.1 Strategy

The power system optimization in this study follows a multistep process utilizing two primary modeling codes: GenX and cGrid. These codes are instrumental in constructing a comprehensive set of power systems for various scenarios, future model years, and different weather years.

The GenX tool, further described below in Section 3.3.1, is used to study the long-term evolution of the Polish power system across multiple investment stages. Through capacity expansion optimization, this tool aims to minimize total system costs, facilitating the construction of a power system that satisfies demand every hour of a typical weather year. This optimization process is designed to meet direct emission targets, maintain a capacity reserve margin, and ensure the profitability of each technology. Within this simulation, retirements are contemplated based on the technical and economic life of both pre-existing installed capacity and capacity built within the model's timeframe. Additionally, the concept of retrofitting, elaborated in Section 4.7, is considered. Retrofitting involves upgrading uncompetitive technologies instead of retiring them, transforming them into cost-effective alternatives.

The multi-year capacity expansion planning involves five-year stages, with the first stage commencing in 2026 and concluding in 2030. This pattern continues until 2050.

The optimization approach adopts a myopic strategy, where capacity expansion is individually optimized for each stage, treating investment decisions from previous stages as fixed. This contrasts with a full-model horizon perfect-foresight strategy, where cost and policy assumptions about all stages are known and exploited to determine the least-cost investment trajectory. While long-term perfect-foresight optimization carries an unrealistic investment logic due to the uncertainties of the distant future, it does require profitability for all technologies across the entire model horizon. Though the current myopic approach has a more reasonable foresight of five years, the long-term profitability of resulting investments needs to be further examined which is part of the analysis.

In an initial optimization step with GenX, Poland is modelled as an isolated system, functioning as an island without any interconnections to its neighbours. This approach is deemed reasonable since Poland's load exceeds the transmission capacity of its interconnections. However, the validity of this isolation is tested in the second step using cGrid.

In the subsequent phase, a pre-optimization of installed generation capacities for the power system technologies in the regions' surrounding Poland is conducted with cGrid. This process spans five-year intervals from 2030 to 2050. Installed generation capacities in neighbouring regions are derived from ENTSO-E [16] and other public data sources, with adjustments made to ensure realistic electricity prices and credible trade between the Polish power system and external regions. This step aims to avoid the capacity expansion for Poland subsidizing inadequate generation capacities in surrounding regions or being subsidized by artificially low import prices. Given the study's focus on the electricity market, the geographical scope and resolution have been thoroughly examined to replicate historical power market dynamics (see also Section 4.8).

[16] European Network of Transmission System Operators for Electricity

Following the realistic representation of electricity trade established through pre-optimization, cGrid executes a modified capacity expansion based on the GenX myopic multi-stage investment optimization. This continued optimization facilitates further expansion of key clean energy technologies for all model years spanning from 2030 to 2050. Similar to GenX, previous stages are considered fixed, setting a lower limit for allowed installed capacity. In each model year, the expansion is conducted for 35 weather years. While GenX expansion is conducted based on one typical weather year, cGrid expansion is conducted for 35 weather years (1982-2016), thus introducing variation for the weather-dependent generators and in the space heating part of the demand profiles. The final installed capacity is determined by averaging these weather-year expansions. This approach ensures that each technology proves profitable not just in a single typical weather year but across a range of weather years. Subsequently, the weather-year expanded system is tested against all weather years to assess its performance under diverse conditions.

3.2 Limitations and exogenous assumptions

The current study, with a focus on the power system, relies on exogenous assumptions to handle certain limitations in the interaction with the other sectors. These assumptions are outlined as follows:

- A fixed demand scenario is established from present day to 2050, with assumptions for heating, hydrogen, electric vehicles (EVs), and industry, including associated flexibility (see Section 4.2 for details) that are in-line with a fully decarbonized Polish economy by 2050.
- A floor price for CO_2 emissions of 122 €/tCO_2 is applied. The power system optimization determines required increase of CO_2 price to meet the CO_2 target (see also Section 4.1).
- The model optimization accounts for direct emissions from the combustion of thermal power plants. Indirect emissions are integrated into the analysis by considering lifecycle emissions (see Section 6).
- Biobased technologies are assumed to have zero direct emissions in line with current policy[17]. Negative emissions are not considered.
- The model allows for the capacity expansion of biobased power technologies with limited fuel consumption according to current policy[18] (as detailed in Section 4.4.3).
- The Polish power network is not explicitly modelled. Reinvestments to maintain the existing Polish national grids (220 kV and 400 kV) are assumed to occur.
- GIS-based analysis has determined additional fixed investment costs related to high-voltage grid reinforcement needed to connect new onshore wind and solar PV capacity. This is part of the power system optimization.
- Transmission expansion for international connections is assumed to occur in all modelling cases according to ENTSO-E plans (as described in Section 4.8).
- Carbon capture and storage (CCS) is a technology that fossil fuel power plants can employ. Plant operators are assumed to pay a tariff, an additional variable cost, representing cost for CO_2 transport and storage infrastructure. This infrastructure is not modelled explicitly and assumed to exist from 2035 onwards (as further described in Section 4.4.6).
- Costs to achieve demand-side flexibility of heat and EV demand, described in Section 4.2.2, are not included to the total costs.

[17] Ministry of Climate and Environment Republic of Poland (2021), Energy policy of Poland until 2040.
[18] Ministry of Climate and Environment Republic of Poland (2021), Energy policy of Poland until 2040.

- Infrastructure investments related to the production, transmission, and storage of hydrogen *purely for demand side* are excluded in the optimization. The investments are primarily to be carried by consumers; however they provide the power system valuable flexibility. Note that production and storage of hydrogen for *regeneration of electricity* is an endogenous part of the power system optimization.
- Hydrogen market, including electrolyser demand for both industrial direct use and regeneration of electricity with hydrogen gas turbines, is modelled for Poland without limits to transmission. Imported hydrogen is not considered.
- Near-term expansions of power production capacity, where investments are already made or projects are likely to progress, are prescribed. This includes solar PV and combined-cycle natural gas power plants.
- Unless deemed uncompetitive, existing capacity follows a prescribed retirement according to its technical lifetime. Fossil-fuelled combined-heat and power (CHP) plants are assumed to retire fully by 2050 according to a linear trend, see also Section 4.4. An exception is coal power plants for which retirement is purely determined by the model optimization.
- While the model incorporates a capacity reserve margin, aligned with Polish regulations as discussed in Section 4.9, satisfactory required levels of inertia and spinning reserves have not been included in the modelling.

Finally, it's important to underscore that the present analysis focuses on the power system within the electricity market, serving as an initial phase to inform power system development. Subsequently, a thorough analysis of the resulting power system is required, taking into account factors like frequency stability, N-1 criteria, black start capability, and more. However, such a detailed analysis is beyond the scope of this study.

3.3 Tools

3.3.1 GenX

GenX is a highly configurable open-source tool[19] for capacity expansion of generation resources, which includes several state-of-the-art methods for exploring cost-optimized power systems. In this study, an extended version of GenX v. 0.3.3 has been used, which allows for:

- limiting the minimum and/or maximum consumption of each defined fuel type,
- limiting flows between zones at the same time resolution as other input values, thus taking into account a variable transmission capacity as well as asymmetries in the direction, and
- limiting the maximum instantaneous consumption of flexible loads.

GenX builds cost-optimal power systems based on the prerequisites presented earlier forming the initial optimization step here. It is worth noting that GenX and cGrid share a common approach in modelling the capacity reserve requirement[20].

In the context of this study, GenX faces limitations with thorough modelling of hydrogen markets and the dispatch of long-duration storage—crucial considerations for modelling future power systems with a substantial penetration of variable renewable energy coupled with storage.

[19] https://github.com/GenXProject/GenX
[20] https://genxproject.github.io/GenX/dev/policies/#Capacity-Reserve-Margin

Additionally, GenX's computational intensity poses a challenge, making it less suitable for sensitivity analyses that involve a large number of weather years and scenarios.

3.3.2 cGrid

cGrid is a dedicated electricity market modelling tool originally designed to simulate a realistic bidding pattern of reservoir hydro power dispatch, especially important for the Nordics. Diverging from GenX's linear optimization with complete foresight over the entire model year, cGrid shapes its dispatch strategy for flexible demand resources and storage technologies around short-term electricity price forecasts. This distinction becomes particularly important for realistic dispatch as well as electricity prices in power systems with long-duration storage resources, including hydro reservoir power or hydrogen storage utilized to fuel hydrogen gas turbine power plants.

cGrid allows for the modelling of the hydrogen market, encompassing both direct demand for hydrogen and its utilization for electricity regeneration coupled with hydrogen storage energy capacity, shared through a hydrogen network. The approach ensures realistic pricing of hydrogen, for instance, to fuel combined-cycle hydrogen gas turbine power plants.

Finally, cGrid is capable of performing a modified expansion, fine-tuning of capacities, but unlike GenX it cannot perform a greenfield optimization. This distinction underscores the rationale behind employing both codes simultaneously. Additionally, cGrid's notably faster runtime makes it the preferred choice for handling the extensive set of scenarios analysed in the current study.

4 Input assumptions

This section provides an overview of the study's input assumptions, with further details available in Appendix. Appendix A includes a comprehensive list of power supply technologies incorporated in the model and assumed existing installed generation capacities. Additionally, background information on investment and operational cost assumptions, along with the calculation of the levelized cost of electricity, is detailed. Appendix B offers an in-depth exploration of the GIS analysis methodology employed to determine wind and solar expansion potential. Lastly, Appendix C outlines the methodology and assumptions used for lifecycle estimates of emissions, land use, and critical mineral consumption.

4.1 CO2 emissions

The fundamental premise of our modelling approach centres on Poland's trajectory towards a decarbonized economy. This trajectory is ultimately defined by a nationwide net-zero emission objective by the year 2050, complemented by interim emissions targets. Within the power sector, we implement mass-based emission constraints. Poland is obligated to fulfil its binding national target, stipulated in the EU's 'Fit for 55' package, by achieving a 17% reduction from 2005 levels by 2030.

To specifically address CO2 emissions in the power sector, our model incorporates the CO2 reduction target derived from the most recent 'Poland Energy Policy until 2040 – Scenario 3' report. The 2030 CO2 emission target is set at 90 Mt. Looking ahead to the year 2050, our modelling assumes an emission target constraint of 2 Mt corresponding to 99% reduction relative to 1990s level of 190 Mt for the power sector[21]. This corresponds to about 5 TWh yearly generation for a combined-cycle gas power plant.

Furthermore, our modelling incorporates carbon allowance price projections of the European Union Allowance (EUA) and EU Emissions Trading System (ETS). Near-term projections until 2030 which are deemed credible and with rather few uncertainties given clear plans[22] enter as a baseline in the modelling. We apply a floor CO2 price of 122 €/tCO2 according to ERAA 2023 projections for 2030[23]. Further increases in CO2 prices is imposed by the model to reach the set Polish power system CO2 cap constraints.

We implement a tailored reduction of the CO2 emission cap constraint from 2030 to 2050, as outlined in Table 6. Two primary reasons drive this approach. Firstly, the adjustment of the 2030 target from 90 Mt to 55 Mt was made, as it was noted that the initial 90 Mt target was consistently surpassed with a margin across scenarios. Cost-effective clean energy technologies efficiently lowered emissions to approximately 45 Mt in 2030, even with a floor CO2 price of 100 €/tCO2. Secondly, multi-year GenX simulations with perfect foresight favoured a rather ambitious decarbonization pace to meet the 2 Mt target in 2050 cost-effectively. This initial analysis guided the formulation of the decarbonization curve.

[21] Instrat (2021), Achieving the goal. Coal phase-out in the Polish power sector.

[22] European Commission (2023), Our ambition for 2030.

[23] ERAA (2023), Proposal of commodity prices for call for evidence.

Table 6. Mass-based power sector emission target for each model year.

Year	2030	2035	2040	2045	2050
CO_2 emission target (Mt)	55	35	18	8	2

Upstream emissions, which is especially important for the case of natural gas supply, is incorporated into the modelling by the enforcement of increased prices. This increase is determined by the estimated level of upstream emissions and the external CO_2 price[24] indicated in Figure 11. Upstream emissions have been determined for natural gas to 10.0 kgCO_2/GJ[25] and for coal to 7.3 kgCO_2/GJ[26]. The pricing aims to imitate the European Union's Carbon Border Adjustment Mechanism[27], or CBAM, which came into effect in June 2023. This framework currently does not encompass fossil fuels but it is deemed likely do so in the future[28], which the EU methane strategy further signals[29].

4.2 Demand

4.2.1 Demand scenarios

Figure 3 shows estimated breakdown by demand category for year 2021 and for this study used projection until 2050.

Electricity demand for electrolysers is assumed to reach 30 TWh/yr by 2050 or about 540 kt/yr of hydrogen (in 2022 Poland consumed 784 kt hydrogen[30]).

Electricity consumption for transport is assumed to reach 44 TWh/yr by 2050 which corresponds to 80 % of passenger transport activity (pkm) being conducted by electric vehicles (EVs). The trajectory of passenger transport activity from EU reference 2020 scenario was used[31].

Heating demand is estimated to grow to 59 TWh/yr by 2050, which corresponds to electrifying current individual heating with heat pumps.

[24] ERAA (2023), Proposal of commodity prices for call for evidence.
[25] ACS (2022), Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways.
[26] IEAGHG (2019), Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass.
[27] European Commission (2023), Carbon Border Adjustment Mechanism.
[28] KAPSARC (2022), Potential implications of the EU Carbon Border Adjustment Mechanism.
[29] European Commission (2020), EU Methane Strategy.
[30] European Hydrogen Observatory - Hydrogen demand
[31] EU Reference Scenario 2020

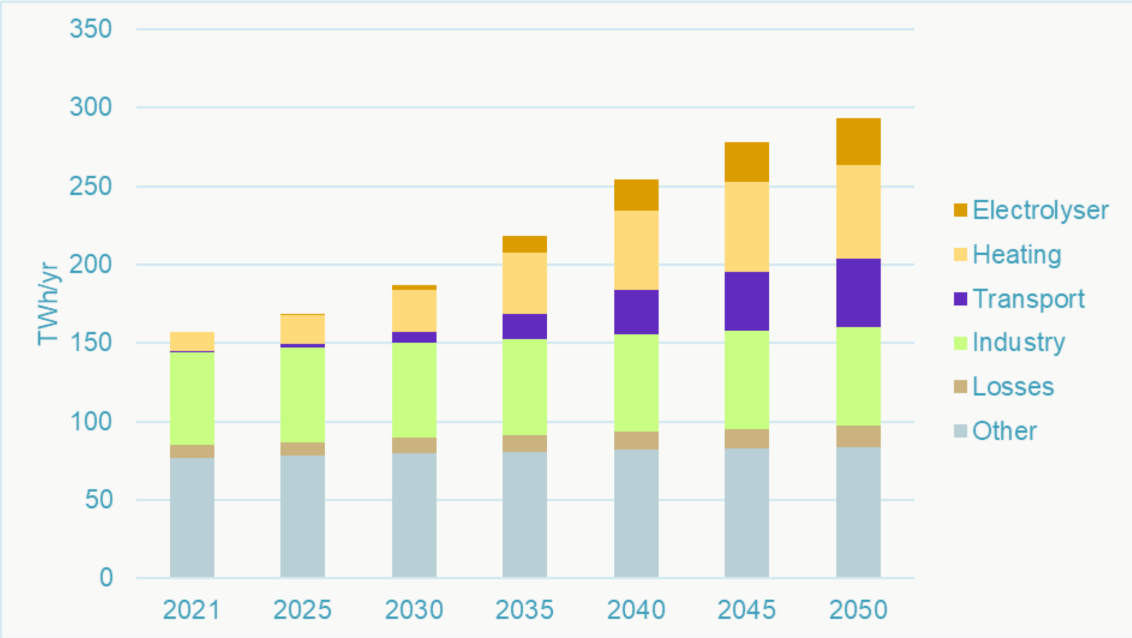

Figure 3. Electricity demand breakdown by demand category for year 2021 and projection for the future until 2050.

Figure 4 shows the yearly total electric demand trajectory of this study in comparison with other recent studies. The main differentiator between the studies is how large the hydrogen by electrolysis demand is projected to grow, where both the CFE – ADP 2023 Core and Ember – Technology Driven projections assume a larger growth for this sector.

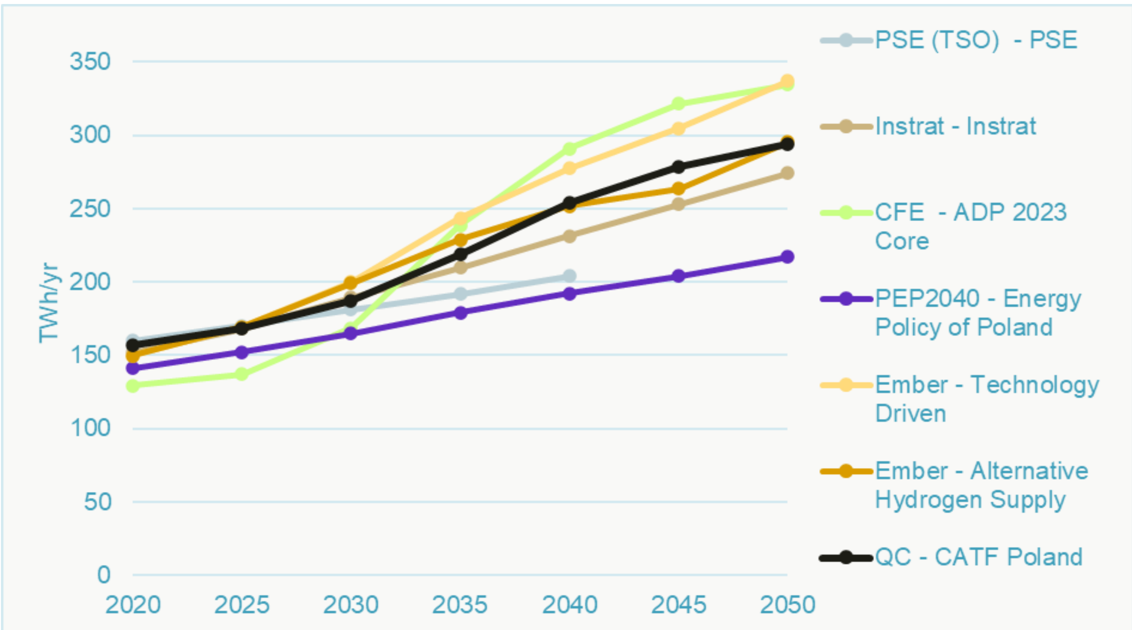

Figure 4. Yearly total electricity demand trajectory of this study (black) in comparison with other recent study scenarios[32].

[32] PSE (2022) - Plan 2023-2032, Instrat (2023) - PyPSA-PL , Carbon-Free Europe (2023), Annual Decarbonization Perspective, PEP2040 (2023), Ember (2023), New Generation

4.2.2 Flexibility

The modelling incorporates two distinct forms of demand-side flexibility: shifting and cutting. The shifting demand response for a demand category is represented through four key parameters and input values:

1. A time series of the demand deemed flexible, defined by the product of the *share* and demand profile of the category.
2. A maximum time *duration* within which this flexible load can be shifted both forward and backward.
3. A maximum capacity measured in megawatts (MW) for the flexible load which represents to the maximum possible instantaneous consumption ("flex up"). This capacity is determined as the inverse of the *utilization* multiplied by the average demand consumption.
4. A minimum capacity measured in megawatts (MW) for the flexible load which represents to the minimum possible instantaneous consumption ("flex down"). This capacity is determined by the multiplication of *minimum fraction* multiplied by the average demand consumption.

It is relevant to note that the energy of the flexible shifting load is always conserved, ensuring no energy is lost during the shifting process. In contrast, cutting demand-side response involves the reduction or elimination of demand, resulting in a loss of consumption. This reduction in consumption typically occurs in response to high electricity prices and may be referred to as "non-served energy". Table 7 presents the input assumptions used for the demand-side flexible loads in the model, grouped by demand scenario and by modelled year. The demand-side flexibility outlined in the table comes at *no cost* to the Polish power system.

Figure 5 illustrates the share of demand that is considered flexible at average. Note that each demand category possesses distinct load profiles, resulting in varying levels of available flexibility during each hour (for example, there is no space heating demand during summer). The share deemed flexible remains consistent across future years for all categories except electrolysis, see Table 7 for more detailed assumption used for this study. Poland's plans include the adoption of dynamic pricing from 2024, extending to also households. Presently, 20% of households have smart meters, and the goal is to increase this coverage to 80% by 2028[33]. Notably, a large share of demand side flexibility in 2030 is attributed to the space heating demand category. However, as new demand of EVs and electrolysers evolve, they contribute significantly to the overall flexibility as they are assumed to be inherently more flexible from the outset.

[33] Notes from Poland (2023), Poland adopts dynamic electricity pricing amid growing share of renewables in energy mix.

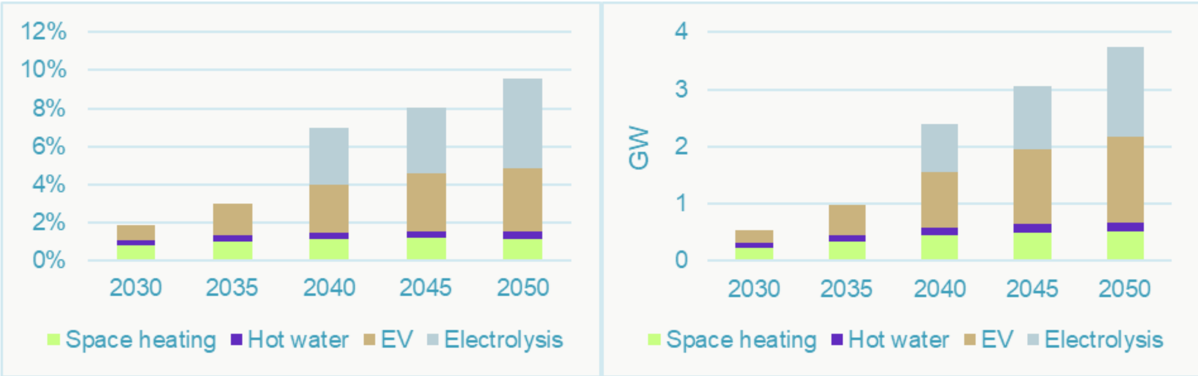

Figure 5. Share of demand that is flexible on average (left panel) and as capacity (right panel). Data presented per resource type, and future year.

Table 7. General input assumptions of demand-side flexibility for their different categories and potential variations with regards to future model year. Inapplicable parameter values indicated with hyphen.

Category (type)	Year	Share	Utilization	Minimum fraction	Duration
Electrolysis (shifting)	2030	0%	-	-	-
	2035				
	2040	50%	77%[34]	25%[35]	24h
	2045				168h
	2050	60%			
Electric vehicles (shifting)	2030	30%	50%	0%	24h
	2035				
	2040				
	2045				
	2050				
Heating, space & sanitary (shifting)	2030	10%	50%	0%	8h
	2035				
	2040				
	2045				
	2050				
Baseload (cutting)	2030	5%	-	-	-
	2035				
	2040				
	2045				
	2050				

[34] Quantified Carbon (2023), Nordic Power Systems for a Competitive and Sustainable Economy.
[35] Quantified Carbon (2023), Nordic Power Systems for a Competitive and Sustainable Economy.

The remaining demand after reduction of the shifting flexible demand is denoted baseload. The baseload demand is subject to cutting demand-side response, representing consumers cutting their demand when electricity prices are too high. Drawing inspiration from observations during the energy crisis, the current analysis assumes that up to 5% of the baseload demand may be cut at a price of 1000 €/MWh. Costs are assumed to increase linearly from 100 to 1000 €/MWh for lower cuts. Finally, Value of Lost Load (VOLL) which applies to cutting demand in excess of 5% has been set to 5000 €/MWh.

4.2.3 Hydrogen

The electrolysis category in Table 7 represents hydrogen production. An optimistic scenario of hydrogen utilization in Poland may be assumed to align with the ambitious vision outlined by the European Hydrogen Backbone[36]. In this vision, by 2035, significant progress has been made, with the establishment of key segments of the hydrogen network and the introduction of the initial hydrogen small-scale storage facilities, e.g., in Germany. Within Poland, the Damasławek project could play a valuable role in linking industrial clusters and planned hydrogen valleys, currently aiming to have the first salt cavern storage operational around 2030. By 2040, the realization of the Nordic-Baltic Hydrogen corridor has been achieved, providing access to larger storage facilities, including the aquifer in Latvia, boasting a substantial capacity of approximately 10 terawatt-hours (TWh). As we progress through the 2040s, Europe takes significant strides in creating a robust hydrogen network, thereby increasing the effective storage capacity for hydrogen by Polish actors. Incremental rise in the share of hydrogen in the energy mix is expected following the incorporation of more facilities into the grid as we approach 2050.

The current study assumes a scenario five years delayed of the ambitious vision described above, for instance evident from the storage accessibility available from 2040 onwards in Table 7. One day of storage is assumed in 2040, while one week's storage capacity is deemed assessable from 2045. From the modelling perspective, the energy storage capacity is derived based on the product of the average hourly consumption and the duration of the electrolyser resource. As such, the hydrogen storage capacity scales with the total electrolysis demand in the respective zone. The corresponding energy storage capacity of hydrogen is 20, 170 and 250 GWh (H_2) in 2040, 2045 and 2050, respectively. It is relevant to note that 25% of the flexible electrolyser demand remains inflexible, representing a constant baseload for the electrolysis facilities. Additionally, the electrolyser utilization is assumed constant at 77% based on values determined in optimization of facilities for hydrogen-based direct reduction of iron ore[37].

4.2.4 Heat-sector coupling

The two main paths for sector coupling between heat and power are a) when both heat and power are cogenerated in combined heat and power (CHP) plants and b) when electricity is used for heating. Figure 6 shows how heat is used currently in Poland. District heating covers about 24 % of the heat demand, whereof about 60% is provided by mainly coal and gas fired CHP plants. Current consumption of individual heating is estimated to 225 TWh/yr[38] whereof about 13 TWh are estimated (by regression analysis) to be provided by electricity. The projection for the future is that the individual heating for non-industrial purposes will be electrified by 2050 (see Section 4.2) which will increase the coupling between the heating and the power sectors. District heating is assumed to

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[36] European Hydrogen Backbone (2022), A European Hydrogen infrastructure vision covering 28 countries.
[37] Quantified Carbon (2023), Nordic Power Systems for a Competitive and Sustainable Economy.
[38] https://www.ure.gov.pl/pl/cieplo/charakterystyka-rynku/10795,2021.html

keep its current share but to achieve decarbonisation goals it would need to find other sources of heat than fossil-based CHP plants. This is not further explored in this power sector focused study but could for example be biomass, geothermal, large heat pumps, nuclear (both CHP and heat only), and excess heat from industrial processes (for example the projected electrolysis growth would mean that about 10 TWh/yr of low temperature heat would be available in 2050).

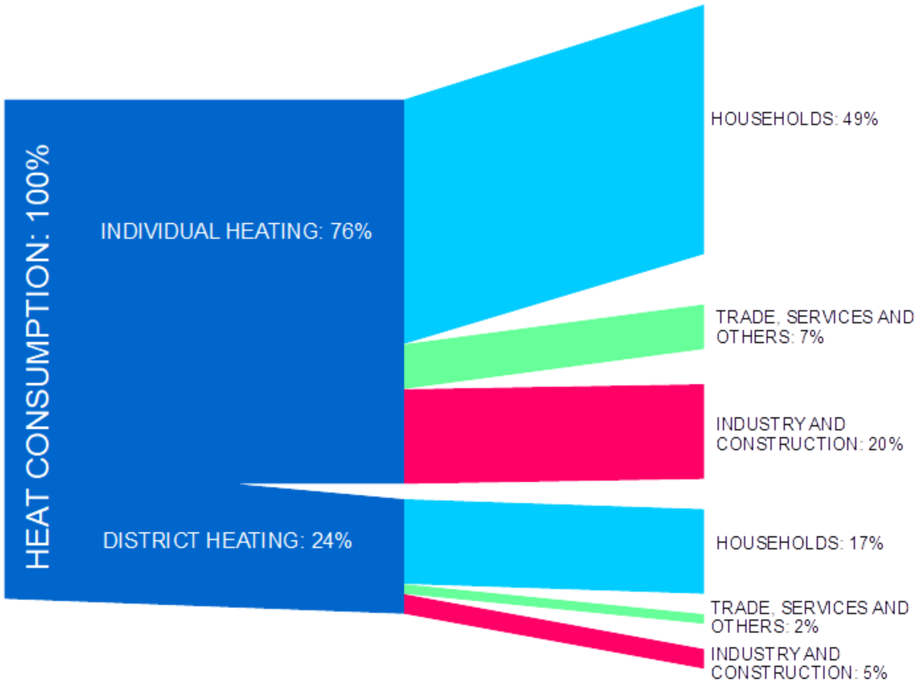

Figure 6. Consumption of heat in Poland – based on Heating in Poland[39].

[39] https://www.forum-energii.eu/en/analizy/cieplownictwo-2019#:~:text=Facts%20and%20figures%20on%20heating&text=47%25%20of%20Polish%20households%20heat,are%20consumed%20annually%20by%20heating.

4.3 Wind and solar expansion potential

4.3.1 Expansion limits

Before we dive into the specific details of applied GIS approach, we quickly summarize the main numbers (Table 8) adopted in our analysis divided into three main categories, onshore wind, offshore wind and solar PV.

Table 8. Potential of wind and solar as estimated by QC.

Technology	Scenario	Max capacity [GW]	Commentary
Onshore wind	Restrictive	1.8	follows the most restrictive rules considering the development of wind power in the form of 10H rule.
	Conservative	27	assumes the current regulations (700 meters distance between residential area and wind turbine) and additional 300-meter buffer zone between the forests and the potential location of the wind turbine.
	Optimistic	200	relaxes the current regulations and allows wind turbines to be placed 500 meters to the residential areas.
Rooftop PV	-	30	considers the available roof area of buildings located and rural and urban environment. Constrained by selecting only the most suitable roofs with S, SW and SE orientations with slope less than 60 degrees.
Utility PV	-	324	assumes realistic availability of the land area considering their suitability for agriculture and the current regulations.
Offshore wind	In stages	33	based on the ongoing projections made by the Polish government[40] and the Polish Wind Energy Association[41].

4.3.2 Comparison other studies

The renewables potential in Poland estimated by QC and other studies is shown in Table 9. The capacity range for offshore wind varies among sources from 12 to 74 GW highlighting the varying perspectives on the potential offshore wind capacity, possibly influenced by different methodologies

[40] https://www.gov.pl/web/morska-energetyka-wiatrowa/program-rozwoju-morskich-farm-wiatrowych
[41] Polish Wind Energy Association http://psew.pl/en/

or considerations. The capacity range for onshore wind is notably diverse. Carbon-Free Europe suggests 3.6-125 GW, the European Commission estimates 105 GW, Instrat reports 44 GW, and QC provides a wide range of 1.8-200 GW. This variation may stem from differences in geographic considerations, resource assessments, or technological assumptions. The capacity estimates for utility-scale photovoltaic (PV) systems exhibit substantial differences ranging from 47 to 802 GW. These disparities could be influenced by factors such as solar resource availability, land use constraints, methodology, and technology considered. For example, our analysis in Appendix B explores the potentially available land but does not further analyse what fraction of such potentially available land that in practice could be suitable for PV installations after considering also factors such as preferred or competing land uses or grid constraints. The rooftop PV capacity estimates are less variable across sources. Carbon-Free Europe does not specify a capacity range, the European Commission suggests 91 GW, Instrat reports 32 GW, and QC provides a capacity of 30 GW. The narrower range may indicate more consensus regarding the potential capacity of rooftop PV, possibly due to more localized and predictable factors influencing this technology.

In summary, while there is a general alignment on certain capacity estimates, discrepancies across different sources highlight the complexity of predicting renewable energy potential. Methodological differences, regional considerations, and technological assumptions contribute to the diversity in these assessments. These variations underscore the need for careful consideration and collaboration when evaluating and planning for the future deployment of renewable energy resources.

Table 9 Potential of wind and solar as reported by Carbon-Free Europe[42], Instrat[43], European Commission[44] and QC.

Resource	Source	Capacity range [GW]
Offshore wind	Carbon-Free Europe	68-74
	European Commission	12
	Instrat	31
	QC	33
Onshore wind	Carbon-Free Europe	3.6-125
	European Commission	105
	Instrat	44
	QC	1.8-200
Utility scale PV	Carbon-Free Europe	67.6-2250
	European Commission	802
	Instrat	47
	QC	304
Rooftop PV	Carbon-Free Europe	-
	European Commission	91
	Instrat	32
	QC	30

[42] https://docs.google.com/spreadsheets/d/1eNatnobBdpiqKDvpW4oTWVImfiwlq6tYzkVOQl3saNc/edit#gid=823496908
[43] https://instrat.pl/wp-content/uploads/2021/06/Instrat-Co-po-w%C4%99glu.pdf
[44] https://ec.europa.eu/regional_policy/whats-new/panorama/2023/09/13-09-2023-poland-s-energy-transition-in-the-spotlight_en

4.3.3 Historic and near-term development

Based on the national TSO[45] data it can be concluded that currently a total of 8.5 GW of off-shore systems are requesting connection to the national grid, followed by 2.8 GW in onshore systems, 4.6 GW in utility-scale PV systems (with a mean capacity of 140 MW). It can be concluded that these projects have already secured their grid connection and will most likely be completed. A report by the national TSO[46] indicates no available capacity above the already granted (mentioned above) until at least 2028. The reports provided by the national DSOs indicate an available grid capacity of 5.7 GW which combined with the granted capacities by the TSO leaves room for further expansion by at least 13 GW for onshore wind and PV, followed by 8.5 GW for offshore wind. The most likely development of solar PV in Poland is shown in Figure 10. The projected capacity for 2025 has been adopted from a robust forecast made by the Institute of Renewable Energy[47]. The market as for now is dominated (70%) by small-scale PV systems (<50 kW) and the average capacity of utility-scale PV oscillates around 1 MW – nevertheless a few 100+ MW projects either entered the market very recently or have been announced.

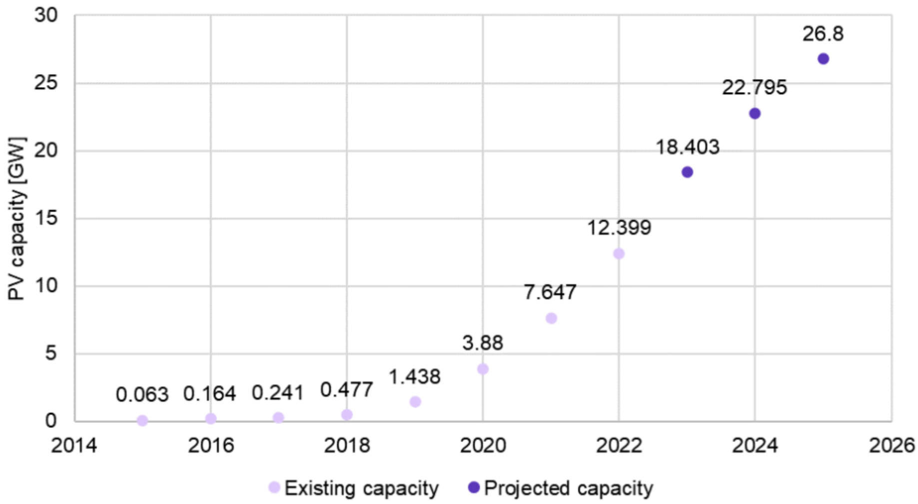

Figure 7. Projected (and most likely) short-term expansion of solar PV in Poland.

4.3.4 Retirement

First wind parks in Poland have been installed in the year 2000[48], Figure 8. Assuming a 25-years lifetime of typical industrial scale wind turbines the first retirements can be expected in early 2025. Largest retirement can be expected in the year 2041 (exceeding 1.2 GW).

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[45] https://www.pse.pl/obszary-dzialalnosci/krajowy-system-elektroenergetyczny/wykaz-obiektow-planowanych-do-przylaczenia

[46] https://www.pse.pl/obszary-dzialalnosci/krajowy-system-elektroenergetyczny/informacja-o-dostepnosci-mocy-przylaczeniowej

[47] https://ieo.pl/en/pv-projects

[48] https://pl.wikipedia.org/wiki/Energetyka_wiatrowa_w_Polsce

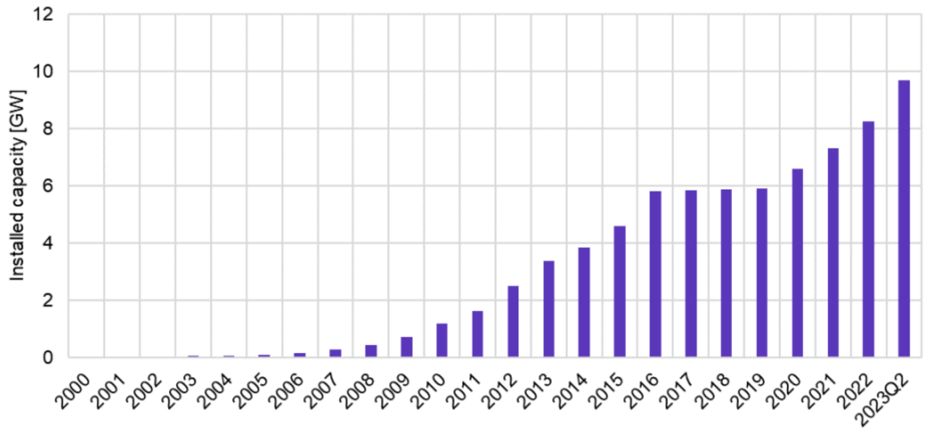

Figure 8. Installed capacity in the wind farms in Poland.

For a long time, solar PV did not play a significant role in the Polish power system. However, in the recent 3-4 years a massive increase in the installed capacity could be observed and the sector became mostly dominated by small scale (prosumer) systems installed on the roofs. The retirement of the first utility-scale PV systems can be expected during the 2040s. The current study assumes a linear retirement of the 26.8 GW projected in 2025 from 2045 to 2055.

4.3.5 Offshore wind

According to the ongoing political discussion and undertaken action, the offshore wind is envisioned to play a significant role in the transformation of the Polish power system and very recently it became a relevant part of the National Energy Policy[49]. It is envisioned that the first off-shore wind parks will be put into operation in 2025/26. The national TSO undertook[50] first actions aiming at strengthening the transmission infrastructure to enable power flow from off-shore locations to Southern and Central Poland where major demand centers are located. According to the Polish Wind Energy Association (PWEA)[51] the total potential of off-shore wind farms in the Polish Exclusive economic zone can be as high as 33 GW (130.3 TWh/year) and can be realized in three phases: 5.9 GW by 2030 followed by 9.4 GW and 17.7 GW (year of development undefined). Because Baltic See in the Polish Exclusive Economic Zone is a relatively shallow water body the potential indicated by the PWEA is perceived as a realistic number and adopted in this study.

4.4 Thermal power plants

Modelling and input assumptions for thermal power plants is covered in this section except for commodity prices handled in Section 4.6.

4.4.1 Gas

With CO2 prices establishing above 100 EUR/tCO2, gas combined-cycle power plants outcompete coal due to its relatively lower CO2 emission intensity. Current Poland Energy Policy report[52] projects a significant increase in their installed capacity from 2.5 GW to 10.0 GW in 2030. The current report assumes an existing capacity of combined-cycle gas power plants of 6 GW present in the first stage of the modelling in 2030. This installed capacity corresponds to advertised projects deemed very

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[49] https://www.gov.pl/web/ia/polityka-energetyczna-polski-do-2040-r-pep2040
[50] https://biznesalert.pl/choczewo-zarnowiec-linia-400-kv-pse-decyzja-srodowiskowa-morskie-farmy-wiatrowe-offshore-polska/
[51] PSEW (2022) Potencjał Morskiej Energetyki Wiatrowej w Polsce.
[52] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.

probable to be completed in the next few years[53]. At the latest, these are assumed to have fully retired by 2055.

4.4.2 Coal

Lignite and hard coal fuelled power plants are modelled separately with existing installed capacity of 8.2 GW and 16.1 GW, respectively. With the exception of the 'coal slow phaseout' sensitivity, the retirement of the coal plants is purely determined by the optimisation. The prescribed retirement of coal power in the 'coal slow phaseout' sensitivity follows that presented in Table 10.

Table 10. Prescribed retirement of coal power plants in the 'coal slow phaseout' sensitivity.

	2030	2035	2040	2045-
coal_hard	10.0 GW	9.1 GW	7.6 GW	Free
coal_lignite	6.5 GW	3.3 GW	0.7 GW	Free

4.4.3 Biomass and biogas

The model permits the expansion of biomass thermal and open-cycle biogas power plants. Consistent with the current Polish energy policy[54], the combustion of biomass and biogas is assumed to have a CO_2 emissivity of zero. Similarly, upper limits on biomass and biogas fuel consumption align with the projections outlined in the current Polish energy policy[55], as detailed in Table 11.

Table 11. Upper limit of total annual generation in TWh for thermal power plants using biomass and biogas fuels, respectively.

	2030	2035	2040	2045	2050
biomass	9.4	11	13	15	17
biogas	0.9	1.1	1.3	1.4	1.6

4.4.4 CHPs

Coal, natural gas and biomass fuelled combined heat and power plants (CHPs) currently exist in Poland with installed power capacity of 4.6 GW, 3.2 GW and 0.3 GW, respectively. The CHPs are modelled as must run, i.e., required to follow a specific production profile correlated to weather year temperatures. The production profiles were determined based on an analysis of historical data where it was concluded that one profile sufficed for coal and biomass CHP each, while two different profiles were applied to natural gas fuelled CHPs, industrially connected and district heating connected.

The fossil-fuelled CHPs were prescribed a linear retirement to become fully phased out in 2050. Biomass CHP capacity was assumed to remain constant.

4.4.5 Hydrogen power plants and storage

The model optimization includes the possibility to build gas turbine power plants fuelled with hydrogen. The model includes the electrolyser charging of a centralised Polish hydrogen storage. An overnight capital cost of electrolysers has been assumed at 970 €/kW in 2030 decreasing to 520 €/kW

[53] https://wysokienapiecie.pl/85387-energetyka-gazowa-nie-zamierza-sie-zwijac/ (accessed 06.11.2023)
[54] Ministry of Climate and Environment Republic of Poland (2021), Energy policy of Poland until 2040.
[55] Ministry of Climate and Environment Republic of Poland (2021), Energy policy of Poland until 2040.

in 2050. The model has the option to either build open-cycle or combined-cycle hydrogen gas power plants with investment and operational costs equal to the natural gas counterpart.

Geological storage of hydrogen gas in Poland shows high potential. Considering known suitable geological formations in Poland, the maximum potential for working gas capacity is in the order of 90 MtH2 (3000 TWh) for saline aquifers[56] and 1.2 MtH2 (40 TWh) for salt caverns[57]. We have for the current study calculated[58] the levelized cost of underground hydrogen storage based on the referenced geological data obtaining values of 3.3 €/kgH2 for saline aquifers and 2.5 €/kgH2 for salt caverns. The current study assumes the levelized cost of hydrogen storage at 2.5 €/kgH2 (75 €/MWh), which is based on a lifetime of 40 years and a capacity factor of 0.8 corresponds to an overnight capital cost of hydrogen storage at 920 €/MWh.

4.4.6 CCS

Geologic storage of CO2 is set to play a crucial role in mitigating carbon emissions, particularly in sectors like heavy industry, which have limited options for reducing emissions other than through carbon capture. In this section, we explore the key aspects of Carbon Capture and Storage (CCS) and the input assumptions considered in our power system optimization study.

Poland has significant CO2 storage potential, with a substantial portion of this potential found in saline (non-potable) aquifers with example estimates ranging from 7.4 Gt[59] to 13.8 Gt[60]. It is relevant to note that conflicts of interest with hydrogen (H2) storage and geothermal energy may arise in utilizing these storage resources. Put into perspective, expanding the scope to the entire European region, the combined saline storage capacities amount to a staggering 482 Gt of CO2. This is equivalent to more than 300 years' worth of European Union (EU) emissions.

Being an emerging technology, only a few CCS projects have been to this date proposed in Poland[61] while several storage projects are planned or under development in Europe[62]. On this background, the CCS technology is not allowed in 2030 due to the limited number of CCS projects and their low maturity in Poland. However, beginning in 2035, CCS is allowed with no restrictions on the annual CO2 injection capacity.

Recent studies have highlighted the techno-economic feasibility of achieving approximately 100% capture efficiency through post-combustion capture, with manageable increases in investment and operational costs[63]. There are few examples where carbon capture technology has been demonstrated until today[64,65] but it still needs to be proved commercially and on a larger scale. We

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56 Ministry of Environment - Poland (2014), Assessment of formations and structures suitable for safe CO2 geological storage (in Poland) including the monitoring plans.
57 International Journal of Hydrogen Energy (2018), Salt domes in Poland – Potential sites for hydrogen storage in caverns.
58 International Journal of Hydrogen Energy (2023), Capacity assessment and cost analysis of geologic storage of hydrogen: A case study in Intermountain-West Region USA.
59 Ministry of Environment (2014), Assessment of Formations and Structures suitable for Safe CO2 Geological Storage (in Poland) Including Monitoring Plans.
60 CCS4CEE (2021), Assessment of current state, past experiences and potential for CCS deployment in the CEE region Poland.
61 CCS4CEE (2021), Assessment of current state, past experiences and potential for CCS deployment in the CEE region Poland.
62 Reuters (2023), Carbon storage projects across Europe.
63 IEAGHG (2019), Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass.
64 International CCS Knowledge Centre (2018), The Shand CCS Feasibility Study Public Report.
65 Reuters (2020), Problems plagued U.S. CO2 capture project before shutdown.

have optimistically assumed a steady increase in capture efficiency, starting at 90% in 2030 and linearly progressing to 100% by 2050. This assumption is balanced by not accounting for learning effects on the operational and maintenance costs.

The cost of transport and storage is estimated as a variable OM cost of 20 EUR/tCO_2. However, the levelized cost of transport and storage can vary significantly based on factors like infrastructure, transport distance, monitoring, reservoir geology, and transport costs. Studies have suggested a range of estimates, from 4–45 US$/t$CO_2$[66] to 6–75 US$/tCO_2[67]. To account for these variations, we conducted a sensitivity run with a variable OM cost set to 40 EUR/tCO_2, creating the "CCS expensive" scenario.

A final note, process disturbances associated with highly flexible power plant operations, including start-up and shut-down cycles in CCS systems, lead to deviations from optimal conditions[68]. This deviation can result in an increase in residual CO_2 emissions, unless additional investments in equipment such as solvent storage or additional heating are made[69]. Our current modelling does not account for these increased emissions which ultimately leads to an overestimated value for CCS technologies in the simulation as well as underestimated costs for the simulated power systems which increasingly rely on the CCS technologies for achieving deep decarbonisation.

4.5 Investment and operational costs

The current study considers a set of general financial assumptions that form the foundation for our analysis. All financial values are expressed in real currency in terms of Euros (EUR) for the year 2022. These currency adjustments ensure consistency and accuracy in our cost evaluations. Furthermore, the financial assumptions encompass the Weighted Average Cost of Capital (WACC), which varies across different scenarios. In the optimistic scenario, the WACC is set at 5%, while the base scenario utilizes a WACC of 7%, and the conservative scenario employs a 9% WACC. To accommodate the financial dynamics during the construction phase of projects, we employ an interest rate equal to half of the respective scenario's WACC for the construction time as a mark-up on total investment costs. Capital recovery periods have been set equal to the technical lifetime with the exception for retrofit technologies as described in Section 4.7.

Investment and operational costs as well as operational characteristics for the energy technologies included in the current study have been determined based on review of references presented in Table 12. The references encompass historical, present-day/near-future and future projections. References to relevant Polish governmental studies are included for comparison of modelling assumptions.

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[66] International Journal of Greenhouse Gas Control (2021), The cost of CO2 transport and storage in global integrated assessment modeling.
[67] Energy Conversion & Management (2005), The low cost of geological assessment for underground CO 2 storage: Policy and economic implications.
[68] iScience (2023), The prospects of flexible natural gas-fired CCGT within a green taxonomy.
[69] AECOM for BEIS (2020), Start-up and shut-down times of power CCUS facilities.

Table 12. Main source of references building investment and operational cost estimates for power technologies considered.

Reference	Acronym	Type
US Energy and Information Administration (2022), Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022.	EIA_2022	Present-day/near future
National Renewable Energy Laboratory (2022), Annual Technology Baseline.	ATB_2022	Future projections, 2020 - 2050
International Energy Agency & Nuclear Energy Agency (2020), Projected Costs of Generating Electricity.	IEA_NEA_2020	Present-day/near future
International Renewable Energy Agency (2022), Renewable Power Generation Costs in 2021.	IRENA_2021	Historical
Energiforsk (2021), El Från Nya Anläggningar.	Energiforsk_2021	Present-day/near future
Idaho National Laboratory (2023), Literature Review of Advanced Reactor Cost Estimates.	INL_2023	Present-day/near future
European Commission (2021), EU Reference Scenario 2020.	EU_2020	Future projections, 2020 – 2050
Ministry of Climate and Environment Republic of Poland (2021), Energy policy of Poland until 2040.	PEP_2040	Modelling assumptions
Ministry of Climate and Environment Republic of Poland (2023), Energy policy of Poland until 2040 - Scenario 3.	PEP_2040_S3	Modelling assumptions

Investment and operational costs have been made in three scenarios: optimistic, base and conservative. Technology cost assumptions is a vital component of our analysis, and it has been conducted by comprehensive investigation of a diverse array of credible sources as outlined in Table 12. Cost estimates from these sources were made both prior to and during the transformative landscape of 2022, which was marked by the invasion of Ukraine, the energy crisis, inflationary pressures, and increasing geopolitical tensions. Notably, the costs associated with renewables have exhibited an upward trajectory since 2020, attributed to the evolving global context characterized by escalating prices of commodities and energy[70], inflation, and geopolitical complexities[71]. Costs

[70] IEA (2021), What is the impact of increasing commodity and energy prices on solar PV, wind and biofuels?
[71] BloombergNEF (2022), Cost of New Renewables Temporarily Rises as Inflation Starts to Bite

"are expected to decline by 2024, but not rapidly enough to fall below pre Covid-19 values in most markets outside China."[72] It is further worth mentioning, that while solar PV deployment is set to shatter many records in 2023[73], wind power is facing challenges[74] with a growth more uncertain[75].

Figure 9 illustrates the projection of overnight capital costs for utility-scale solar PV and onshore wind assumed in the current study. Starting value is based on EIA_2022[76], reflecting the increased costs observed over the last years. Values at the endpoints of 2050 are primarily based on ATB_2022[77], utilizing their default class for each technology, and encompassing moderate (denoted base in the current study), conservative and advanced (denoted optimistic in the current study) scenarios. To align with our dedicated endpoints, learning rates have been adjusted accordingly, with the optimistic scenario adopting a higher learning rate of approximately 12% in contrast to the lower 8% employed in the conservative scenario. Custom Polish-specific additional investment costs for grid connections based on needed high-voltage transmission lines for onshore wind and solar PV has been estimated to 44 €/kW while general grid connection costs for offshore wind have been set according to ATB_2022. Further grid aspects are discussed in Section 5.7.1.

As a third example, the bottom panel in Figure 9 presents the overnight capital cost for battery storage. Both starting value and end point are based on ATB_2022[78]. The calculation of total overnight capital costs (EUR/kW) involved the summation of overnight capital costs for charge and discharge, incorporating energy considerations through the equation: Total overnight capital cost (EUR/kW) = Energy Cost (EUR/kWh) * Storage Duration (hr) + Charge/Discharge Cost (EUR/kW). The illustrated total overnight capital costs in the figure were contingent upon a presumed storage duration of 6 hours for QC_CATF and ATB_2022. The determination of storage duration within the GenX model was executed under constraints dictated by a predefined interval, exemplified by a range such as 2-10 hours for battery storage.

Like for solar, wind and battery storage, a similar methodology has been applied to other technologies, as well as for other costs inputs, such as fixed and variable operational and maintenance costs.

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[72] IEA (2023), Renewable Energy Market Update – Outlook for 2023 and 2024.
[73] Canary Media (2023), Chart: Solar installations set to break global, US records in 2023.
[74] Reuters (2023), Siemens Energy's shares tumble as wind turbine troubles deepen.
[75] IEA (2023), Renewable Energy Market Update – Outlook for 2023 and 2024.
[76] US Energy and Information Administration (2022), Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022.
[77] National Renewable Energy Laboratory (2022), Annual Technology Baseline.
[78] National Renewable Energy Laboratory (2022), Annual Technology Baseline.

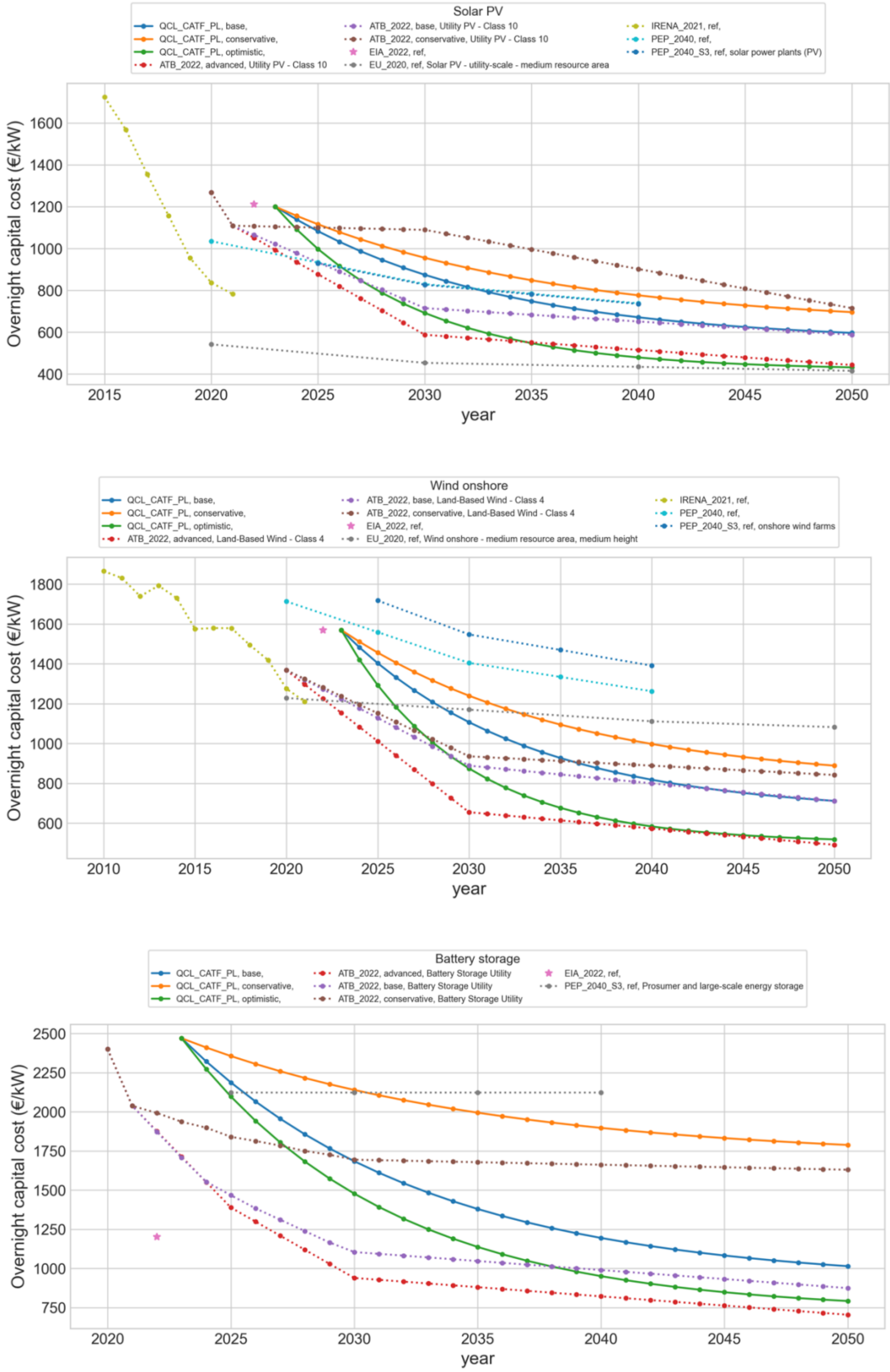

Figure 9. Overnight capital costs for solar (top panel), wind onshore (middle panel) and battery storage (bottom panel) in the current study compared to other sources as indicated in the legend.

Unlike the typical "learn-by-doing" trends observed in solar PV and wind power, the realm of nuclear power plant construction exhibits significant variations, contingent upon the specific project in question[79,80]. To illustrate, the development of novel nuclear reactor designs in Western Europe has been accompanied by notably high price tags[81], emerging nuclear power nations such as Turkey and the United Arab Emirates have realized their initial reactors at relatively lower costs[82,83]. Table 13 aims to put the investment costs of nuclear power plants, which dominate the total costs of nuclear power generation, further into perspective by listing four scenarios and comparing them to observed costs for nuclear power projects in the 21st century[84]. As a final note, it is important to recognize that the widespread expectation is that serial construction, i.e., building many reactors of the same kind, and manufacturing of advanced reactor designs, will refine practices, ultimately resulting in cost reductions[85].

Table 13. Nuclear costs in perspective based on analysis of nuclear projects in the time period 2000-2020[86].

Scenario	Description	Overnight Capital Cost (€/kW)
Low	Meets a realistic expectation for a very successful project outside Asia today. However, the value is 45% higher than the world average of projects between 2000 and 2020.	3200
Medium	Equivalent to what VVER and APR reactors have been built for in recent years in countries that previously lacked nuclear power (e.g., the United Arab Emirates, Turkey), and the average for new nuclear power outside leading nuclear power nations (China, India, Russia and South Korea).	4200
High	Corresponds to the approximate expected cost of a new generation EPR (Sizewell-C in the UK).	5300
Very high	Equivalent to the very expensive single overnight costs for EPR projects in France, UK and Finland.	6900

Nuclear costs follow a slightly different logic and has therefore been treated separately for the current study's modelling input. The projection of the nuclear overnight capital cost is presented in Figure 10. The starting values are based on INL_2023[87]. Low for optimistic at 3960 €/kW, medium for base at 5950 €/kW and high for conservative at 6940 €/kW. The starting point has been shifted with

79 Energy Policy (2016), Historical construction costs of global nuclear power reactors.
80 Energiforsk (2021), El från nya anläggningar.
81 Institute for Energy Economic and Financial Analysis (2023), European Pressurized Reactors: Nuclear power's latest costly and delayed disappointments.
82 WNA (2023), Nuclear Power in the United Arab Emirates.
83 WNA (2023), Nuclear Power in Turkey.
84 Energiforsk (2021), El från nya anläggningar.
85 Idaho National Laboratory (2023), Literature Review of Advanced Reactor Cost Estimates.
86 Energiforsk (2021), El från nya anläggningar.
87 Idaho National Laboratory (2023), Literature Review of Advanced Reactor Cost Estimates.

construction time to imitate at which point in time learning is initiated. The endpoint values are determined by considering learning rates for the construction of multiple nuclear units of the same kind[88]. In the optimistic scenario, 15 similar units are constructed reaching 3240 €/kW in 2050. Correspondingly in the base and conservative scenarios, 10 and 5 similar units are employed reaching 4190 €/kW and 4760 €/kW, respectively. Additionally, the construction time for these nuclear units initiates at 5 years for the optimistic scenario, 6 years for the base scenario, and 7 years for the conservative scenario. Over time, these construction periods decrease in alignment with learning rate of 10%, to 3, 3.5, and 4 years for the optimistic, base, and conservative scenarios, respectively.

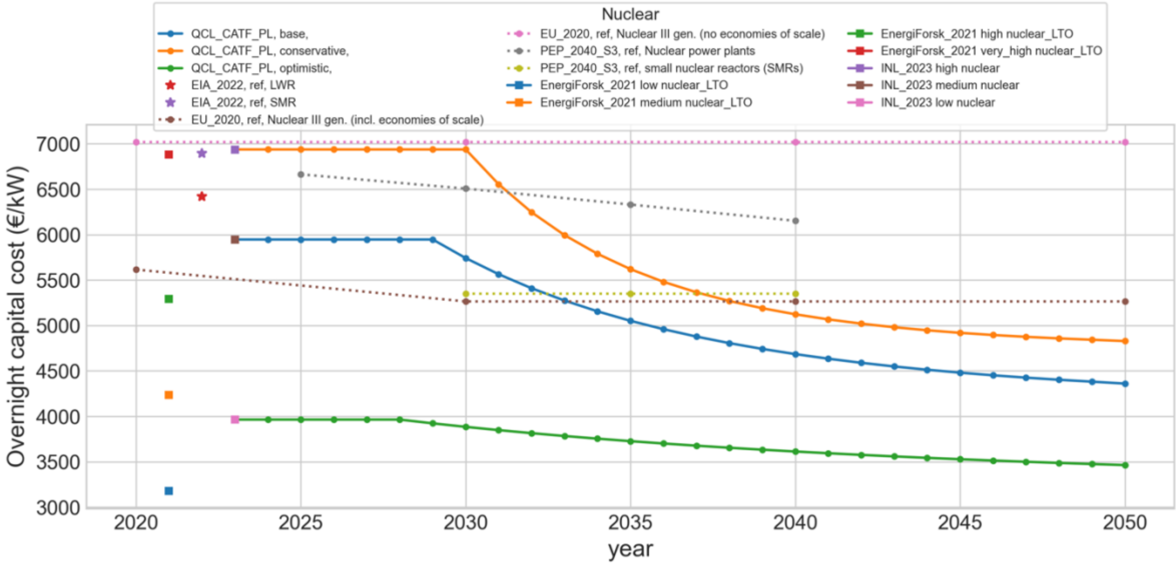

Figure 10. Nuclear overnight capital costs in the current study compared to other sources as indicated in the legend.

The Levelized Cost of Electricity (LCOE), denoting the average cost of unit electricity generated by a specific technology, exhibits certain limitations in facilitating meaningful comparisons between technologies[89]. A crucial criterion for capacity expansion is the profitability of all technologies, necessitating their capture price—defined as the average electricity price experienced by the technology—to surpass the LCOE. Transparency of the LCOE ensures a full understanding of input assumptions related to investment and operational costs for various technologies, where the Weighted Average Cost of Capital (WACC) plays a pivotal role. .

Table 14 in the current study presents LCOE values for the primary technologies, serving as a basis for comparison with values employed in other studies to achieve a more comprehensive understanding. Finally, the LCOE calculation methodology employed in the current study is presented in Appendix A4.

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[88] Equation 3, Idaho National Laboratory (2023), Literature Review of Advanced Reactor Cost Estimates.
[89] World Resources Institute (2019), INSIDER: Not All Electricity Is Equal—Uses and Misuses of Levelized Cost of Electricity (LCOE).

Table 14. Compiled levelized cost of electricity (LCOE) in €/MWh for the main technologies considered in the current study, optimistic, base and conservative scenarios and years 2035 and 2050.

technology	optimistic		base		conservative	
	2035	2050	2035	2050	2035	2050
nuclear	47	44	76	65	104	87
nuclear_retrofit	43	41	68	59	92	77
gas_OC	150	144	174	165	198	185
gas_CC	111	106	129	121	147	136
gas_CC_CCS	112	102	136	122	160	143
gas_CC_CCS_retrofit	105	96	125	113	145	131
coal_hard_CCS	110	99	170	150	196	172
coal_hard_CCS_retrofit	114	124	145	151	158	162
wind_onshore	28	22	41	32	55	46
wind_offshore_fixed	63	52	86	75	111	102
wind_offshore_floating	71	60	96	85	122	113
biomass	119	113	133	125	147	136
biogas_OC	248	235	261	248	274	260
solar	45	37	69	56	90	75

4.6 Commodity prices

Commodity and CO_2 prices assumed for the current study are presented in Figure 11.

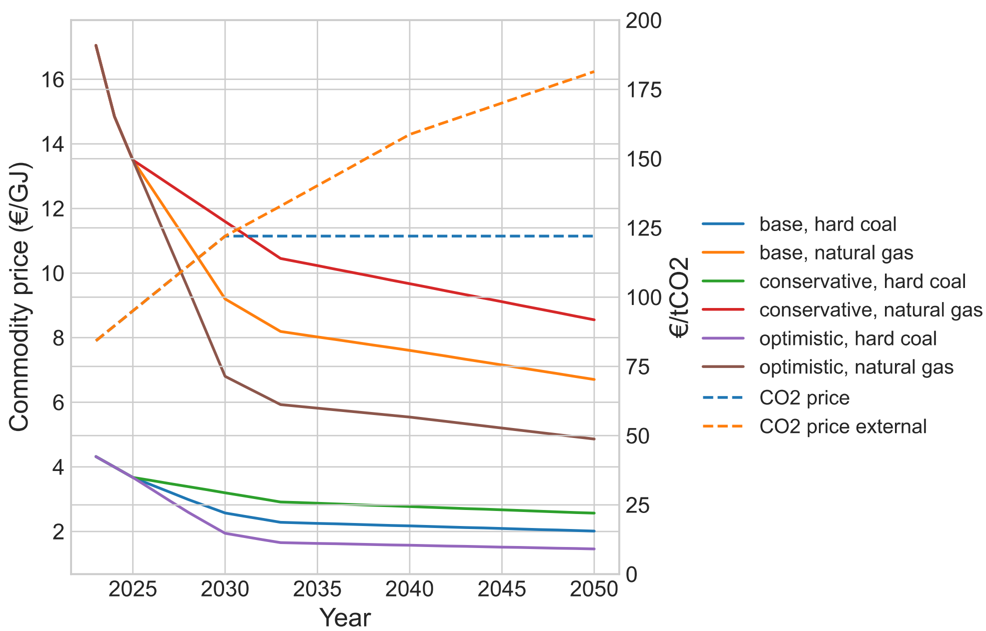

Figure 11. Natural gas and coal commodity prices for the three scenarios considered in the current study. CO_2 prices imposed on the Polish power system and outside Poland also shown.

The natural gas price scenarios considered in our study closely follow the fundamental trends of the ERAA 2023 proposal[90]. In the optimistic scenario, it is assumed that natural gas prices will approach levels reminiscent of those in the European Union before the energy crisis, indicating a reduction of approximately 10% by the mid-2030s, with a target price of 20 €2021/MWh by 2035. Conversely, the conservative scenario anticipates natural gas prices to approach levels akin to those observed in Asia for liquefied natural gas (LNG) before the energy crisis, reflecting an increase of approximately 10% by the mid-2030s, with a projected price of 34 €2021/MWh by 2035. The base scenario, as an average between the optimistic and conservative scenarios, anticipates natural gas prices to reach 27 €2021/MWh by 2035. Notably, the pricing trends for hard coal have been directly linked to those of natural gas and scaled accordingly.

Other commodity prices used in the current study only assume a base scenario. Lignite coal has been set a value of 1.96 €/GJ[91], biogas 19.7 €/GJ[92], biomass 5.13 €/GJ[93] and uranium 0.51 €/GJ[94].

4.7 Retrofitting

In the current study, we introduce the concept of power plant retrofitting as a new feature within the GenX framework. Retrofitting opens up opportunities for existing power plants that may not be cost-effective in their current state. Instead of retiring such power plants, they can be retrofitted with more cost-effective technologies. The retrofitting process involves two key parameters: the retrofit investment cost and the efficiency of the retrofit, which quantifies how much capacity is regained when transitioning to the new technology. In addition, a shorter capital recovery period and lifetime are other considerations that should be made for retrofit technologies to account for the service life of retrofit equipment being shorter compared to greenfield projects investments.

The current study does not assess the retrofitting of natural gas power with hydrogen.

4.7.1 CCS

Within the GenX model, we allow for CCS retrofitting of modern existing coal plants and for all new natural gas power capacity being built in the model. This means that our retrofitting approach extends to coal (lignite and hard) power plants, as well as gas combined-cycle (gas_CC) plants. To determine the costs associated with retrofitting, the difference in investment costs between the power plant with and without carbon-capture technology forms the baseline. The retrofit investment cost is then calculated by use of a retrofit difficulty factor as presented in two recent reports from the Office of Scientific and Technical Information. A retrofit difficulty factor represents the difference on the investment of greenfield vs. brownfield projects. In the current study, retrofit difficulty factors of 1.10 for the case of coal CCS power plants[95] and 1.09 for natural gas combined-cycle power plants[96] were assumed.

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[90] ERAA (2023), Proposal of commodity prices for call for evidence.
[91] ERAA (2023), Proposal of commodity prices for call for evidence.
[92] ERAA (2023), Proposal of commodity prices for call for evidence.
[93] National Renewable Energy Laboratory (2022), Annual Technology Baseline.
[94] ERAA (2023), Proposal of commodity prices for call for evidence.
[95] Office of Scientific and Technical Information (2023), Eliminating the Derate of Carbon Capture Retrofits (Rev. 2).
[96] Office of Scientific and Technical Information (2023), Cost and Performance of Retrofitting NGCC Units for Carbon Capture – Revision 3.

Additionally, the eligibility of coal power plants in Poland for CCS retrofitting is derived from Energies (2021)[97]. For retrofitted natural gas CCS power plants we assume a 20 year lifetime and capital recovery period while for coal we assume the lifetime to be 30 years for plants retrofitted in 2035 and 15 years for plants hypothetically retrofitted in 2050. The capital recovery period is set to half the lifetime for coal power plants. Finally, the eligible capacity of coal power plants for CCS retrofitting has been assumed 5.8 GW in total[98].

4.7.2 Nuclear

In addition to CCS retrofitting, coal power plants are eligible for nuclear repowering. An exemplary case study on coal power plant retrofits conducted in Poland[99] has identified a total of 38 coal units, collectively boasting a current electric capacity of approximately 10 GW, as prime candidates for retrofitting with Small Modular Reactors (SMRs) to achieve decarbonization. Moreover, the study determined potential cost savings, with upfront overnight capital cost reductions ranging from 28% to 35% for full repowering compared to the construction of entirely new plants as greenfield projects.

Building from the initial work focused on Poland, the RepowerScore calculator is being developed by Quantified Carbon as part of the Repower initiative to quantify repowering suitability for coal plants worldwide through a number of pathways.

Returning to repowering with nuclear, we can use this ranking to estimate the potential repowering capacity within Poland. Taking the top 10 plants for repowering gives ~19GW of capacity. Of these a number a marked for repowering by gas in the near future, i.e., before 2030, including Kozienice, Dolna Odra and Ostrołęka[100].

Excluding these plants, ~10GW is left with potential for nuclear repowering. Of these sites, one is of particular interest, Bełchatów has undergone substantial modernisation in the last decade bringing the average effective age to ten years (in 2023). It is reasonable to assume that some amount of savings is possible by partial reuse of components on site.

For most other plants the age of the components will exclude them from use in repowering but the site itself is still a valuable asset with an existing grid connection.

Based on this, these sites should be attractive for either partial repowering, where some assets or reused or site repowering where the existing site allows for some measure of savings.

Using this argument, we can motivate up to 5 GW or partial repowering and 5 GW or site repowering, with perhaps a 20% and 10% reduction on costs respectively, leading to an average saving of 15% compared to greenfield sites.

A capital recovery period of 30 years is assumed for the nuclear retrofit investment, which is ten years shorter compared to greenfield nuclear projects. This adjustment takes into account the remaining service life of retrofit equipment. For most plants considered, site repurposing is a

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[97] Energies (2021), Retrofit Decarbonization of Coal Power Plants - A Case Study for Poland.
[98] Energies (2021), Retrofit Decarbonization of Coal Power Plants - A Case Study for Poland.
[99] Energies (2021), Retrofit Decarbonization of Coal Power Plants - A Case Study for Poland.
[100] https://wysokienapiecie.pl/85387-energetyka-gazowa-nie-zamierza-sie-zwijac/

primary interest, and equipment reuse is typically limited. The lifetime of the nuclear retrofit plant is also assumed 10 years shorter than greenfield, i.e., 50 years.

Finally, in the current study we have built a scenario 'nucl. retro' which aims to examine the value of nuclear retrofitting in Poland's decarbonization pathway. It is assumed that first nuclear retrofit of coal power plants can take place in 2035 to a capacity of 1 GW, corresponding to one coal power plant site. Another 3 GW is allowed in 2040 while the remaining 6 GW is free to retrofit after 2040.

4.8 Modelling regions and transmission capacities

A full market optimized expansion model for Poland is used in this study. This method ensures that crucial factors such as transmission capacities, generation limits, and demand fluctuations are all accounted for, leading to a more accurate representation of the system's behaviour compared to dispatch only analysis. This holistic view enables more informed decision-making, ensuring not just the efficient dispatch of available resources but also addressing network constraints, potential congestion issues, and the influence of neighbouring regions. The modelling regions and Polish transmissions considered in the power modelling are shown in Figure 12. For computational purposes, zones are grouped together in the Nordics and Baltics. This grouping does not affect the overall behaviour of the power market in these regions, which is the most important for the power modelling in Poland. Ukraine (UA) was simplified to only the transmission capacity due to unavailability and uncertainty in the data; however this consideration is sufficient for the present study since this transmission flow is small.

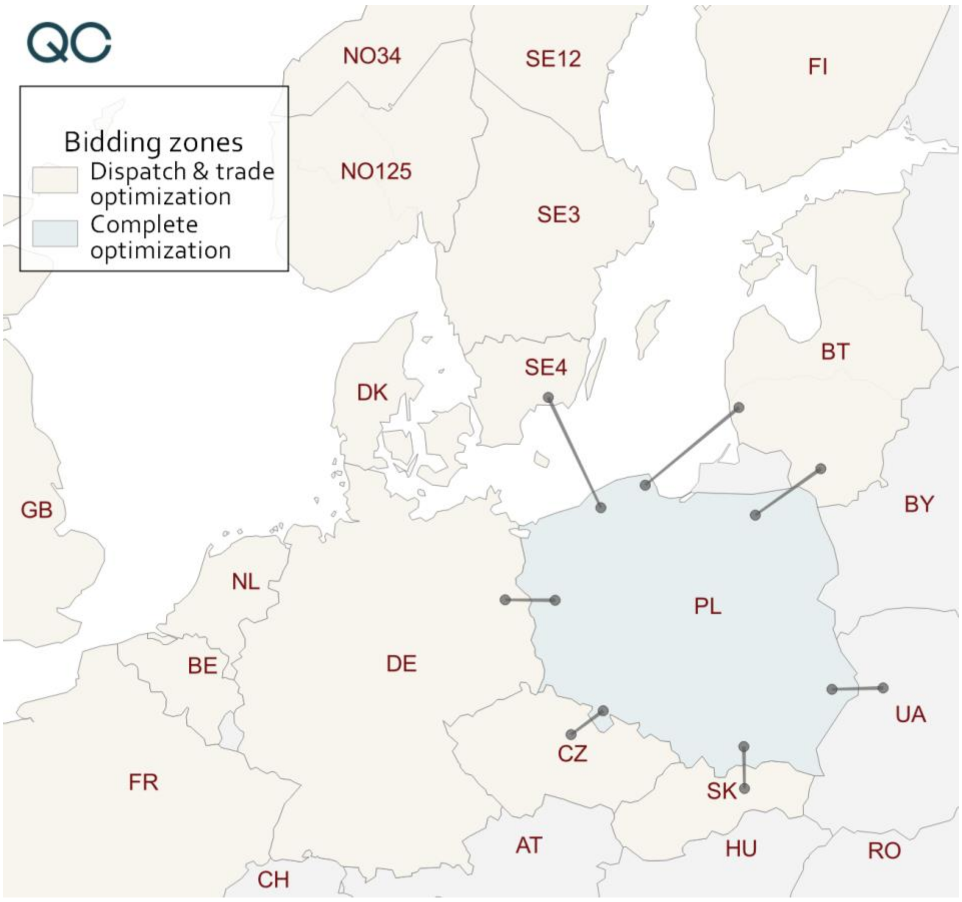

Figure 12. Geographical boundaries with regions included in the modelling and how they are treated in the optimization. Only transmission lines directly connected with Poland are shown.

4.9 Capacity reserve margin

The required reserve[101] in the Polish power system is defined as the amount of required surplus power available to the transmission system operator determined for each hour as a percentage of the demand to be covered by domestic power plants. It is as follows: 9% for hours of days D+1 and D+2 14% for hours of days D+3 to D+9 17% for hours of days D+10 to D+40 18% for hours of days D+41 and onward. This allocation outlines the percentage of excess power capacity that must be maintained for specific periods to ensure the stability and reliability of the power system. A time series illustrating the historical power system and reserves is shown in Figure 13.

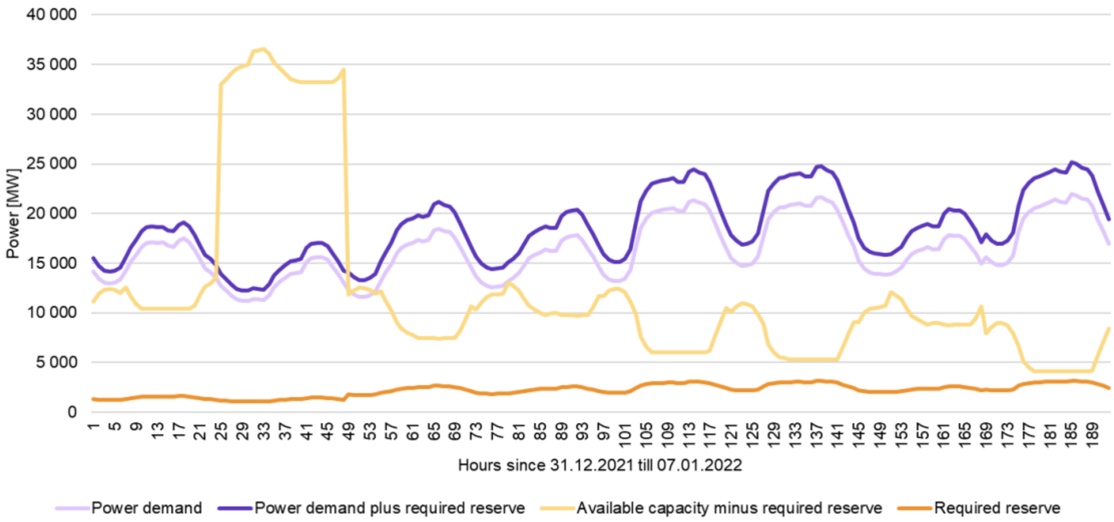

Figure 13. Snapshot from the historical[102] power system operation showing projected demand along the required and available capacity over the period of next eight days.

The polish capacity market is non-discriminatory[103] in the sense of technology (all technologies must meet the same conditions), it excludes the units that are using other forms of support and as for now does not allow participation of foreign generation units. The capacity auctions are following the system realized in Great Britain with equal prices for all entities that were participating in the auction and were granted the capacity contract. The contracts are signed for 7 years for units with emissivity lower than 550 tCO2/MWh and for 5 years for unites with greater one (as on 2019). For new units the contracts are signed for 15 years.

The current analysis assumes a capacity reserve margin of 9% for the Polish power system. It treats all technologies equal, including flexible demand resources (see Section 4.2.2), meaning that all may contribute to the capacity reserve in accordance with their availability during times of scarce power supply. The exception is coal power which currently have contracts extending to 2035[104]. For the current modelling, coal power plants are merely allowed in the capacity market in model years 2030 and 2035.

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[101] https://www.pse.pl/dane-systemowe/plany-pracy-kse/plan-koordynacyjny-dobowy-pkd/bilans-uproszczony

[102] https://www.pse.pl/dane-systemowe/plany-pracy-kse/plan-koordynacyjny-dobowy-pkd/bilans-uproszczony

[103] https://mostwiedzy.pl/pl/publication/download/1/mechanizmy-mocowe-na-rynkach-energii-elektrycznej_40777.pdf

[104] Wysokienapiecie (2022), Z czym do rynku mocy? Będą kolejne bloki gazowe.

4.10 Build rates

In our analysis, we consider a phased approach to capacity expansion, acknowledging that various factors influence the rate at which different energy resources can be deployed. These constraints are particularly relevant within the context of short-term and long-term planning, and we aim to strike a balance between technological advancements and practical limitations. A summary of the build rates is presented in Table 15.

Historic and near-term future development of wind and solar PV in Poland is described in Section 4.3.3. For solar PV, the model assumes a minimum installed capacity of 26.8 GW complete in 2025 and the potential of an additional 25 GW until 2030. For onshore wind power the model assumes a maximum build rate of 1 GW per year for onshore wind power between 2024 and 2030 which is double the build rate of 0.5 GW/year observed in average during 2010-2022 but slower than the 1.5 GW observed in the last full year of 2022 for Poland[105]. This assumed build rate still exceeds current estimates on both projected available grid capacity and projects in pipeline. Projected available capacity for onshore wind allows a total installed capacity of 14 GW in 2030[106] of which 9.7 GW is currently installed. 3.8 GW is the total sum of approved onshore wind projects in the pipeline[107]. In the case of offshore wind, projects in the pipeline total 5.9 GW setting the limit for 2030[108].

Between 2031 and 2040, the constraints begin to loosen as European wind power supply chain is improved with respect to today[109]. During this phase, we set a maximum build rate for onshore and offshore wind energy of 1.5 GW per year for both in the early part of this phase, which is assumed to be accommodated by expanded grid capacity. This value aligns with the build rate observed in 2022 for Poland[110]. In the latter half of this phase, from 2036 to 2040, we allow for a more accelerated build rate of 2.0 GW per year for both onshore and offshore wind. However, the total installed capacity is not allowed to exceed the maximum expansion limit as introduced in Section 4.3.1.

Due to significant changes in legal conditions, determining the development of onshore wind power projects was very uneven and unpredictable in recent years. According to Respect Energy[111] in the upcoming years the expected annual growth of onshore wind is expected to reach the level of 2GW/year. Massive potential of new capacities (without the need of investing in grid infrastructure) is hidden in existing single source wind/solar parks through cable-pooling.

For solar PV, the projected growth will reach a total installed capacity of 26.8 GW by 2025 as introduced in Section B.2, achieving a maximum yearly deployment rate of 4.4 GW. Until 2030 we have assumed a maximum build rate of 5 GW per year.

Poland has ambitious plans for new nuclear power, encompassing a diverse portfolio of state and private initiatives for constructing both large conventional reactors and small modular reactors, collectively exceeding 10 GW of installed capacity with margin[112]. The current study makes

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105 Wind Europe (2023), 2022 Statistics and the outlook for 2023-2027.
106 PSE (2022), Transmission System Development Plan 2023-2032.
107 PSE (2023), Information on the availability of connection capacity to the transmission network.
108 Government Poland (2023), Wind farm development program.
109 Wind Europe (2023), The EU built only 16 GW new wind in 2022.
110 Wind Europe (2023), 2022 Statistics and the outlook for 2023-2027.
111 https://www.wnp.pl/energetyka/inwestycje-w-energetyke-wiatrowa-i-sloneczna-w-polsce-przyspiesza,669817.html
112 World Nuclear Association (2023), Nuclear Power in Poland.

assumptions in line with Poland Energy Policy[113]. New nuclear capacity is first allowed in 2035, totalling 3.4 GW, increasing to 7.8 GW in 2040.

To account for different scenarios and sensitivities, we have considered two key build rate scenarios: fast wind expansion and slow nuclear expansion. In the fast wind expansion scenario, we project even higher growth rate at 15 GW between 2024 and 2030 as well as for the two five-year periods in the 2030s. In contrast, our slow nuclear expansion scenario assumes half of the base build rate, i.e., 2 GW and 4 GW in 2035 and 2040, respectively.

As the impact of escalating CO2 taxes diminishes the cost-effectiveness of coal power generation, the model transitions towards natural gas, biogas and biomass power plants. To set build rate in 2030, we have taken guidance from Poland Energy Policy[114]. Plan for combined-cycle natural gas-fired power plants is an increase of 7 GW until 2030[115]. Based on historical data from the UK[116], specifically the 5-year period from 2008 to 2013, we allow a build rate of 10 GW for new natural gas capacity. This is applied to the period 2024-2030, between 2031 and 2035 as well as for 2036 to 2040. In the first period combined-cycle gas power dominate. From 2031 onwards, this expansion is assumed to be equally distributed between open-cycle and combined-cycle technology types to ensure flexibility in response to market demands. Biogas and biomass power plant (excluding CHP) capacity is set to see an increase to 2.2 GW in 2030[117], of which 1/5 has been allocated to open-cycle biogas and the rest to biomass. Beyond 2030, increase in capacity of 1 GW per year is assumed which for the case of biogas is within reach[118].

For technologies not listed in Table 15 no build rate limits have been assumed. Lastly, beyond 2040, the landscape of possibilities is extensive, and for the years 2045 and 2050, capacity expansion is unrestricted.

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[113] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.
[114] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.
[115] Wysokienapiecie (2022), Z czym do rynku mocy? Będą kolejne bloki gazowe.
[116] Ember (2023), Gas.
[117] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.
[118] Business Insider (2023), "This is the beginning of the biogas plant boom." Facilitations under construction and later large subsidies.

Table 15. Maximum build rate limits applied in the modelling presented by technology and sensitivity (where base is the default). The unit is GW per seven years for the 2024-2030 column and then GW per five years for the last two columns. Existing capacity by end of 2023 in GW is also given.

Technology	Sensitivity	Existing (2023)	2024-2030	2031 - 2035	2036-2040
Solar PV	base	18	35	-	-
Onshore Wind	base	9.7	7.3	7.5	10.0
Onshore Wind	fast	9.7	15.0	15.0	15.0
Offshore Wind	base	0.0	5.9	7.5	10.0
Offshore Wind	fast	0.0	5.9	15.0	15.0
Solar PV	base	18	35	-	-
Nuclear	base	0.0	0.0	3.4	7.8
Nuclear	slow	0.0	0.0	1.7	3.9
Natural Gas OC	base	0.0	2.0	5.0	5.0
Natural Gas CC	base	1.4	6.6	5.0	5.0
Biomass	base	0.3	1.3	1.0	1.0
Biogas OC	base	0.3	0.3	1.0	1.0

5 Results

5.1 Scenario comparison

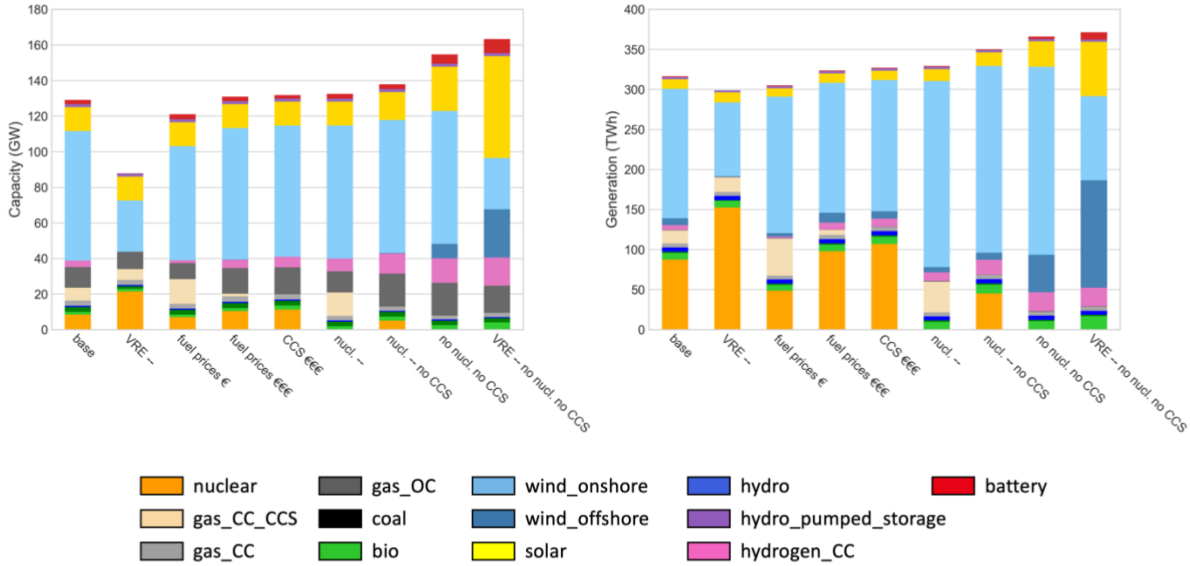

Figure 14. Installed capacity (top panel) and annual generation (bottom panel) for the fully decarbonized Polish power system in 2050 across a large subset of scenarios considered for the current study.

At a first glance of the Polish generation mix in 2050 for the full set of different scenarios, several scenarios were observed to exhibit similar decarbonized systems. This ultimately indicates that many of the sensitivities, i.e., parameter variations alone do not significantly impact the resulting Polish 2050 power system for 2050. To this set of scenarios belong the build rate sensitivities, 'wind fast' and 'nuclear slow', as well as 'coal slow phaseout' and 'status quo'.

Installed capacity and power generation by technology for 2050 for a subset of simulated scenarios, which form a good representation of the full scenario suite, are presented in Figure 14.

The scenarios relating to fossil fuels, '*CCS €€€*', '*no CCS*', '*fuel prices* ++' and '*fuel prices* --' scenarios impact the division of dispatchable capacity between gas and nuclear power. Intuitively, '*fuel prices* --', being optimistic on the evolution of commodity prices, triggers the expansion of more fossil-based power while the other scenarios limit their expansion and turns more to nuclear power as well as hydrogen gas turbines for dispatchable power. It is observed that the doubled cost for transport and storage of CO2 in the '*CCS €€€*' scenario has a significant impact leading to the negligible expansion of *gas_CC_CCS*.

The scenarios 'nucl. ++' and 'VRE --' bring about a comparable modification to the system, notably with a substantial increase in nuclear power, exceeding 20 GW of installed capacity. Compared to base, the primary difference is that nuclear replaces a fair share of onshore wind. Notably, these systems are the only ones not depending on dispatchable hydrogen gas power.

Scenarios that arguably do produce significantly different Polish decarbonised power systems include scenarios 'no nucl. no CCS', 'nucl. --', and 'nucl. -- no CCS'[119]. With more conservative assumptions on the cost of new nuclear, the power system comprises a lot of onshore wind combined with *gas_CC_CCS* in the 'nucl. --' scenario. The second most challenging scenario is the 'nucl. -- no CCS', where available dispatchable power is expensive and creates a nuclear plus renewables system. The 'no nucl. no CCS' scenario is the most technology restrictive and exhibits systems dominated by wind and solar. Combined-cycle hydrogen gas turbines play a significant role to provide dispatchable power at times of low generation of solar and wind. In the most conservative scenario, 'VRE -- no nucl. no CCS', as onshore wind is limited by land availability to a maximum installed capacity of 28 GW, this is the only scenario in which offshore wind takes a larger share of the generation mix.

Notably, open-cycle gas turbine power plants display a significant capacity of at least around 10 GW across all scenarios. Being light on the capital investment, the model prefers to build these highly dispatchable power plants to fulfil the capacity reserve margin requirement.

5.2 Path to decarbonization

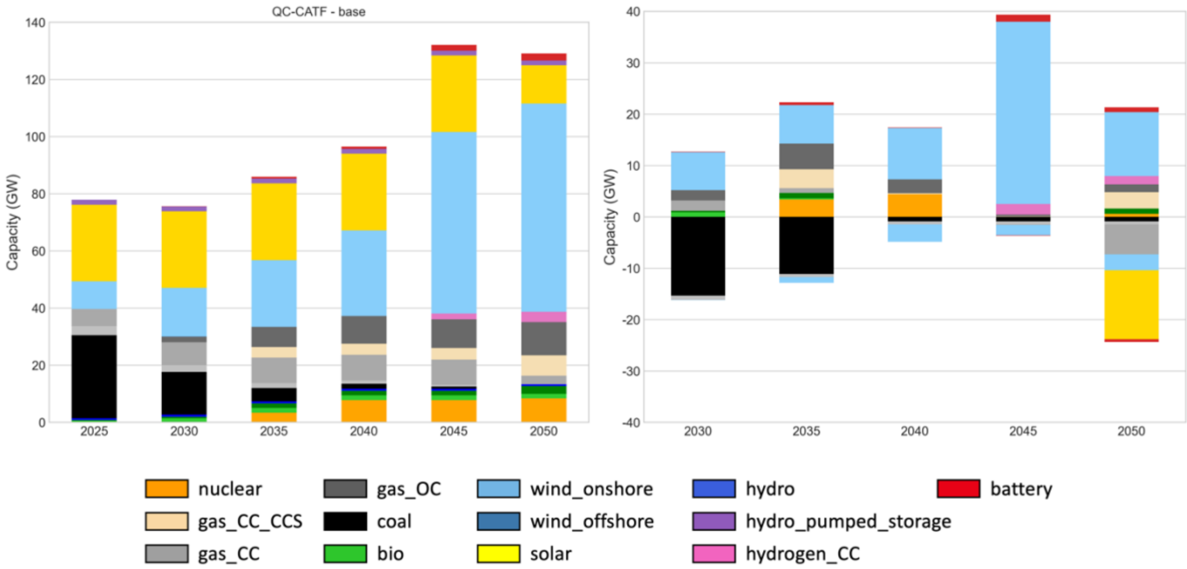

Figure 15. Top panel: Installed capacity for the Polish power system across the model horizon for the base scenario. Bottom panel: New (positive) and retired (negative) capacity of the Polish power system throughout the model horizon in the base scenario.

This section examines the trajectory of decarbonization in the Polish power system, extending from 2030 to 2050, as depicted in Figure 15 for the 'base' scenario.

A swift phase-out of coal is a common element across all scenarios, driven by its cost ineffectiveness compared to gas power plants (attributed to anticipated significant CO_2 prices) and other clean technologies. In scenarios devoid of capacity market revenues, coal would be phased out as early as 2030. Combined-cycle natural gas power plants with and without CCS along with open-cycle gas

[119] Scenario 'VRE ++', not shown in the figure, illustrates a power system with access to a lot of cheap wind and solar complemented with nuclear and CCS.

power replace coal's dispatchability in the short term, with the open-cycle gas turbine power plants playing a substantial role in the capacity reserve market.

Onshore wind takes the lead in clean power generation, following a growth trajectory aligned with its allowed build rate throughout the 2030s. It peaks at 7 GW/year from 2040 to 2045 and reaches an installed capacity of 73 GW by 2050, approaching its maximum expansion potential of 74 GW. Over the entire model time horizon, onshore wind maintains an average build rate of 3 GW/year, underscoring the considerable ramp-up needed in the wind power supply chain to sustain this transition—a notable increase from the observed 1.5 GW in Poland in 2022[120].

Nuclear power experiences significant growth in the 2030s reaching 8 GW of installed capacity, approaching its allowed expansion rate. This installed capacity corresponds to building approximately eight large conventional reactors (around 1 GW each) until 2040, in line with the current Polish energy policy[121]. This objective bears resemblance to the Barakah project in the UAE, which achieved around 5 GW in 10 years[122]. Notably, this marks a significant undertaking for a country with no prior experience in nuclear construction. With a modelled lifetime of 60 years, no nuclear capacity is retired within the model horizon.

The short-term solar projections lie behind a 27 GW installed capacity, representing a significant portion of the Polish power system's overall capacity by 2030. However, the model does not perceive further expansion of solar capacity as economically viable and the solar capacity starts to be phased out around 2050. Similarly, offshore wind does not emerge as competitive.

As "net-zero" is approached between 2045 and 2050, the model necessitates the removal of most unabated gas power plants. The combination of gas power plants equipped with CCS at a capacity of 7.2 GW and hydrogen gas turbine power plants with a capacity of 3.7 GW take the role of dispatchable power capacity in the Polish power system.

A possible extension to 2070 could provide additional insights into the retirement and replacement of solar and wind power, revealing evolving cost dynamics among different technologies.

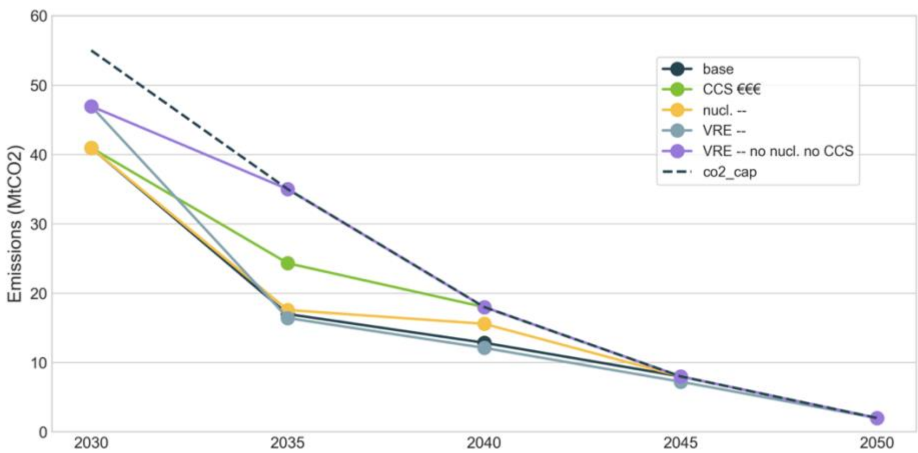

Figure 16. Annual emissions for the typical Polish power system from the GenX simulations for a typical weather year and for a subset of scenarios.

[120] Wind Europe (2023), 2022 Statistics and the outlook for 2023-2027.
[121] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.
[122] WNA (2023), Nuclear Power in the United Arab Emirates.

An alternative perspective on the trajectory toward a decarbonized Polish power system is evident in the resulting direct emissions, as illustrated in Figure 16 for select scenarios with distinct power system characteristics, introduced in Section 4.1. With the exception of the scenario 'VRE -- no nucl. no CCS', these scenarios achieve a reduction to 20 Mt, purely driven by a floor CO_2 price of 122 €/tCO_2[123]. Achieving "full decarbonization", defined as meeting a maximum of 2 Mt annual direct emissions for the Polish power system in 2050, generally necessitates a CO_2 price of approximately 230 €/tCO_2. Systems with a substantial share of nuclear power, such as 'VRE --' and 'nucl. ++' manage with CO_2 prices not exceeding 200 €/tCO_2, while the more challenging 'VRE -- no nucl. no CCS' scenario requires a CO_2 price exceeding 600 €/tCO_2.

[123] Further simulations showed that a floor CO_2 price of 100 €/tCO_2 also achieved the reduction to 20 Mt.

5.3 Comparison with other studies

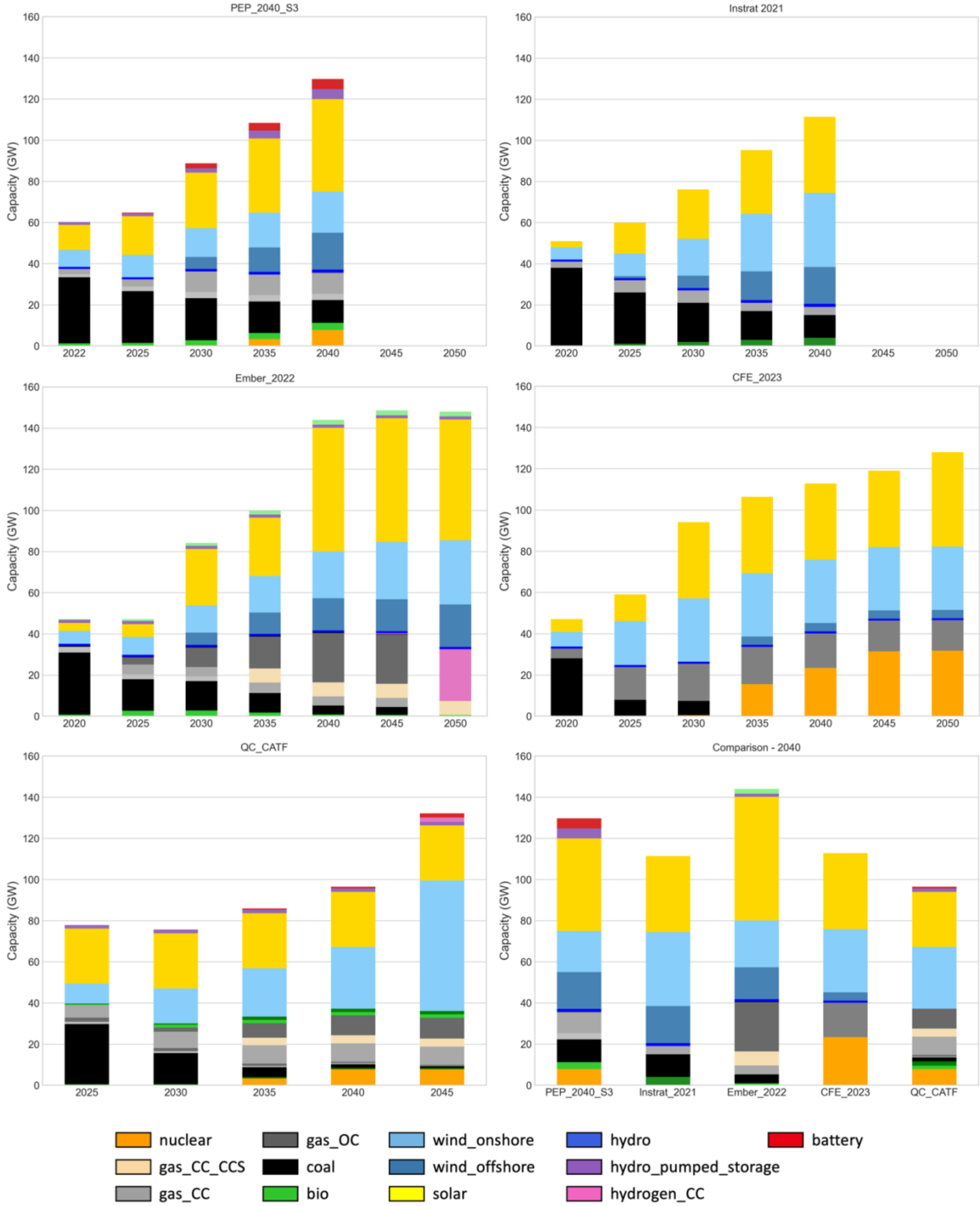

Figure 17. Comparison capacity expansion between power system studies.

To fully appreciate the results from this study it is relevant to discuss them in relation to the results from other studies publicly available. Figure 17 presents a comparison of the current study, denoted QC_CATF, with a set of relevant studies, some of which were introduced in Section 2.3:

- Current energy policy[124], denoted 'PEP_2040_S3'
- Instrat's central scenario[125], denoted 'Instrat_2021'
- Ember and the 'Technology Driven' scenario[126], denoted 'Ember_2022'
- Carbon-Free Europe and the 'Core' scenario[127], denoted 'CFE_2023'.

The pace of coal phase-out varies among the studies, with CFE_2023 achieving the fastest transition, while QC_CATF and Ember_2022 show alignment. Instrat_2021 follows with PEP_2040_S3 exhibiting the slowest pace. Notably, Instrat_2021 employs a modest CO2 price of 72 €/tCO2 and PEP_2040_S3 adopts an aggressive CO2 price of 250 €/tCO2 for 204. This contrasts with the floor price of 122 €/tCO2 and 108 €/tCO2 applied in QC_CATF and CFE_2023, respectively.

Short-term natural gas expansion is evident in all studies except for Instrat_2021, with open-cycle gas turbines dominating in both QC_CATF and Ember_2022 with an installed capacity in 2040 of 10 GW and 24 GW, respectively.

Until 2040, the combined capacity of onshore and offshore wind is relatively consistent across the studies. However, beyond 2040, there is a significant divergence, with onshore wind exhibiting the most substantial expansion in QC_CATF. Offshore wind plays a substantial role in PEP_2040_S3, Instrat_2021, and Ember_2022, while being less prominent in QC_CATF and CFE_2023.

Merely in QC_CATF, solar PV expansion stagnates post-2030. This could indicate more optimistic cost projections for solar relative to other technologies in other studies.

Nuclear power plays a significant role in PEP_2040_S3, CFE_2023, and QC-CATF, whereas it is either absent or modest in Instrat_2021 and Ember_2022. There are variations in total dispatchable capacity (including coal, gas, hydro pumped storage, biobased technologies, and nuclear) in 2040 between the studies:

- ~37 GW in QC_CATF
- ~37 GW in PEP_2040_S3
- ~20 GW in Instrat_2021
- ~40 GW in Ember
- ~40 GW in CFE_2023.

The dispatchable capacity combined with demand-side flexibility should give some indication on the capacity reserve. However, it is challenging to compare across studies due to variations in assumptions regarding total demand, demand profiles, and demand-side flexibility. For instance, the differences in total demand, as illustrated in Figure 4, complicate direct comparisons. It is worth noting that properties of demand-side flexibility in the current study, is shown in Figure 5, while Ember_2022 includes a demand-side response fleet of 2.9 GW. Additionally, to the best of the author's current knowledge, capacity reserve was not integrated into the modelling for Ember_2022, CFE_2023, or Instrat_2021. However, it is expected to be part of future Instrat studies[128].

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[124] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.
[125] Instrat (2021), Achieving the goal. Coal phase-out in the Polish power sector.
[126] Ember (2022), New Generation - Building a clean European electricity system by 2035.
[127] Carbon-Free Europe (2023), Annual Decarbonization Perspective 2023.
[128] Instrat (2023), Modelling the Polish energy system – new findings of PyPSA-PL.

5.4 Weather-year expansion in cGrid

In Figure 18 (left) we show an example of the weather-year expansion for the capacity of the resource *gas_CC_CCS* in the 'base' scenario. The corresponding average prices based on the weather-year expansion is shown in Figure 18 (right). In the first model year, 2030, the technology is not yet allowed in the expansion and hence the resulting capacity is zero. In the following model year, 2035, the technology is allowed and the resulting capacity from the expansion is now between 2.5 and 5 GW with a mean value of almost 4 GW. The mean value in 2035 is then used a second time for all weather years to find the resulting price level. Next, the mean value from 2035 is used as a starting value for the expansion in 2040. In this step a resource is not retired as long as it can recover its operational costs. The mean value from the previous model year then typically becomes the lowest value possible in the following expansion. In this example, only two weather years see an expansion beyond the previous capacity, and the mean value of the capacity is barely changed. This is repeated also for the expansion in model year 2045. However, in the final expansion step for model year 2050, we again observe a significant expansion of the resource's capacity reaching between 5 and 11 GW; the mean capacity is 7 GW.

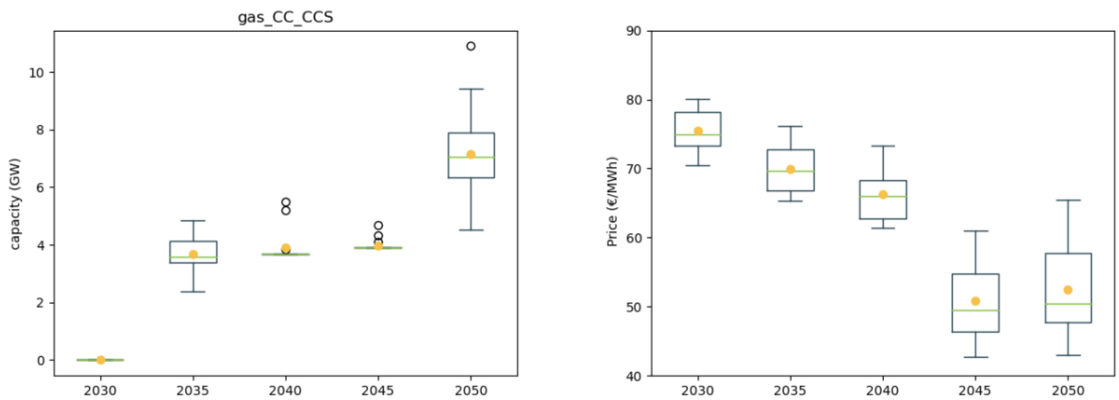

Figure 18. Left panel: An example of the weather-year expansion for the capacity of the resource gas_CC_CCS in the 'base' scenario. Right panel: average electricity prices based on the weather-year expansion. Both are shown as a function of model year.

In Figure 19 the resulting minimum capacity reserve margin as a percentage of simulated day ahead load is shown for the full set of weather years in the 'base' scenario. For each expansion step a requirement is set at 9% margin. This margin is maintained by introducing a capacity reserve revenue for all dispatchable resources, which is weighted relative to their available capacity at the hour with the lowest margin. This revenue is included in both the GenX initial optimisation step as well as in the cGrid optimization step for each weather year.

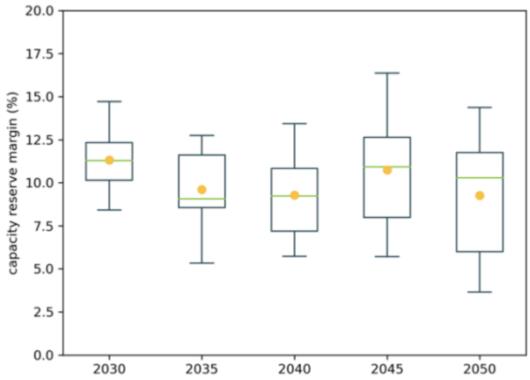

Figure 19. Resulting capacity reserve margin in percentage to day-ahead load for the base scenario. The boxplots cover the range of outcomes for the full set of weather years with boxes representing the 25% to 75% quartiles. Median values are shown with green lines and mean values with yellow dots.

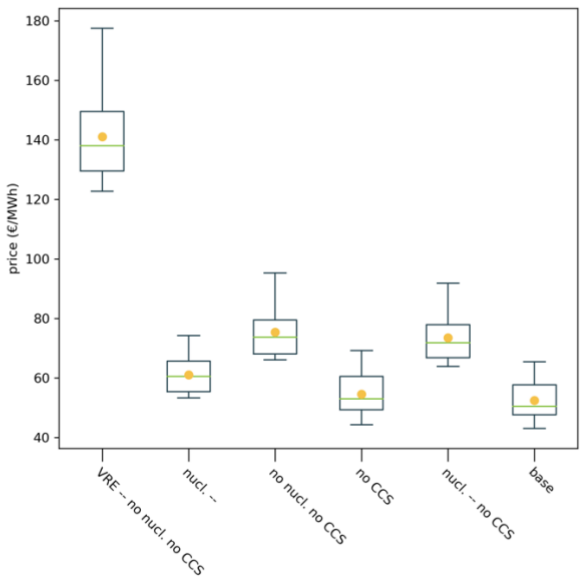

Figure 20. Average electricity prices for a selection of the different scenarios. The boxplots cover the range of outcomes for the full set of weather years with boxes representing the 25% to 75% quartiles. Median values are shown with green lines and mean values with yellow dots.

The resulting electricity prices for model year 2050 for a selection of the scenarios are shown in Figure 20. The mean price for the 'base' scenario is €53. For the scenarios where one technology is assumed to have a pessimistic outlook, 'CCS €€€' and 'nucl. --', the prices are slightly higher at €55 and €60, respectively. The scenarios assuming pessimistic outlooks for several technologies, 'nucl. -- no CCS' and 'no nucl. no CCS', have still higher average prices at €74 and €75, respectively. Finally, in the all-out pessimistic scenario, 'VRE -- no nucl. no CCS', prices however increase to €141 on average.

It should be noted that these prices do not include the costs to maintain the capacity reserve margin, which amounts to about €5/MWh if the cost is spread out over the total generation for the year. Compared to the historical variation in electricity prices, the spread seen in figure X for different weather years is rather low. The reason for this result is the capacity reserve margin, guaranteeing that there is always free dispatchable capacity available to meet demand, and thereby avoiding costly periods of power deficits.

5.5 Dispatch time series

In this section we demonstrate examples of dispatch time series. Starting in Figure 21, a period during winter is shown for the 'no nucl. no CCS' scenario for model year 2050 and weather year 1994. This example highlights two periods, each lasting about a week, where wind power generation remains weak throughout the entire system. The first such period starts around hour 875 and the second around hour 1125. The zones in the model manage this differently. In the Nordic regions where hydro power is dominating, this is mainly handled by running hydro at a sustained high level. In SE4 and DK, and to some extent also in SE3, import becomes the most important part. The remaining zones manage these periods using a combination of dispatchable resources, such as nuclear and gas turbines.

In addition, the model has included hydrogen combined cycle turbines in Poland, which contribute to the generation during the first constrained period, starting around hour 875. Part of this generation were also exported to neighboring zones. The hydrogen turbines were however not used during the second constrained period starting around hour 1125, during which Poland to a larger degree relied on imports instead.

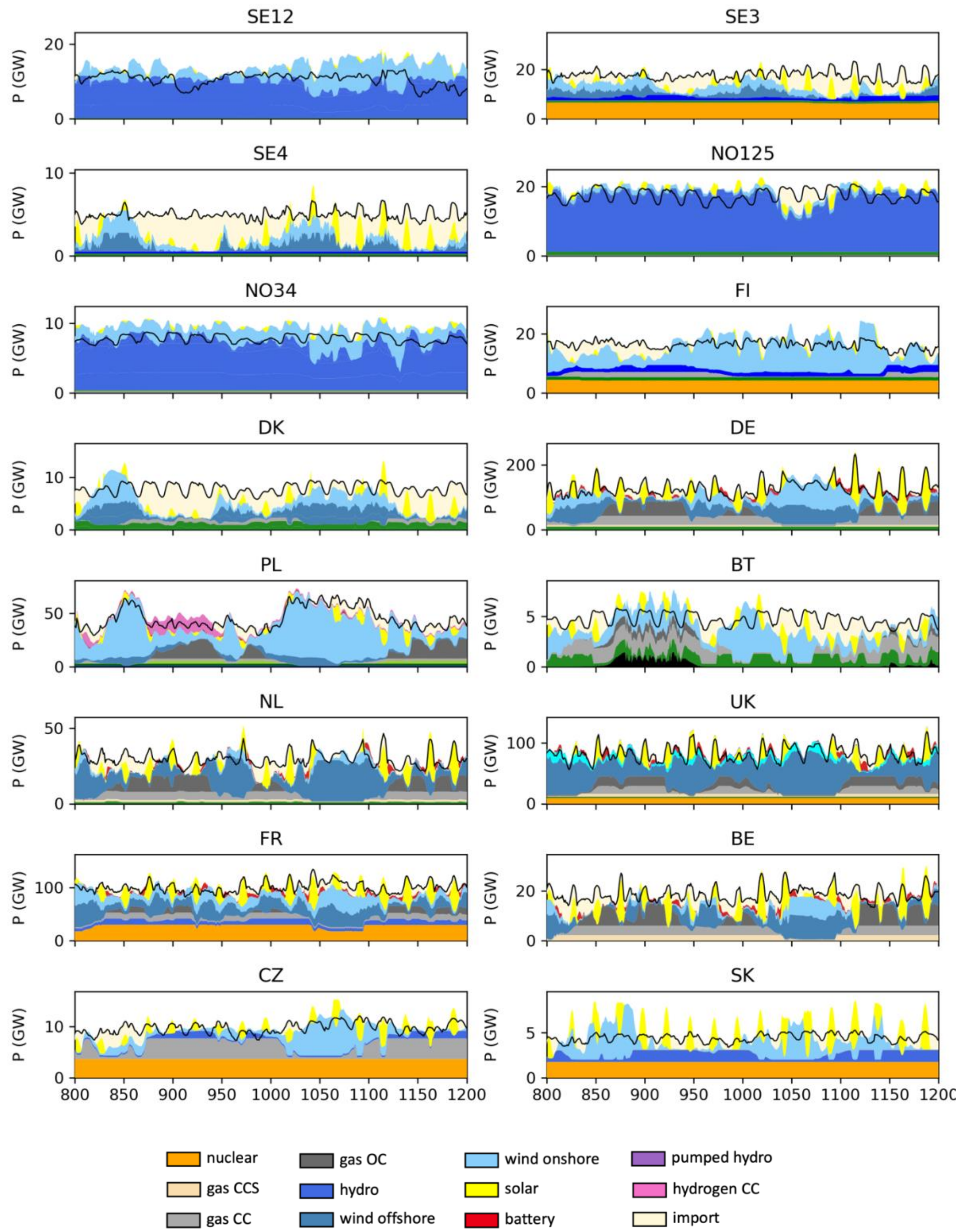

Figure 21. Example of dispatch time series for all modelled zones. The scenario is 'no nucl. no CCS' at model year 2050 and weather year 1994 and depicts a winter period with two week-long periods of constrained supply through the system.

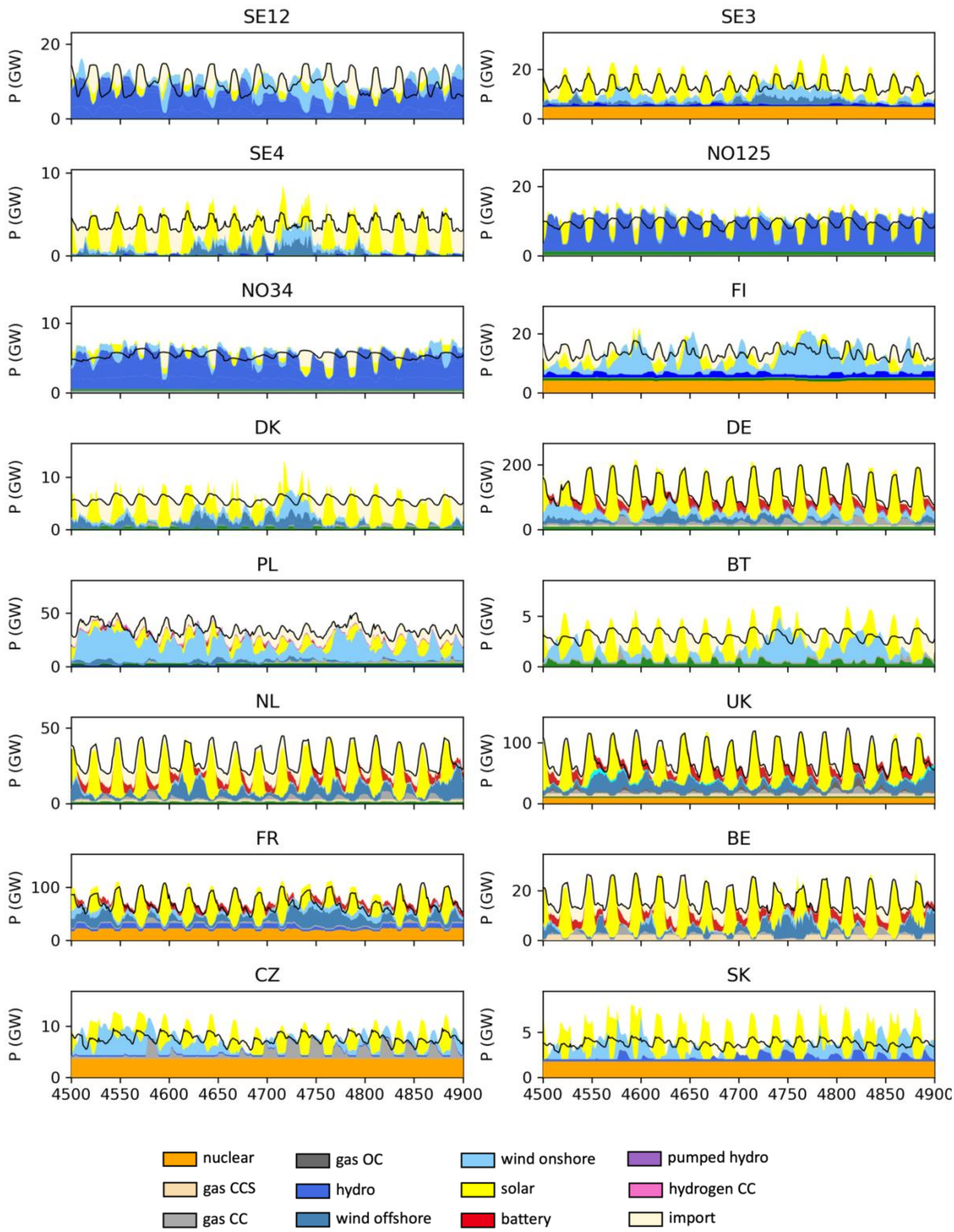

Figure 22. Example of dispatch time series for all modelled zones. The scenario is 'no nucl. no_CCS' for model year 2050 and weather year 1994 and depicts a summer period.

In Figure 22, similar plots are shown for the entire modelled region, but during a summer period. Here we can see that for the model year 2050, the system is to a large degree served by solar and batteries. The charging of batteries during daytime can be seen as narrow peaks coinciding with the solar production and the discharging of batteries during the periods in between. In the Nordic zones, the balancing of solar is primarily made using hydro power.

In Figure 23 we show a close-up view of the Polish dispatch for the first wind constrained period starting around hour 875 for the scenarios base (left) and 'no nucl. no CCS' (right). Here we see the different roles played by the dispatchable technologies, where the hydrogen storage plays a much bigger role in the 'no nucl. no CCS' scenario. We also see the total demand peaking more than 10 GW higher in the 'no nucl. no CCS' scenario, reflecting the increased need to recharge the hydrogen storage during the periods with high wind.

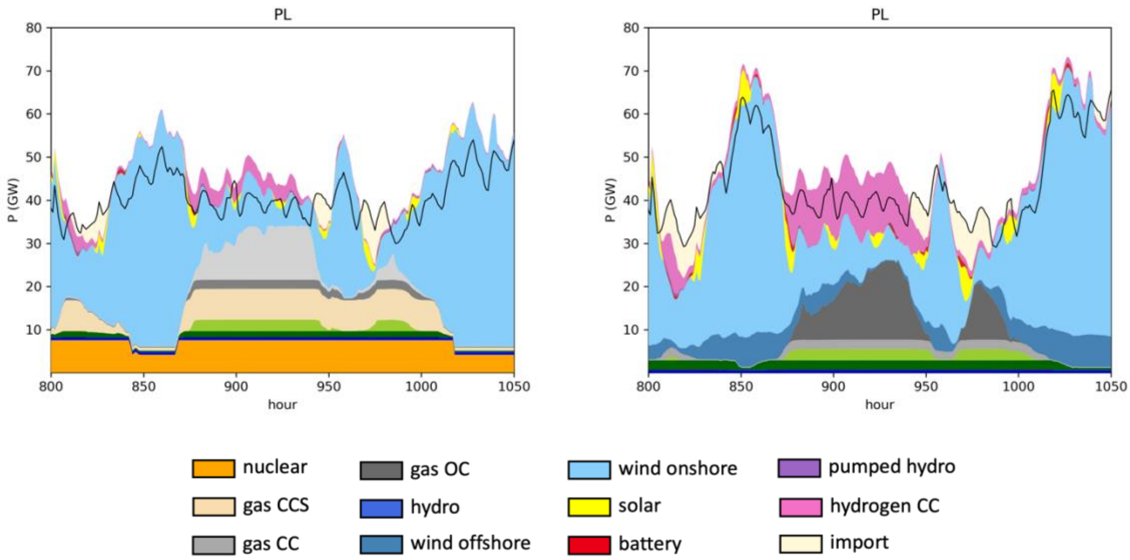

Figure 23. Close up of dispatch in Poland for a period during winter in the base scenario (left) and the no nucl. no CCS scenario (right). Model year is 2050 and weather year is 1994.

Finally, in Figure 24, the evolution of the hydrogen storage level for the same two scenarios during weather year 1994 are shown. The effect of the wind constrained period starting at hour 875 discussed above can clearly be seen as a sharp drop in the storage level.

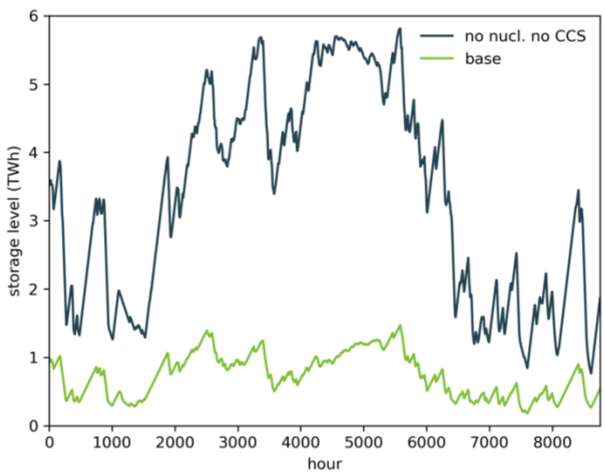

Figure 24. Example of hydrogen storage level in PL for the base and 'no nucl. no CCS' scenarios. Model year is 2050 and weather year is 1994.

5.6 System costs

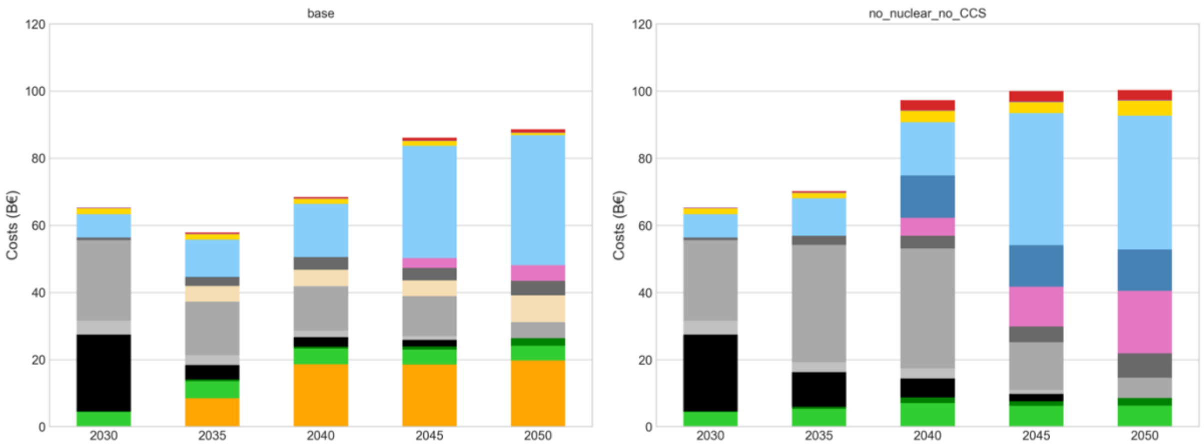

Figure 25. Total system costs as a function of model year for the base (left panel) and 'no nucl. no CCS' (right panel) scenarios split by technology.

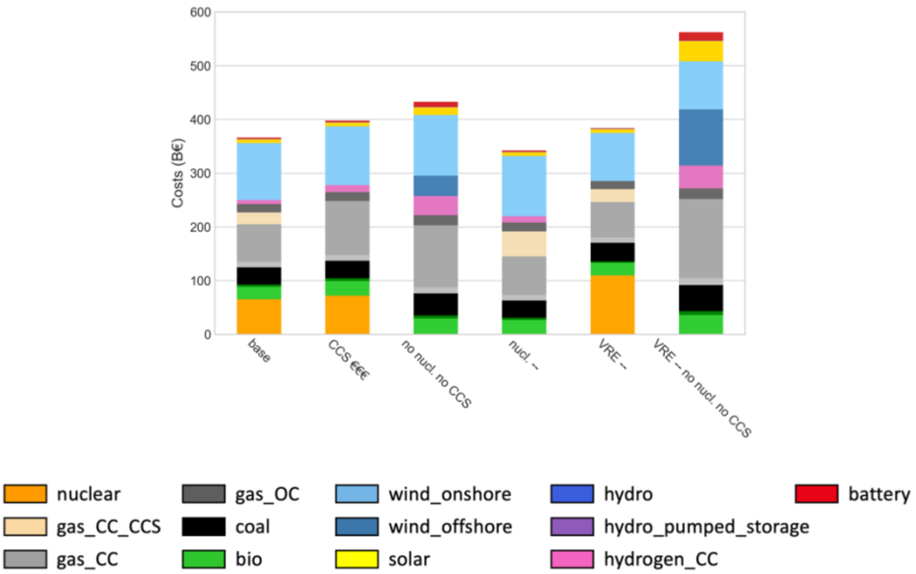

Figure 26. Total cumulative system costs for 2030 to 2050 and main scenarios split by technology.

In Figure 25 the total system cost divided by resource technology and separated by model year is shown for the base scenario (left) and 'no nucl. no CCS' scenario (right). System costs have been calculated summing yearly CAPEX, OM costs and fuel costs for each resource. We see that during the initial phase, all costs are dominated by the existing fossil fuel system, mainly consisting of fuel costs and CO2 emissions prices. By the end of the studied period, CAPEX costs of nuclear and wind are dominating for the base scenario, while for the 'no nucl. no CCS' scenario CAPEX for wind and hydrogen storage dominates.

In Figure 26, the total cumulative system costs for all years are shown for different scenarios divided by technology type. Overall, these cumulative costs follow the same trends as the simulated electricity spot prices shown in Figure 20. However, there is one notable exception, the 'nucl. --' scenario, which shows costs lower than that of the 'base' scenario. At first this might seem counter intuitive, but the reason can be traced to an increased reliance on trade with neighbouring regions. Compared with the base scenario, the optimizer expands gas powered generation, with relatively low CAPEX costs, to compensate for the lack of nuclear capacity. However, without the low marginal cost firm capacity in nuclear, Poland becomes price coupled with its neighbouring regions to a larger extent, and also relies more on imports. This in turn increases the prices seen in Poland compared to the 'base' scenario.

5.7 Transmission infrastructure

5.7.1 Power transmission

The transmission system development requirements are based on the following assumptions:

- The spatial distribution of the demand does not change significantly in the year 2050 compared to 2020;
- Retrofitting and investment in new generation units (mostly dispatchable) utilizes the existing sites (*brown field*) as these can utilize the existing transmission capacity;
- New manufacturing facilities will be in special *energy zones*[129] in proximity to supply sources for the existing ones there is a strong incentive to invest in[130] or own renewables-based power supply and implement a direct connecting power line – this solution is also supported by the current regulations and governmental plans.
- Due to uniform solar and wind conditions in Poland firstly solar-wind *cable pooling*[131] is a favoured option followed by the development of individual parks close to existing transmission lines;
- Following the current trends ~60%[132] of the future installed capacity in PV systems is deployed as rooftop small-scale systems, followed by utility-scale PV systems coupled with wind generation;
- As on 11.2023 the existing grid capacity connects 33 GW of installed coal generation, followed by 4.6 GW in gas, 2.7 GW in hydropower and ~25 GW in combined solar and wind generation;
- Innovative and emerging solutions such as use of existing railway infrastructure as a part of the distribution/transmission network[133] is not accounted for.
- As offshore wind is concentrated in northern Poland it was assumed that a transmission corridor is mandatory to efficiently utilize the available energy. The length of transmission line was estimated to be 500 km capable of connecting north and south Poland. It is estimated that only in the Pomeranian province the TSO will have to invest in 250 km[134] (400 kV) of transmission capacity for the planned 8.4 GW of first offshore wind parks. According to the governmental plans[135] once the nuclear power plant will be built in this region a further grid reinforcement through HVDC[136] (700 km – 4 GW) cable will be needed to further support the north-south power transmission.

[129] https://www.pse.pl/-/powstana-specjalne-strefy-energetyczne-skorzystaja-inwestorzy-oraz-system-elektroenergetyczny?safeargs=696e686572697452656469726563743d74727565

[130] https://www.gov.pl/web/rozwoj-technologia/linie-bezposrednie-prostsze-i-tansze-korzystanie-z-oze

[131] https://orka.sejm.gov.pl/proc9.nsf/ustawy/3279_u.htm

[132] https://ieo.pl/en/39-o-instytucie/1613-rynek-fotowoltaiki-w-polsce-2023

[133] https://cordis.europa.eu/article/id/442777-smart-electricity-exchange-and-synergies-between-the-grid-and-railways

[134] https://www.cire.pl/artykuly/materialy-problemowe/instalacja-kabli-wewnetrznych-i-wyprowadzenie-mocy-z-mfw-morskich-farm-wiatrowych

[135] https://www.rynekinfrastruktury.pl/wiadomosci/biznes-i-przemysl/offshore-jest-decyzja-lokalizacyjna-dla-nowej-linii-najwyzszego-napiecia-88218.html

[136] https://wysokienapiecie.pl/67636-autostrada-energetyczna-polnoc-poludnie-polski-za-10-lat/

Note that system costs associated with necessary grid reinforcement for high-voltage transmission lines for onshore wind and solar PV have been included as part of the investment costs in the model. The calculations assumed that the model would first build the solar and wind parks located in the locations yielding the highest capacity factor while simultaneously in proximity to the transmission lines. The average distance between the potential location for the solar/wind park in Poland to the transmission line was found to be 5 kilometres. This value was subsequently used to increase the overnight costs as shown in Figure 28.

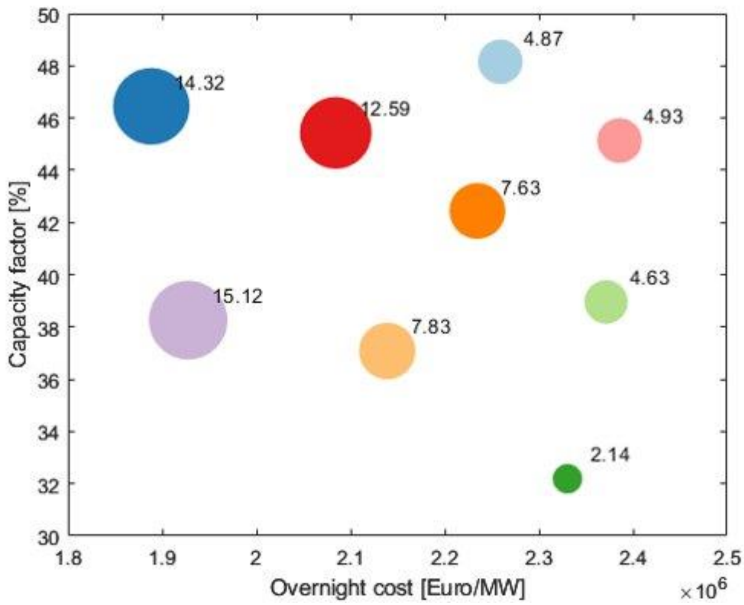

Figure 27. Total wind parks capacity (dots in GW) clustered into nine categories depending on their overnight cost (driven primarily by distance to transmission line and park size) and capacity factor (determined based on Global Wind Energy Atlas).

The results concerning the projected additional transmission capacity are visualized in Figure 28 and are clearly driven by the required total capacity of renewable generation (solar and wind) and in particular offshore wind. Higher LCOE of offshore wind connected with additional costs associated with required development of transmission infrastructure has a significant impact on the end results. On the other hand, the above-mentioned HVDC lines needed for the installation of the offshore wind parks have been disregarded in the capacity expansion optimization.

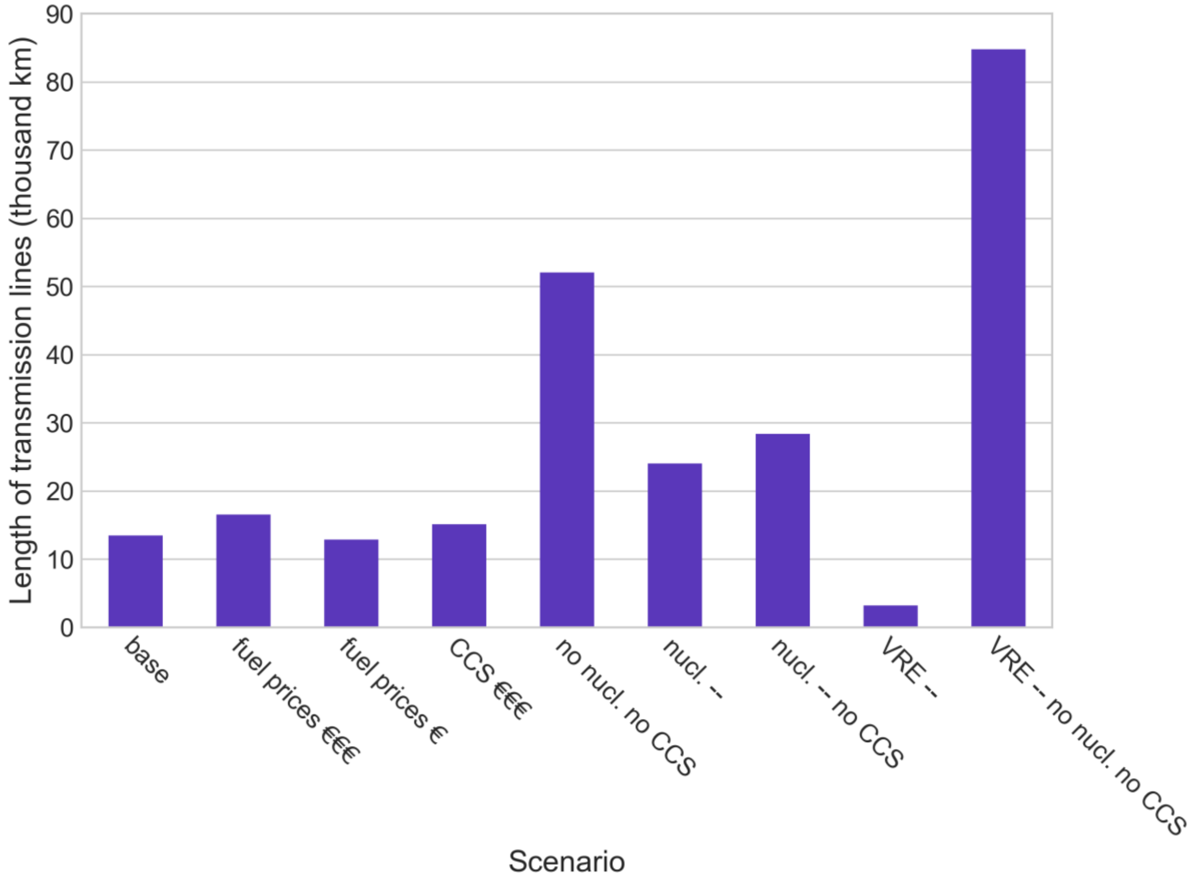

Figure 28. Estimated transmission capacity required development considering all scenarios.

5.7.2 Hydrogen infrastructure

Resulting hydrogen energy storage capacity from the power system optimisation, i.e., expansion needed for production and storage of hydrogen for the purpose of regeneration of electricity through combined-cycle hydrogen gas turbine power plants, is shown in Figure 29. Across the scenarios the largest required installed capacity in hydrogen CC storage is observed for the scenario 'VRE – no nucl. no CCS' where 15 GW is exceeded and hydrogen storage capacity of almost 8 TWh is required.

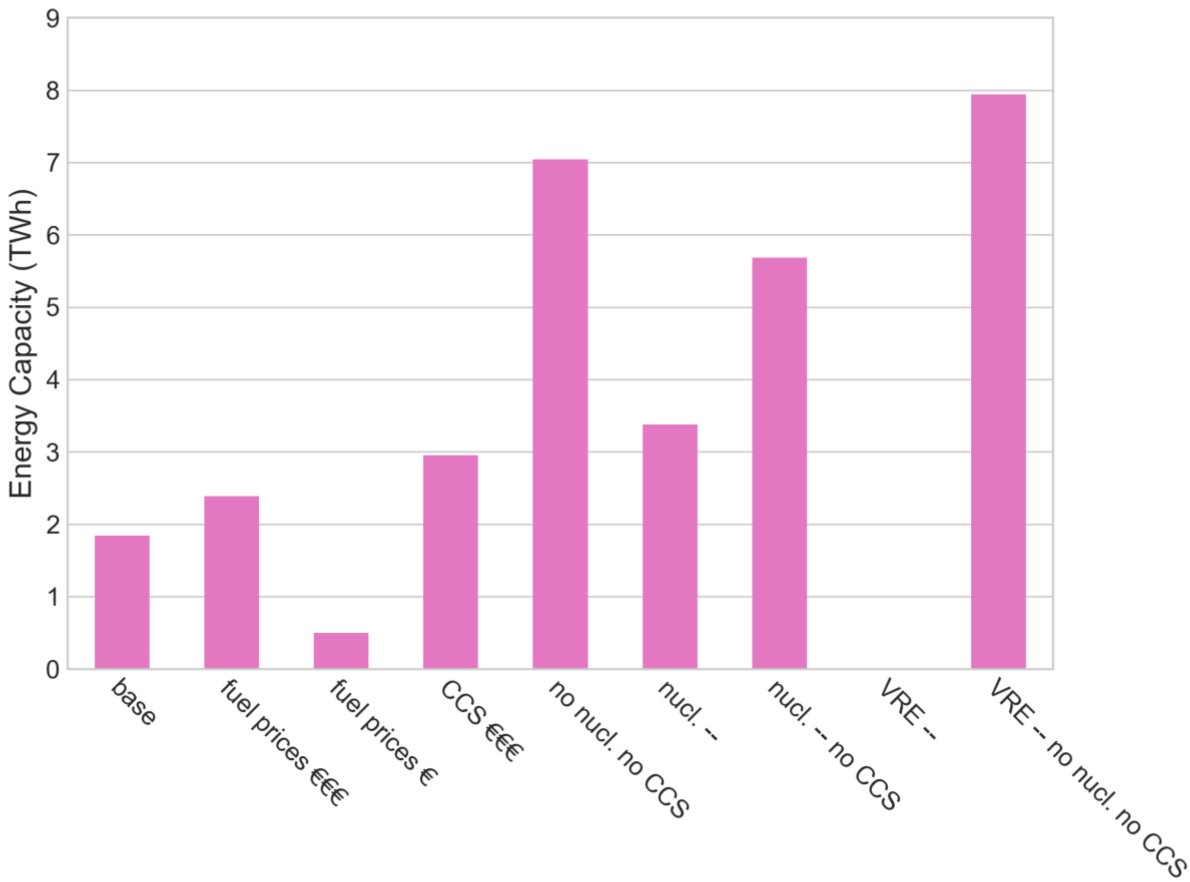

Figure 29. Installed hydrogen storage infrastructure in 2050 for the Polish power system and main scenarios.

The hydrogen power stations may be realised from brownfield investments or directly replacing existing gas power stations, i.e. a site repurposing. This to an extent enables them to exploit the existing transmission infrastructure if such will be modernized to transport hydrogen. Apart from hydrogen peaking power stations it is likely that the development of the hydrogen infrastructure will be mostly driven by large infrastructure projects (e.g., steel industry, fertilizers) of which optimal location within the Polish power system is outside the scope of this study. Note that hydrogen pipeline infrastructure has neither been included in the optimization nor the total system costs.

5.7.3 CO2 infrastructure

The model incorporates merely *gas_CC_CCS* relying on infrastructure for transmission and storage of CO2. Largest CCS utilization is observed in cases where nuclear expansion is limited, and often it is present already in 2035. The final installed capacity varies from 4 GW in the base scenario to 14 GW maximum. In terms of carbon captured, which is shown in Figure, the base scenario requires about 9 Mt CO2 captured per year, which in addition can vary with weather year ±10%. The 'nucl. --' scenario reaches the highest annual injection rate, approaching 20 Mt CO2 per year in 2050. Note that CO2 pipeline and storage infrastructure has been included as a variable cost to the Polish power system.

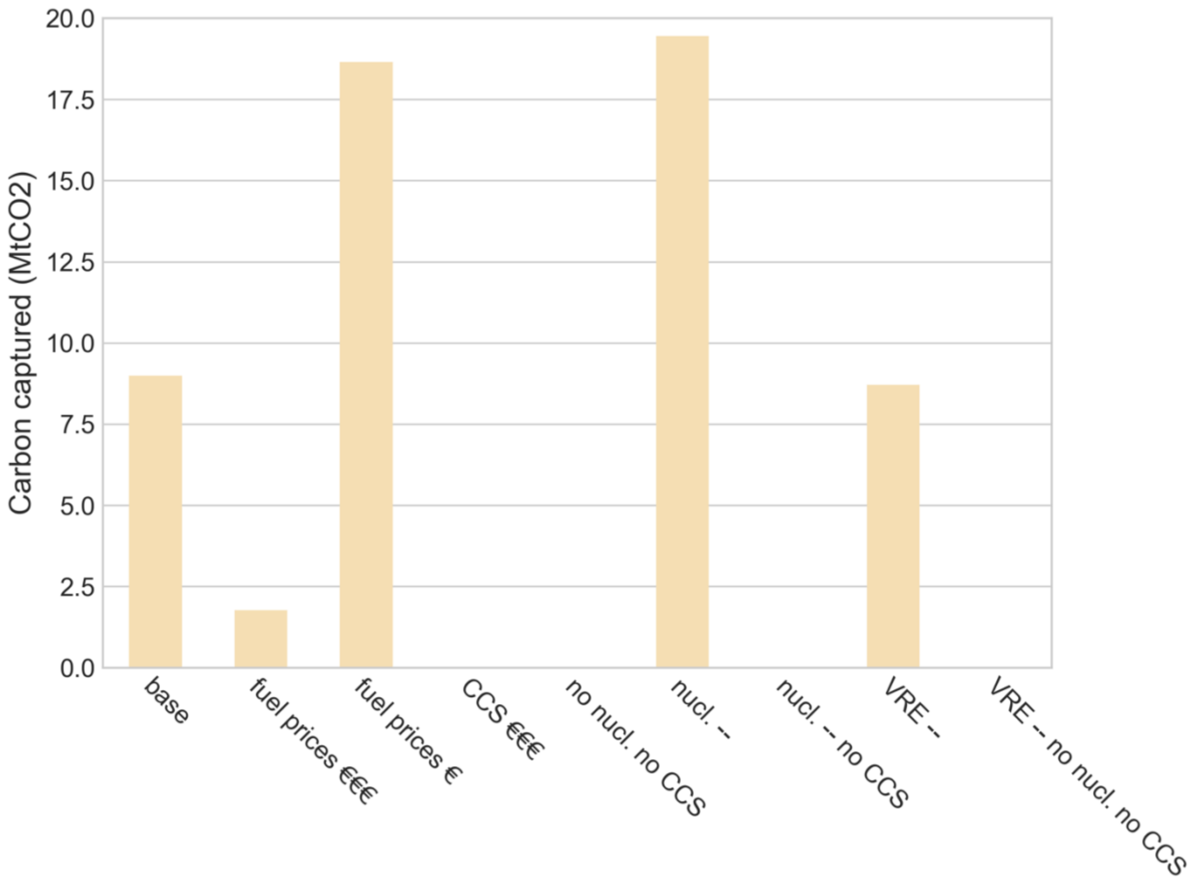

Figure 30. Annual CO_2 injection rate for the Polish power system in 2050 and main scenarios.

5.8 Retrofitting

The investigation into the value of retrofitting considered three distinct scenarios. In the first scenario, labelled 'CCS retro', retrofitting of coal and combined-cycle natural gas power plants with CCS was explored. The second and third scenarios, denoted 'nucl. retro' and 'nucl. -- no CCS nucl. retro', focused on coal to nuclear retrofitting within the base scenario and a scenario where greenfield nuclear faced challenges, such as unsuccessful projects and the absence of CCS infrastructure. A comparison of these retrofit scenarios with their counterparts, without retrofitting, is detailed in Table 16, showcasing the total installed capacity of nuclear and *gas_CC_CCS* in 2050.

Table 16. Total installed capacity (GW) for nuclear and gas_CC_CCS in the 'base' and 'nucl. -- no CCS' scenario in 2050 compared to retrofit scenarios.

	base	CCS retro	nucl. retro	nucl. -- no CCS	nucl. -- no CCS nucl. retro
nuclear	8.4	5.9	9.6	5.0	9.5
gas_CC_CCS	7.2	14.3	6.2	-	-

A noteworthy finding was that the model did not deem retrofitting of coal as cost-effective. Retrofitting of gas CC with CCS was observed in small amounts in 2045 but significantly increased in 2050. As CCS retrofitting was allowed, the model built less nuclear and more natural gas power compared to the 'base' scenario in 2050. However, by the 2070 end-point, installed nuclear capacity was identical to the 'base' scenario. This showcases the value of CCS retrofitting, facilitating in the transition toward a decarbonized power system.

For coal to nuclear retrofitting, the model capitalized on the reduced investment cost for brownfield nuclear, resulting in an additional 2 GW of nuclear capacity compared to the base scenario. In scenarios with conservative development of new nuclear and no CCS, a 6 GW increase in installed nuclear capacity was achieved until 2050. Furthermore, the model leveraged the heightened build rate of nuclear in the 2030s, as defined in the retrofit scenario, consequently limiting the construction of new gas power capacity to a greater extent. Coal to nuclear retrofitting offers more advantages than solely lower investment costs, encompassing factors such as siting, permits, grid connections, and worker retention, among others. Therefore, these results may not fully capture the comprehensive value of retrofitting, emphasizing its specific role in speeding up decarbonization by preventing emissions from coal power.

6 Summary

This study delves into various pathways aimed at achieving a decarbonized Polish power system by the year 2050 defined by a 99% reduction of power system emissions compared to level in 1990. Using a meticulously crafted set of scenarios, e.g., including custom GIS analysis for wind and solar expansion potential, the analysis highlights variations in projections pertaining to technology-relevant developments. These scenarios consider both optimistic and conservative perspectives on factors such as investment and operational costs, commodity prices, maximum expansion potential, and build rates.

The study employs a dedicated multi-year capacity expansion optimization framework with first stop in 2030 and then with five-year increments until 2050. The methodology emphasizes a robust integration of investment and dispatch optimization. Notably, the method bases the expansion off a comprehensive set of 35 historical weather years. This approach is crucial for not only constructing reliable power systems but also obtaining realistic dispatch schedules and electricity prices. Ultimately, the current study aims to lay the groundwork for determining the most sustainable and competitive type of power system to guide the future of the Polish power landscape.

The results underscore a swift and comprehensive phase-out of economically burdensome coal power by 2035. This is a primary aspect diverging from the current trajectory of Polish energy policy[137] suggesting a comparatively gradual phase-out. Otherwise, the decarbonization efforts in the 2030s are primarily steered by fossil-free onshore wind, complemented by a modest share of offshore wind. Simultaneously, new nuclear power steadily comes online, contributing firm capacity to the evolving power mix. Notably, the repurposing and partial repowering of coal power plant sites with nuclear power stand out as a potentially pivotal opportunity. This initiative holds the promise of not only facilitating the rapid deployment of new and more competitive nuclear power but also concurrently phasing out and replacing coal. It leverages the repurposing of existing sites and infrastructure, while retaining the skilled workforce from the coal plants.

To compensate for the decommissioning of coal plants, a combination of cost-effective natural gas power plants, open- and combined-cycle gas turbines, and facilities equipped with carbon capture and storage (CCS) are required to fulfil the systems' needs for dispatchable power. As stricter CO_2 emission constraints come into play, unabated gas power plants gradually retire, making way for firm nuclear capacity and dispatchable combined-cycle hydrogen power plants.

[137] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.

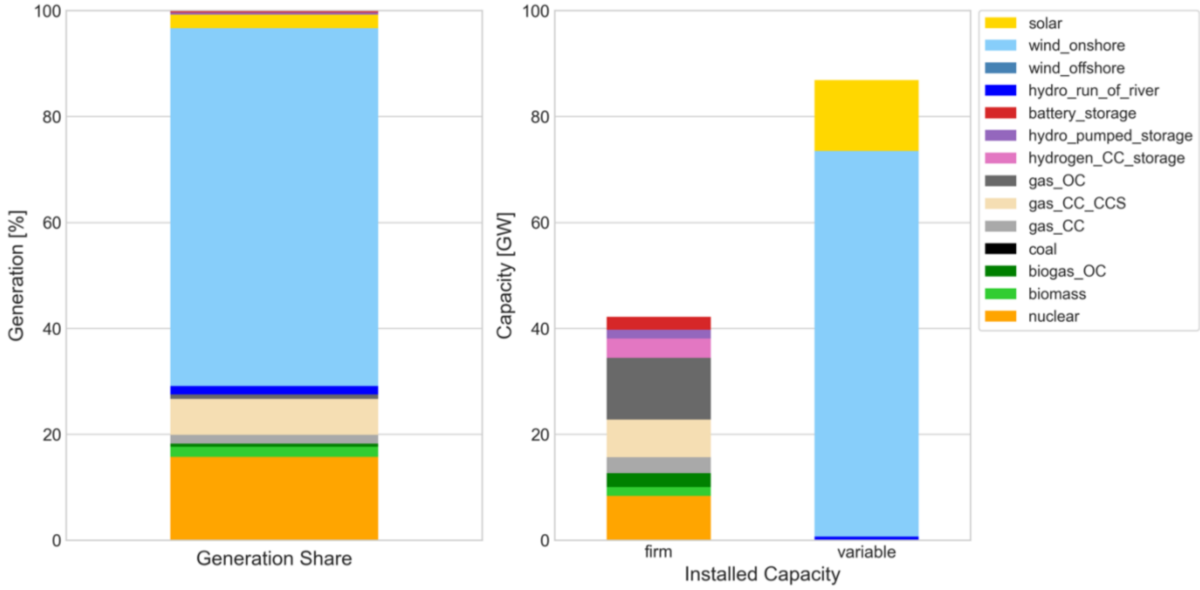

Figure 31. Generation share (left panel) and capacity mix (right panel), split with respect to firm and variable type, of the decarbonized Polish power system in 2050 in the base scenario.

The base scenario, rooted in a technology-neutral perspective and based on best-estimate input assumptions, outlines the blueprint for a decarbonized 2050 power system, as illustrated in Figure 31. The backbone of this system is onshore wind, emerging as the most cost-effective source of low-carbon generation in the Polish energy transformation. With an installed capacity of approximately 70 GW, a significant increase from the current 10 GW, onshore wind covers over half of the annual generation. This expansion is notable for its peak build rate, surpassing 7 GW/year in the early 2040s, and a sustained long-term build rate of about 3 GW/year. Offshore wind and solar, while present, play more modest roles.

Nuclear power, showing an installed capacity of around 8 GW, assumes a significant role, contributing over 15% of the annual Polish power production. This is complemented primarily by gas power plants, featuring open-cycle configurations fuelled by natural gas (~10 GW) and biogas (~3 GW). The model builds these relatively low-investment cost plants due to their high dispatchability required to ensure a stable power system also in situations of deficits or faults as required by the capacity reserve margin. Additionally, combined-cycle natural gas plants, without (~3 GW) and with (~7 GW) carbon capture and storage (CCS), further diversify the energy mix. Complementing the substantial onshore wind generation in the system, hydrogen-fuelled plants reach a capacity of close to 4 GW coupled to a hydrogen energy storage capacity of ~2 TWh. Finally, pumped hydro and battery storage are integrated into the system. Collectively, firm and dispatchable capacity approaches 40 GW, a figure relevant to compare to current energy policy[138] and other studies in further research.

The base scenario anticipates significant advancements across all technologies. Notably for renewables, this involves a sustained cost reduction until 2050 and a regulatory-based upper limit on onshore wind expansion, capped at 74 GW in total, without accounting for potential local opposition. In parallel, the new nuclear power is envisioned to align with expectations of a moderately successful project, avoiding prolonged delays. The scenario also assumes the existence of infrastructure for the

[138] Ministry of Climate and Environment - Poland (2023), Energy policy of Poland until 2040 - Scenario 3.

transport and storage of CO_2 by 2035 and a carbon capture efficiency of approximately 100% for power plants equipped with CCS by 2050. Additionally, the base scenario assumes the establishment of groundwork, such as regulatory frameworks and permitting processes, to facilitate the necessary expansion of all technologies, including nuclear and CCS.

Deviations from the above-described base scenario assumptions are explored with a set of sensitivity scenarios. In the event that the anticipated technological developments do not materialize, or the necessary groundwork is not established for all technologies, the study explores conservative scenarios. These scenarios simulate a less optimistic development for different technologies—renewables, nuclear, and CCS. The resulting generation and capacity mixes for the scenarios are presented in Figure 32. Table 17 provides a comparative analysis, aiming to highlight the power systems' performance concerning sustainability and competitiveness in these conservative scenarios. The unique characteristics of these scenarios make them particularly interesting for comparison, as they represent distinctly different decarbonized systems.

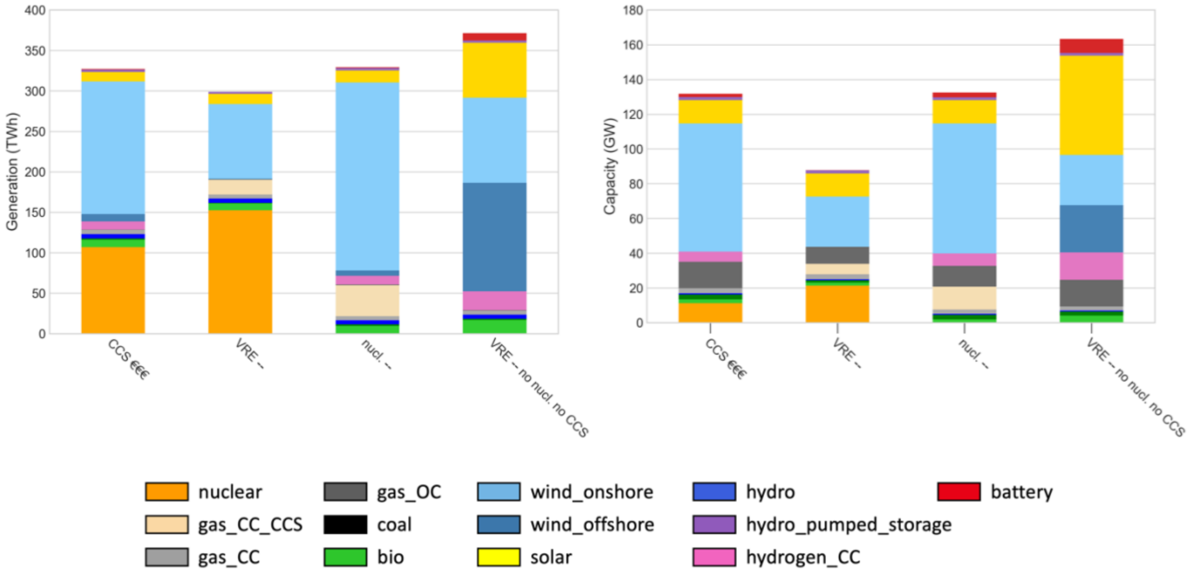

Figure 32. Generation (left panel) and capacity (right panel) mixes for main conservative scenarios.

First of all, the current modelling incorporates a capacity reserve margin of 9% in accordance with Polish regulations (see also Section 4.9). Consequently, all scenarios meet the defined *security of supply* criteria outlined in Table 17. In practice, this ensures that the Polish power systems are well-equipped to handle challenging conditions, including adverse weather years, e.g., characterized by prolonged periods of low wind production or unforeseen contingencies.

In terms of competitiveness metrics, such as electricity prices and total system costs in Table 17, scenarios inclusive of diverse technologies demonstrate comparable performance. This suggests that a policy embracing and facilitating the development of a broad set of technologies is well-equipped to handle uncertainties, such as unexpected hindrances in development, resistance to onshore wind expansion, and challenges with larger and more complex nuclear and CCS projects. In practical terms, when one technology faces conservative development, another technology can step up to compensate.

In stark contrast, the scenario excluding both nuclear and CCS technologies, 'VRE -- no nucl. no CCS', coupled with an assumption of stagnation in renewables' cost reduction and negative public opinion on onshore wind, emerges as highly non-competitive. Expanding on this aspect, technology inclusiveness is arguably a prerequisite for achieving decarbonization of the Polish power system.

The high electricity prices in this scenario are likely unacceptable to the general public and render the Polish industry uncompetitive. Additionally, the significant price spread due to different weather conditions, already evident in the 'no nucl. no CCS' scenario with more optimistic conditions for variable renewable energy, indicates unstable market conditions, posing negative consequences for any investor in energy-intensive industries.

Moreover, it is important to emphasize that the demand scenario, peaking at around 300 TWh in 2050, is relatively modest in this study. For perspective, Sweden, with only one-fourth of Poland's population, aspires to achieve 300 TWh by 2045 as part of its political ambitions[139]. Given the observed increased system costs and onshore wind nearing its technological expansion limits, an exclusive focus on certain technologies would pose even greater challenges with a larger increase in demand. Considerable demand-side flexibility is an important part of all modelled scenarios in the current study. However, future work should consider variations in demand-side flexibility and the required flexibility by industries to ensure competitiveness with higher penetration of variable renewable energy in a decarbonized Polish power system.

Additional parameters in Table 17 shed light on the power systems' dependence on transmission infrastructure—a crucial facilitator of new production and consumption, yet a potential obstacle in decarbonization. These parameters include the length of additional power transmission needed, the size of hydrogen storage required for generating backup electricity, and the power system's annual injection capacity of CO_2 into geological storage. First and foremost, it is crucial to emphasize the importance of significant grid reinforcement across all scenarios. This is essential to facilitate the deployment of as much cost-effective onshore wind capacity as possible. Secondly, the systems with larger share of nuclear power, 'VRE --' and 'CCS €€€', combined exhibit the lowest values across all three parameters. This underscores that nuclear power in the Polish system has the potential to reduce reliance on an expanded transmission infrastructure, a prospect further enhanced by the possibility of repurposing coal sites for nuclear power.

Quantified Carbon lifecycle greenhouse gas emissions, land use and use of critical minerals, as further presented in Table 17, aim to probe how the power systems perform with respect to sustainability.

First it is relevant to note, that the lifecycle greenhouse gas emission values also include upstream emissions in contrast to the power system optimisation which only considers direct emission. Comparing the power systems, the 'CCS €€€' performs best. The power systems more dependent on fossil fuel and biopower exhibit poorer performance, but due to their low share in the overall generation, the systems arguably don't deviate a lot.

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[139] Government office – Sweden (2023), Concerning the governments priorities: climate and energy.

Table 17. Summarized results comparing parameters, measuring security of supply, competitiveness, reliance on transmission infrastructure and sustainability, of the power systems for conservative scenario and year.

Parameter	Scenario				
	Base	VRE --	CCS €€€	NUCL. --	VRE -- no nucl. no CCS
Security of supply	✓	✓	✓	✓	✓
Electricity price level (mean €/MWh)	53	61	55	60	140
Total system cost (B€)[140]	370	380	400	340	560
Power transmission (km)[141]	13 000	3 200	14 000	24 000	85 000
Hydrogen storage capacity (TWh)[142]	2	0	3	3	8
Annual injection of CO2 (Mt)[143]	6.5	7.2	0.3	15	0
Life-cycle greenhouse gas emissions (g CO2eq/kWh)	36	41	28	47	45
Land use (km^2)	29 000	18 000	29 000	40 000	27 000
Use of critical materials (kt)	710	470	710	950	1200

Onshore wind, being the dominant source in the future power system, plays a central role in both extensive land use and reliance on critical materials. In contrast, systems primarily dependent on nuclear power demonstrate the lowest usage of land and critical materials. This not only makes nuclear-dependent systems less susceptible to issues related to public acceptance of renewables but also mitigates risks associated with the security of critical mineral supplies, as the current concentrations are limited to a small number of quasi-monopolistic countries.

The investigated measures on the power systems' dependency on transmission infrastructure and sustainability highlights an additional value of nuclear in the Polish power system. Ultimately, the measures corroborate the conclusion that technology-neutral approach yields the most favourable outcomes.

Finally, it's important to underscore that the present analysis focuses on the power system within the electricity market, serving as an initial phase to inform power system development. Subsequently, a thorough analysis of the resulting power system is required, taking into account

[140] Aggregated total system costs from 2030 to 2050.
[141] See Section 5.7.1 for calculation methodology.
[142] In hydrogen thermal energy capacity. Representing expansion needed for regeneration of electricity through combined-cycle hydrogen gas turbine power plants.
[143] Only representing needs from power sector.

factors like frequency stability, N-1 criteria, black start capability, and more. However, such a detailed analysis is beyond the scope of this study.

Concluding policy recommendations derived from the current study for fostering a competitive and sustainable decarbonization of the Polish power system are presented in Section Policy recommendations.

Appendix A Input assumptions

A.1 Technologies in model

Table 18. Power supply technologies included in the GenX model along with a brief description. Technology category also indicated where 'Thermal' represents thermal power plant, 'Must run' power plant forced to follow dispatch profile, 'VRE' variable renewable energy subject to production profile and curtailment and 'Storage' systems.

Technology	Category	Description
nuclear	Thermal	General representation of greenfield nuclear power.
nuclear_retrofit	Thermal	Brownfield retrofit nuclear power.
hydro_run_of_river	Must run	Profile based on average of historical years.
coal_CHP	Must run	Coal-fuelled CHP with profile based on average of historical years.
gas_CHP	Must run	Natural gas-fuelled CHP with profile based on average of historical years.
biomass_CHP	Must run	Biomass-fuelled CHP with profile based on average of historical years.
coal_hard	Thermal	Hard coal-fuelled thermal power plant.
coal_lignite	Thermal	Lignite coal-fuelled thermal power plant.
coal_hard_CCS	Thermal	Hard coal-fuelled thermal power plant with CCS.
coal_hard_CCS_retrofit	Thermal	Hard coal-fuelled thermal power plant retrofitted with CCS.
coal_lignite_CCS	Thermal	Lignite coal-fuelled thermal power plant with CCS.
coal_lignite_CCS_retrofit	Thermal	Lignite coal-fuelled thermal power plant retrofitted with CCS.
biogas_OC	Thermal	Biogas fuelled open-cycle turbine power plant.
biomass	Thermal	Biomass-fuelled thermal power plant.
biomass_CCS	Thermal	Biomass-fuelled thermal power plant with CCS.
gas_OC	Thermal	Natural gas fuelled open-cycle turbine power plant.
gas_CC	Thermal	Natural gas fuelled combined-cycle turbine power plant.
gas_CC_CCS	Thermal	Natural gas fuelled combined-cycle turbine power plant with CCS.
gas_CC_CCS_retrofit	Thermal	Natural gas fuelled combined-cycle turbine power plant retrofitted with CCS.
wind_offshore_floating	VRE	Offshore wind power with floating foundation.
wind_offshore_fixed	VRE	Offshore wind power with fixed foundation.
wind_onshore	VRE	Utility-scale onshore wind power.
solar	VRE	Utility-scale solar PV.
hydrogen_OC_storage	Storage	Hydrogen-fuelled open-cycle turbine power plant with electrolyser charging station and hydrogen energy storage.
hydrogen_CC_storage	Storage	Hydrogen-fuelled open-cycle turbine power plant with electrolyser charging station and hydrogen energy storage.
battery_storage	Storage	Utility-scale lithium-ion battery storage.
hydro_pumped_storage	Storage	Closed-loop pumped storage hydropower.

A.2 Existing installed generation capacities

Table 19. Existing dispatch capacity before expansion in 2030 for the different power generating technologies in Poland. For 'solar' and 'gas_CC' the capacity includes prescribed near-term expansion.

Technology	Existing capacity (MW)
nuclear	0
nuclear_retrofit	0
hydro_run_of_river	668
coal_CHP	4629
gas_CHP	3160
biomass_CHP	261
coal_hard	16148
coal_lignite	8249
coal_hard_CCS	0
coal_hard_CCS_retrofit	0
coal_lignite_CCS	0
coal_lignite_CCS_retrofit	0
biogas_OC	270
biomass	275
biomass_CCS	0
gas_OC	0
gas_CC	6000
gas_CC_CCS	0
gas_CC_CCS_retrofit	0
wind_offshore_floating	0
wind_offshore_fixed	0
wind_onshore	9700
solar	26800
hydrogen_OC_storage	0
hydrogen_CC_storage	0
battery_storage	0

Table 20. Existing discharge, energy storage and charge capacity for pumped hydro storage in Poland.

Technology	Discharge capacity (MW)	Energy storage capacity (MWh)	Charge capacity (MW)
hydro_pumped_storage	1700	58970	1640

A.3 Description of LCOE calculations

The Levelized Cost of Electricity (LCOE) is a metric used to determine the average cost of producing one megawatt-hour (MWh) of electricity over the lifetime of a power generation project. It combines the initial construction cost, annual fixed and variable operating costs, and the electrical output to provide a standardized measure of the cost of electricity. Here's how LCOE is calculated, broken down into its key components:

1. Construction Cost (EUR/MW):

Represents the upfront cost of building the power generation facility, accounting for construction duration and interest rate. The interest rate has been assumed to be half of the WACC.

$$
\begin{aligned}
construction\_cost &= (overnight\_capital\_cost + grid\_cost) \\
&\quad * (1 + construction\_interest\_rate)^{construction\_duration} \\
&\quad - overnight\_capital\_cost - grid\_cost
\end{aligned}
$$

2. Investment Cost (EUR/MW):

The total investment required for the project, combining the construction cost, overnight capital cost, and grid connection cost.

$$investment\_cost = construction\_cost + overnight\_capital\_cost + grid\_cost$$

3. Annuity Factor:

Factor used to calculate annualized costs, incorporating the Weighted Average Cost of Capital (WACC) and the project's capital recovery period.

$$annuity\_factor = \frac{WACC * (1 + WACC)^{capital\_recovery\_period}}{(1 + WACC)^{capital\_recovery\_period} - 1}$$

4. Annual costs (EUR/MW-yr):

Annual costs are relevant for investment as well as fixed costs for operating and maintaining the facility, which may involve reinvestment.

$$annual\_investment\_cost = investment\_cost * annuity\_factor$$

$$annual\_fixed\_OM = fixed\_OM + reinvestment$$

5. Marginal Cost of Electricity (EUR/MWh):

Additional cost associated with producing one extra MWh of electricity, incorporating variable operating costs and fuel expenses.

$$
\begin{aligned}
marginal\_cost\_of\_electricity &= total\_variable\_cost + fuel\_price\_per\_MWh\_with\_upstream\_emissions
\end{aligned}
$$

Here the total variable cost comprises variable OM as well as potential tariffs for transport and storage of CO2 ($variable\_cost\_CCS$). Fuel price per MWh (fuel cost per MWh of generated electricity) with upstream emissions (EUR/MWh) is calculated according to:

$$
\begin{aligned}
fuel\_price\_per\_MWh\_with\_upstream\_emissions &= fuel\_price\_per\_MWh + (CO2\_price \\
&\quad * CO2\_emission\_coefficient\_upstream * heat\_rate)
\end{aligned}
$$

Where $CO2\_emission\_coefficient\_upstream$ represents indirect emissions associated with the combustion of the fuel. For thermal power plants with direct emissions cost of emitting CO2 is added to the marginal cost of electricity in the following way:

$$marginal\_cost\_of\_electricity += CO2\_price * CO2\_emission\_coefficient * heat\_rate * (1 - carbon\_capture\_efficiency)$$

6. Full Load Hours (hours):

Number of hours in a year that the power plant operates at full capacity, determined by the capacity factor.

$$full\_load\_hours = 8760 * capacity\_factor$$

7. LCOE (Levelized Cost of Electricity) (EUR/MWh):

Primary metric indicating the cost of generating electricity per MWh over the project's lifetime.

$$LCOE = \frac{annual\_\_investment + annual\_fixed\_OM}{full\_load\_hours} + marginal\_cost\_of\_electricity$$

Appendix B GIS analysis for wind and solar expansion potential

GIS (geographic information system) is a work environment that uses spatial analysis tools, cartographic methods and databases of spatial objects or spatial distributions of variables. Significant developments in the availability of GIS for research and analysis are related not only to technological advances but also to broader access to ever larger geospatial databases, including open-access data. Renewable energy systems research uses vector and raster data, reflecting the shape and structure of building roofs or representing the terrain.

Numerous scientific studies[144] in individual countries, continents, and on a global scale show the possibilities of using GIS data and tools to analyse energy supply. Most scientific research does not differ in terms of the adopted methodology, which is based on basic tools and analyses, but the differentiating parameter are the type and resolution of the spatial data, as well as the conditions and assumptions adopted for the analyses.

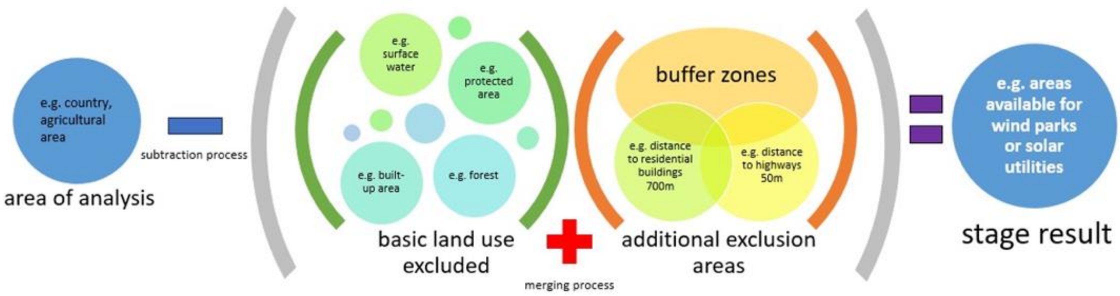

Figure 33. Illustration of the adopted GIS approach.

B.1 Core input data

In terms of input data, the analysis was based on two crucial databases, namely:

- Topographic Objects Database (BDOT10k)[145]

BDOT10k is a vector database which contains the spatial location of topographic features with their properties descriptions. The content and detail level of the BDOT10k database corresponds to a map at the scale of 1:10,000. The Topographic Objects Database contains information concerning watercourses, roads and railways; utility lines; land cover; protected areas; buildings, structures and equipment. BDOT10k data is successively updated and supplemented. BDOT10k in Poland is the most up-to-date database of information about topographic objects.

- Digital Elevation Model (DEM)[146]

DEM is a discrete (point-based) representation of land surface elevation. Digital elevation model includes information about the elevation of objects on the ground, such as buildings, tree crowns, masts, or the terrain. The resources available include DEMs with a spatial resolution of 1 m, or for large

[144] https://www.mdpi.com/2079-9276/8/3/149
Avtar, R., Sahu, N., Aggarwal, A. K., Chakraborty, S., Kharrazi, A., Yunus, A. P., ... & Kurniawan, T. A. (2019). Exploring renewable energy resources using remote sensing and GIS—A review. *Resources*, *8*(3), 149. **https://doi.org/10.3390/resources8030149**
[145] https://www.geoportal.gov.pl/en/data/topographic-objects-database-bdot10k/
[146] https://www.geoportal.gov.pl/en/data/digital-elevation-model-dem/

cities with increased accuracy - a spatial resolution of 0.5 m. Typically, the input to create a DEM comes from airborne laser scanning. This state resource contains data obtained by various national government institutions, which are successively updated with newly acquired data.

B.2 Solar PV

Analysis for assessing the potential of locating solar PV installations was divided into two stages: solar PV rooftop and solar utility. Although both types of facilities are based on the production of energy from the sun, the estimation of the development potential of this branch is completely different. The solar rooftop assessment focused on the records of buildings and their shape and geographical location, while for solar utilities an analysis of topographic conditions was carried out, indicating available areas for the location of such facilities.

B.2.1 Rooftop

The analysis used DEM data representing the elevation of objects, including building roofs, and BDOT10k, from which the location of the building outline was obtained[147,148].

Several cities in Poland were selected for analysis. The selection criterion was the size of the administrative unit, from small villages, through towns, to large agglomerations, but also the location in the country, which represented the cultural and historical aspect of construction, including the size and shape of buildings, but also their location in relation to the directions of the world.

The aim of the analysis was to estimate the available roof area for a solar PV installation. The basic criteria of the analysis were the slope of roofs and the exposition of roof surfaces, which was compared with the technical conditions for installing panels on the roofs of buildings, and shading conditions on characteristic days of the year, the longest and shortest day and the equinox, taking into account the horizontal and vertical angle of incidence of sunlight in the geographical location of the building. The summary of analysis is shown on Figure 34.

The analysis was performed using a DEM with a spatial resolution of 1m or 0.5m (for cities with over 100k inhabitants), from which a slope model, an exposition model and shading models were created in the GIS environment Figure 35.

As a result of the analysis, data was obtained for each recorded building on the size of the available area for the installation of roof solar panels, considering the angle of the roof, its exposition and the share of the area shaded by the building itself or taller neighbouring objects.

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[147] Dąbek P.B., Jurasz J., 2018, „GIS estimated potential of rooftop PVs in urban areas – case study Wrocław (Poland)", E3S Web of Conferences 45: 00014, DOI: 10.1051/e3sconf/20184500014

[148] Jurasz, J.K., Dąbek, P.B., Campana, P.E., 2020, „Can a city reach energy self-sufficiency by means of rooftopphotovoltaics? Case study from Poland", Journal of Cleaner Production 245: 118813, DOI: 10.1016/j.jclepro.2019.118813

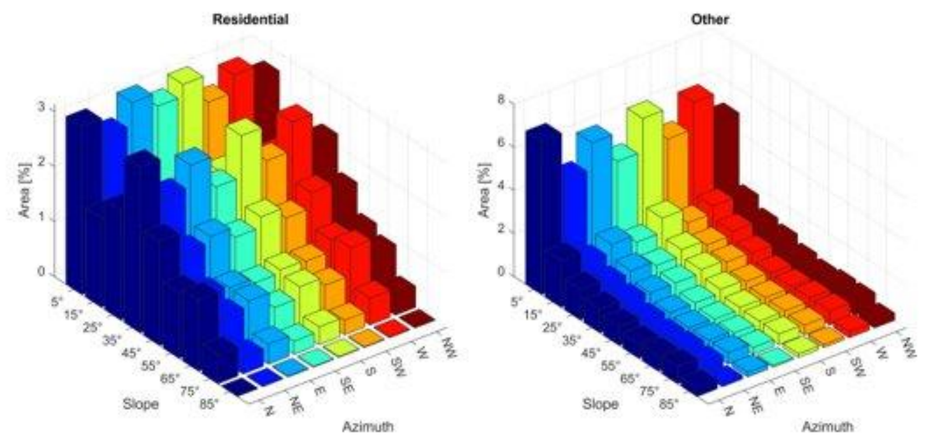

Figure 34 Structure of roofs are in residential and other (commercial, industrial etc.) buildings depending on their slope and azimuth.

Figure 35 Installed capacity in the wind farms in Poland.

Summarizing our analysis indicates that the realistic potential of rooftop PV in Poland is around ~30 GW and this number is very much in line with the potential of 32 GW indicated by Instrat.

B.2.2 Utility

The analysis of areas available in Poland for solar utility installations was made based on BDOT10k data and current legal regulations regarding the required location conditions.

The following vector data were obtained from the BDOT10k database: land use/land cover data, protected areas (Natura2000 areas, national parks, landscape parks, nature reserves), location of residential buildings and roads in the country (motorways, expressways, national roads, local roads).

In Poland, the law prohibits changing the intended use of forest land for non-forest purposes, as well as locating such facilities on land not intended for investment[149] purposes[150]. Apart from the currently available areas that are not yet developed (mainly areas in cities), the greatest and only potential has agricultural land, such as areas for cultivation and green areas (grasslands and pastures).

The basic legal exclusions from investment are protected areas[151], forests, areas covered by surface water (rivers, reservoirs, lakes), areas at risk of flood risk.

The analysis was performed for several scenarios:

- all agricultural and grassland areas (Figure 36)

-as above but, excluding areas under nature protection (Natura2000, national parks, landscape parks, reserves)

- as above plus excluding areas at risk of flood risk 1%[152] and located more than 500m from a residential area

- the above-mentioned, considering the selection according to the size of the available compact area of at least 2 ha

- the above, excluding those located further than 200 m from closest roads.

[149] Act on Forests 1991
https://isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=wdu19911010444
[150] ACT on Agricultural and Forest Land Protection 1995
https://isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=wdu19950160078
[151] https://isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=wdu20040920880
[152] https://data.jrc.ec.europa.eu/collection/id-0054

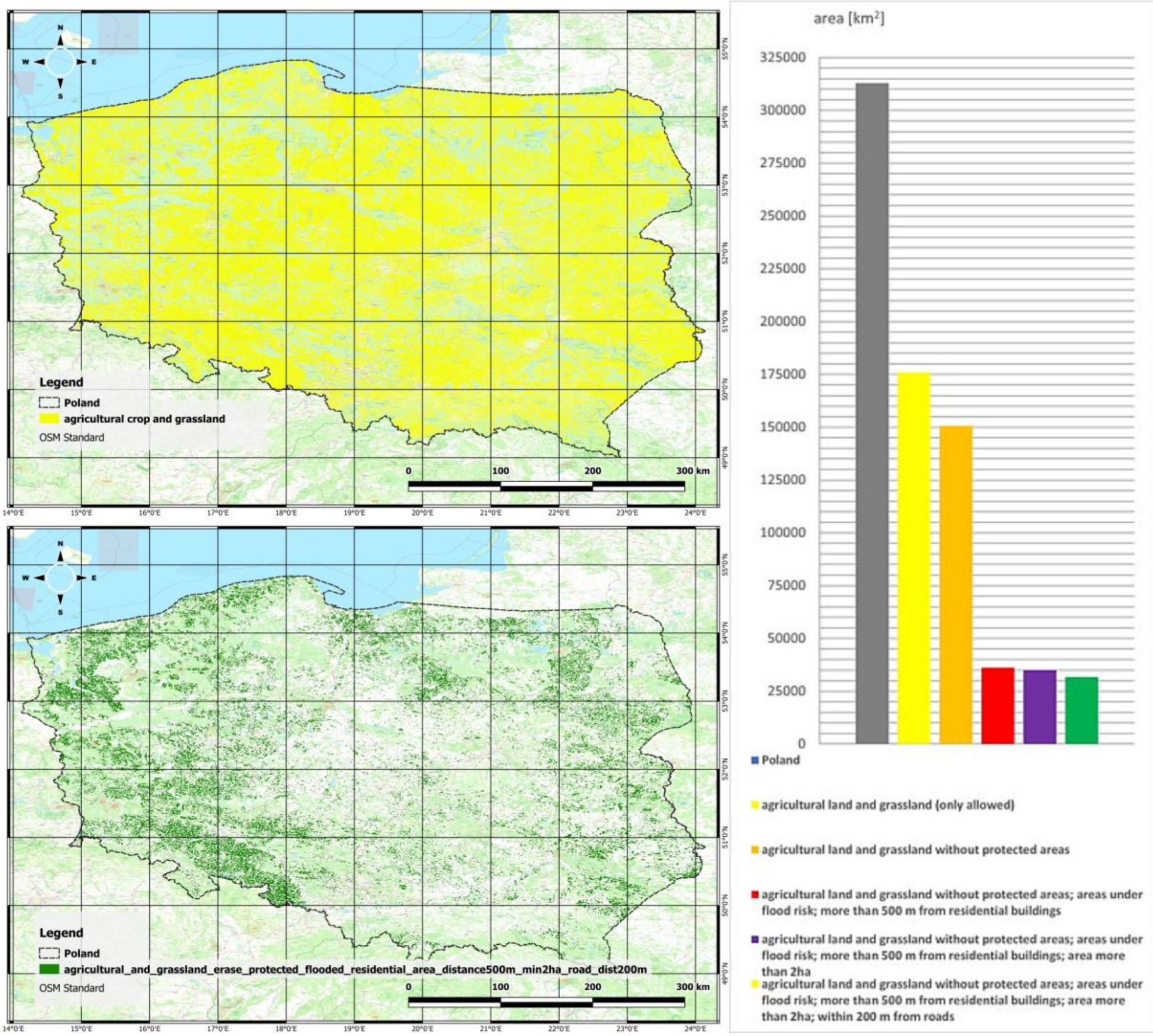

Figure 36 Agricultural lands for crops and grasslands in Poland. Location of areas available for solar utility installation, taking into account the criteria of land use, flood risk, protection areas, distance to built-up areas and roads. Chart of changes in the size of available area for solar utilities

Our analysis indicates a potential corresponding to 324 GW if all identified available land would be covered with PV utility scale installations. This can be seen as upper boundary as there are other reasons, not covered in the analysis, why a site will note suitable for solar installation. For example, lacking or expensive grid connection or other preferred or competing land use cases. However, the identity potentially available land is very large compared to the potential need of the power system and it can be concluded that land availability will not limit the expansion of solar utility installations. This number falls between the values reported by other organizations where Carbon-Free Europe indicated between 67 and 2246 GW, European Commission 802 GW, and Instrat 47 GW.

B.3 Onshore wind

The analysis of areas available in Poland for the installation of wind parks was made based on BDOT10k data, supplemented with DEM, and current legal regulations regarding the required location conditions. Legal issues regarding the location of wind turbines in Poland are well described and defined in legal acts. The main change in the law took place in March 2023, when the provision regarding the required distance from residential buildings equal to 10 times the height of the turbine with the blades was abandoned (the so-called Act 10H). It was allowed to locate turbines at a distance of at least 700 m, with the consent of local administrative authorities.

The following vector data were obtained from the BDOT10k database: land use/land cover data (built-up areas, forests, surface waters), protected areas (Natura2000 areas, national parks, landscape parks, nature reserves), location of residential buildings and roads in the country (motorways, expressways, national roads, roads local), coastal belt, high voltage lines (Figure 37).

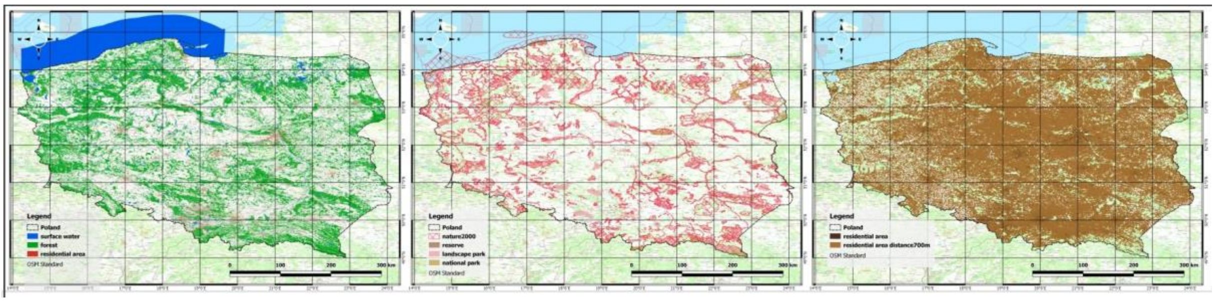

Figure 37 Visualization of land use and land cover in Poland based on BDOT10k data from 2023.

The analysis was performed in the GIS environment as an analysis of polygon vector data. Using available tools, areas excluded from the accepted permitted areas were subtracted (masked). Buffering tools were used to determine exclusion areas around residential buildings.

Throughout the analysis, several dozen scenarios were performed, with different numbers of exclusions and in various configurations. Ultimately, 4 scenarios were developed. The main so-called baseline 2 scenario (Figure 37) includes the following exclusion criteria from the entire available area of the country:

- forest areas,

- built-up areas (all types),

- surface waters (rivers, lakes, ponds, reservoirs),

- areas at risk of flooding 1%,

- protected areas (natura2000, national parks, landscape parks, reserves),

- buffer zone from roads,

- buffer zone from surface waters,

- buffer zone from national parks and nature reserves,

- buffer zone for the highest voltage lines,

- coastal strip,

- buffer zone for residential buildings (current legal regulations 700m),

- terrain above 500 m amsl.

The remaining two scenarios differed in the criterion of distance to residential buildings, previous (2016-2023) legal regulations 10 times the height of the turbine with blades, previous (before 2016) legal regulations 500 m. A variant of the analysis was also performed for the baseline 2 scenario, additionally excluding a strip of 300 m from the forest areas. The location of potential wind parks juxtaposed with the transmission infrastructure and the wind conditions[153] has been presented in Figure 38 whereas Figure 27 categorized the wind parks depending on wind conditions and the estimated CAPEX (driven by wind park size and distance to the transmission lines).

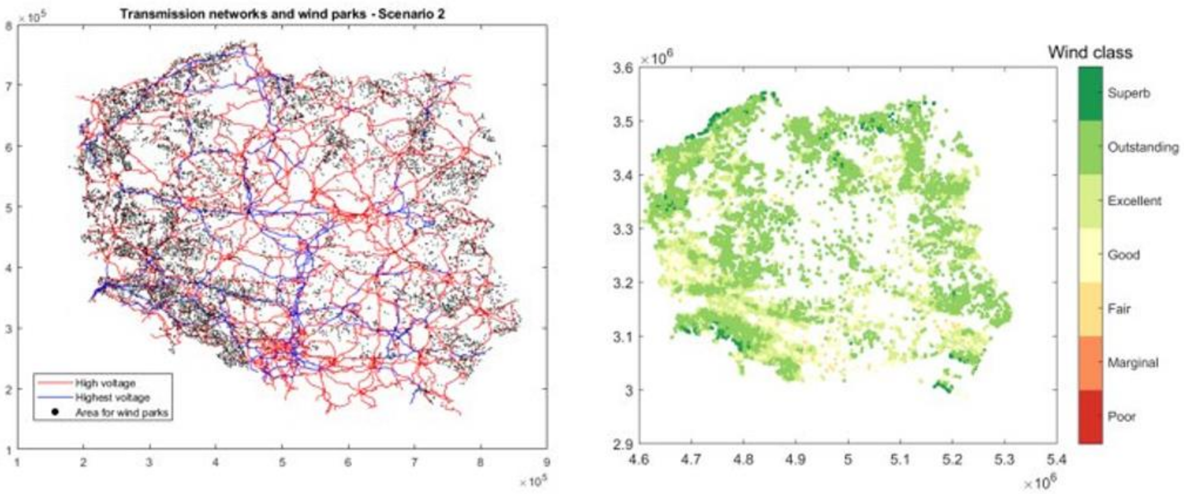

Figure 38 Spatial distribution of wind parks plotted against transmission lines (left) and wind resources (right).

Summarizing, both the literature and our analysis have shown that the potential of onshore wind power can vary significantly. Our results indicate values ranging from 1.75 GW to almost 200 GW depending on the adopted policy.

B.4 Criteria for wind, and solar parks.

Conditions for the location of wind farms and solar utility in Poland			
Criteria	Wind park	Solar utility	References
Built-up areas	excluded	excluded	1; 2
Forests	excluded	excluded	3; 4
Protection area (national parks, landscape parks, nature reserves, Natura 2000)	excluded	excluded	1; 2; 5
Surface water (standing, flowing)	excluded	excluded	5
From a residential building or a building with a residential function	*not allowed up to 500 m*	N/A	*Before 2016*
From a residential building or a building with a residential function	*not allowed up to min. 10times the height of the turbine with blades*	N/A	*Valid in 2016-2023*
From a residential building or a building with a residential function	not allowed up to min. 10times the height of the turbine with blades, unless the local spatial development plan provides otherwise, but not less than 700m	not allowed up to 500 m ***	1; 2 **
From surface water	not allowed up to 100 m	N/A	5

[153] Global Wind Atlas v 3.3

Area at risk of flooding 1%	excluded	excluded	6
From the national park area	not allowed up to 10times the height of the turbine with blades	N\A	1; 2
From the nature reserve area	not allowed up to 500 m	N\A	1; 2
From the forest promotional complexes	not allowed up to 10times the height of the turbine with blades, unless the local spatial development plan provides then min. 700 m *	N\A	1; 2
Agricultural and grassland with soils of valuation class I-III	excluded ****	excluded ****	4
From the highest voltage power grid	not allowed at a distance equal to or greater than 3times diameter of the rotor including blades; or not allowed at a distance equal to or greater than 2times height of the wind turbine *	N\A	1; 2
From the roads	not allowed in the distance highway 50 m, expressway 40 m, national road 25 m, district road 20 m, municipal road 15 m	N\A excluded those that are further than 200 m from roads ***	7 **
Protection zones of health resorts type A and B	excluded *	N\A	8
Sea shore	not allowed at technical belt of the seashore and not allowed up to 200 m from the cliffs	N\A	5
Elevation	not allowed more than 500m amsl ***	N\A	

* - not used in the analysis

** - applies only to wind park

*** - own technical criterion adopted

**** - excluded in quantitative analyses

Appendix C Methodology for emission, land use and critical minerals use

Table B1 presents general assumptions on aspects of sustainability for the technologies considered in the current report. These are further introduced and motivated in the sections below.

Table B1: Greenhouse gas emission, land use and critical materials factors for different power and energy generation sources. Closed cycle, carbon capture & storage and photovoltaic abbreviated as CC, CCS and PV respectively.

	Emissions	***Land use***	***Critical minerals & materials***
Power generation type	*kg CO_2eq/MWh*	*km^2a/TWh*	*kg/MW*
Battery discharge	160*	21	6834
Biomass	230	580	0
Hard coal	820	17	2485
Hard coal, CCS	220	24	2485
Gas, CC	490	0.8	1166
Gas, CC, CCS	170	1.3	1166
Hydropower	24	11	0
Hydropwer, flexible	24	11	0
Nuclear	12	1	5274
Solar, PV	48	21	6835
Wind, offshore	12	1	10167
Wind, onshore	11	1**/150***	10167

*Storage emissions are calculated via installed capacity
**Direct land use
***Project site area land use

C.1 Assumptions for the current study

For this study the project site area was used for wind power (i.e., the area of the entire farm), but direct impact is also shown in Table B1. Using direct land use value instead would reduce the total land use results to ~20% of the stated value, but project area was chosen since the entire site area is affected at some level. For PV, it was assumed that 30% of existing and new PV was ground mounted and 70% was roof mounted[154]. Bioenergy in Poland is mainly generated using forest biomass, where some is direct use, and some are byproducts. Biomass was therefore assumed to use 70% of the emission and land use allocation of a purpose grown, dedicated energy biomass [155].

C.2 Energy use and installed generation capacity

The energy use and installed capacity used in calculations are a result from the simulations of this report. The normalized yearly energy consumption was used for emission calculations and land use whereas the installed capacity was used for critical material use.

C.3 Greenhouse gas emissions

Greenhouse gas emissions quantifies the increase in atmospheric greenhouse gases, measured in kg CO_2eq/MWh. The data used was taken from IPCC[156] and Electricity Maps[157] and includes the entire life cycle of the generation type, both for the fuel and the generation plant. The global median life

[154] IEO (2023) Rynek fotowoltaiki w Polsce
[155] Assumption based on Polish biomass composition
[156] IPCC (2018) AR 5
[157] Electricity maps (2023) Methodology

cycle emissions were used. Battery discharge emissions were calculated using 160 kg CO_2eq/MW installed capacity[158], and then adding the emissions of the local electricity mix for the energy discharged by batteries for that year. Electricity generation from biomass by-products and waste can be assumed to have a lower emission impact then dedicated biomass. In several methodologies, waste and by-products are not assigned any allocation and have a zero-emission value for greenhouse gases[159]. In this way, some of the Polish bioenergy was assumed to have a lower emission than the listed values, as seen in the specific assumptions for this study (C.1)

C.4 Land use

All land use values are taken from UNECE[160] and include the land for mining the materials, manufacturing, and installation. In addition, the value for wind power is validated with the median project site land use from National Renewable Energy Laboratory (NREL)[161].

Biomass, wind power and solar land use are all somewhat variable depending on the method used for calculation. Wind power either use directly impacted land use or project site land use, where the former is the immediate area around the wind turbine and the latter includes the spacing between turbines as well. For PV, roof mounting was assumed to have zero direct land use while ground mounted PV have both the direct land use and the land use from mining and such. Biomass grown for dedicated energy usage have a higher land use area than biomass from waste or by-products, where the land use mainly is allocated on the primary product and can be considered less for the by-product[162]. To accommodate for this, and the lack of accurate source data for biomass, an assumption of 70% of the listed land use value were used as an aggregate.

C.5 Critical metals & minerals

The use of critical materials per installed capacity is taken from IEA[163], and includes the use of the critical minerals copper, nickel, manganese, cobalt, chromium, molybdenum, zinc, rare earth minerals and silicon, as well as minor critical minerals. All values include the life-cycle material use, but not the energy infrastructure such as the power grids.

[158] Emilsson & Dahllöf (2019) LI-ion vehicle battery production
[159] Brandao et al. (2022) RED, PEF, and EPD: Conflicting rules for determining the carbon footprint of biofuels...
[160] UNECE (2022) Carbon neutrality in the UNECE region
[161] NREL (2009)Land use requirement of modern wind power in the united states
[162] How much is less is intensively discussed in the LCA community. As an example, Brandao et al (20220 suggest 50% for HVO and a variable amount for biogas from waste.
[163] IEA (2022) The role of critcal minerals in clean energy transition

Quantified Carbon