

Powering Denmark in 2050

An Evaluation of
Climate-Neutral Power Systems

FULL REPORT

A STUDY BY QUANTIFIED CARBON

FOR DANISH NUCLEAR ALLIANCE

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ABOUT THIS PUBLICATION

This report has been produced by Quantified Carbon (QC) on commission from the Danish Nuclear Alliance. The analytical framework, scenario design, modelling, and conclusions presented in this work are the authors'.

The study is published in two versions. The full report (this document) documents the complete methodology, assumptions, results and appendices, for readers who want to examine the analysis in detail. The condensed version presents the main findings and policy implications in a shorter format and refers to the full report for supporting detail.



ABOUT QUANTIFIED CARBON

We are an international consultancy firm providing complex problem solving, modelling, and optimisation to support decarbonisation of energy systems and industries.

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Executive Summary

In 2025, the Danish Government announced its intention to revisit the 1985 parliamentary decision that excluded nuclear power from Danish energy planning, as part of the broader development of a climate-neutral Danish energy system. The question, however, is broader than nuclear alone. Climate neutrality does not prescribe a single technology configuration, and several plausible end-state systems can satisfy the climate objective while differing in cost structure, security of supply, market behaviour, and exposure to external developments. Sound long-term policy benefits from clarifying the range of these end-states before evaluating individual technologies within them. On this basis, the present study explores alternative climate-neutral Danish power systems for 2050 and compares them on a coherent set of performance indicators relevant for policy decisions.

The role of nuclear energy in a climate-neutral Danish power system has been examined in recent academic work^{1,2} and, most recently, in a system analysis commissioned by the Danish Energy Agency from EA Energianalyse and VTT³ (henceforth referred to as the EA study). That work starts from three predefined pathways for the Danish energy system and examines what changes when Small Modular Reactors (SMRs) are added to them, providing a thorough techno-economic basis for SMRs and a detailed system-value assessment under multiple demand and cost variations. The present study takes a different approach. Rather than adding one technology to predefined pathways, it optimises the full power mix in several structurally different configurations and compares them to illuminate the role and value of different technologies. Cost assumptions are varied across all major technologies, not only for nuclear, and the evaluation extends beyond monetised system cost to the categories of self-sufficiency, competitiveness, environmental & climate impact, alongside grid and operational safety. Different levels of self-sufficiency, in particular, is evaluated explicitly which opens up for its exploration as a policy variable.

The core of the methodology, carried out with Quantified Carbon's power market model cGrid, proceeds in three steps. First, a capacity expansion optimisation is performed for each scenario on a reference weather year representing average market conditions, identifying the cost-optimal supply mix under the relevant scenario assumptions. Second, the resulting system is evaluated against an extreme weather event – the cold, low-wind period of mid-January 1985 – to assess generation adequacy beyond average conditions. Where adequacy is insufficient, a capacity requirement adjustment adds dispatchable capacity in the form of gas turbines and battery storage to restore it. This assessment also incorporates the role of dispatchable capacity to provide services related to operational safety (frequency balancing services and non-frequency ancillary services, grid congestion and aspects relating to preparedness). Third, the resulting systems are simulated across 33 historical weather years (1983–2015) and evaluated on

¹ Thellufsen et al., (2024) Cost and system effects of nuclear power in carbon-neutral energy systems

² Aarflot Moen, K, et al., (2025), The Total Costs of Energy Transitions with and Without Nuclear Energy

³ EA Energianalyse (2026), Analyse af atomkraft i Danmark

a wide set of indicators, including average prices and price volatility, import costs, gas consumption, demand coverage in extreme hours, generation and capacity costs and their exposure to cost escalation, market profitability gaps, life-cycle emissions, critical-mineral demand, grid upgrade costs, and dispatchable capacity.

Two methodological choices warrant particular attention. First, technology cost assumptions have throughout the current work been derived from a comprehensive research-based review of the available literature for each major technology, with five technology cost scenarios – Conservative-1&2, Reference, and Optimistic-1&2 – defined consistently across all technologies. The resulting reference cost levels therefore deviate in some cases from those used in other recent Danish analyses; more importantly, the variation across technology scenarios makes it possible to characterise where each scenario is most sensitive to cost realisation rather than being constrained to a limited option space. Second, the installed capacity in neighbouring regions is pre-optimised on a reference scenario and then held fixed during the capacity expansion of the Danish system. Given Denmark's high level of interconnection, this is a deliberate analytical choice: allowing neighbours to re-optimize in response to Danish supply choices would dampen the differences between scenarios by absorbing them into adjusted neighbouring capacity. This would not reflect the actual energy-policy reality, in which national decisions are primarily made independently rather than co-optimised across borders. The flip side is that the results may understate what closer cross-border coordination could achieve.

The scenario design, illustrated in [Figure 1](#), does not aim to identify the single most likely future for the Danish power system. Instead, it is built to explore the characteristics and trade-offs of structurally different technology mixes, i.e., testing what it would mean for the system if one foundational supply technology were to play a dominant role. From a common Balanced reference case, three technology directions are pursued: Offshore wind, Solar, and Nuclear. Each direction probes how the system changes as cost assumptions and supporting conditions are progressively tilted in favour of that technology. A stepped approach is taken, where a balanced variant is followed by a fully committed variant, to allow a more informed reading of how results shift as you move away from the Balanced. Each direction is paired with a type of demand-side flexibility (hydrogen production for Offshore; short-duration flexibility such as batteries, electric vehicles and heating for Solar), and the step from the balanced to the committed variant moves the favoured technology from the Optimistic-1 to the Optimistic-2 technology cost scenario and raises the nuclear capacity cap (Nuclear) or removes nuclear (Offshore, Solar). Demand, fuel and CO₂ prices, cross-border transmission capacity and the neighbouring power systems are common to all seven scenarios.

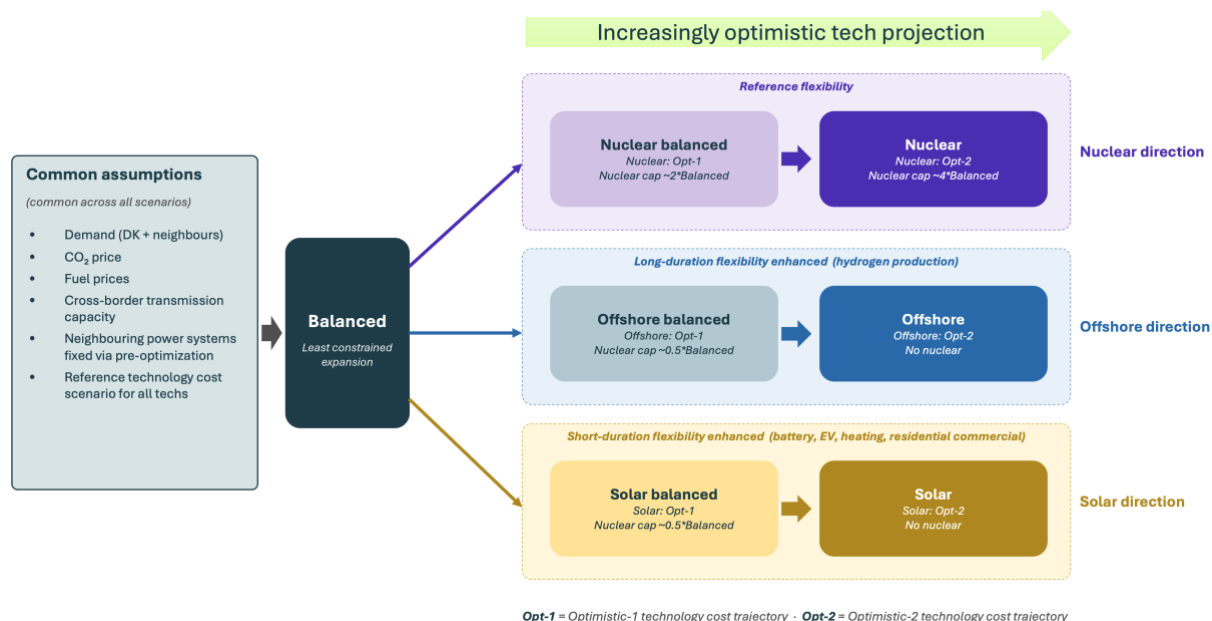


Figure 1. Scenario creation flow chart.

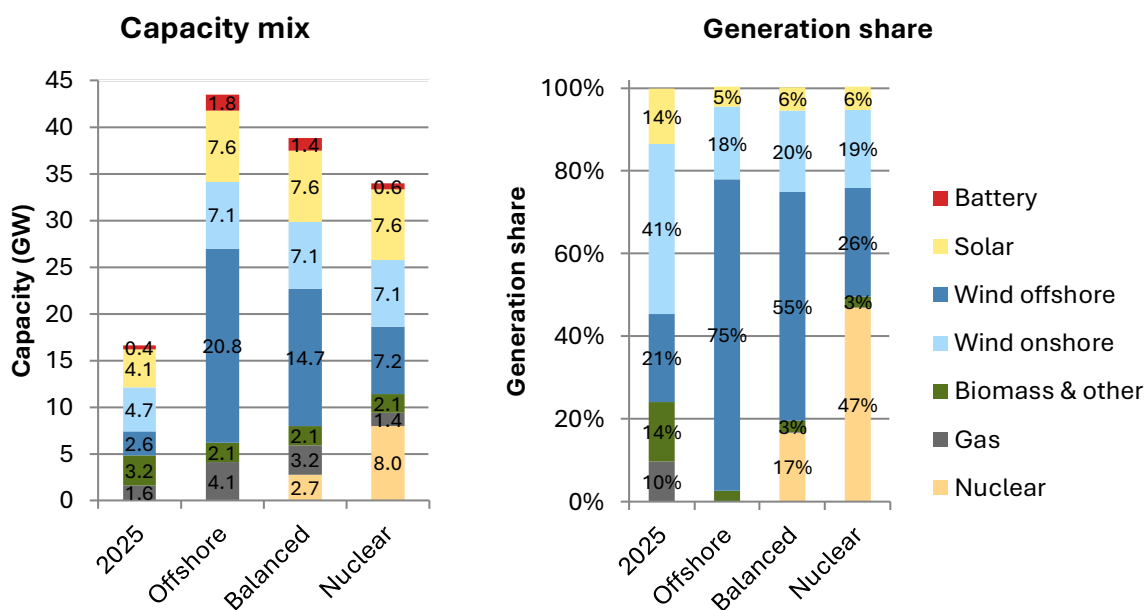


Figure 2. Capacity mix (left panel) and generation share (right panel) split by technology for Offshore, Balanced and Nuclear scenarios alongside the 2025 power system.⁴

The resulting capacity mixes and generation share of the Offshore, Balanced and the Nuclear scenarios compared to the Danish system in 2025 (shown for reference) are

⁴ For 2025, Gas in the generation share covers all fossil-fuelled generation (natural gas, coal and oil) and the fossil share of waste incineration; the remaining waste is included in Biomass & other. The 2025 capacities follow the categories in Figure 20, where oil and waste fall under Other, shown here as part of Biomass & other.

presented in [Figure 2](#). A shared feature across all scenarios is substantial system growth: the applied demand trajectory reaches 102 TWh by 2050⁵ compared to around 38 TWh in 2025, with demand-side flexibility from electric vehicles, heating, behind-the-meter batteries, and hydrogen storage playing a significant role throughout.

Across all scenarios, the system remains heavily wind-dominated, with onshore and offshore wind accounting for a generation share of between 45% and over 90%. Residential solar is present in all mixes. Even in the Nuclear scenario, wind provides 45% of generation, so the scenario names indicate a direction of emphasis rather than single-technology systems. This summary focuses on the Offshore, Balanced, and Nuclear scenarios as the most structurally distinct: the Solar scenarios are excluded because they converge in the modelling towards mixes that closely resemble the Offshore direction.

Performance across different parameters for the three scenarios are presented in [Table 1](#).

⁵ 102 TWh broadly consistent with the central scenario in the EA study. Demand growth scenario variations which total 138 and 64 TWh has been analysed too, but not as comprehensively.

Table 1. Comparison of Offshore, Balanced, and Nuclear scenarios across parameters for self-sufficiency, competitiveness, environmental and climate impact, and operational safety and grid upgrade costs. Light shade and dark shade green represents best and worst performance, respectively.

Category	Parameter	Offshore	Balanced	Nuclear
Self-sufficiency	Import cost (€/MWh)	9.0	1.8	-11.5
	Gas consumption (TWh)	1.0	0.6	0.1
	Demand coverage (%)	55	61	80
Competitiveness	System cost incl. imports (€/MWh)	78	71	69
	Costs escalation (€/MWh)	26	30	40
	Average price (€/MWh)	73	78	72
	Price volatility vs Balanced	-2%	0%	-8%
	Profitability gap (€/MWh)	+12.7	-1.2	+0.9
Environmental & climate impact	Emissions vs 2025	-82%	-82%	-82%
	Minerals use (kt) vs Balanced	+17%	0%	-18%
	Land use (km ² · 10 ³)	1.0	1.1	1.1
Grid & operational safety	Grid upgrade cost (€/MWh) vs Balanced	+28%	0%	-31%
	Dispatchable capacity (GW) vs Balanced	6.2 (-22%)	8.0 (0%)	11.4 (+43%)

Emissions fall sharply in all scenarios: an 82% reduction in lifecycle emissions to 23 gCO₂eq/kWh relative to the 2025 power system, equivalent to a 96% reduction in direct emissions versus 1990 and well below the 2040 target. This reflects the scenario design, in which only open-cycle gas turbines run on fossil fuels and only in a reserve role. Land use varies little across scenarios, as all directions deploy onshore wind to its expansion limit (an increase from 4.7 GW today to 7.1 GW in 2050, approximately +70%) with comparatively modest solar growth. Offshore wind, excluded from the land-use calculation, expands substantially in every direction, from 2.6 GW today to 14.7 GW in the Balanced direction and more in the Offshore direction. Associated sea-area, permitting, and stakeholder concerns and related challenges for nuclear sites sit outside this analysis.

Read by direction, the Offshore scenario shows lower exposure to cost escalation, comparable average prices and price volatility, and slightly higher overall costs at reference technology cost scenario when compared with the Balanced reference case. It shows lower domestic generation potential during the most challenging hours, higher import costs, higher critical-mineral demand, and higher grid upgrade costs. Its principal economic vulnerability is a system-aggregated profitability gap of around 13 €/MWh under reference technology cost scenario assumptions. This profitability gap, representing the shortfall between system-wide technology costs and the market revenues captured by the supply technologies, is driven primarily by cannibalisation of wind-fleet market revenues at high deployment levels.

The Nuclear configuration shows lower import costs and achieves net export revenues on average, the highest demand coverage by domestic generation in extreme hours, the lowest gas consumption, the lowest price volatility, and lower grid upgrade and critical-mineral demand than the Balanced case. It shows the largest exposure to cost escalation among the directions examined, and at the actor level it implies directed support to nuclear producers under reference cost assumptions, even though the system-aggregated profitability gap remains small.

The differences between the Offshore and Nuclear directions are best understood not as differences in cost level – which are small in relative terms and subject to great uncertainty – but as differences in where uncertainty is concentrated. The Offshore direction concentrates uncertainty on the revenue side, through the exposure of large wind fleets to revenue cannibalisation as deployment grows. The Nuclear direction concentrates uncertainty on the cost side, through the exposure of nuclear capital costs to the realised pace of industrial learning and project delivery. Both directions require state intervention to manage their respective uncertainties.

The relationship between this work, different models and other recent Danish system studies deserves highlighting. As a key contribution, the current work has built an open-source PyPSA model which provides a cross-model check of the capacity-expansion results of the proprietary cGrid tool, presented in this report.

Traditional energy models optimise for lowest total system cost but share several structural limitations. First, they typically do not ensure that individual technologies

recover their costs from market revenues, so a least-cost configuration may still leave individual technologies dependent on state support or risk-sharing mechanisms. Second, simplified marginal-price formation in linear models (typically a single heat rate per dispatchable technology) produces stepwise price patterns that can overestimate the capture prices and inflate the revenue expectations underpinning the deployment of variable renewables. Third, such models typically assume intra-year perfect foresight, dispatching storage and flexible demand as though they had full knowledge of supply and demand across the planning horizon. The cGrid model used in this study addresses all three limitations through endogenous price-based bidding and dispatch, an iterative profitability check, and short-term-forecast-based dispatch of storage and flexible demand⁶. Insights from the PyPSA cross-model comparison done in this work has illuminated considerable differences with and without profitability requirement and perfect-foresight assumption exemplified through battery storage dispatch model differences.

Methodological and assumption choices have empirical consequences, illustrated by comparison with the recent EA study. Capacity expansion optimisation with limited constraints on buildouts reveals small differences to the EA study power system mix for the scenarios where nuclear is excluded. However, as nuclear is included differences in the power system mix emerge. At the heart of the discrepancy between the current work and the EA study lies the considerably lower capture rate of the wind fleet in the current work at around 75% and 65% for offshore wind in the Balanced and Offshore scenarios compared to 95% (derived) in the EA study. Slightly higher production costs of 60 €/MWh in the current study vs 55 €/MWh in the EA for the marginal resource (Wind Offshore) in the expansion further drive the difference alongside slightly lower production costs for nuclear (86 €/MWh vs 93 €/MWh). The difference manifests in average spot prices of around 75 €/MWh in this study compared to 60 €/MWh in the EA work. As such, our set of power system mixes comes close to the EA scenario. The two studies are therefore not in contradiction; they place the cost-uncertainty boundary in different positions. The EA study goes deeper along specific pathways; the current study covers a wider range of system configurations.

A second structural finding bears emphasising. Denmark's level of interconnection, relative to its system size, means that average prices, price volatility, and market revenues are to a large extent shaped by developments in the surrounding European market rather than by domestic supply choices alone. This holds across all scenarios examined and is directly linked to the assumptions of fixed neighbouring power systems whilst capacity expansion is performed in Denmark. From a policy perspective, it limits the influence of Danish decisions on market outcomes and places weight on those system attributes that Denmark can influence directly.

⁶ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

The implications for decision-makers can be summarised as follows.

1. The level of self-sufficiency that Denmark wishes to maintain is a policy variable, not an output of cost optimisation; the scenarios examined here span a range of self-sufficiency outcomes (as highlighted by import dependency) that reflect different choices on this question, and that question deserves explicit treatment in the policy process.
2. The timing horizons of the two directions and the value in different levels of expansion differ. Offshore wind, building on existing Danish industrial capability, can in principle deliver expansion within a near-term horizon, given transmission grid upgrades follow timelines, and sees higher relative value in smaller demand growth scenarios as the least cost-effective resources are not needed. The establishment of nuclear capacity in Denmark would require building regulatory frameworks, supply chains, and workforce from a low base, with a longer lead time linked to broader European nuclear development that carries increased value in larger demand growth scenarios.
3. Both directions require state intervention to materialise their projected cost reductions, addressing different underlying risks: project delivery and capital cost realisation for nuclear; cost-reduction realisation and revenue cannibalisation for offshore wind as well as general limitations in energy-only market.
4. Intermediate or portfolio configurations such as the Balanced scenario distribute these risks rather than concentrating them. The trade-off is symmetric: less upside if either technology develops more favourably than projected, but equally less exposure if either direction fails to materialise as expected.

The objective of this work is to provide a transparent, technology-neutral, and analytically grounded foundation for policy discussion on Denmark's long-term energy system development. Rather than identifying a single optimal configuration, a framing that in any case implies more precision than the underlying uncertainties can bear, the analysis makes visible where the uncertainty sits in each direction. For instance, on capital cost and project delivery for nuclear and on revenue exposure for offshore. The intended contribution is to move the policy conversation away from a binary choice between technologies and toward a comparison of what each system configuration requires, what capabilities it brings to system operation, and how its risks are distributed. The choice and prioritisation of directions remain with decision-makers.

1 Introduction

The future role of nuclear power has become an increasingly prominent topic in European energy policy discussions in recent years, alongside continuing debate over the appropriate balance of variable renewables, storage, demand-side flexibility, and dispatchable generation in long-term system design. In Denmark, nuclear power has been banned since 1985. In 2025, the Danish Government announced its intention to assess whether this ban should be reconsidered⁷ and commissioned a study to evaluate the role of nuclear power in the Danish energy system. The discussion sits within a broader question that any climate-neutrality target raises but does not itself answer how the future Danish power system should be configured to deliver climate neutrality by 2050. Climate neutrality does not prescribe a single technology configuration, and several plausible end-state systems can satisfy the climate objective while differing materially in their cost structure, security of supply, market behaviour, and exposure to external developments. The present report contributes to this discussion.

This report has been produced by Quantified Carbon (QC) on commission from the Danish Nuclear Alliance. The analytical framework, scenario design, modelling, and conclusions presented in this work are the authors'. Quantified Carbon⁸ is an international consultancy performing modelling and analysis of decarbonisation pathways for energy systems and industries. Recent work includes power system studies for Sweden, Germany, Poland, and Finland^{9,10,11,12,13}, with contributions used by the Swedish Government in national energy policy formation, cited in the European Commission's Nuclear Illustrative Programme, and applied in work for the United Nations Economic Commission for Europe¹⁴. The present study extends this body of work to the Danish power system in 2050, drawing on the modelling capabilities and analytical methods developed in those previous studies.

The remainder of the report is structured as follows. Section 2 sets out the study's objective and design and discusses how it complements other recent system analyses on the role of nuclear in Denmark. Section 3 describes the modelling framework, including the proprietary cGrid tool and a parallel open-source pyPSA implementation developed for this work, together with the treatment of cross-border exchanges with neighbouring regions, the role of weather years in capacity expansion and resource adequacy, the scenario framework and model configuration, constraints and exogenous assumptions. Section 4 presents the underlying assumptions on emissions and commodity prices, demand and flexibility, technology costs, limits and fixed expansion of wind and solar and existing thermal capacity, alongside the heat sector. Section 5

⁷ Reuters (2025), Denmark is considering lifting 40-year-old nuclear power ban, minister says

⁸ <https://www.quantifiedcarbon.com/>

⁹ Quantified Carbon (2023), Nordic Power Systems for a Competitive and Sustainable Economy

¹⁰ Quantified Carbon (2025), Swedish power systems robust for 300 TWh

¹¹ Quantified Carbon (2024), Power System Expansion Poland

¹² Quantified Carbon (2025), Role of Nuclear in Germany's Decarbonisation

¹³ Quantified Carbon (2025), Power System Expansion Germany

¹⁴ Quantified Carbon (2025), Understanding the Full System Costs of the Electricity System.

reports the modelling results, starting with the result from the pre-optimisation of neighbouring regions to then focus in on the seven main scenarios in focus. Capacity and generation mix, power system dispatch, capacity requirements, costs, market dynamics, self-sufficiency, and grid considerations are aspects covered. Model comparisons between cGrid and pyPSA and sensitivity variations on demand and flexibility also belong to the results presentation. Section 6 provides a summary analysis that compares the scenarios on a coherent set of performance indicators. The appendices provide additional detail on formulas, the 2025 power system, offshore wind potential, technology cost assumptions, and import model results.

2 Study

2.1 Objective

The overall question that has guided this work is:

OBJECTIVE:

Based on an integrated modelling and scenario framework, the study explores alternative climate-neutral Danish power systems in 2050. It evaluates diverse technology supply mixes – including wind, solar, and nuclear – to assess how different configurations can ensure a cost-effective, sustainable, and robust power system.

The objective is to provide a transparent and technology-neutral analytically grounded foundation for policy discussions on Denmark's long-term energy system development.

2.2 How the current study complements others

2.2.1 Previous Denmark system studies on the role of nuclear

One of the primary motivations for the current study is the lack of system studies that properly evaluate the role of nuclear energy with Denmark as the focus region.

However, two recently published academic papers do address this topic. Furthermore, following the Danish Government announcement of a study on the role of nuclear energy in Denmark, the Energistyrelsen (Danish Energy Agency) has published a study conducted by EA Energianalyse and VTT¹⁵.

Thellufsen et al. (2024)¹⁶ compare renewable- and nuclear-based configurations of a carbon-neutral Danish energy system and find the nuclear-based ones more costly. Aarflot Moen et al. (2025)¹⁷, a team of Norwegian researchers from NTNU, revisit the question with a more thorough cost sensitivity analysis covering nuclear, VRE and weather conditions, and instead obtain limited cost differences between systems with and without nuclear. This highlights the uncertainties in cost optimisation, a conclusion also reached in our work¹⁸. What sets the current work apart from Aarflot Moen et al. (2025) is its focus beyond costs, offering a transparent assessment of broader system performance paving the way for insights of greater relevance to policymaking.

¹⁵ EA Energianalyse (2026), Analyse af atomkraft i Danmark

¹⁶ Thellufsen et al., (2024), Cost and system effects of nuclear power in carbon-neutral energy systems

¹⁷ Aarflot Moen, K, et al., (2025), The Total Costs of Energy Transitions with and Without Nuclear Energy

¹⁸ Quantified Carbon (2025), Swedish power systems robust for 300 TWh

2.2.2 EA and VTT study on SMR technologies in Denmark

Following the Danish government's decision to evaluate the potential role of nuclear energy in Denmark, the Danish Energy Agency issued a tender for a system analysis¹⁹. The stated objective was that "the study should evaluate impacts on electricity prices, consequences and business cases for existing and future technologies and producers if SMRs were to participate in the Danish electricity market." The final report by EA Energianalyse and VTT²⁰ objective similarly emphasised identifying "the possibilities and consequences of integrating Small Modular Reactor (SMR) technologies into the Danish energy system."

This framing primarily focuses on assessing the effects of introducing a specific technology into an otherwise implicitly defined future energy system. Such an approach corresponds to a marginal technology-entry perspective, where the central question concerns how the addition of a new generation technology interacts with existing market actors and structures.

This perspective is most defensible in the short term, where the trajectory of investment, infrastructure, and policy is still being established and reversing it carries the highest costs. Over the 2050 horizon examined here, however, the structure of the future system is not yet fixed by prior commitment, and more than one structurally distinct configuration remains reachable. Climate neutrality does not prescribe a single technology configuration, e.g. wind and solar. Instead, different combinations of generation, flexibility, infrastructure, and demand evolution may satisfy climate objectives while leading to distinct cost structures, risk profiles, and resilience characteristics.

Sound long-term energy policy therefore benefits from first clarifying the range of plausible end-state system configurations before evaluating individual technologies within them. Only once alternative climate-neutral system designs are explored can policy instruments and market conditions be robustly aligned with long-term societal objectives.

On this background, the current study by Quantified Carbon adopts a long-term and technology-neutral perspective with the objective presented in Section 2.1.

2.2.3 Current study design in relation to the EA study

Table 2 compares the design of the current study with the EA study, discussed below. The current study aims to capture synergies with these studies while extending policy

¹⁹ Energistyrelsen (2025-2026): Opgavebeskrivelse vedr. levering af analyse af SMR teknologiers indpasning og effekter i det danske energisystem

²⁰ EA Energianalyse (2026), Effects and value of SMR technologies in the Danish energy system

relevance through a wider set of performance parameters that reflects a full-system perspective.

Although the objective framing sets certain analytical boundaries, the study by EA Energianalyse and VTT provides substantial insight into the potential role of nuclear power in Denmark²¹. It represents the most comprehensive system-based assessment to date within the Danish context.

The first part of the work offers a thorough introduction to nuclear technology, including techno-economic assumptions for SMRs, and applies a detailed scenario-based modelling approach. The second part, the energy system analysis, conducted using the Balmorel model, covers a broad European geography and including detailed representation of heat and hydrogen sector coupling, expansion of wind and solar generation, and demand-side flexibility. A notable strength is the inclusion of three substantially different Danish demand development scenarios: one developed by EA Energianalyse and two based on governmental institute projections (AF-25 and KF-25). This allows nuclear deployment to be assessed under materially different demand outlooks.

Methodologically, the study evaluates the system value of introducing SMR capacities (600 MW and 1500 MW) into the Danish system. For each case, the remaining supply mix is re-optimised. System value is defined as the total system cost reduction relative to a reference scenario without nuclear. The system cost evaluation includes a broad set of components such as balancing services, distribution grid reinforcement, resource adequacy mechanisms (capacity markets and reserves), and operational costs. The assessment is conducted for multiple nuclear cost assumptions, with and without heat integration, for both 2040 and 2050.

This framework effectively illustrates how the economic value of nuclear depends on demand trajectories, cost assumptions, and sector coupling configurations. However, two methodological constraints are worth highlighting.

First, the analysis evaluates nuclear against a largely predefined structural development of other technologies. Cost and deployment assumptions for alternative generation and flexibility technologies are exogenously specified, limiting the exploration of broader structural uncertainty in the future technology landscape. As a result, the option space for alternative climate-neutral system configurations remains relatively narrow. Second, the evaluation is primarily conducted through monetised system cost metrics. While comprehensive in cost coverage, the framework does not explicitly assess broader performance dimensions, aspects that may influence long-term policy considerations beyond cost efficiency alone.

In comparison with the EA Energianalyse and VTT study (see [Table 2](#)), the present study adopts a different analytical perspective. Rather than assessing the marginal value of

²¹ EA Energianalyse & VTT (2026), Effects and value of SMR technologies in the Danish energy system

nuclear in a predefined system, it explores a spectrum of structurally distinct climate-neutral system configurations for Denmark. The analysis systematically varies both technology mixes and cost uncertainties across all major technologies. What further sets the current study aside from the others is the that installed capacity in neighbouring regions is pre-optimised on a Reference scenario and then held fixed during the capacity expansion of the Danish system. Given Denmark's high level of interconnection, this is a deliberate analytical choice: allowing neighbours to re-optimize in response to Danish supply choices would dampen the differences between scenarios by absorbing them into adjusted neighbouring capacity, and would not reflect the actual energy-policy reality, in which national decisions are primarily made independently rather than co-optimised across borders. The flip side is that the results may understate what closer cross-border coordination could achieve.

Beyond system cost outcomes, the study evaluates additional performance indicators including price volatility, resource adequacy, reliance on critical materials, and the role of public financial support. By presenting a coherent set of quantified indicators across alternative technology pathways, the study aims to provide decision-makers with transparent insights into trade-offs, risks, and structural choices relevant for Denmark's long-term energy system development.

Table 2. Key differences between the EA Energianalyse and VTT (2026) and the current Quantified Carbon study.

Aspect	EA Energianalyse and VTT study (2026)	Quantified Carbon study
Main analytical question	Effects and system value of introducing specified SMR capacity into defined future pathways	Characteristics and trade-offs of structurally different climate-neutral 2050 power-system configurations
Time perspective	Pathway-oriented analysis	2050 end-state analysis
Weather years	Capacity expansion on weather year 2014	Capacity expansion on weather year 1991; resource adequacy dimensioned on weather year 1985; evaluated on 33 weather years
Neighbouring capacity	Co-regional capacity expansion	Pre-optimised on a reference scenario and held fixed during Danish capacity expansion
Technology cost uncertainty	Multiple nuclear cost assumptions; other technology development largely specified	Cost uncertainty varied across all major technologies
Demand variation	Three substantially different Danish demand scenarios	Focus on 102 TWh, with 64 TWh and 138 TWh sensitivities
Evaluation framework	Broad monetised system-cost assessment, including balancing, grids and adequacy mechanisms	System costs plus additional indicators for prices, volatility, self-sufficiency, resources and operational considerations

Notably, this comparison does not incorporate all relevant studies.

3 Methodology

The study follows a five-step modelling workflow, illustrated in [Figure 3](#). All steps from pre-optimisation through evaluation (steps 2–5) are carried out using the electricity market modelling tool cGrid, Quantified Carbon's proprietary capacity expansion and dispatch model. An independent verification of the capacity expansion results (step 3) is performed using the open-source model PyPSA. Modelling tools are further introduced in [Section 3.1](#).

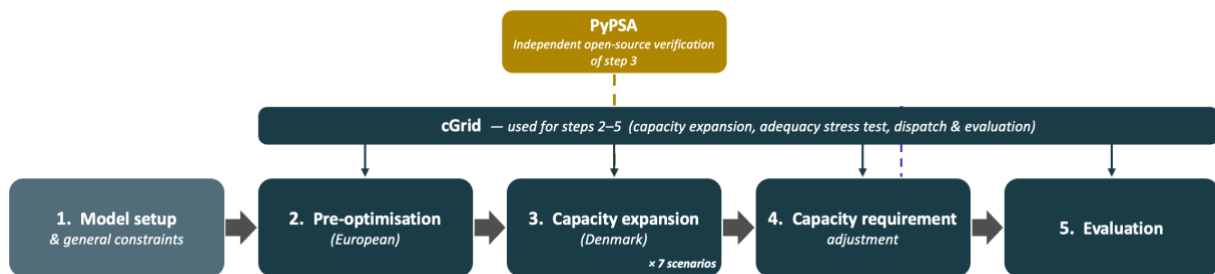


Figure 3. Flowchart of overarching model workflow.

The model workflow is walked through step by step in the following.

Step 1: Model setup establishes the common modelling environment and general constraints that underpin all subsequent steps. This includes key assumptions, relating to CO₂ and commodity prices, electricity and heat demand, demand-side flexibility, technology costs, and exogenous constraints on existing thermal capacity and expansion limits for offshore wind and residential solar, as documented in [Section 4](#).

Step 2: Pre-optimisation determines a fixed European generation and storage mix, given assumed cross-border transmission capacities, that is held constant across all scenarios simulated for the Danish power system in the following. This ensures that differences in results between scenarios reflect Danish system choices rather than variations in the surrounding European system. The rationale for this approach is described in [Section 3.2](#) whereas the results are presented in [Section 5.1](#).

Step 3: Capacity expansion optimisation is performed for the Danish power system mix for the seven main scenarios. The scenarios are defined by three technology directions: nuclear, offshore wind and solar, whilst demand-side flexibility, and technology cost assumptions enable structural variations in power system mixes. The scenario framework is introduced in [Section 3.4](#).

Step 4: Capacity requirement adjustment augments each of the seven optimised mixes from step 3 with gas peaking capacity and battery storage as needed to satisfy resource adequacy requirements. The adequacy assessment is based on one period of extreme scarcity in the weather year of 1985.

Step 5: Evaluation assesses the seven final Danish systems across four dimensions: cost and economics, security of supply, environment and resources, and system integration in Section 5 and 6.

3.1 Modelling

3.1.1 cGrid

Many long-term capacity expansion studies rely on linear, cost-optimising models with perfect foresight of the full time series of weather-driven generation and demand. This can lead to overly optimistic dispatch of storage and flexible demand, and it can understate how market dynamics and price formation affect investment incentives. Quantified Carbon therefore complements conventional capacity expansion modelling with additional steps that are designed to be more realistic and policy-relevant.

First, candidate 2050 system configurations are tested across multiple historical weather years, rather than relying on a single "typical" year. This helps quantify robustness to interannual variability and identify problematic combinations of conditions (e.g., periods with correlated low wind output and reduced hydro inflows), which can materially affect prices, adequacy and the value of different technologies. In a Nordic case study, by Quantified Carbon and several Nordic researchers²², this approach is demonstrated by evaluating outcomes across 33 historical weather years (1983-2015).

Second, Quantified Carbon uses its proprietary non-linear electricity market model cGrid to mitigate the intra-year perfect-foresight limitation in conventional capacity expansion planning. Rather than optimising storage and flexible assets with full knowledge of the year ahead, cGrid uses rolling short-term price forecasts to guide dispatch and bidding decisions for price-responsive assets. In Cox et al. (2026)²³, cGrid is historically validated and reproduces annual average prices within about ±EUR 1/MWh across Sweden's bidding zones. The paper also shows that under problematic weather conditions, perfect-foresight capacity expansion modelling and a rolling-forecast approach can diverge substantially in price trajectories and the implied need for firm capacity (with half-year average price differences up to around ±EUR 40/MWh and opposite nuclear capacity recommendations in their Swedish case study).

For Denmark, with high shares of wind, strong cross-border market integration, and growing interest in long-duration flexibility (e.g., PtX/hydrogen), these methodological elements provide a practical way to stress-test policy-relevant questions about robustness, price volatility and security of supply, and to ensure that conclusions are not

²² Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

²³ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

driven by a single weather year in the evaluation (capacities are sized on weather year 1991) or by unrealistic operational foresight.

As presented in the scientific article introducing cGrid²⁴, historical benchmarks of model performance are integral to the current modelling study as well as the Quantified Carbon price forecast “Quantified Power Outlook”. The performance on historical year of 2025 is presented in Figure 4.

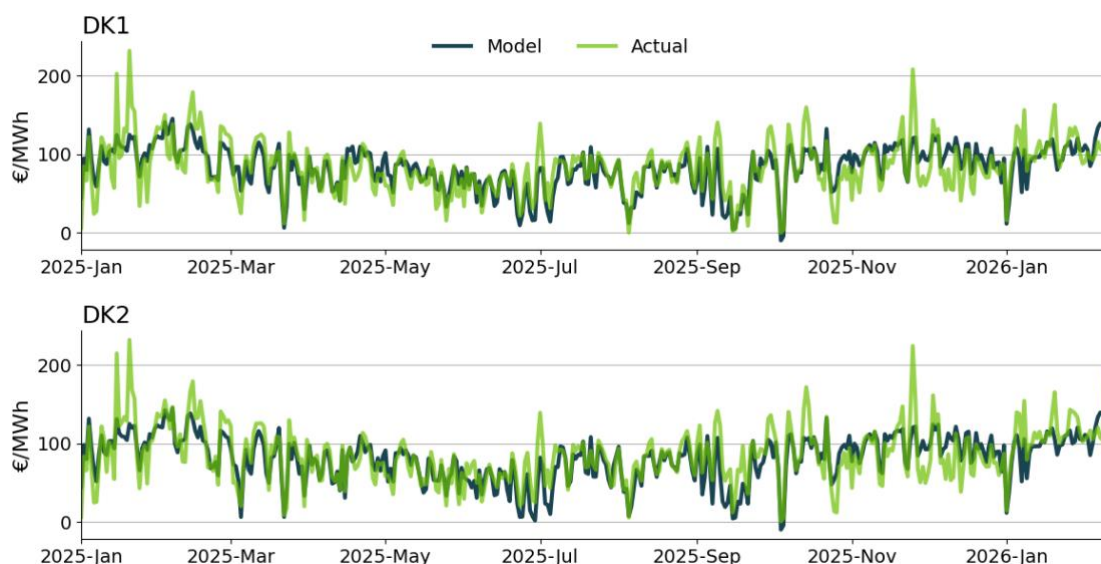


Figure 4. Historical benchmark of cGrid electricity market modelling, comparing model results to actual day-ahead market prices across the year 2025 and start of 2026.

The role of the expanding wind power fleet is important to understand from a market profitability point of view, both to analyse near-term deployments and in the evaluation of capacity expansion optimisation in the long-term. Historical capture price of onshore wind is compared to cGrid model results in Figure 5.

²⁴ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

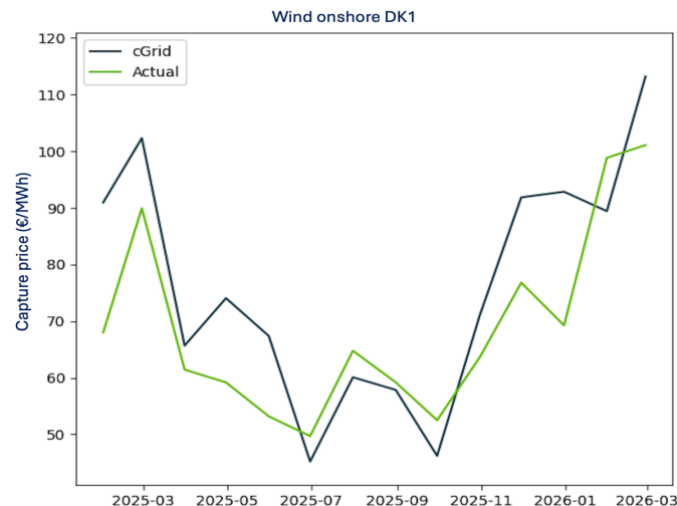


Figure 5. Comparison between model (cGrid) and market actual historic data for monthly average capture prices of onshore wind in DK1 for the year 2025 and start of 2026.

3.1.2 PyPSA – open source

3.1.2.1 Purpose of the PyPSA implementation

As mentioned earlier, an independent verification of the cGrid methodology has been performed using PyPSA²⁵ (Python for Power System Analysis), an open-source modelling framework designed for large-scale optimisation of electricity and multi-energy systems. PyPSA enables both capacity expansion planning and dispatch within a unified optimisation framework, making it particularly suitable for long-term decarbonisation studies. PyPSA is widely used in both academic and policy-oriented studies, particularly in European system modelling^{26, 27}.

cGrid has been shown to provide reliable results, see Cox et al.²⁸, where benchmarking against 2018 historical data shows close agreement in both yearly average prices and hourly prices. cGrid is however proprietary and closed source. PyPSA, and the PyPSA model developed for this study are open source, this has many advantages for transparency and future development beyond the scope of this report.

²⁵ <https://pypsa.org/>

²⁶ Brown et al. (2018) Synergies of sector coupling and transmission reinforcement in a cost-optimised, highly renewable European Energy System

²⁷ Victoria et al. (2019) The role of storage technologies throughout the decarbonisation of the sector-coupled European energy system

²⁸ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

3.1.2.2 Spatial resolution and model geography

PyPSA models can be built at many levels of granularity depending on the intended use case. For siting of new industrial loads, near-term grid expansion, and other uses that are sensitive to individual sub-station, low voltage cables, or similar small details, PyPSA can represent this with highly detailed with a highly detailed nodal mode. For long-term studies involving a large amount of the inter-European, such as this one, see [Figure 9](#) for model scale, such granularity is not feasible for 2050, with too many unknowns such as generation and demand locations, local grid reinforcement, or similar. Aside from the difficulty in defining such a granular model there are two further considerations, such a model would be very computationally expensive to solve and would also not align with the cGrid model, thus precluding any meaningful comparison.

For these reasons, a “copper plate” approach has been taken in the design of this PyPSA model, each modelled zone is treated a single node, with all its generation and demand attached to it, and only inter-zone connections modelled.

3.1.2.3 Component representation

Several components map directly from cGrid to PyPSA, a cGrid zone, becomes a PyPSA bus, and a cGrid transmission becomes a PyPSA link. In the following sections the conversion of components from cGrid to PyPSA will be detailed, included specialised components that describe fleet-level behaviour.²⁹ For greater detail refer to open-source repository.

Zones

A cGrid zone directly maps onto a bus in PyPSA, this bus then has all loads and generators for that zone attached to it and is connected to relevant zones as by transmission lines modelled as PyPSA links.

3.1.2.4 Generator Types

Dispatchable Generators

The simplest form of generator simply produces power at a given marginal cost and is paid for this production determined by the marginal generator, if the price offered is below the marginal cost it will not produce. This generator can have a minimum generation requirement enforced, to represent price-insensitive generation, such as captive generation for heat where electricity is a byproduct. This can be further modified to have a quadratic marginal cost whereby the marginal cost increases linearly as generation scales up to the maximum capacity. This gives a realistic fleet level response for dispatchable generation, whereby units with a lower marginal cost will activate first

²⁹ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

and progressively more expensive units will activate as the price rises. This is similar to the approach employed in cGrid, but somewhat simpler as the response is linear in PyPSA as opposed to following an s-curve.

This introduces a quadratic term into the optimisation and stops it being a purely linear problem, which creates problem for some solvers. A further refinement here could be switching to N banded generators, with constraints of matching capacity that expand or contract together. This would increase the number of generators in the model by roughly $30 \times N$, slowing the solve but purely linear problems generally solve faster so this is worth investigating, it could also allow some simplifications in the solve pipeline but this would need to be balanced with the discretisation of the represented fleet producing power instead of responding smoothly to demand.

Variable Renewable Generators

For wind and solar, the power generation is determined by the weather, and this behaviour is reproduced in PyPSA by providing a variability profile and enforcing generation at this level, by locking the minimum and maximum generation to this value. This enforcement is important as otherwise the generator would shield itself from negative prices by choosing not to dispatch, which would not reflect realistic behaviour.

Hydro Generators

Hydro generation, whilst not part of the Danish grid does compose a large fraction of the European grid and provides stability, as such it is important to model accurately. This is done by allowing free dispatch based on market conditions akin to dispatchable generators but also strictly enforcing a minimum and maximum hourly reservoir level over the year. The reservoir is also filled by an inflow generator that has a production profile determined by the weather. These limitations largely mitigates the issue of perfect foresight whereby PyPSA will optimise the discharge of the reservoirs because it knows exactly when they will be refilled.

PyPSA generator type representations

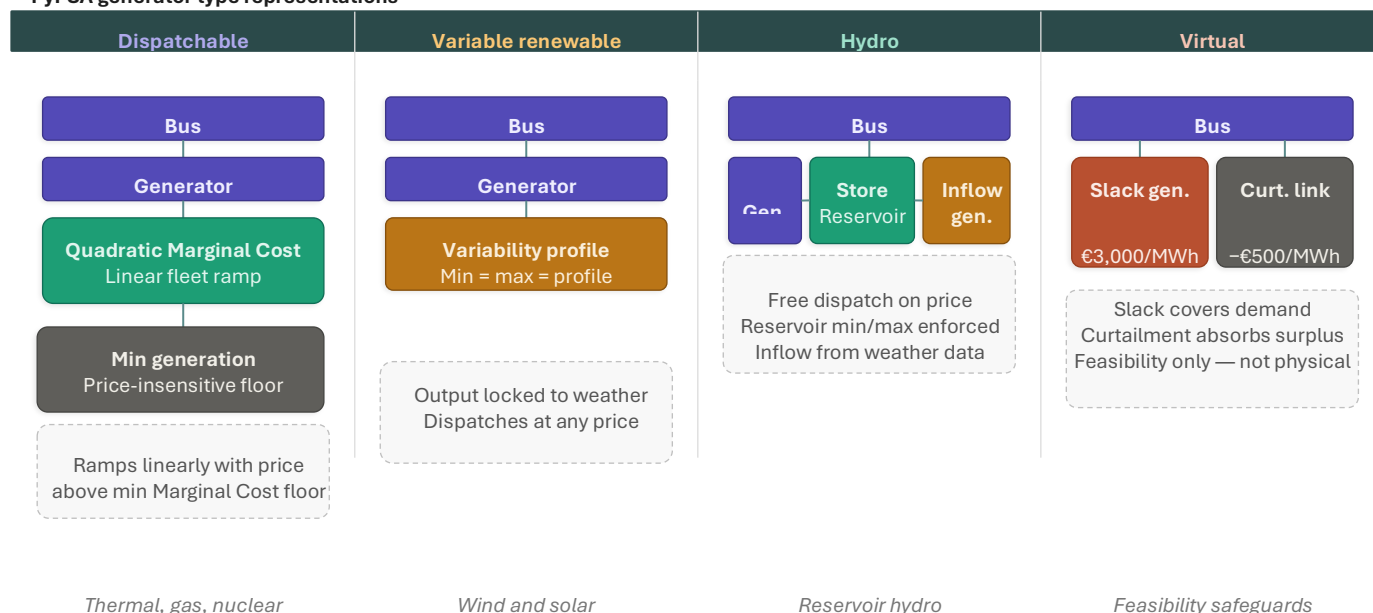


Figure 6. Representation of the Generator Components in the PyPSA model, additionally virtual components are shown.

3.1.2.5 Load Types

Loads

The simplest form of load requires its demand to be fulfilled and will pay the cost of the marginal generator. In PyPSA loads are treated as a fixed point in the solution and must be satisfied. This type of load is good for representing inelastic and price-insensitive loads such as residential and commercial demand.

Linear loads

PyPSA Loads have no flexibility to reduce their demand in response to high prices, and many realistic loads will do just that so this needs to be accounted for in the model. This is handled by modelling the load as a series of negative generators that consume power up to their capacity until the price rises sufficiently and then they stop consuming. To the model this is seen as a load that reduces its size based on the price, or a price-sensitive load.

Linear loads with an inflexible component

The simple load and the linear load can be combined to give a load that is partially sensitive to price but has a component that must always fulfilled.

Flexible Loads

With linear loads demand is reduced if prices are too high, this reflects many real-world scenarios but some loads, such as residential heating or EV charging cannot be reduced but they can be shifted temporally. This is handled by adding a store to the load that is dimensioned based on the flexibility of the given demand. This has the result that the consumption can be shifted between grid and the store so the inflexible load and appear flexible in the model. A cyclic constraint is applied to the store enforcing that its level is 0.5 at the start and end of the year meaning no demand isn't artificially reduced.

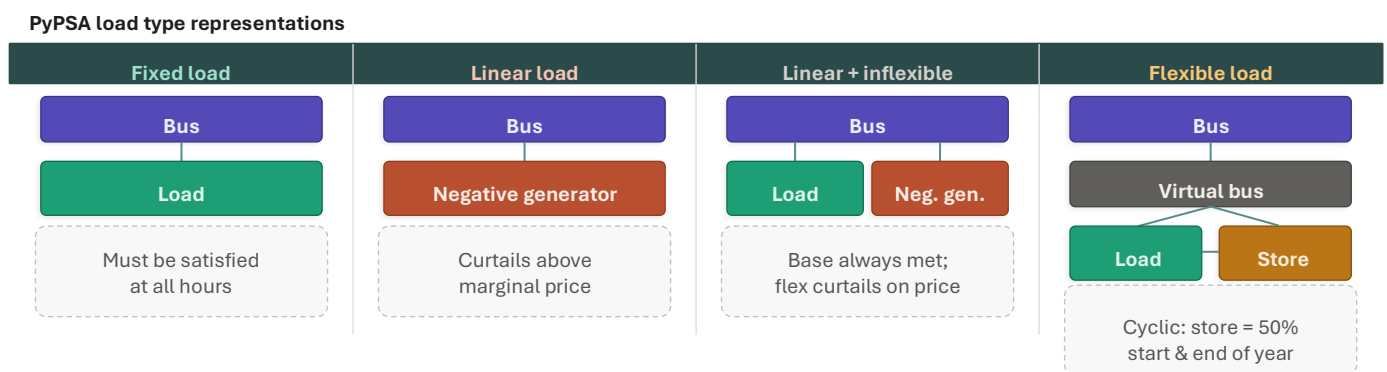


Figure 7. Representation of the load types in the PyPSA model.

Stores

Batteries and hydro storage are modelled as stores in PyPSA, this is somewhat simpler than the approach in cGrid where a storage is modelled as a paired load and generator but functionally the approaches are the same.

Transmissions

Transmission lines are modelled a paired set of one-way links between the two zones, one for each direction in PyPSA, this allows for simple handling of asymmetric capacity and availability. In cGrid this functionality is built into a single transmission line. Again, these approaches are functionally the same.

3.1.2.6 Custom modelling extensions

Alongside these directly mapping real world components several virtual components are added to ensure the model will also have a feasible solution.

Curtailment Link

First of these is a zero-efficiency curtailment link with a marginal cost of €500 between each zone and a curtailment bus for that zone. This has the effect on the model that if for any hour there is too much enforced generation in the system, for instance due to wind production, that the power is sent through this link and essentially lost, whilst producing a strong negative price signal to discourage the model from overbuilding. The capacity of this link is scaled to be sufficient to cover the generation in the zone to keep the optimisation feasible, as overly large values can cause numeric infeasibility in solvers.

Slack Generator

To handle the opposite problem of too much power in the system, namely not enough power in the system each zone has a slack generator, with a marginal cost of €3000, that is scaled to be able to fulfil the demand in the zone, without adversely affecting the feasibility.

3.1.2.7 Solve workflow

With the above-described implementation, it is not possible to perform capacity expansion and dispatch optimisation in a single stage, due to the dependence of the quadratic marginal cost on the capacity, which is not known before expansion.

Investment Pre-Solve

For the quadratic marginal cost applied to fleet-level dispatchable generators, the quadratic term is dependent on the total capacity, which is not known before the expansion, so it is modelled with a single marginal cost at the centre of distribution to give a sensible starting point for the iterative solve. Then once the capacities are fixed, the quadratic marginal costs are calculated and applied to the generators.

Dispatch Solve

The model with capacities determined in the pre-solve can now be optimised with a cost-minimising hourly dispatch where all flexible loads/generators/storages can find their optimal state to deliver the lowest total system cost.

Fully linearising the model would have the potential to combine these two steps into a single step, as detailed earlier.

Iterative Dispatch Solve with Capacity and Availability Adjustment

After performing the investment pre-solve and a first iteration of the dispatch solve, the profitability of each generator can be calculated. If a generator, for instance gas, is shown to be losing money on each MW of capacity, it can be adjusted down. Conversely if a generator is making a lot of money on each MW of capacity it can be adjusted upwards. Here a limit of 5% minimum capacity adjustment in a step is applied to

discourage many small, and potentially oscillatory, steps elongating the solve time without meaningful improvement to the result.

At the same time, the year is split into chunks and if a generator can reduce its costs by temporarily reducing its capacity for that chunk, it can do so. This reproduces the fleet level behaviour of unit commitment.

These two adjustments on each iterative loop produce a system that is cost-optimised whilst enforcing any generators built in Denmark maintain profitability.

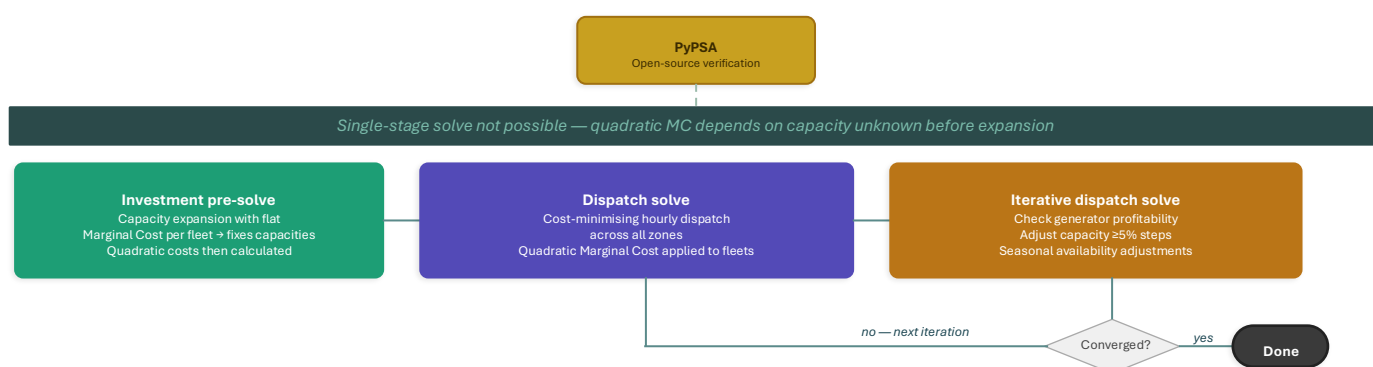


Figure 8. Flowchart of iterative PyPSA workflow

3.2 Pre-optimisation to establish exchange with neighbouring regions

The regions included in the modelling and assumed transmission capacities³⁰ are shown in [Figure 9](#). A modest development of new or strengthened transmission line projects across EU are assumed to take place compared to 2025 as highlighted in [Table 3](#).

³⁰ Availability of transmission line capacities have been assumed to be identical to observed data in 2025.

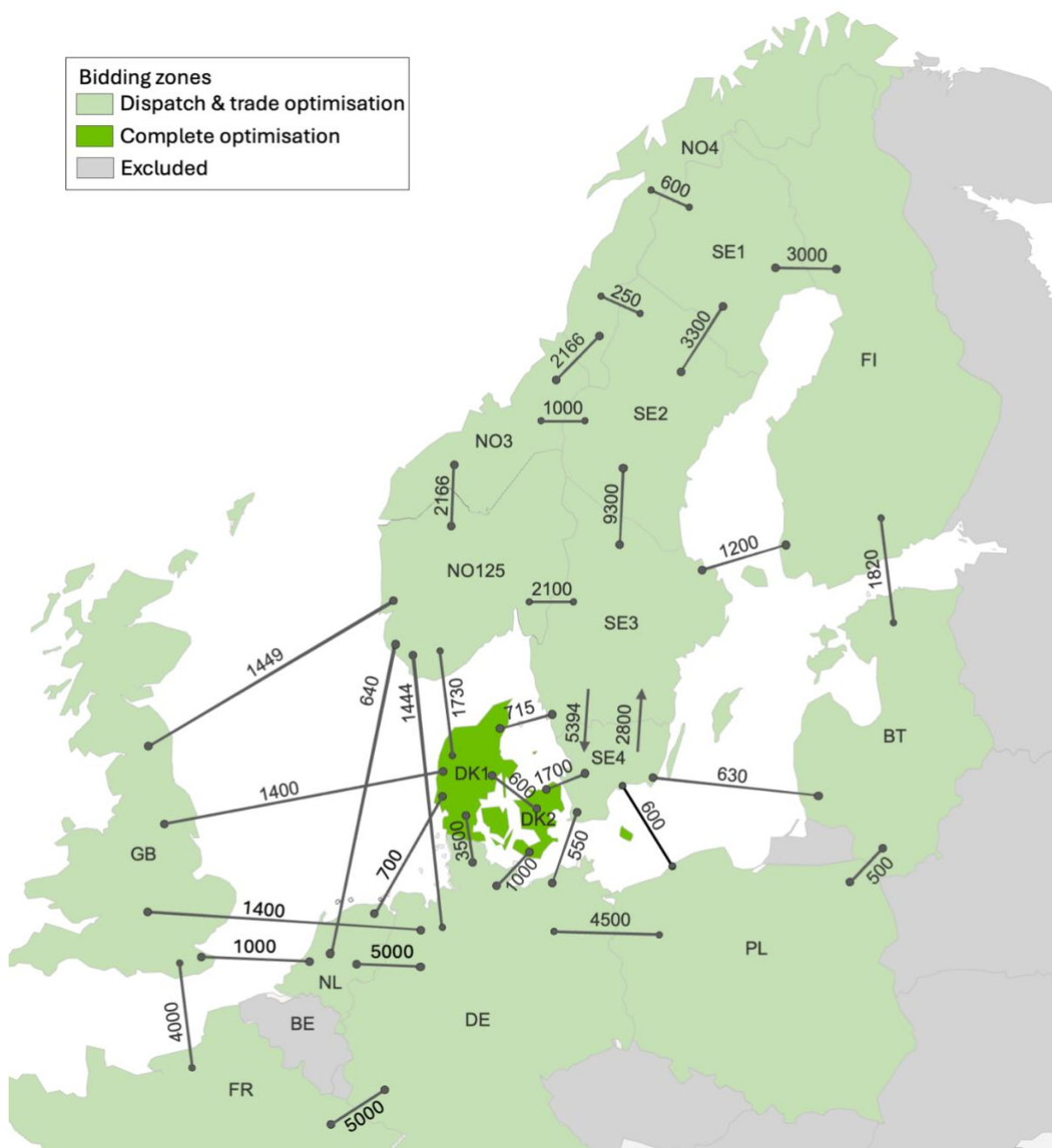


Figure 9. Geographical boundaries showing the regions included in the modelling and how they are treated in the optimisation. The lines represent transfer capacities in the model, and the numbers indicate the associated net transfer capacity (MW), NTC, for the model year 2050. The zones NO125 and BT represent a merger of NO1, NO2 and NO5 and the Baltic zones, respectively. Although not visible in the figure, Spain has also been included in the model.

Table 3. Transmission capacity of interconnections in 2025 compared to model assumptions in 2050 for expanding lines.

Interconnection	Capacity in 2025	Capacity in 2050
SE2-SE3	8030	9300
SE1-FI	1550	3000
DK1-DE	2500	3500
DE-GB	0	1400
FI-BT	1020	1820

In this study, we have included international trade by defining the necessary inputs, i.e. installed generation capacity per power type and load and its flexibility, for all areas outside Denmark. The Danish power system, which is small, is greatly affected by assumptions about future power systems in neighbouring countries. In this work, we have chosen to use pre-optimisation of generation capacities outside Denmark's borders instead of jointly optimising all countries in the study for all scenarios. The reason for this is that pre-optimisation better reflects the actual energy policy conditions and reduces the risk of overestimating coordination gains between countries.

The pre-optimisation has been carried out using the "Balanced" scenario as a starting point. Here, limits have been set for nuclear, onshore wind and gas power with carbon capture based on each country's energy policy. In contrast, solar and offshore wind have been given free rein to expand as long as they are economically viable, as area conflicts are easier to manage for these power sources. The power systems identified through the pre-optimisation have then been used in all scenarios in the study.

One alternative option would have been to co-optimize all countries, which could potentially capture coordination gains between Denmark and other countries. For example, if Denmark builds a system with a low share of dispatchable power, it may be more profitable for neighbouring countries to invest in such production, and vice versa. This would in turn reduce the difference between the scenarios, as neighbouring countries could compensate for Denmark's choice.

However, we believe that such a model would result in an overestimation of the coordination gains, since in practice there is no optimal coordination between how Denmark's and the rest of the world's energy systems develop. In reality, the coordination gains may even be negative. A common argument in the energy policy debate is that the country should follow neighbouring countries that invest in a certain

type of power generation in order not to ‘become the worst in class’. This can then lead to both Denmark, in this case, and neighbouring countries investing in the same type of power, which increases the correlation in electricity production and thus the covariance in the regional power system. Since energy policy decisions are made nationally, Denmark’s energy policy primarily affect new production within Denmark. It is Denmark’s own responsibility to ensure a power system that works for its national needs and whether and to what extent it can rely on other countries to build production capacity to give us reasonable electricity prices or prevent power shortages. This is why we have chosen a pre-optimisation model rather than co-optimisation, as it provides a more realistic picture of the differences between different areas.

3.3 Weather years – capacity expansion and adequacy assessment

To capture the multiannual variability of renewable generation and demand, which is fundamental in the design and operation of power systems with high share of variable renewable generation this study uses 33 weather years covering period 1983-2015^{31, 32}. Weather-driven time series are generated using the Weather2Energy tool, which converts climate data into consistent profiles for wind, solar, and temperature-dependent demand. The dataset spans over 30 years, enabling the model to capture a wide range of meteorological conditions, including extreme years. Such a multi-year approach improves the robustness of capacity expansion and adequacy assessments by explicitly accounting for weather-driven variability. Further, with the adopted market model the use of multiple weather years enables a detailed deep dive into the price variability and dynamics over those years.

³¹ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

³² Quantified Carbon (2025), Swedish power systems robust for 300 TWh.

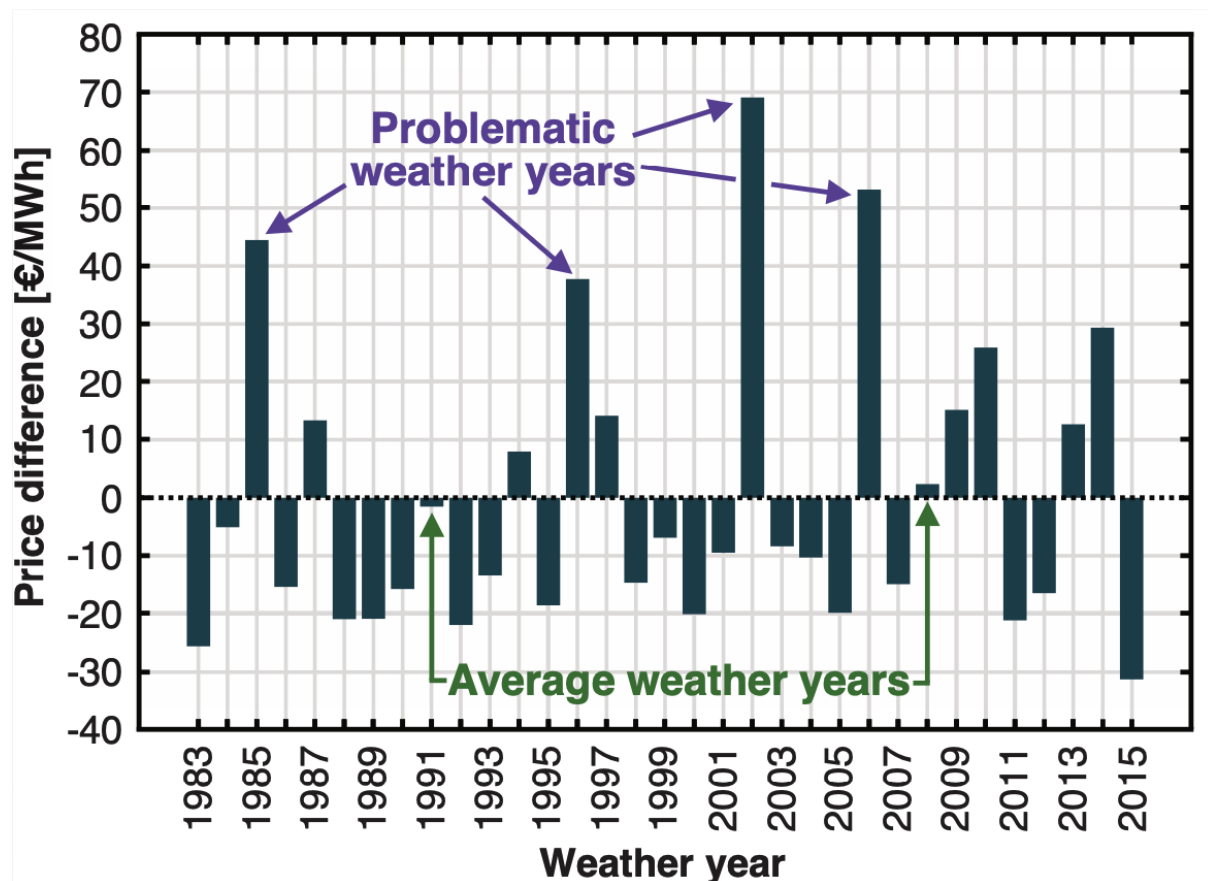


Figure 10. Relative deviation of yearly modelled electricity price across 33 weather years (1983–2015) averaged over all bidding zones included in model. Based on evaluation performed by Cox et., al³³.

The characteristics of the weather year set employed in the current study is illustrated through the deviation to the average market price for all bidding zones included in the model in Figure 10. The year 1991 exhibits the lowest deviation and was therefore chosen as a representative year for capacity expansion. This means that it is considered to be average in terms of weather-driven market conditions. With this analysis it becomes possible to identify problematic weather years as well. Weather years 1985, 1996, 2002, and 2006 emerge as those with the highest average yearly electricity prices. Recent work in the Swedish context for Energiforsk³⁴ identified 1996 and 2002 in particular to be characterised by energy deficit, i.e. month-long periods of low wind-solar production and hydro inflow. Weather year 1985 naturally also features reduced supply, however, it also features a short-duration 1-day event at the end of January with extreme system stress across Europe.

³³ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

³⁴ Energiforsk (2025), Bilagor: Så får industrin tillräckligt med el till 2035.

As per this analysis, the following study uses the 1985 January event to perform resource adequacy assessment. The current study enforces a capacity requirement to the main scenarios which implies a degree of resource adequacy with no loss of load expectation across the 33 simulated weather years. This deterministic approach does not explicitly incorporate a stochastic evaluation of outages similarly to what the European Resource Adequacy Assessment (ERAA)³⁵ takes on. The ERAA, in particular, aims to evaluate loss of load expectation and estimated energy not served in a more short-term and constrained context compared to the current work. The capacity requirement adjustment is presented in more detail in Section 5.4.

3.4 Scenario framework

A set of seven scenarios is developed to explore alternative pathways for the Danish power system. Scenario definitions are provided in Table 4 while a visualisation is given in Figure 11.

The Balanced scenario serves as the common reference point, applying reference-level cost assumptions across all technologies with no scenario-specific capacity constraints (common expansion limits, such as about 7 GW of onshore wind, apply to all scenarios), the scenario with the least constrained expansion. From this baseline, three technology directions are explored, each representing a potentially foundational supply source for the future Danish energy system: a Nuclear direction, an Offshore wind direction, and a Solar direction.

The purpose of these directions is not to identify the most likely outcome, but to explore the characteristics and implications of structurally different technology mixes, thus testing more extreme ends of the option space rather than clustering around the Balanced scenario. Each direction is defined by two scenarios of increasing ambition: a balanced variant that takes a moderate first step in the directional push, enabling a more informed reading of how results shift as you move away from the Balanced scenario, and a fully committed variant that pursues the direction to its logical extreme.

Making a technology direction viable at scale requires more than optimistic cost assumptions for that technology alone. Two further adjustments are therefore applied. First, the technology cost trajectory is set progressively more optimistic for the technology in focus. The technology cost scenario, see also Section 4.3, Optimistic-1 is applied in the balanced variant to Optimistic-2 in the full variant. Second, for the variable renewable directions (Offshore and Solar), demand-side flexibility assumptions are adjusted to better reflect the capabilities and system needs of those technologies: long-duration flexibility (hydrogen production) for the Offshore direction, and short-duration flexibility (EVs, residential commercial, heating) for the Solar direction which is further elaborated in Section 4.2.2.

³⁵ ENTSO-E (2025), European Resource Adequacy Assessment 2025 Edition.

Nuclear capacity limits require separate treatment. In an unconstrained optimisation, nuclear expansion can jump to implausibly large values as cost assumptions improve, departing from a realistic deployment trajectory. The caps applied in the Nuclear scenarios are therefore anchored to the nuclear capacity that emerges from the least constrained Balanced scenario. The caps have been set at approximately 2× and 4× the level obtained in the Balanced scenario, respectively. In the results, nuclear is built up to these caps, at 4.5 GW in Nuclear Balanced and 8.0 GW in Nuclear. As no scenario varies nuclear alone at Reference costs, the value of nuclear by itself is not isolated, and the directions should be compared as packages. In the Offshore and Solar directions, where nuclear is not the technology of focus, the cap is set to roughly half the Balanced level, limiting its role without excluding it entirely. In the full Offshore and Solar scenarios, nuclear is prohibited altogether.

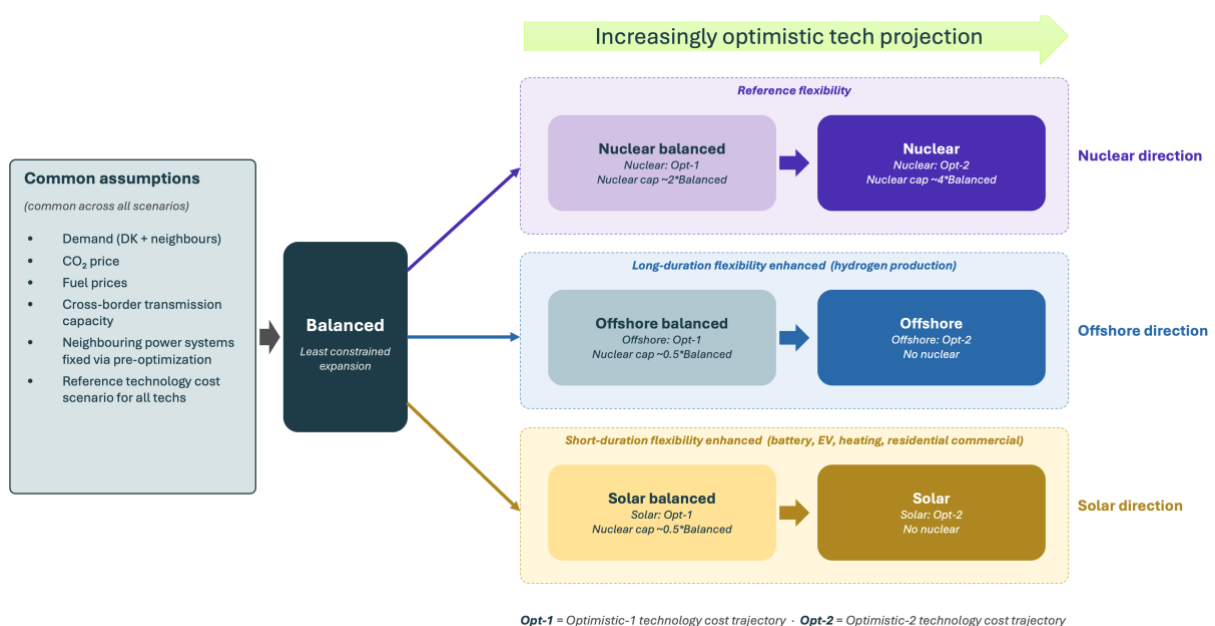


Figure 11. Scenario creation flow chart.

Table 4. Supply scenario definitions.

Scenario	Nuclear SMR cost	Offshore wind cost	Solar & battery cost	Demand-side flexibility	Nuclear cap
Balanced	Reference	Reference	Reference	Reference	No cap
Offshore Balanced	Reference	Optimistic-1	Reference	Optimistic, long-duration (H ₂)	~0.5 × Balanced
Offshore	—	Optimistic-2	Reference	Optimistic, long-duration (H ₂)	0
Solar Balanced	Reference	Reference	Optimistic-1	Optimistic, short-duration (EV, heating, residential commercial)	~0.5 × Balanced
Solar	—	Reference	Optimistic-2	Optimistic, short-duration (EV, heating, residential commercial)	0
Nuclear Balanced	Optimistic-1	Reference	Reference	Reference	~2 × Balanced
Nuclear	Optimistic-2	Reference	Reference	Reference	~4 × Balanced

3.5 Model configuration, constraints and exogenous assumptions

The study has the following model configuration, restrictions and exogenous assumptions:

Focus on one demand scenario:

- The study has a focus on scenario with an annual demand of 102 TWh. Variations in scenarios of 64 TWh and 138 TWh are only examined in an initial sensitivity analysis in Section 5.8. Demand assumptions are described in Section 4.2.1.

Hydrogen:

- Infrastructure investments for the production, transmission and storage of hydrogen on the demand side have been excluded from the optimisation, although these investments are expected to be significant. These investments are expected to be borne mainly by consumers (and thus should not be included as a cost of the electricity system), but they provide valuable flexibility to the electricity system. Sensitivity to the flexibility stemming from hydrogen production and its impact on the power system is included by one optimistic and one conservative scenario variation.
- Hydrogen-fuelled gas turbines have not been considered.

CO₂ emissions and price:

- In this study, a CO₂ price of 132 €/tonne CO₂ is assumed as the main driver for decarbonisation and emission reductions (see also Section 4.1). This value lags behind the level of around 250 €/tonne CO₂ in 2050 for advanced economies with net zero emission targets which that IEA estimates³⁶ but exceeds current levels.
- All existing fossil-fuelled power plants in the Danish power system will be decommissioned. However, natural gas-fuelled turbines are used to ensure resource adequacy as described in detail in Section 5.4. Notably, merely open-cycle gas turbines are considered given their prescribed activation at prices merely exceeding 500 €/MWh which means low utilisation that is a poor fit for the more capital intensive combined-cycle gas turbines. By design, this means that the emissions level of the Danish power system scenarios is very low. Consequences on varying these assumptions are discussed in Section 5.7.2.
- The model takes into account direct emissions from combustion in thermal power plants. Indirect emissions are integrated into the analysis by including life cycle emissions.

³⁶ IEA (2025), World Energy Outlook 2025.

Transmission grid and trade:

- A fixed (constant) expansion of transmission capacity for all connections between bidding zones has been assumed in all modelling cases according to ENTSO-E plans.
- The pre-optimised European power system is not fully fossil-free and has a certain amount of natural gas-fired power plants with and without CCS. This is considered realistic and allows the optimised Danish power system to import dispatchable power to some extent.
- Reinforcement of transmission capacity between the Danish bidding zones has not been part of the optimisation. Notably, aligning price averages DK1 and DK2 has been evaluated across scenarios to ensure this is a reasonable assumption.
- Only transmissions between bidding zones are included. This means that a more granular modelling of the Danish electricity network that includes transmission lines or regional and local grids is not considered
- Reinvestments and new investments to maintain and expand the existing Danish transmission grid, regional and local distribution networks are assumed in all modelling scenarios. The costs for this have not been incorporated in the analysis.
- The energy islands (meaning two large-scale offshore wind projects located in the North and Baltic Seas) are not being explicitly modelled given the uncertainty regarding their final nature in the sense of hydrogen production or electricity production with the ongoing delays when it comes to commencing the projects. Nevertheless, the potential of these locations for hosting offshore wind is considered in capacity expansion limits as elaborated in Section 4.4.

Demand-side flexibility:

- Demand-side flexibility assumptions are made exogenously as introduced in Section 4.2.2.
- The costs of achieving demand response, i.e. building infrastructure or enabling technologies, are not included in the total system costs. Instead, these costs are expected to be borne by consumers who build the development of flexibility around their own business.

Existing production capacity and expansion:

- Danish existing CHP plants are assumed to be steadily phased out to a large degree. Reinvestments to maintain the remaining installed production capacity, with an average annual electricity production of around 3 TWh across all modelling scenarios, have been assumed. However, the thermal power plants have been excluded in the expansion optimisation, and the associated reinvestment costs have not been considered.
- Pumped-storage power plants is not considered on the background that they are assumed to have limited expansion possibility.
- Carbon capture and storage technology has not been considered in the current study due to its limited commercial-scale maturity at the present as discussed in previous study for Germany.³⁷ It is a possible direction that future work could consider.
- Scenario variation of non-technical land use constraints, such as local opposition to large projects, has not been taken into account in the scenario variation for the expansion of onshore wind power.
- No explicit consideration has been given to factors such as development, siting, permitting and other planning or supply chain aspects that may affect annual build-out rates.

Long-term focus - limited insights into road dependence

- The modelling is carried out only for model year 2050 and does not take account path dependency, i.e. different paths that the power system may evolve from today until 2050.
- Legacy gas infrastructure could see impact on phasing alternative technology development
- The model assumes a perfect market, i.e., each actor has perfect knowledge of each other's decisions. This means that, for instance, investment decisions into supply and demand are in perfect sync with the consequence harmonising average price levels.

³⁷ Quantified Carbon (2025), Power System Expansion Germany

Capacity and frequency reserves:

- The capacity market, which, for example, provides incentives to provide installed capacity to deal with shortages, has not been explicitly included in the modelling. However, by simulating the power systems over 33 weather years, an evaluation of the ability of the various scenarios to fulfil power and energy needs, including for extreme weather situations, alongside capacity requirement process has been incorporated to address these aspects (see Section 5.4). However, a stochastic analysis of outages has not been performed.
- The model is limited to an energy-only market with a day-ahead focus and only considers energy arbitrage, which means that short-term grid services such as frequency regulation are not optimised. This may lead to an underestimation of technologies such as batteries, which have a central role in such services.
- The cost estimates in this study do not include frequency-balancing services or non-frequency ancillary services such as inertia provision. Balancing needs have increased in recent years in Denmark driven by growing wind and solar production³⁸. A consistent forward projection is difficult: observed balancing costs reflect a historical generation mix and market design³⁹. The capacity-adequacy framework applied in this study ensures that the modelled fleet can meet demand under the simulated weather conditions but does not capture the additional operational cost of balancing forecast errors at sub-hourly resolution. Recently reported balancing costs in Denmark are around 2 €/MWh⁴⁰, small relative to total system cost but not negligible. Notably, balancing requirements scale with the share and forecast variability of wind and solar, while firm dispatchable technologies contribute relatively little; the high-VRE directions can therefore be expected to carry higher balancing costs than the high-firm-capacity directions.

Finally, it is important to emphasise that this analysis focuses primarily on the power system within the electricity market and serves as a first phase to provide a basis for further development of the power system. Grid-related aspects, balancing services and short-term markets have not been included in the model. Following this study, a detailed analysis of the resulting power system is required, including frequency stability, black start capacity and other important factors. However, such detailed analysis is beyond the scope of this study.

³⁸ Energinet (2025), ELECTRICITY MARKET REPORT 2025.

³⁹ Svenska Kraftnät (2024), Balancing Market Outlook 2030.

⁴⁰ GreenPowerDenmark (2025), Vindmøllejere må stoppe produktionen i dyre timer.

4 Assumptions

4.1 CO₂ emissions and commodity prices

The current study assumes a long-term projection on CO₂ at 132 €/tCO₂ aligning with the recent study by EA⁴¹. This aims to reflect steadily increasing constraints on emissions conditions in the future year of 2050, though not as aggressively as earlier studies for instance suggesting levels of 200 €/tCO₂⁴².

Similarly, long-term natural gas prices have been assumed to settle to 27 MWh_{th} aligning with the recent study by EA⁴³. Hard coal has been set a value of 12 €/MWh_{th}, biomass to 30 €/MWh_{th} and uranium 1.65 €/MWh_{th}.

4.2 Demand and flexibility

Electricity demand is modelled across six demand categories, each with distinct drivers and temporal characteristics. [Table 5](#) provides an overview of the categories and their associated flexibility.

Data centres are treated as purely inflexible baseload with a flat hourly profile throughout this study. In practice, data centres typically feature behind-the-meter flexibility, such as on-site batteries and backup generators, primarily to manage operational security and local grid constraints⁴⁴. For the current system-level analysis, this means that the associated flexibility is assessed on a front-of-meter basis. Capturing this potential is left for future work.

⁴¹ EA Energy Analysis & VTT (2026), Effects and value of SMR technologies in the Danish energy system.

⁴² ERAA (2023), Proposal of Commodity Prices for Call for Evidence.

⁴³ EA Energy Analysis & VTT (2026), Effects and value of SMR technologies in the Danish energy system.

⁴⁴ ENTSO-E (2026). Data centres and the power system: expected trends, challenges and opportunities.

Table 5. Demand categories alongside descriptions and flexibility.

Demand category	Description	Flexibility
Electric Vehicle (EV)	Road transport electrification (light-, medium-, heavy-duty; trains excluded). Linked to transport electrification rates and mobility demand.	EV charging has a flexible share capable of moving demand ± 24 h.
Electrolysers	Grid-connected hydrogen production for DRI steel, e-fuels, chemicals, etc. Driven by hydrogen demand scenarios and industrial decarbonisation pathways.	Electrolysers have a long-term flex up to 1 week.
Industry	Manufacturing, defence production, chemicals, steel (EAF), aluminium, glass, paper & pulp, etc. Excludes electrolyser-based hydrogen products.	Mainly baseload but with a share of short-term flex (± 8 h).
Data centre	Hyperscale, AI training/inference, cloud services. Driven by digitalisation, AI growth, and localisation strategies.	Purely baseload.
Heating	Distributed space heating and sanitary hot water via heat pumps, direct electric heating. Driven by building stock, electrification policies, and weather conditions.	Mainly non-flexible but with a share of short-term flex (± 4 h).
Residential commercial	Households and tertiary sector: services, offices, retail, education, farming & construction. Linked to population, electrification, and appliance penetration. Behind-the-meter storage included.	Mainly baseload but with a share of short-term flex (± 8 h).

Each profile is decomposed into a *base* component and a *flex* component, shown in and [Figure 12](#) with stylised example profiles, subject to different types of demand response.

The base proportion of demand can be (temporary) curtailed during price spikes, such as industrial operations with built-in downtime buffers, triggered when electricity prices

exceed certain thresholds. Assumptions on price and minimum levels are those presented in Cox et al., al^{45, 46}.

The flex proportion of demand represent the portion of demand can shift its load, forward or backward within a certain time range, such as EV charging during off-peak hours. Associated assumptions are further discussed in Section 4.2.2.

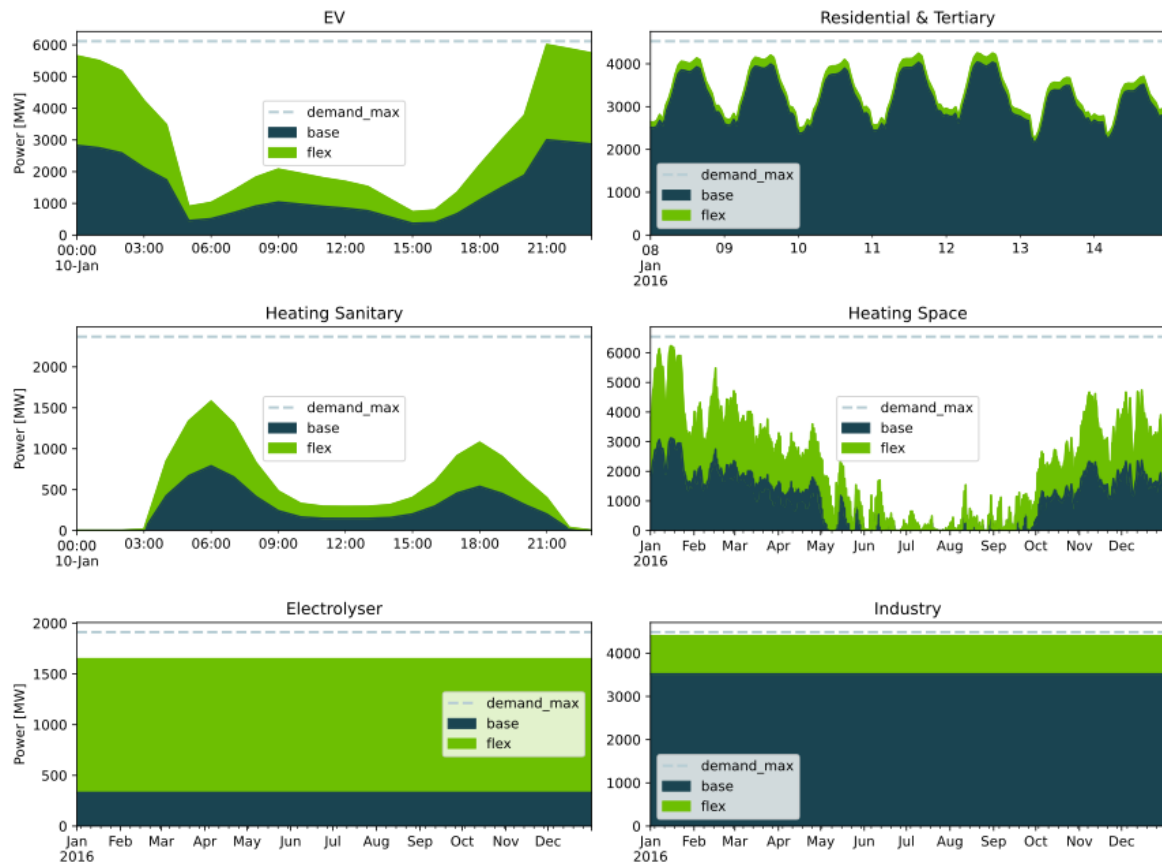


Figure 12. Stylised example demand profiles by category as indicated in each panel. The base and flex areas represent demand segments where cutting and shifting flexibility are applied, respectively. The dashed line indicates the maximum capacity increase allowed for demand. Note, data centres (not included here) are completely inflexible baseload.

4.2.1 Demand scenarios

Denmark's electricity demand is projected to grow substantially to 2050, driven by the electrification of transport, heating, industry, and the emergence of new loads including hydrogen production and data centres. The current study's reference scenario reaches

⁴⁵ Cox et al., (2026), Supplemental Material: Robust capacity expansion planning in hydro-dominated power systems: A Nordic case study

⁴⁶ Cox et al., (2026), Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

approximately 102 TWh by 2050, up from around 38 TWh today, i.e., nearly a tripling over the period as shown in Figure 13.

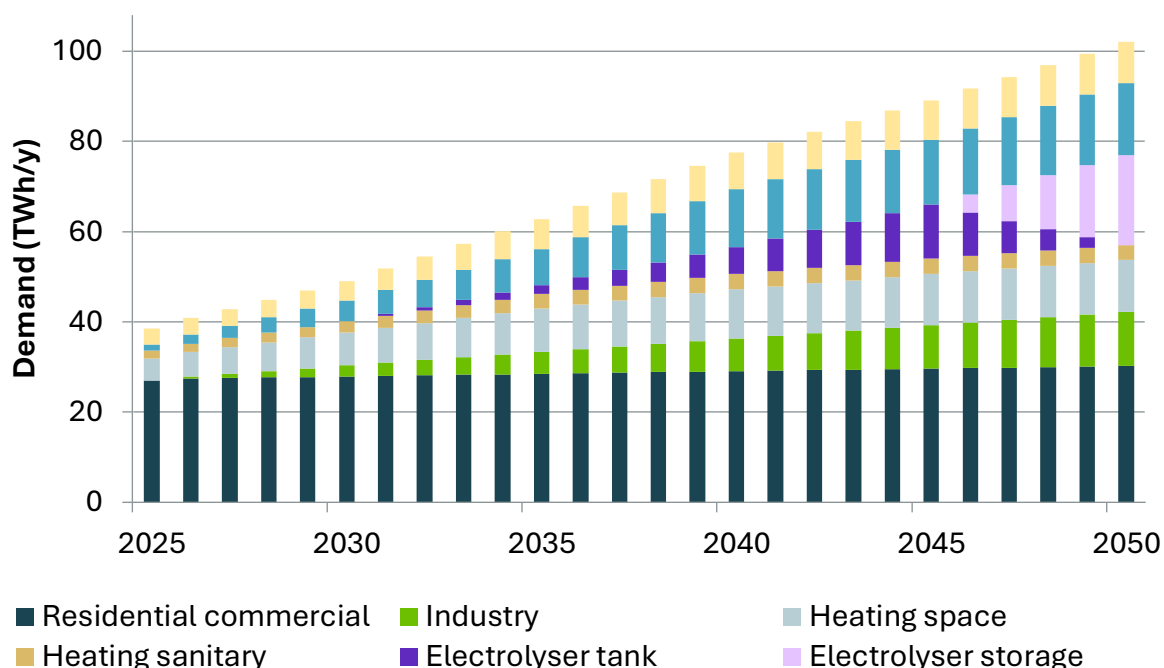


Figure 13. Reference demand scenario with categories and development until 2050.

The demand scenario projections have been inspired by two complementary Danish national studies. KF25 (*Klimastatus og Fremskrivning*)⁴⁷ describes where Denmark is headed under currently decided policies. AF25 (*Analyseforudsætninger*)⁴⁸ takes a more fundamental stance, asking what the energy system must look like to fulfil Denmark's climate targets. For the reference scenario's electricity demand, we additionally draw on the Balmorel-based scenario developed by EA Energy Analysis⁴⁹. Notably, the demand scenarios explored in the current work should not be governed as likely outlooks but rather as representative of projections in related long-term system studies.

Beyond the reference, two demand growth scenarios have been constructed to probe influence on system design performance along the technology scenario directions. The optimistic scenario (totalling 138 TWh) reflects a direction where Denmark, and Europe more broadly, takes on a larger role in the green transition: higher electrolyser deployment for e-fuel and hydrogen export, faster transport electrification, and stronger industrial electrification. In this scenario, data centre growth is more constrained, reflecting policy choices that prioritise electrification over data infrastructure. The conservative scenario (totalling 64 TWh) goes in the other direction, with slower climate

⁴⁷ Klima-, Energi- og Forsyningsministeriet (2025), *Klimastatus og -fremskrivning 2025*.

⁴⁸ Energistyrelsen (2025), *Analyseforudsætning til Energinet 2025 (AF25)*, Datasættet for grundforløb

⁴⁹ EA Energy Analysis & VTT (2026), *Effects and value of SMR technologies in the Danish energy system*.

action, limited hydrogen ambition, minimal industrial electrification, and more modest transport uptake but considerable growth of data centres

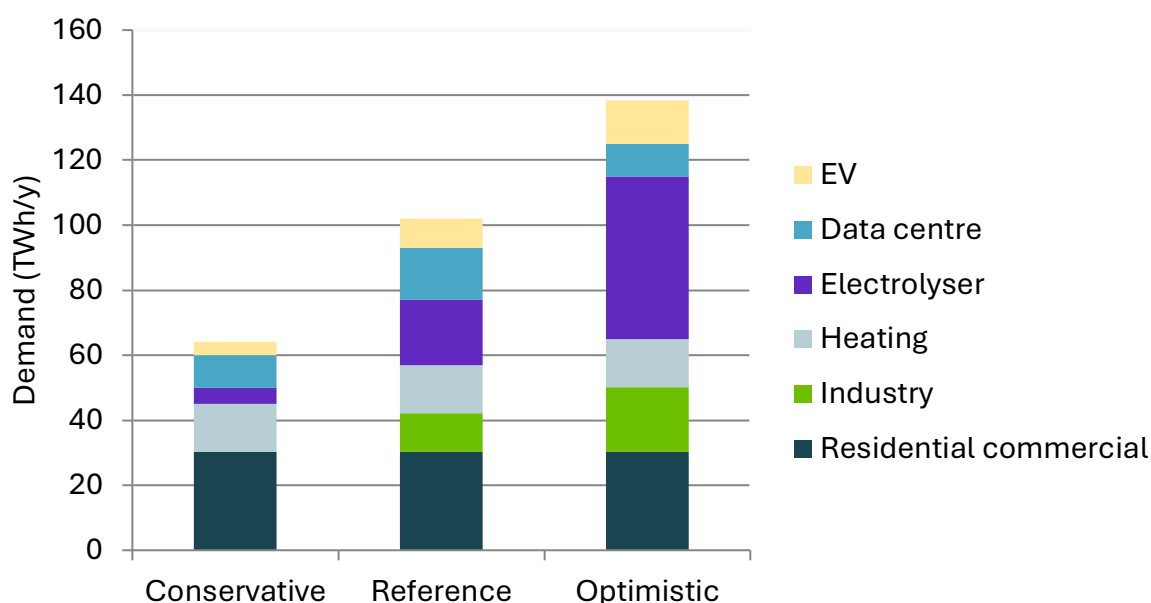


Figure 14. Demand by scenario and category for 2050.

The following gives a brief overview of the demand projections by category:

Residential and commercial demand grows modestly from around 27 TWh today to 30 TWh by 2050. This category is stable across all three scenarios, driven by population and appliance trends rather than climate policy.

Heating reaches around 15 TWh in all three scenarios by 2050, driven by heat pump penetration. Space heating dominates, with sanitary hot water a smaller, year-round load. See also Section 4.5.

EVs grow from 3.5 TWh today to 9 TWh in the reference, ranging from 4 TWh (conservative) to 13 TWh (optimistic), tracking electrification across light- and heavy-duty road vehicles.

Industry reaches 12 TWh in the reference, potentially driven by electrification of process heat in food processing, pharmaceuticals, and chemicals and defence manufacturing. The conservative assumes negligible industrial electrification; the optimistic reaches 20 TWh under stronger carbon pricing and policy support.

Data centres grow from 1.4 TWh today to 16 TWh in the reference, driven by hyperscale and AI infrastructure expansion through the 2030s. Notably, the optimistic scenario assumes lower data centre growth (10 TWh) than the reference, reflecting policy choices that prioritise electrification over data infrastructure.

Electrolysers represent the largest new load and the greatest source of uncertainty, ranging from 5 TWh (conservative) to 20 TWh (reference) to 50 TWh (optimistic). Demand is driven primarily by e-fuel production for aviation and shipping, sectors where Denmark could have strong strategic interests.

4.2.2 Flexibility scenarios

As introduced earlier, each demand category is characterised by its own hourly load profile and flexibility potential. In the modelling framework, demand-side flexibility is represented by two mechanisms: load shifting and demand reduction (cutting). Both operate on market price signals. Shifting exploits price differences within a time window determined by storage capacity, while cutting increasingly reduces demand when prices exceed a threshold.

The focus in the current section is on the shifting component, where storage is the enabling mechanism (hydrogen storage, batteries, or thermal mass in buildings). The share of demand subject to shifting flexibility is presented for each category and flexibility scenario in [Table 6](#), derived from the Power System Expansion Germany report⁵⁰.

[Figure 15](#) illustrates the resulting average flexible capacity by scenario. This is expressed as the yearly average flexible demand per category (see also equation on page 7 in previous work⁵¹). It is important to note that available flexibility varies significantly across the year, reflecting each category's distinct load profile. Space heating flexibility, for example, is negligible in summer months. The calculation also does not account for constraints on shift duration or total shiftable energy over time.

⁵⁰ Quantified Carbon (2025), Power System Expansion Germany.

⁵¹ Cox et al., (2026), Supplemental Material: Robust capacity expansion planning in hydro-dominated power systems: A Nordic case study

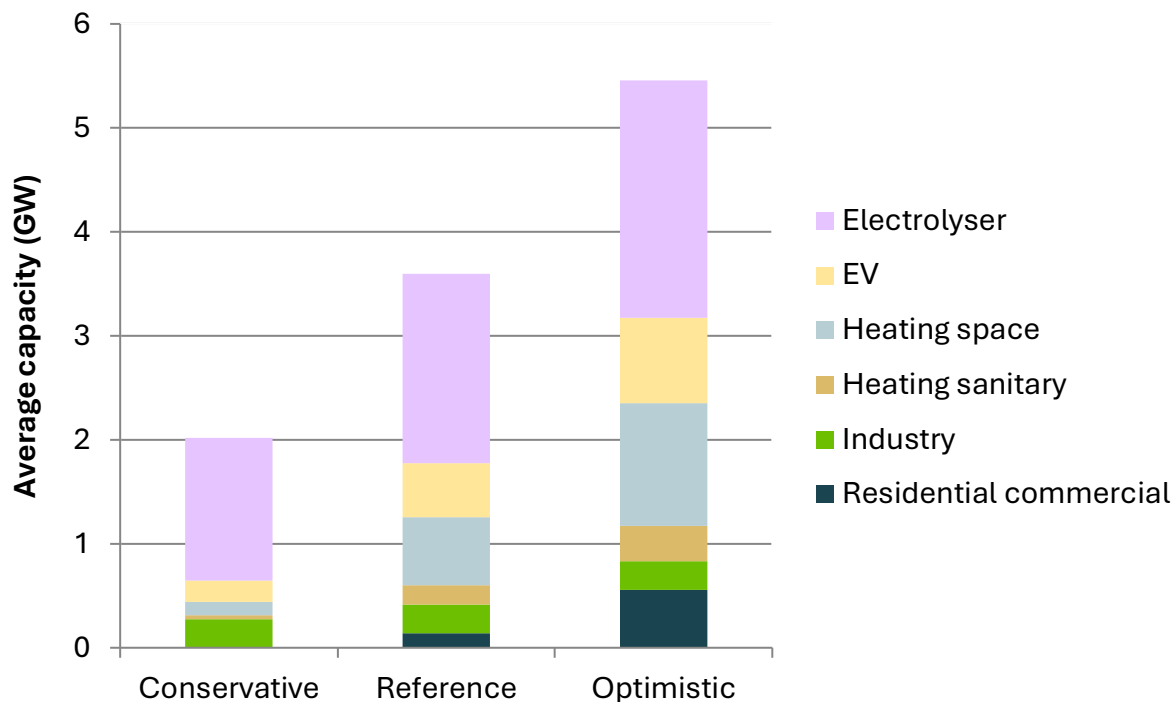


Figure 15. Yearly averaged demand subject to shifting flexibility by category for the different sensitivities aggregated for Denmark by flexibility scenario.

Relative to a peak load of around 15 GW, the three flexibility scenarios correspond to roughly 10%, 20%, and 30% flexible capacity in the conservative, reference, and optimistic cases respectively. Electrolysers provide the largest and most consistent flexibility contribution across scenarios. This corresponds to around 1.8 GW in the reference (± 500 MW across scenarios) enabled by the expected development of hydrogen network infrastructure and storage with approximately 12 days of duration. Industry and residential commercial also make significant contributions; in the case of industry and residential, this flexibility represents behind-the-meter battery installations, amounting to around 400 MW in the reference. EVs contribute an additional ~500 MW, together constituting a big share of the short-duration flexibility. Notably, the heating sector provides considerable flexibility through thermal storage capacity in the district heating system.

The flexibility scenario also links to the technology direction scenarios explored in this study as also presented in Table 6. As introduced in Section 3.4, the Offshore scenario features enhanced long-duration flexibility, while the Solar scenario features predominantly short-duration flexibility. The Balanced scenario and the Nuclear direction follow the reference flexibility assumption throughout. The Flex high and low sensitivities, where all categories align on optimistic and conservative respectively, are explored in Section 5.8.

Table 6. Flexible share for the demand categories in Denmark for the three flexibility scenarios. Last column indicates for which technology direction the flexibility scenario is employed.

Category	Flexibility scenario	Share flexible	Technology direction
Residential commercial	Optimistic	20%	Solar
	Reference	5%	Balanced, Nuclear, Offshore
	Conservative	0%	
Heating	Optimistic	90%	Solar
	Reference	50%	Balanced, Nuclear, Offshore
	Conservative	10%	
EV	Optimistic	90%	Solar
	Reference	50%	Balanced, Nuclear, Offshore
	Conservative	20%	
Industry	Optimistic	20%	Solar
	Reference	20%	Balanced, Nuclear, Offshore
	Conservative	20%	
Data centre	Optimistic	0%	
	Reference	0%	Balanced, Nuclear, Offshore
	Conservative	0%	
Electrolyser	Optimistic	100%	Offshore
	Reference	80%	Balanced, Nuclear, Solar
	Conservative	60%	

4.3 Overview of cost assumptions

In capacity expansion modelling, production costs, with LCOE in focus, drive the results, and therefore it is important to transparently present assumptions as well as the methodology which determines model inputs. The financial framework is anchored in the Weighted Average Cost of Capital (WACC), which varies across sensitivity scenarios: 6% in the reference case, 4% in the optimistic case, and 8% in the conservative case. The medium value (6%) is selected as a moderately conservative private-investor financing assumption for Denmark⁵². To reflect financing dynamics during project construction, an interest rate equal to half of the WACC is applied as a mark-up to total capital expenditures over the construction period. The capital recovery period is consistently set to two-thirds of each technology's technical lifetime, thereby avoiding the need for reinvestment within the modelling horizon. The assumption is deliberately conservative, reflecting that investors normally require capital recovery before the end of the full technical lifetime because of market, policy and technology risks. All monetary values are expressed in real terms pre-tax, in euros (€), referenced to the year 2025. We assume an average cost weighting for investment and operational costs representative of the time period 2025–2050, accounting for technological development and capacity deployment.

4.3.1 Reference Sources and Cross-Validation

We strive to base our assumption on a broad range of source, including historical data, current market conditions, and forward-looking projections (as presented in [Table 7](#)). Our assumptions are designed to reflect structural trends, while avoiding influence from any single project or datapoint. The objective is to put strong emphasis on the transparency of the data inputs.

⁵² Energistyrelsen (2024). Determining the Cost of New Entry (CONE) for Denmark

Table 7. 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 (2023), Annual Technology Baseline.	ATB_2023	Future projections, 2021 - 2050
International Energy Agency & Nuclear Energy Agency (2020), Projected Costs of Generating Electricity.	IEA_NEA_2020	Present-day/near future
International Renewable Energy Agency (2023), Renewable Power Generation Costs in 2022.	IRENA_2023	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
Ten-Year Network Development Plan 2024 (2023).	TYNDP_2024	Future projections, 2022 – 2050
National Renewable Energy Laboratory (2024), Annual Technology Baseline.	ATB_2024	Future projections, 2022 - 2050
IEA (2025), World Energy Outlook 2025.	IEA_2025	Future projections, 2024 - 2050
EA & VTT (2026), Small Modular Reactors in Denmark: A Technology and Cost Review.	EA_2026	Future projections, 2035 - 2050
International Renewable Energy Agency (2025), Renewable Power Generation Costs in 2024.	IRENA_2024	Historical

4.3.2 Selection of 2040 as Central

The year 2040 is selected as the central cost reference year for the analysis. Nuclear is the exception: it is costed as the capacity-weighted average over its 2040–2050 deployment, since its learning occurs later than for the mature technologies costed at 2040. This choice reflects:

- The expected peak investment period required to meet EU and Danish decarbonization targets,
- Its position as a midpoint between current infrastructure expansion and full climate neutrality in 2050.

By focusing on 2040, the analysis captures technologies in a relatively mature deployment phase while still reflecting cost evolution and system integration effects.

4.3.3 Adjustment to Danish Context

Although global datasets (IRENA, IEA, NREL) provide long-term cost trajectories, regional conditions significantly influence realized investment costs. Therefore:

- Cost values were adjusted to reflect European labour, supply-chain, and regulatory conditions.
- For offshore wind and grid-related technologies, Danish-specific catalogue data were given particular weight.
- Recent European project announcements and auction results were used as empirical benchmarks.

All CAPEX values represent overnight investment costs, while financing conditions are incorporated consistently via the assumed weighted average cost of capital (WACC).

4.3.4 Scenario-Based Cost Trajectories

Three cost trajectories (Optimistic, Reference, Conservative) are defined to reflect structural uncertainty in long-term technology development. The ranges are not symmetric by design: for mature technologies the larger risk is cost escalation, while for nuclear, before serial deployment, both escalation and learning-driven reductions are large. These scenarios aim capture:

- Variations in supply-chain maturity,
- Financing conditions,
- Industrial learning,

- Permitting and regulatory risks,
- Global competition for materials and equipment.

The Reference scenario represents the central techno-economic pathway used in the study. It is constructed from the central or median assumptions reported in the institutional sources used for each technology, including Danish Energy Agency technology catalogues, NREL ATB, IEA and IRENA cost projections where applicable. It should therefore be interpreted as a harmonised “middle-of-the-road” estimate rather than as a single-source forecast. A short cross-reference is added here, while the full scenario logic is described in the “Technology Development Scenarios – Conceptual Framing” section. The Optimistic and Conservative pathways reflect deviations driven by favourable or adverse macroeconomic and structural conditions.

4.3.5 Capacity Factor and Performance Assumptions

Projected capacity factors are not assumed to remain constant at present-day peak values. Instead, adjustments are introduced to account for:

- Gradual saturation of high-quality locations,
- Increased curtailment due to system integration constraints,

This prevents systematic overestimation of generation potential and ensures that declining LCOE projections are not driven solely by optimistic performance assumptions.

4.3.6 Technology Development Scenarios – Conceptual Framing

Across all technologies, the Conservative pathway reflects persistent supply-chain frictions, slower industrial learning, higher input material prices, tighter permitting regimes, and elevated perceived investment risk. These factors translate into higher overnight CAPEX, weaker cost reductions over time, and higher WACC assumptions in the most adverse variant (Conservative-2). The intermediate Conservative case (Conservative-1) isolates financing improvements while holding underlying technology cost trajectories unchanged. The Reference pathway represents the central convergence case based on cross-validated projections from IRENA, IEA, NREL ATB, and the Danish Energy Agency. It assumes continued but incremental technological learning, gradual normalization of supply chains, and moderate improvements in installation practices and operational performance. The Optimistic pathway reflects accelerated industrial learning, scale effects, standardization, and improved project execution efficiency. Under this trajectory, global manufacturing capacity expands without major bottlenecks, input material markets stabilize, and deployment volumes sustain downward pressure on CAPEX. The most favourable variant (Optimistic-2) additionally assumes structurally lower risk premiums and improved access to capital, whereas Optimistic-1 isolates technology and cost improvements while maintaining reference financing assumptions.

It is relevant to highlight that across the different scenarios a wide range of different investment and operating costs are explored as the estimated LCOE in [Table 8](#) demonstrates.

Table 8. Estimated levelised cost of electricity (all in EUR/MWh) for inputs and primary technologies for scenarios where cost is varied. Considers only the electricity market, e.g. revenues from nuclear power through sales of heat are not considered.

Technology cost scenario	Nuclear SMR	Solar	Wind offshore nearshore	Wind offshore (bottom-fixed)	Wind onshore	Gas OC
Conservative-2	134	62	76	88	60	550
Conservative-1	108	53	66	76	51	510
Reference	86	42	53	64	41	470
Optimistic-1	60	38	47	58	36	440
Optimistic-2	49	33	40	50	31	410

4.4 Capacity build-out: limits, fixed expansion, and existing fleet

The capacity expansion modelling is a combination of endogenous expansion coupled with exogenous capacity assumptions further limited by technology-specific upper bounds. Consequently, the model is not representing the unconstrained theoretical potential but reflects the power system in which certain technologies are allowed based on their techno-economic relevance for the system while other are limited by spatial, technical, policy or legal factors.

As the model is built for the year 2050 it therefore does not explicitly optimise the annual build-out pathway from today to 2050. So the resulting capacities should be interpreted as feasible end state configuration. Summarizing, the annual deployment constraints permitting bottlenecks siting delays or supply-chain limitations are only represented indirectly through technology-specific assumptions and capacity limits rather than through explicit year-by-year build-out constraints.

4.4.1 Wind and solar expansion

Wind and solar are represented differently. In the sense that their expansion is either market-driven or exogenously determined. For onshore and offshore wind and utility scale solar an endogenous expansion is considered, subject to capacity limits for the case of wind, while solar residential is treated as exogenous inputs.

Onshore wind

The model assumes that additional onshore wind capacity is primarily achieved through repowering rather than extensive greenfield development. The upper bound for onshore wind is set at approximately 7 GW. This value is based on the 1000 m distance scenario reported by the Joint Research Centre⁵³ and is consistent with a conservative interpretation of Danish land-use constraints.

Offshore wind

The offshore wind is divided into three distinct categories according to the distance from the shore. This is driven by the fact that the distance affects the grid connection costs, installation costs and most likely also the order at which the sites will be adopted. Floating offshore wind is not included as a separate technology category because the identified Danish offshore deployment zones do not require it under the assumed bathymetric conditions. The maximum offshore wind expansion potentials are assigned separately to DK1 and DK2. Nearshore potential is set to 4.4 GW in DK1 and 6.7 GW in DK2, giving a total nearshore potential of 11.1 GW. Offshore potential is set to 23.0 GW in DK1 and 1.6 GW in DK2, giving a total offshore potential of 24.6 GW. Although not being utilised in the modelled scenarios of the current work, the farshore potential has been

⁵³ JRC/EIGL (2025) The Onshore Wind Potential of the EU and Neighbouring Countries

determined to 25.9 GW in DK1 and 0.0 GW in DK2, giving a total farshore potential of 25.9 GW.

Solar PV

Solar PV is divided into exogenous distributed residential solar and endogenous utility-scale solar. The residential solar capacity is 7.6 GW in 2050 across all scenarios, based on AF25⁵⁴. Additional utility-scale solar PV is allowed as an endogenous investment option.

4.4.2 Existing thermal power plants

The modelling assumes projected installed capacity relating to existing thermal power plants according to AF25^{55,56}.

In 2025 there were 5.2 GW of operational thermal plants in Denmark which provided 9.5 TWh of electricity (24% of the net electricity production)⁵⁷. 3.2 GW was allocated to the centralised plants: 2.6 GW operated as cogeneration units (16 plants) and 0.6 GW as reserve units in the condensation mode; further 2 GW were allocated in decentralised plants. According to the AF25 projections, formulated by Danish Energy Agency, most of Danish thermal plants are going to be decommissioned in the 2030s or even earlier. In 2040 there would remain only 1.2 GW of central capacity (majority of that in DK2) and 1.3 GW in decentralised capacity.

According to AF25 waste, biomass and biogas would supply only 2.9 TWh of power in 2040, compared with 9.6 TWh in 2025. However, its share in power generation would fall to less than 2%, due to rapid expansion of the offshore wind capacities.

While in current economy, heat and power are often generated simultaneously using CHP plants, DEA projections suggest decoupling of both sectors. Due to decreasing number of load hours, thermal plants are going to work mainly in the condensation mode whereas the peak heat load would be covered by heat-only boilers.

⁵⁴ Energistyrelsen (2026), Monthly Energy Statistic, Electricity

⁵⁵ [Energistyrelsen \(2025\), Analyseforudsætning til Energinet 2025 \(AF25\), Datasættet for grundforløb](#)

⁵⁶ Energistyrelsen (2026), Monthly Energy Statistic, Electricity

⁵⁷ Energistyrelsen (2026), Monthly Energy Statistic, Electricity

Table 9. Future capacities for conventional power generation – own summary based on AF25 projections.⁵⁸

Fuel	Type	Zone	2025	2030	2035	2040	2045	2050
Natural gas	CHP	DK1	1172	999	582	444	388	388
		DK2	382	350	235	212	212	212
		DK	1554	1349	817	657	601	600
Biomass + waste	CHP	DK1	1428	1372	585	437	415	387
		DK2	1242	1242	922	918	912	906
		DK	2670	2614	1507	1355	1327	1293
Coal/oil	CHP	DK1	385	-	-	-	-	-
		DK2	3	3	-	-	-	-
		DK	388	3	0	0	0	0
Oil	Con-densing	DK1	14	14	-	-	-	-
		DK2	538	538	538	538	538	538
		DK	552	552	538	538	538	538

4.5 Heat sector

Low temperature heat use plays important role in contemporary Danish energy supply. Such heat is consumed mainly by the residential and commercial sector. The energy use of residential sector alone for space heating (32 TWh)⁵⁹ and domestic hot water (12 TWh) together represented 27% of total final energy consumption (155 TWh). This value is higher than the total electricity use (21% of final consumption)⁶⁰.

For 2026 only minor share of heat production is electrified – the energy needs are covered mainly by combustion of waste and biomass as well as oil and natural gas. Concomitantly, currently the sector is mainly electricity producer concerning large share of combined heat and power units. However, in the future that relation is likely to reverse – with growing share of heat pumps and electric boilers, as well as CHP capacities being decommissioned (compare Table 9) - heat-induced electricity demand is going to play larger role in the power load profile⁶¹.

In this study the power demand for electrified heating has been modelled from end-use perspective. *Space heating* refers to the temperature dependent component of the heat load (coherent with the weather data series for renewable energy production), whereas *sanitary* refers to heat needed for domestic hot water (constant load profile for each day

⁵⁸ For decentralised electricity capacity decentralized electricity capacity based on the natural gas was counted as "natural gas CHP", whereas decentralized based on other types of fuels was counted as biomass + waste

⁵⁹ IEA (2026), *Energy End-uses and Efficiency Indicators Data Explorer*

⁶⁰ Energistyrelsen (2026), *Monthly Energy Statistic, Electricity*

⁶¹ Energistyrelsen (2025), *Analyseforudsætninger til Energinet 2025 – Termisk kapacitet, store varmepumper m.m. Baggrundsnotat*

of the year). Both profiles have certain degree of flexibility, which partially allows the heat load to adjust to prices. This accounts both for the elasticity at the level of the individual heat pumps (short-term load shifting) as well as for the district heating flexibility (thermal energy storage and substitution of heat pumps with conventional heat-only boilers). Yearly electricity demand has been presented in the [Table 10](#).

Table 10. Projected electricity demand in TWh for heating by end-use category (space heating and sanitary demand) and zone (DK1, DK2, and total Denmark) from 2025 to 2050, showing the evolution of electrified heat demand over time⁶².

Demand type	Zone	2025	2030	2035	2040	2045	2050
Space heating	DK1	2.6	3.9	5.2	5.8	6.1	6.1
	DK2	2.4	3.4	4.5	5.1	5.3	5.3
	DK	4.9	7.3	9.7	10.9	11.3	11.5
Sanitary	DK1	0.9	1.3	1.7	1.8	1.8	1.8
	DK2	0.8	1.2	1.5	1.6	1.6	1.5
	DK	1.7	2.5	3.2	3.4	3.4	3.3
Total electricity demand for heating	DK1	3.5	5.2	6.9	7.7	7.9	7.9
	DK2	3.2	4.6	6.0	6.7	6.8	6.9
	DK	6.7	9.8	12.9	14.3	14.7	14.8

Electricity consumption levels assumed in the study are compatible with the AF25 projections ([Figure 16](#)).

⁶² Own estimation in accordance with the methodology presented in: Cox et al., (2026), Supplemental Material: Robust capacity expansion planning in hydro-dominated power systems: A Nordic case study

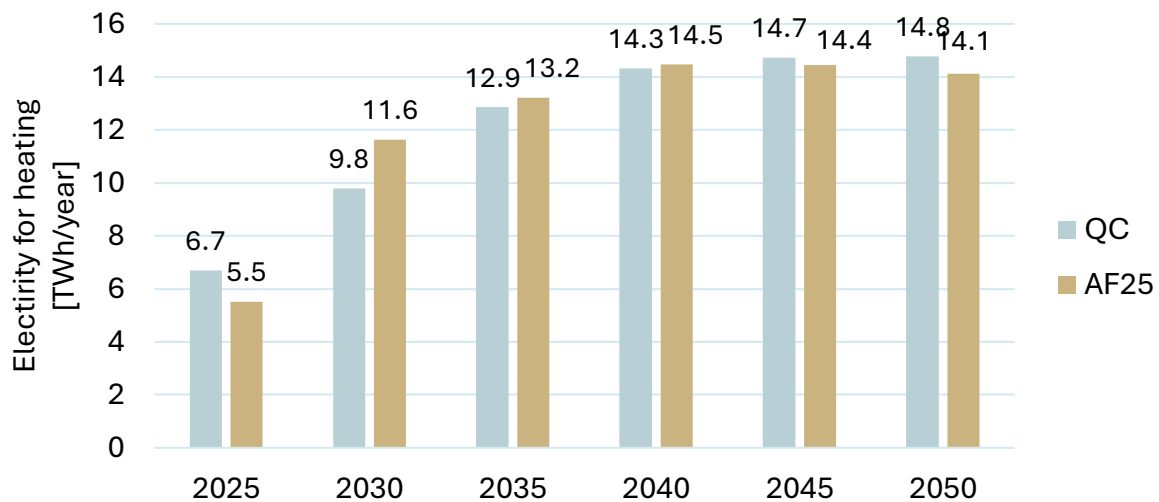


Figure 16. Comparison of yearly electricity consumption for heating purposes between QC and AF25 prognosis. Source: own analysis based on own data and AF25.⁶³

Table 11. Electricity demand for heating by sector and zone (DK1, DK2, and total Denmark) from 2025 to 2050, including individual heating, decentralised and centralised district heating, and electric boilers. Projections of AF25.⁶⁴

Sector	Demand	Zone	2025	2030	2035	2040	2045	2050
Individual heating	Small heat pumps	DK1	2.0	2.7	3.4	3.6	3.6	3.6
		DK2	1.1	1.4	2.1	2.2	2.2	2.3
		DK	3.0	4.1	5.5	5.8	5.8	6.0
Decentrali- sed DH	Large heat pumps	DK1	0.9	1.5	1.7	1.7	1.8	1.8
		DK2	0.3	0.7	0.8	0.8	0.8	0.8
		DK	1.1	2.2	2.5	2.5	2.6	2.6
Centralised DH	Large heat pumps	DK1	0.6	1.3	1.5	1.7	1.8	1.9
		DK2	0.2	1.5	1.9	2.0	2.0	2.1
		DK	0.8	2.8	3.4	3.7	3.8	4.1
District heating	Electric boilers	DK1	0.3	2.0	1.3	1.5	1.3	0.8
		DK2	0.2	0.5	0.6	1.0	0.9	0.7
		DK	0.5	2.6	1.9	2.5	2.3	1.5
Total electricity demand for heating		DK1	3.80	3.8	7.5	7.9	8.5	8.5
		DK2	1.73	1.7	4.1	5.3	6.0	6.0
		DK	5.52	5.5	11.6	13.2	14.5	14.4

⁶³ Summarized from: Energistyrelsen (2025), Analyseforudsætning til Energinet 2025 (AF25), Datasættet for grundforløb

⁶⁴ Summarized from: Energistyrelsen (2025), Analyseforudsætning til Energinet 2025 (AF25), Datasættet for grundforløb

5 Results

5.1 Pre-optimised neighbouring regions

Figure 17 presents the results of the pre-optimisation of the power system mix in the entire model geography for 2050 and compares this with the current system in 2025. The current electricity system in 2025 is dominated by dispatchable power generation, which accounts for more than 60% of annual electricity production, while wind and solar power account for 36%. By 2050, the electricity system has undergone a major transition towards an almost entirely climate-neutral power system. Driven by electrification, total generation has increased by around 75% in the modelled system, from 2280 TWh in 2025 to 3990 TWh in 2050. Further emissions reductions are achieved reaching around 90% decrease compared to 1990. Wind and solar power then make up 55% of the electricity mix, while nuclear power's share has decreased and high-emission fossil fuel coal power sources have been mostly phased out. System flexibility is ensured through battery storage, gas-fired power plants with and without CCS, and flexible demand from electric vehicles, heating and hydrogen production. It is worth emphasising that as a result of electrification, electricity consumption is increasing in all countries but typically varies between 50%-100% compared to today.

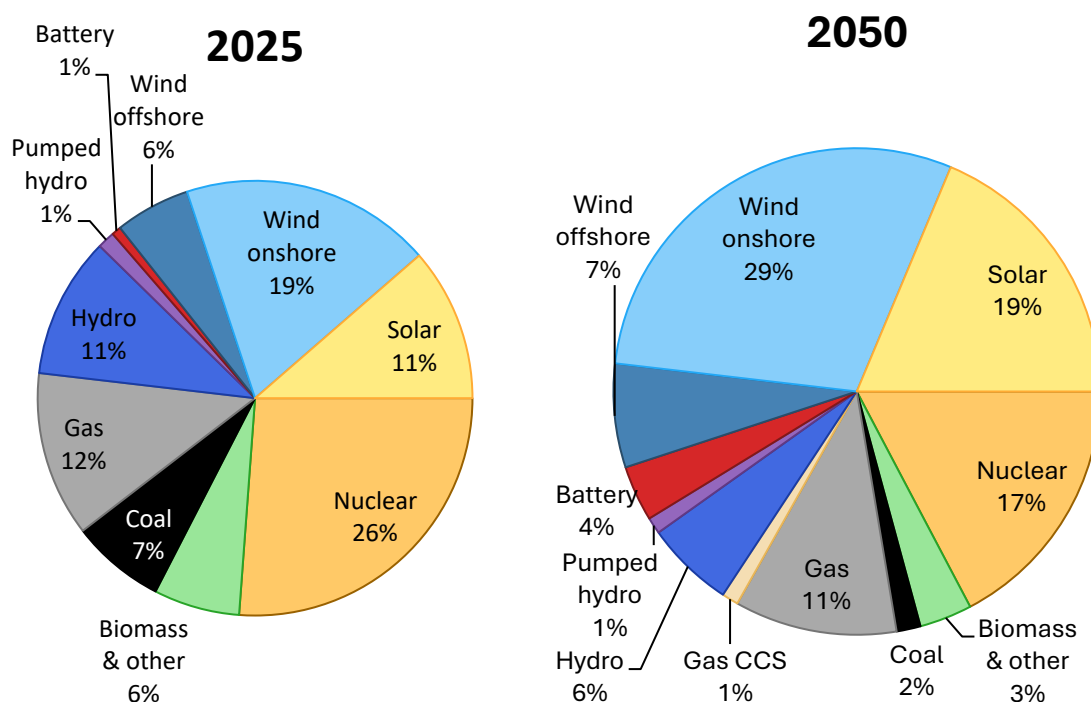


Figure 17. Share of annual electricity generation by technology for the entire model geography for the year 2025 (left panel, totalling 2280 TWh) and the modelled year 2050 (right panel, totalling 3990 TWh).

Figure 18 presents the resulting system from the pre-optimisation but instead from the view of installed supply capacity. While the generation from dispatchable power decreases so does the relative size of the fleet in capacity. However, in actual installed capacity dispatchable supply increases from 348 GW to 370 GW where the increased

supply capacity from gas turbines from 138 GW to 168 GW (+28%) where only 6 GW is gas CCS stands out. While coal capacity shrinks, nuclear capacity is slightly increased from 88 GW to 101 GW (+15%) owing to retirement of some plants (9 GW) and new builds (22 GW). Notably, the deployment of new nuclear power plants of 22 GW represents a fair share of the 30 GW deployment scenario assumed for SMRs in Western countries (see Section D.4). However, this represents both SMR and large-scale reactors and the model geography does not include US, Canada, Australia, and further European countries, e.g., Czech Republic with firm nuclear expansion plans. Finally, [Figure 19](#) provides an overview of how installed capacity is distributed across a subset of regions included in the model.

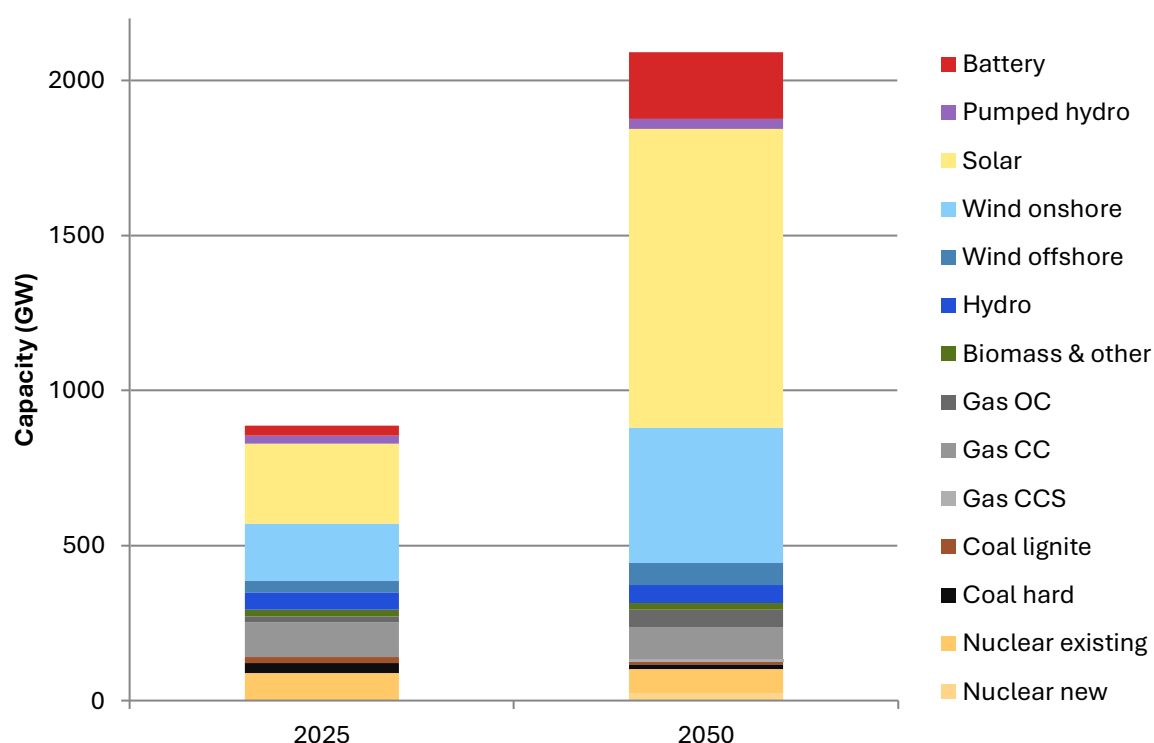


Figure 18. Installed supply capacity across the entire modelled region in 2025 and 2050.

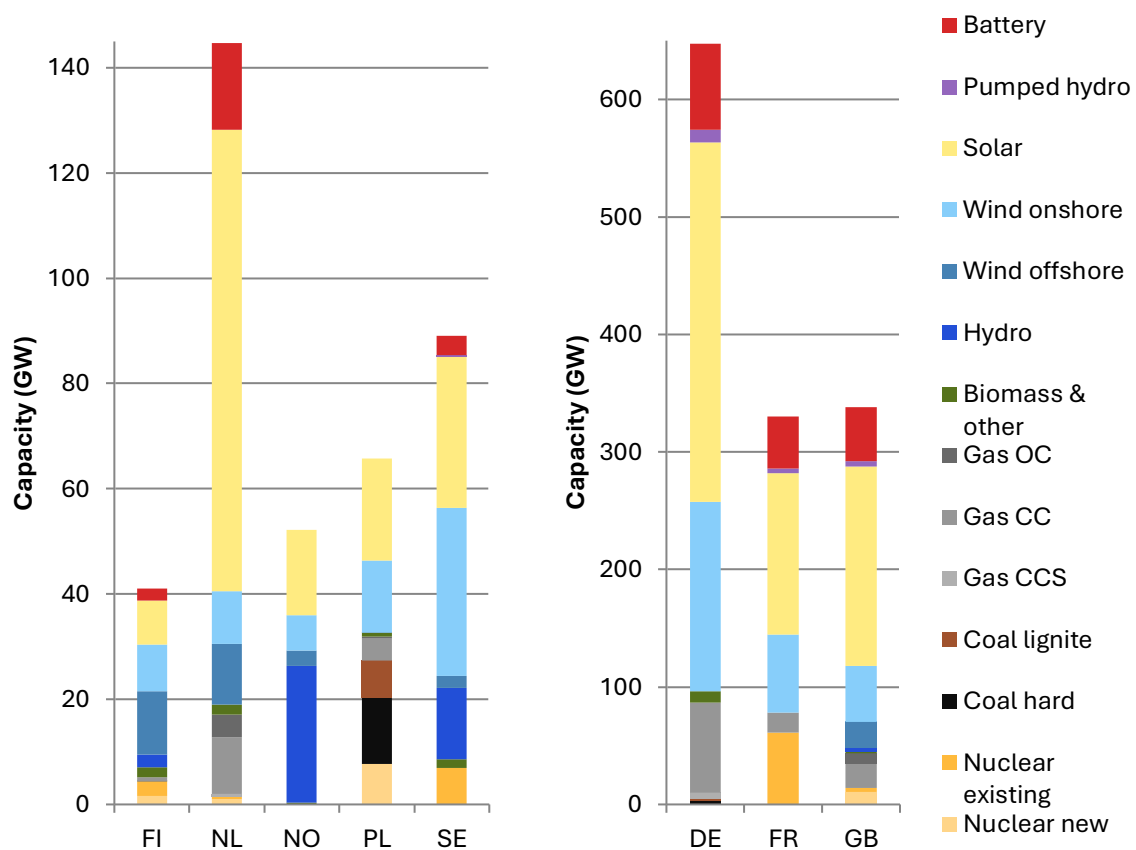


Figure 19. How installed supply capacity is distributed across major modelled regions for 2050.

Take-aways - Pre-optimised neighbouring regions:

- The 2050 system is almost entirely climate-neutral: emissions fall by ~90% relative to 1990, wind and solar rise from 36% to 55% of annual generation, and total generation grows by ~75% (2,280 in 2025 to 3,990 TWh) driven by electrification.
- Coal is mostly phased out and nuclear's share of generation decreases, while flexibility is provided through battery storage, gas-fired plants (with and without CCS), and flexible demand from electric vehicles, heating, and hydrogen.
- Dispatchable capacity increases in absolute terms (348 GW in 2025 to 370 GW): gas turbines from 131 to 168 GW (+28%, of which 6 GW is gas-CCS), and nuclear from 88 to 101 GW (+15%, comprising 9 GW retirements and 22 GW new build), while coal capacity shrinks.

5.2 Capacity and generation mix

This section presents the main characteristics of the seven Danish power system scenarios focused in the current study. Installed capacity of gas turbines and battery storage has been determined based on the capacity requirements adjustments (see step 4 of methodology in [Figure 3](#)) which is presented in Section 5.4. The current section primarily considers the other technologies which have been determined based on the capacity expansion optimisation, i.e., step 3 of methodology in [Figure 3](#).

The combined installed capacity ([Figure 20](#)) ranges from 32.6 GW (scenario: Nuclear) to 42.2 GW (scenario: Offshore). These two scenarios simultaneously exhibit the highest and lowest share of installed dispatchable capacity, respectively 31.2% and 11.7%. On average the share of dispatchable capacity was found to be 18%.

Across all the scenarios the onshore wind potential is being fully exploited. This is not surprising given the technology maturity and lowest cost of electricity delivered. Furthermore, apart from scenario “Solar” the model sees no value in investing in utility scale solar PV. This is mostly driven by the fact that the exogenous expansion of 7.6 GW of residential systems already impacts the market price, and future systems would operate at much lower capture rates yielding them not economically viable, furthermore, the neighbouring regions in particular Germany shows a significant built out of solar PV leading to regional cannibalization.

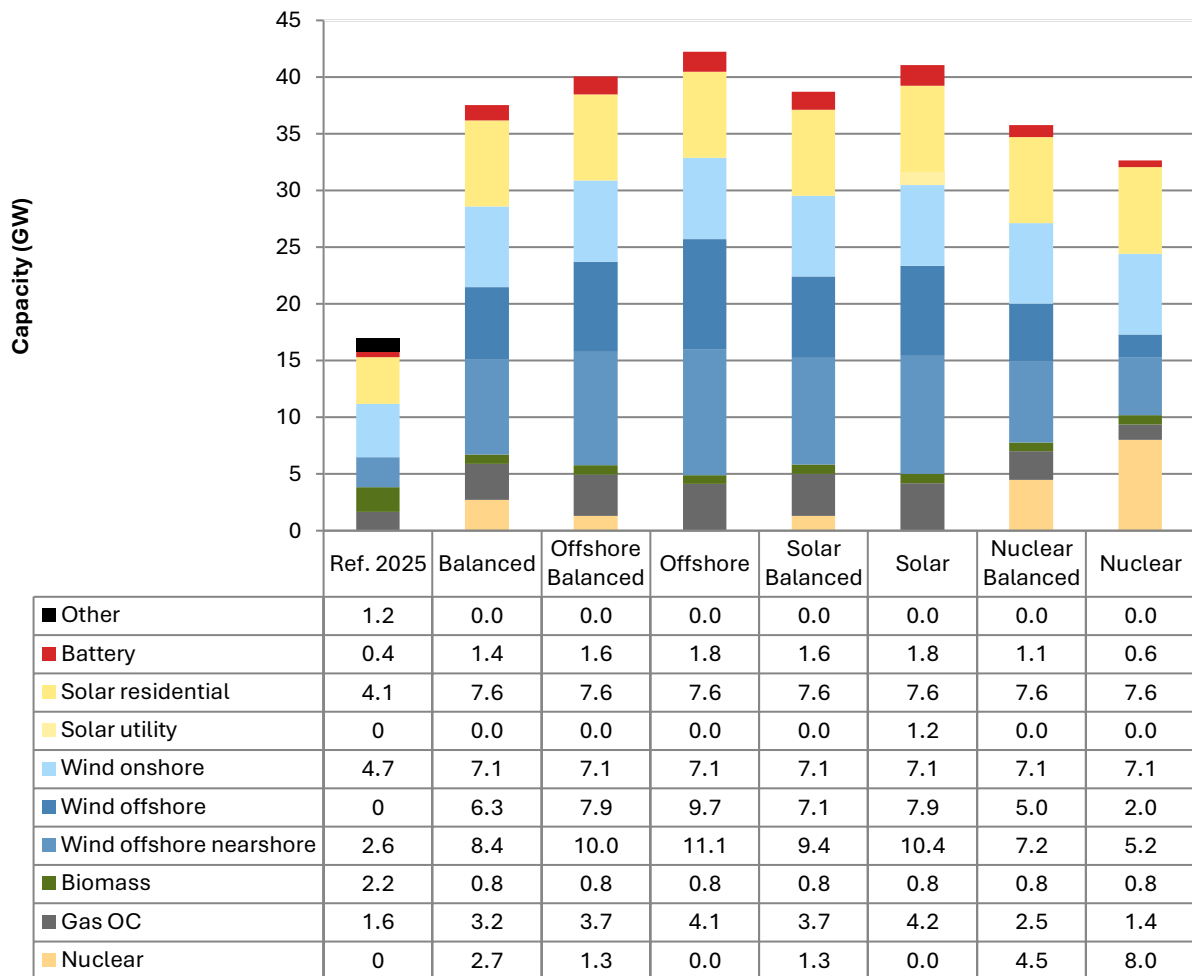


Figure 20. Installed capacity in various technologies on a country level across modelled scenarios. For *Ref. 2025*, *Solar residential* covers all installed solar capacity, including utility-scale, and the category *Other* includes: oil, waste and unspecified as per EnergyCharts⁶⁵.

Although the combined capacity remains at relatively similar level the scenarios exhibit structurally different technology mixes. Apart from the Nuclear scenario the wind (all technologies) represents at least 53% of the installed capacity, reaching as much as 67% in the Offshore scenario. Battery storage capacity remains relatively constant at 1.4 to 1.8 GW with an exception to nuclear heavy scenarios (namely Nuclear Balanced and Nuclear) where it drops to respectively 1.1 GW and 0.6 GW clearly indicating lower value of battery storage when dispatchable generation is available.

The zone-wise (Figure 21) capacity distribution is not even and on average DK1 hosts a cumulative capacity of 26.2 GW compared to 10.6 GW in DK2. This capacity proportion remains quite constant across the scenarios with scenario Solar being most balanced,

⁶⁵ EnergyCharts (2026), *Installierte Netto-Leistung zur Stromerzeugung in Dänemark in 2025*

namely 68.8% of capacity installed in DK1 and scenario Nuclear being least balanced, with 74.3% of total capacity being installed in DK1. Notably, the 1.2 GW of utility scale solar PV that is installed across all scenarios is being deployed in DK2 (only under scenario Solar).

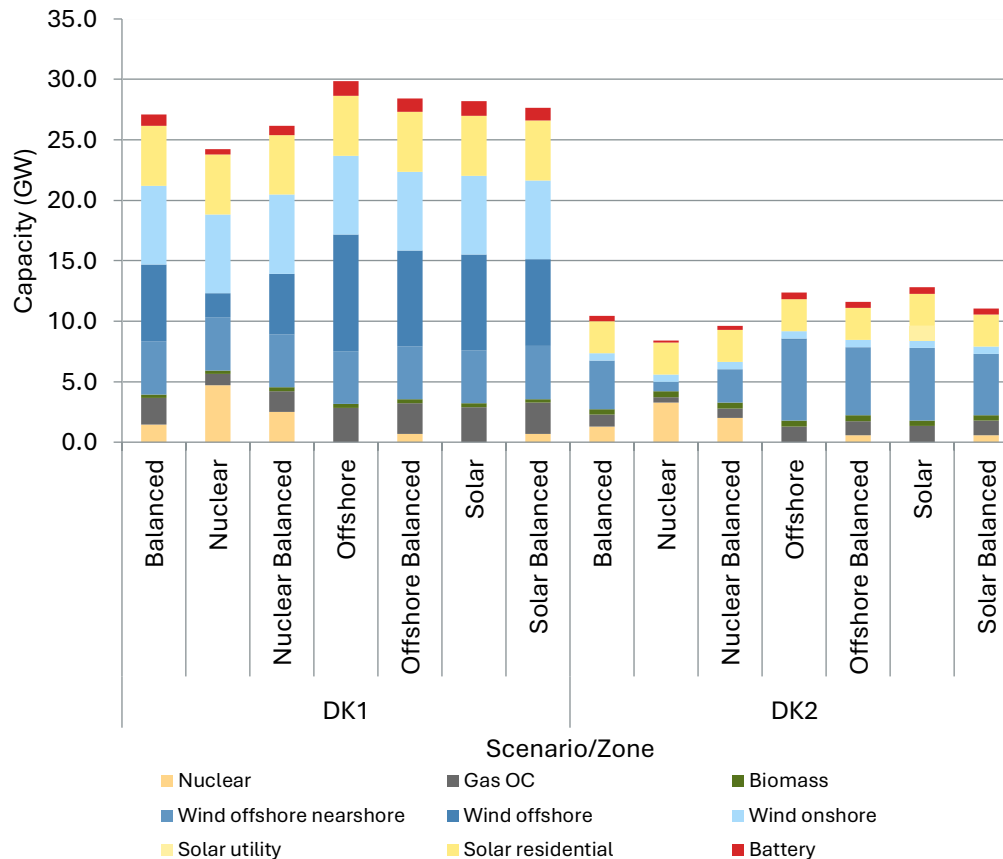


Figure 21. Installed capacities in specific technologies across different scenarios and two price zones in Denmark.

Installing on average (across scenarios) ~15 GW in offshore projects translates into more than full realization of AF25 assumptions (13.9 GW in 2040) concerning grid connected wind parks in both DK1 and DK2.

In terms of total electricity generation, in the analysed scenarios (Figure 22) it oscillates around 119 TWh/year with highest values reported for the nuclear (124 TWh/year) one and lowest for Solar (114 TWh/year). This variation stems from how relatively cost-effective it is to expand supply capacity in Denmark compared to import. For instance, the Nuclear scenario features cheaper production costs of nuclear power in Denmark. In contrast, the Solar scenario has the least cost-effective system-value adding supply available with nuclear prohibited and offshore wind at reference technology costs while solar, though cheapest, provides limited system value. Apart from the Nuclear scenario the wind energy is the true backbone of the energy supply with shares ranging from 65% (Nuclear Balanced) to 92% (Offshore). The contribution from nuclear ranges from 8% to

47% and in two scenario (Offshore and Solar) the contribution is 0% as it is prohibited y scenario design.

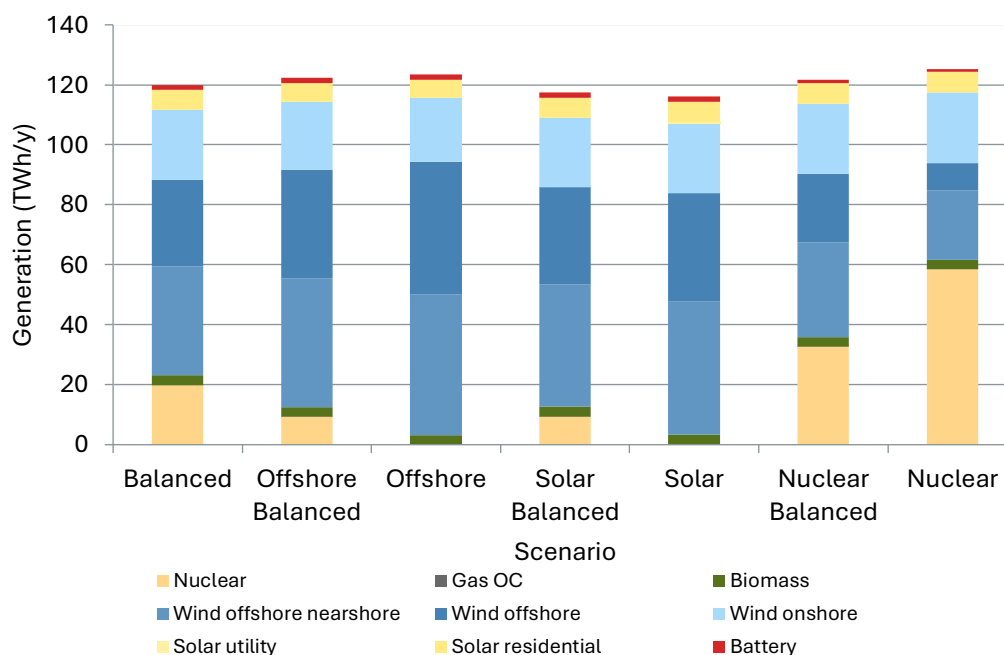


Figure 22. Total electricity generation across all scenarios with individual contributions from each technology.

The contributions from the remaining technologies are relatively minor with Solar PV delivering on average 6%, followed by biomass which adds 3% and Gas OC which is not providing more than a 1/10th of percent (indicating its clear role as a peaking power plant ensuring system adequacy).

Take-aways – Capacity and generation mix:

- Regardless of the scenario the wind energy remains the power and energy backbone of the Danish energy system.
- Solar energy is not expanded while the increasing share of non-dispatchable generation calls for greater investment in BESS and Gas OC for balancing.
- Onshore and offshore capacity is being intensively exhausted with an exception of more farshore resources which are either not needed or too expensive from the system point of view.
- The Nuclear scenario calls for a considerable buildout of new capacity which raises a question about spatial feasibility placing such new investments – further elaborated in Section 5.10.1.

5.3 Power system dispatch

Figure 23 and Figure 24 how the daily mean power system dispatch across Danish and broader Nordic-European bidding zones for weather year 1991.

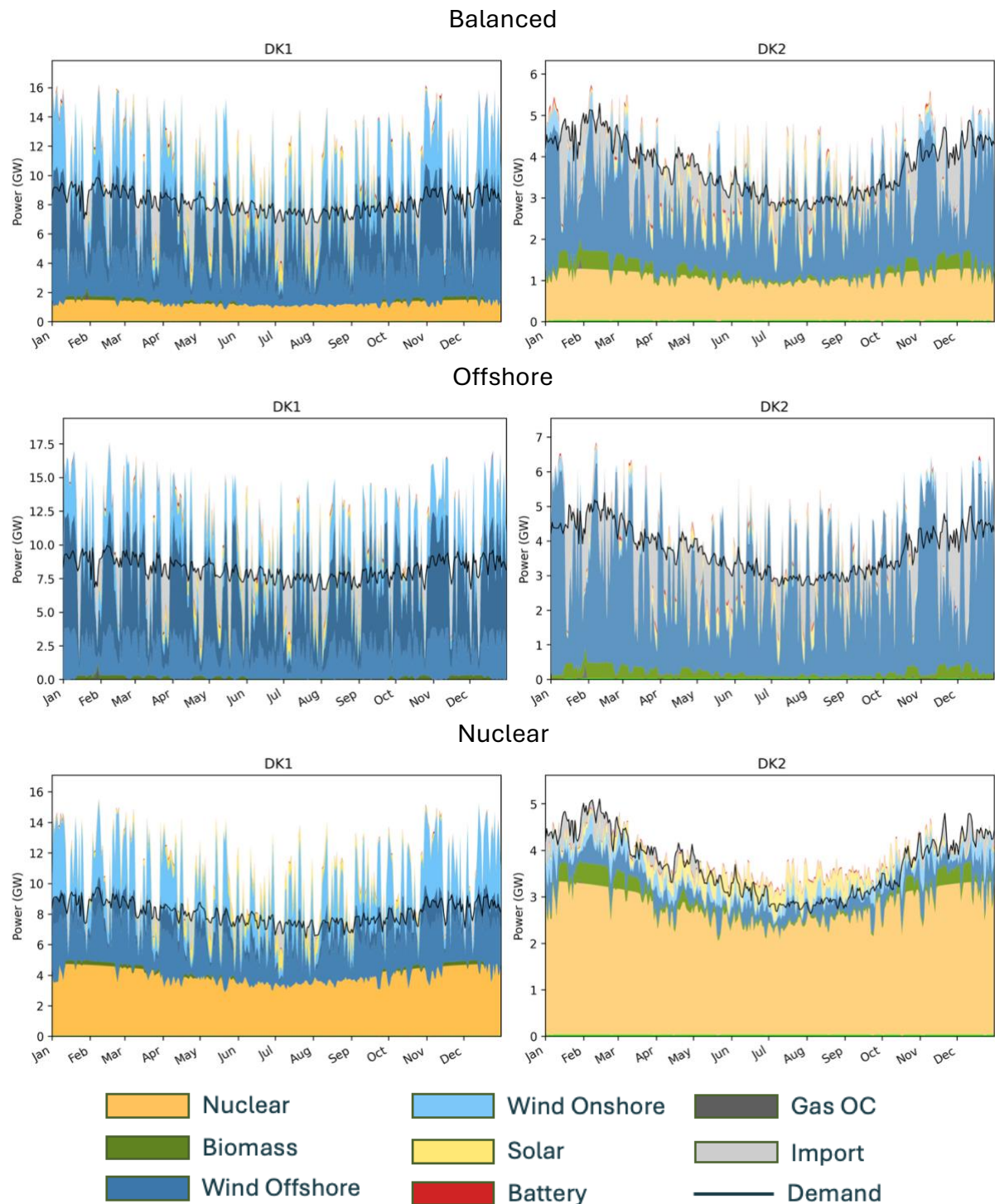


Figure 23. Power system dispatch, daily mean, across the two different Danish bidding zones for weather year 1991 and three scenarios Balanced, Offshore and Nuclear in the top, middle and bottom panel, respectively.

For the Danish bidding zones (Figure 23), the dispatch patterns broadly align with expectations. Both DK1 and DK2 are dominated by wind (except for the Nuclear scenario), with solar displaying contributions during summer months. Periods of import are varying across the year, reflecting Denmark's role as a net importer during low-wind periods and a net exporter when wind is abundant, reflecting a system highly dependent on interconnections for balancing. In the Nuclear scenario, DK2 shows a markedly larger baseload contribution from nuclear. The smoothened nuclear availability profile with highest availability, 100%, during winter and lowest (80%) at mid-summer time is pronounced. Nuclear dispatch exhibits slight ramping across the year (see also Section D.4.4).

The broader Nordic-European zones in Figure 24 illustrate dispatch profiles of different system types. Germany (DE) and the Netherlands (NL) show pronounced seasonal variation in the residual load met in large by gas turbines with substantial ramping up and down across the year as wind and solar output fluctuate. This reflects a continued role of dispatchable gas capacity in these systems as a balancing resource. Norway (NO125) displays the characteristic hydro-dominated dispatch, with hydro generation responding dynamically to system conditions and effectively acting as the region's primary flexibility provider. Poland (PL) remains heavily baseload dispatched with some remaining coal lignite and hard coal but a considerable nuclear bottom plate. Sweden (e.g., SE3) and Finland (FI) feature strong shares of nuclear representing primarily the existing nuclear fleets.

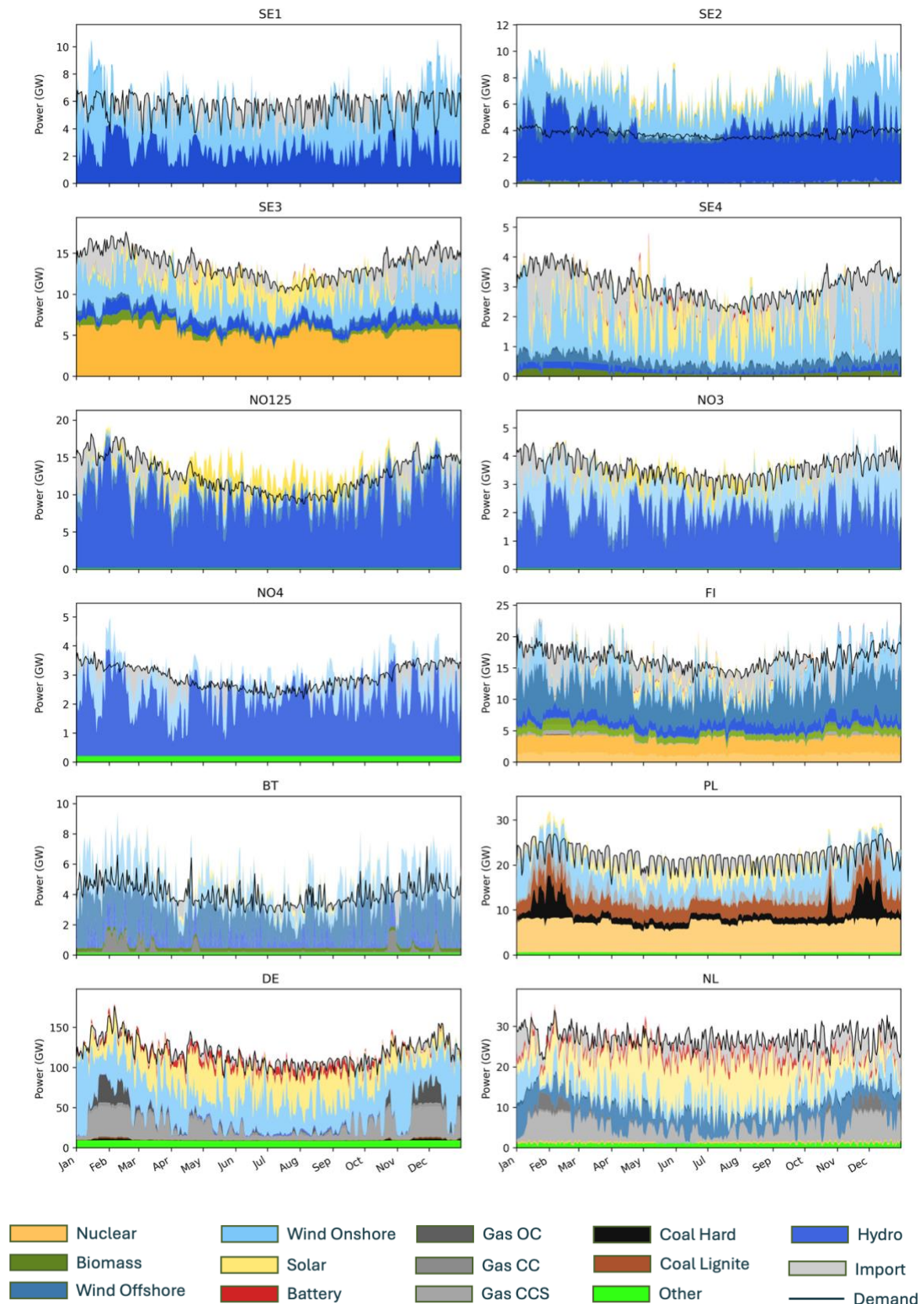


Figure 24. Power system dispatch, daily mean, across most of modelled bidding zones and three in the Balanced scenario for weather year 1991.

Take-aways – Power system dispatch:

- Danish dispatch is wind-dominated across scenarios, with a notable nuclear baseload in DK2 under the Nuclear scenario, and relies on interconnections for balancing: net imports during low-wind periods, net exports when wind is abundant.
- Neighbouring zones show characteristic dispatch profiles: gas-balanced and seasonally varying in Germany and the Netherlands, hydro-flexible in Norway, baseload-heavy in Poland (coal and nuclear), and high nuclear shares in southern Sweden and Finland.

5.4 Capacity requirements

The capacity and generation mix in the different scenarios of the Danish energy systems was first evaluated based on an energy-only market (cf. today's day-ahead market), representing the third step of the methodology (see [Figure 3](#)). The capacity expansion optimisation was performed on a weather year representing average market conditions, and thus representative market revenues for the technologies considered for investments.

In addition to adequate performance on supplying energy cost effectively over average conditions, the power system need to fulfil generation adequacy against extreme weather events and outages, provide frequency and non-frequency balancing services to ensure operational safety.

In normal operation, dispatchable capacity contributes to frequency and voltage restoration through, among other things, inertia and high short-circuit power. An increased share of volatile electricity generation that lacks synchronous generators places higher and, above all, changed demands on balancing measures that entail both increased risks and costs but also, from certain aspects, new opportunities⁶⁶.

Outside normal operations, dispatchable capacity becomes even more critical. Following a contingency, such as the loss of a major generation unit or grid connection, high dispatchable capacity helps to quickly replace lost generation. In case of islanding and black start, power plants with high short-circuit power and stable synchronous generation become crucial. A power system with a lower share of dispatchable capacity will require a higher element of flexibility - for example through battery storage or dispatchable consumption, but also gas turbines - to maintain operational reliability.

To ensure island operation and restoration, a degree of gas turbines is likely to be required. For reliability reasons, it may also be necessary to keep gas turbines warm in standby mode, which may lead to increased fuel consumption and emissions. These aspects go beyond what is considered in the current study.

Adequate capacity to ensure generation adequacy and operational safety was interrogated based on the extreme event driven by the conditions of the historical weather during a weekday in mid-January (19th) of 1985. This event has been identified and characterised in the Swedish context during previous work⁶⁷ and has also been described in [Section 3.3](#). In addition to the background provided above, the following analysis further guides the self-sufficiency level of the Danish power system.

In the cGrid model, market clearing is iterative: the price is increased stepwise until supply meets demand, subject to a maximum price cap of 3,000 €/MWh. Before the cap is reached, demand is progressively cut in response to elevated prices according to the

⁶⁶ Nordic Transmission System Operators (2023), Nordic Grid Development Perspective 2023.

⁶⁷ Energiforsk (2025), Så får industrin tillräckligt med el till 2035 – bilagor till slutrapport.

demand-flexibility representation introduced in Section 4.2. Loss of load is therefore defined as the residual unmet demand remaining when the iterative market-clearing reaches the 3,000 €/MWh ceiling. It is an endogenous outcome of evaluating a fixed system configuration across the simulated weather year, not an event imposed on the model. Because the clearing covers Denmark and its neighbours simultaneously, the capacity available for import into Denmark depends on the state of the neighbouring systems: when those systems are themselves short, imports are correspondingly limited. Interconnector capacity itself is treated as exogenous with availability according to 2025 data, not directly incorporating outages as well as scenarios on projected development of transmission lines, for instance, subject to political climate.

The January 1985 weather year contains one of the most demanding resource-adequacy events in the dataset. Low wind production contributes to a wider regional generation shortfall, combined with cold weather that drives up electricity demand for heat supply. Although the event duration is comparatively short, prices rise across essentially the entire modelled European system, indicating that this event is driven to a substantial extent by generation scarcity in continental Europe, not by Danish conditions alone. We use this event as a reasonable case for dimensioning capacity requirements. It is not necessarily the only suitable event; what matters is that the chosen case is paired with a thorough evaluation of system performance, which the subsequent analysis provides.

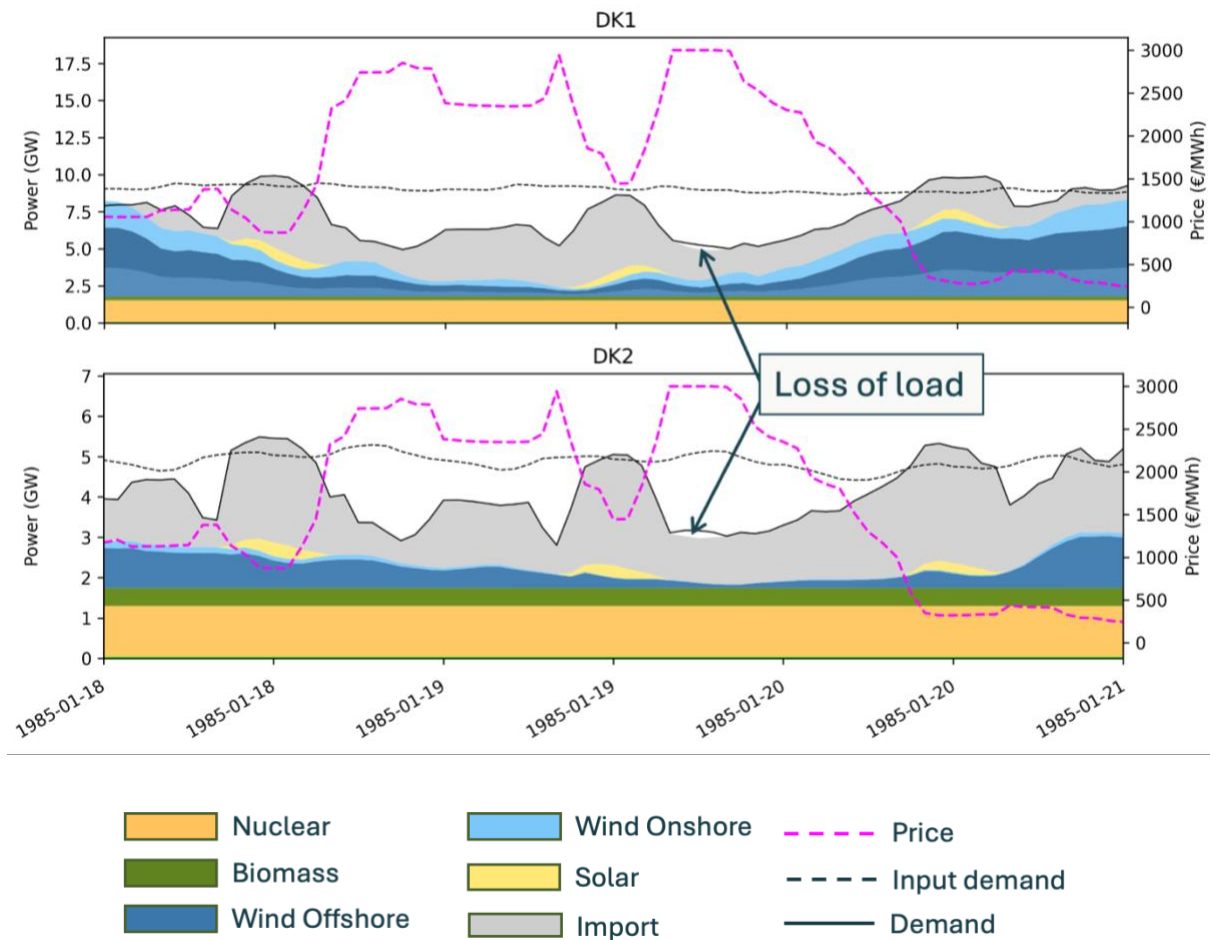


Figure 25. Dispatch in the two Danish bidding zones for different technologies, as indicated by the legend, of the challenging event of January weather year 1985 in the Balanced scenario. Input demand is the realised demand at a flat price of 75 €/MWh. Time of loss of load is indicated by annotation.

Figure 25 illustrates the dispatch in the Balanced scenario across 18–21 January of the 1985 weather year, separately for the two Danish bidding zones DK1 and DK2. Across the displayed period, firm generation from nuclear and biomass operates at high load factors and wind output varies substantially day to day, with the lowest wind hours coinciding with the price peaks. Imports form a large share of the supply stack in both zones during the stressed period. In both DK1 and DK2, a loss-of-load event occurs centred around 17:00 19th January.

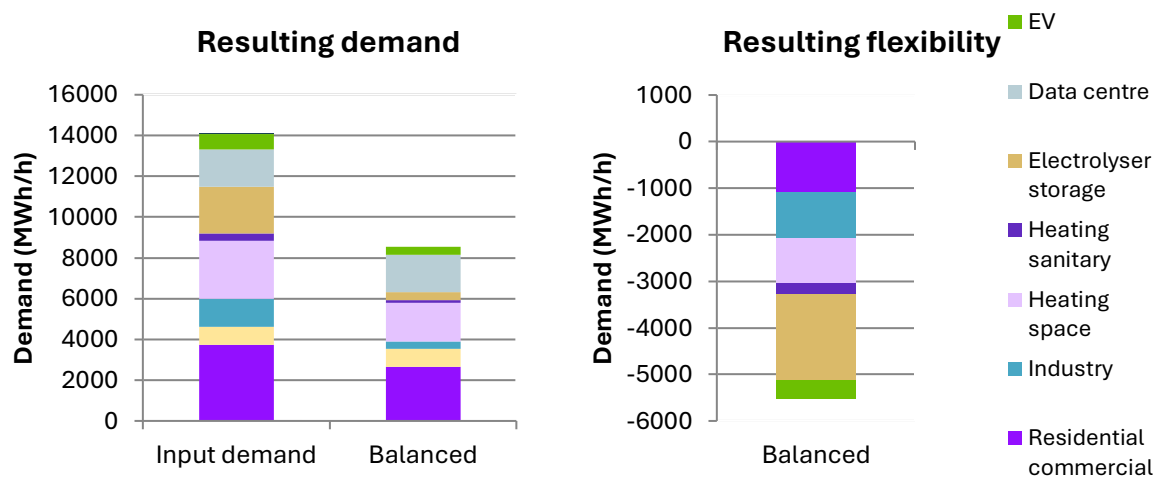


Figure 26. Input demand and resulting demand (left panel) and resulting flexibility at most challenging hour during 1985-01 event.

Figure 26 zooms in on the system demand response for the hour January 19th 17:00. Being a winter weekday, this hour means a combination of high heat and evening peak demand. Due to considerable share of hydrogen production in the system its response is the largest, but response from heating and industry together contributes the largest. Driven by some variation in the price throughout the day (see Figure 25), the shifting part of the flexible response is moved around to avoid load at the event. This relates to the response by all categories, except Losses and Data centre. Notably, this is not the case in the Nuclear scenario (not shown here), where only the Electrolyser storage category with a duration of 12 days is able to avoid the worst of the price peak. The very elevated prices trigger cutting response of load categories to minimum levels throughout the event. Here industry is the largest contributor.

Figure 27 shows the supply composition of the Danish power system during the 1985-01 event across the seven main scenarios. Because realised demand is similar across scenarios (see preceding section), differences in total supply primarily reflect whether the scenario carries firm generation in excess of domestic demand. Six of the seven scenarios cluster around 8 GW of combined supply, i.e., the level required to meet Danish demand during this event and differ in how that supply is met rather than in how much is supplied. The Nuclear scenario is the primary exception: at approximately 10.5 GW its larger firm generation share means that a larger demand is realised for Denmark with no loss of load as a consequence in the cGrid simulation, which also is the case in the Nuclear Balanced scenario.

Within the six scenarios at ~8 GW of combined supply, the composition of supply varies systematically with the nuclear capacity in the portfolio. More domestic firm generation translates into less reliance on imports during a wide-area stress event, since neighbouring systems are simultaneously short. In the Balanced scenario, imports cover 24% of input demand which is broadly consistent with the 27% import share observed in the Danish power system in 2025 (see Appendix B). Across all scenarios, the import share

spans from 6% in the Nuclear scenario to 37% in the Solar scenario, with the renewable-heavy variants (Offshore, Solar) at the high end.

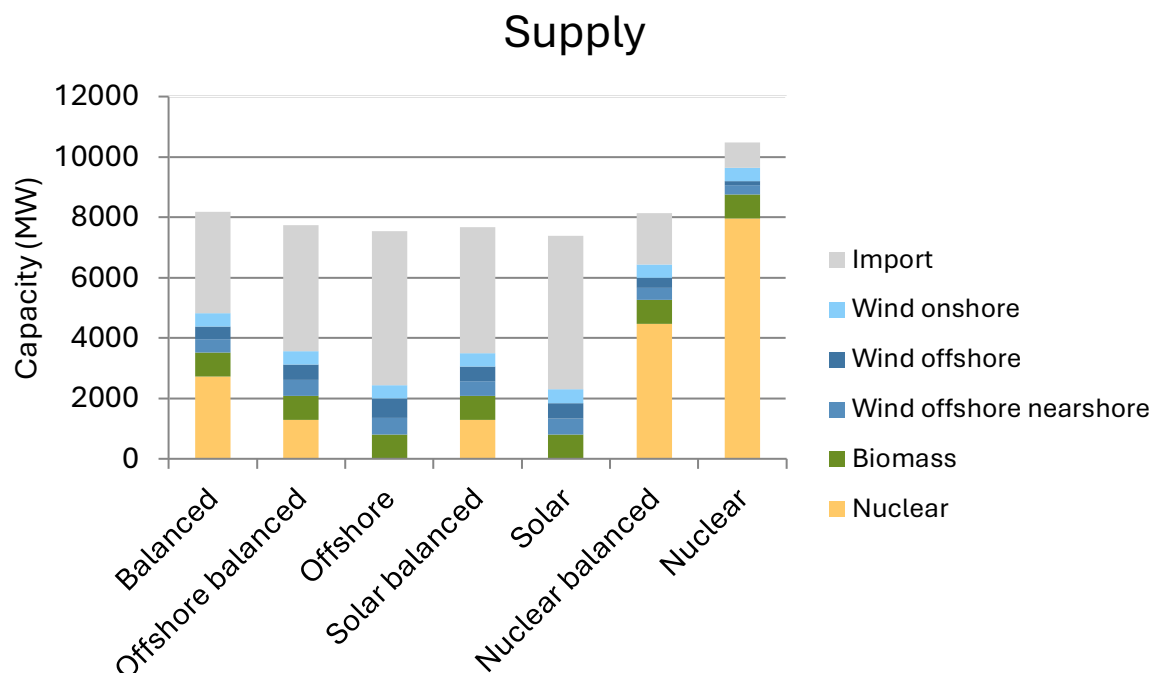


Figure 27. Supply capacity of the Danish power system at the 1985-01 event across the main scenarios.

The model simulation indicates a loss of load (lacking ~400 MW). However, the model simulation does not activate potential reserves, nor does it account for N-1 contingency. These are aspects that are considered post-modelling in the following.

We have assumed an installed capacity of dispatchable power from CHP plants according to AF25.⁶⁸ Normal operation biomass CHP plants are assumed in the model to not provide peaking capabilities which means there is potentially capacity not activated in the simulation of the 1985 event. Remaining biomass CHP, centralised and decentralised, which could be called for peaking operation have been determined according to derating capacity factor 0.77.⁶⁹ to 1262 MW, denoted reserves in the figure.

Evaluation of the power system balance for the event is given with the waterfall diagram in Figure 28. Incorporating the reserves and an N-1 criterion of 1000 MW,⁷⁰ the system is almost in balance. However, the system is very dependent on demand-side flexibility and imports raising concerns on limitations of materialising flexibility and self-sufficiency priorities.

⁶⁸ Energistyrelsen (2025), Analyseforudsætning til Energinet 2025 (AF25).

⁶⁹ Energimyndigheten (2023), Förslag till en fjärrvärme-och kraftvärmestrategi.

⁷⁰ Energinet (2024), Dimensionerende hændelse hæves til 1.000 MW i 2030.

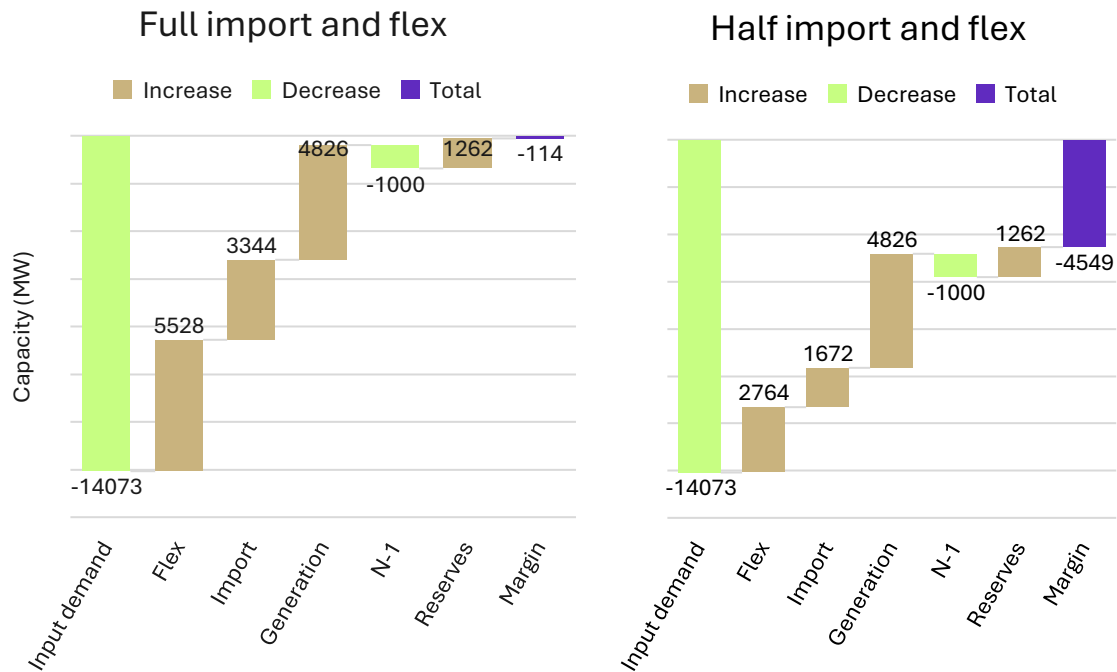


Figure 28. Power system balance in the Danish power system split up by components in the Balanced scenario for the 1985-01 event. Full, 100%, and half, 50%, availability of import and flex in the left and right panel, respectively.

The current study assumes a policy measure to ensure an arbitrary level of self-sufficiency and robustness towards demand-side flexibility materialising by cutting the availability of flexibility and imports in half. The resulting system margin following this policy measure is used to determine additional firm dispatchable capacity needs.

The assumed policy measure is motivated by the following argumentation. Regarding imports, this relies on requirement of self-sufficiency level, each country cannot depend too heavily on neighbours in times of shortage. On imports, a meaningful self-sufficiency requirement implies that countries cannot lean heavily on neighbours during regionally correlated shortages. On flexibility, most demand-side response is short-duration, and there is substantial uncertainty over how much of the assumed flexibility will materialise and which system services it can reliably provide. The long-duration flexibility that the electrolyser load provides in the simulation is an example of flexibility that does not exist in scale today and where uncertainty in development is arguable considerable.

After recalculations with half imports and flexibility, the Balanced scenario sees a negative balance of 4500 MW. The missing supply capacity is compensated with:

- 70% gas turbines
- 30% battery energy storage systems

Following this implementation, loss of load in modelled is never seen across all weather years and scenarios for Denmark. The proportion, gas turbines to batteries, represents an arbitrary implementation level but motivated through the following argumentation.

The two technologies typically operate on different time scales and therefore address different dimensions of supply security. Battery energy storage systems are well suited to delivering fast-acting response, primary and secondary frequency control, and short-duration grid support, including grid-forming capabilities that become increasingly valuable as synchronous generation retires and the system relies more heavily on inverter-based resources for dynamic stability. The capability of the battery storage to provide capacity during challenging conditions in part depends on which markets it participates in, which is an aspect that future studies could better highlight.

Gas turbines are dimensioned to provide sustained energy during prolonged low-generation periods, non-frequency ancillary services such as voltage support and rotational inertia, and the preparedness and black-start capability required for system restoration following major disturbances. Similar to batteries, its capability to provide capacity to the system depends on market participation.

To preserve energy-only market conditions and technology profitability resulting from the capacity expansion optimisation, performed before the capacity requirements adjustments, the Gas OC capacity is assumed to act as reserve. Modelling-wise, this means that they will only be dispatched at market prices exceeding 500 €/MWh representing periods of real supply scarcity and system stress. This is a very important assumption. If the gas turbines were to bid in with their marginal cost of around 160 €/MWh their average production would be considerable with capacity factors approaching 20%.

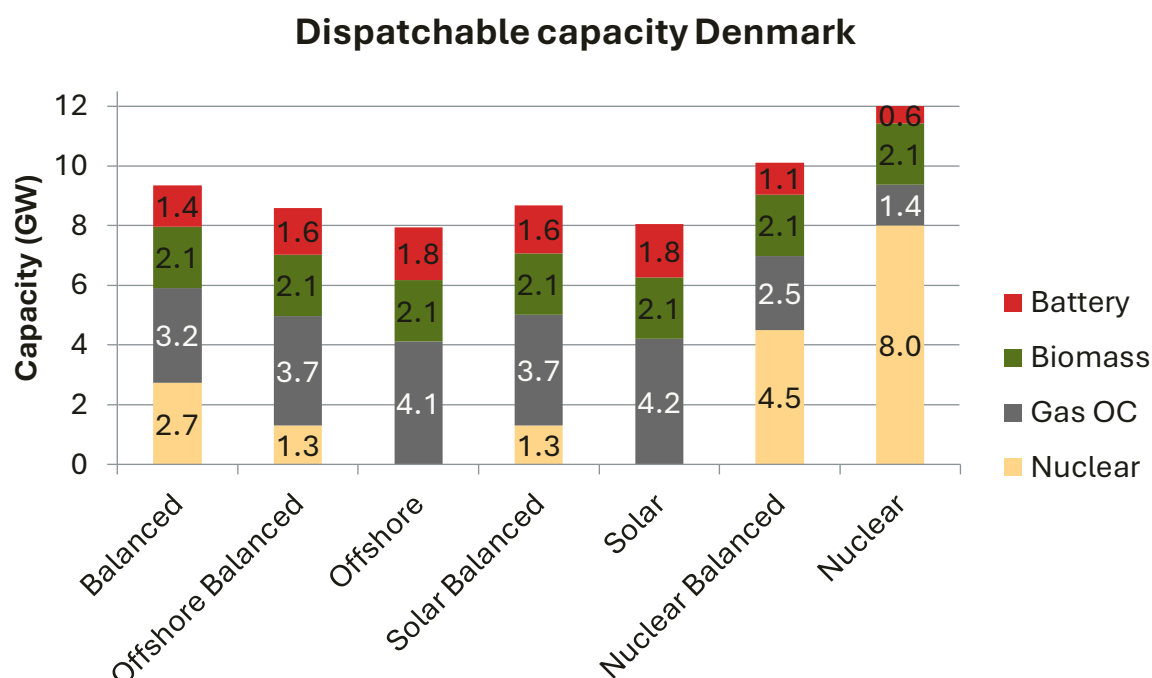


Figure 29. Installed dispatchable capacity in Denmark by technology and across scenarios.

Based on the methodology outlined above, resulting total dispatchable capacity including Battery and Gas OC is shown in [Figure 29](#). The applied methodology results in an installed dispatchable capacity (excluding Battery) of 8 GW in the Balanced scenario with variations between 6.2 GW at the lowest in the Offshore scenario to 11.4 GW in the Nuclear at the maximum. This includes 1.3 GW relating to Bio CHP capacity typically not activated in normal operating conditions but could possibly aid in system stress conditions.

Furthermore, a strong correlation is found on a zone level ([Figure 30](#)) behind the share of installed non-dispatchable capacity and installed capacity in battery storage. Depending on the scenario increasing the share of non-dispatchable capacity from 18% to ~90% rises the demand for storage from 0.2 GW to 1.2 GW. Clearly indicating BESS role in balancing the supply-demand mismatches resulting from VRES non-dispatchability. A similar relationship was observed between non-dispatchable share and installed capacity in Gas OC.

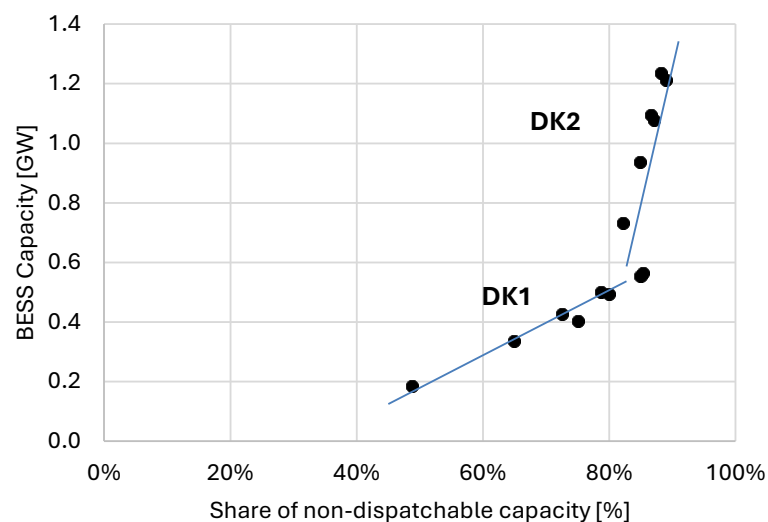


Figure 30. Relationship between non-dispatchable and installed capacity in battery storage.

Take-aways – Capacity requirements:

- Denmark power system based on energy-only market capacity expansion optimisation has been evaluated based on the extreme event characterised by the historical weather of January 1985.
- All system scenarios exhibited strong import dependence as well as demand-side flexibility in response to manage the event.
- By means of incorporating half the import capacity and demand-side flexibility a considerable negative margin was determined and then used to determine dispatchable capacity additions to the Danish system.
- Battery storage and gas turbine capacity was added, reflecting complementary system values: battery for fast response, frequency balancing services and grid support and gas turbines for long-duration supply, non-frequency ancillary services, preparedness and restoration.
- The applied methodology results in an installed dispatchable capacity (excluding Battery) of 8 GW in the Balanced scenario with variations between 6.2 GW at the lowest in the Offshore scenario to 11.4 GW in the Nuclear at the maximum.

5.5 Generation and capacity costs

Generation and capacity costs have been determined for all scenarios investigated in the current study and are presented according to technology contributions or cost types: investment costs, fixed costs, variable costs, import costs and excluded costs. These costs are annual, 'levelised' costs, meaning that the investment costs are spread evenly over the economic lifetime of the technology. Presented values represent the absolute costs normalised to total power demand, being 102 TWh in the reference scenario, unless otherwise indicated.

- Variable costs include both operation and maintenance (O&M) costs
- Investment costs represent investment costs
- Fixed costs represent fixed O&M
- Import costs relate to the net cost of importing electricity due to trade with bidding zones outside Denmark. For scenarios with net export revenue, this is shown as a negative item in the system cost. See also Section 5.7.1.
- Fuel and CO₂ costs represent fuel expenses and total cost of emission allowances based on the assumed CO₂ price.

Excluded costs are primarily related to reinvestment and maintenance costs of existing power plants and the grid infrastructure. Notably, grid capacity expansion relating to offshore wind connection to shore is included in the presented costs here. However, *onshore* grid upgrade costs is an aspect discussed separately in Section 5.10. Furthermore, costs relating to balancing services has not been explicitly considered, see also Section 3.5.

The generation and capacity costs following the capacity expansion optimisation, but before imposing the capacity requirements, on the reference weather year 1991 is shown in Figure 31. The Balanced scenario exhibits largest costs due to larger cost base, recall that the other scenarios assume cost reductions and larger levels of flexibility. In all scenarios Denmark is a net exporter of power, however, except for Nuclear Balanced and Nuclear, they show net import costs. This means that export revenues in the Nuclear Balanced and the Nuclear scenarios decrease total costs. Note, no CO₂ costs are observed since the gas turbine capacity additions is made post the capacity expansion optimisation.

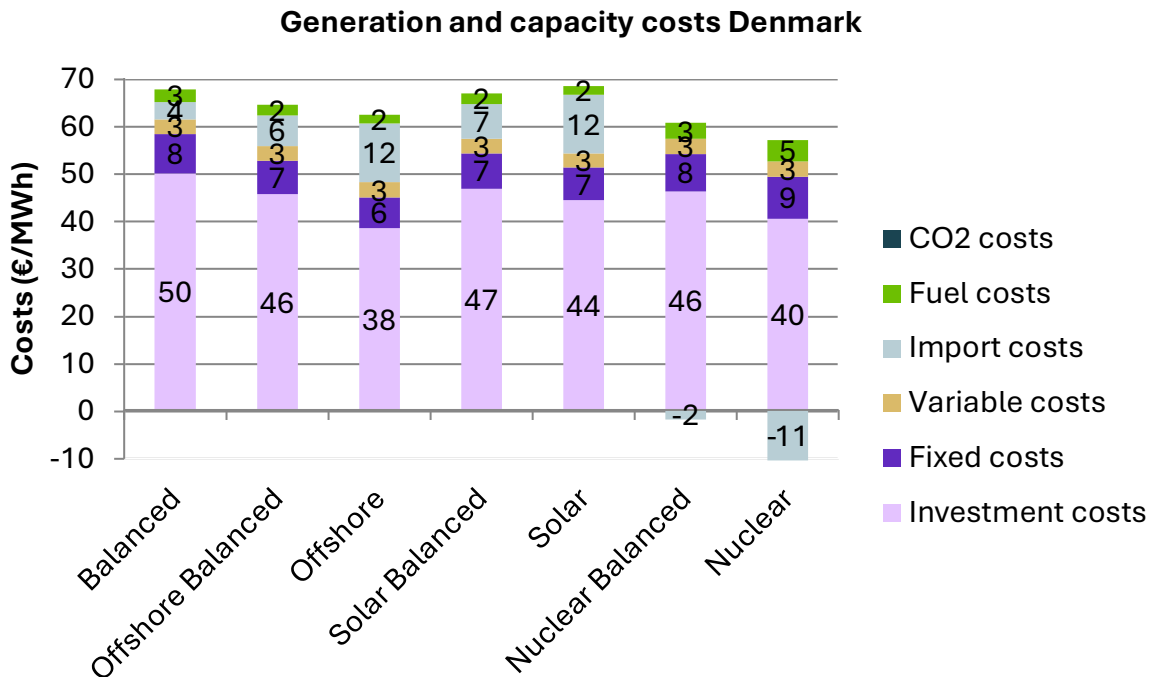


Figure 31. Generation and capacity cost, including import costs, normalised to annual demand broken down by cost component across main scenarios for the resulting system of the capacity expansion optimisation step (step 3 in [Figure 3](#)).

To further evaluate system costs we introduce cost variations as shown in [Figure 32](#), based on the technology cost scenarios introduced in [Table 8](#). The cost variations represent:

- **Base:** the costs following the capacity expansion optimisation, i.e., the aggregate of cost components in [Figure 31](#).
- **Capacity requirement:** the costs associated with additional dispatchable capacity of battery and gas turbines following the capacity requirement methodology presented in [Section 5.3](#).
- **Tech. cost norm.:** the technology cost normalisation levels represent costs following adjustment of technology cost assumptions to the reference scenario across all technologies. In the capacity expansion optimisation, Optimistic-1 and Optimistic-2 levels for technology costs are also employed in some scenarios. In the calculation of the technology cost normalisation levels, all technology costs are bumped up to the reference technology cost scenario level to introduce a fairer scenario comparison.
- **Conservative-1 and Conservative 2:** similarly to the Tech. cost norm., these levels represent costs following adjustment of technology cost assumptions to the Conservative-1 and Conservative-2 scenario across all technologies, respectively.

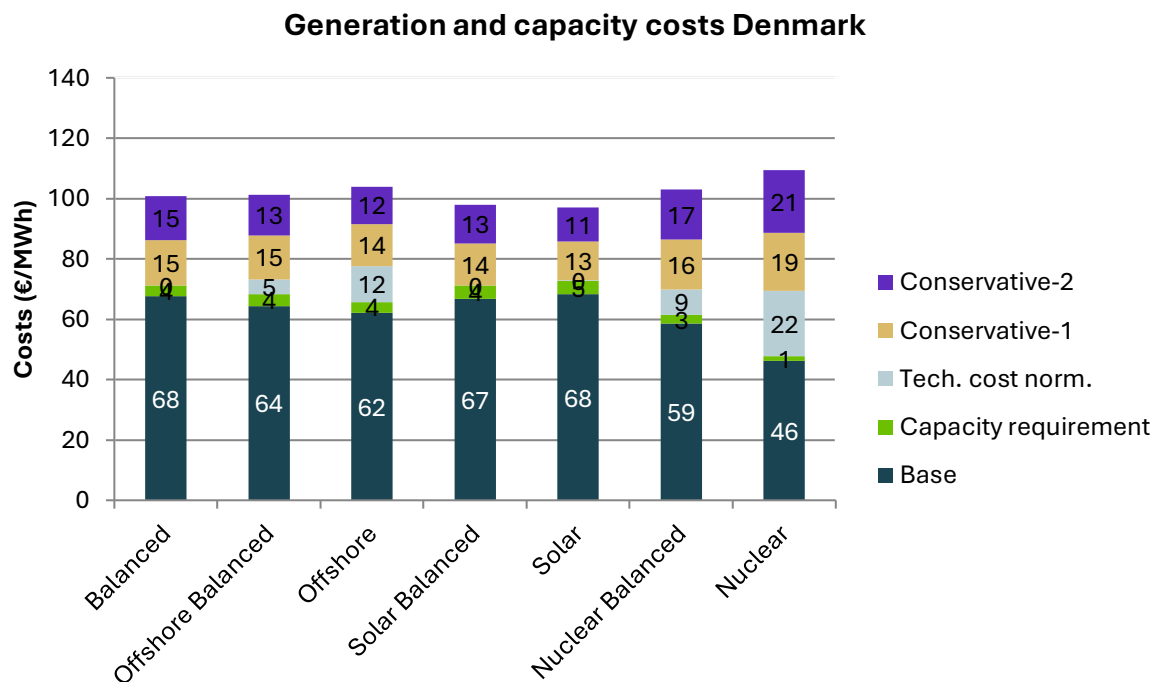


Figure 32. Generation and capacity cost, including import costs, normalised to annual demand broken down by cost variation across main scenarios.

Considering the overall costs of the Base cost variation, the nuclear-heavy scenarios show smallest cost (46 €/MWh and 59 €/MWh for Nuclear and Nuclear Balanced, respectively) followed by Offshore (62 €/MWh) due to their lower cost assumptions and/or export revenues. A possible interpretation of the lower costs in the nuclear-heavy scenarios is that they show the potentially strongest cost benefit if the more optimistic underlying technology cost assumptions materialise compared to the Offshore scenario. This reflects the relatively stronger reduction in technology costs for nuclear compared to offshore wind.

Following the capacity requirement of battery and gas turbines, the investment costs are bumped up in accordance with the level of the capacity additions. These additional investment costs range from 1-5 €/MWh. However, these additional costs are compensated by decreased import costs as the gas turbines and battery storage reduce Denmark's import dependence, providing an explanation to why the capacity requirement costs of the Balanced scenario (4 €/MWh) is similar to the Offshore scenario (4 €/MWh). Due to already demonstrating net export revenues before the capacity requirement, the nuclear-heavy scenarios combined with lower capacity additions demonstrate smallest cost impact of the capacity requirement (3 and 1 €/MWh, for Nuclear Balanced and Nuclear, respectively). Overall, the capacity requirement costs are relatively limited with a 5% increase in the Balanced scenario.

Folding in the Tech. cost norm. variation enables a fairer comparison between the scenarios. As expected, the Offshore and Nuclear scenarios display largest subsidy costs at 12 and 22 €/MWh for the Reference technology cost scenarios, respectively, due to these power systems expanding supply capacity to the largest extent. As per design, the Balanced scenario shows no cost addition in the technology cost normalisation. At a total level, the cost level, including import costs, only varies marginally away from the Balanced scenario at 71 €/MWh to 69 €/MWh (-3%) in the Nuclear scenario to 78 €/MWh (+9%) in the Offshore scenario. A possible interpretation of the technology cost normalisation is required technology subsidy costs, which is a topic further discussed in Section 5.6.4.

Before moving to Conservative-1 and Conservative-2 levels, it is worth to consider the technology cost shares as shown in Figure 33. From this pure technology cost frame, the cost share very well mimics the generation share in Figure 22. Gas OC being the primary exception where costs ranging from 1-4 €/MWh reflects its dominating investment cost component since it has very low utilisation.

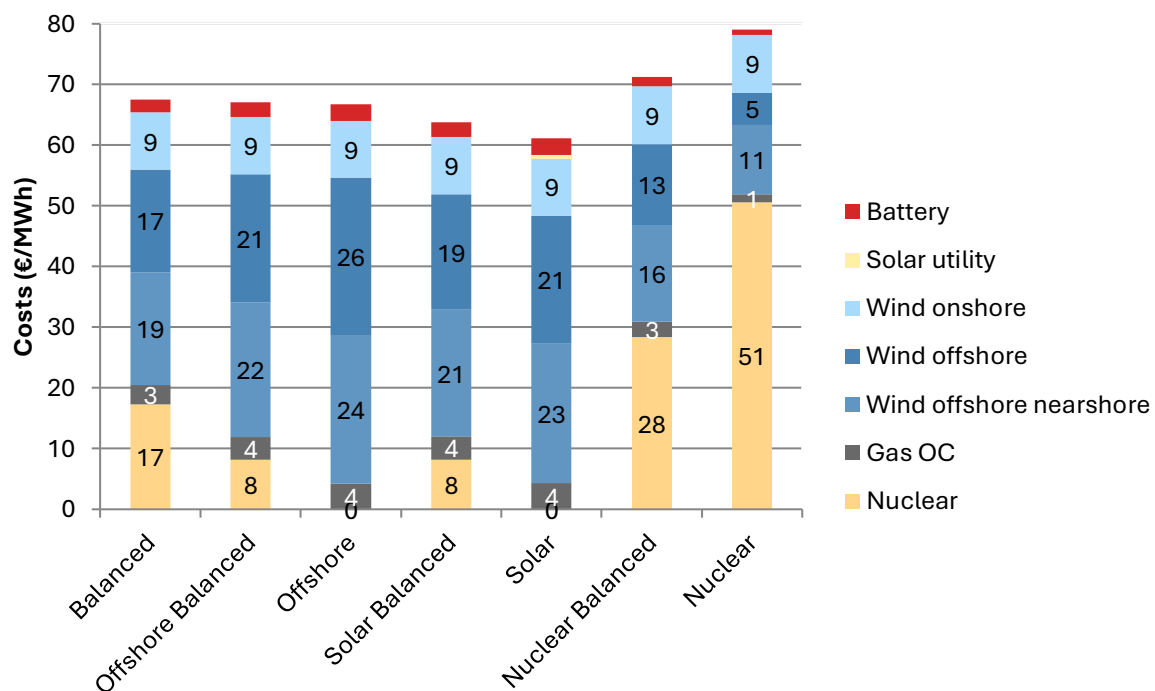


Figure 33. Generation and capacity cost in the reference technology cost scenario normalised to annual demand broken down by main technologies. Note, costs here do not include imports. Battery costs range between 1-3 €/MWh.

Considering potential risk of cost escalations in the Conservative-1 and Conservative-2 variations, it is observed that the nuclear-weighted scenarios carry the largest risks shifting these to show highest costs instead. This is driven by the very large uncertainty in nuclear costs. The solar scenarios show least risks due to least local investment in the Danish system. The Offshore scenario shows smaller risks compared to the Nuclear scenario but levels out with the Nuclear Balanced scenario which carry a more balanced risk between nuclear and offshore wind cost escalations.

In the comparison of the Conservative-1 and Conservative-2 aggregated costs levels, remarkably small variations between the power system scenarios with -1% to +6% in Conservative-1 and -4% to 8% in Conservative-2 are observed. This observation is contingent on the fully aligned technology cost scenario across all technologies simultaneously.

Different views on technology cost projections may be extracted from the shown cost escalation broken down by technology and power system scenario for the Conservative-1 and Conservative-2 technology cost scenarios in Figure 34. For example, a view that nuclear cost should deviate to the Conservative-2 technology cost scenario means cost escalations of 10 (+14%), 24 (+35%) and 50 €/MWh (+72%) in the Balanced, Nuclear Balanced and Nuclear scenario measured from the Base step in Figure 34 (percentages relative to total costs at the Tech. cost norm. level), respectively. Correspondingly, a view that offshore wind cost should deviate to the Conservative-2 technology cost scenario means cost escalations of 14 (+20%), 22 (+30%) and 32 €/MWh (+41%) in the Balanced, Offshore Balanced and Offshore scenario, respectively.

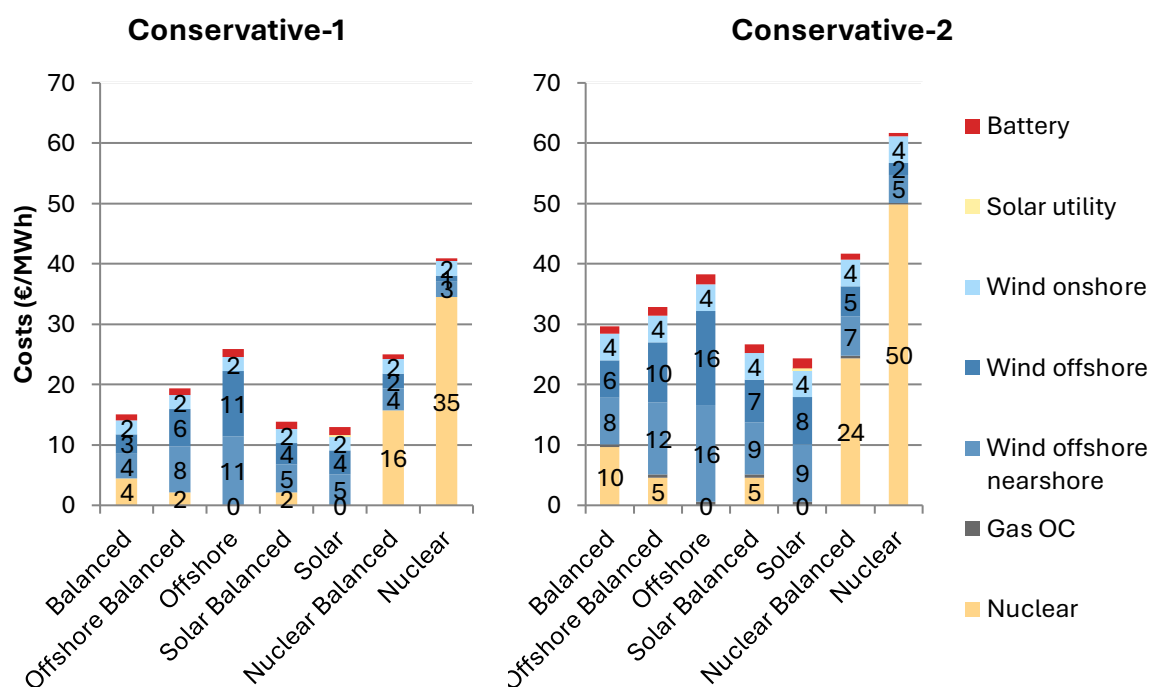


Figure 34. Generation and capacity cost escalation in the Conservative-1 (left panel) and Conservative-2 (right panel) technology cost scenarios broken down by main technologies. Presented costs are normalised to annual demand and do not include imports. Cost escalation for battery is of the order of 1-2 €/MWh while for Gas OC is below 1 €/MWh.

Take-aways – Generation and capacity costs:

- Generation and capacity costs have been evaluated comprehensively across the Danish power system scenarios based on cost components (investment costs, import costs, etc.) as well as cost variations (capacity requirements, subsidy costs and conservative levels).
- The capacity requirement costs generally stand for a relatively limited share with a 5% increase in the Balanced scenario, with the Nuclear scenario diverging a most at only a 2% increase.
- Considering the Tech. cost norm. variation, the Offshore and Nuclear scenarios display largest values at 12 and 22 €/MWh, respectively, potentially representing subsidy costs.
- The Nuclear scenarios show both the largest potential cost benefit as well as cost risk if the more optimistic and conservative underlying technology cost assumptions materialise, respectively.
- In conclusion, the technology cost scenario variations imposed on the Danish power system scenarios show remarkably small variations between the power system scenarios within the range of -4% to +9% relative to the Balanced scenario for Reference, Conservative-1 and Conservative-2 cost variations.

5.6 Electricity market

The price of electricity is a key determinant of both the functioning of the energy market and the wider economy. It affects industrial competitiveness, household electricity costs and investment incentives for new electricity generation. Scenario analyses, such as this one, often focus on system costs, which can be linked to the average electricity price required for producers - such as wind developers - to reach profitability in the modelled scenarios. At the same time, the electricity price is affected by how the power system balances local production and trade with other countries. Depending on the scenario, the system may lean more or less towards imports and exports, which leads to electricity prices varying both in Denmark and throughout the model. A holistic view of both system costs and electricity prices is therefore required to understand the economic conditions of the future power system.

However, a discussion of electricity prices is incomplete without considering price volatility, that is, how electricity prices vary over time. Price fluctuations can be caused by factors such as fuel prices and capacity constraints such as power plants or transmission, but this study focuses in particular on weather-dependent variations.

Lower electricity price volatility is valuable for a society, as it provides predictability and stability for both consumers and producers. This stability can reduce financial risks, facilitate investment planning and ensure more consistent electricity costs, contributing to a reliable and efficient energy market. Low electricity price volatility also reduces the need for flexibility measures, such as energy storage and demand response, which are commonly used to manage price variations. This can lead to lower overall costs of maintaining system balance and reliability and a more attractive market for electricity-intensive industries, as it reduces the need for extensive flexibility infrastructure to take advantage of lower electricity prices.

Electricity price volatility can vary depending on the time horizon relevant for different actors. For example, developers of batteries for the day-ahead market are mainly interested in short-term price variations on an hourly basis, as their energy storage capacity is often limited to a few hours. In this study, we have chosen to analyse electricity price volatility on a quarterly basis. I.e., for each scenario and each calendar quarter (Q1–Q4) we compute the average day-ahead price across the hours of that quarter, repeated across the 33 simulated weather years, and report the resulting distribution of quarterly average prices. This choice is based on a trade-off between short- and long-term volatility. Too short a time horizon could imply that there are flexible solutions not included in the modelling that have the capacity to smooth out price variations, and thus risk misrepresenting the actual volatility of the system. On the other hand, as the expansion optimisation takes place with an annual time horizon, the annual variations are dampened, which means that an analysis of price volatility at the annual level would be less insightful. The quarterly horizon provides a balanced level that captures virtually inevitable price variations.

5.6.1 Average prices

Figure 35 presents the average yearly prices for all weather years. Average prices for DK1 and DK2 combined are presented here, on the background that average price levels in DK1 and DK2 are very consistent merely varying ± 2 €/MWh. The day ahead yearly average market prices arguably show limited variations, -8% to +6% compared to the Balanced scenario, despite their significantly varying structures. This is a consequence of Denmark's large interconnectivity in the market relative to its system size. This ultimately means that neighbouring regions set the price for most hours. Nevertheless, the scenarios which expands most capacity locally in Denmark (Offshore and Nuclear scenarios) exhibit lowest prices, as expected. Compared to the average market price of the power system in 2025, all scenarios exhibit a decrease (with the Balanced scenario at -5% and Nuclear reaching the maximum at -13%). This is thanks to considerable technology cost reductions across all involved technologies.

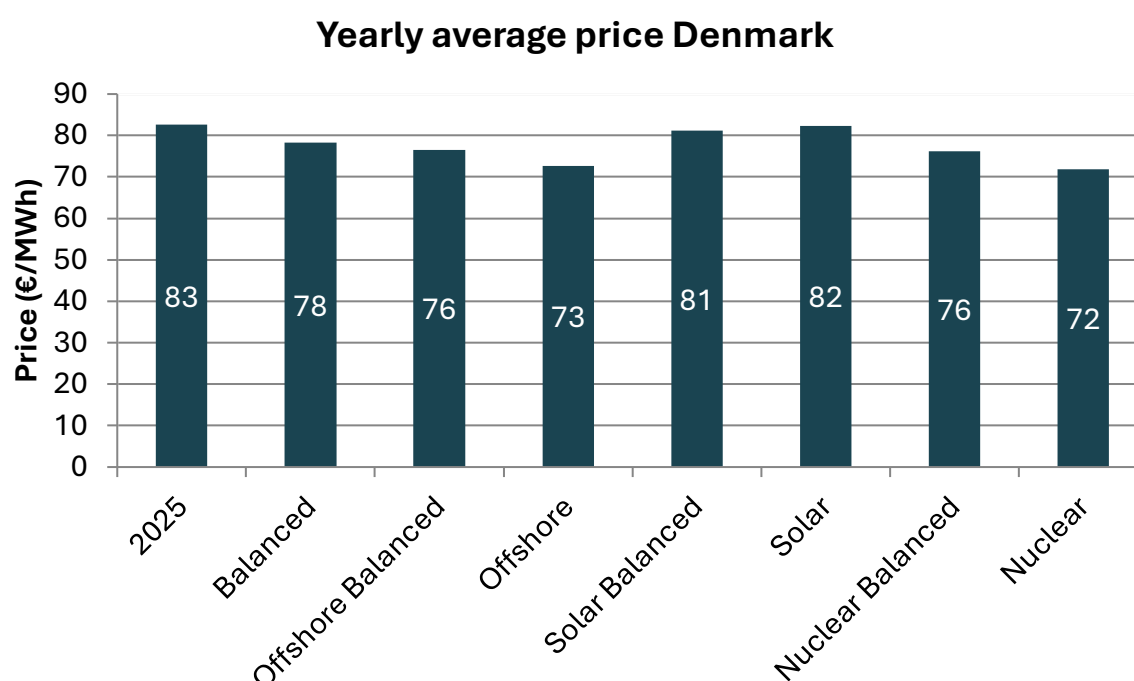


Figure 35. Yearly average market price for all weather years across the scenarios.

5.6.2 Price volatility

Figure 36 shows the outcome of average prices per quarter for the 33 weather years used in this study for a historical reference year (2025) and the seven different scenarios.

To obtain a relevant reference point for the electricity market and the electricity price picture in the current situation, a simulation was carried out with the aim of recreating electricity market conditions in 2025. This simulation used installed generation capacity, transmission capacity and fuel prices, with most of the input data being taken from the European Network of Transmission System Operators (ENTSO-E) and national system

operators, such as Energinet. As for the other scenarios, simulations were carried out for 33 historical weather years (1983-2015) to reflect the weather-dependent variation in the power system.

For the other 2050 scenarios, simulations were performed with installed generation capacity locked to the expansion values obtained for the reference weather year 1991 in the optimisation and the capacity requirement adjustment. The boxes cover 50% of the outcomes and the whisker lines cover all 1%-99% of all outcomes. The average of all quarters is shown as a triangle. The quantified volatility numbers are calculated as the average of the width of the box and the whisker lines.

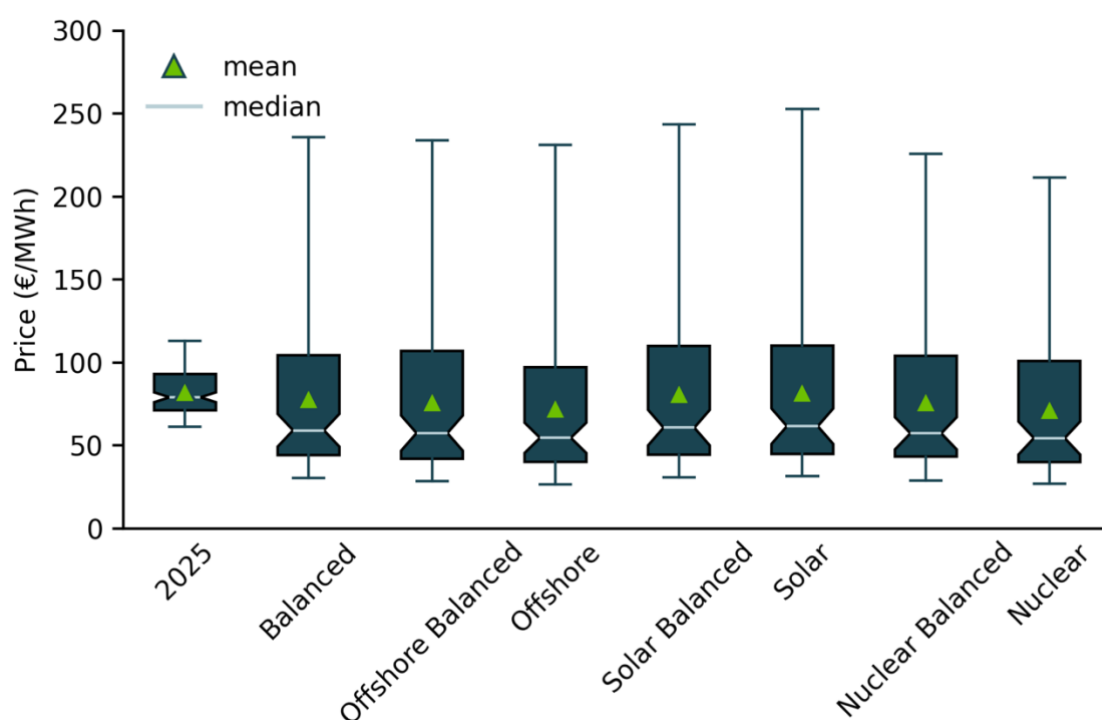


Figure 36. Quarterly average prices for the full set of 33 weather years for the simulation of the Danish power system for historical year 2025 and seven main scenarios. The boxplot diagrams cover the range of outcomes from 0% to 100% for the full set of weather years, where the boxes represent 25% - 75% quartiles. Median values are shown by horizontal white lines and mean values by green triangles.

In terms of volatility, very limited variations are generally observed across the future scenarios. Similar to the average level, this is also explained by Denmark's large interconnectivity in the market relative to its system size. However, the boxes (25%-75% quartiles) indicate that the Offshore and Nuclear scenario in particular show smaller volatility. This is thanks to their larger net power export which means that the system is capable to balance the additional supply more effectively to lower market prices (e.g., saving of hydro reservoirs). Similar results are observed for the whiskers (1%-99%). Averaging the width of the box and the whiskers, the Offshore, Nuclear Balanced and Nuclear scenario exhibits lowest values with -2%, -3% and -8% compared to the

Balanced scenario, respectively. The differences are arguably very small which is the key conclusion from this analysis.

Compared to the historical reference of the year 2025, a significant increase in volatility with 260% is observed in the Balanced scenario. Due to Denmark's strong market coupling, the increasing volatility may be explained by the considerable increased share of weather dependent generation in neighbouring regions relative to dispatchable capacity that is able to balance the supply variations on longer time scales. The development of volatility with the inclusion of the power system in 2015 was further investigated in a QC blog post⁷¹.

5.6.3 Prices in neighbouring regions

Denmark's strong market coupling is an important feature across the analysis of electricity market prices and volatility. Its large interconnectivity relative to system size strongly constrains the potential for Danish scenarios to diverge from broader regional market outcomes. Against this background, the simulated Danish power system is heavily influenced by neighbouring regions, and [Figure 37](#) illustrates the average market conditions across all modelled zones for weather year 1991 in the Balanced scenario.

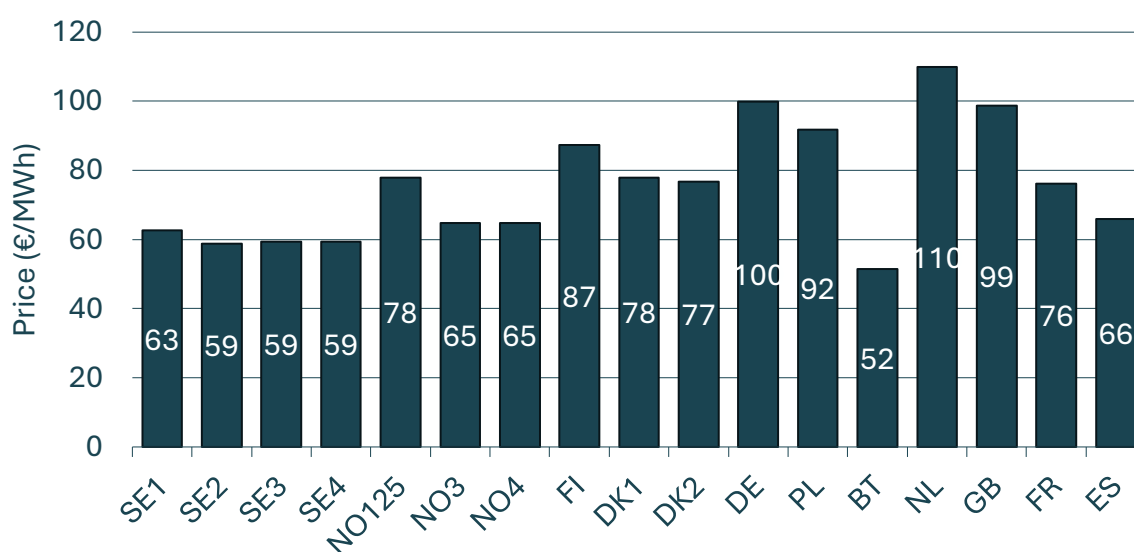


Figure 37. Yearly average price for weather year 1991 for all modelled zones in the Balanced scenario.

Considering direct transmission capacity to neighbours, the ranking of influence runs from highest to lowest: DE (~4,500 MW), SE3 & SE4 (~2,400 MW), NO125 (~1,700 MW), and GB (~1,400 MW). Average prices in DE and GB — at around 100 €/MWh — exceed Denmark's 78 €/MWh, while SE3/SE4 prices are considerably lower at around 60 €/MWh.

⁷¹ Quantified Carbon (2025), Understanding & Quantifying Electricity Price Volatility.

NO125 average prices align closely with Denmark's, reflecting strong coupling between these zones.

These price differentials, for instance, carry implications for investment conditions across the region. DE and GB, with average prices near 100 €/MWh, can support a broader range of baseload technologies on purely market terms, whereas the lower SE price level of ~60 €/MWh points to a more constrained investment case for thermal capacity there. Denmark, which sits between these two regimes at ~78 €/MWh, faces conditions where the viability of new supply investments is sensitive to both the cost of technology and the degree to which Danish prices are pulled toward the higher-priced German and British markets or anchored by low-cost Nordic hydro. Similar reasoning can be made for all technologies if their respective capture prices are evaluated.

5.6.4 Market profitability

By comparing market revenues and technology costs we can assess their relative profitability under market conditions. A positive value means market revenues exceed the LCOE – the technology is cost-recovering at market prices. A negative value means market revenues fall short of the LCOE – the technology requires support to be commercially viable.

These results can be interpreted through the lens of a two-sided Contract for Difference (CfD), where the strike price is set equal to the technology's LCOE. Under such a contract, the difference between the strike price and the captured market price determines the net settlement: negative values indicate that market revenues fall short of the LCOE, and the producer receives a top-up payment from the counterparty (typically the state), while positive values indicate that market revenues exceed the LCOE, and the producer must pay back the surplus. A value of zero corresponds to a technology that is exactly cost recovering at market prices, with no settlement in either direction.

Figure 38 presents the profitability results (difference between revenue and cost) by technology for the reference technology cost assumptions. The profitability values are presented from the actor's perspective, i.e., normalised to total technology generation.

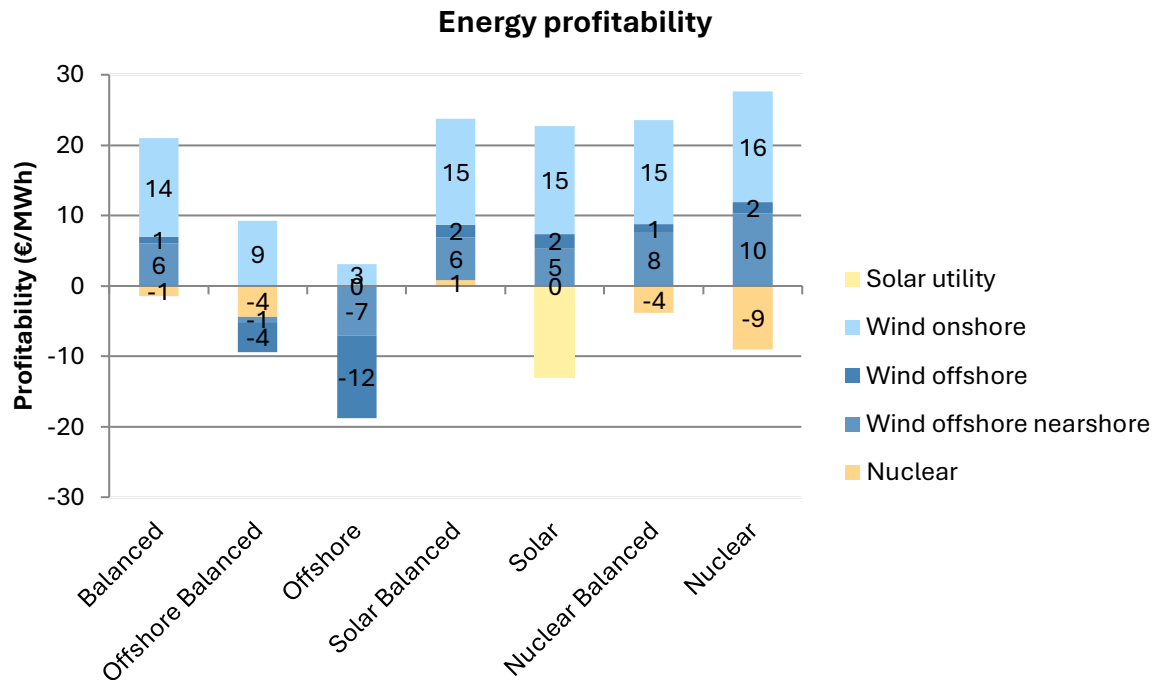


Figure 38. Profitability based on the Reference technology cost scenario and revenues normalised to total production by main generation technology across the scenarios. Note, the values for the different technologies should not be aggregated to compare scenarios since they carry varying normalisation factors. For that purpose, see [Figure 40](#).

As per definition, the defined profitability here is zero in a capacity expansion optimisation for the case of an unconstrained expansion of the technology. Thus, for technologies with capacity expansion constraints, such as Wind onshore and Wind offshore nearshore, positive values may be observed. Notably, the current analysis considers the system post the capacity requirement adjustment step (step 4 in [Figure 3](#)).

Consider the Balanced scenario. If this would have been directly off the optimisation step (step 3 in [Figure 3](#)), the values for nuclear and wind offshore would be 0. However, the capacity requirement adjustment perturbs the market, although not that much. For instance, battery storage acting on day-ahead improves profitability for wind power (Wind offshore sees a profitability of 1 €/MWh) but worsens nuclear profitability which ends up at about -1 €/MWh. Wind onshore and Wind offshore nearshore exhibit net profits since their expansion is limited by areal conditions instead of profitability.

As we lower costs for offshore wind and nuclear technologies with more optimistic technology scenarios we see decreasing profitability reaching -12 €/MWh for Wind offshore and -9 €/MWh for nuclear in the Offshore and Nuclear scenarios, respectively. The lower profitability relates to price cannibalisation which is most pronounced for wind and solar power. This also manifests in the other direction, as we lower the installed capacity of wind in the system (Nuclear) we see a better profitability for the wind producers.

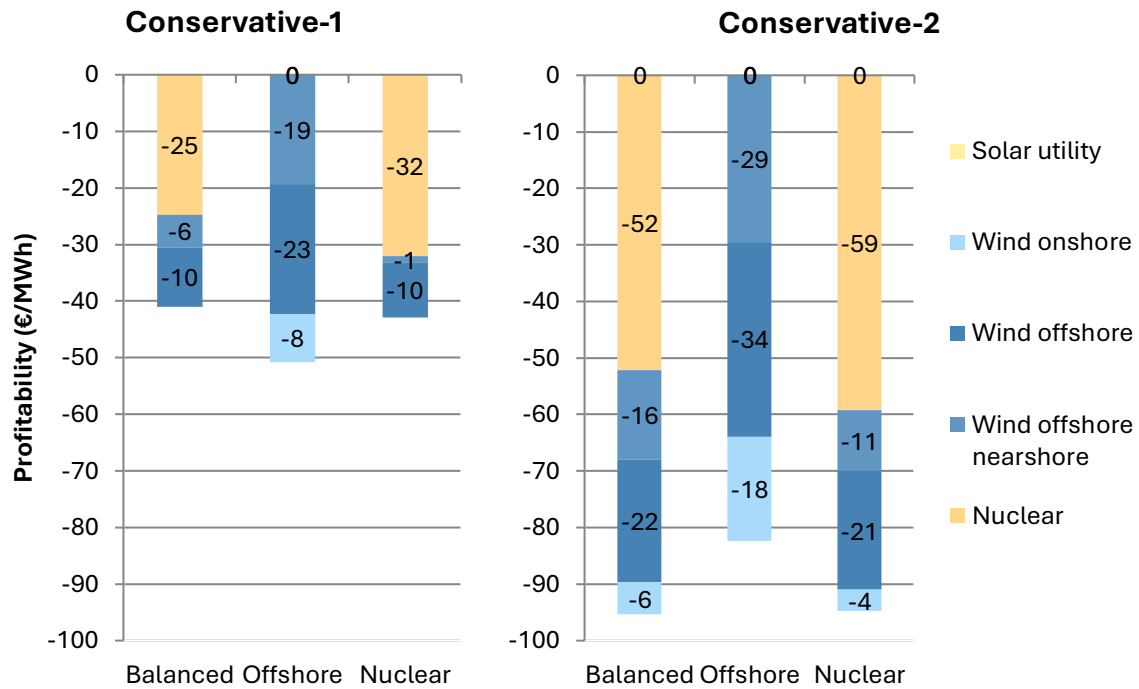


Figure 39. Profitability based on the Conservative-1 (left panel) and Conservative-2 (right panel) technology cost scenario and revenues normalised to total production by technology across the scenarios. Note, the values for the different technologies should not be aggregated to compare scenarios since they carry varying normalisation factors. For that purpose, generation and capacity costs should instead be considered.

Figure 39, similarly to Figure 38, shows the profitability but instead for the Conservative-1 and Conservative-2 technology cost scenario for a subset of power system scenarios. That means If we consider higher actual production costs, such as 134 €/MWh for nuclear in Conservative-2 cost scenario, then nuclear’s market revenues are considerably lower than its LCOE. For example, profitability levels for nuclear reaches 52 and 59 €/MWh in the Balanced and Nuclear scenario, respectively. Similarly, at a production cost of 88 €/MWh for Wind offshore in the Conservative-2 technology scenario, it requires a directed subsidy cost of 34 €/MWh in the Offshore scenario.

Notably, neither Wind offshore nearshore and Wind onshore meets their level of profitability, i.e., they display negative profitability levels, in the Offshore scenario for the Conservative-1 technology cost scenario with production costs at 70 and 51 €/MWh, respectively. The power system mix in the Offshore scenario puts most actors at risk of not reaching profitability as onshore wind sees lowest profitability compared to other scenarios.

The analysis highlights the challenges of managing a power system where profitability for different technology producers may vary greatly. It also illuminates the potential consequences on market intervention with potential state subsidies due to uncertain development of technology costs. For example, in the case offshore wind is given state

subsidies, larger expansions are likely to put other market actors at a higher risk of profitability compared to state subsidies for a nuclear expansion.

Figure 40 present the profitability for the Reference technology cost scenario but from the system perspective, i.e., normalising to total demand, but also including Battery and Gas OC. The results show, as expected, the profitability gap for Battery and Gas OC, as these technologies were not expanded in the capacity expansion optimisation and were introduced following the capacity requirement adjustment presented in Section 5.4. This analysis only considers day-ahead energy market revenues. Battery storage will most likely see revenues from balancing services markets and to address grid congestion. Correspondingly, Gas OC could potentially obtain revenues contracts on reserve or capacity markets, whereas the latter could also involve nuclear power.

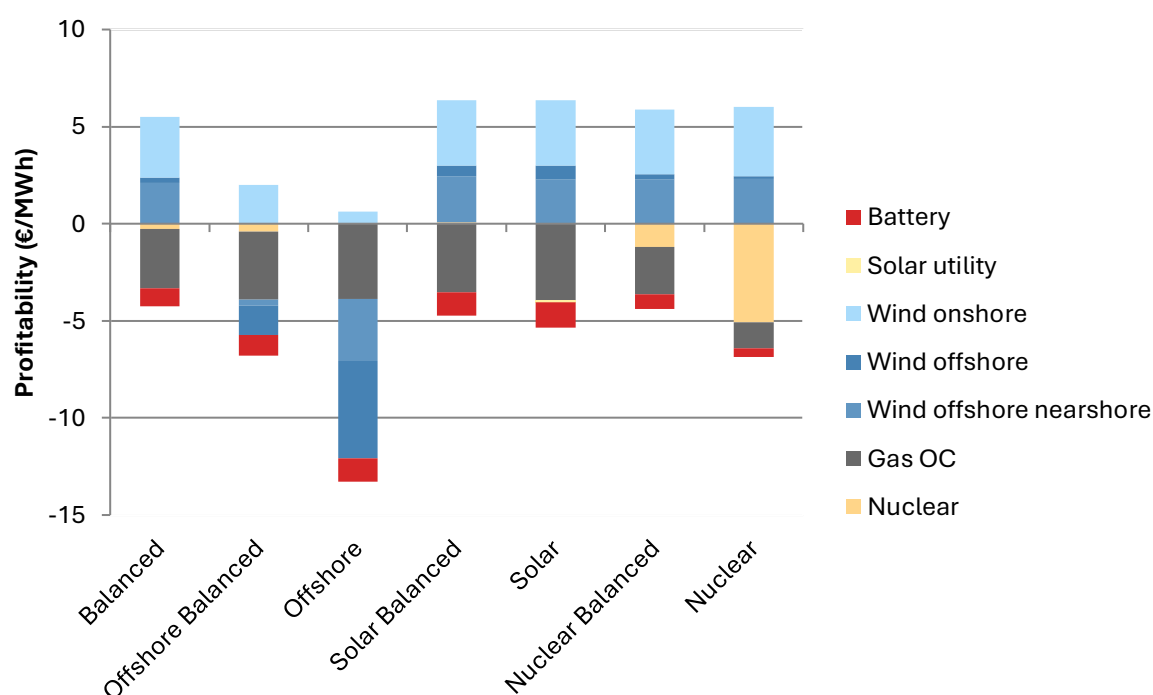


Figure 40. Profitability based on the Reference technology cost scenario and values normalised to total demand by technology across the scenarios.

Summed across technologies and normalised to total demand, the profitability gives a system-wide profitability gap. A negative total means reference costs exceed market revenues across the whole system; a positive total means the system over-earns at reference costs. The scenario totals are given in Table 12. The Offshore Balanced and Offshore scenarios stand out at -5 and -13 €/MWh respectively (a profitability gap of +4.8 and +12.7 €/MWh in the summary tables), while the remaining scenarios sit close to zero. This reflects the structural vulnerability of wind-heavy systems to technology cost variation: large wind fleets cannibalise their own market revenues, so once costs are normalised to reference levels the revenue side cannot keep up and a substantial profitability gap opens, dragging down even the technologies that would otherwise show considerable net revenue.

Table 12. Aggregated profitability across the Reference, Conservative-1 and Conservative-2 technology cost scenarios and the Danish power system scenarios.

Scenario	Reference	Conservative-1	Conservative-2
Balanced	1	-14	-28
Offshore Balanced	-5	-19	-33
Offshore	-13	-27	-39
Solar Balanced	2	-12	-25
Solar	1	-12	-23
Nuclear Balanced	1	-15	-32
Nuclear	-1	-20	-41

Take-aways – Electricity market:

- The day ahead yearly average market prices arguably show limited variations, -8% to +6% compared to the Balanced scenario, despite their significantly varying structures. Scenarios expanding production capacity locally to the greatest extent, namely the Offshore and Nuclear scenarios, see the lowest prices.
- The electricity price volatility exhibits largely the same trends as the average prices with small variations across future scenarios. Compiled, the Offshore, Nuclear Balanced and Nuclear scenario demonstrates lowest volatility with -2%, -3% and -8% compared to the Balanced scenario, respectively.
- Compared to 2025, all scenarios show a decreased average price but a significantly increased volatility, exemplified with the Balanced scenario of -5% and +260%, respectively, providing a benchmark on general investment conditions.
- Denmark's large interconnectivity in the market relative to its system size strongly constrains its potential impact on the electricity market outcomes across the different scenarios. Average prices in neighbouring regions range from lower at about 60 €/MWh (SE and NO3 & NO4) to higher at around 100 €/MWh (DE, NL, PL & GB).
- Analysis on relative profitability from actor's perspective reveals net profits for Wind offshore nearshore and Wind onshore technologies in most scenarios due to expansion limited by areal conditions. The scenarios more heavily relying on a single technology, a cost is observed representing directed subsidy costs of 12 €/MWh for Wind offshore and 9 €/MWh for nuclear in the Offshore and Nuclear scenarios, respectively.
- Analysis on technology profitability illuminated that increased cannibalisation driven by the larger wind fleet in the Offshore scenarios exposes larger vulnerability to technology cost assumptions, as demonstrated by an overall profitability gap of 13 €/MWh in the Offshore scenario, compared to the level of 1 €/MWh in the Nuclear scenario.

5.7 Degree of self-sufficiency

According to the European Commission, “Energy security is about ensuring sufficient supplies to meet our needs, even during the most challenging of times. It’s about protecting people’s wellbeing and is a basic building block of the functioning of our economy and society.”⁷² In a briefing, European Parliament Think Tank writes that security of energy supply can be defined as the availability of energy at all times, in different forms, in sufficient quantities and at reasonable and/or affordable prices⁷³. In this section, the focus is on the availability of energy in sufficient quantities to fulfil societal requirements, which can be captured by the concept of self-sufficiency, as illustrated by import costs and natural gas consumption in the different power systems. Import costs, in contrast to energy imports alone, incorporates the value of electricity in the hour of trade and highlights scenarios where the power system potentially rely more heavily on other countries to supply energy when needed, which introduces a certain vulnerability. Natural gas consumption similarly acts as a gauge of the power system's dependence on fossil fuels and fossil infrastructure and imports, with associated emissions directly linked to consumption. Dependence on natural gas could be associated with geopolitical uncertainties (potential strong dependence on authoritarian states), climate-related risks (natural gas may not be politically acceptable in 2050) and cost volatility (the price may fluctuate significantly depending on CO₂ pricing and natural gas market developments).

5.7.1 Imports and import costs

Analysing electricity imports or trade requires care in how the metric is defined. Aggregating net exchange over a year, where net exports cancel against net imports, can substantially understate actual dependence on imported electricity. For a small grid like Denmark with interconnection capacity exceeding total domestic demand, real net imports (the sum of importing hours) and real net exports (the sum of exporting hours) are distinct phenomena and should be assessed separately. Equally important is the hourly distribution: the number of importing hours and, crucially, the share of demand covered by imports in those hours, which aggregate annual figures obscure. Finally, the monetised trade incorporates the value of energy and therefore ultimately provides information on potential import dependence.

Even when Denmark is a net importer or net exporter in a given hour, there may be strong simultaneous utilisation of lines in both directions. This is exemplified with [Figure 41](#) where the flow across lines connecting Denmark to neighbours are shown for the most extreme hour of the 1985 event, as described in [Section 5.4](#), for main scenarios. At this period of high system stress, Denmark is both exporting, most notably to Germany (DE), whilst generally importing from Great Britain (GB), Sweden (SE3 and SE4) and Norway (NO125). By summing the total flow, it is possible to determine the net trade, which when positive means it is an export hour and negative means it is an import hour. In the

⁷² European Commission (2026), In focus: EU energy security explained.

⁷³ Security of Energy Supply (2024), European Parliament, Think Tank.

following the net trade on an hourly dynamic is considered and the detail of the flow across different lines is disregarded.

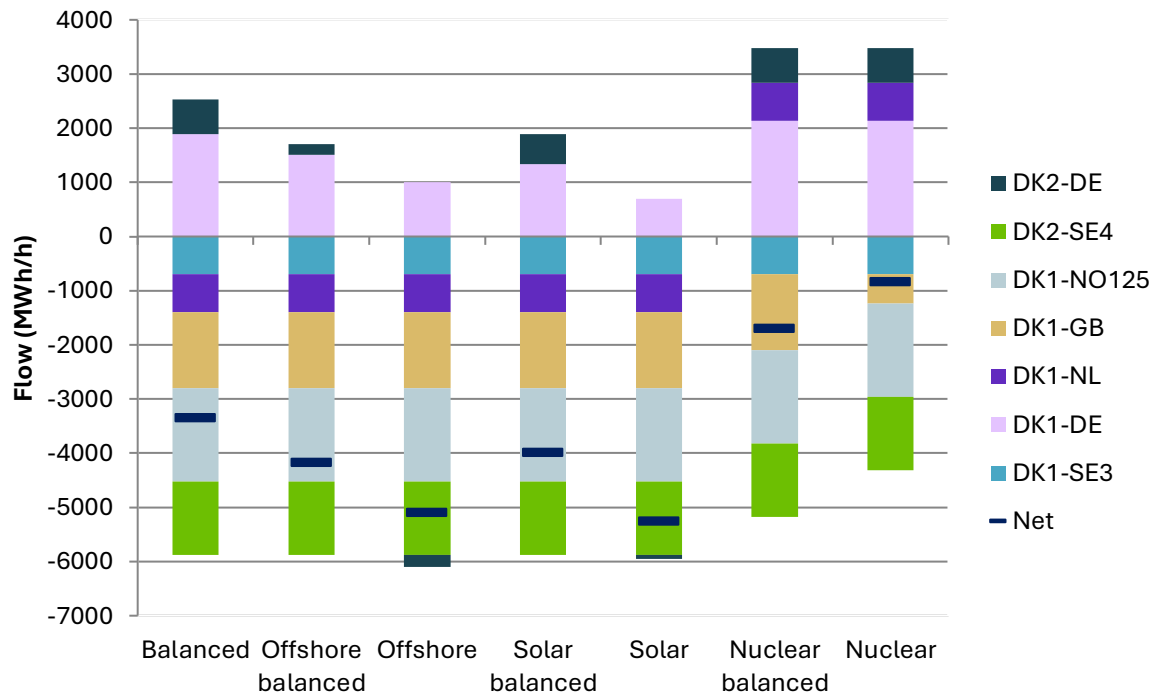


Figure 41. Flow across lines connecting Denmark's two bidding zones with neighbouring countries for the most extreme hour in weather year 1985 event and the seven main scenarios. The aggregated flow imports and exports are indicated with the net dash marker.

Further, as a concrete example, [Figure 42](#) displays the power system dispatch in the cGrid model for the Danish zones alongside its interconnected neighbours. Through the lens of the Danish system, it is possible to observe a period of excess supply as wind production is high in the early period until 13th January. A brief period of roughly two days follows with very low wind production where Denmark turns to a net importer. Moving forward, this dynamic continues back and forth, notably with DK1 generally showing higher wind production compared to DK2. Looking outside Denmark, especially zooming in on Germany (DE), there is a gradual decrease in wind production throughout first half of January ultimately leading into a period with sustained supply scarcity that is felt across the model geography as thermal power plants ramp up to their installed capacity. The most extreme supply scarcity hour occurs on the 29th of January which instantiates the response of gas turbines in Denmark.

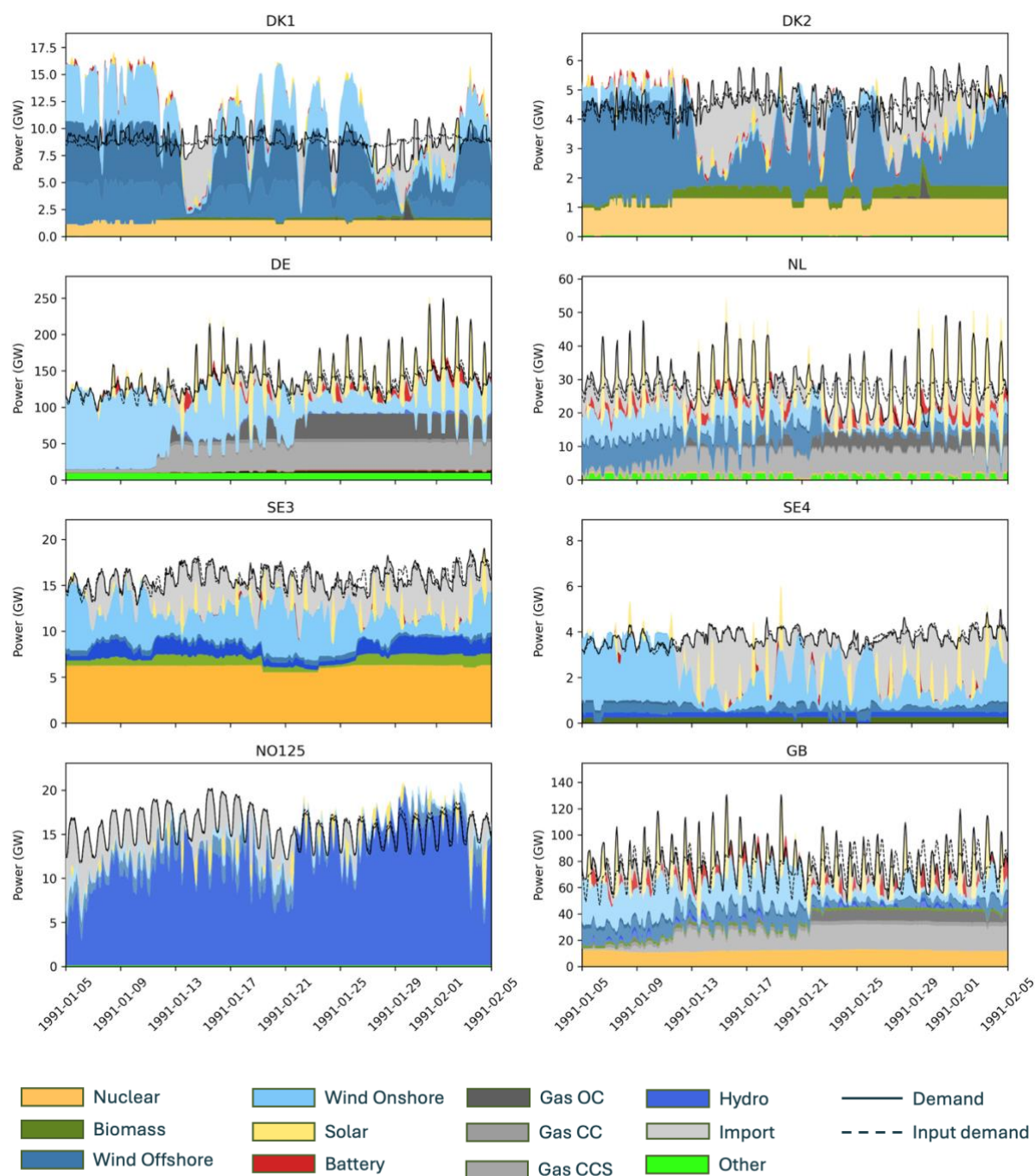


Figure 42. Power system dispatch, hourly, across Danish bidding zones and directly interconnected neighbours zoomed in on early month of weather year 1991.

The actual trade exchange for Denmark alongside the market prices, presented in [Figure 43](#), enhance the outlined system dynamics also incorporating the 2025 reference system alongside key scenario variations: Offshore, Balanced and Nuclear. The early period exhibits considerable net exports from Denmark. Due to a general excess of supply in this period, low electricity prices are also observed in Denmark (not as low in 2025 reference). Moving forward in time all scenarios agree on the direction of exchange with time and the dynamics of the electricity price, although 2025 reference shows a less volatile electricity price. What differentiates the future scenarios is the magnitude of the

exchange in particular, but also the electricity price level. Here, the Offshore scenario generally shows the largest net exports and imports while variations are the smallest in the Nuclear scenario.

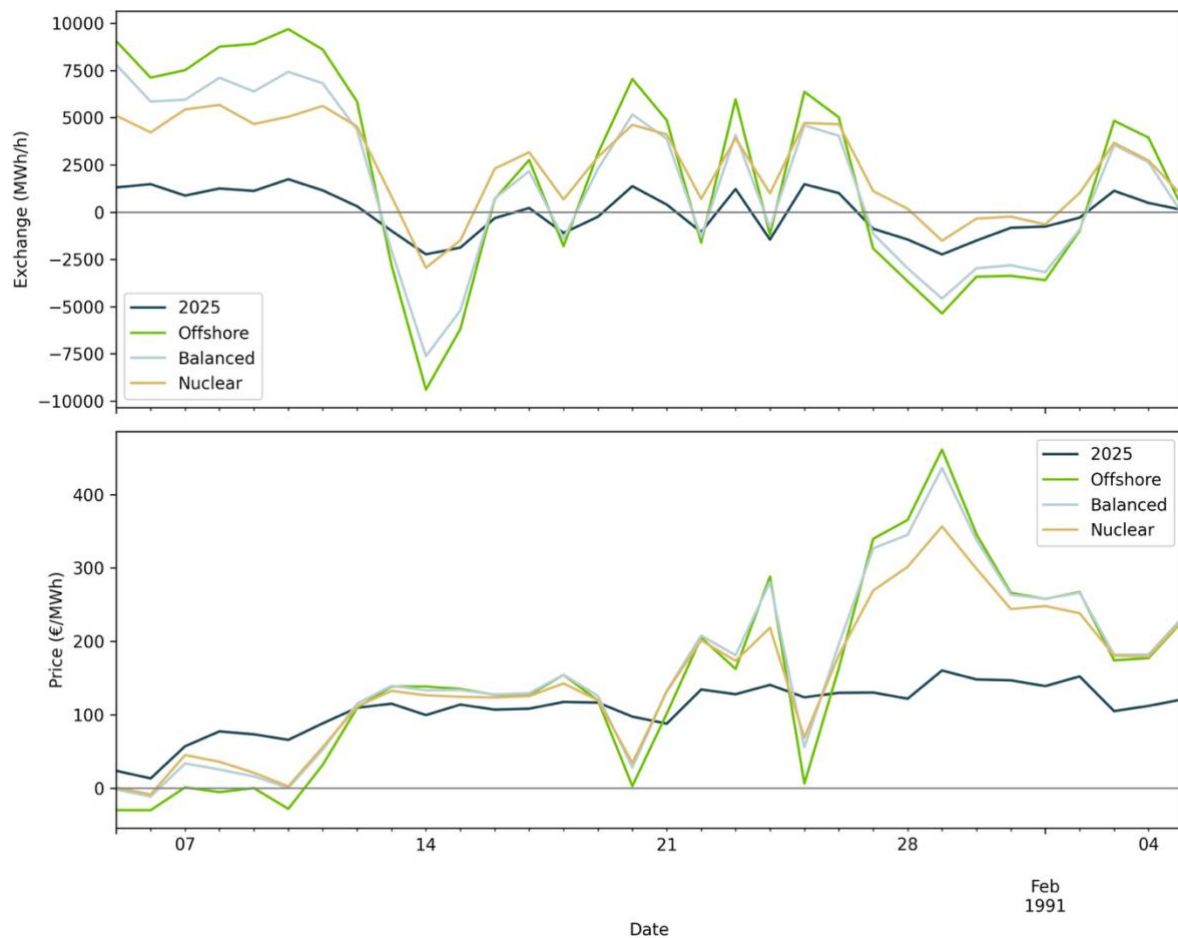


Figure 43. Daily average exchange for the Danish power system (top panel) and market price in DK1 (bottom panel) zoomed in on the early period weather year 1991 across the 2025 reference, Offshore, Balanced and Nuclear scenarios. For the exchange, positive and negative values represent net export and net import, respectively.

Considering Denmark's duration curve of trade exchange, [Figure 44](#) zooms out to the full weather year 1991. The 2025 reference shows slight majority of hours importing at 57%. This is changed in all future scenarios where hours of importing are lowered to around 35% in the Balanced and Offshore scenarios while the corresponding for Nuclear scenario is 20%.

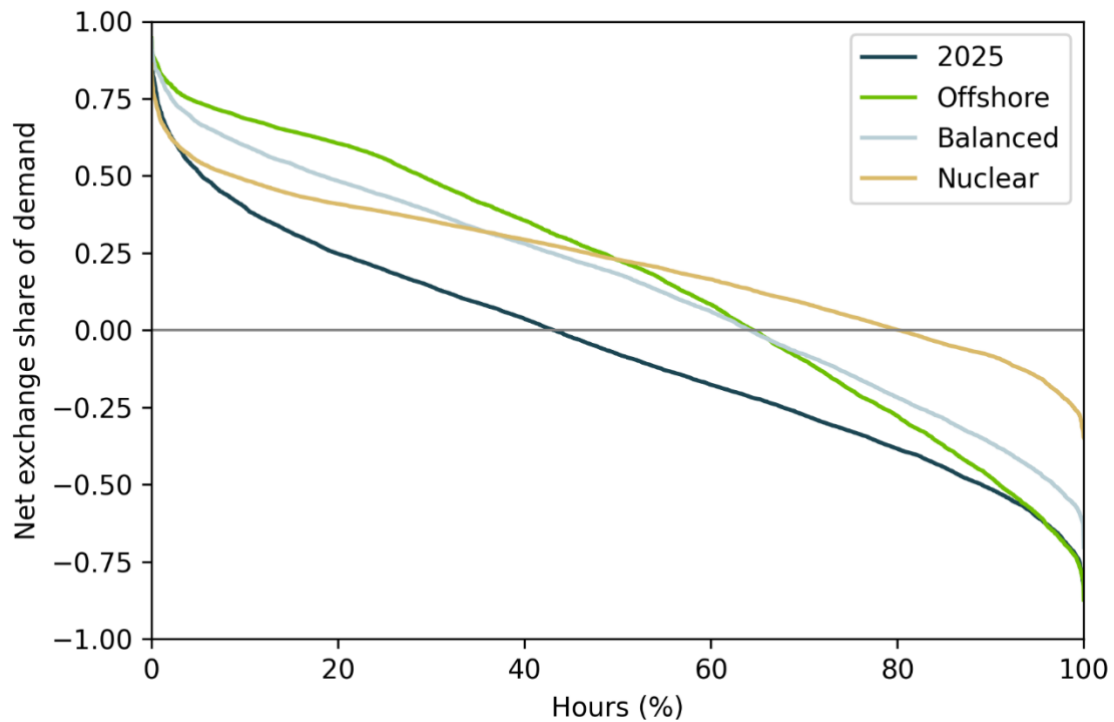


Figure 44. Duration curve of exchange normalised to demand for weather year 1991 across the 2025 reference, Offshore, Balanced and Nuclear scenarios. For the exchange, positive and negative values represent net export and net import, respectively.

A similar picture is revealed as total net import and net export hours are considered in [Figure 45](#) compared between all scenarios. All the future scenarios modelled show a positive net export on an annual basis. The balanced scenario exhibits a 15 TWh net export with Solar and Nuclear scenarios at lowest and highest level with 11 TWh and 21 TWh net exports, respectively. The scenarios materialising the largest domestic production, being the Offshore and the Nuclear scenario (see also [Figure 22](#)), shows as expected the largest net exports with the Solar scenario conversely with lowest domestic production capacity showing the lowest net exports. Notably, the 2025 power system shows a contrasting net trade level of -2 TWh on average. The variation across weather years is presented in [Figure 77](#) and shows consistent positive net trade for future scenarios, although strongly varying, while the 2025 reference varies between positive and negative net trade at lower volatility.

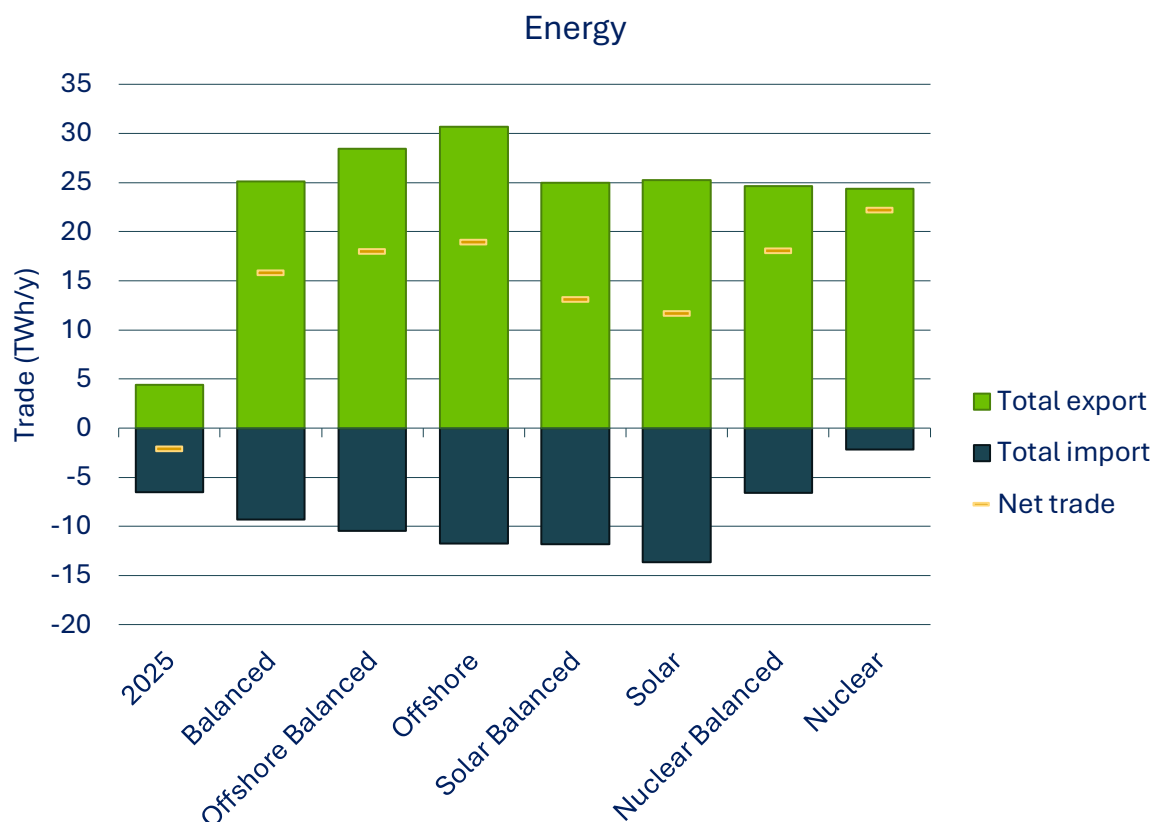


Figure 45. Yearly trade for weather year 1991 in Denmark across the scenarios. For the trade, positive and negative values represent net export and net import, respectively.

Merely evaluating trade measured in energy may lead to neglecting an essential aspect: at what times and how much electricity is imported or exported and what is its cost? The monetised trade, i.e., export revenues and import costs and the monetised net trade, presented in [Figure 46](#) (net values across weather years are shown in [Figure 78](#)), capture this dynamic. Interestingly, the monetised trade shows a completely different picture

compared to the energy-based where net export revenues generally come in lower compared to net import costs.

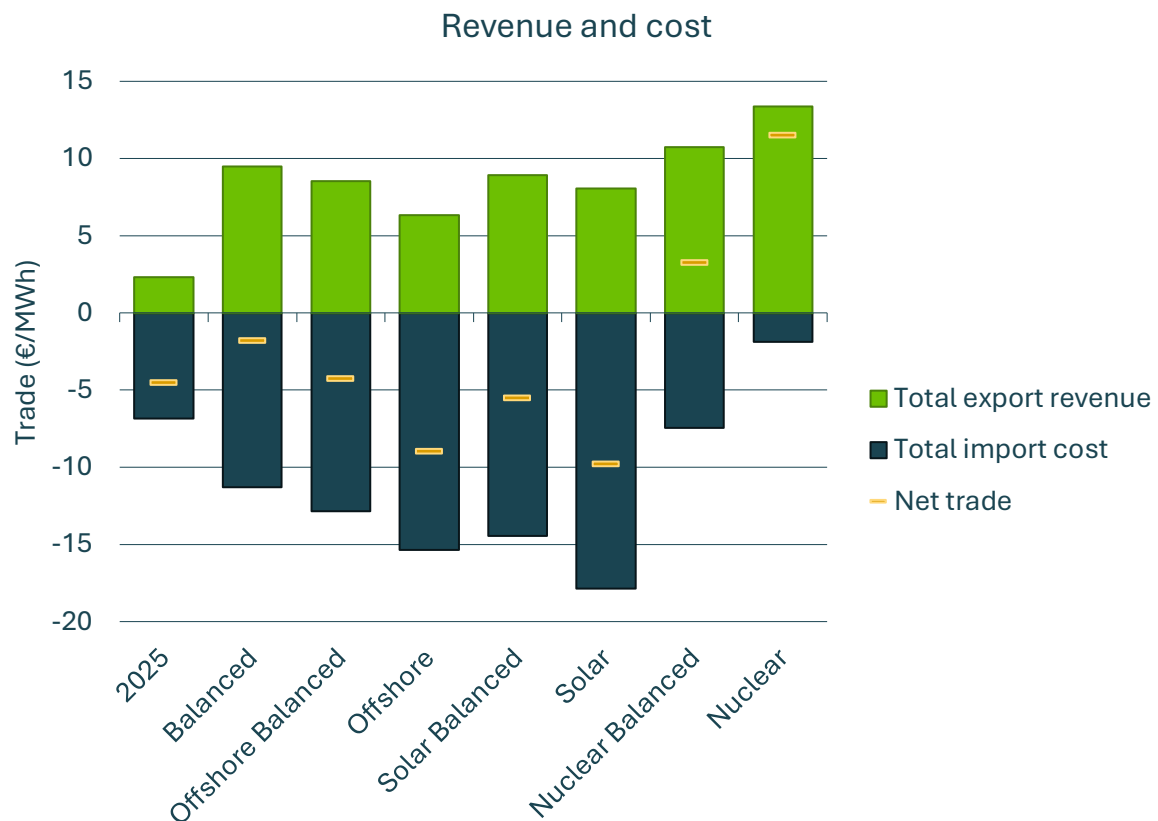


Figure 46. Monetised trade normalised to total demand in Denmark for weather year 1991 across the scenarios. For the trade, positive and negative values represent net export revenues and net import costs, respectively.

The 2025 reference displays a net trade of -4.5 €/MWh compared to the Balanced scenario at -1.8 €/MWh. Moving towards the Offshore and the Solar scenarios, net values decrease to approach -10 €/MWh. The more nuclear heavy scenarios show an opposite trend with decreasing import costs and increasing export revenues with positive net values of 3.3 €/MWh and 11.5 €/MWh for the Nuclear Balanced and Nuclear scenario, respectively.

These results are explained by the increased variation of supply dispatch in the Offshore and Solar due to larger share of weather dependent generation combined with lower clean firm capacity. With lower clean firm capacity, the model relies to a greater extent on neighbouring countries to balance the system. As weather conditions are highly correlated across northern Europe, see [Figure 42](#), there is a high probability that neighbouring regions experience low wind and solar production at the same time as Denmark, leading to price coupling and a greater need for imports during periods of high prices. This leads to both higher electricity prices and import costs and indicates a generally higher vulnerability of these power systems. These power systems with lower

clean firm capacity and greater import dependence risk being more exposed to external factors, such as political decisions in exporting countries, weather conditions in neighbouring countries or bottlenecks in the transmission network. Conversely, the scenarios with a larger degree of clean firm capacity in Denmark provides export to neighbouring regions in more challenging conditions decreasing exposure to price shocks and supply security across the model geography.

5.7.2 Gas consumption

The dependency on gas consumption for gas-fired power plants in the Danish power system is illustrated by annual demand in Figure 47. Notably, the gas consumption is limited. This is because they are assumed to act as reserves and merely being invoked in moments of extreme scarcity of supply, defined by prices exceeding 500 €/MWh. These observed levels of around 1 TWh, are considerably lower than the consumption in the Danish power system in 2025 of about 5 TWh⁷⁴.

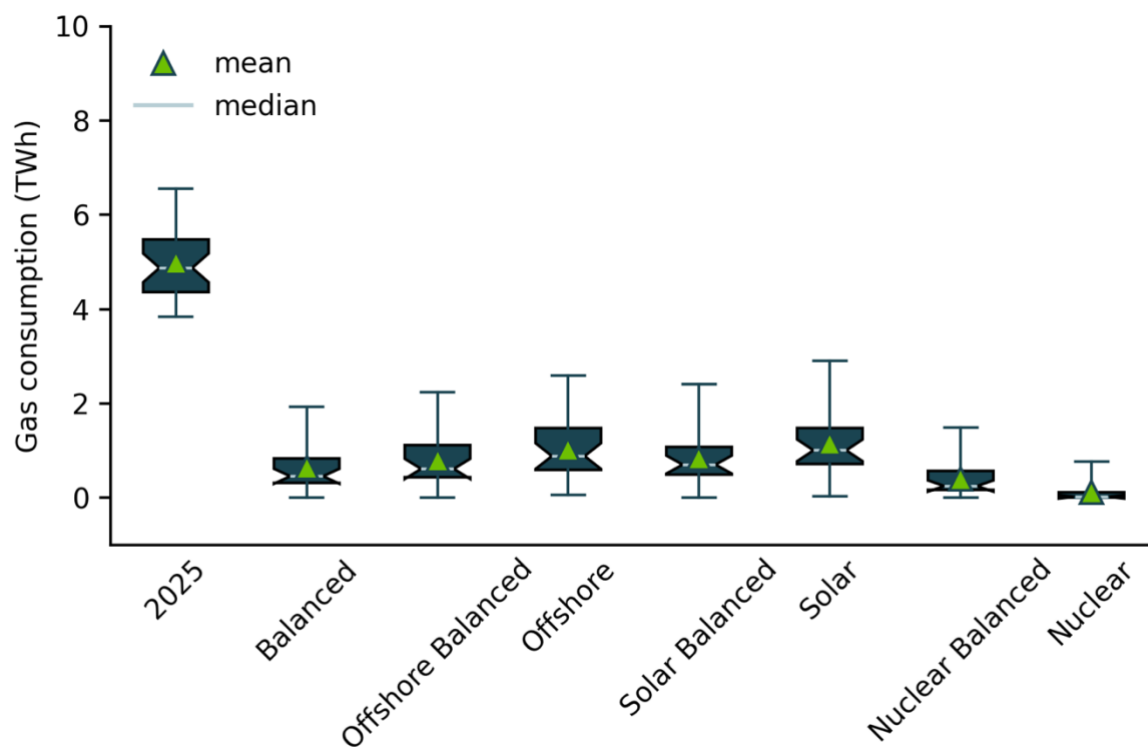


Figure 47. Annual average gas consumption of turbine power plants for all 33 weather years. The boxplot diagrams cover the range of outcomes from 1% to 99% for the full set of weather years, with the boxes representing 25% - 75% quartiles and the circles representing extreme values. Median values are shown by horizontal white lines and mean values by green triangles.

⁷⁴ Based on the average across simulated 33 weather years of the 2025 power system.

If the gas power plants would be able to bid in normally in the day-ahead market, the picture would change considerably as shown in [Table 13](#) where it is compared to the default behaviour where the gas turbine only dispatch at prices exceeding 500 €/MWh. The gas consumption is observed to increase to 17 TWh in the Balanced scenario, to 20 TWh in the Offshore scenario and to 6.6 TWh in the Nuclear scenario. With the increased supply also comes reduced prices with yearly averages decreasing by 6 €/MWh (-9%) in the Balanced scenario. Opposite to the expectation, free gas consumption or larger share of clean firm capacity in Denmark does not drive down gas consumption considerably in neighbouring regions. Instead, its primary effect is to drive down prices as it replaces cutting of demand at price peaks.

Table 13. Comparison on average fuel consumption at constrained operation to market-based bidding of gas turbine power plants.

Scenario	Fuel consumption constrained	Fuel consumption free
2025		5.0
Balanced	0.6	16.7
Offshore Balanced	0.8	18.6
Offshore	1.0	20.2
Solar Balanced	0.8	19.8
Solar	1.1	22.7
Nuclear Balanced	0.4	12.8
Nuclear	0.1	6.6

However, this potential pathway opens up the discussion to the type of gas, technical feasibility and potential consequences.

Based on European Biogas Association⁷⁵, there is a potential of about 2.5 bcm per year biomethane production in Denmark in 2050. Based on a gross calorific value of 37 MJ/m³, this translates to around 24 TWh_{th}. Based on energy statistics from Danish Energy Agency

⁷⁵ European Biogas Association (2022), Biomethane production potentials in the EU.

on actual energy consumption, the total consumption of natural gas in Denmark in 2024 was around 16.5 TWh⁷⁶. Based on today's total infrastructure capacity and consumption, also increased gas consumption could be in reach. Notably, biogas is produced continuously, which does not match the intermittent operation pattern of peaking power plants that are only used during shortage periods triggered by weather variation but this could be managed with existing large-scale natural gas storage capacity. Consumption variation could mean that some years no gas is used at all to then consume 3-4 times the average in other years. At the same time, biogas could see competition from other use cases, such as from industry and for road transport⁷⁷.

If gas consumption is not limited and given these uncertainties, there is a significant risk that a substantial part of future gas consumption in peaking power plants will be covered by natural gas, which has implications for both carbon footprint and energy security. The comparison of natural gas consumption between the scenarios thus serves as a proxy for these potential risks. In terms of carbon footprint, the operation of the turbines with natural gas corresponds to direct annual emissions of 3.8 Mt in the Balanced scenario. These levels can be compared to 5.35 Mt (53.5 Mt in 1990⁷⁸) corresponding to Denmark's 2040 target according to EU guidelines⁷⁹ which would thus mean that emissions for the Balanced scenario on average over all weather years would occupy 70% of Denmark's possible emissions in 2040. Notably, when in the constrained dispatch of the gas turbines direct emissions is associated with a 96% decrease compared to 1990's level for the Balanced scenario, i.e., well below 2040 targets.

5.7.3 Demand coverage at extremes

As important as analysing the average of these parameters, it is highly relevant to carefully evaluate the extremes more carefully. It is often these peaks that, in practice, govern and dictate how the power system is dimensioned and designed. The ability of the system to handle extreme situations, such as unusually high demand or sudden generation outages, is crucial to ensure robust and stable operation. Extremes also put pressure on the need for reserves, both in terms of generation capacity and storage, as well as on the capacity of the infrastructure to handle high load flows and potential bottlenecks.

As a mean to investigate this aspect we consider the demand coverage by local supply in Denmark for the 1000 worst hours across the 33 weather years. The worst hours have been defined by their lowest demand coverage. This analysis highlights a complementary perspective with physical supply conditions (generation potential) compared to the cost oriented one in Section 5.7.1 alongside zooming in on the extremes. From a Danish perspective, this factors in to the potential role it would like to position itself concerning contribution at challenging operating conditions. The physical security of supply is

⁷⁶ Energistyrelsen, Årlig energistatistik 2024.

⁷⁷ Biogas Danmark (2025), Biogas Outlook 2025.

⁷⁸ Our World in Data, Denmark Country Profile CO₂ and Greenhouse Gas Emissions (accessed 2026-05-28).

⁷⁹ European Commission, Targets for 2040.

primarily represented by the generation potential, whilst realised generation (actual market dispatch in model) indicates how cost-effective demand-side flexibility or imports step in to cover demand.

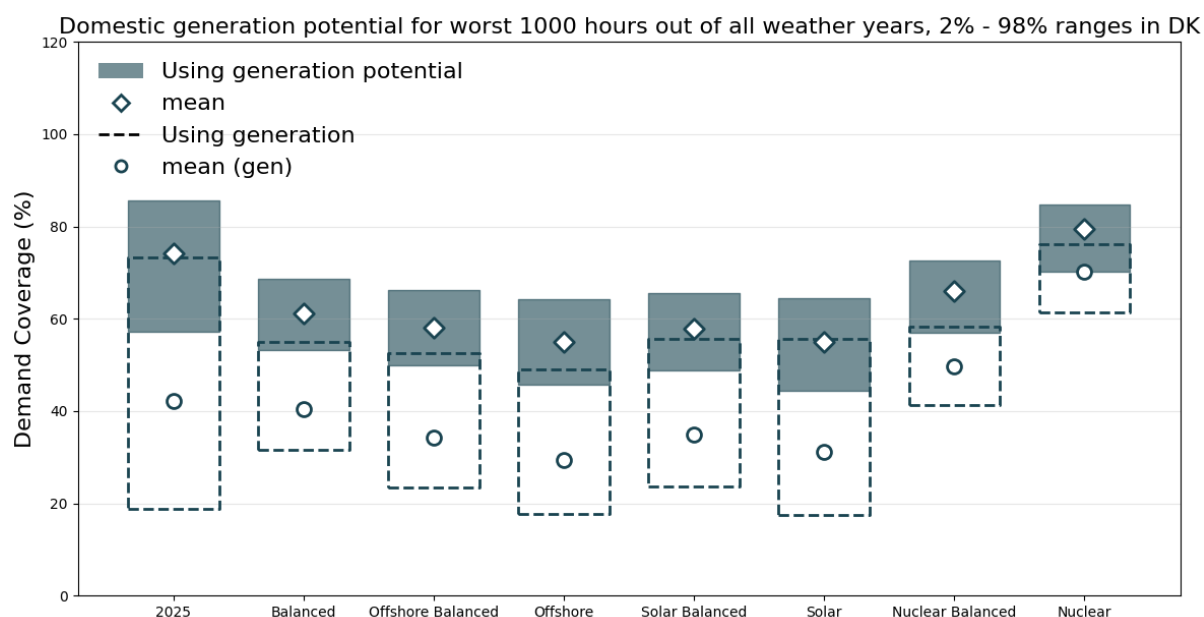


Figure 48. Demand coverage by realised generation and generation potential and their spread in Denmark during the worst 1000 hours across all weather years under different scenarios. The worst hours have been defined by their lowest demand coverage.

The results, alongside the corresponding conditions for the 2025 Danish power system, are shown in [Figure 66](#) in the appendix. For the future scenarios Denmark generally exhibits a decreased level of demand coverage compared to 2025 by generation potential, moving from 74% to 61% (-18%) for the Balanced scenario. The Solar and Offshore scenarios show the largest decrease with 55% (-26%) and the Nuclear Balanced scenario 66% (-11%) while the Nuclear scenario is the one exception to the trend with an increase to 80% (+7%). These results is a direct consequence of the installed dispatchable capacity in the different scenarios as presented in [Figure 29](#).

Considering the realised generation, the results paint a slightly different picture. The 2025 system achieves a demand coverage of 42% which is very similar to the Balanced scenario of 40% (-4%). The Offshore scenario exhibits the lowest coverage of 30% (-30%) while the more nuclear-heavy scenarios show a clear increase to 50% (+18%) and 70% (+66%) in the Nuclear Balanced and Nuclear scenarios, respectively. Lower levels in the Offshore and Solar scenarios are enabled thanks to larger demand-side flexibility and imports. The realised generation here reflects the results for import costs, see Section

5.7.1, representing Denmark's ability to contribute with affordable supply in times of scarcity.

Take-aways – Degree of self-sufficiency:

- While all scenarios show a considerable positive net trade, i.e., export, between 12 and 22 TWh, contrasting the 2025 power system at 2.5 TWh net import, import costs exhibit a more varying trend. The Offshore and Solar scenarios increase monetised net trade from 2025 level of -5 €/MWh to approaching -10 €/MWh. Owing to their increased share of clean firm capacity, the nuclear scenarios instead demonstrate positive monetised trade at 3 €/MWh and 11 €/MWh.
- Gas consumption is limited across all scenarios at around 1 TWh compared to around 16 TWh in 2024 due to their activation only during periods of prices exceeding 500 €/MWh. In the case of free bidding of gas turbine power plants, considerable fuel consumption reaching beyond 20 TWh in the most extreme scenarios were observed. Operation of gas turbines on this level comes with significant consequences on market prices, averages decreasing by 9%, and question the feasibility to supply all demand with biogas potentially leading to natural gas use which has implications for both carbon footprint and energy security.
- Complementary to the analysis on monetised trade, the demand coverage by generation potential at the 1000 most extreme hours were investigated putting the spotlight on physical self-sufficiency. Denmark generally exhibits a decreased level of demand coverage compared to 2025 by generation potential, moving from 74% to 61% (-18%) for the Balanced scenario. The Solar and Offshore scenarios show the largest decrease with 55% (-26%) and the Nuclear Balanced scenario 66% (-11%) while the Nuclear scenario is the one exception to the trend with an increase to 80% (+7%) owing to their increased installed dispatchable capacity.

5.8 Demand and flexibility scenario variations

The capacity expansion optimisation was investigated against two demand growth scenario variations, which total 138 and 64 TWh compared to 102 TWh in the Reference, and two flexibility scenario variations, presented in Section 4.2.2, to better understand the sensitivity of the results. Figure 49 presents the change in installed capacity for these scenario variations when compared to the Balanced scenario while Figure 50 presents the generation share for the Balanced scenario alongside the scenario variations.

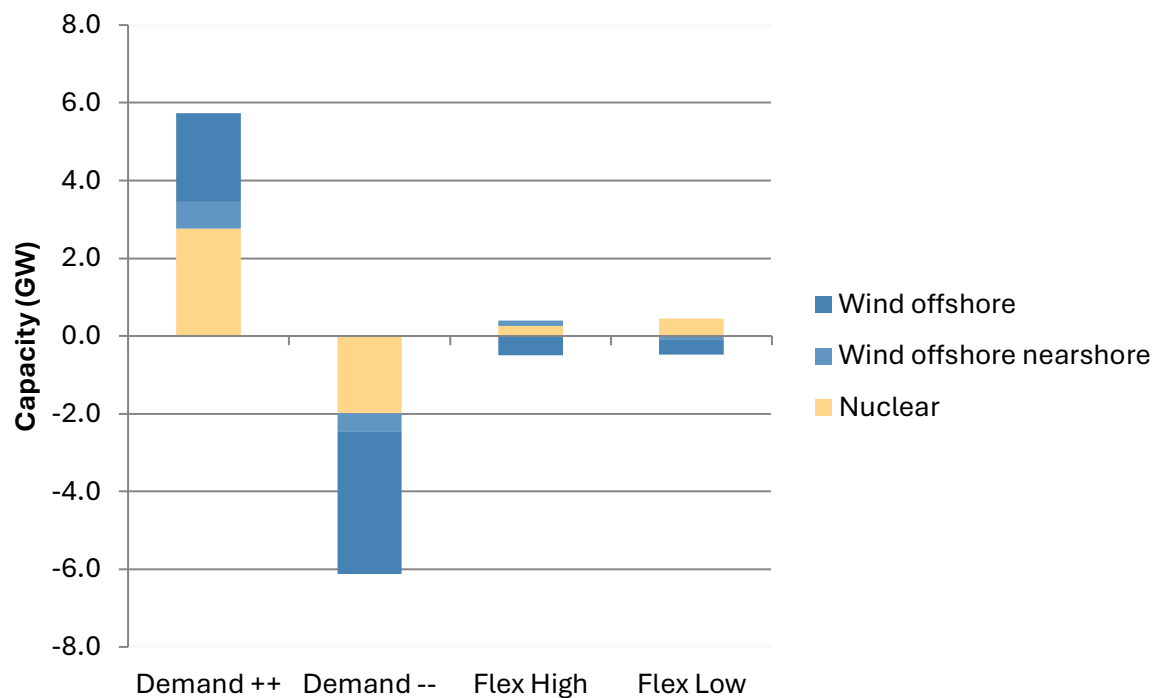


Figure 49. Change in installed capacity for scenario variations compared to the Balanced scenario.

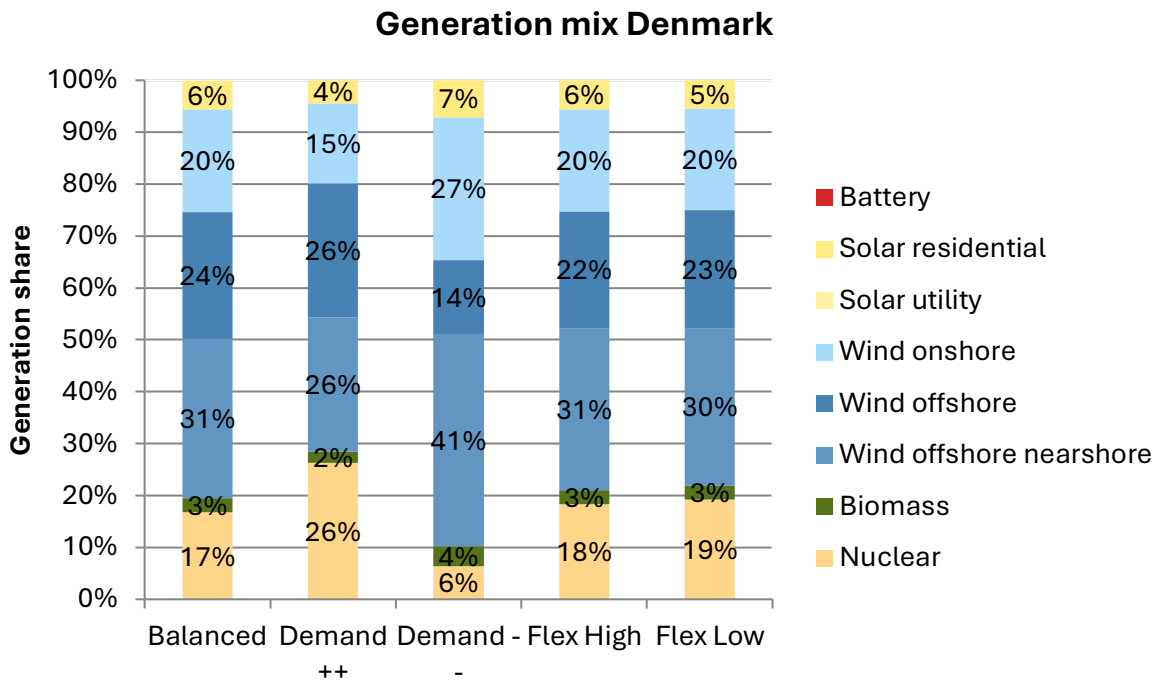


Figure 50. Generation share for different technologies for the Balanced and scenario variations.

When varying the flexibility, very small variations to the resulting mix is observed. Somewhat unexpectedly, both the low and high flex scenarios cater to a larger installed nuclear capacity. Lower flexibility reasonably increases the value for firm capacity. The competition between offshore wind and nuclear could be at a point where small increase in flexibility actually means that nuclear does not need to ramp up and down as much due to more stable prices and increases its capture rate relatively more compared to offshore wind.

Considerably larger impact on the resulting generation mix has the demand growth scenario variations. In the optimistic demand scenario, the increased demand is covered by a combination of offshore wind and nuclear, weighted more to nuclear as the share in the generation mix increases from 17% to 26%. The opposite is observed for the conservative demand scenario, where the share of wind increases from 75% in the Balanced scenario to 83% while nuclear decreases to 6%.

The resulting generation and capacity costs and average market prices and their deviation compared to the Balanced scenario is shown in [Table 14](#). Given the limited variations in the resulting power systems, the small variations in both costs and average prices are expected. Interesting is to see that significant demand growth variations does not impose considerable impact on average prices. The resulting market price is determined by the marginal resource additions in the capacity expansion which is represented by the competition of offshore wind and nuclear. Neither resource is able to drive down market prices considerably, therefore not impacting the other's expansion. The lower expansion of nuclear, is primarily a consequence of a smaller Danish power

system. Once again, this is driven by Denmark's large interconnectivity in the market relative to its system size. Notably, the neighbouring regions have been kept fixed across all the simulations in the current study. Varying system changes in Europe influencing the market conditions and how they impose market consequences to the Danish power system expansion are really driving the results. This is an aspect that deserves further investigation in following studies.

Table 14. Deviation of generation and capacity costs and average market prices compared to Balanced scenario for scenario variations.

	Demand optimistic	Demand conservative	Flex High	Flex Low
Generation and capacity costs	+1.8	-0.9%	-0.8%	+5.5%
Average price	+0.6%	-1.3%	-0.3%	+0.1%

Take-aways – Demand and flexibility scenario variations:

- The capacity expansion optimisation was investigated against two demand and two flexibility scenario variations to better understand the sensitivity of the results.
- While, the flexibility scenario variations showed very limited impact on the resulting power system mix, the demand growth scenarios, which total 138 and 64 TWh compared to 102 TWh in the Reference, saw considerable impact. The larger system in the high demand scenario sees an increasing role for nuclear with share of generation mix moving from 17% to 26%. The opposite is observed for the conservative demand scenario, where the share of wind increases from 75% in the Balanced scenario to 83% while nuclear decreases to 6%.
- Despite considerable changes to the power system mixes in the demand growth scenario variations, minimal impact is seen on costs and average price. Once again, this is driven by Denmark's large interconnectivity in the market relative to its system size.

5.9 Model comparisons

The cGrid model, with capacity adjustment in Danish zones and endogenously optimised dispatch and transmission across all zones, and the PyPSA model with capacity expansion in Danish zones and endogenously optimised dispatch and transmission across all zones, perform very similarly. This is somewhat to be expected as they share the same input but the two models work fundamentally differently, cGrid's non-linear approach with rolling-short terms price forecasts is an entirely different approach to the perfect foresight linear optimisation performed in PyPSA.

Figure 51 and Figure 52 show comparisons of the price-duration curves for DK1 and DK2, between cGrid and PyPSA for the Balanced scenario. For the majority of the duration the prices are very similar. A few hours in PyPSA drop to -€500, this price is the negative price signal created by the curtailment link, see section 3.1.2.6, cGrid, conversely has a lower limit of -€30 set to its prices. PyPSA spend less time at its lower limit than cGrid which can be explained as PyPSA's perfect foresight knowing when these negative price hours will occur and optimising battery charging around this. At the highest price hours PyPSA has slightly more, largely due to stronger price signals from neighbouring countries, due to the presence of slack generators, see section 3.1.2.6.

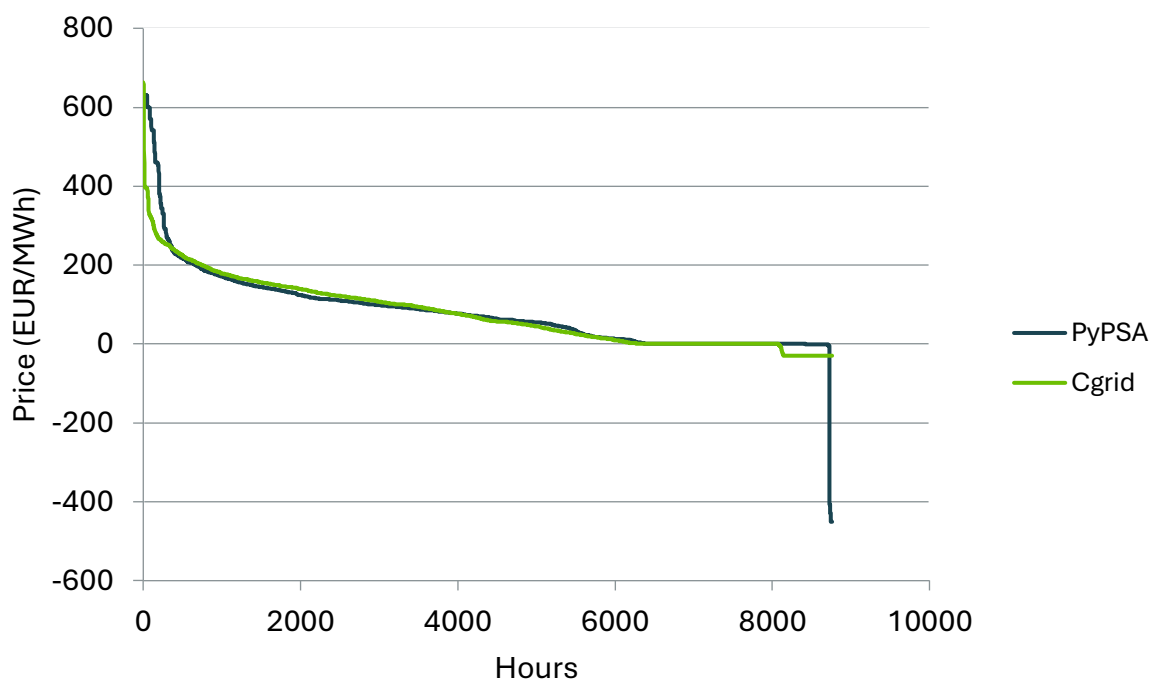


Figure 51. DK1 price duration curve comparison between PyPSA and cGrid for the Balanced scenario.

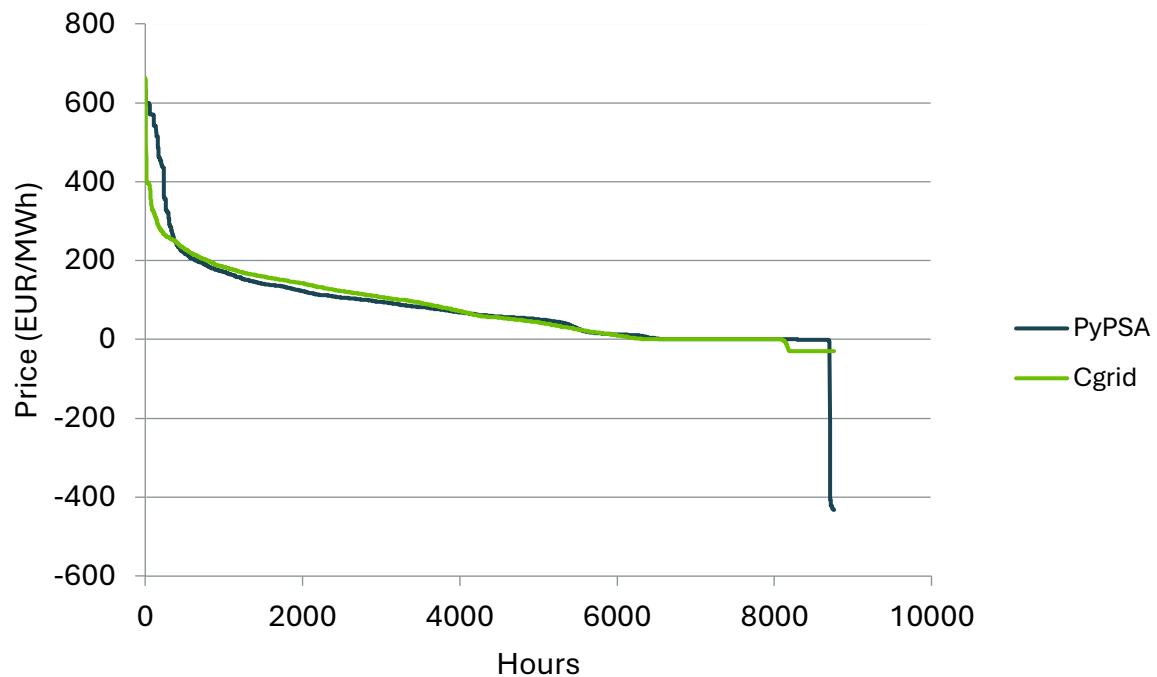


Figure 52. DK2 price duration curve comparison between PyPSA and cGrid for the Balanced scenario.

5.9.1 Capacity comparison between PyPSA and cGrid

Figure 53 shows the installed capacity in both PyPSA and cGrid for the Balanced scenario. In total, PyPSA installs 5.6% and 2.7% (1.3GW and 0.24GW) less capacity in DK1 and DK2 respectively, or 4.8% (1.6GW) all of Denmark. This is a difference that is borne out across all the scenarios, as can be seen in Figure 54, where Offshore Balanced shows the greatest reduction of 8.0% and the Solar scenario is the single case of PyPSA installing more than cGrid, with an extra 5.4% capacity overall.

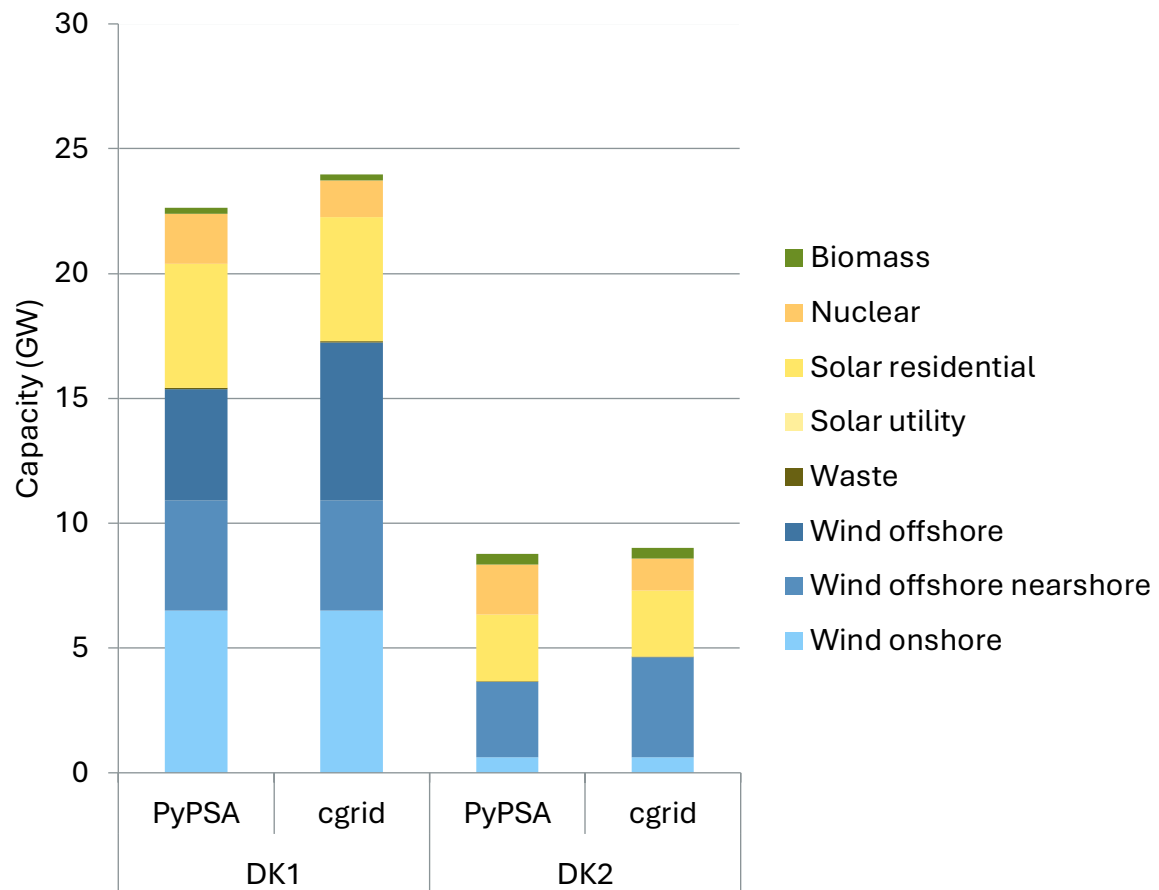


Figure 53. Installed capacity in DK1 and DK2 comparison between PyPSA and cGrid for the Balanced scenario.

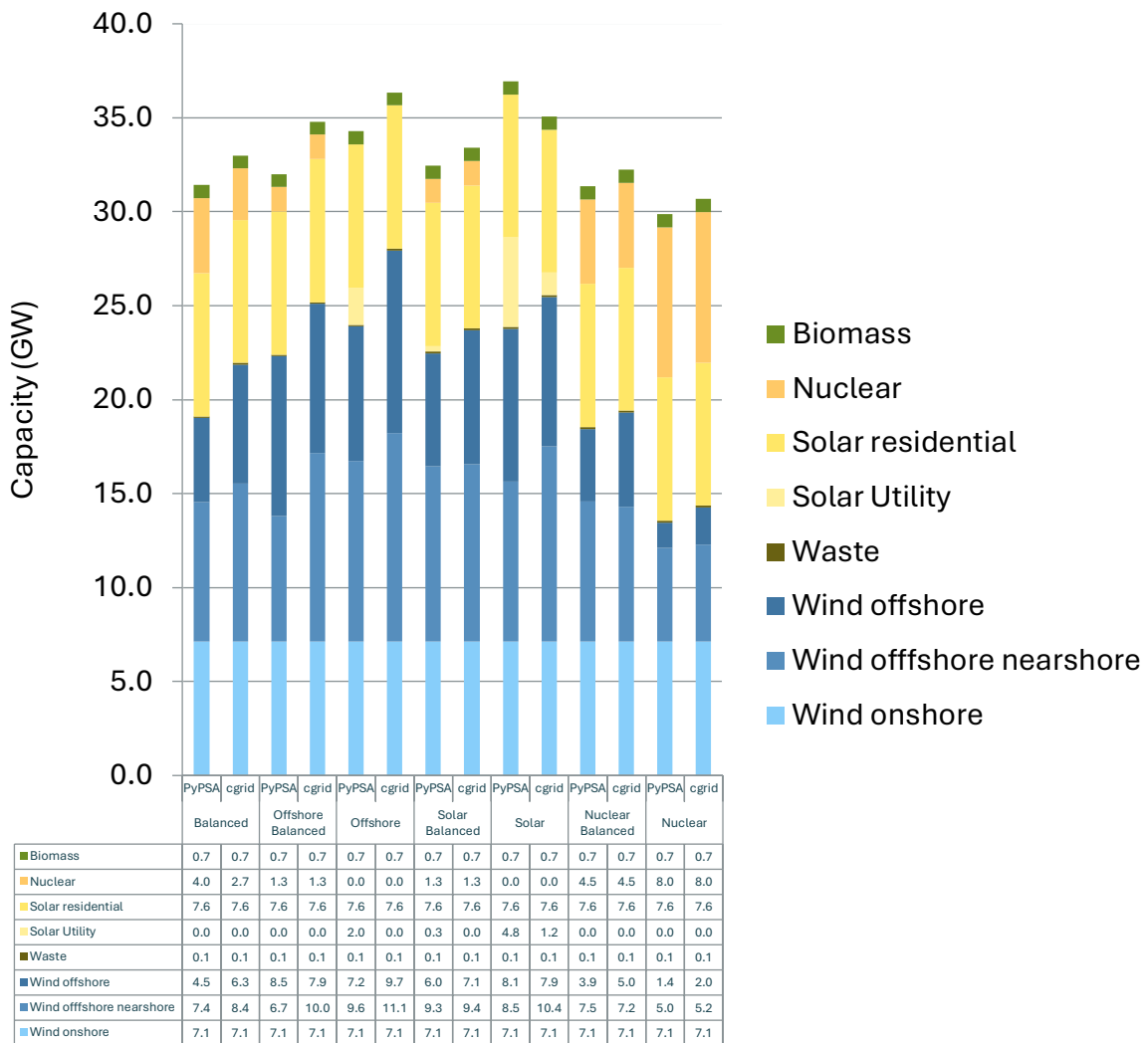


Figure 54. Installed capacity in the Danish system comparison between PyPSA and cGrid across seven scenarios.

These absolute differences are small between PyPSA and cGrid, but this is not unexpected, it should be noted that installed generation capacities outside of Denmark are determined exogenously, as are transmission line capacities, and demands for the entire model, including Denmark.

If we look deeper into the differences in the capacity mix determined by PyPSA and cGrid, as shown in Figure 55, we can see a pattern emerging. cGrid will in all scenarios build ~1-4GW of more wind than PyPSA and PyPSA favours smaller systems, as already shown, but with a different generator making up the remaining capacity that changes from scenario to scenario. For the Balanced scenario almost 3GW of wind are substituted by just over 1GW of nuclear. Offshore, Solar, and Solar Balanced scenarios favour building predominantly solar over wind. Offshore Balanced favours a smaller offshore wind build out to a larger nearshore wind one, with Nuclear Balanced favouring the opposite but on a smaller scale. The final scenario, Nuclear, reduces the wind buildout in PyPSA as compared to cGrid but does not build anything in its place.

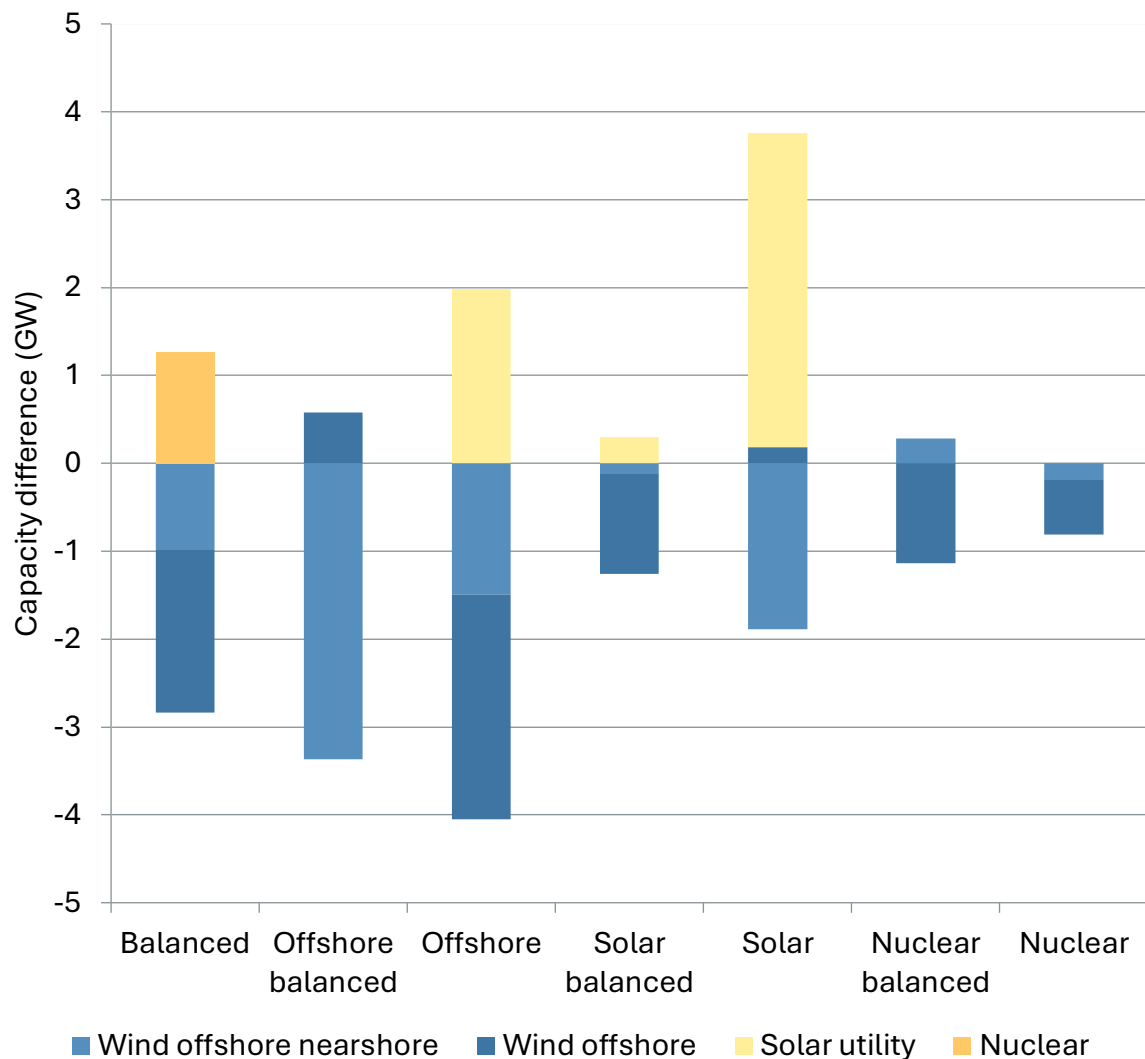


Figure 55. Capacity difference between PyPSA and cGrid for the seven scenarios. Positive values denote larger capacity in PyPSA, and negative values denote larger capacity in cGrid.

5.9.2 Generation comparison between PyPSA and cGrid

Moving from comparing the capacity buildout in each model to comparing the generation mix for each model, we see in [Figure 56](#), we have between 3.6 and 11.2% (4.3 and 13.5 TWh) less generation over the year.

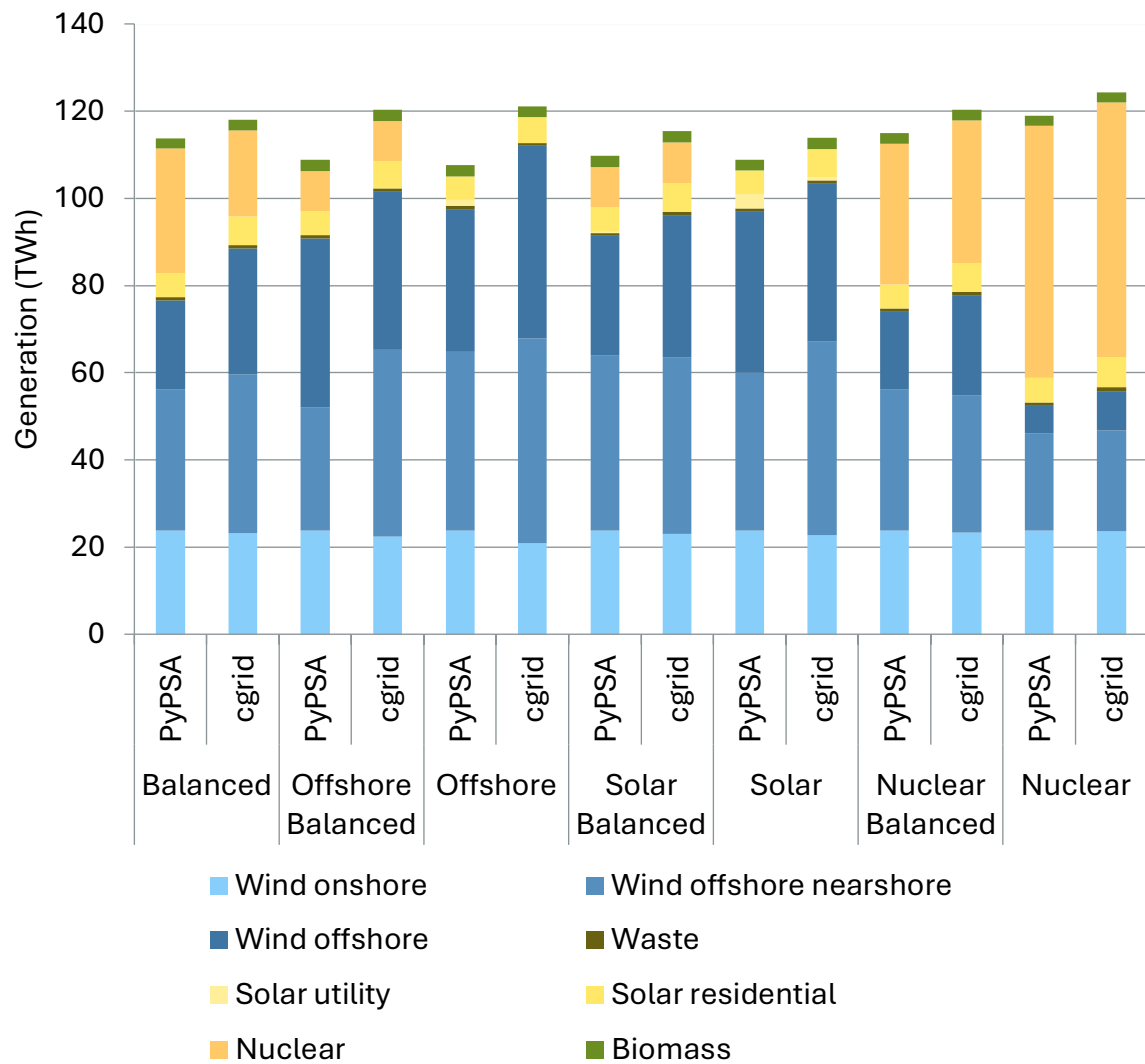


Figure 56. Generation comparison between PyPSA and cGrid for the seven scenarios.

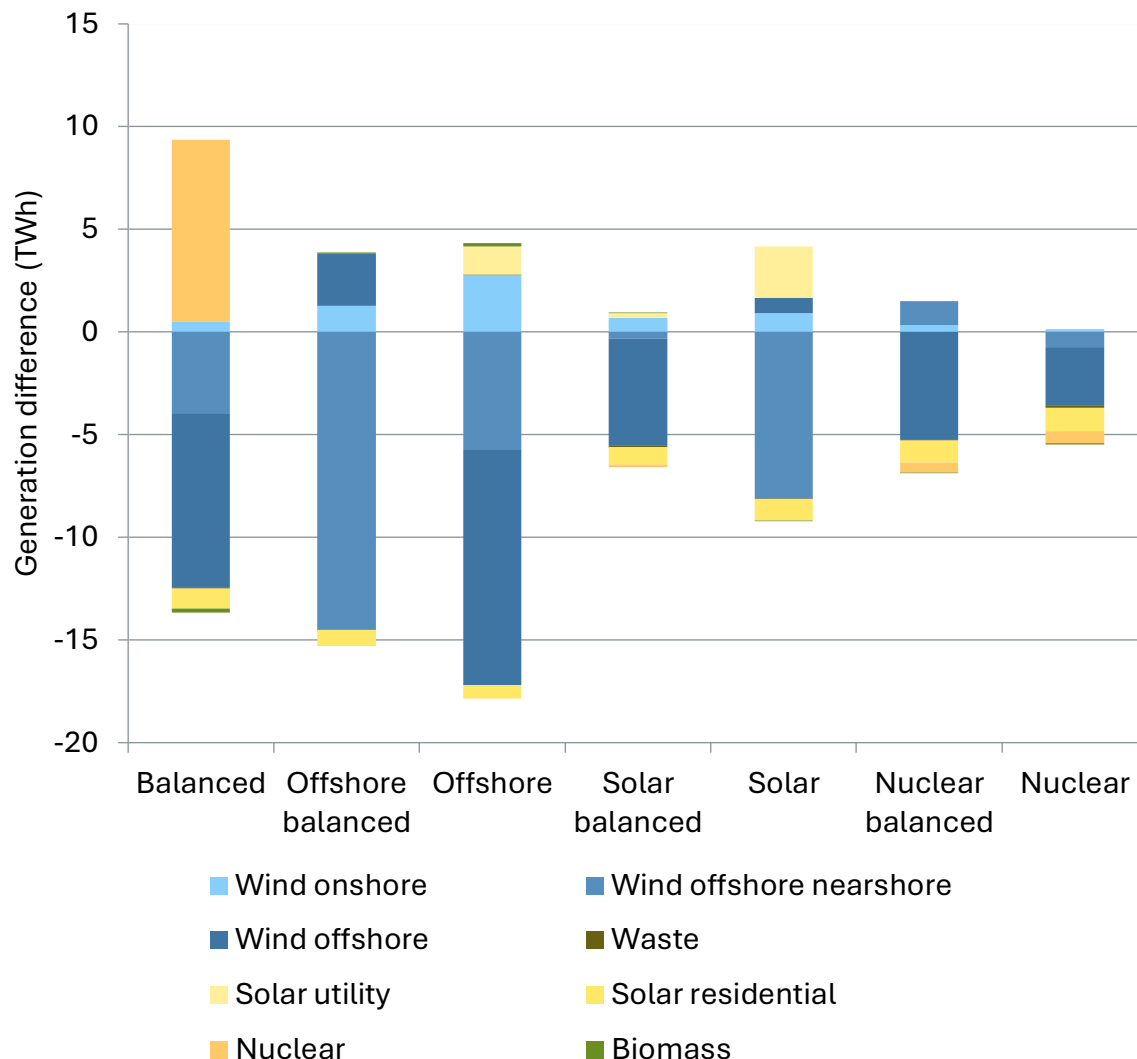


Figure 57. Generation difference between PyPSA and cGrid for the seven scenarios. Positive values denote greater generation in PyPSA, negative values greater generation in cGrid.

5.9.3 Dispatch comparison between PyPSA and cGrid

Demand in all zones is set exogenously, as are transmission and storage capacities, the only parameters given to the models to optimise is the installed generation capacity in Denmark and the optimising of the dispatch across the full model. In the previous sections we have discussed how the capacity buildout differs across the models and how the total generation is also different. In both cases, PyPSA fulfils the same demand by using less capacity and generating less power. Crucially, PyPSA has perfect foresight and cGrid does not.

Figure 56 only shows the primary generation and not power generated from discharging batteries, also the fixed demand given to the models does not include the demand for charging batteries, which is purely determined within the optimisation. Looking at the transmission of power into and out of Denmark in Figure 58, consistently across all

scenarios. DE, NL, and GB are the biggest importers of Danish-generated power in both PyPSA and cGrid but in cGrid they import significantly more. Depending on the scenario, PyPSA exports between 5.5 and 14.9TWh less than cGrid, which in every scenario is greater than the reduced generation seen by PyPSA by ~1.3TWh. This remaining difference can be accounted for by considering both, PyPSA's perfect foresight optimisation allowing for better optimisation of flexing loads, and the simplified approach of linear scaling of marginal cost across fleets when compared to cGrid's s-curve approach. For the latter, minor differences at the lower and higher utilisation of generators can cause differences in how loads curtail, but it should be noted that 1.3TWh accounts to a ~1% discrepancy in total generation between PyPSA and cGrid.

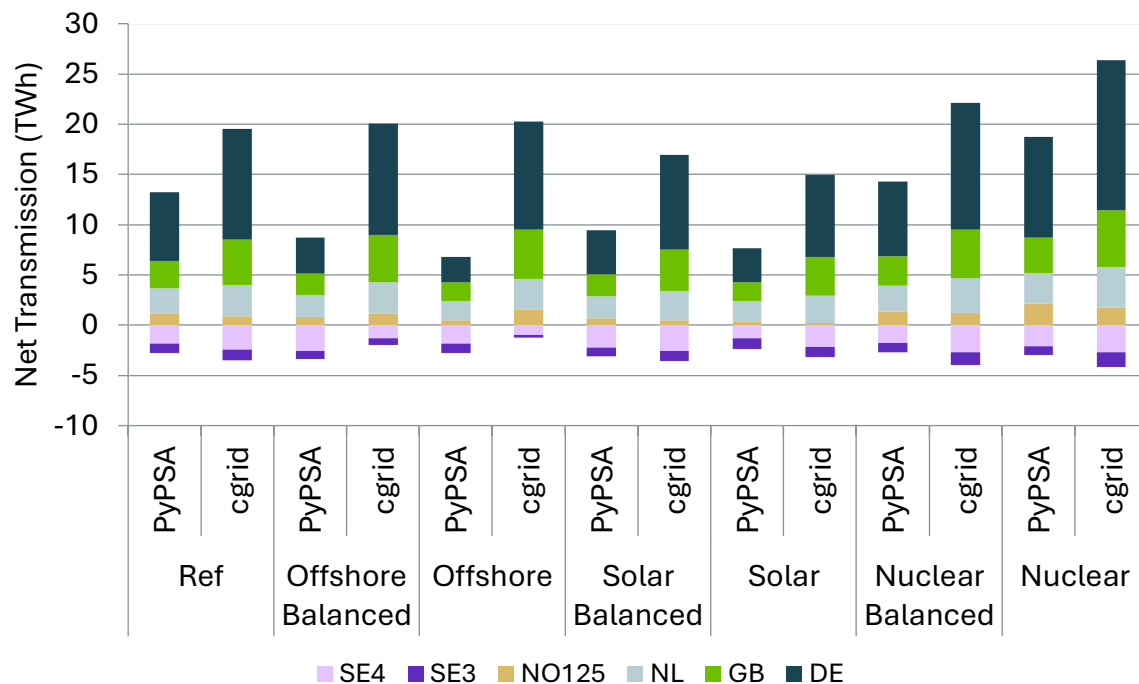


Figure 58. DK transmission balance comparison between PyPSA and cGrid divided by neighbouring zone, positive amounts denote net export.

Further verification of this difference caused by perfect foresight can be seen in [Figure 59](#) where the battery cycling in DE, the largest importer of Danish electricity, is shown. In PyPSA the batteries are utilised more heavily across all scenarios, this leads to lower need for imported energy which, as Denmark is the only zone where capacity can change, leads to a lower build out of capacity in Denmark in PyPSA when compared to cGrid.

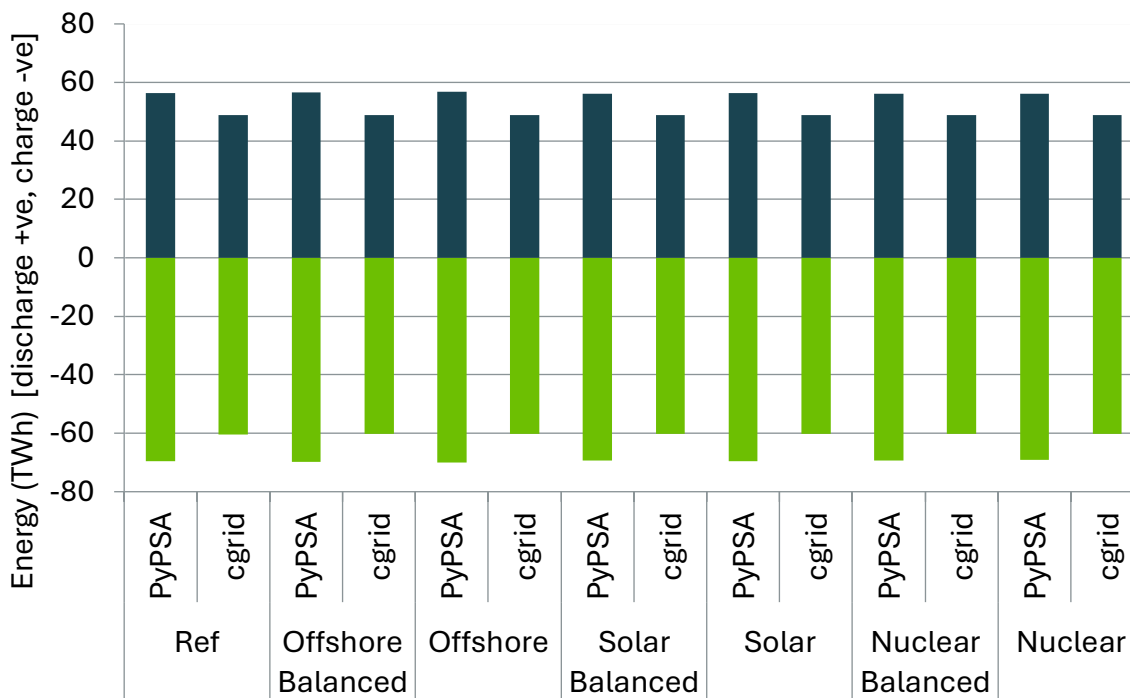


Figure 59. Yearly battery charge/discharge values in DE compared between PyPSA and cGrid for the seven scenarios.

5.9.4 Discussion of PyPSA results

Some of the most consequential limitations of large-scale system optimisation models are not technical. They arise from the disconnect between system-level optimisation and national or investor-driven decision-making. System-level optimisation is optimising for the lowest system cost, in this case the pan-European grid, with many varied zones of different makeups, of which Denmark sits at the centre of, and is, to varying degrees, exposed to. For instance, this can lead to a large buildout of open cycle gas in Denmark to provide stability to the rest of the network or an overbuilding of wind if it becomes the cheapest option to inject more energy into an undersupplied grid, when only optimising the capacity buildout in Denmark.

This can be somewhat mitigated by an increasingly granularity of the PyPSA model and reducing the potential space due to realistic grid constraints but determining siting for all new plants, calculating weather profiles at all turbine sites and solar farms, predicting loads on a substation level, becomes prohibitively difficult to design and computationally difficult to solve. Conversely cGrid, cannot expand from a greenfield due to its iterative approach being multiplicative with respect to capacity it can optimise capacity using a revenue-based approach, without the granularity requirement. The European Resource Adequacy Assessment (ERAA) methodology has followed a cost-minimisation approach since ERAA 2021 but since 2024 they have been developing a

revenue-based approach.⁸⁰ similar to cGrid's. The methodology described below starts with a cost-minimisation approach and develops into a revenue-based approach performed with consecutive PyPSA iterations. Though not explored in this study a greenfield expansion in PyPSA could be used as the sensible starting point for a cGrid revenue-based optimisation that would solve in a quicker time as cGrid does not require the Gurobi Optimizer.⁸¹ to solve and can iterate much faster on even a modest laptop. This approach has been employed several times utilising GenX rather than PyPSA.⁸² but the concept is the same.

In this study 33 weather years, determining wind and solar production, and demand due to heating needs and similar, have been used to confront a system across seven scenarios, and the 2025 system. This is more than 250 individual runs and even without expansion they would still need iterations to determine variability in PyPSA. This would be at the minimum several days of running with Gurobi and several hundreds of Euros in fees. Different approaches are possible in PyPSA for interrogating a system with ongoing developments but cGrid's approach is very mature.

Greenfield capacity expansion (PyPSA)

With the model as designed performing a single stage capacity expansion with a single representative generator for a fleet requires setting a single marginal cost for the entire fleet, this has the result that entire fleet will produce or not at the same time unless it is the marginal generator, this gives unrealistic flexibility to the system. It can be partially mitigated by enforcing ramping limits to the generators, but this is also difficult as the large fleet will behave significantly different to a small fleet and the fleet size cannot be known a priori. This could be improved in the future as detailed earlier [ref]. This would allow combining the first expansion and dispatch into a single step which would likely give more realistic results.

Greenfield + Marginal Cost Bidding (PyPSA)

The approach to this issue used in this study is moving away from a single stage solve to an iterative series of solves. In an initial investment pre-solve fleets are modelled as simple generators with a single marginal cost. Then once a capacity is found, a quadratic marginal cost is applied to the representative generators whereby above a base marginal cost (the lowest price a single generator in the fleet would choose to dispatch), generation can increase linearly with price until the entire fleet is generating. This approach is largely required for dispatchable generators such as thermal plants and nuclear, which cannot conceivably be expected have identical marginal costs over an entire fleet. This more representative fleet can then be used for optimising dispatch.

⁸⁰ ERAA 2025 Results – Public Webinar (and contained slides)

⁸¹ Gurobi Optimizer

⁸² Nordic Power Systems for a Competitive and Sustainable Economy – Quantified Carbon

Brownfield adjustment (cGrid)

As opposed to the greenfield capacity-expansion, linear-optimisation approach of PyPSA, cGrid employs a dispatch strategy for flexible demand and supply based on rolling short-term electricity prices. This approach is limited in it cannot work from greenfield, but it also has distinct advantages over the PyPSA approach. The iterate loop approach allows for adjustments to be made with feedback from the previous iteration. Thus, profitability of each generator can be ensured, and unit commitment behaviour can be reproduced.

Greenfield + Marginal Cost Bidding + Iterative adjustment (PyPSA)

Running a single expansion step, followed by a dispatch step will give the minimised system cost for a given system but lacks certain realistic behaviours, namely, fleet profitability and unit commitment. Also due to the lack the quadratic term in the marginal cost when expanding generators may be over/under built depending on their average utilisation and whether that falls above or below the flat marginal cost used in the expansion.

After the first investment pre-solve and dispatch solve in PyPSA the profitability of each resource can be calculated, here generators that lower the system cost by existing and dispatching but also lose money on every MW generated become visible. This can be caused by conditions outside of Denmark. As capacity expansion is restricted to Denmark, whilst dispatch optimisation is applied to the full system, shortcomings in connected zones can influence the model in the only way they are able to by encouraging extra buildout in Denmark to then import that power and lower their own system costs. This is seen as buildout of extra open-cycle gas to supply, constrained Dutch, German, Polish, and British grids. Once profitability is checked at the end of the dispatch loop it is found that several resources are over/underbuilt with respect to their profit/loss so these can be adjusted for the next loop. Concerning dispatchable generation, if a generator has a minimum generation requirement but is in a particularly low demand time period it is allowed to take part of its capacity offline for a time period, this can be thought of as such units not being on standby and so lowering operating costs.

This iterative loop allows PyPSA to converge on a cost optimal system where each generator also fulfils a profitability requirement. It should be noted that the non-linear approach of cGrid converges much faster than PyPSA where a full linear optimisation is required for each step.

5.9.5 Comparison to the EA study

As detailed in 2.2.2 and 2.2.3, the EA study has methodological difference to this study. This study is only optimising the capacity in Denmark, with all other modelled zones optimised for dispatch only, whereas the EA study optimises the entire system together. This study also focuses on a single year, 2050. The EA study models from 2025 to 2050 in five-year increments. Finally, grid reinforcement is determined endogenously within the model for the EA study, where it is exogenously set in this study.

In the EA study, the expansion between the modelled years is myopic, meaning that the model never anticipates future conditions when making investment decisions. This introduces path-dependence, whereby for instance a decision made in 2030, influences decisions made later.

In Figure 60 the capacity mix given in the SMR0_Bal scenario of the EA study alongside the Offshore, Balanced, and Nuclear scenarios from the current study.

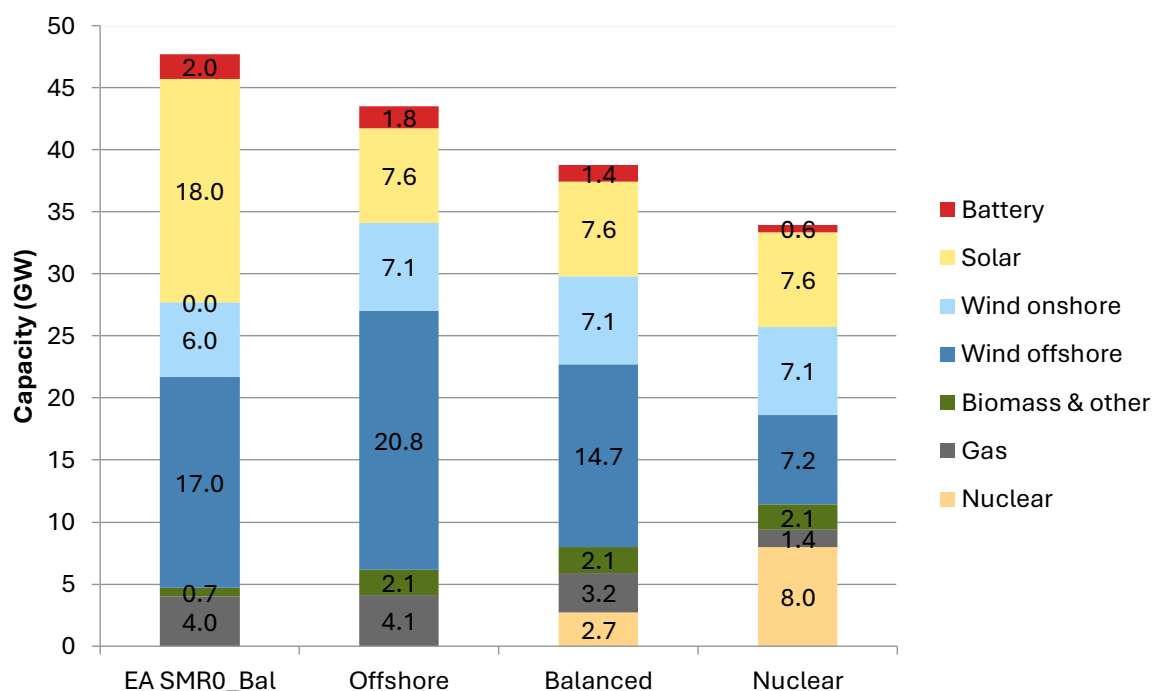


Figure 60. Installed capacity in EA study compared to three scenarios from this study.

The EA scenario has a comparable buildout of offshore wind to the Offshore scenario in the current report but favours a significant amount of solar capacity over other firm generation options. Figure 61 shows the amounts of dispatchable power in the same set of scenarios. It can be seen that the EA scenario has the smallest amount of dispatchable power, despite the largest overall capacity.

To understand this divergence Table 15 contains comparison on the average prices, capture prices, and capture rate of offshore wind. It should be noted that the EA study uses 2014 as the weather whereas the values from this study use 1991, this complicates

the comparison somewhat in the study⁸³, which determined 1991 as the average weather year, 2014 was shown to be the fifth most expensive weather year for that approach. The average capture price is largely determined by the LCOE of the marginal resource, for the EA and Offshore scenarios that is offshore wind and for the Balanced scenario that is nuclear.

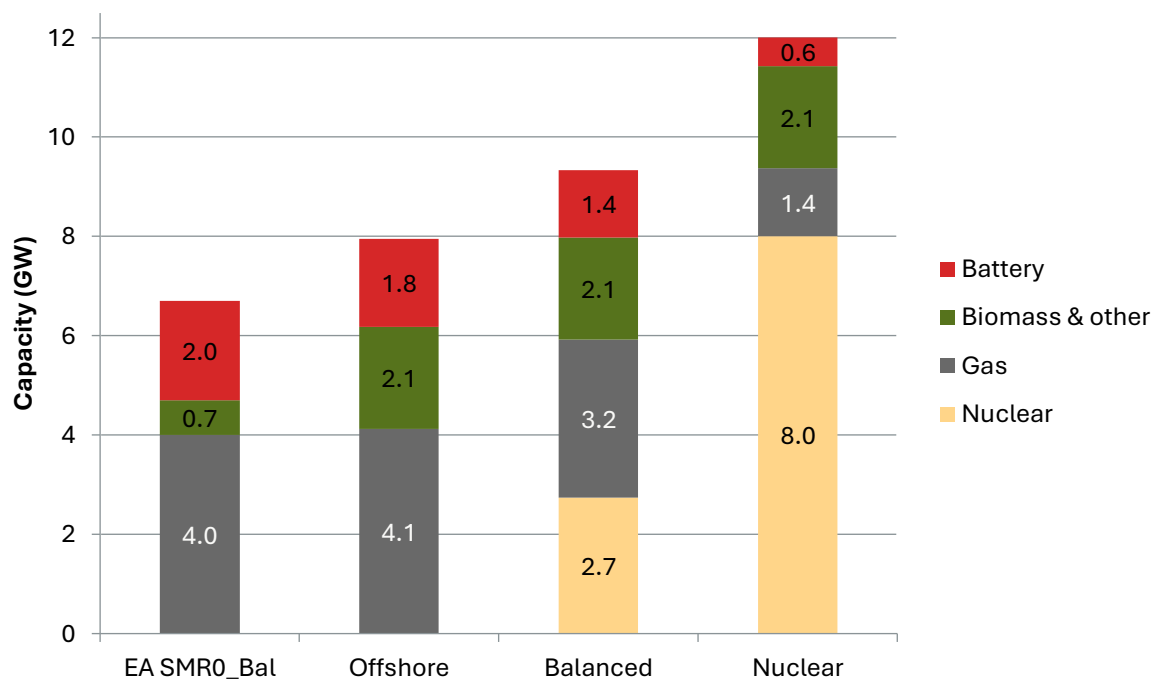


Figure 61. Dispatchable capacity in the EA study compared to three scenarios in this study.

As can be seen by comparing the 2025 values with the Balanced and Offshore scenarios, increasing penetration of wind into the energy system both lowers the capture price and capture rate. This can be explained by price cannibalisation, the large buildout of wind turbines will largely see the same weather and so they will all produce at the same time, pushing the prices down in the market and lowering their own capture. The EA scenario does not show this pattern, a large buildout of wind is accompanied with an increase in capture rate suggesting that the wind is not cannibalising its own prices, despite being the marginal resource and therefore setting prices in the hours it generates most. From the EA report offshore wind runs at 4,800 full load hours and has an LCOE of €55/MWh. If we assume that the model expands until wind reaches its profitability limit and the average electricity price in 2050 is €58, we get a capture rate $55/58 = 0.95$.

Price cannibalisation could be mitigated by large amounts of flexibility in the system, in the balanced scenario, battery capacity totals ~212 GW, the EA scenario includes 350

⁸³ Cox et al., (2026), Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

GW⁸⁴ of batteries, i.e., similar flexibility, considering there are six additional countries modelled, and only 2 GW of these are located in Denmark, so it would be expected to have limited ability to protect Danish wind from cannibalisation. Without sufficient local flexibility to absorb surplus generation, a large number of negative price hours would be expected lowering the capture rate of wind.

Table 15. Average market price, capture price and capture rate for offshore wind in weather year 1991. *EA SMR0_Bal is for weather year 2014.

	Average price	Capture price	Capture rate
2025	76	64	84%
EA SMR0_Bal*	58	55	95% (derived*)
Balanced (cGrid)	DK1: 78	DK1: 60	DK1: 78%
	DK2: 77	DK2: 55	DK2: 72%
Offshore (cGrid)	DK1: 71	DK1: 48	DK1: 68%
	DK2: 74	DK2: 45	DK2: 61%

* Estimated based on capture price divided by average price, inferred from the EA capacity expansion results where profitability requirement is included.

Table 16 summarises the key methodological and assumption differences between the two studies. The studies are broadly aligned on CO₂ price and Danish battery capacity but differ substantially in scope and approach. The EA study optimises capacity across the entire European system from 2025 to 2050, with endogenous grid reinforcement, whereas this study focuses solely on Danish capacity expansion in 2050 against fixed neighbouring systems. The weather year difference — 2014 in the EA study versus 1991 here — complicates direct comparison, as 2014 represents a more expensive weather year. Most consequentially for the results, the two studies apply fundamentally different methodological frameworks: the EA uses perfect foresight within each modelled year but is myopic between years, meaning investment decisions made in 2030 cannot anticipate conditions in 2035 or beyond, introducing path-dependence into the results. This study instead applies an iterative revenue-based feedback approach, enforcing actor-level

⁸⁴ pg.30 EA Energianalyse (2026), Effects and value of SMR technologies in the Danish energy system

profitability requirements at each step, which materially affects capacity expansion outcomes as discussed above.

Table 16. Comparison of values and methodological approaches between this study and the EA study.

	EA	This study
CO₂ Price (€/t)	~132	132
Danish Battery Capacity (GW)	2	1.4
Countries Modelled	As current study, plus AT, BE, CH, CZ, IT, PT	See Figure 9
Modelled Grid Battery Capacity (GW)	350	212
Years modelled	2025-2050 (in five-year increments)	2050
Methodology	Intra-year: Perfect foresight Inter-year: Myopic	cGrid: Iterative with rolling horizon PyPSA: Perfect foresight with iterative with revenue-based feedback
Weather year (for expansion)	2014	1991
Weather years modelled	2014	1983-2015
Grid reinforcement	Allowed	Fixed
Capacity expansion zones	All	DK1, DK2
Nuclear capacity	Exogenous	Exogenous outside of Denmark

Take-aways – Model Comparison:

- Despite fundamentally different approaches, cGrid and PyPSA produce broadly similar system configurations, providing a cross-model check of the capacity-expansion results.
- PyPSA exports less power from Denmark than cGrid across all scenarios. This is primarily due to perfect foresight enabling more optimal battery dispatch in neighbouring zones, reducing their need to import Danish-generated power. The residual discrepancy in total generation is sufficiently small to confirm the results are robust to methodology choice.
- Compared to the EA study, capacity mixes are broadly similar in nuclear-excluded scenarios but diverge when nuclear is introduced. The key driver for the difference is offshore wind capture rates of around 75% (Balanced) and 65% (Offshore) in this study versus around 95% (derived) in the EA study. At such a high capture rate price cannibalisation would be expected, which is what limits expansion in this study.
- The EA study models investment decisions from 2025 to 2050 using a myopic inter-year approach, meaning choices made in earlier years constrain later ones. As this study focuses solely on 2050, it avoids this path-dependence, which is particularly consequential for the role of nuclear in the resulting capacity mix.

5.10 Thermal power plant sites and grid upgrade costs

5.10.1 Brownfield sites

Some of the scenarios reported above call for a significant build out of nuclear power stations reaching values as high as 8 GW of cumulative capacity (Nuclear scenario). Question then emerges where this new capacity could be located. Previous research^{85, 86, 87} has shown that a brownfield approach not only allows for a certain reduction in investment costs but often solves many challenges such as grid access or access to cooling medium. The [Table 17](#) reports on the sites that (apart from the last two) have been assessed in terms of their suitability for converting them into nuclear SMRs within the RepowerScore initiative⁸⁸ – plotted also on [Figure 62](#). Setting the threshold of the RepowerScore to 70 the total available capacity of brownfield sites adds up to 4,208 MW + 1,036 MW in sites not covered by RepowerScore. For the Nuclear scenario (8 GW) this calls for additional 2,756 MW of sites suitable for SMRs. In terms of physical land required as indicated by Holtec International⁸⁹ each SMR-300 requires 15 hectares of land (notably this is less for floating power barges). This overall adds up to additional ~140 hectares of new sites required for SMRs.

On top of the sites required for SMRs we note that the system in various scenarios will have to host from 1.4 GW to 4.2 GW of open-cycle gas turbines and 2.2 GW of biomass. This combined with nuclear SMRs results in thermal power plant capacity ranging from 6.3 GW to 11.6 GW. Naturally, these technologies might potentially compete for the same brownfield sites as the nuclear SMRs. We acknowledge that open-cycle gas stations might be most suitable in sites with existing natural gas pipeline including Fyn Power Station and Viborg Power Station.

Further, locations with existing grid connections and of already degraded environment are sites where oil refineries are in Kalundborg and Fredericia. These sites in the future might host SMRs to supply own demand or become synthetic fuels production hubs.

⁸⁵ Desire (2026, Coal-to-Nuclear for Poland – National Potential

⁸⁶ Haneklaus et al., (2025), Why coal-fired power plants should get nuclear-ready

⁸⁷ Jing et al., (2025), Uncovering the technical potential of coal-to-nuclear (C2N) power generation on a global scale

⁸⁸ REPOWER (2026), RepowerScore

⁸⁹ HOLTEC, International (2026), SMR

Table 17. Locations of larger conventional power stations in Denmark along with Repower score for SMR (where available)

Plant name	Unit name	Repower Score	Unit status	Unit electric capacity [MWe]
Esbjerg power station	Unit 3	83	retired	407
Nordjylland power station	Unit 2	79	retired	305
Nordjylland power station	Unit 3	81	operating	411
Randers power station	Unit 1	59	retired	52
Studstrup power station	Unit 3	76	retired	380
Studstrup power station	Unit 4	77	retired	380
Fyns power station	Unit 3	78	retired	235
Fyns power station	Unit 7	80	retired	362
Asnaes power station	Unit 2	75	retired	147
Asnaes power station	Unit 3	74	retired	262
Asnaes power station	Unit 4	71	retired	270
Asnaes power station	Unit 5	74	retired	640
Stigsnaes power station	Unit 1	84	retired	143
Stigsnaes power station	Unit 2	84	retired	266
Avedøre power station	Unit 1	50	retired	263
Amager power station	Unit 1	10	retired	70
Amager power station	Unit 2	10	retired	91
Amager power station	Unit 3	10	retired	263
Ostkraft power station	Unit 6	0	retired	108
Skærbæk Power Station	<i>Skærbæk</i>	NA	retired	392
Kyndbyværket	<i>Kyndby</i>	NA	Reserve	644

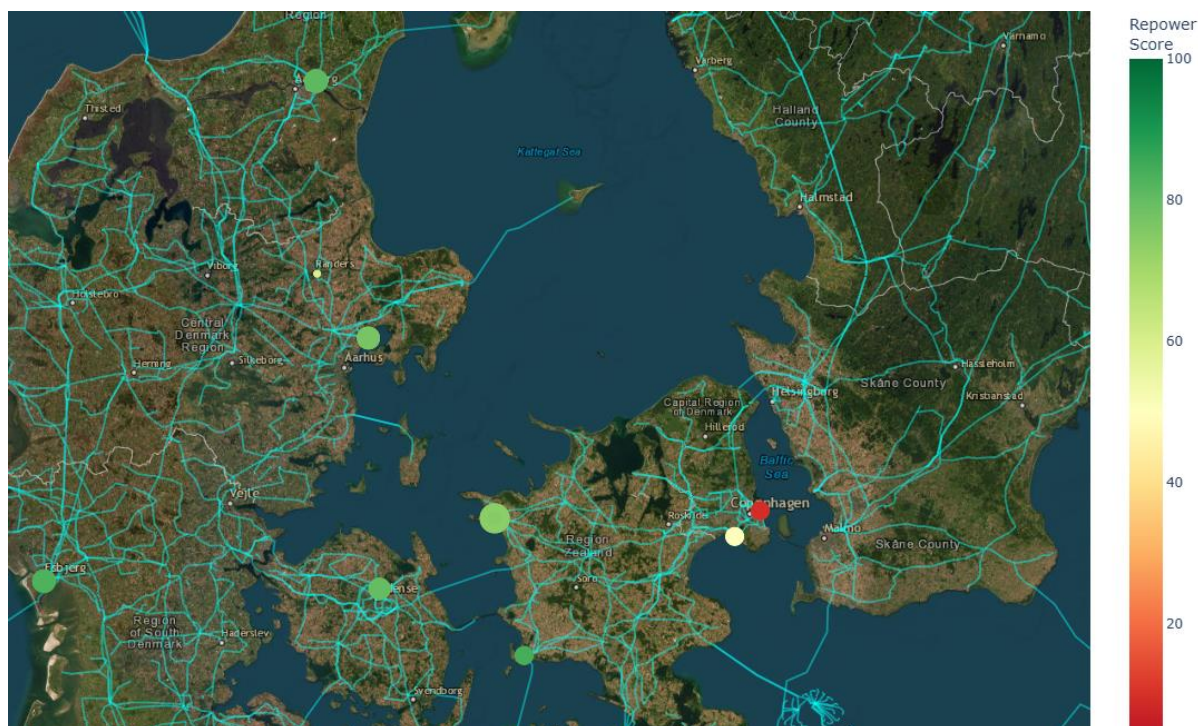


Figure 62. RepowerScore based suitability of converting existing power stations into SMR units.

5.10.2 Grid upgrade

For electricity infrastructure upgrades we are following assumptions made in the Ea Energianalyse⁹⁰ study (Table 7 page 25 of their report). Similarly to this study the cost of evacuating electricity from offshore wind turbines to the mainland is already included in technology-specific cost assumptions in the current work – [Appendix D](#). For dispatchable power stations, we are using existing sites as elaborated in Section 5.10.1 with a hosting capacity of 5.244 GW – which is then consequently assumed not to require a grid upgrade. Finally, the grid upgrade cost (GUC) is following the below equation:

$$GUC = \sum_{i=1}^n \alpha_i P_i$$

where: α – technology specific grid upgrade cost (€/MW), P – new capacity installed in given technology i , and $P_{thermal} = \max(0, \text{new thermal capacity} - 5,244 \text{ MW})$.

We treat Biomass, Gas OC and Nuclear as the same category of “thermal” capacity. Reduction in solar capacity does not result in emergence of free grid capacity for alternative technologies as this reduction applies to residential PV systems. While the reduction of Biomass capacity is considered to reduce the grid upgrade cost in 1:1 ratio.

⁹⁰ Ea Energianalyse (2026), Effects and value of SMR technologies in the Danish energy system

Consequently, the projected total grid upgrade cost depending on scenario ranges from 0.8 B€ to 2.6 B€ respectively for Nuclear and Solar scenarios. Based on the assumption of 40 years capital recovery period and 6% WACC, the annualised costs, normalised to total demand of 102 TWh, are shown in Figure 63. As expected, a massive build out of non-dispatchable capacity, most of the time further away from major demand centres, results in higher demand for transmission infrastructure. It is acknowledged, that scenarios using existing sites (brownfield investment) are advantaged in terms of grid upgrade costs. Being pessimistic and assuming that the dispatchable units are treated as “New thermal” (see. Table 7 page 26 of the Ea/VTI study) the grid upgrade costs increase on average by 13% depending on the scenario – with solar being least affected (7% increase) and nuclear the most (22% increase). Compared to Balanced scenario the offshore grid upgrade cost is 28% higher and for the Nuclear one -31% lower.

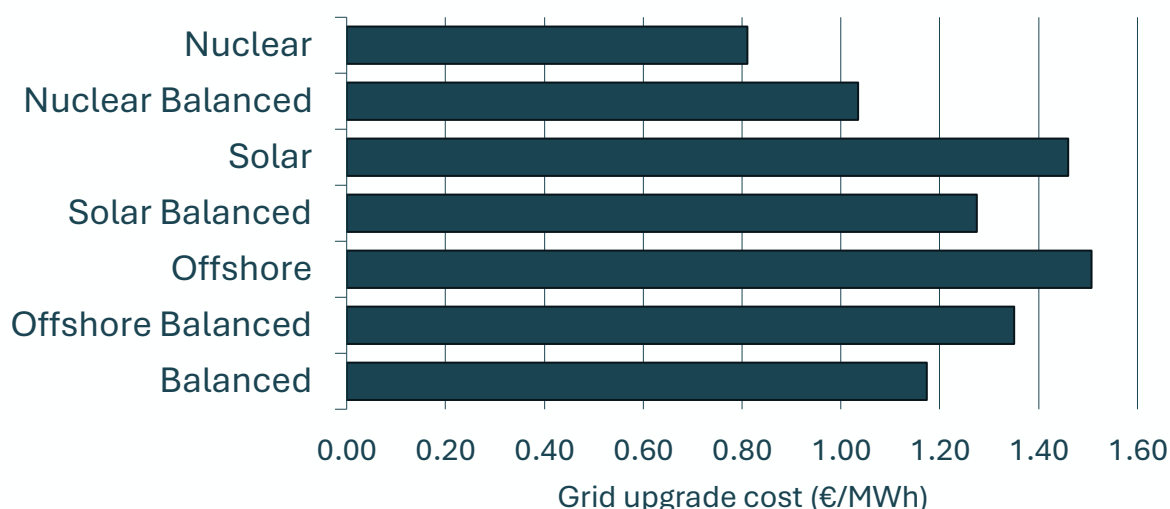


Figure 63. Annualised grid upgrade cost, normalised to total demand of 102 TWh, in each scenario.

It is worth noting that the grid upgrade costs estimated here, in absolute terms, are modest compared to generation and capacity costs, which range from 70-100 €/MWh in the present study. This is not an uncommon observation in power system analyses: transmission and distribution infrastructure typically represent a relatively small share of total system cost. However, the figures reported here capture only the *incremental* reinforcement triggered by new generation, and exclude the much larger cost of operating, maintaining and reinvesting in the existing network. For comparison, the network-cost component of Danish non-household electricity prices were approximately 32 €/MWh in 2025, i.e., of the same order of magnitude as the wholesale energy cost itself⁹¹. Most of what end-users pay for the grid relates to the legacy asset base and its ongoing operation, maintenance and reinvestment, not to incremental upgrades for new generation. It can nevertheless be tempting to treat grid costs as a secondary consideration in scenario comparisons. However, the practical importance

⁹¹ Eurostat, *Electricity prices components for non-household consumers — annual data*, dataset nrg_pc_205_c, "Network costs" component, Denmark, "Consumption of kWh — all bands", 2025 value, last updated 28 April 2026. https://ec.europa.eu/eurostat/databrowser/view/nrg_pc_205_c

of grid investment extends well beyond its direct cost. Grid expansion is a prerequisite for connecting new supply and demand, and it carries long lead times including permitting, and public consultation which can become binding constraints on the pace at which any of the scenarios examined here can be implemented. There is therefore a strong rationale for designing system pathways that minimise reliance on incremental grid build-out where feasible, for example by maximising use of existing sites and existing transmission corridors which also limits risks associated with public opposition.

It should also be acknowledged that the treatment of grid upgrade costs in this work is intentionally simple, serving as a proxy rather than a detailed assessment. The unit costs underpinning the calculation are based on the standard production connection charges (*tilslutningsbidrag for produktion*) published by the Danish DSOs and Energinet⁹², which are designed to recover the local reinforcement cost of connecting a new plant rather than to reflect the full system-wide cost of accommodating large changes in the generation mix. A more rigorous analysis would require dedicated network models capable of representing grid dynamics under stressed operating conditions, that is, the moments when over- or under-voltage, congestion and stability issues actually materialise and drive the need for reinforcement. Such modelling lies beyond the scope of the present study and is recommended as a priority for follow-up work.

⁹² Standard production connection charges (*standardtilslutningsbidrag for produktion*) published by Green Power Denmark on behalf of the Danish DSOs (<https://elnet.dk/nettariffer-priser-gebyrer/tilslutningsbidrag-produktion>), supplemented by Energinet's transmission connection charges (<https://energinet.dk/el/elmarkedet/tariffer/aktuelle-tariffer/>). The unit cost ranges quoted in Table 7 of Ea Energianalyse / VTT (2026) are derived from these tariff schedules.

Take-aways – Thermal power plant sites and grid upgrade costs:

- The nuclear-heavy scenarios call for a significant build-out of thermal power plants (as high as 8 GW) which could be located at greenfield but also brownfield sites which could reach around 5.2 GW according to our analysis.
- Open cycle gas turbine power plants (1.4-4.2 GW) alongside biomass CHP (2.2 GW) compete for the same sites which means that for the Balanced scenario with 8 GW of total thermal power plant capacity that 2.8 GW greenfield sites are required.
- Incorporating the possibility to use brownfield sites for new thermal power plant capacity, grid upgrade costs following the expansion of the Danish system was estimated. While the Offshore scenario shows an increased cost of 30% relative to the Balanced scenario, the Nuclear scenario shows 30% decrease, the costs in absolute terms are modest at around 1 €/MWh.
- The estimated grid costs only capture the investments associated with the incremental grid reinforcement due to an expanding grid which overlooks expenditures relating to ongoing operation, maintenance and reinvestments of the existing grid. Beyond costs, lead times, permitting and public consultation are further aspects that could be considered in further analyses.

6 Summary analysis

The summary analysis compiles the results of the current study for a better overview. This study does not carry out a complete analysis of all below aspects, but provides an overall picture of how the different scenarios perform for each parameter which extends to the parameters in associated with climate and environmental impact not presented in the results section. The aim is to broaden the focus of the energy system study and also include aspects that are sometimes overlooked, aspects that are absolutely central to being able to identify which scenarios and possible power systems are realistic to aim for. Nevertheless, more aspects than what is captured among the quantified indicators in the summary table need to be evaluated. This extended reasoning completes the analysis of the current work.

6.1 Summary table – comparing scenarios

The thirteen parameters analysed in this study are;

Degree of self-sufficiency

1. Gas consumption - Highlighting the dependence on securing a gas supply infrastructure.
2. Import cost - Highlights the role of imports and whether they occur at low or high prices.
3. Demand coverage – Highlights the how capable the system is to physically supply power to meet demand in the most extreme operating conditions.

Competitiveness

4. Generation and capacity cost - Shows the cost to society of building and operating the power system.
5. Cost escalation - Highlights how much exposure a scenario has to cost increases
6. Electricity price level - Measures the average electricity price level and its impact on industry and households.
7. Electricity price volatility - Measured as how electricity prices vary over time and with weather conditions, highlighting market stability and price risks
8. Profitability gap - Measures the gap between technology costs at reference levels and the revenues earned in the market, showing how exposed each scenario is to revenue cannibalisation and to technology cost variation.

Environmental and climate impact

9. Life-cycle GHG emissions - Measures total production-based GHG emissions over the entire life cycle, including fuel extraction, manufacturing, operation and decommissioning of power plants.

- 10. Use of critical materials - Quantifies the need for raw materials such as metals and rare earth elements for the construction and operation of the energy infrastructure.
- 11. Land use - Indicates the amount of land area that needs to be allocated to electricity production.

Operational safety

- 12. Grid upgrade costs - Analyses the investment costs to the power grid associated with accommodating the increased supply and demand expansion.
- 13. Dispatchable capacity - Highlights how much dispatchable capacity is available and its role in different operational states and for system stability.

A summary of the results is presented in [Table 18](#), where the results per category are also ranked according to their attractiveness for Denmark. [Table 19](#) describes the quantified parameters. Fossil gas consumption is not considered desirable. Import costs should be low and so should system costs, escalation costs and profitability gap. A low electricity price is desirable and so is low electricity price volatility. Life cycle emissions and use of critical materials should be low. Grid upgrade costs should be low while share of dispatchable capacity high. The best outcome is shown in light green and the worst outcome in dark green, with the remaining outcomes in shades of green in between. It should be made clear that the ranking is subjective.

Table 18. Compiled results ranking parameters measuring self-sufficiency, competitiveness, environmental & climate impact and operational safety for different Danish power systems in 2050. The ranking is colour-coded from light to dark. Description of parameters in [Table 19](#).

Parameter/Scenario	Balanced	Offshore Balanced	Offshore	Solar Balanced	Solar	Nuclear Balanced	Nuclear
Import cost (€/MWh) vs 2025	1.8 (-60%)	4.3 (-5%)	9.0 (+99%)	5.5 (+22%)	9.8 (+120%)	-3.3 (-170%)	-11.5 (-350%)
Gas consumption (TWh) vs 2025	0.6 (-87%)	0.8 (-84%)	1.0 (-79%)	0.8 (-83%)	1.1 (-77%)	0.4 (-92%)	0.1 (-98%)
Demand coverage (%) vs 2025	61 (-18%)	58 (-22%)	55 (-26%)	58 (-22%)	55 (-26%)	66 (-11%)	80 (+7%)
System cost incl. imports (€/MWh) vs Balanced	71 (0%)	73 (+3%)	78 (+9%)	71 (0%)	73 (+2%)	70 (-2%)	69 (-3%)
Costs escalation (€/MWh) vs Balanced	30 (0%)	28 (-6%)	26 (-11%)	27 (-10%)	24 (-18%)	33 (+12%)	40 (+35%)
Average price (€/MWh) vs 2025	78 (-5%)	76 (-8%)	73 (-12%)	81 (-2%)	82 (0%)	76 (-8%)	72 (-13%)
Price volatility vs Balanced	0%	2%	-2%	5%	8%	-3%	-8%
Profitability gap (€/MWh)	-1.2	4.8	12.7	-1.6	-1.0	-1.5	0.9
Emissions (gCO ₂ eq/kWh) vs 2025	23.1 (-82%)	23.2 (-82%)	23.2 (-82%)	22.9 (-82%)	23.2 (-82%)	23.2 (-82%)	23.4 (-82%)
Minerals use (kt) vs Balanced	292 (0%)	318 (+9%)	341 (+17%)	304 (+4%)	324 (+11%)	275 (-6%)	241 (-18%)
Land use (km ² · 10 ³)	1.1	1.1	1.0	1.1	1.1	1.1	1.1
Grid upgrade cost (€/MWh) vs Balanced	1.2 (0%)	1.4 (+15%)	1.5 (+28%)	1.3 (+9%)	1.5 (+24%)	1.0 (-12%)	0.8 (-31%)
Dispatchable capacity (GW) vs Balanced	8.0 (0%)	7.0 (-12%)	6.2 (-22%)	7.1 (-11%)	6.3 (-21%)	9.0 (+13%)	11.4 (+43%)

Table 19. Description of quantified parameters in [Table 18](#).

Parameter	Description
Import cost (€/MWh) vs 2025	Represents net import cost from Danish power imports normalised to demand in the model for weather year 1991 compared to 2025 power system reference.
Gas consumption (TWh) vs 2025	Represents gas consumption (thermal energy value) of natural gas-fired power plants in the model as average of 33 weather years compared to 2025 power system reference.
Demand coverage (%) vs 2025	Represents demand coverage by generation potential (installed supply capacity) for the 1000 worst hours by supply-demand balance and compared to the 2025 power system reference.
System cost incl. imports (€/MWh) vs Balanced	Represents absolute generation and capacity costs normalised to annual demand when using reference technology cost assumptions compared to the Balanced scenario. Import costs/export revenues are included. See also Section 5.5 .
Costs escalation (€/MWh) vs Balanced	Increase in technology costs (€/MWh, normalised to annual demand) when the scenario's own capacity mix is costed at Conservative-2 instead of Reference technology costs. The capacity mix and dispatch are unchanged, and import and fuel costs are excluded. The percentage compares this increase with Balanced. See also Section 5.5 .
Average price (€/MWh) vs 2025	Represents the average price for Denmark for 33 weather years compared to corresponding of the 2025 power system reference, see also Section 5.6.1 .
Price volatility vs Balanced	Represents the average of the absolute range between the 25th and 75th combine with 1st and 99th percentiles of quarterly averages compared to the Balanced scenario. This volatility assessment only covers fluctuations caused by weather dependencies and does not include variations stemming from fuel prices. See also Section 5.6.2 .
Profitability gap (€/MWh)	Difference between generation and capacity costs and day-ahead market revenues for Reference technology cost scenario assumptions aggregated across all technologies for each scenario. This is inverse of profitability numbers in Table 12 . See also Section 5.6.4 .
Emissions (gCO₂eq/kWh) vs 2025	Values for Danish generation (production-based, imports excluded) normalised to annual demand are given based on 735 for gas OC, about 230 for biomass, 48 for solar, 12 for nuclear, 12 for offshore wind and 11 for onshore wind in g CO ₂ eq/kWh. 2024 value has been assumed 130 g CO ₂ eq/kWh according to ElectricityMaps .
Minerals use (kt) vs Balanced	Calculated based on installed production capacity for different technologies and IEA (2022) compared to the Balanced scenario.
Land use (km² · 10³)	Calculation based on 43 m ² /MWh for onshore wind, 21 m ² /MWh for solar utility, 1 m ² /MWh for nuclear and 0.8 m ² /MWh for gas turbines. Biomass and solar residential omitted as well as areal use for offshore wind.
Grid upgrade cost (€/MWh) vs Balanced	Calculation based on estimated investment cost for grid expansion relating to new supply capacity, incorporating brownfield vs greenfield sites for thermal power plants compared to the Balanced scenario.
Dispatchable capacity (GW) vs Balanced	Calculation based on installed capacity of biomass CHP, nuclear power and gas turbines (batteries excluded) compared to the Balanced scenario.

First of all, all scenarios show a considerable decrease in emissions compared to the 2025 power system as demonstrated by the decrease in lifecycle emissions of 82%. Instead considering direct emissions, this level means a 96% decrease compared to 1990's level, i.e., well below 2040 targets. This is primarily a result driven by scenario design, where only open-cycle gas turbines run on fossil fuels but its utilisation is strongly limited with its assigned role as reserve power plants.

Secondly, the scenarios exhibit very limited variation in land use. This is due to their consistent deployment of onshore wind to its maximum expansion limit and very limited solar expansion. The onshore wind expansion corresponds to a 70% increase, purely based on installed capacity, from 4.7 GW in 2025 to 7.1 GW in 2050, giving some indication of additional requirement of land use vs today. Offshore wind is not included in the land-use calculation but does feature a substantial growth from today's 2.6 GW to 14.7 GW in the Balanced scenario. This growth, which is even larger in the Offshore scenario, may be subject to areal conflicts, permitting and social opposition which may deserve further attention in future work.

Now let's consider the different core generation technology directions.

6.1.1 Solar direction

Relative to the Balanced scenario, the solar scenarios represent variations with less dispatchable capacity and more short-duration demand-side flexibility but only marginal increase in solar capacity, due to its low market profitability. Driven by its lower domestic generation capacity, the scenarios show the worst performance on self-sufficiency levels and price average and volatility. Conversely, it also results in the best performance on costs escalation and profitability gap while for costs the solar scenario ranks moderately. With regards to minerals use, grid upgrade cost and dispatchable capacity the solar scenarios are exhibiting similar performance to the Offshore scenarios with decreased performance compared to the Balanced scenario.

6.1.2 Offshore direction

The offshore direction, with larger long-duration demand-side flexibility, realised by hydrogen storage, and larger fleets of offshore wind a similar performance on self-sufficiency level as the solar scenarios is seen with steadily worse conditions due to increasing weather dependency. On competitiveness we see varying performance. The costs show the largest increase in the Offshore scenario but at the same scenario exhibits very limited cost escalation. Furthermore, due to large domestic supply, the market price average and volatility are comparable to the Balanced scenario. However, the offshore direction shows the largest profitability gap owing to its vulnerability to the large revenue cannibalisation of the wind fleet. With regards to minerals use, grid upgrade cost and dispatchable capacity the Offshore scenarios are exhibiting similar performance to the Solar scenarios with decreased performance compared to the Balanced scenario.

6.1.3 Nuclear direction

In the nuclear direction, with larger shares of clean firm generation in the form of nuclear power, the scenarios deliver clear improvements on self-sufficiency: import costs fall the most across all directions, demand coverage rises markedly, and gas consumption drops to the lowest levels modelled. On competitiveness, performance is mixed. Price average and volatility reach the best values of any direction, supported by consistent firm output, and the system-aggregated profitability gap is small. However, cost escalation is the most pronounced of any direction, reflecting the modelled uncertainty in nuclear capital costs. With regards to minerals use, grid upgrade cost and dispatchable capacity, the nuclear scenarios show the strongest performance, with reductions in mineral demand and grid upgrade costs alongside an increase in available dispatchable capacity relative to the Balanced scenario.

6.1.4 Risk-benefit trade-offs

Across the three directions, the trade-offs are not best framed as "cheap versus expensive" but as "where the uncertainty sits." The Nuclear direction shifts uncertainty onto the cost side. Its modelled cost escalation is the highest of all scenarios, but in return it delivers the best price levels, the lowest volatility, the strongest dispatchable capacity, lower grid upgrade costs, and lower mineral demand than the Balanced reference. The Offshore direction shifts uncertainty onto the revenue side. Here costs escalate less, but market exposure is potentially high through wind-fleet cannibalisation, expressed in the largest system-aggregated profitability gap of any scenario. The Nuclear direction's small, aggregated profitability gap, by contrast, masks an actor-level reality: directed support to nuclear producers is likely still required, but is not as visible since other producers carry a net profit. Solar's marginal expansion is itself a finding, manifested even where scenario design favours it (Solar scenario). This is a result of anti-correlated production profile compared to annual demand and considerable solar capacity in neighbouring regions cannibalising potential revenues for solar installations. The Nuclear direction's better performance on minerals use, grid upgrade costs, and dispatchable capacity translates into less exposure to critical-mineral supply chains⁹³, decreased bottlenecks and lower risk associated with grid expansion, and stronger system services (frequency and non-frequency balancing, black-start, islanding) provided through mature thermal generation rather than through alternatives whose maturity at scale remains uncertain.

6.2 Extended reasoning

The evaluation of the summary table in Section 6.1 has painted a picture of the risks and benefits of pursuing different technology mixes for the Danish power system based on the energy system modelling analysis. First of all, it is very important to emphasise that all scenarios heavily rely on especially wind power, but also integrates solar residential installations. As such, one should not directly associate each scenario with a certain

⁹³ DN Debatt (2025), Europe is grabbing the world's critical metals.

technology but regard them as holistic systems of different technology mixes. Bearing this in mind, it is still possible to argue that core generation technologies offshore wind and nuclear add value to the Danish power system. Meaning that their exclusion does potentially carry significant negative effects on the performance of the system.

Moving further, we narrow down the focus to two scenarios: the Offshore scenario and the Nuclear scenario. The Offshore scenario represents a direction of a system more dependent on wind power while the Nuclear scenario represents a system direction more heavily dependent on nuclear power. The Balanced scenario represents a diversified mix and as such inherently balances risks and benefits of the Offshore and Nuclear directions. The solar scenarios are excluded from the extended discussion because they converge in the modelling towards mixes that closely resemble the Offshore direction, solar does not emerge as a major capacity contributor even under scenario assumptions designed to favour it.

Table 20 presents risks and dependencies, contrasting the nuclear and offshore directions, across aspects not captured in the modelling analysis and derived quantified results in Table 18. These qualitative considerations are related back to the quantitative indicators in Table 18 where relevant. The following sections walk through the aspects carefully.

Table 20. Risks and dependencies not captured in the modelling analysis evaluated for future two contrasting power system directions.

Aspect	Nuclear direction	Offshore direction
Energy technology industry	Technology cost reductions require the build-up of and strongly supported European nuclear industry to enable amplified learning rates and successful projects	Technology cost reductions require a revived European and Danish wind industry to enable amplified learning rates but also low material costs
State intervention	Likely means state support for nuclear power to address high project risks (delays and cost escalation) Requires broad national acceptance Needs to consider supply-demand phasing to limit impacts on other market actors	Likely means state support for offshore wind power due to uncertainty in materialising cost reductions Requires broad national acceptance Need to consider revenue cannibalisation on other market actors
Development in neighbouring regions	Means contributing to security of supply in Europe Market revenues determined by European market and average price	Likely means Denmark is relying on neighbours for clean firm capacity Market revenues determined by European market and wind fleet cannibalisation
Demand growth	Plays a smaller role in a low-demand-growth future and a larger role in a high-demand-growth future	Plays a larger role in a low-demand-growth future and a smaller role in a high-demand-growth future
Timing	Danish starting point to commissioning is long	Revived industry likely to deliver concrete expansion within the 10-year near-term
Sector-coupling considerations	Heat co-generation not assessed in this study	Hydrogen long-duration storage is a meaningful synergy but not foundational

6.2.1 Energy technology industry and state intervention

Energy system modelling in general relies heavily on technology cost assumptions, and this study is no exception. What this study emphasises though, is the inclusion of technology cost scenarios to capture potentially varying materialising technology costs. The optimistic technology cost scenarios in the Nuclear and Offshore scenarios are built on framings presented in [Appendix D](#):

- Nuclear: The optimistic trajectory reflects serial deployment of standardized reactor designs (e.g., SMR fleets or replicated large-unit builds), strong regulatory streamlining, and improved project execution discipline. Industrial learning, modularization, and supply-chain scaling reduce overnight CAPEX and shorten construction duration to 2 years. Risk perception declines as multiple projects are successfully delivered on time and on budget, reducing WACC.
- Offshore wind: This scenario assumes a lower cost of capital, supported by reduced risk premiums, clearer CfD frameworks, and a stable permitting regime in Denmark. Supply-chain normalisation and scale effects, larger turbines (18–20+ MW), serial production, industrial learning, and standardised foundations and installation methods, drive further unit-cost reductions.

Denmark starts from very different industrial positions: a mature offshore wind ecosystem with global incumbents on one hand, and effectively no domestic nuclear supply chain on the other (but with two renowned SMR start-ups).

In the case of nuclear, this essentially means that materialising technology cost reductions requires the build-up of and strongly supported European nuclear industry to enable amplified learning rates and successful projects. But it also means state intervention. With financial support for nuclear power to address high project risks relating to delays in construction and general cost escalation, particularly relevant in a starting phase, as the analysis on varying technology cost scenarios in [Figure 34](#) shows. Notably, recent European nuclear new builds have systematically run over budget and behind schedule. Consequently, considerable state support requires broad national acceptance. Because each nuclear reactor adds a large block of capacity at commissioning, the market needs to consider supply-demand phasing to manage impacts on other market actors.

Similarly for offshore wind, these technology cost reductions require a revived European and Danish wind industry. Notably, challenges include that cost reductions may be primarily linked to the scale of turbines that is realised in contrast to pure learning by doing⁹⁴ and due to it being a rather material intensive technology, higher than expected material costs could hamper improvements. Similar to nuclear, the development likely means state support for offshore wind power. Notably, offshore wind saw zero bids in the Danish 2024 tender⁹⁵. Large financial support requires broad national acceptance. Unlike nuclear, the market needs to consider revenue cannibalisation (see also

⁹⁴ Wind Energy (2025), *Cost Development and Cost Drivers in UK Offshore Wind Farms*.

⁹⁵ <https://ens.dk/en/press/danish-energy-agency-opens-tenders-three-new-danish-offshore-wind-farms>

profitability gap in [Table 18](#)) as a key aspect on other market actors in the implementation of the state support schemes.

Technology cost projections are not an uncontrolled externality. Policy levers, such as industrial strategies, permitting conditions, CfD/procurement designs, cross-border supply-chain coordination, play a vital role. Therefore, Danish energy policies alongside the European energy policies of today ultimately shape the technology cost projections of the future.

6.2.2 Development in neighbouring regions

One of the key insights from the modelling is that Denmark's large interconnectivity, relative to its system size, makes domestic market foundations, average prices, volatility, market revenues, strongly dependent on European market development. From an actor's perspective, project profitability therefore sits largely in the hands of factors outside Denmark's control, and these factors will themselves vary strongly over time in a liberalised market.

The market revenues from the nuclear producer's perspective are most concerned with average levels while the offshore wind producer is also sensitive to revenue cannibalisation which is associated with the degree of wind fleet expansion in the first instance but also market flexibility and grid capacity to absorb production during periods of oversupply. For both directions, building the case for profitability on pure market projections is therefore insufficient. This is why state intervention, discussed in the previous section, is not incidental but structural to either pathway.

The deployment of nuclear contributes to the security of supply in Denmark as the analysis presented in [Table 18](#) clearly conveys. However, this contribution also extends to neighbouring regions, both directly following its system dispatch but also potentially indirectly as the Nuclear scenario is contingent on broad European support for nuclear, which would in turn enable larger deployment across the continent. The Offshore direction inverts this logic. Rather than Denmark contributing clean firm capacity to Europe, it would rely on neighbours to provide it, converting a domestic security-of-supply question into a dependency on the policy trajectories of countries such as Sweden, Norway, Germany, and the UK.

6.2.3 Demand growth and timing

Uncertainty in Danish power demand growth is considerable, and it has been probed by means of one conservative scenario (64 TWh) and one optimistic scenario (138 TWh) in addition to the Reference scenario at 102 TWh (see [Section 5.8](#) for full analysis). The results showed for nuclear that it plays a relatively smaller role in a low-demand-growth future and a larger role in a high-demand-growth future while the opposite was true for offshore wind.

The capacity expansion optimisation results are primarily driven by the value of offshore wind at different levels of expansion to the Danish power system. At lower levels, the

most cost-effective resources are expanded reaching profitability even at lower price levels. As deployment increases, progressively less cost-effective wind resources are required, and further deployment cannibalises its own revenues. The expansion of nuclear is effectively determined by the limits of the expansion of the most cost-effective wind offshore resource, incorporating revenue cannibalisation.

Given recent hesitations around electrifying hard-to-abate industries in favour of hydrogen-based alternatives, the conservative demand scenario, still representing a 70% growth compared to today, seems more relevant for discussions compared to the optimistic which means a corresponding 260% demand increase. For the conservative demand scenario, this implies that the cost-optimal role of nuclear in the Balanced scenario is more modest. Setting cost-optimal expansion aside, the cost-benefit case for adding more costly firm capacity weakens at smaller system sizes. However, its foundational system value contributions, i.e., increasing self-sufficiency, operational safety and decreasing volatility and grid upgrade costs will remain.

Intimately linked to the demand growth is the timing of the related expansions of nuclear and offshore wind technologies. Both technologies carry long lead times, however, given Denmark's starting point with no nuclear supply chain, regulatory framework, or trained workforce, the time until reactors may be commissioned in Denmark will be long, and most likely also tied to the development of the European nuclear industry as a whole. If the offshore industry manages to bounce back from its recent setbacks, it is more likely to deliver concrete expansions within the 10-year near term horizon if associated necessary grid reinforcement can be realised.

Taken together, the offshore wind direction could be considered to carry a stronger near-term focus to meet increasing demand, particularly because moderate expansion levels remain cost-effective before cannibalisation becomes binding and less cost-effective sites need to be pursued. The nuclear direction case, on the other hand, rests more on long-term foundational value rather than near-term cost optimality. The current study's long-term focus also implies that co-expansion of supply (with lead-time constraints) and demand is a natural direction for further work.

6.2.4 Sector-coupling consideration

Energy system modelling often emphasises sector coupling as vital for absorbing variable renewable generation and enabling decarbonisation. The current study, focused on Denmark, finds that sector coupling does add system value in both directions but is not decisive in the choice between them. This is a finding that reflects Denmark's large interconnection capacity rather than any general dismissal of sector coupling.

Although not a primary focus of the study, hydrogen production and the associated flexibility from long-duration storage in salt caverns are represented in the modelling. The Offshore scenarios were specifically assumed to feature greater hydrogen-production flexibility, and Section 5.8 investigates variations in both hydrogen demand levels and the degree of flexibility. Most prominently, demand-side flexibility from hydrogen production played a substantial role in handling the extreme weather event analysed in

Section 5.4: it allowed the Offshore scenarios to install less dispatchable capacity, lowering resource-adequacy costs. Across the wider sensitivity range, however, the system-level impact was limited.

More broadly, this is another instance of Denmark's large interconnectivity, relative to its system size, dampening the system-level impact of domestic variations, here, sector-coupling parameter variations. Further work could examine how sector-coupling design choices interact with the broader trade-off between regional coordination and national autonomy.

6.3 Conclusion

The current work has, based on an integrated modelling and scenario framework, explored alternative climate-neutral Danish power systems in 2050. Diverse technology supply mixes – including wind, solar, and nuclear – have been evaluated to assess how different configurations can ensure a cost-effective, sustainable, and robust power system. The evaluation has painted a landscape of risks and benefits associated with different Danish power system mixes, representing technology focused directions. The analysis has highlighted a Nuclear and an Offshore direction.

The Nuclear direction was shown to provide increased level of self-sufficiency, low electricity prices and volatility, and lowest risks concerning operational safety and grid upgrade costs on the upside. Cost escalation was identified as a critical risk also involving directed support to ensure profitability.

The Offshore direction highlighted competitive prices and lower-price volatility alongside low-cost escalation. On the downside, the Offshore direction illuminated risks associated with a lower level of self-sufficiency, higher costs and considerable vulnerability to market profitability alongside increasing grid upgrade costs, minerals use and reliance on emerging technologies to maintain system stability under very high shares of inverter-based generation.⁹⁶

It is very important to emphasise that all scenarios heavily rely on wind power. Incorporating uncertainties and beyond model analysis quantifications, reveals further complementary aspects between the Nuclear and Offshore directions. Relative nuclear, the role of offshore wind increases at more limited demand growth scenarios, and it is more capable to respond to near-term capacity needs. Both nuclear and offshore wind technologies rely on favourable cost reductions that in turn rely on strong support for the industries and state intervention to provide suitable conditions for positive development, ultimately meaning supportive energy policies.

One of the key insights from the study is that Denmark's large interconnectivity, relative to its system size, makes domestic market foundations, average prices, volatility, market

⁹⁶ Capabilities such as grid-forming inverters and synthetic inertia, which substitute for the rotational inertia and other ancillary services provided by synchronous machines, are still maturing at the scales required.

revenues, strongly dependent on European market development. From an actor's perspective, project profitability therefore sits largely in the hands of factors outside Denmark's control, and these factors will themselves vary strongly over time in a liberalised market. From a policy perspective, the same exposure operates one level up. The evolving European energy transition, driven by electrification, carbon pricing, and regional coordination on cross-border interconnection, increasingly governs both the demand for power and the constraints on cross-border exchange. The trajectory of the wider European power system therefore carries direct consequences for the Danish system, adding to the actor-level exposure noted above.

The employed methodology in the current work is itself a response to the uncertainties just described. Rather than identifying a single cost-optimal pathway, a framing that would imply more precision than the underlying cost and market assumptions can support over a 2050 horizon, the current study evaluates qualitatively distinct system configurations across multiple dimensions: what each configuration requires of policy and industry, what capabilities it brings to system operation, what benefits it delivers, and which risks it exposes Denmark to. The contribution lies in the comparative evaluation across directions rather than in the selection of one as cheapest. We hold that emphasising system performance and the capabilities that different technology mixes bring is more useful to long-horizon policy than a single cost ranking that masks the choices underneath it.

The study is bounded in scope. Demand growth scenarios could deserve further scrutiny, and an analysis of varying development of neighbouring regions and transmission lines could provide further insights. It models the year 2050 only and does not assess transition pathways or path dependencies between the present and 2050. It treats grid upgrade costs as a proxy based on standardised connection charges rather than through full network modelling under stressed operating conditions. It examines the day-ahead energy market and includes resource adequacy through the capacity requirement adjustment, and only implicitly incorporate model frequency regulation, ancillary services markets, or preparedness capabilities (including islanding or restoration) as part of discussions. These dimensions are recommended for follow-up work.

To conclude, the objective of this work has been to provide a transparent, technology-neutral, and analytically grounded foundation for policy discussion on Denmark's long-term energy system development. Rather than identifying a single optimal configuration, a framing that in any case implies more precision than the underlying uncertainties can bear, the analysis made visible where the uncertainty sits in each direction. For instance, on capital cost and project delivery for nuclear and on revenue exposure for offshore. The intended contribution has been to move the policy conversation away from a binary choice between technologies and toward a comparison of what each system configuration requires, what capabilities it brings to system operation, and how its risks are distributed. We hope that this work drive fruitful policy discussions on Denmark's energy system development.

Appendix A Formulas

The Levelised Cost of Electricity (LCOE) is a metric used to determine the average cost of producing one 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 standardised measure of the cost of electricity. Here is how LCOE is calculated, broken down into its key components:

1. Overnight Cost (€/MW):

The overnight capital cost represents the sum of construction costs and associated grid investments relating to direct transmission lines (relevant for offshore wind). Indirect reinforcement of transmission and distribution grids is *not* included here.

$$\text{overnight_capital_cost} = \text{overnight_capital_cost_base} + \text{grid_cost}$$

2. Construction Financing Cost (€/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.

$$\text{construction_interest_rate} = \text{WACC} / 2$$

$$\begin{aligned} \text{construction_financing_cost} &= \text{overnight_capital_cost} \\ &\quad * (1 + \text{construction_interest_rate})^{\text{construction_duration}} \\ &\quad - \text{overnight_capital_cost} \end{aligned}$$

3. Investment Cost (€/MW):

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

$$\text{investment_cost} = \text{construction_financing_cost} + \text{overnight_capital_cost}$$

4. Annuity Factor:

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

$$\text{annuity_factor} = \frac{\text{WACC} * (1 + \text{WACC})^{\text{capital_recovery_period}}}{(1 + \text{WACC})^{\text{capital_recovery_period}} - 1}$$

5. Annual Costs (€/MW/yr):

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

$$annual_investment_cost = investment_cost * annuity_factor$$

$$annual_fixed_OM = fixed_OM + reinvestment$$

6. Marginal Cost of Electricity (€/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 (€/MWh) is calculated according to:

$$\begin{aligned} fuel_price_per_MWh_with_upstream_emissions \\ &= fuel_price_per_MWh + (CO2_price \\ &* CO2_emission_coefficient_upstream * heat_rate) \end{aligned}$$

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:

$$\begin{aligned} marginal_cost_of_electricity + \\ &= CO2_price * CO2_emission_coefficient * heat_rate * (1 \\ &- carbon_capture_efficiency) \end{aligned}$$

7. Full Load Hours (hours):

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

$$full_load_hours = 8760 * capacity_factor$$

8. LCOE (€/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 Power system in 2025

Figure 64 presents the dispatch in the two Danish bidding zones for the installed capacity in the Danish as well as the European power system in 2025 but simulated for the historical weather conditions of 1985-01 event. Event in 2025's power system is much less challenging compared to 2050 scenarios, with elevated prices but only peaking at around 200 €/MWh. The event is managed well thanks to lower weather dependency and higher share of installed dispatchable capacity relative to demand. This holds for both Denmark and its neighbouring regions.

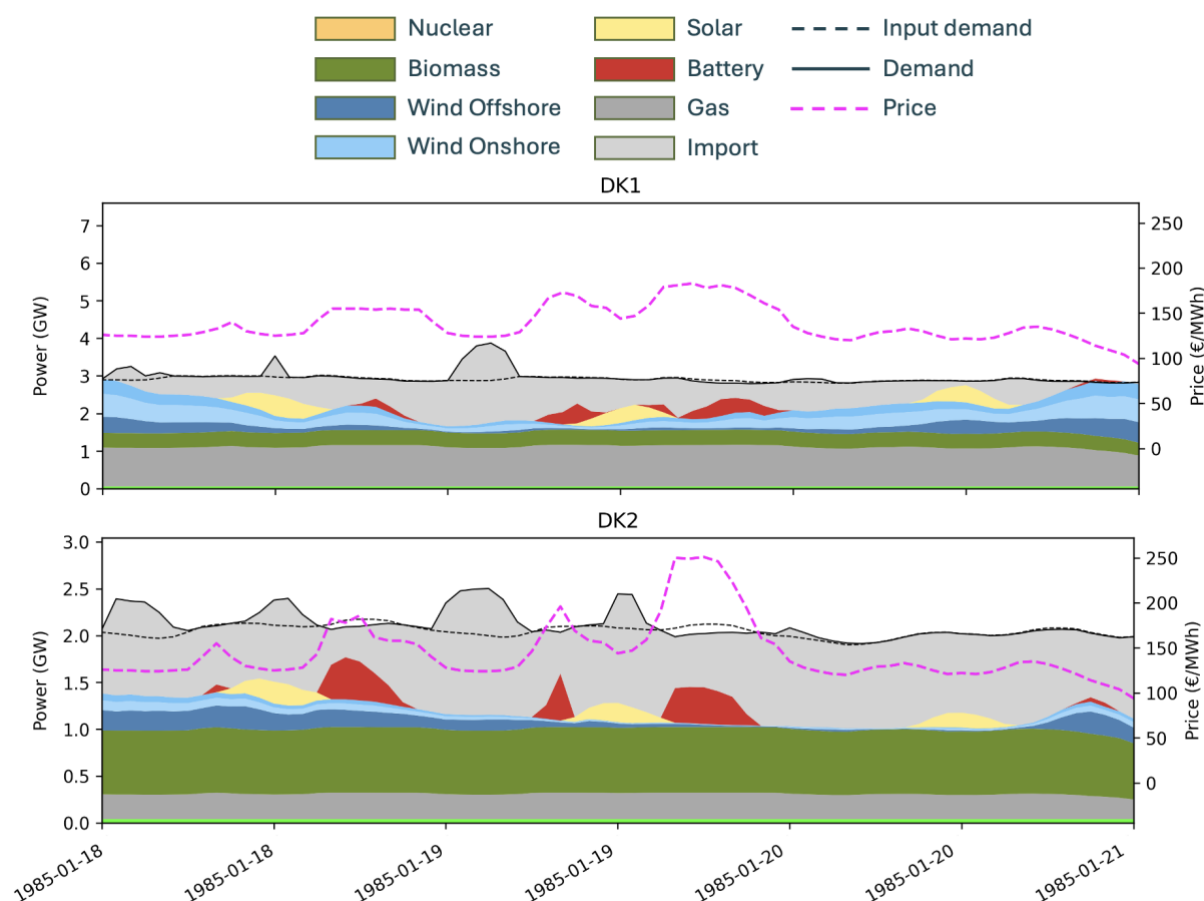


Figure 64. Dispatch in the two Danish bidding zones for different technologies, as indicated by the legend, of the challenging event of January weather year 1985 for the 2025 power system. Input demand is the realised demand at a flat price of 75 €/MWh.

The power balance for the event is presented in Figure 65. The event displays import dependency (stands for ~27%), but with a considerable portion of capacity in reserve (supply capacity not activated or in reserve) the system has margin. Even to handle largest fault (N-1). We have assumed an installed capacity of dispatchable power from CHP plants according to AF25⁹⁷. Normal operation biomass CHP plants are assumed in

⁹⁷ Energistyrelsen (2025), Analyseforudsætning til Energinet 2025 (AF25).

the model to not provide peaking capabilities which means there is potentially capacity not activated in the simulation of the 1985 event. Remaining biomass CHP, centralised and decentralised, which could be called for peaking operation have been determined according to derating capacity factor 0.77⁹⁸ to 2119 MW, denoted reserves in the figure.

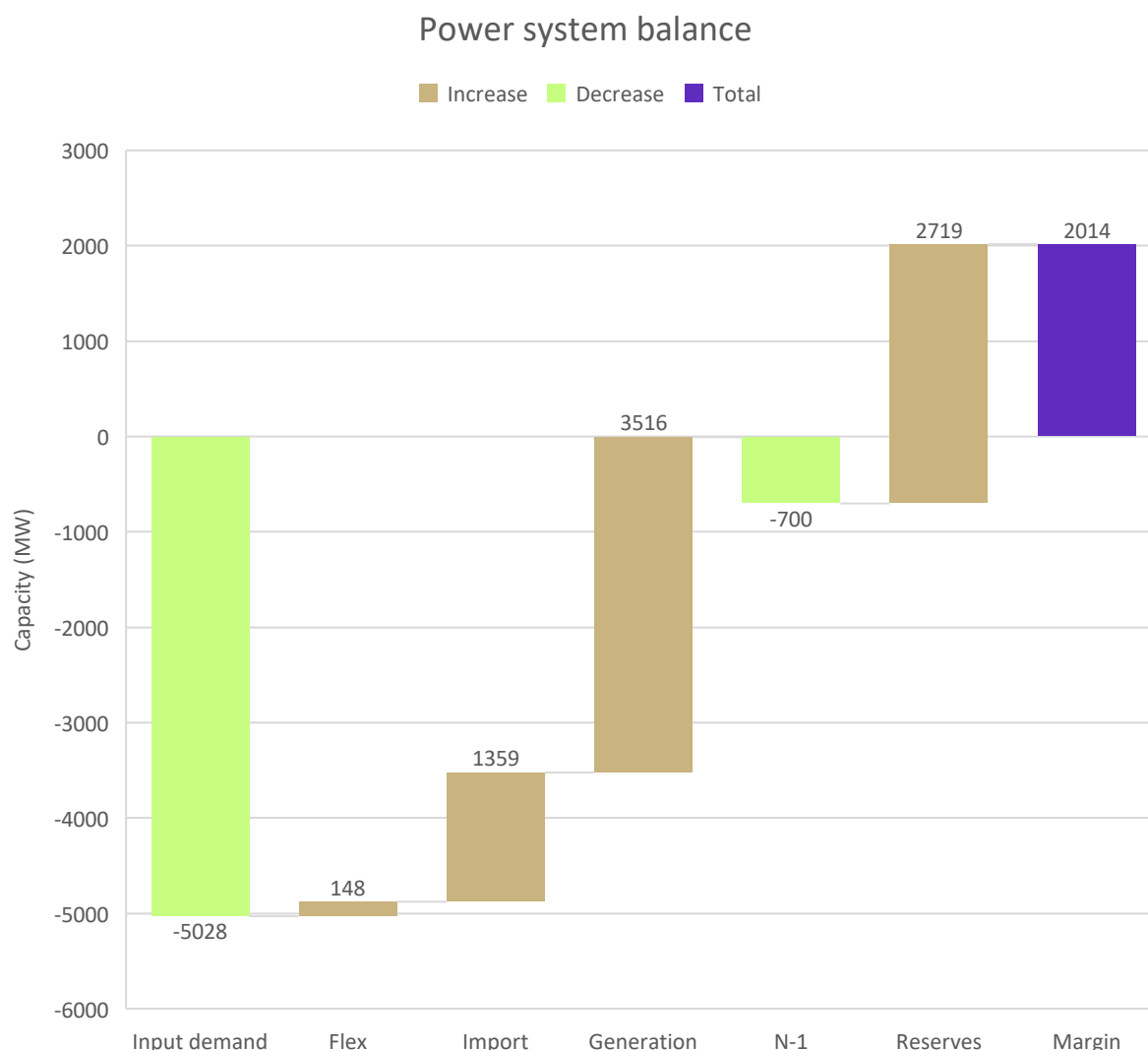


Figure 65. Power system balance in the Danish power system split up by components in for the 2025 power system for the 1985-01 event.

Self-sufficiency measured by demand coverage for the 1000 worst hours for the Danish power system in 2025 is presented in Figure 66. Self-sufficiency during the worst 1000 hours across all weather years in model year 2025 for selected European countries.. Compared to other European countries, Denmark's self-sufficiency during critical hours is mid-range. Hydro-dominated systems (in particular Norway followed by Sweden) show consistently high self-sufficiency, reflecting the buffering effect of reservoir storage. Similarly, large systems with diversified generation mixes (e.g. France or Germany) tend

⁹⁸Energimyndigheten (2023), Förslag till en fjärrvärme-och kraftvärmestrategi.

to achieve higher minimum levels due to a combination of nuclear, thermal, and renewable resources. By contrast, Denmark; like other smaller, highly renewable systems; shows greater sensitivity to weather-driven variability, with wider spreads between minimum and maximum self-sufficiency. This indicates a stronger dependence on cross-border exchanges.

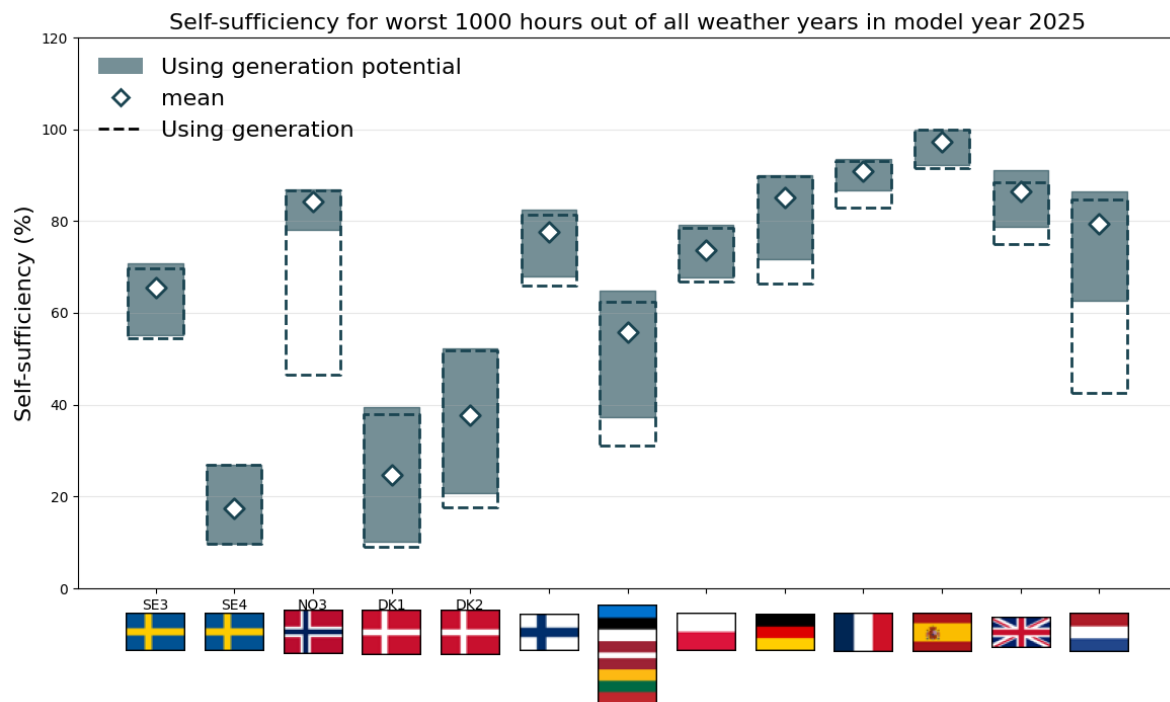


Figure 66. Self-sufficiency during the worst 1000 hours across all weather years in model year 2025 for selected European countries.

Appendix C Offshore

The offshore wind potential in Denmark has been divided into three distinct categories which will vary in the grid connection cost. These categories are in line with the Danish Energy Catalogue. Given that the water depth⁹⁹ of the zones designated for offshore wind deployment^{100, 101} does not exceed 60 meters (Figure 67) the floating category was discarded. Consequently, the categories are distinguished by their distance to the shore with Nearshore being less than 15 km, Offshore from 15 to 60 km and Farshore exceeding 60 km. Further, the respective categories were assigned based on zone proximity to DK1 and DK2, with Bornholm region being assigned to DK2 by default. The cumulative maximum potential per zone and technology is presented in Table 21.

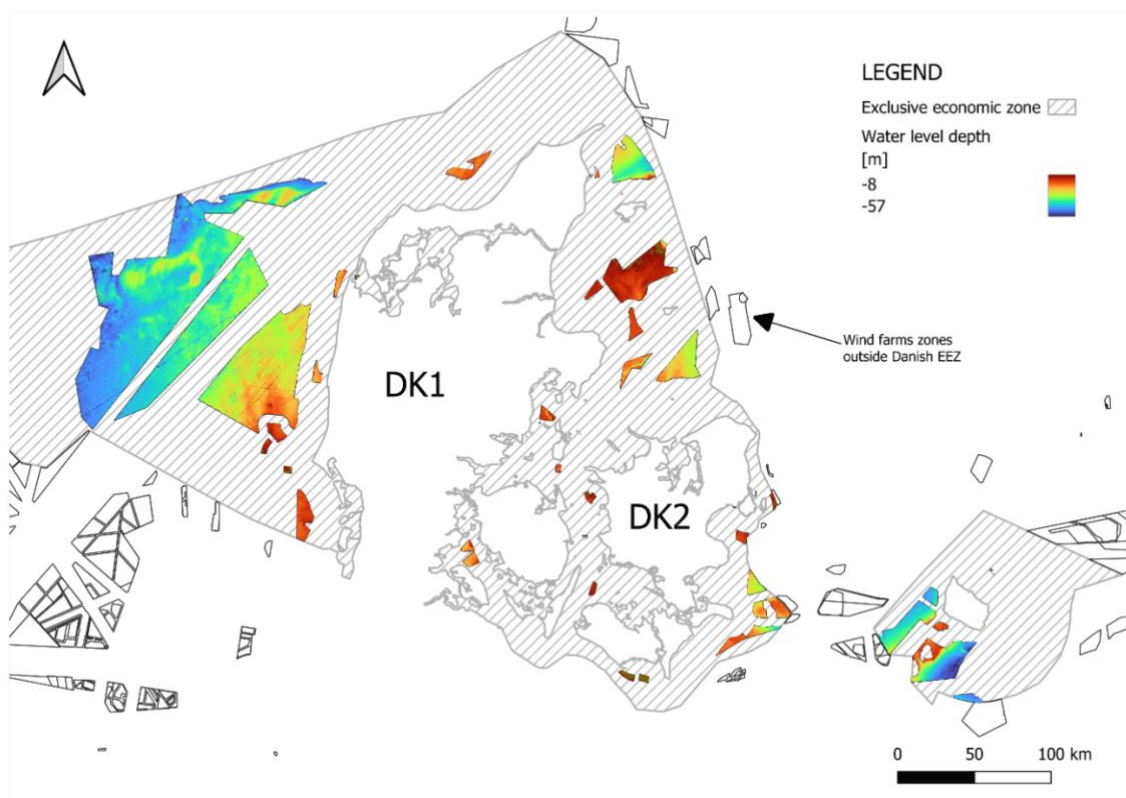


Figure 67. Location of potential areas for offshore wind deployments in the Danish Exclusive Economic Zone (EEZ) juxtaposed with the water depth.

⁹⁹ General Bathymetric Chart of the Oceans (2026), Gridded Bathymetry Data

¹⁰⁰ EnergyData.Info (2026), Offshore Wind Technical Potential

¹⁰¹ Marine Analyst (2026), Wind Farms *Polygons

Table 21. Technology specific capacity expansions potential in DK1 and DK2 zones.

Technology	DK1 [GW]	DK2 [GW]	Distance [km]
Nearshore	4.4	6.7	≤ 15
Offshore	23.0	1.6	15-60
Farshore	25.9	0.0	≥ 60

The reasoning behind the distance-specific offshore subcategories to shore was based on the analysis of offshore projects at various stages (for example: operational, retired or shelved)¹⁰². Considering the land masses database¹⁰³ and global bathymetry¹⁰⁴ it was estimated that the projects with “operating” status in Europe has an average distance to shore of 12.3 km and are installed at depth of ~27.5 m. The projects under construction (excluding Dogger Bank) are placed 45 km away from the shore while the average distance of all projects is currently 60 km.

¹⁰² Global Energy Monitor (2026), Global Wind Power Tracker

¹⁰³ Open Street Maps (2026), Data Derived from OpenStreetMap for Download

¹⁰⁴ General Bathymetric Chart of the Oceans (2026), Gridded Bathymetry Data

Appendix D Technology cost assumptions

D.1 Solar PV

D.1.1 Past trends and projections

Global utility-scale PV costs have declined rapidly since the mid-2010s, driven by sustained module price reductions, manufacturing scale-up, and balance-of-system learning, as documented by IRENA.¹⁰⁵ The historical data, shown in Figure 68, show a steep downward trend followed by a gradual flattening of the cost curve in recent years. Forward projections from major outlooks (e.g., IEA WEO.¹⁰⁶) indicate continued but more moderate cost reductions toward 2050, reflecting technology maturation and partial offset from rising soft costs and grid integration requirements. The shaded band illustrates the historical global cost range reported by IRENA.

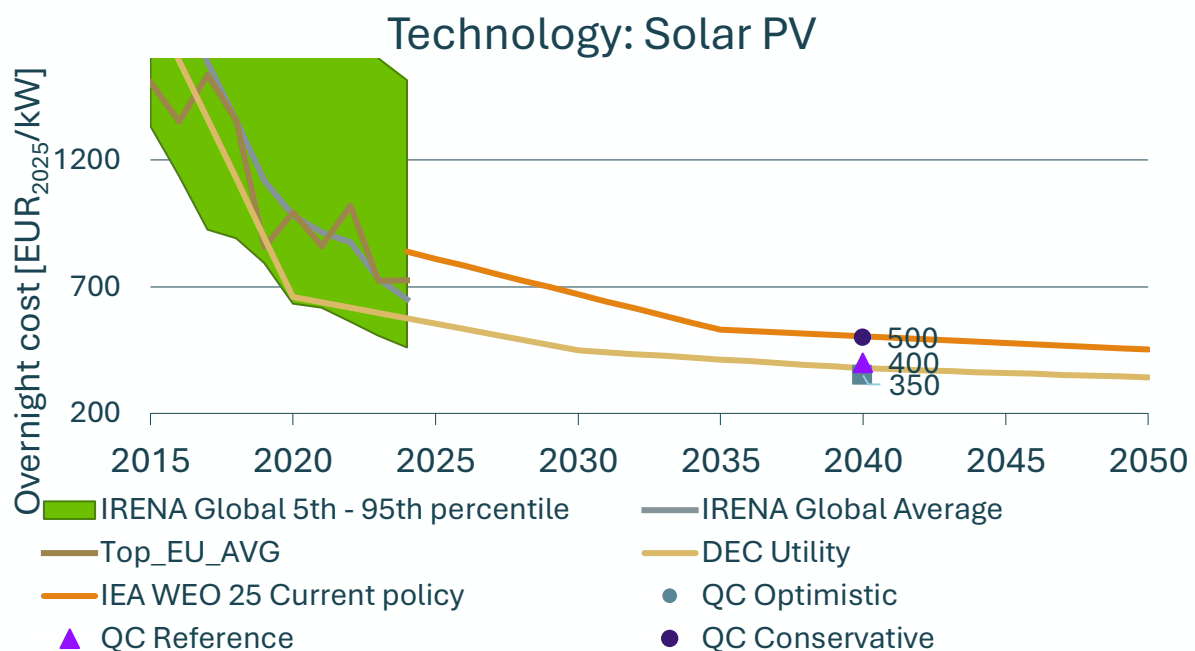


Figure 68. Historical and projected overnight capital cost trajectory for utility-scale solar PV.

Figure 69 shows the LCOE for utility scale solar based on global averages. The global weighted average shows quite competitive production costs at around 43 EUR/MWh. Adjusted production costs based on Danish conditions produces an LCOE level of 63 EUR/MWh providing an indication of current status of utility solar in Denmark.

¹⁰⁵ International Renewable Energy Agency (2025), Renewable Power Generation Costs in 2024

¹⁰⁶ International Energy Agency (2025), World Energy Outlook 2025

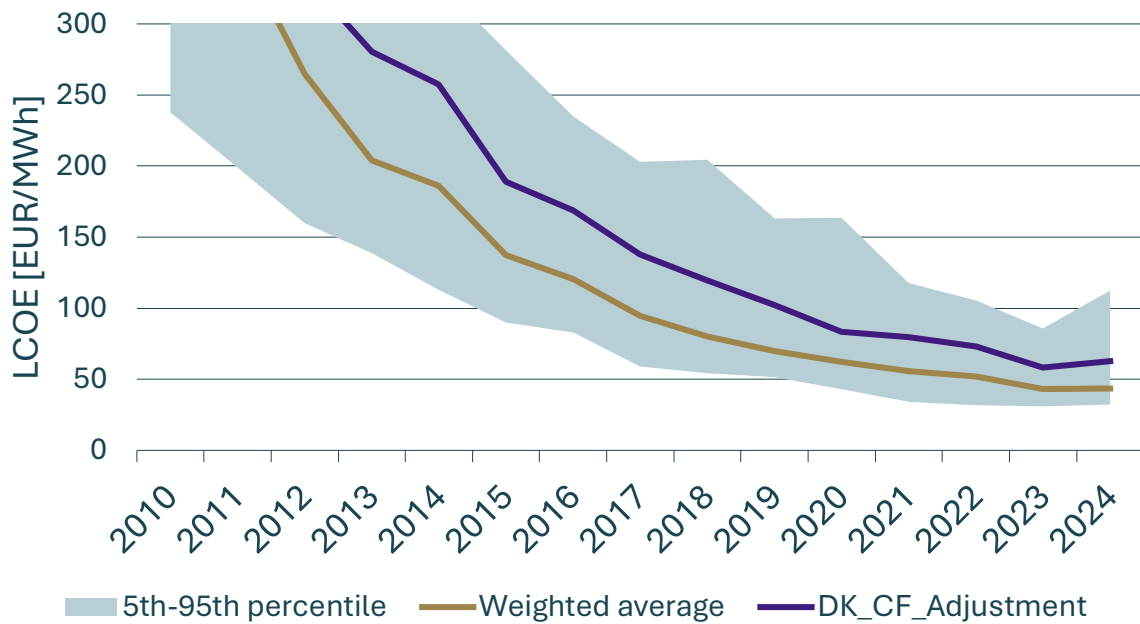


Figure 69. Trajectory of global (Weighted average) LCOE for utility scale PV systems and adjustment (DK_CF_Adjustment) for local solar conditions in Denmark. Based on: IRENA¹⁰⁷.

D.1.2 Technology development scenario reasoning

Within each development pathway, the distinction between the scenarios (Conservative-2 vs Conservative-1, Optimistic-1 vs Optimistic-2) is driven by different WACC assumptions, while system size, installation concept, supply-chain conditions, and grid cost assumptions are kept constant.

Optimistic: In this scenario the lower WACC is supported by stable Danish/EU support schemes and strong PPA market. Normalized global PV supply chain keeps equipment prices structurally low.

Conservative: In the conservative scenario the higher financing costs stem from higher demand. Furthermore, grid congestion and rising connection costs are observed high. Additionally, the investment process is slowed down due to permitting and land-use constraints.

Reference: The gradual cost decline results from ongoing efficiency improvements. The market situation is stable but only a modest improvement is observed in financing and grid costs.

D.1.3 Cost assumptions

The assumed techno-economic parameters and resulting LCOE for utility-scale solar PV in Denmark across five financing and cost scenarios (from Conservative-2 to Optimistic-

¹⁰⁷ International Renewable Energy Agency (2025), Renewable Power Generation Costs in 2024

2). The analysis assumes a short construction time (0.5 years), a 40-year lifetime, zero variable O&M and fuel costs, and fixed O&M of 13.2 EUR/kW/yr, primarily based on Danish Energy Agency data. The capacity factor is held constant at 12% across scenarios, while the main drivers of LCOE variation are the assumed overnight capital cost (350–550 €/kW) and the weighted average cost of capital (4–8%). Under these assumptions, the calculated LCOE declines from 62 EUR/MWh in the most conservative case to 33 EUR/MWh in the most optimistic case, highlighting the strong sensitivity of PV economics to financing conditions and capital expenditure in the Danish context. The LCOE values reported in [Table 22](#) align well with the IRENA report ([Figure 69](#)).

Table 22. Assumed techno-economic parameters and levelized cost of electricity (LCOE) for solar PV across scenario variations.

Parameter	Conservative-2	Conservative-1	Reference	Optimistic-1	Optimistic-2	Reference
WACC [%]	8	6	6	6	4	SNL
Overnight cost [EUR/kW]	550	550	400	350	350	DEA
Construction duration [yr]	0.5	0.5	0.5	0.5	0.5	DEA
Fixed OM [EUR/kW/yr]	13.2	13.2	13.2	13.2	13.2	DEA
Variable OM [EUR/MWh]	0	0	0	0	0	-
Fuel cost [EUR/MWh]	0	0	0	0	0	-
Capacity factor [%]	12	12	12	12	12	DEA*
Lifetime [yr]	40	40	40	40	40	DEA
Capital recovery period [yr]	26.7	26.7	26.7	26.7	26.7	-
LCOE [EUR/MWh]	62	53	42	38	33	-

* 12% is CF_DC net of curtailment and marginal siting for 2040 which is different from originally reported 14% by DEA.

D.1.4 Technology specific modelling assumptions

In the updated modelling framework, residential and commercial solar PV capacities are treated as exogenous inputs. These installations are assumed rather than optimized within the model. In addition, the model retains the ability to additionally invest in further solar capacity where it is economically justified, allowing for market-driven expansion beyond the predefined baseline.

D.2 Onshore wind

D.2.1 Past trends and projections

The historical and projected CAPEX trajectory, presented in [Figure 70](#) shows that onshore wind investment costs have declined substantially since 2010. Looking toward 2040–2050, most institutional projections converge toward a moderate cost stabilization range between approximately 1,100 and 1,300 EUR/kW in real terms. Breakthrough cost reductions comparable to the previous decade are not widely expected. Instead, incremental efficiency gains and repowering effects are likely to improve project

economics more through performance enhancement (higher energy yield per turbine) than through dramatic CAPEX reduction.

Technology: onshore wind

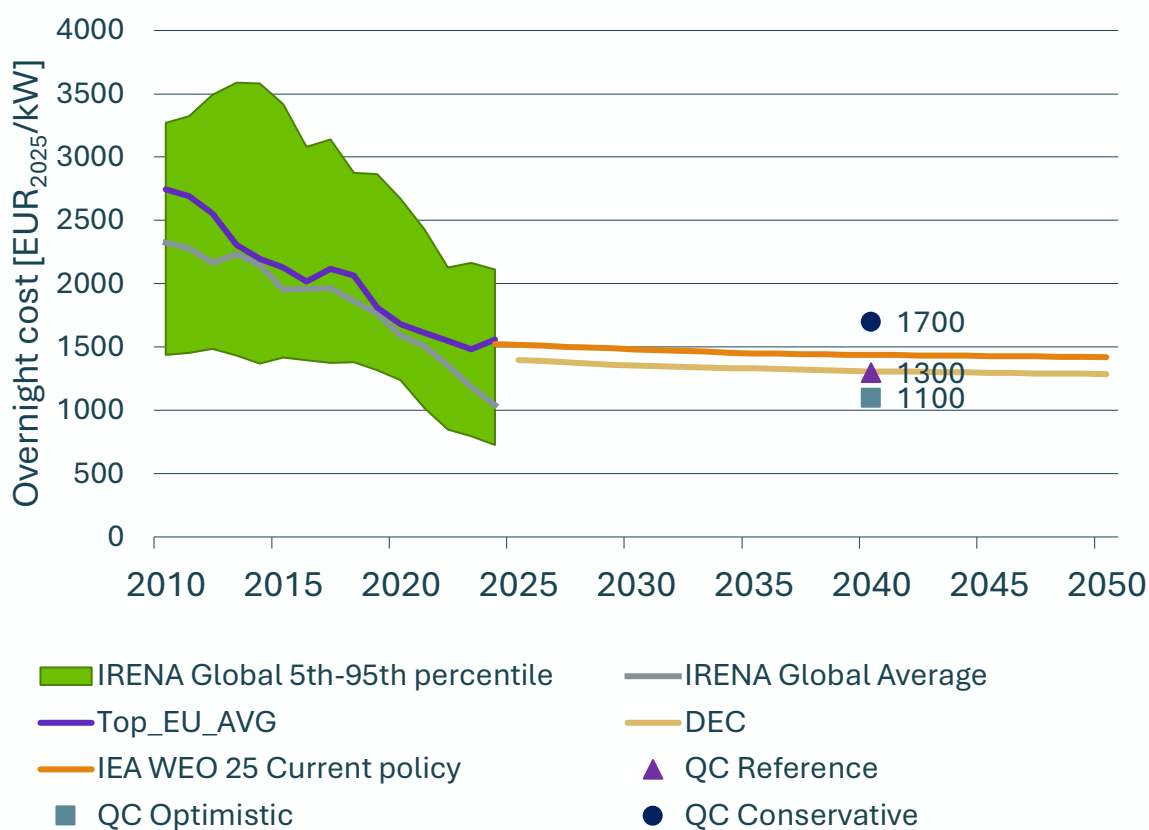


Figure 70. Historical and projected overnight capital cost trajectory for onshore wind.
Source: IRENA¹⁰⁸, IEA WEO¹⁰⁹.

¹⁰⁸ International Renewable Energy Agency (2025), Renewable Power Generation Costs in 2024

¹⁰⁹ International Energy Agency (2025), World Energy Outlook 2025

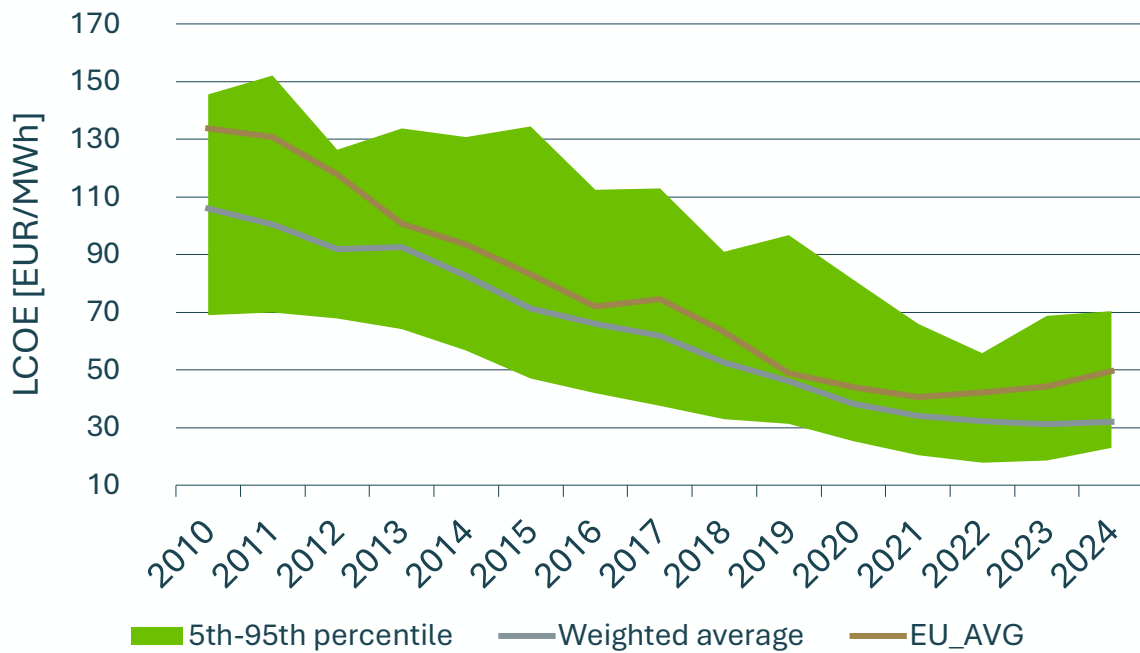


Figure 71. Trajectory of global (Weighted average) LCOE for global onshore and EU average for five top countries. Based on: IRENA¹¹⁰.

D.2.2 Technology development scenario reasoning

Optimistic: Accelerated repowering of existing wind sites with larger, more efficient turbines. Improved permitting processes and clearer municipal planning frameworks. Moderate industrial learning and supply-chain stabilization keeping turbine prices competitive.

Conservative: Permitting constraints and local opposition limiting new site development. Increased turbine and installation costs due to supply-chain volatility. Elevated financing costs reflecting regulatory and siting uncertainty.

Reference: Gradual repowering of aging wind parks with incremental turbine efficiency improvements. Limited but stable pipeline of new projects subject to existing spatial constraints. Moderately stable equipment costs and financing conditions.

D.2.3 Cost assumptions

The analysis assumes (Table 23) a short construction period of 1.5 years, a 35-year technical lifetime, fixed O&M of 18.8 EUR/kW/yr, variable O&M of 2.2 EUR/MWh, zero fuel cost, and a constant capacity factor of 38% across all scenarios. The primary drivers of LCOE variation are the assumed overnight capital cost (1,100–1,700 €/kW) and the weighted average cost of capital (4–8%). Under these assumptions, the calculated LCOE

¹¹⁰ International Renewable Energy Agency (2025), Renewable Power Generation Costs in 2024

declines from 59.8 EUR/MWh in the most conservative case to 30.6 EUR/MWh in the most optimistic case. As with other capital-intensive technologies, onshore wind economics remain highly sensitive to financing conditions, though the overall cost spread is narrower than for offshore wind or nuclear due to shorter construction times and lower capital intensity. The [Figure 71](#) confirms the results, showing a decline in onshore wind LCOE from ~60 to ~30 EUR/MWh, consistent with the calculated range (56–31 EUR/MWh).

Table 23. Assumed techno-economic parameters and levelized cost of electricity (LCOE) for onshore wind across scenario variants.

Parameter	Conservative-2	Conservative-1	Reference	Optimistic-1	Optimistic-2	Reference
WACC [%]	8	6	6	6	4	SNL
Overnight cost [EUR/kW]	1700	1700	1300	1100	1100	DEA
Construction duration [yr]	1.5	1.5	1.5	1.5	1.5	DEA
Fixed OM [EUR/kW/yr]	18.8	18.8	18.8	18.8	18.8	DEA
Variable OM [EUR/MWh]	2.2	2.2	2.2	2.2	2.2	DEA
Fuel cost [EUR/MWh]	0	0	0	0	0	-
Capacity factor [%]	38	38	38	38	38	DEA
Lifetime [yr]	35	35	35	35	35	DEA
Capital recovery period [yr]	23.3	23.3	23.3	23.3	23.3	-
LCOE [EUR/MWh]	60	51	41	36	31	-

D.2.4 Technology-specific modelling assumptions

In the modelling framework, future onshore wind expansion in Denmark is assumed to be driven primarily by repowering of existing wind parks rather than large-scale development of new sites. This reflects spatial planning constraints, local acceptance challenges, and the limited availability of high-quality new locations. As a result, capacity additions are modeled mainly as replacement of older turbines with fewer, larger, and more efficient units at established sites, leading to higher energy yield without substantial expansion of occupied land area. The upper bound is set to 7 GW which corresponds to the 1000 meters scenario presented by Joint Research Centre¹¹¹ report.

¹¹¹ Joint Research Centre (2025), The Onshore Wind Potential of the EU and Neighbouring Countries

D.3 Offshore wind

D.3.1 Past trends and projections

Offshore wind overnight capital costs, as presented in Figure 72, show a clear long-term downward trend. In the early 2010s, costs were high and widely dispersed, reflecting strong project heterogeneity and a still-maturing industry. Between 2010 and 2020, the IRENA average declines markedly, accompanied by a narrowing percentile range, indicating technological learning and increasing standardization. From the mid-2020s onward, projections from IEA WEO 2025 (Current Policies) and the Danish Energy Agency (DEC, Offshore AC Fixed) suggest continued cost reductions, though at a slower pace than in the previous decade. By 2040–2050, costs converge toward roughly 2,200–2,500 EUR/kWC, with the DEC trajectory slightly below the IEA pathway, implying somewhat stronger cost improvements under the Danish technology catalogue assumptions.

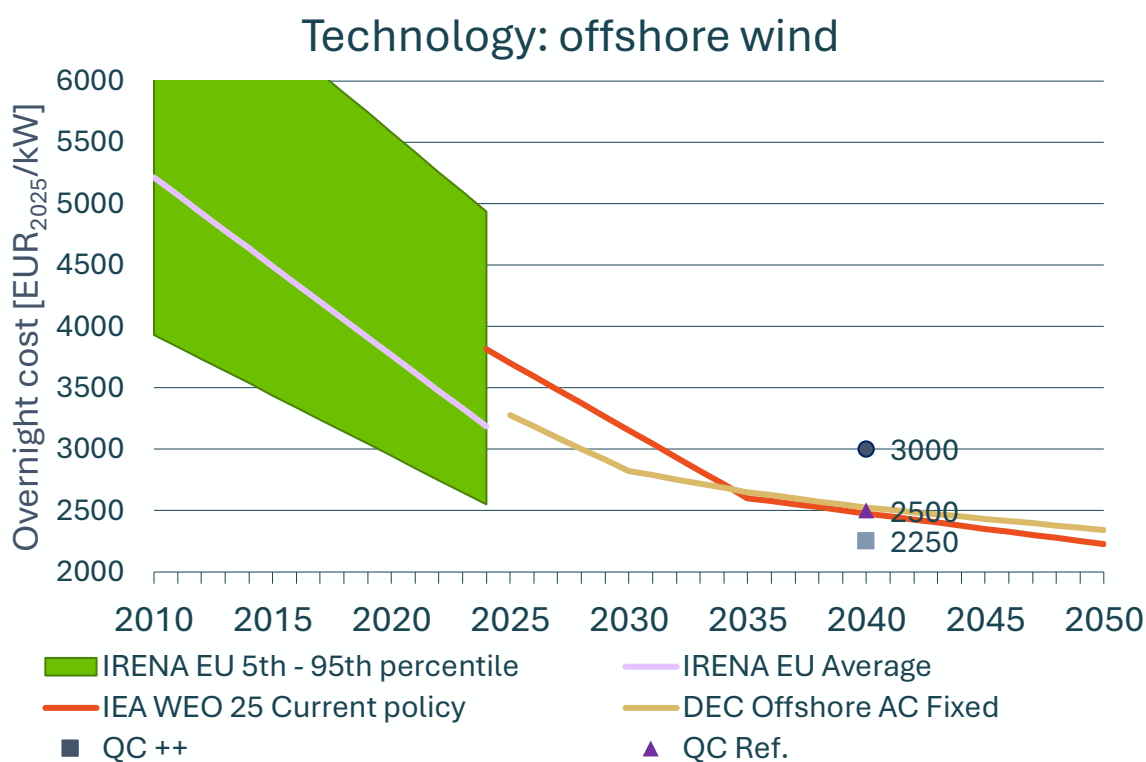


Figure 72. Historical and projected overnight capital cost trajectory for offshore wind.
Source: IRENA¹¹², IEA WEO¹¹³.

¹¹² International Renewable Energy Agency (2025), Renewable Power Generation Costs in 2024

¹¹³ International Energy Agency (2025), World Energy Outlook 2025

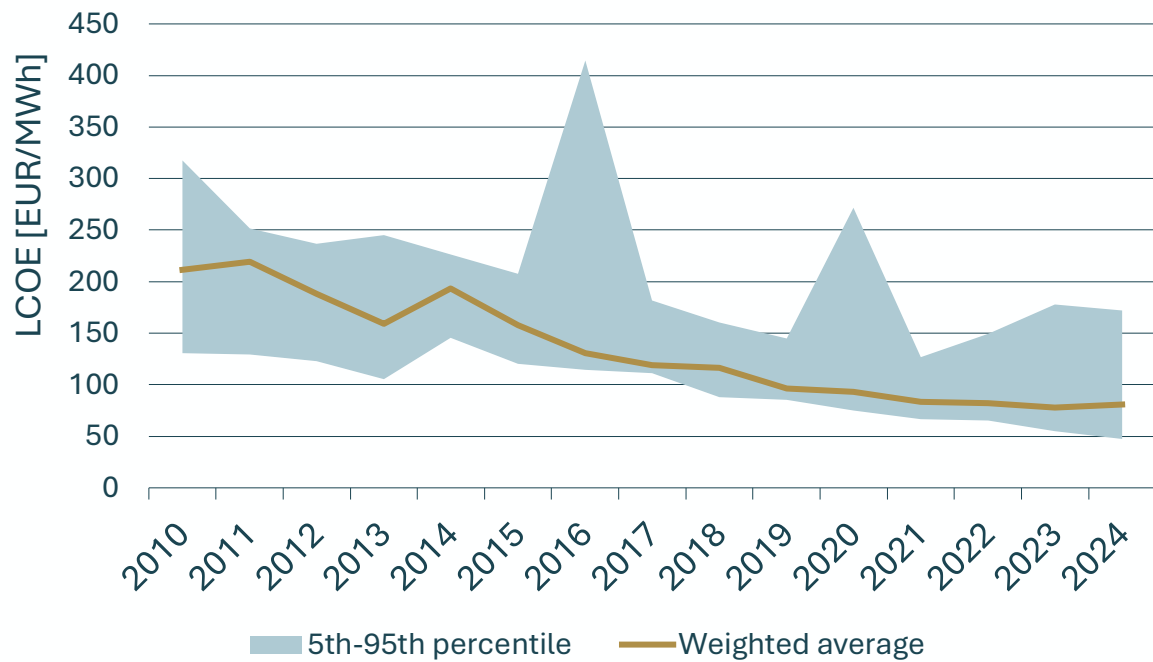


Figure 73. Trajectory of global (Weighted average) LCOE for offshore wind, based on IRENA¹¹⁴.

D.3.2 Technology development scenario reasoning

Optimistic: In this scenario the lower cost of capital stability (reduced risk premiums, clearer CfD frameworks, stable permitting regime in DK). Supply-chain normalization and scale effects (larger turbines 18-20+ MW, serial production, industrial learning) combined with standardized foundations and installation methods.

Conservative: Supply-chain bottlenecks (installation vessels, cables, substations), slower permitting and tighter environmental constraints.

Reference: Gradual efficiency improvements in installation practices and turbine performance. Moderate normalization of input costs (steel, vessels, turbines) without major structural breakthroughs.

D.3.3 Cost assumptions

The assumed (Table 24) techno-economic parameters and resulting LCOE for offshore wind in Denmark are evaluated across five financing and cost scenarios (from Conservative-2 to Optimistic-2). The analysis assumes a 1.5-year construction period, a 20-year capital recovery period, constant variable O&M and zero fuel costs, and a capacity factor of 48% across all scenarios. Fixed O&M varies between 25–35 EUR/kW/yr depending on the scenario. The primary drivers of LCOE variation are the assumed

¹¹⁴ International Renewable Energy Agency (2025), Renewable Power Generation Costs in 2024

overnight capital cost (1,750–3,400 EUR/kW, including grid connection) and the weighted average cost of capital (4–8%). Under these assumptions, the LCOE ranges from 99 EUR/MWh (farshore, most conservative) to 40 EUR/MWh (nearshore, most optimistic), illustrating the strong sensitivity of offshore wind economics to financing conditions and capital expenditure.

In addition to nearshore projects (less than 15 km from shoreline), the analysis distinguishes offshore and farshore configuration (respectively 15-60 km from the shore and more than 60 km), where higher transmission and grid connection costs are included (assumed at $56.8 + 8.5 \cdot D$ where D is the distance to shore in km as in Jonasson et al.¹¹⁵). The [Figure 73](#) reflects to an extent the increasing LCOE of projects located further from shore, consistent with the assumption that the most favourable nearshore sites have already been exploited. As development moves to more distant and deeper locations, higher grid connection and installation costs contribute to the wider cost spread. The considered Reference value of the LCOE is lower compared to the historical one reported by IRENA ([Figure 73](#)) indicating further technological development.

¹¹⁵ Jonasson et al., (2026) Global techno-economic assessment of hybrid offshore wind, wave, and solar power

Table 24. Assumed techno-economic parameters and levelized cost of electricity (LCOE) for offshore wind across scenario variations (Grid costs based on distance and cost per km as in Satymov et al.¹¹⁶ & Lopez et al.¹¹⁷).

Parameter	Conservative-2	Conservative-1	Reference	Optimistic-1	Optimistic-2	Reference
WACC [%]	8	6	6	6	4	SNL
Overnight cost [EUR/kW]	2500	2500	2000	1750	1750	DEA
Construction duration [yr]	1.5	1.5	1.5	1.5	1.5	DEA
Fixed OM [EUR /kW/yr]	35	35	30	25	25	DEA
Variable OM [EUR /MWh]	3	3	3	3	3	-
Fuel cost [EUR /MWh]	0	0	0	0	0	-
Capacity factor [%]	48	48	48	48	48	DEA
Lifetime [yr]	30	30	30	30	30	DEA
Capital recovery period [yr]	20.0	20.0	20.0	20.0	20.0	-
Grid cost	0.0	0.0	0.0	0.0	0.0	GC
Total overnight cost [EUR /kW]	2500	2500	2000	1750	1750	DEA
LCOE nearshore [EUR /MWh]	76	66	53	47	40	-
Grid cost	500.0	500.0	500.0	500.0	500.0	GC
Total overnight cost [EUR /kW]	3000	3000	2500	2250	2250	DEA
LCOE offshore [EUR /MWh]	88	76	64	58	50	-
Grid cost	900.0	900.0	900.0	900.0	900.0	GC
Total overnight cost [EUR /kW]	3400	3400	2900	2650	2650	DEA
LCOE farshore [EUR /MWh]	99	85	73	66	57	-

D.3.4 Technology specific modelling assumptions

Please refer to [Appendix C](#) for further details on offshore wind modelling and capacity limits.

¹¹⁶ Satymov et al., (2025), Techno-economics of offshore wind power in global resolution

¹¹⁷ Lopez et al., (2024), Ocean energy enabling a sustainable energy-industry transition for Hawai'i

D.4 Nuclear – Small Modular Reactors (SMRs)

D.4.1 Current estimates and projections

The projected overnight capital costs for small-modular nuclear reactors is presented in Figure 74. SMR costs exhibit a pronounced downward trajectory toward 2050 but remain associated with high uncertainty. Except for ATB 2024, initial costs in 2030-2035 seem to agree rather well to a range 8,000- 10,000 EUR/kW reflecting first fleet of SMRs deployed in western countries. Development beyond 2035 and towards 2050 span a rather broad range roughly from 2,000–9,000 EUR/kW – reflecting fundamentally different assumptions regarding learning rates, supply chain development, standardisation, and deployment scale. Compared to mature technologies such as wind, solar PV, or batteries; where cost trajectories are supported by decades of deployment data; SMR projections rely heavily on expectations of future industrialisation rather than demonstrated cost performance.

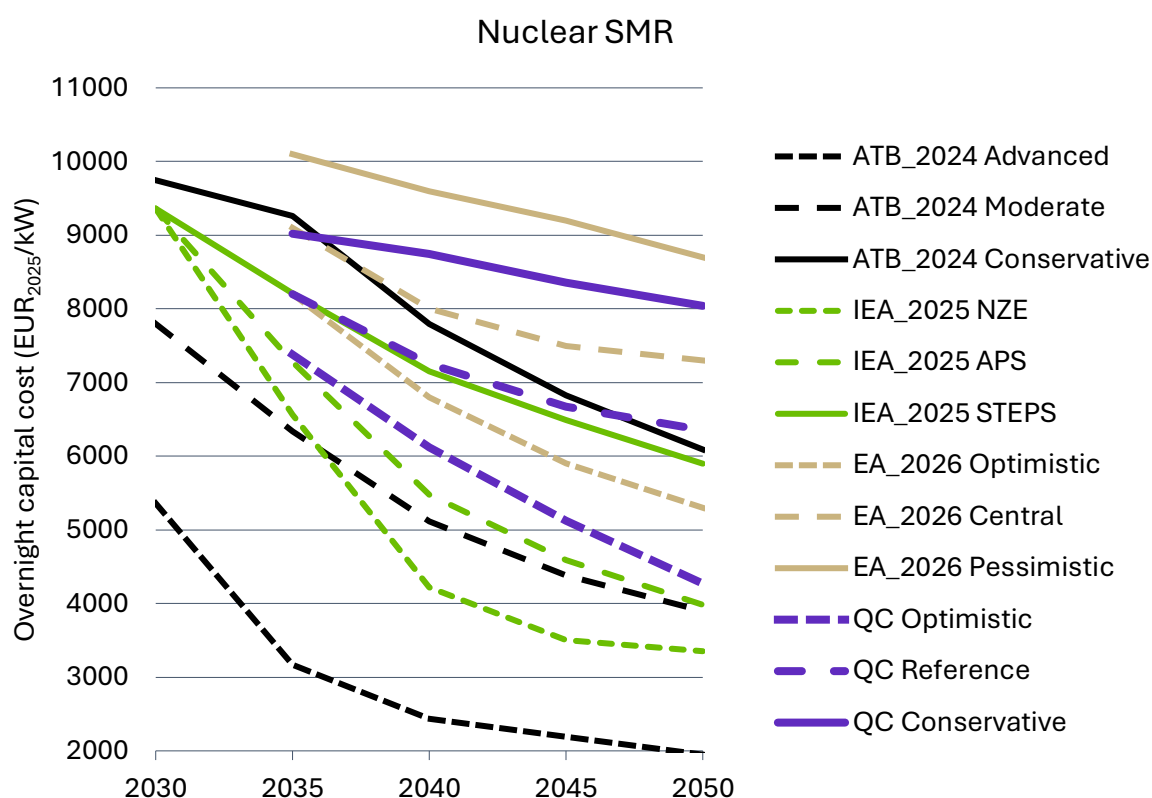


Figure 74. Comparison of small-modular nuclear reactor overnight capital costs in the present study with those from other references, as specified in the legend.

The projected overnight capital costs large-scale conventional nuclear projects is presented in Figure 75. The current study considers only the construction of SMRs in the Danish energy system. However, the data is relevant to highlight recent project costs and how they relate to projected costs. Importantly, Olkiluoto 3, Barakah 1-4, Flamanville 3 and Hinkley Point C, all represent first-of-a-kind-like projects, and they do demonstrate a very wide range of costs. Future projections aim to represent averages across a larger deployment and therefore, alongside cost reductions due to learning, a smaller variation

compared to the historical excerpt is expected. This in part relates to a more firm understanding of large conventional nuclear compared to SMRs.

We employ the same learning rate methodology developed in recent work^{118, 119}. Table 25 presents the assumptions relating to nuclear deployment scenarios in western countries that has been applied in the current study. Starting point in 2035 has been set to 8,200 EUR/kW in the reference, reflecting a balance between the different sources. This starting point was varied $\pm 10\%$ in the optimistic and conservative variations.

Table 25. Nuclear SMR deployment scenarios in Western countries assumed in the current study.

Parameter	Scenario	2035	2040	2045	2050
Learning rate	Conservative		6.4%	6.4%	6.4%
	Reference		8.0%	8.0%	8.0%
	Optimistic		9.6%	9.6%	9.6%
Buildout (GW)	Conservative	3.6	5	8	12
	Reference	3.6	10	20	30
	Optimistic	3.6	13	44	154

¹¹⁸ National Renewable Energy Laboratory (2024), Annual Technology Baseline.
¹¹⁹ EA & VTT (2026), Small Modular Reactors in Denmark: A Technology and Cost Review.

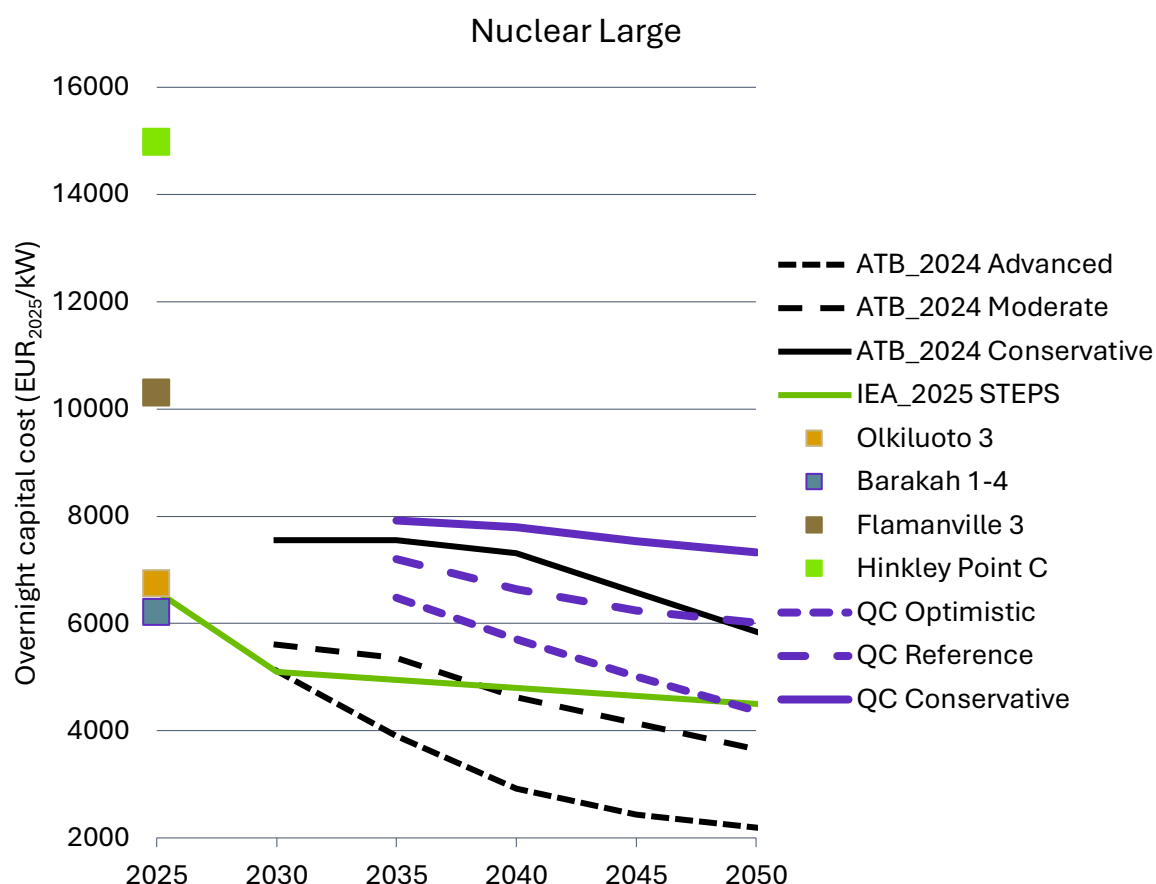


Figure 75. Comparison of large-scale nuclear overnight capital costs in the present study with those from other references, as specified in the legend. The data points are differentiated by markers and line styles: square-points represent recent projects and lines represent projections.

D.4.2 Technology development scenario reasoning

Within each development pathway, scenarios differ only in financing assumptions (WACC), while technical parameters such as lifetime, fuel cost, capacity factor, and waste cost remain unchanged. Fixed costs have been set to 1.5% of the overnight capital costs and cost for waste determined based on Ref.¹²⁰.

Conservative:

High overnight costs reflect first-of-a-kind (FOAK) deployment risk, limited domestic nuclear supply chain, regulatory uncertainty, and long construction timelines. Cost overruns, extended licensing processes, and elevated risk premiums lead to high WACC and prolonged capital exposure. Limited fleet deployment prevents realization of

¹²⁰ EA & VTT (2026), Small Modular Reactors in Denmark: A Technology and Cost Review.

industrial learning effects, keeping EPC (Engineering, Procurement, and Construction), engineering, and contingency margins high.

Reference:

The reference pathway assumes gradual normalization of project delivery risks through standardized reactor designs and moderate European deployment experience. Construction schedules improve compared to FOAK projects, but no breakthrough cost compression is assumed. Financing conditions reflect mature infrastructure investment levels, with partial but not complete reduction of risk premiums.

Optimistic:

The optimistic trajectory reflects serial deployment of standardized reactor designs (e.g., SMR fleets or replicated large-unit builds), strong regulatory streamlining, and improved project execution discipline. Industrial learning, modularization, and supply-chain scaling reduce overnight CAPEX and shorten construction duration to 2 years. Risk perception declines as multiple projects are successfully delivered on time and on budget, reducing WACC.

Table 26. Assumed techno-economic parameters and levelized cost of electricity (LCOE) for nuclear SMRs

Parameter	Conservative-2	Conservative-1	Reference	Optimistic-1	Optimistic-2
WACC [%]	8	6	6	6	4
Overnight cost [EUR/kW]	8375	8375	6699	4611	4611
Construction duration [yr]	4	4	3	2	2
Fixed O&M [EUR/kW/yr]	126	126	100	69	69
Fuel and waste cost [EUR /MWh]	7.9	7.9	7.9	7.9	7.9
Capacity factor [%]	86	86	86	86	86
Lifetime [yr]	60	60	60	60	60
Capital recovery period [yr]	40	40	40	40	40
LCOE [EUR/MWh]	134	108	86	60	49

D.4.3 Cost assumptions

The primary drivers of LCOE variation are the assumed overnight capital cost (4,611–8,375 EUR/kW), the weighted average cost of capital (4–8%), and, to a lesser extent, fixed O&M (69–126 EUR/kW/yr). Under these assumptions, the calculated LCOE declines from 134 EUR/MWh in the most conservative case to 49 EUR/MWh in the most optimistic scenario.

D.4.4 Technology specific modelling assumptions

In the modelling framework, SMRs are primarily represented as power-only supply. The nuclear power plant fleet is modelled as a step resource with a bidding price set to its marginal cost. As market clearing price drops below the marginal cost of the nuclear plant, it may ramp down to 70% of the total available capacity with no constraint on rate. The availability of the nuclear fleet follows smoothed profile¹²¹ with highest availability, 100%, during winter and lowest (80%) at mid-summer time corresponding to an average of 90% with no ramping. The 86% capacity factor used for the LCOE in [Table 26](#) is a separate assumption from this modelled availability profile.

¹²¹ Cox et al. (2026) Strategic capacity expansion planning in hydro-dominated power systems: Insights from the Nordics

D.5 Battery energy storage

D.5.1 Past trends and projections

As illustrated (Figure 76) in the updated projections (ATB 2025), recent market developments and deployment volumes support a steeper cost decline trajectory than assumed in ATB 2024. In particular, the 2024 “Advanced” case now aligns more closely with a cautious cost pathway rather than a central expectation. To ensure consistency with the most recent evidence and with the rapid global expansion of battery manufacturing capacity, we therefore adopt the more optimistic ATB 2025 trajectory as the new reference. Consequently, ATB 2024 Advanced is reinterpreted as our conservative case.

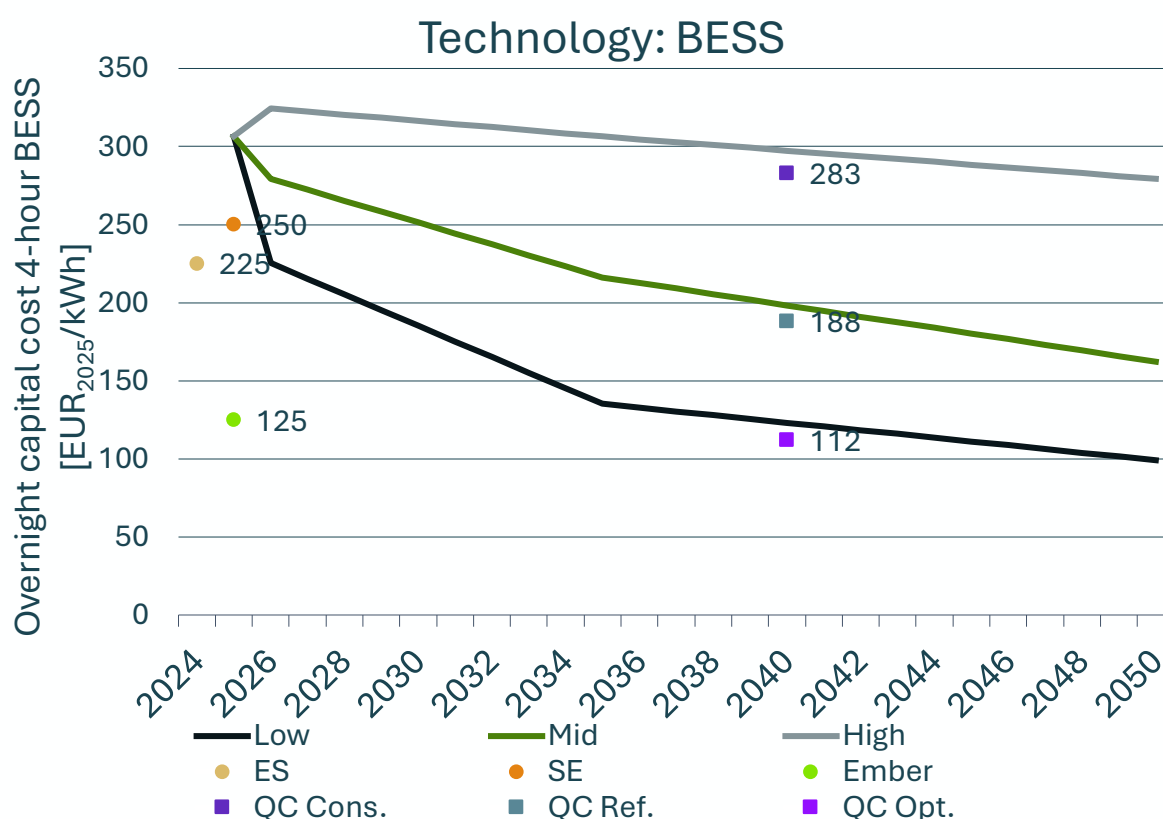


Figure 76. Projected (ATB 2025) and reported overnight capital cost trajectory for battery energy storage.¹²²

D.5.2 Technology development scenario reasoning

Recent market developments indicate that deployment growth has exceeded earlier expectations, suggesting steeper cost reductions than assumed in older projections. As a result, earlier cost outlooks (e.g., ATB 2024) are considered conservative relative to

¹²² Ember (2025), How cheap is battery storage?

current market dynamics. The updated projections (ATB 2025) better reflect recent cost reduction in both storage capacity (kWh) and power (kW) – hence are used as representative as outlined in [Table 27](#).

Table 27. Assumed techno-economic parameters for BESS.

Parameter	Conservative-2	Conservative-1	Reference	Optimistic-1	Optimistic-2
WACC [%]	8	6	6	6	4
Overnight cost [EUR/kW]	318	318	276	247	247
Overnight cost [EUR/kWh]	204	204	119	51	51
Fixed OM [EUR/kW/yr]	73	73	51	34	34
Construction duration [yr]	0.5	0.5	0.5	0.5	0.5
Variable OM [EUR/MWh]	0	0	0	0	0
Lifetime [yr]	15	15	15	15	15

D.5.3 Technology specific modelling assumptions

In the modelling framework, battery energy storage systems (BESS) are represented as storage units with a predefined energy-to-power (E/P) ratio, meaning the storage duration (e.g., 2h, 4h) is fixed exogenously. Investment is therefore made in power capacity (MW), while energy capacity (MWh) scales proportionally according to the assumed duration. Consistent with current European market trends, a share of battery deployment is assumed to occur alongside distributed solar PV installations, particularly in residential and commercial/industrial systems. In practice, these batteries are primarily installed to increase self-consumption, reduce peak demand charges, and hedge against retail price volatility. In modelling terms, this implies that part of battery capacity is effectively coupled to distributed PV generation and local demand, rather than operating purely as a wholesale arbitrage asset. While grid-scale BESS participates in system-level optimization, behind-the-meter storage primarily reduces net load and export volumes, reflecting the heterogeneous investment logic observed in real markets.

D.6 Open cycle gas turbines

D.6.1 Past trends and projections

DEA¹²³ OCGT “nominal investment” looks structurally low for today’s reality. The DEA values of 440–500 EUR/kW are closer to equipment-only / older benchmark levels than what recent project-development evidence suggests for delivered projects (incl. balance-of-plant, civils, commissioning, connections and development risk). ATB is updated frequently and reflects the post-2021 cost environment. ATB’s combustion turbine CAPEX pathway (roughly \$900–\$1,100/kW in the 2020s, declining gradually) is consistent with the idea that gas turbine technology is mature (no big learning), but the delivered cost is strongly affected by market environment.

D.6.2 Technology development scenario reasoning

For open-cycle gas turbines (OCGT), cost assumptions are based primarily on the latest ATB data. Across the defined scenarios, the techno-economic parameters (CAPEX, O&M, efficiency) are assumed to remain constant in real terms. The scenarios therefore vary in principle only through the weighted average cost of capital (WACC), reflecting differences in financing conditions, market risk perception, and macroeconomic environment rather than technology evolution.

D.6.3 Cost assumptions

Cost assumptions are presented in [Table 28](#). The high WACC scenario reflects a situation where the investment bears substantial market risk: the plant operates only during limited high-price hours, revenues are uncertain, and there is no long-term revenue stabilization mechanism. In such a case, investors require high returns to compensate for volatility and underutilization risk. Conversely, the low WACC scenario represents a case where the OCGT benefits from strong policy support. Such as a capacity mechanism, strategic reserve contract, or other revenue stabilization instrument—thereby significantly reducing investment risk and lowering financing costs. At low utilisation, below 15%, the LCOE of the gas turbines is very high therefore limiting their investment profitability based on an energy-only market revenues. In [Table 28](#) “*” denotes fuel cost which includes both the underlying gas price and the CO₂ price component and a thermal efficiency of 35%.

¹²³ DEA (2025), Technology Data for Generation of Electricity and District Heating v17

Table 28. Assumed techno-economic parameters for gas peakers.

Parameter	Conservative-2	Conservative-1	Reference	Optimistic-1	Optimistic-2	Reference
WACC [%]	10	8	6	4	2	SNL
Overnight cost [EUR/kW]	900	900	900	900	900	ATB
Construction duration [yr]	2	2	2	2	2	DEA
Fixed OM [EUR/kW/yr]	10	10	10	10	10	DEA
Variable OM [EUR/MWh]	5	5	5	5	5	-
Fuel cost* [EUR/MWh]	233	233	233	233	233	SNL
Capacity factor [%]	5	5	5	5	5	DEA
Lifetime [yr]	25	25	25	25	25	DEA
Capital recovery period [yr]	16.7	16.7	16.7	16.7	16.7	-
LCOE [EUR/MWh]	546	507	471	439	410	-

D.6.4 Technology specific modelling assumptions

Fossil natural gas is assumed as primary fuel, meaning that gas and carbon price trajectories effectively determine the variable cost of the plant.

Biomethane could be considered as a potential alternative fuel. When sustainably sourced, biomethane can be treated as largely carbon-neutral within accounting frameworks, implying limited or potentially zero net CO₂ cost exposure, depending on regulatory treatment. However, its availability is expected to be constrained and subject to competition from other sectors (e.g., industry, transport), making it a strategic but limited decarbonization option for OCGT operation.

Appendix E Import

Table 29. Compiled statistics relating to trade for 2025 reference alongside main scenarios.

Scenario	2025	Balanced	Offshore Balanced	Offshore	Solar Balanced	Solar	Nuclear Balanced	Nuclear
Share hours with import	57%	36%	35%	35%	38%	40%	32%	20%
Share hours with export	43%	64%	65%	65%	62%	60%	68%	80%
10% quantile of exchange	-40%	-60%	-66%	-69%	-62%	-64%	-56%	-49%
90% quantile of exchange	51%	36%	42%	48%	44%	50%	27%	8%
Total import (TWh/y)	6.5	9.3	10.5	11.8	11.9	13.6	6.6	2.2
Total export (TWh/y)	-4.4	-25.1	-28.4	-30.7	-24.9	-25.2	-24.6	-24.3
Net trade (TWh/y)	2.1	-15.8	-18.0	-18.9	-13.1	-11.6	-18.0	-22.1
Total import cost (€/MWh)	6.9	11.3	12.8	15.3	14.4	17.9	7.5	1.9
Total export revenue (€/MWh)	-2.3	-9.5	-8.6	-6.3	-8.9	-8.1	-10.7	-13.4
Net trade (€/MWh)	4.5	1.8	4.3	9.0	5.5	9.8	-3.3	-11.5

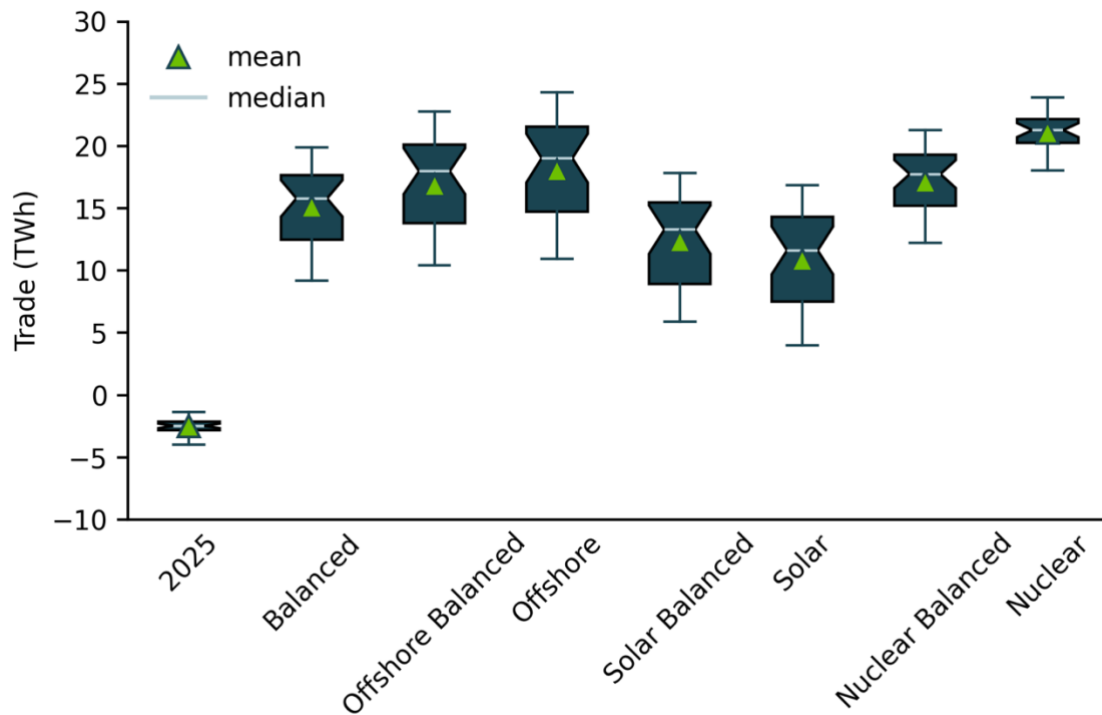


Figure 77. Annualised average net trade for the full set of 33 weather years for the main scenarios. For the trade, positive and negative values represent net export and net import, respectively. The boxplot diagrams cover the range of outcomes from 0% to 95% for the full set of weather years, where the boxes represent 25% - 75% quartiles and the circles represent extreme values. Averages for reference weather year 1991 are shown with grey squares. Median values are shown by horizontal white lines and mean values by green triangles.

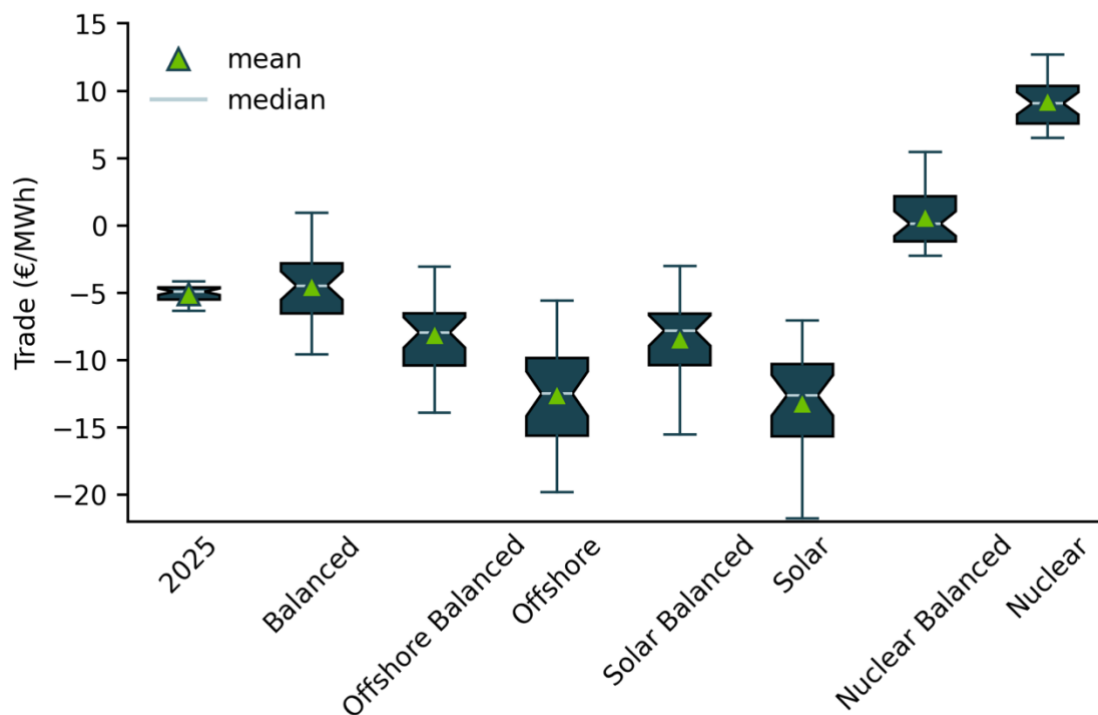


Figure 78. Annual average monetised trade normalised for annual demand for the full set of 33 weather years for the main scenarios. For the trade, positive and negative values represent net export revenues and net import costs, respectively. The boxplot diagrams cover the range of outcomes from 0% to 95% for the full set of weather years, with the boxes representing 25% - 75% quartiles and the circles representing extreme values. Averages for reference weather year 1991 are shown with grey squares. Median values are shown by horizontal white lines and mean values by green triangles.

Glossary

This glossary lists the abbreviations and the principal technical and study-specific terms used in this report. Where a term is defined in a manner specific to this study (for example, the system-aggregated profitability gap, or the loss-of-load mechanism), the entry references the relevant methodological section.

Table 30. Abbreviations and acronyms.

Term	Definition
AF25	Analyseforudsætninger 2025; the Danish Energy Agency's reference assumption framework used in long-term energy-system planning.
ATB	Annual Technology Baseline; technology cost benchmarks published by the U.S. National Renewable Energy Laboratory (NREL).
BESS	Battery Energy Storage System.
BT	Merged Baltic bidding zone, representing Estonia, Latvia and Lithuania in the modelled European grid.
CAPEX	Capital expenditure.
CCS	Carbon Capture and Storage.
CfD	Contract for Difference; a market-design instrument in which a strike price is guaranteed to a developer and the difference between strike price and market price is settled by the public counterparty.
CHP	Combined Heat and Power.
CO₂	Carbon dioxide.
DEA	Danish Energy Agency (Energistyrelsen).
DH	District Heating.
DK1, DK2	Western and Eastern Danish electricity bidding zones.
DNA	Danish Nuclear Alliance; commissioner of this study.

EA	EA Energianalyse; consultancy that produced the parallel SMR system analysis commissioned by the Danish Energy Agency (DEA), referenced throughout this report.
ENTSO-E	European Network of Transmission System Operators for Electricity.
ERAA	European Resource Adequacy Assessment; annual ENTSO-E assessment of capacity adequacy across the European synchronous area.
EV	Electric Vehicle.
IEA	International Energy Agency.
IEO	International Energy Outlook (U.S. Energy Information Administration).
IRENA	International Renewable Energy Agency.
LCOE	Levelised Cost of Electricity; the discounted lifetime cost of a generator per unit of energy produced (€/MWh).
NREL	National Renewable Energy Laboratory (United States).
NTC	Net Transfer Capacity; the maximum exchange capacity assumed available across a cross-border interconnection.
NO125	Merged Norwegian bidding zone, representing NO1, NO2 and NO5 in the modelled European grid.
O&M	Operations and Maintenance (costs).
OC	Open-Cycle (Gas Turbine)
PPA	Power Purchase Agreement; long-term bilateral contract between a generator and an offtaker at a fixed or indexed price.
PV	Photovoltaic (solar).
PyPSA	Python for Power System Analysis; open-source modelling framework used in parallel verification of selected cGrid results.
QC	Quantified Carbon; author of this report.

SMR	Small Modular Reactor.
TES	Thermal Energy Storage.
VRE	Variable Renewable Energy; weather-dependent generation, primarily wind and solar.
VTT	VTT Technical Research Centre of Finland; collaborator with EA Energianalyse on the SMR system analysis.
WACC	Weighted Average Cost of Capital.
WEO	World Energy Outlook (International Energy Agency).

Table 31. Terms and concepts

Term	Definition
Balanced (scenario)	Reference Danish 2050 system configuration combining nuclear, offshore wind and other firm and variable generation; serves as the central scenario from which the Nuclear, Offshore and Solar directions are explored.
Price cannibalisation	The effect whereby simultaneous production from a fleet of similar generators (notably offshore wind) depresses prices when they produce, reducing the average price each technology captures relative to the system average.
Capture price	Average price received per MWh by a given technology fleet, weighted by its actual hourly production profile. Typically, below the time-weighted system average for variable renewable technologies due to cannibalisation.
Capture rate	Ratio of a technology's capture price to the average market price. Values below 100% indicate exposure to cannibalisation.
cGrid	Proprietary electricity market model developed by Quantified Carbon.
Curtailement	Deliberate reduction of available generation, typically VRE, when output exceeds what the system can absorb or transport at the prevailing price.
Dispatchable	Generation capacity that can be controlled to follow demand, in contrast to weather-dependent variable generation.

Loss of load	Residual unmet demand remaining after the iterative market-clearing process has reached the assumed price cap (3 000 €/MWh in this study).
Nuclear (scenario/direction)	Danish 2050 scenario emphasising nuclear capacity. The Nuclear balanced variant pairs nuclear with a smaller offshore and solar share.
Offshore (scenario/direction)	Danish 2050 scenario and direction emphasising offshore wind. The Offshore balanced variant retains some firm capacity in support.
Pre-optimisation step	Initial system-level optimisation across the wider European model geography that establishes neighbour-system capacity, generation mix and transmission. The Danish scenarios are then evaluated against this fixed European backbone.
Profitability gap (system-aggregated)	Shortfall between system-wide technology costs and the market revenues captured by those technologies, reported in €/MWh. A positive gap implies that the modelled portfolio cannot recover its full costs from wholesale-market revenues alone under the assumed market design.
Solar (scenario/direction)	Danish 2050 scenario and direction emphasising solar capacity. The Solar balanced variant retains some firm capacity in support.
System stability / Ancillary services	Services required to maintain the technical operation of the power system, including frequency response, inertia, voltage control and reactive-power support. Not modelled directly in this study; flagged as required follow-on analysis.



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