Nordic Energy Research

Integrated Power Markets

How European Market Design Reforms Could Shape Nordic Electricity Markets Towards 2035

Contents

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Foreword

European electricity markets are undergoing significant transformation. While many of the current market design reforms are developed and implemented outside the Nordic region, their implications are not confined by national borders. As this report demonstrates, developments in neighbouring countries can have important consequences for Nordic electricity prices, trade patterns and welfare.

The Nordic power system has long been characterised by strong cross-border integration and a high degree of trust in market-based solutions. This interconnectedness has been a key strength, but it also implies that policy and market changes elsewhere in Europe increasingly shape outcomes in the Nordic countries. Understanding these spillover effects is therefore essential for informed decision-making.

This study, commissioned by the Nordic Council of Ministers, contributes to this understanding by analysing how selected European market design reforms may affect the Nordic electricity markets towards 2035. Through detailed power market modelling, the report provides new insights into how capacity mechanisms, renewable expansion, battery deployment and trade measures in neighbouring countries may influence Nordic market outcomes.

The findings underline the importance of continued Nordic cooperation and active engagement in European energy policy processes. As the Nordic countries work towards their shared vision for 2030—aiming for a carbon-neutral, competitive and secure energy system—maintaining well-functioning, interconnected markets will be crucial.

I hope this study will contribute to a deeper understanding of our increasingly integrated electricity markets and inform future policy discussions.

Klaus Skytte
CEO, Nordic Energy Research

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1. Executive summary

Nordic electricity markets are integrated with other European markets through interconnectors to Germany, the Netherlands, Great Britain, Poland, and the Baltics. Policy decisions made in these neighbouring markets—on capacity mechanisms, renewable support schemes, interconnector development, and trade regulations—can thereby directly affect Nordic electricity prices and trade flows. This can impact power producers, consumers, and Transmission System Operators (TSOs).

The regulatory trajectory in these countries remains highly uncertain. For example, Germany faces unresolved questions about firm capacity support and grid expansion, Great Britain is navigating post-Brexit market integration, and Poland is managing a complex coal phase-out. Understanding how these developments could impact Nordic electricity markets is therefore important for Nordic policymakers, regulators, and market participants.

1.1 Methodological approach

This study first examines the political and regulatory landscape in Germany, Great Britain, the Netherlands, Poland, and the Baltics, identifying the key uncertainties and political developments most relevant for the Nordics. We map these country-specific developments to broader regulatory trends with relevance across multiple markets. Using THEMA's fundamental market model, we then conduct a sensitivity analysis to quantify how alternative outcomes for these regulatory trends would affect Nordic electricity prices, trade patterns, and welfare. The analysis focuses on the year 2035—far enough in the future for relevant market design outcomes to materialise, yet near enough to support meaningful policy guidance.

1.2 Regulatory developments analysed

The study examines four regulatory trends:

1. **Capacity mechanisms and firm capacity build-out:** Germany and Poland are planning firm gas-fired capacity additions through capacity mechanisms, but outcomes remain uncertain. We assess scenarios ranging from implementation delays to accelerated expansion driven by security of supply concerns.
2. **Renewable generation and battery storage:** Continental countries have ambitious targets for offshore wind, solar, and batteries, though actual build-out trajectories are highly uncertain. We examine the price and market effects if these targets are reached—or fall short.
3. **Interconnector availability and trade restrictions**: New transmission projects (EstLink3, Bornholm, Kriegers Flak) are under consideration, and internal grid constraints may limit effective interconnector capacity. We assess the impact of project delays and reduced availability due to continental bottlenecks. In addition, future EU-UK trade arrangements remain unclear, and broader protectionist pressures cannot be ruled out. We examine the impact of CBAM on electricity trade between the UK and the EU, as well as the effects of general trade fees on Nordic-European interconnectors.
4. **Bidding zone split:** A German bidding zone split is discussed as a remedy to internal congestion and high redispatch costs. We assess the potential impact on Nordic prices, while noting that such a split currently appears unlikely.

1.3 Key findings

Our analysis and simulations show that developments in neighbouring markets can have a significant impact on prices in the Nordics, and hence on consumers, producers, and TSOs. Average price levels, price volatility and peak prices are all affected. Even though the Nordic market does not couple completely with neighbouring markets, developments in other markets matter.

The actual impact, however, varies significantly depending on which parameters vary by how much.

Some of the main observations are:

1. **A lack of firm capacity in neighbouring markets would not only increase the number of price spikes in these markets, but also in Nordic bidding zones.** For example, if Germany fails to meet its targets for firm gas-fired capacity (as currently reflected in the government's *Kraftwerksstrategie*), the frequency of day-ahead price spikes in Nordic zones could increase, in particular in Nordic zones directly connected to Continental Europe.

2. **If European countries reach their ambitious offshore targets without corresponding demand growth, day-ahead prices in Europe and the Nordics could fall significantly. The effect is less pronounced for alternative developments in solar and battery capacities.** Should Germany, Great Britain, and the Netherlands achieve their offshore wind build-out targets without corresponding additional demand growth, power prices in North-West Europe would fall significantly, and power prices in the Nordics could fall by more than 50% compared to the Base scenario. Ambitious solar and battery expansion plans have more modest effects on Nordic prices, although the impact can still be significant, in particular for large PV-build out scenarios.
3. **Policies reducing interconnector availability could result in a net welfare loss for the Nordic region.** If trade between the Nordic region and the rest of Europe is restricted, Nordic prices will drop. This would benefit consumers (who would need to pay less) and harm generators (who would earn less). But the Nordic area as a whole generates more than it consumes. Sweden, in particular, has significant excess generation. As a result, generators' total simulated losses exceed consumers' gains, a result of the terms of trade. The consequence is a net welfare loss for the Nordic region.
4. **Trade restrictions in the form of transmission tariffs or surcharges would reduce cross-border flows and congestion revenues.** Fees or surcharges could significantly affect trade flows and congestion rents. While the impact on baseload prices is relatively limited, the effects on power flows and congestion rents can be substantial depending on the fee level and the countries to which such measures apply.
5. **Bidding zones in Germany could lower prices in the Nordics.** A bidding zone split in Germany could significantly reduce power prices in northern Germany. This would also result in a price decline in the Nordic countries, due to the links between the Nordic market and northern Germany. However, the price decline in the Nordics is less pronounced than that in northern Germany.

These findings underscore the interdependence of European electricity markets: The extent to which Germany reaches its firm capacity expansion plans has direct implications for Nordic peak price risk; rapid offshore wind expansion would fundamentally reshape Nordic price formation; restrictions in interconnector availability or cross-border trade would impact prices, trade flows and welfare. In short, developments in neighbouring markets matter, and policymakers and market participants in the Nordics should be aware of these interdependencies when making their own decisions.


↑ **Images:** iStock

2. Introduction

Electricity market outcomes in the Nordic region are increasingly shaped by developments beyond Nordic borders. Interconnectors linking Norway, Sweden, Denmark, and Finland to Continental Europe and Great Britain transmit not only electrons but also price signals. When German wind generation surges, wholesale prices fall across Scandinavia; when Continental thermal capacity runs short, price spikes propagate northward.

This exposure to external market conditions creates a strategic challenge for Nordic policymakers and market participants. Decisions on capacity mechanisms in Germany, renewable support schemes in Great Britain, or trade policy between the EU and UK are made in capitals where Nordic interests carry limited weight. Yet the consequences of these decisions for Nordic generators, consumers, and Transmission System Operators (TSOs) can be substantial. As neighbouring countries navigate uncertain regulatory pathways over the coming decade, Nordic policymakers and market participants need to understand the range of potential impacts on their own markets.

2.1 Methodological approach

This study proceeds in two stages: regulatory mapping and quantitative impact assessment. In the first stage, we examine national policies across neighbouring markets and map them to broader regulatory trends that could affect the Nordic electricity system. This mapping provides a structured framework for analysis. In the second stage, we conduct a sensitivity analysis to quantify how alternative outcomes for these regulatory trends would affect Nordic prices, trade flows, and welfare—translating qualitative policy uncertainty into concrete market impacts.

Regulatory mapping: We first examine the political and regulatory landscape in Germany, Great Britain, the Netherlands, Poland, and the Baltics, identifying the key uncertainties and policy developments most relevant for Nordic electricity markets. Chapter 3 presents this analysis, summarising national policies in each country and relating them to broader regulatory trends that span multiple markets. We map country-specific developments to the following four overarching regulatory trends that could significantly affect Nordic markets:

1. **Capacity mechanisms and the build-out of firm capacity:** A key uncertainty is how firm capacity will develop in continental Europe. Germany and Poland are both planning to establish or further develop capacity mechanisms, yet the outcomes remain uncertain. We assess what happens if these countries fall short of their planned gas capacity additions by modelling a range of scenarios from low capacity levels due to implementation delays, to accelerated expansion driven by security of supply concerns. Additional sensitivities examine whether Nordic countries could mitigate continental shortfalls by investing in domestic firm capacity.
2. **Renewable generation and battery storage:** Future build-out trajectories for renewables and batteries are highly uncertain. Despite ambitious government targets, it remains unclear what volumes the market will accommodate and how support schemes will evolve. We assess what would happen if Germany, Great Britain, and the Netherlands reach their ambitious renewable energy targets, and what role batteries could play in mitigating the associated market effects.
3. **Interconnector availability and trade restrictions:** Further market integration of the Nordic countries is under consideration through new or upgraded interconnections, including EstLink3, new links via Bornholm, and upgrades around Kriegers Flak. We assess the impact of delays to these planned transmission projects. Furthermore, internal grid constraints can limit the effective availability of interconnectors, so we examine what happens if grid bottlenecks in continental Europe reduce the available capacity of Nordic interconnectors to other markets. Future trade arrangements between the United Kingdom and the EU—and consequently with the Nordic region—also remain unclear. We examine the impact of applying CBAM to EU-GB electricity trade in a scenario where the UK and EU fail to link their emissions trading systems and assess the effects of introducing general trade fees between the Nordic region and other markets. It should be noted that such fees are not permitted under current EU internal market rules; however, we include this sensitivity to illustrate the potential impact should economic protectionism or regulatory changes alter this framework in the future.
4. **Bidding-zone split:** Internal bottlenecks in Germany have, in recent years, resulted in trade restrictions and high redispatch costs. Introducing multiple bidding zones is often mentioned as a remedy to these challenges. We therefore assess the potential impact of a German bidding zone split on Nordic electricity prices. However, we do not consider such a split very likely at present. Furthermore, the actual impact would depend strongly on the geographical delimitation and topology of the resulting bidding zones.

Quantitative impact assessment: To quantify the impact of these regulatory trends on Nordic markets, we conduct a sensitivity analysis. Specifically, we establish a baseline scenario (THEMA Base) that reflects credible 2035 market conditions. The key assumptions used in THEMA Base are outlined in section 4.1. Then, we systematically vary some key assumptions to assess how alternative regulatory developments or build-out trajectories affect Nordic prices, trade patterns, and welfare. A sensitivity analysis is particularly well-suited to this context because we can single out the effect of individual policies or assumptions. Furthermore, by testing alternative outcomes—from ambitious government targets being exceeded to plans falling significantly short—we can assess how the range of plausible regulatory developments would affect Nordic markets. We focus our analysis on the year 2035 because it is far enough in the future for a variety of relevant market design outcomes to materialise, yet near and tangible enough to support meaningful policy guidance and impact analysis.

The quantification is done using TheMA, THEMA's fundamental electricity market model. TheMA determines hourly day-ahead electricity prices by matching supply and demand across European bidding zones, incorporating detailed representations of thermal plants, hydropower systems, and variable renewable generation and a detailed model of the European transmission interconnector grid.

Chapter 3 provides an overview of the regulatory initiatives and national policies most relevant to Nordic power markets. The analysis covers Germany, Great Britain, the Netherlands, Poland, and the Baltic countries, summarising national policies and relating them to the five regulatory trends listed above.

Chapter 4 presents the quantitative sensitivity analysis. Section 4.1. describes our THEMA Base scenario and provides a detailed explanation of the methodological approach of the sensitivity analysis. Each of the following sections examines one of the four regulatory trends, describing the sensitivity definitions, presenting results on prices, trade flows, and welfare impacts, and drawing conclusions for the Nordic markets:

- Section 4.2 examines capacity mechanisms and the build-out of firm gas capacity in Germany and Poland
- Section 4.3 analyses policy support schemes for renewable generation and battery storage
- Section 4.4 assesses policies affecting interconnector availability and quantifies the impact of trade restrictions, including CBAM
- Section 4.5 evaluates the potential effects of a German bidding zone split

 

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3. Key market design reforms in European electricity markets

3.1 Germany

3.1.1 Summary

Germany's power sector is marked by considerable uncertainty. Government signals on RES and grid expansion are mixed, and there is no settled approach to support firm capacity additions or long-term industrial demand. At the same time, market outcomes are interdependent and hence uncertain: demand, renewables, firm capacity, storage and interconnectors all shape each other's costs and revenues. Key unknowns relate to the scale and timing of additions to firm capacity and renewable energy sources (RES), future electricity demand, and the expansion of interconnectors with neighbouring bidding zones.

3.1.2 Political backdrop

The governing coalition of conservatives and social democrats holds a mandate for economic reform. Many businesses and households recognise that the existing economic model is under strain: Exports of machinery and vehicles face rising competition from China, while energy costs remain high. With the next federal election three years away, the government has time to implement reforms. The government seeks to revive economic growth, while continuing Germany's decarbonisation pathway. While it has a reform mandate, the government is bound by the need to assure an ageing electorate that pensions are safe, and the reforms will not negatively impact their livelihoods.

3.1.3 Policy overview

Decarbonisation remains a central objective, but the government has several additional goals for the power sector:

1. **Security of supply in times of low wind and solar power generation:** Germany has faced several extreme weather events with high scarcity prices in recent years. As additional coal-fired units are scheduled to be decommissioned, Germany likely faces a shortage of firm capacity. The EU has signalled that it will allow Germany to subsidise around 12 GW of gas- and H_2-fired power plants soon. However, the design of the capacity mechanism to support the gas-fired units and the timeline of their construction are uncertain. Germany also plans to introduce an additional capacity market, though its design is still unclear. Nevertheless, Germany will likely add significant gas-fired generation capacity in the upcoming decade.
2. **Cost containment in the power sector:** The government aims to limit overall power system costs, particularly those associated with RES support schemes and grid expansion. The government, therefore, announced that it might consider reforming RES subsidy schemes to lower consumer/taxpayer costs.
3. **Stabilising power demand from industry:** This goal is indirect. Industrial demand accounts for more than a third of Germany´s total net power demand, and total industrial demand has declined in recent years owing to the challenges facing German industry in its product markets. If the government is successful in strengthening German industrial performance, it will indirectly support industrial power demand. Key policy measures that will strengthen industrial demand include a subsidised industrial power price and large grid fee reductions for industrial power consumers.
4. **Continued RES expansion:** The government plans to maintain substantial subsidies for solar and onshore wind in support of continued additions to RES capacity. The build-out of renewable generation capacity recently accelerated following regulatory simplifications. However, solar and onshore wind expansion faces constraints from limited grid access, public opposition and falling revenues due to cannibalisation. Offshore wind auctions are still in place but had little success in 2025 due to high costs for offshore cables, converters and turbines. The government is attempting to ensure both that future auctions result in contract awards for new capacity deployment and that past tender awards are built.

These objectives create uncertainty. Some are in direct tension, notably cost containment versus rapid RES expansion. Moreover, there is no clear legislative pathway for delivery. Key questions remain unanswered, including the size and timing of gas capacity auctions and the duration of industrial power subsidies.

3.1.4 Relevant market developments

Several other developments add to the political uncertainty:

- Increased uncertainty over plans for the build-out of offshore wind is having a knock-on effect on planned interconnector capacity. Offshore wind hubs are expected to include transmission capacity to several countries, offering both wind generation and greater interconnection with adjacent bidding zones. However, as offshore wind development is struggling, so too are plans to build additional interconnection capacity.
- Persistent north–south grid bottlenecks remain. If delays in transmission grid expansions continue, the EU may require Germany to split its single bidding zone. Currently, all relevant political parties and most industry associations oppose a bidding zone split as they fear higher electricity prices for the industrial hubs in Southern Germany.
- A battery investment boom is emerging, supported by strong market revenues, but is constrained by grid availability and cannibalisation effects.

Table 1 summarises the key political developments in Germany and maps them to the specific quantitative sensitivity analyses in Chapter 4, which study their impact on the Nordic markets. Column "Sensitivity chapters" points to the subchapters in Chapter 4 that describe the relevant sensitivities.

Table 1. Developments in Germany that are most relevant for the Nordics

DEVELOPMENT	RELEVANT MODELLING ANALYSIS	SENSITIVITY CHAPTERS	UNCERTAINTY LEVEL
Policy: Continued RES expansion	Renewables build-out: wind and solar build-out depend on both policies and market developments. For the impact of RES build-out on the Nordic markets. See **sensitivities on renewable capacity expansion.**	4.3.1 4.3.2 4.3.4	High
Policy: Security of supply in times of low wind and solar power generation	Germany intends to build-out at least 12 GW of gas-fired capacity. See **sensitivities on capacity mechanisms and firm capacity build out.**	4.2	Medium
Policy: Cost containment in the power sector	Cost containment has little impact per se. But it may slow down the build-out of renewables. Compare **sensitivities on renewable capacity expansion.**	4.3.1 4.3.2 4.3.4	Medium
Market development: Battery grid access rush	Battery storage capacity: the current grid access request wave may or may not translate into operating storage capacity. For storage's impact on the Nordics, see the **sensitivity on battery storage.**	4.3.4	Medium
Market development: Slow build-out of offshore wind generation and interconnection capacity	Limits to cross-border trade: a delayed offshore wind build-out may also result in delayed or cancelled interconnector projects. Compare the **sensitivity on interconnector availability and capacity.**	4.4	Low
Market development: Persistent north-south grid bottlenecks	If the EU and some of Germany's neighbours are successful, Germany may have to split its bidding zone. To understand a split's effects, compare the **sensitivity on a bidding zone split.**	4.5	Low

3.2 Great Britain

3.2.1 Summary

The GB power sector is also marked by considerable uncertainty. The current British Government has recently rejected options to introduce locational wholesale pricing and has instead opted to retain a single national price. While alternative proposals for managing congestion are still to be detailed, the direction of travel is towards a more strategic, plan-led model in which planners play a significant role in steering what new capacity is developed and where it is located. At the same time, Government policy continues to prioritise an accelerated roll-out of new renewable and flexible capacity, while retaining commitments to new nuclear. Internationally, the UK is moving towards closer alignment with the European Union (EU), with plans to link emissions trading systems to avoid the carbon border adjustment mechanism (CBAM) being applied to electricity exports from GB. Talks have resulted in plans for further discussions about a potential route back towards full participation in the Internal Energy Market (IEM), though the scope and timelines around any return remain highly uncertain, and sensitive to shifts in broader political sentiment about the United Kingdom's relationship with the EU.

3.2.2 Political backdrop

The Labour Government remains committed to rapid decarbonisation and has anchored policy around its *Clean Power 2030* plan. The plan aims to deliver at least 95% of generation from clean, low-carbon sources by 2030. This policy is being coordinated by a central *Mission Control* team to bring together and coordinate policy across the energy section. The Government also opened discussions about negotiating GB's return to the EU's internal electricity market (IEM). However, any sign of closer integration with the EU faces strong political headwinds. At the same time, "net zero" has become a more contentious goal, with opponents often framing their arguments around negative impacts on affordability. The 'Reform UK' party currently leads national voting-intention polling and has pledged to repeal net-zero legislation and pivot towards expanded oil, gas and coal production alongside new nuclear. The 'Conservative Party' (in office from 2010–2024) has also shifted away from the net-zero consensus, arguing the current framework is unaffordable. With the next general election due in 2029, a change in government could at that point trigger a step-change in energy policy. In the meantime, the Government and other supporters of ambitious decarbonisation goals focus much more on the benefits for energy security/sovereignty and lower long-term volatility in energy bills through reduced exposure to global gas prices and talk less about 'net zero' as an end in itself.

3.2.3 Policy overview

The following policy objectives in GB are noted:

1. **Cost containment in the power sector**: The Government is under pressure to bring down household energy costs, which are widely perceived domestically to be among the highest in Europe. In November 2025, it opted to shift a large share of legacy renewables policy costs off electricity bills and into general taxation. In parallel, it has consulted on changing the inflation indexation of legacy renewable support mechanisms to reduce the long-run burden on consumers. The Government has also weighed cutting VAT on domestic energy.
2. **Continued RES expansion**: The Government remains committed to accelerating the build-out of renewables through its *Clean Power 2030* action plan, with offshore wind positioned as the backbone technology. Its latest annual auction (AR7) secured 8.4GW of new offshore wind on 20-year contracts, with strike prices of around £91/MWh (2024 prices). Meeting the Government's targets, however, would require a further step-change in annual delivery equivalent to securing up to ~12GW of offshore wind in the next annual auction round (AR8), alongside rapid parallel deployment of onshore wind and solar.
3. **Interventions to reduce renewable turn-down costs**: There is increasing focus on the cost of "wasted" renewable energy—particularly in the north of the island, where transmission bottlenecks mean that wind capacity is increasingly constrained off and replacement generation (often gas) is brought on elsewhere. This was the central backdrop to a multi-year debate over whether to introduce more locational wholesale pricing to help better manage network congestion. While the Government has now opted to retain national pricing, it has signalled a package of potential alternative measures to tackle constraints. These include reforms to balancing arrangements, adding more locational features to "out-of-market" frameworks (e.g., capacity market design), and strengthening the TSO's tools to prevent or reverse cross-border schedules which are seen to contribute to network congestion.
4. **Long-duration energy storage (LDES)**: The development of new LDES capacity has emerged as a key priority. In 2024, the British Government accordingly launched a new "cap and floor" scheme for long-duration storage, which is designed to provide improved revenue certainty to developers. Under the scheme, consumers will fund revenue shortfalls below a certain "floor" in exchange for payments where revenues exceed a certain "cap". Ofgem (the GB regulator) has flagged that it intends to contract between 2.7 and 7.7 GW of new LDES capacity through the first application window of the scheme.
5. **Nuclear generation**: The Government has continued to prioritise new nuclear generation. A new regulatory model was confirmed in 2025 for a 3.2GW nuclear reactor (Sizewell C) in the south of GB. The Government holds a 44.9% stake in the project and a further £36.6 billion loan will be provided from UK National Wealth Fund (NWF). The support scheme means that electricity consumers will underwrite market revenues earned by the project.

6. **Rapprochement with the EU**: British and EU authorities issued a joint commitment in May 2025 to link the British emission trading system (ETS) and the EU ETS such that the carbon border adjustment mechanism (CBAM) will not need to apply to GB electricity exports. In December 2025, the British Government and the EU further committed to discussions about a potential route for Great Britain to participate in the EU's internal electricity market, though scope and timelines around any return remain highly uncertain and sensitive to shifts in broader political sentiment about Great Britain's relationship with the EU. Full participation would materially reshape trading arrangements across GB–EU interconnectors and would require closer alignment of GB regulation and market arrangements with EU rules and institutions. Political and technical negotiations are expected to run through 2026.

3.2.4 Relevant market developments

The British Government has decided against zonal/nodal pricing and to instead retain a single GB-wide wholesale price. However, the detailed design of "Reformed National Pricing" (RNP) and the tools that will form an alternative to locational pricing for managing constraints are still not fully specified. This generates uncertainty for developers, who need to consider whether the Government will strengthen locational signals elsewhere, such as through network charging reform.

Table 2 summarises the key developments in GB and maps them to the specific quantitative sensitivity analyses in Chapter 4, which study their impact on the Nordic markets. Column "Sensitivity chapters" refers to the subchapters in Chapter 4 that contain the respective sensitivities related to each policy.

Table 2. Developments in Great Britain that are most relevant for the Nordics

DEVELOPMENT	RELEVANT MODELLING ANALYSIS	SENSITIVITY CHAPTERS	UNCERTAINTY LEVEL
Policy: Rapprochement with the EU	Closer EU-UK ties could see GB being fully **re-integrated into the IEM** and the **permanent removal of the CBAM from GB electricity exports**. This would transform the cross-border trading arrangements that are currently in force. **To assess the impact of CBAM on Nordic electricity prices, compare sensitivities on trade restrictions.**	4.4	High
Policy: Continued RES expansion	Great Britain intends to **accelerate the deployment of new offshore wind, onshore wind, and solar capacity** by 2030 as part of its *Clean Power 2030* action plan. Compare **sensitivities on renewable capacity expansion.**	4.3.1 4.3.2 4.3.4	Medium
Policy: Renewable turn-down costs	There is increasing focus on the cost of "wasted" renewable output in GB. One result is that British authorities may **seek to prevent or undo cross-border schedules which are seen to contribute to network congestion**. Compare **sensitivities on renewable capacity expansion.**	4.3.1 4.3.2 4.3.4	Medium
Policy: LDES deployment	GB is seeking to procure up to 7.7 GW of new LDES capacity. This capacity will **compete with cross-border flows as a source of flexibility** in the GB power system. For storage's impact on the Nordics, see the **sensitivity on battery storage.**	4.3.3	Medium
Policy: Nuclear deployment	The Government has continued to **support the development of new nuclear generation units in GB** and has defined an enduring role for nuclear in the future power system. See **sensitivities on firm capacity build out.**	4.2	Medium
Market development: Uncertainty over reformed national pricing (RNP)	The British Government has decided against zonal/nodal pricing and to retain a single GB-wide wholesale price, but the **detailed design of RNP is not specified**. This creates uncertainty for developers but is unlikely to have a direct impact on Nordic markets.	4.5	Medium
Policy: Cost containment in the power sector	The British Government is exploring means of shifting costs away from domestic electricity consumers. Such means are **unlikely to impact market outcomes or Nordic markets**.		Low

3.3 Netherlands

3.3.1 Summary

The Netherlands is decidedly pro-nuclear and pro-renewables. However, recent successes in building out solar and wind have strained the grid and cannibalised revenues for solar and wind investors. There is significant uncertainty as to whether the grid can be strengthened fast enough to handle more renewables and more connections to neighbouring countries. It is also unclear whether the country's unstable political system can achieve meaningful reforms to enable the build-out and integration of renewables.

3.3.2 Political backdrop

The Netherlands currently has a minority government dominated by pro-renewable energy (RES) and pro-green transition parties from both the left and right of the political spectrum. There is broad public support for expanding the country's nuclear capacity. However, uncertainty remains over whether the government can achieve its objectives, as it lacks a parliamentary majority. The previous administration, led by far-right and anti-RES parties, collapsed after just eleven months in office, triggering elections in November 2025 and ushering in the current government in early 2026.

3.3.3 Policy overview

In the Netherlands, the government has set the following priorities:

1. **Accelerated grid build-out:** To enable a faster build-out of wind and solar, the Netherlands needs to build out its distribution and offshore networks. The previous government had planned to remove some legal barriers to accelerate the grid build-out. Whether the new government will be able to follow through on these plans is unclear. The Netherlands is densely populated and, therefore, finding space for new grid infrastructure can be challenging. The Netherlands' ability to increase its transmission capacity with neighbouring countries is also dependent on its ability to strengthen its internal grid.
2. **Change in RES subsidy system:** The Netherlands plans to replace its SDE++ subsidy system for RES with a contract for difference (CfD) system. Its plans are intended to implement EU policy regulation supporting the use of CfDs. The details of the new RES support scheme, as well as its expected impact, remain uncertain.
3. **Reduced offshore wind targets:** Dutch offshore build-out is slowing down. The Netherlands has reduced its offshore wind targets to 30-40 GW of installed capacity by 2040. Key auctions have also been postponed due to limited interest from investors. However, some build-out is still to be expected: A new auction design offering higher subsidies will soon be implemented.

4. **Nuclear expansion plans:** Across the political spectrum, the Netherlands sees nuclear power as necessary and relevant. New plants with a combined capacity of 2 to 3.2 GW will come online in the 2030s. The new capacity will raise total Dutch nuclear capacity even if older plans are decommissioned.

3.3.4 Relevant market developments

Several other developments add to the political uncertainty.

- As in Germany, greater uncertainty over the build-out of offshore wind is having a knock-on effect on planned interconnector capacity. Offshore wind hubs are expected to include transmission capacity to several countries, offering both wind generation and greater interconnection with adjacent bidding zones. However, with offshore wind development struggling, so too are plans to build additional interconnection capacity.
- Solar build-out has boomed in recent years but is now slowing down. 2025 saw capacity additions that were 40% lower than in 2024. The rooftop solar segment was especially hard hit, as grid access and subsidies both dried up. Commercial and industrial installations also decelerated, harmed by a rapid decline in solar capture rates.
- A battery investment boom is emerging, supported by strong market revenues, but is constrained by grid availability and cannibalisation effects.

Table 3 summarises the key political developments in the Netherlands and maps them to the specific quantitative sensitivity analyses in Chapter 4, which study their impact on the Nordic markets.

Table 3. Developments in the Netherlands that are most relevant to the Nordics

DEVELOPMENT	RELEVANT MODELLING ANALYSIS	SENSITIVITY CHAPTERS	UNCERTAINTY LEVEL
Policy: Grid expansion	Wind and solar build-out, as well as international transmission capacity, depend on internal grid build-out. For the impact of RES build-out and transmission build-out on the Nordic markets, see **sensitivities on renewable capacity expansion and transmission capacity.**	4.3.1 4.3.3 4.3.6	High
Policy & market development: Change in RES subsidy system	A change towards CfDs has little impact per se. But it may slow down the build-out of renewables in the short term. Solar build-out is already slowing down, albeit mostly due to other factors. Compare **sensitivities on renewable capacity expansion.**	4.3.1 4.3.2 4.3.4	Medium
Policy & market development: Slow build-out of offshore wind generation and interconnection capacity	A delayed offshore wind build-out may also result in delayed or cancelled interconnector projects. Compare the **sensitivities on wind build-out and on interconnector availability and capacity.**	4.3.1 4.4	Medium
Market development: Battery grid access rush	The current grid access request wave may or may not translate into operating storage capacity. For storage's impact on the Nordics, see the **sensitivity on battery storage.**	4.3.3	Medium
Policy: Build-out of nuclear power	The Netherlands intends to build out at least 2 GW of new nuclear capacity. See **THEMA Base scenario.**	4.2	Low

3.4 Poland

3.4.1 Summary

Poland's energy policy is politically turbulent, shaped by a push–pull between a pro-transition government and a more conservative presidency that can block or delay reforms. The system faces an urgent need to both reduce reliance on coal and, at the same time, strengthen energy security amid geopolitical risks. The core challenge is how to accelerate the green shift—especially through offshore wind, grid investment, and nuclear—while managing coal's legacy and public affordability. The political situation creates persistent uncertainty around the pace of coal's phase-down and the scale and speed of further renewables build-out, with veto power and contested legislation slowing progress on key reforms.

3.4.2 Political backdrop

Poland's energy policy is shaped by a persistent political divide between liberal, pro-European forces and parties emphasising national sovereignty and the protection of legacy industries. While successive governments have signalled a commitment to the energy transition through renewables expansion, grid investment and large-scale low-carbon projects, policymaking remains fragmented and contested. Renewable deployment has accelerated, but key enabling reforms—particularly for onshore wind—remain politically sensitive. Recent vetoes underline uncertainty over the pace of further RES build-out. Coal continues to sit at the centre of political and social tensions, with strong mining unions and regional dependence constraining a clear and credible phase-out path. As a result, energy policy is often shaped by short-term political considerations. Long-dated targets and flagship investments are used to signal ambition, but the most disruptive reforms are deferred beyond the electoral cycle, leaving the underlying structural challenges of decarbonisation, security of supply and market design unresolved.

3.4.3 Policy overview

Ensuring a just transition and energy security are the two main objectives of Poland's energy policy:

1. **Managing the coal transition while maintaining adequacy:** EU climate policy and market signals point toward a continued reduction in coal generation, but coal still contributes to near-term adequacy. Poland is therefore using the capacity market as a bridge. A key recent development is that the European Commission granted a derogation in 2025 allowing coal units to remain eligible for supplementary capacity auctions until end-2028. A supplementary auction is held when the level of generating capacity offered under the main auction (and any earlier supplementary rounds) for a given supply year is insufficient. The supplementary auction for delivery year 2026 was held at end-2025, and additional auctions for delivery year 2027 are expected to take place during 2026, depending on whether the system operator deems additional capacity necessary.

2. **Scaling wind as the main near-term decarbonisation lever:** Offshore wind is moving from policy ambition to delivery and is becoming a core pillar of the future system. The first competitive CfD auction in December 2025 awarded support to more than 3 GW of offshore wind capacity, strengthening investor confidence and setting the stage for further rounds. Onshore wind is also central to decarbonisation efforts because it is typically the cheapest new generation capacity available. However, additional onshore wind capacity will depend on permitting reform and political follow-through, which has proven inconsistent over time.
3. **Nuclear is important for security and decarbonisation**: Nuclear remains the government's key option for large-scale, low-carbon baseload power supply and energy security, with a stated target of 6–9 GW by 2040. However, the programme carries significant delivery risk and the market increasingly assumes that the first power will arrive in the late 2030s. In December 2025, the European Commission approved, under EU state-aid rules, an aid package to support the construction of the first nuclear power plant in Poland. However, Poland's nuclear power program has experienced a significant shift in its timeline, with the commissioning of the first reactor now pushed back by approximately three years, from the original target of 2033 to 2036.
4. **Resolving grid bottlenecks**: Grid capacity is becoming the binding constraint for both renewables and storage deployment, so policy is shifting towards enabling network build-out and smarter access rules. The 2025–2034 network plan prioritises new lines and substations and supports stronger north–south transfer capacity to help integrate offshore wind and northern generation. In parallel, proposed connection-rule changes aim to reduce "queue blocking" and improve network utilisation through higher upfront commitments, shorter validity periods, more flexible connection arrangements, and wider use of cable pooling.

Overall, the policy mix focuses on efforts to ensure a just transition and security of supply. Persistent delivery risk, grid constraints and policy fragmentation mean that actual outcomes will be driven as much by success in execution and coordination as by stated ambitions.

3.4.4 Relevant market developments

Several developments are shaping near-term market conditions and adding uncertainty:

- Investment interest in battery storage systems has risen sharply, supported by subsidy schemes. The December 2025 subsidy scheme was heavily oversubscribed, suggesting a strong pipeline. However, delivery will still depend on grid access, permitting, and project execution.
- Household electricity prices have been repeatedly frozen in recent years. Measures have been approved to extend the freeze through end-2025 by setting a cap of 500 PLN/MWh for household electricity prices. It is currently unclear whether the cap will not continue into 2026 or whether an alternative price control scheme will be implemented.

Table 4. Political developments in Poland that are most relevant for the Nordics

DEVELOPMENT	RELEVANT MODELLING ANALYSIS	SENSITIVITY CHAPTERS	UNCERTAINTY LEVEL
Policy: Nuclear	Nuclear would replace coal plants as firm capacity. See **sensitivities on capacity mechanisms and firm capacity build out** (chapter).	4.2	High
Policy: Coal phase-out schedule	The speed of Poland's coal phase-out and adjustments to the capacity mechanism might impact both base and peak prices in the Nordics. See **sensitivities on capacity mechanisms and firm capacity build-out** (chapter).	4.2	Medium
Policy: Wind capacity expansion	Poland aims to expand its offshore and onshore wind capacity. To analyse the effect of increased renewable capacity on the Nordics, see the **sensitivities on renewable capacity build-out** (chapter).	4.3.1 4.3.2 4.3.4	Medium
Policy: Grid expansion	Internal grid expansion in Poland affects trade volumes, congestion rents, and prices in the Nordics. See our **sensitivities on interconnectors and trade restrictions** (chapter).	4.4	Low
Market development: Battery.	The speed of the expansion of Polish battery capacity depends mainly on whether grid connection problems can be overcome. To understand the impact of higher battery capacity on Nordic prices, see **our sensitivity on battery capacity build-out** (chapter).	4.3.3	Low
Market development: Household cap	The household electricity price cap in Poland will likely have a **negligible impact** on Nordic prices.		Low

3.5 Baltics

3.5.1 Summary

Recent geopolitical developments have exacerbated the Baltics' already strained relationship with Russia. The three countries were quick to ban gas imports after the Russian invasion of Ukraine and fast-tracked the process of desynchronising from the BRELL ring shared with Russia and Belarus. Efforts continue towards ensuring security of supply, while balancing EU-wide green transition ambitions.

3.5.2 Political backdrop

All three Baltic countries have seen changed government coalitions within the last two years, due to internal conflicts within the coalitions and allegations of conflicts of interest. The new coalitions are generally large—2, 3 and 4 parties make up coalitions in Estonia, Latvia and Lithuania respectively. This, along with increasing uneasiness surrounding geopolitical issues, could make it harder to make significant reforms in support of a green transition. As an example, in Estonia, an onshore wind support scheme has been effectively held up since June of last year by one of the two coalition parties, which believes that a different support scheme should be finished first. As a general trend, the governments of the Baltic countries currently put a strong emphasis on national security and increased defence spending, and favour cutting taxes, tariffs and state spending to help improve the economic situation.

3.5.3 Policy overview

Lithuania has been one of the EU countries most dependent on power imports ever since it had to close the Ignalina nuclear plant in 2009. Latvia has a power system largely built on hydropower, but also uses significant gas-fired generation, for which it historically relied greatly on Russian imports. Estonia has, by virtue of its oil shale power, been more independent than its Baltic neighbours historically, at a cost of significantly higher CO_2 emissions. Estonia needs to ensure that it can decarbonise without giving up its energy independence.

The Baltic countries' energy policies are centred around the main goal of **security of supply**:

1. **Renewable expansion:** Build-out of renewable capacity is key to ensuring sufficient power generation. Lithuania, especially, has seen a boom in installations in recent years and has significantly reduced its need for imports. RES build-out remains important in all three countries, but it is worth noting that both Estonia and Latvia have abstained from giving specific numbered targets for installed solar and wind capacities in the most recent EU NECP documents.
2. **Phase-out of oil shale (Estonia):** Estonia needs to phase out power from oil shale. However, this needs to happen alongside the introduction of sufficient new *flexible* capacity, not just intermittent solar and wind. Currently, this is happening through a combination of batteries and gas-powered capacity. It is also worth

noting that the phase-out of oil shale in the Estonian power mix is continually being delayed. When oil-shale power plants will finally be shut down remains to be seen.

3. **Grid infrastructure**: Though not wishing to depend heavily on power imports, the Baltics see interconnection with neighbouring systems as key to their security of supply. They are themselves well interconnected and continue to build out transmission capacity to Finland and Poland. In addition to working on new cables, infrastructure *protection* has surfaced as a key part of maintaining grid infrastructure after several instances of sabotage in the Baltic Sea (notably the severing of Estlink 2 in December 2024).
4. **Affordable energy:** Security of supply should be balanced with the need for affordable energy for Baltic residents, meaning the most affordable options for power generation should be the focus of new build-out. The Estonian government recently ordered Elering to prioritise lower energy prices.

3.5.4 Relevant market developments

Some recent events of note include:

- **Synchronisation with the Continental Europe Synchronous Area**: The Baltic countries successfully decoupled from the BRELL system on February 8th 2025 and synchronised with the Continent on the following day. This was the result of many years' work and is representative of the shift away from Russia. The feat required extensive infrastructure upgrades and new-build transmission projects in the Baltic countries and Poland, as well as the addition of synchronous condensers and BESS to support the balancing of the electricity system.
- **Overwhelming interest in Lithuanian energy storage procurement:** In August 2025, the Ministry of Energy announced the closure of a procurement process for 800 MWh of electric storage capacity. The tender significantly exceeded expectations, resulting in the procurement of 4 GWh of storage capacity.
- **Massive price fluctuations in Baltic reserve markets could drive BESS installations:** Extreme price instability was observed in the Baltic reserve markets in 2025. An expected continuation of fluctuations and high prices in these markets along with large Day-Ahead and Intraday spreads promise high yields and low payback periods for flexibility providers such as batteries. There could be a boom in installed BESS capacity in the Baltics in the next few years, but the potential to earn high profits is expected to subside over time as competition increases.
- **Fluctuating wind support scheme plans in Estonia:** The previous Estonian government coalition, after much debate and back and forth, announced their plans for support schemes for up to 2 TWh of both offshore and onshore wind in January of last year. The support scheme for offshore wind was, however, cancelled within a month of plans being published. The planned support for onshore remains (though it is currently being stalled, as previously described). Offshore wind producers may instead be offered state loan guarantees.

- **Increasing interest in nuclear power in the Baltics:** 2025 saw all three Baltic states discuss the possibility of introducing nuclear power to their energy systems. Estonia has the most advanced plans. The Estonian parliament passed a resolution supporting nuclear power, and the firm Fermi Energia started the site selection process for their two SRMs last year. Lithuania has historically had nuclear power and could capitalise on their experience to efficiently develop new nuclear power. Latvia, meanwhile, has stated an interest in nuclear power, but is currently leaning towards developing this in collaboration with Estonia, on Estonian land. Nuclear power in the Baltics remains uncertain, but policies are already changing to try to accommodate nuclear power. For example, Estonia has switched from a target of 100% "green" energy to "clean" energy, opening the door for nuclear power to contribute.

Table 5. Developments in the Baltics that are most relevant to the Nordics

DEVELOPMENT	RELEVANT MODELLING ANALYSIS	SENSITIVITY CHAPTERS	UNCERTAINTY LEVEL
Build-out of nuclear power	There are discussions about building new nuclear plants in all three Baltic countries to provide additional firm capacity. To study the effect of additional firm capacity on the Nordics, see the **sensitivity on capacity mechanisms and firm capacity build out.**	4.2	High
Renewable expansion	Baltic countries continue to build out renewables, but there remains uncertainty due to a lack of detailed targets in Estonia and Latvia and the delayed implementation of a RES support scheme in Estonia. See **sensitivities on renewable capacity build-out.**	4.3.1 4.3.2 4.3.4	Medium
Grid infrastructure	To understand the effect of reduced trade capacity or regulatory trade restrictions on the Nordics, compare the **sensitivities on the capacity and availability of interconnectors and on trade restrictions.**	4.4	Medium
Phase-out of Estonian oil shale	Estonia needs more flexible and firm generation to compensate for the phase-out of oil shale. Compare the **sensitivities on firm capacity mechanisms and battery capacity expansion.**	4.2 4.3.3	Low

↑ **Images:** iStock

4. Impact analysis of regulatory reforms on Nordic electricity markets

4.1 Description of the methodological approach and the baseline scenario

We use THEMA's fundamental electricity market model, TheMA, to simulate market outcomes for 2035 and run sensitivities to examine the effect of alternative regulatory developments on Nordic prices, trade flows, and welfare.

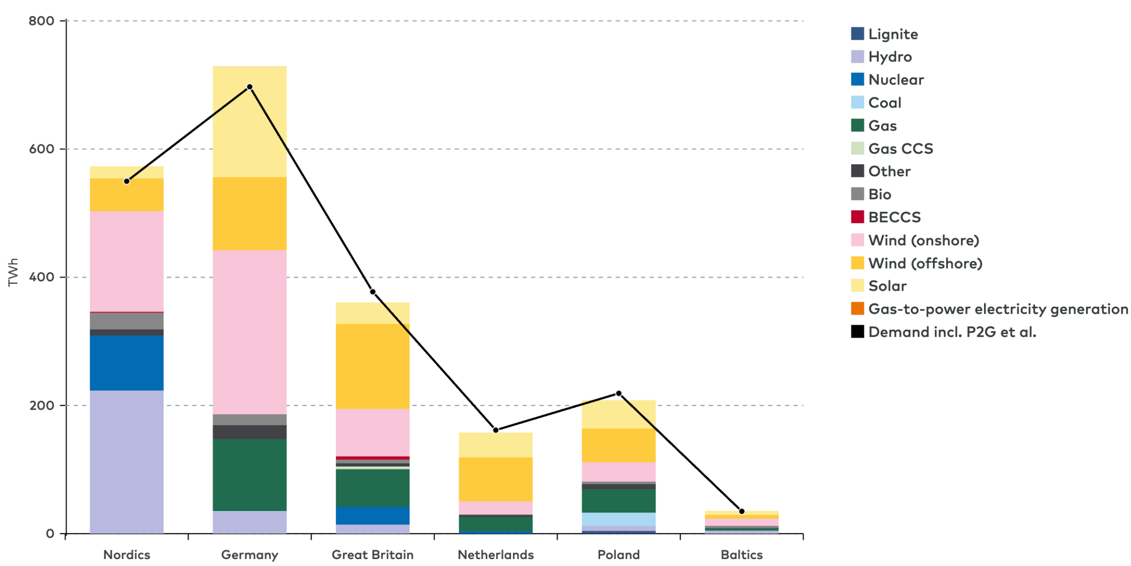
THEMA determines hourly wholesale prices by finding the intersection of supply and demand, with prices set by the marginal cost of the price-setting generator. The model uses linear programming techniques to solve this cost minimisation problem subject to technical constraints including start-up costs, minimum load requirements, and ramping limitations. THEMA incorporates detailed representations of thermal power plants, hydropower systems, and variable renewable generation based on historical production profiles. Cross-border electricity flows are optimised based on price differentials between bidding zones under NTC constraints. We use the NTC approach rather than flow-based market coupling, as there are no reliable parameters available to model flow-based electricity trade for 2035. While flow-based market coupling is used in day-ahead markets in continental Europe and the Nordics today, projecting the relevant grid parameters and constraints a decade into the future would introduce significant uncertainty. The NTC approach relies on fewer input assumptions and therefore introduces less compounding uncertainty, making it a more robust and transparent framework for assessing cross-border trade dynamics in long-term scenarios.

We use the model to calculate a baseline scenario and then systematically vary key input assumptions to assess how deviations from the baseline affect Nordic electricity prices, trade flows, and welfare. This allows us to isolate the price effect of specific policies and developments.

We use THEMA Base as our baseline scenario, which describes a credible development pathway for European electricity markets through 2035. The scenario assumes that gas-fired generation continues to play an important role as dispatchable firm capacity during the energy transition, providing flexibility as coal plants retire across Continental Europe. CO2 prices increase over the outlook horizon, strengthening the incentive to decarbonise, while gas prices remain relatively stable. Electricity demand grows moderately, driven mainly by gradual electrification of transport and heating, while conventional industrial demand remains subdued due to slow economic growth. The EU maintains its 2050 net zero ambition, and renewable generation expands substantially—though capacity build-out falls short of government targets in key European countries due to permitting constraints, supply chain limitations, and financing challenges. Hydrogen deployment is substantially delayed until 2035 relative to current targets. Some new interconnection capacity is installed, though not all planned projects are realised by 2035.

Figure 1 shows the development of the generation mix and total electricity demand in THEMA Base for 2035. More detailed assumptions for individual generation technologies or interconnector capacities are presented in the relevant sections below, alongside the sensitivity definitions for each regulatory trend.

Figure 1. Total electricity demand and generation mix in the Nordics and selected European countries in THEMA Base in 2035



The sensitivities we are simulating are described in the sections below, and focus on the following input variations:

1. Changes in firm capacity to reflect effects of capacity mechanisms (Section 4.2)
2. Changes in renewable capacities and battery developments, reflecting changes in renewable targets, support systems, and build-out trajectories (Section 4.3)
3. Changes in interconnector availabilities and trade arrangements, reflecting policies or developments like internal bottlenecks, tariffs, or surcharges that could reduce trade opportunities (Section 4.4)
4. Changes in bidding zone topologies (Section 4.5)

4.2 Capacity mechanisms and build-out of firm gas capacity in Germany and Poland

In this section, we investigate how Nordic electricity prices react to capacity mechanisms and firm capacity expansion in Germany and Poland. Both countries are planning substantial gas-fired capacity additions: Germany's Kraftwerksstrategie targets 12 GW of additional firm capacity by the early 2030s, while Poland's TSO PSE estimates that approximately 12 GW is required to compensate for coal plant retirements.

The implementation and scale of these mechanisms remain uncertain. Our sensitivities test what happens to Nordic prices if capacity mechanism implementation is delayed, if governments fully deliver on their plans, or if security of supply concerns drive additions beyond current expectations.

4.2.1 Germany and Poland plan substantial gas capacity additions through capacity mechanisms

Figure 2. Operating gas generation capacity, GW

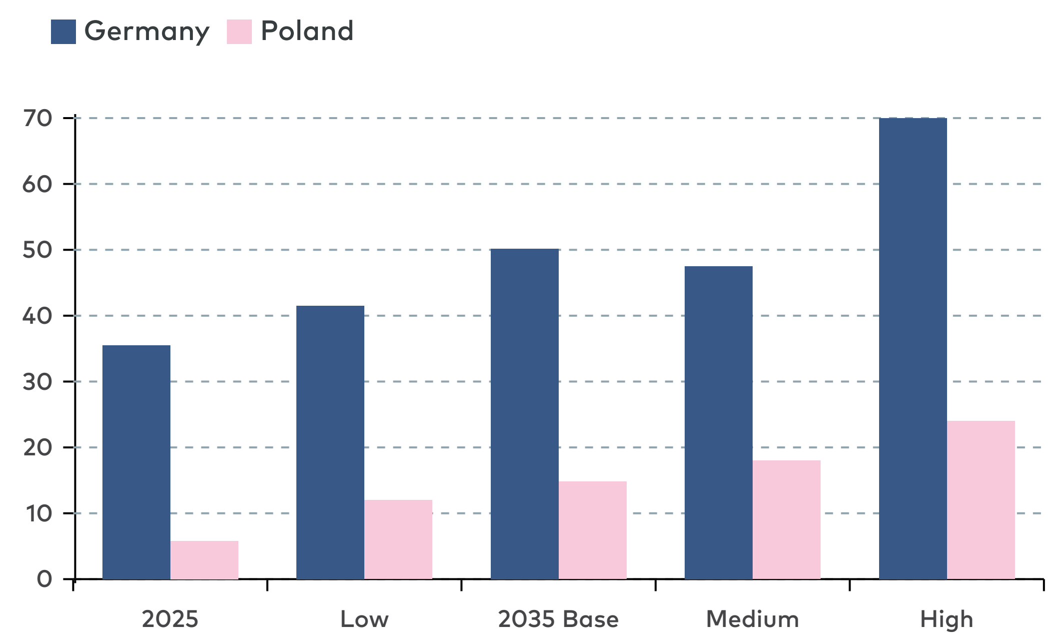


Figure 2 illustrates the gas capacity assumptions underlying our sensitivity analysis. The analysis compares three sensitivities against the THEMA Base scenario. In THEMA Base, Germany reaches 50.2 GW of installed gas-fired capacity by 2035, an increase of roughly 15 GW from 2025 levels, broadly in line with the Kraftwerksstrategie, which targets 12 GW of additional firm capacity by the early 2030s (see hapter 3.1). Poland reaches a total of 14.8 GW of gas-fired capacity by 2035 in THEMA Base, up from 5.8 GW in 2025, consistent with TSO PSE's estimate that approximately 12 GW of new firm capacity is required to compensate for coal plant retirements.

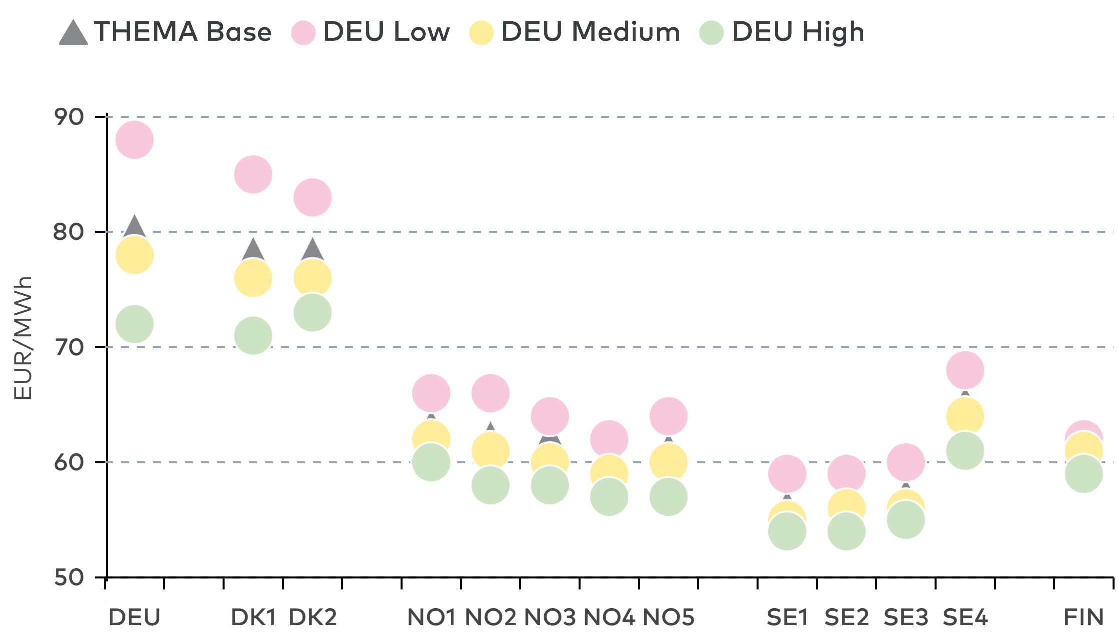
Low sensitivity: Delays in implementing capacity mechanisms and fiscal constraints prevent both countries from delivering planned additions. Each realises only 50% of its targeted expansion. Germany reaches 41.5 GW (+6 GW), Poland reaches 12 GW (+6 GW).

Medium sensitivity: Both countries fully implement their government plans by 2035. Germany reaches 47.5 GW (+12 GW), Poland reaches 18 GW (+12 GW).

High sensitivity: Security of supply concerns and public resistance to price spikes drive capacity additions beyond current plans. Germany reaches 70 GW (+35 GW, the maximum need identified in Bundesnetzagentur's security of supply monitoring), Poland reaches 24 GW (+18 GW, 50% above PSE's baseline requirement).

We run each sensitivity for Germany and Poland separately to isolate individual country effects.

Figure 3. Base prices across bidding zones for the sensitivities on German gas capacities

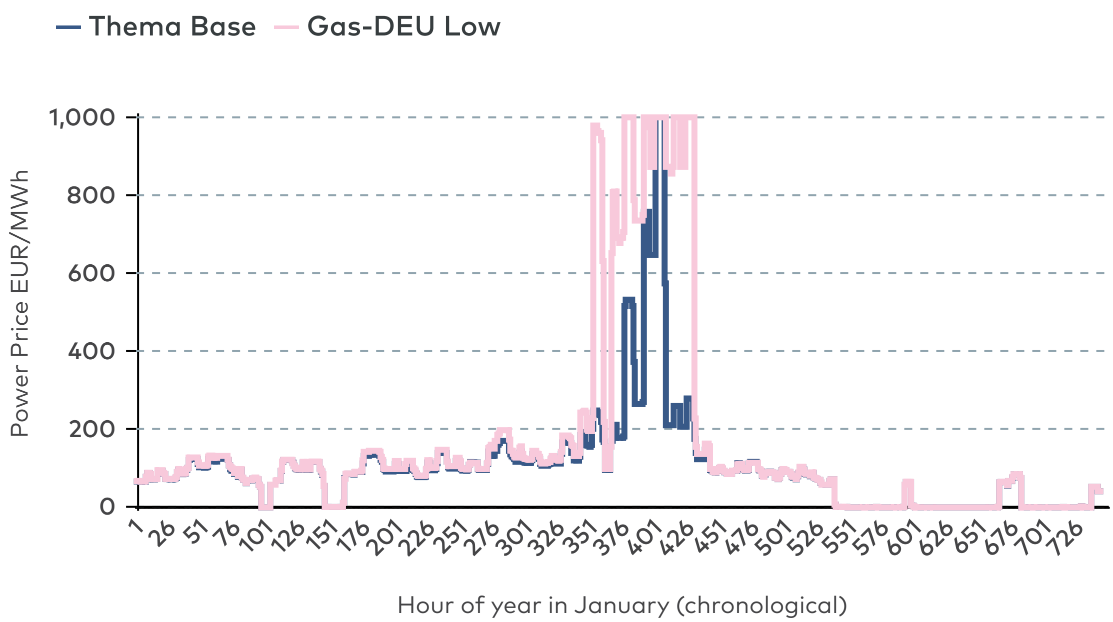


4.2.2 Lower firm gas capacity in Germany leads to more price spikes in the Nordics

Figure 3 shows base prices in Germany and Nordic bidding zones under the sensitivities on German gas capacity. When gas-fired capacity in Germany remains low (DEU Low), Nordic power prices increase moderately by 1–7 EUR/MWh compared to THEMA Base. The effect is most pronounced in Denmark. Danish prices are in general more correlated and coupled with prices in Germany than the other Nordic bidding zones. Norwegian and Swedish zones show smaller but still tangible effects, though price levels in SE4 are notably higher than in other Swedish zones due to its stronger interconnection with the higher-priced Danish and German markets. Finland is least affected by the changes.

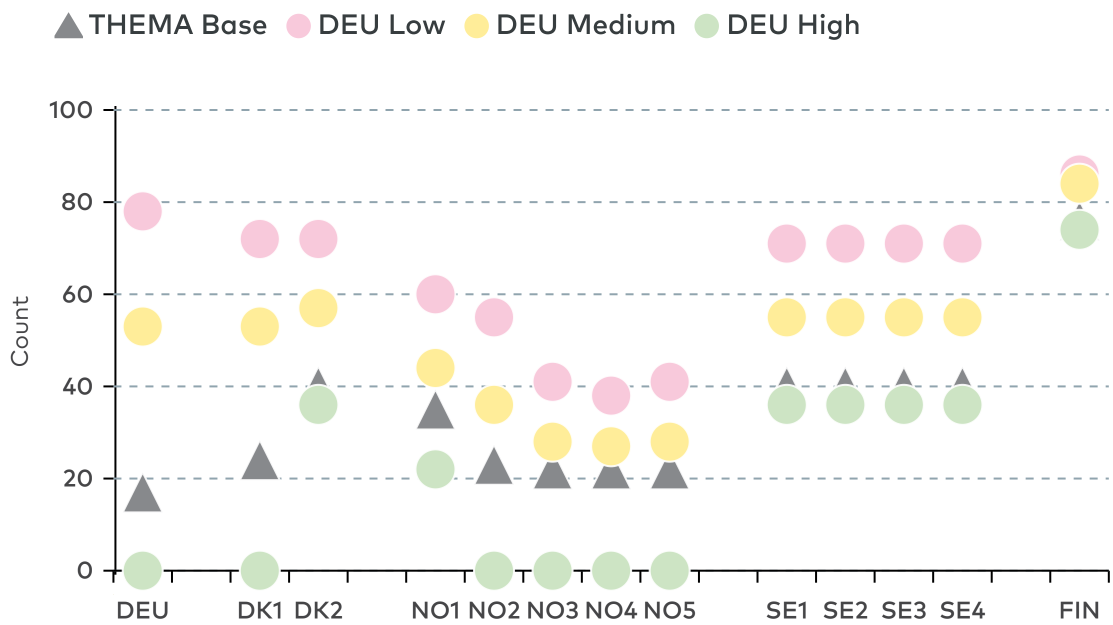
The Polish gas capacity sensitivities produce only negligible effects on Nordic prices as Figure 29 in the Appendix highlights. This is a result of the fact that the Nordic system is coupled more with Germany than with Poland. Hence, the Nordic market is less exposed to changes in Poland.

Figure 4. Hourly electricity prices in January in DK1, EUR/MWh



The reason that prices change is not because prices in all hours change, but that the number of price spikes changes between the firm capacity scenarios. Figure 4 illustrates hourly prices for January in DK1 under the THEMA Base and DEU Low scenarios. The increase in average prices under low German gas capacity stems almost entirely from a higher frequency of peak price events rather than from elevated prices during other hours. Prices in DK1 during non-peak hours remain similar across scenarios. This indicates that price spikes, which become more frequent in Germany with lower firm capacity, transmit into Nordic bidding zones.

Figure 5. Number of peak prices above 500 EUR/MWh



This is also indicated by Figure 5 which shows the number of hours with peak prices above 500 EUR/MWh for Germany and all Nordic bidding zones across the German gas capacity sensitivities. The analysis uses THEMA's standard 2016 weather year, selected because it represents a meteorologically typical year without extreme wind, solar, or hydrological anomalies. Danish zones show the highest sensitivity to German gas capacity levels among Nordic markets, reflecting Denmark's strong interconnection with Germany. Norwegian and Swedish zones display more moderate sensitivity to German gas capacity. Please note that in some cases, the number of price spikes in the Nordics exceeds the number of price spikes in Germany. This implies also that not all price spikes are "imported", and that also local conditions contribute to the price spikes in Nordic bidding zones. This applies in particular to Finland, where scarcity events are driven primarily by domestic constraints or intra-Nordic transmission limitations rather than by continental factors.

4.2.3 The impact of reduced German gas capacity is more pronounced in a 'normal' weather year

To test the robustness of these findings, we have also analysed what happens under different weather conditions. As explained above, the results above are based on one particular weather pattern (2016), and do not reflect the full range of system stress that can occur under different meteorological conditions. However, in the Nordics, weather variability is a key driver of scarcity events: some years are characterised by prolonged periods of low wind and solar generation combined with high demand (so-called "Dunkelflaute" events), while others are milder with ample renewable output.

To assess the robustness of Nordic markets to reduced firm capacity in Germany, we run both the THEMA Base and DEU Low scenarios across 25 historical weather years (range of weather conditions from 2000-2024). This allows us to test whether the increase in peak price exposure under lower German gas capacity is systematic across weather conditions or concentrated in specific types of years.

In the simulations we differ renewable feed-in and hydrological inflow and demand according to observed historical weather conditions. This is done consistently across all European markets and bidding zones and technologies. For each weather year, the THEMA power market model then simulates dispatch and prices. This approach reveals how the same power system configuration responds to different weather patterns and captures the distribution of outcomes across historical weather variability.

Figure 6. Number of peak prices for different weather years in THEMA Base and DEU Low

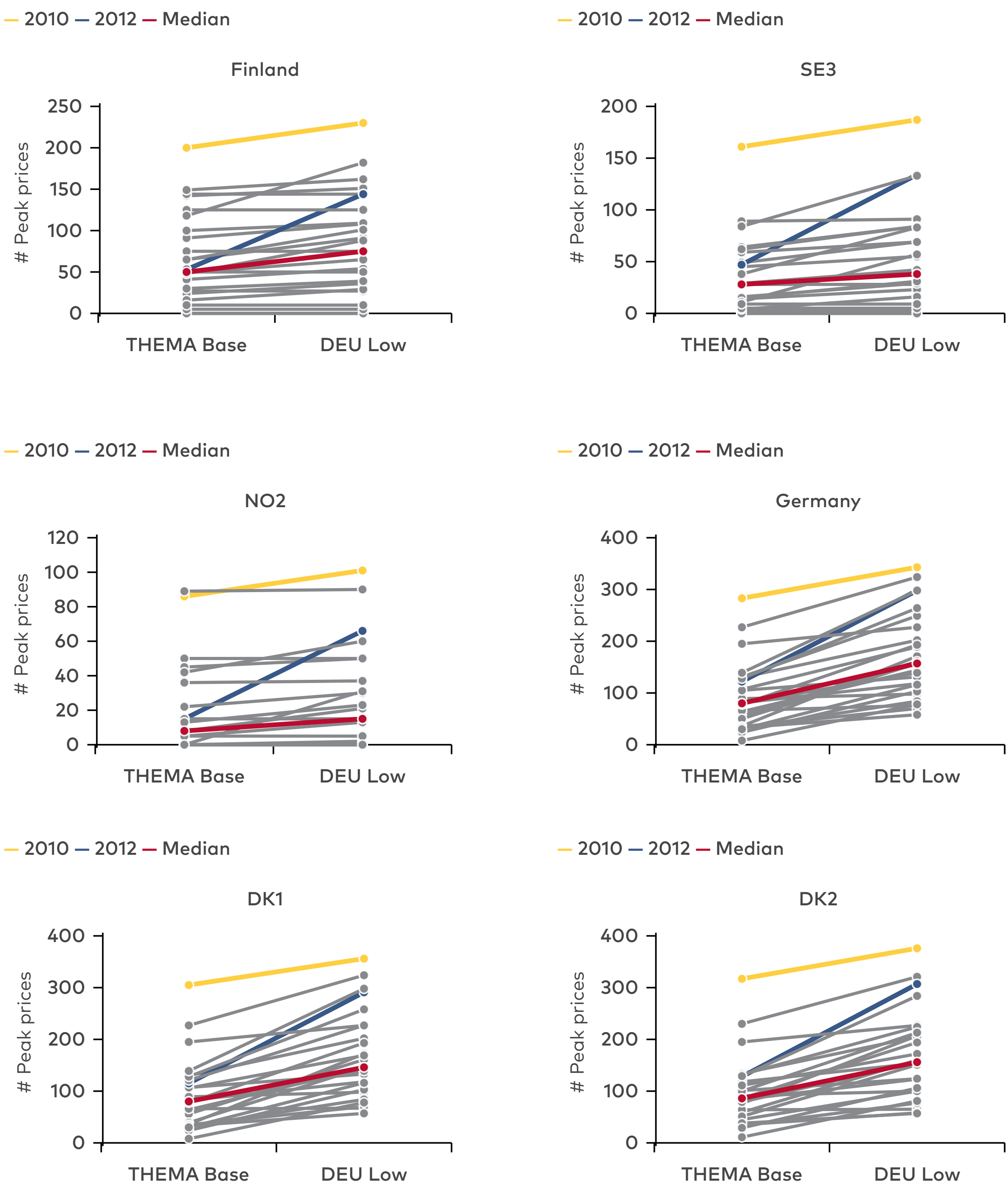


Figure 6 above shows the number of peak price hours above 500 EUR/MWh for selected Nordic zones and Germany for THEMA Base and DEU Low.[1] Each grey line represents one weather year, connecting peak price counts in THEMA Base (left) to DEU Low (right). The red line shows the median across all years. Two representative years are highlighted: 2010 (yellow), an extreme weather year with high scarcity already in THEMA Base, and 2012 (blue), a more typical year with a roughly average number of peak price hours in THEMA Base.

Figure 6 shows that the overall conclusion remains valid: The lower the assumption on firm capacity in Germany, the higher the peak price count across weather years. At the same time, the magnitude of the effect is very different from weather condition to weather condition and differs from zone to zone.

The variations in results can be understood through the concept of tipping points in price formation.[2] In some weather years (like 2012), the system operates closer to the tipping point even under baseline capacity assumptions. While 2012 was meteorologically unremarkable in aggregate, it featured specific periods where moderate renewable shortfalls coincided with seasonal demand peaks — conditions that are not extreme individually but sufficient to push dispatch into the steep segment of the merit order. In this regime, even modest reductions in firm capacity can trigger disproportionate price responses, as the system tips from comfortable margins into scarcity pricing. By contrast, extreme years such as 2010 feature prolonged periods where the system is already deep in scarcity regardless of the capacity assumption. Reducing firm capacity further does not materially increase the peak price hour count — prices are already elevated, and the system has long passed the tipping point.

Norwegian zones with high domestic flexibility, such as NO2, display lower exposure to peak prices, but also here the effect depends on the weather conditions. The Danish zones, DK1 and DK2, on the other hand, closely mirror German outcomes.

Overall, reduced German gas capacity increases Nordic peak price exposure, but the effect differs with weather conditions and with the bidding zone one examines.

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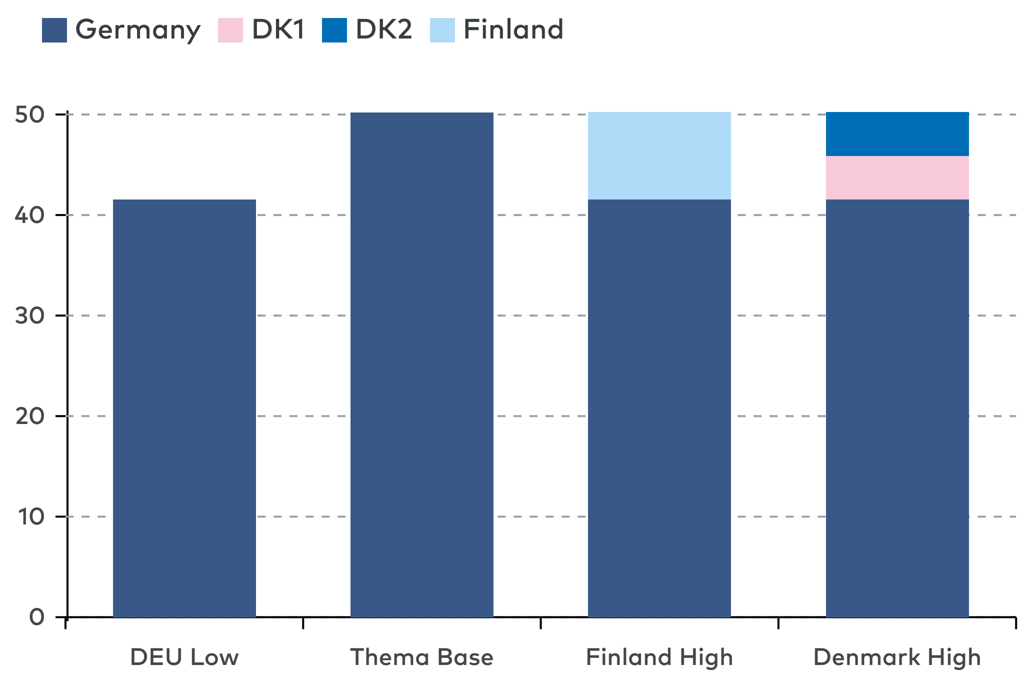
1. To reduce the complexity of Figure 6, we focus on NO2 and SE3 since these are the zones with the highest electricity demand in Norway and Sweden.
2. When demand is low or renewable output is high, the system clears on the left side of the merit order where cheap generation (renewables, nuclear) sets the price. When demand is high and renewable output is low, the system clears further to the right, where more expensive thermal plants set the price. The "tipping point" occurs when the system approaches the steep right-hand portion of the merit order, where small changes in available capacity can lead to large price changes. Beyond a certain threshold, prices rise sharply as the system exhausts lower-cost options and must rely on peaking units or demand response—or, in extreme cases, faces scarcity pricing.

Figure 7. Operating gas-fired generation capacity, GW



4.2.4 Additional Nordic firm capacity can offset lower German gas capacity and reduce regional peak prices

The previous analysis shows that lower German gas capacity increases peak price exposure in Nordic electricity markets, particularly in zones closely connected to Continental Europe. This raises a key policy question: Can Nordic countries mitigate this risk by deploying additional domestic firm capacity, thereby reducing dependence on continental capacity adequacy?

To examine this possibility, we run two additional sensitivities in which Nordic countries respond to lower German gas capacity by adding compensating firm capacity domestically. Figure 7 illustrates the gas capacity assumptions across scenarios.

DEU Low: Germany builds 8.7 GW less gas capacity than in THEMA Base, reaching 41.5 GW instead of 50.2 GW. No compensating capacity is added in the Nordics.

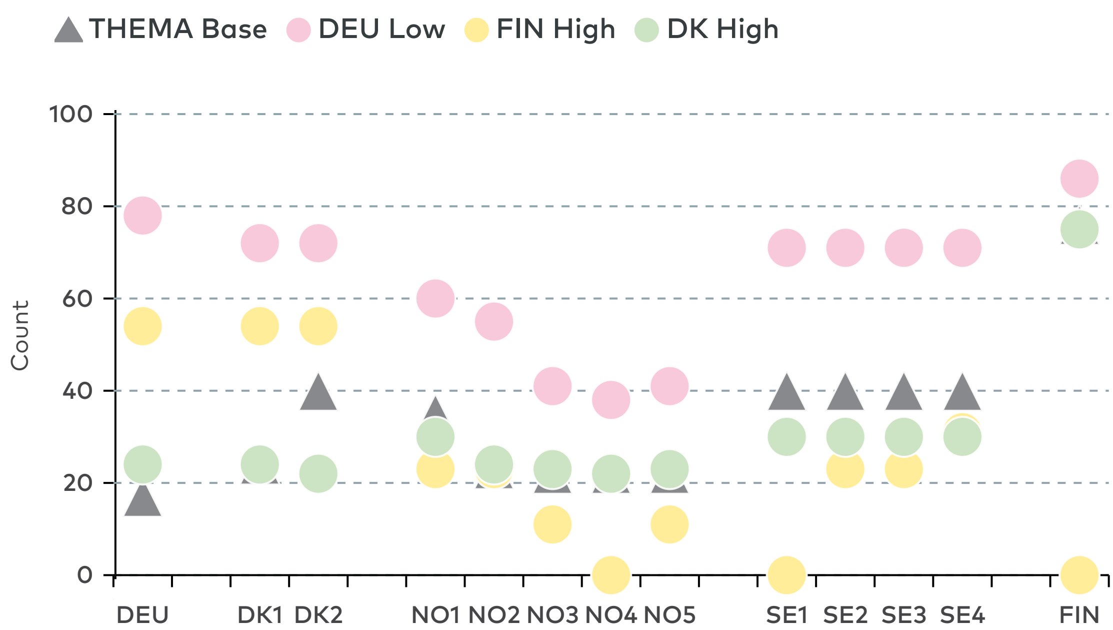
FIN High: Germany builds 8.7 GW less gas capacity, while Finland adds 8.7 GW of gas-fired capacity to offset the German shortfall.

DK High: Germany builds 8.7 GW less gas capacity, while Denmark adds 8.7 GW of gas-fired capacity, split evenly between DK1 and DK2 (4.35 GW each).

The sensitivities are not necessarily meant to reflect any realistic policy scenario or recommendation but are meant to inform about what happens to the number of price spikes if new capacity is domestically deployed instead of abroad. Figure 8 shows the number of peak prices hours above 500 EUR/MWh across Germany and the Nordic bidding zones under the four scenarios: THEMA Base, DEU Low, FIN High, and DK High.

Additional firm gas capacity in Denmark or Finland can in fact mitigate the impact of lower German gas capacity. In most bidding zones, the FIN High and DK High scenarios result in markedly fewer peak price hours than DEU Low. In several zones, peak price counts even fall below THEMA Base levels, despite Germany having 8.7 GW lower/reduced gas capacity. This demonstrates that strategically located Nordic firm capacity can more than offset German capacity shortfalls in terms of regional scarcity outcomes.

Figure 8. Number of peak prices above 500 EUR/MWh



Notably, Nordic gas capacity additions also reduce peak prices in Germany. Under DK High, German peak prices fall to 24 hours, nearly matching THEMA Base levels and almost fully compensating for the reduction in German gas capacity. During scarcity events, Danish gas-fired plants export power to Germany, effectively acting as backup generation when German supply is tight. Finnish gas capacity also lowers German peak prices, though the effect is smaller due to weaker direct market integration. These results highlight the strongly interconnected nature of European electricity markets: firm capacity located in well-connected neighbouring countries can contribute meaningfully to cross-border security of supply. Note, however, that we have not considered any internal grid constraints (e.g. within Germany) in this analysis.

4.3 Policy support schemes for renewable generation and battery storage

In addition to firm capacity, two other factors will shape power system development and can be highly influenced by policy measures and support schemes: renewable build-out and investments in batteries. The pace of renewable energy and battery expansion in continental Europe could vary significantly depending on how these policies evolve.

Several factors could slow expansion below current government targets. Offshore wind auctions have struggled in some countries due to high costs and supply chain constraints, while solar expansion faces grid access limitations. Battery deployment remains constrained by grid availability and uncertain market revenues. At the same time, conditions could also prove more favourable than expected. Falling technology costs, streamlined permitting procedures, or more generous support schemes could accelerate deployment beyond current plans. Given this uncertainty in both directions, we test sensitivities ranging from significant shortfalls to overachievement of government targets.

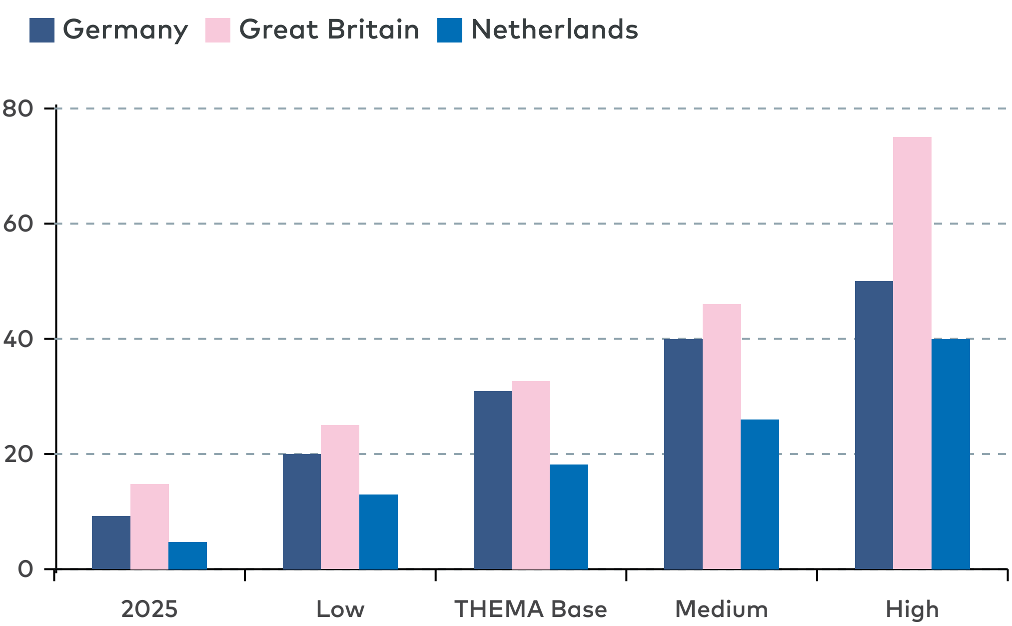
We investigate the following cases:

- Higher and lower offshore wind deployment, to isolate the price effect of more and less offshore deployment
- Higher and lower solar deployment, to isolate the effect of more and less solar deployment
- Higher and lower battery deployment, to isolate the effect of batteries
- Higher and lower battery deployment in combination with higher solar deployment

4.3.1 Offshore wind expansion could strongly impact Nordic prices

We run three sensitivities to test how changes in offshore wind capacity in Germany, Great Britain, and the Netherlands affect Nordic electricity prices, capture prices, and price structures. Figure 9 illustrates the offshore wind capacity assumptions across scenarios.

Figure 9. Operating offshore wind generation capacity, GW



Low sensitivity: Countries do not meet medium-term government targets due to unattractive subsidy schemes and high financing and equipment costs. Germany, Great Britain, and the Netherlands each achieve only 50% of the capacity aimed for by the government targets, reaching 20 GW in Germany, 25 GW in GB, and 13 GW in the Netherlands.

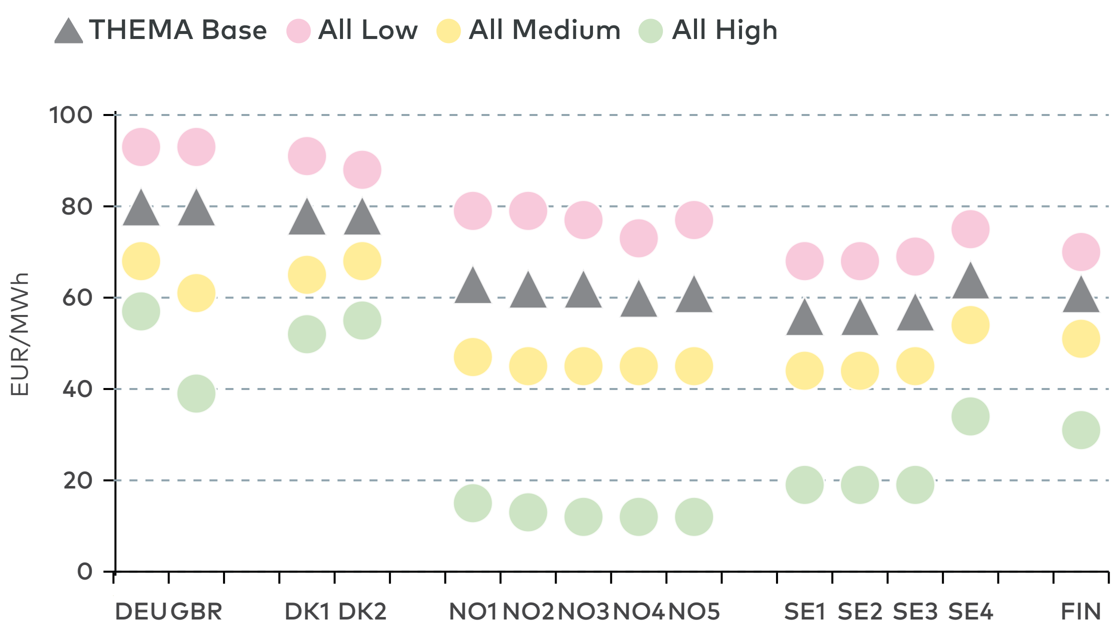
Medium sensitivity: Countries reach their medium-term offshore wind government targets by 2035. Germany meets its 2035 target of 40 GW. Great Britain reaches 46 GW, the midpoint of its 2030 target range of 43–50 GW. The Netherlands reaches 26 GW, on track toward its 2040 target of 30–40 GW.

High sensitivity: Countries overachieve government targets due to reduced financing and equipment costs and generous subsidy schemes. Germany reaches 50 GW, consistent with the government's Offshore Realisation Agreement. Great Britain reaches 75 GW (150% of its 2030 target). The Netherlands achieves 40 GW, meeting its 2040 target already by 2035.

We run each sensitivity for Germany, Great Britain, and the Netherlands simultaneously—that is, all three countries reach their respective Low, Medium, or High capacity levels in the same scenario. This approach reflects the fact that offshore wind build-out is correlated across countries. Beyond national regulatory support schemes, offshore expansion depends on equipment costs, capital availability, and supply chain capacity—factors that are largely shared across the North Sea region. If financing conditions or equipment costs prove more challenging than expected, this is likely to affect all countries; conversely, favourable conditions will benefit the entire region.

Figure 10 shows base prices across Nordic and continental bidding zones under the offshore wind capacity sensitivities. Offshore wind capacity expansion in Germany, Great Britain, and the Netherlands strongly reduces baseload prices across all Nordic zones. Norwegian zones react most strongly, with prices falling by more than 75% in the All High scenario compared to THEMA Base. Swedish, Finnish, and Danish prices decline as well, though less dramatically. Danish zones follow a pattern more similar to Germany than to Norway, reflecting Denmark's strong interconnection with continental markets.

Figure 10. Base prices for the offshore wind sensitivities



The strong impact of offshore wind on Norwegian prices is driven by water value dynamics. High offshore wind deployment creates substantial surplus generation in the North Sea region—the number of zero- and negative price hours in Germany almost doubles in the All High sensitivity relative to THEMA Base. When continental prices are depressed, export opportunities for Norwegian hydropower become less attractive, causing water values to fall. This translates directly into lower Norwegian wholesale prices, with the decline driven by a substantial increase in low-price hours.

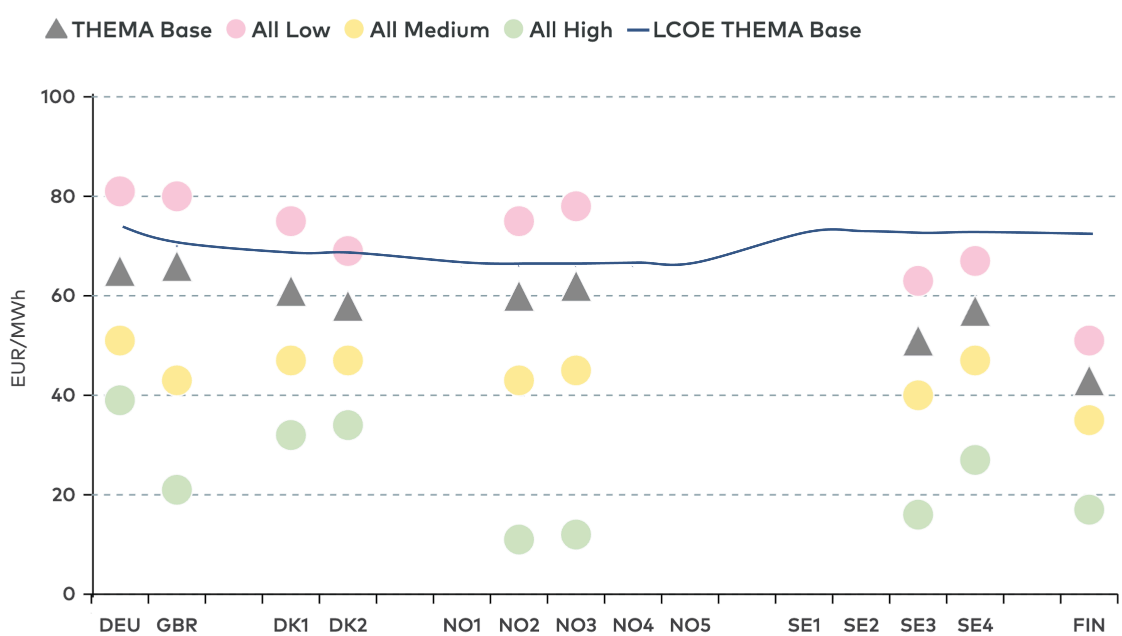
However, price spikes persist even under very high offshore wind capacity. Nordic prices still reach up to 1,000 EUR/MWh during scarcity events, with the number of price spike hours declining only moderately. This pattern emerges because offshore wind cannot provide firm capacity during Dunkelflaute events—when wind generation drops across the North Sea region, the system remains exposed to scarcity regardless of installed offshore capacity.

The price dynamics caused by higher offshore capacity also reshape trade patterns and congestion rents. Table 6 and Table 7 in the appendix detail annual import and export volumes alongside congestion rents between Nordic and continental price zones. Nordic zones increase imports of cheap continental power during surplus offshore wind generation hours, with Denmark functioning as a transit hub that absorbs and redistributes surplus generation. Export congestion rents on links to Germany and Great Britain increase as price differentials during export hours widen—continental prices spike during low-wind periods while Nordic prices remain depressed due to lower water values. Conversely, import congestion rents decline as prices converge during high-wind hours.

Figure 11 shows that offshore wind capture prices decline strongly as continental offshore capacity increases, with Danish capture prices falling by around 40% in the All High scenario. Notably, offshore wind capture prices remain below LCOE even in THEMA Base across most zones, indicating that offshore wind investment will continue to depend on subsidies through 2035. Higher continental offshore capacity also puts significant downward pressure on Nordic solar capture prices, as shown in Figure 30 in the appendix. This effect occurs because increased offshore wind capacity depresses base electricity prices during hours with high solar generation.

It should be noted that the All High sensitivity represents an extreme scenario. The offshore capacity levels appear unrealistically high unless matched by a corresponding increase in electricity demand, which is not assumed in this sensitivity. Nevertheless, the analysis illustrates the directional impact of ambitious offshore wind deployment on Nordic markets when supply growth outpaces demand.

Figure 11. Offshore wind capture prices for the offshore wind sensitivities, EUR/MWh



4.3.2 Continental solar expansion reduces Nordic prices and depresses solar capture prices

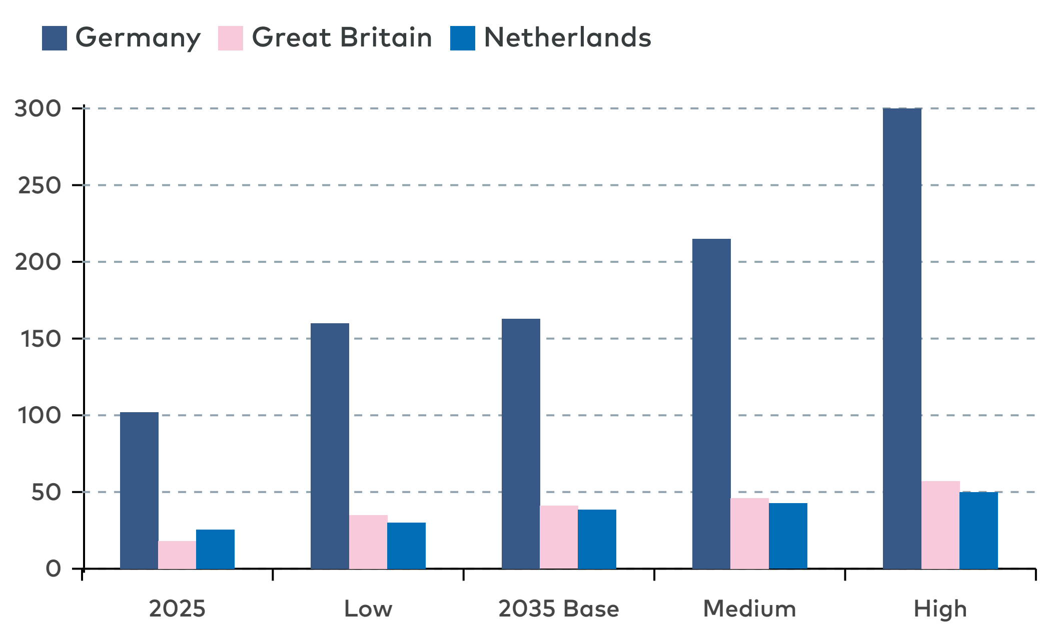
We run three sensitivities to test how changes in solar PV capacity in Germany, Great Britain, and the Netherlands affect Nordic electricity prices, capture prices, and price structures. Figure 12 illustrates the solar capacity assumptions across sensitivities.

Low sensitivity: Countries do not meet medium-term government targets due to less generous solar support schemes and grid connection constraints. Germany achieves 160 GW in 2035, the lower bound of the scenario range in the government's monitoring report. Great Britain reaches 35 GW in 2035, only 75% of its 2030 target. The Netherlands reaches 30 GW, implying a build-out rate at only 50% of the pace required to meet the 2040 government target of 42.6 GW.

Medium sensitivity: Countries reach their medium-term government targets by 2035. Germany and Great Britain achieve their 2030 solar targets (215 GW and 46 GW respectively), while the Netherlands reaches its 2040 target of 42.6 GW already by 2035.

High sensitivity: Germany reaches its government target while Great Britain and the Netherlands overachieve their targets. Germany meets its 2035 target of 300 GW, Great Britain reaches 57 GW (125% of its 2030 target), and the Netherlands reaches 50 GW, building at twice the rate implied by its 2040 target.

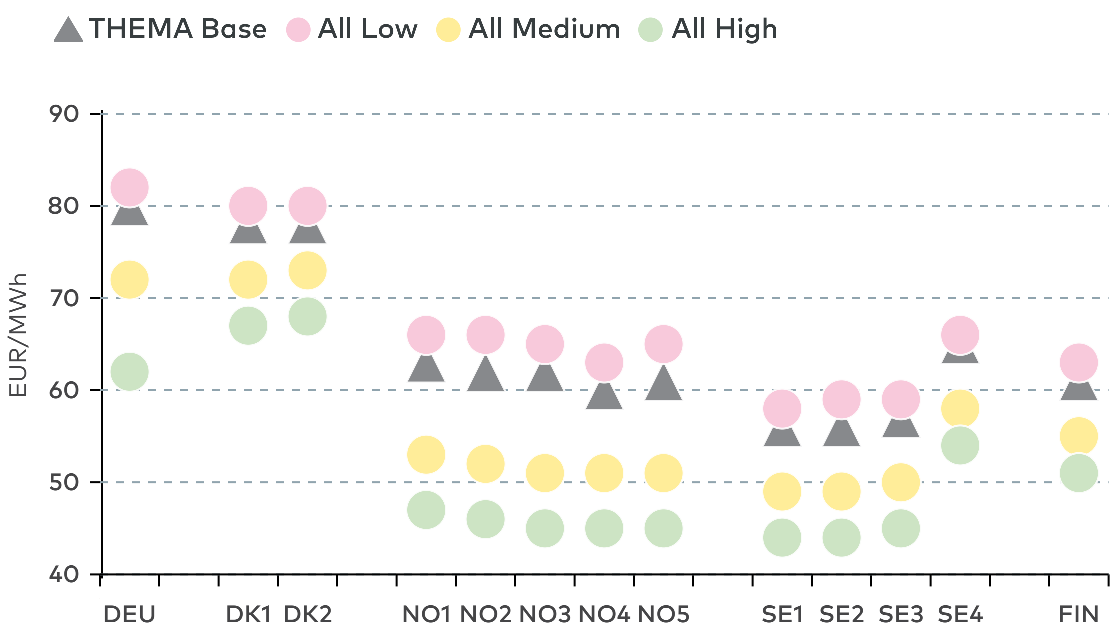
Figure 12. Operating solar PV generation capacity, GW



We run each sensitivity for Germany, Great Britain, and the Netherlands. The Medium and High sensitivities are based on ambitious government targets that presuppose substantial electricity demand growth accompanying the solar expansion.

Figure 13 shows base prices across Nordic and continental bidding zones under the solar capacity sensitivities. In these sensitivities, all three countries (Germany, Great Britain, and the Netherlands) simultaneously reach their respective Low, Medium, or High capacity levels. Higher solar capacity in Continental Europe reduces baseload prices across all Nordic zones, though the effect is more moderate than for offshore wind expansion. Nordic prices decline by around 15–25% in the All High scenario compared to THEMA Base. German prices decline more sharply in both absolute and relative terms.

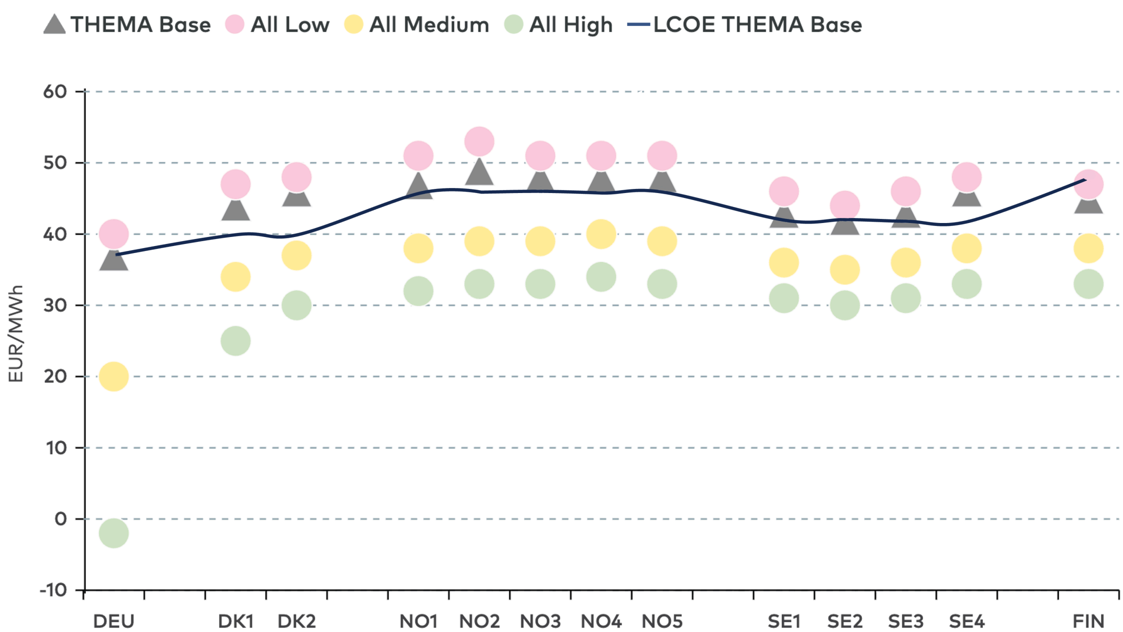
Figure 13. Base prices for the solar capacity sensitivities, EUR/MWh



The decline in baseload prices is partly driven by an increasing number of hours with zero or negative prices as Figure 31 in the appendix shows. Most Nordic zones experience only a significant increase in low-price hours as solar capacity expands, with Danish zones showing the strongest sensitivity due to their direct connection with Germany. The German market faces far more significant changes, with low-price hours rising by more than 50% from THEMA Base to All High reaching approximately 30% of all hours in 2035.

The rising frequency of zero and negative price hours directly depresses solar capture prices. Figure 14 shows that Nordic solar capture prices decline by around 25–40% from THEMA Base to All High, with a consistent pattern across all Nordic zones. Nordic capture prices remain substantially higher than German levels in all scenarios—German capture prices decline far more dramatically, turning even negative under All High.

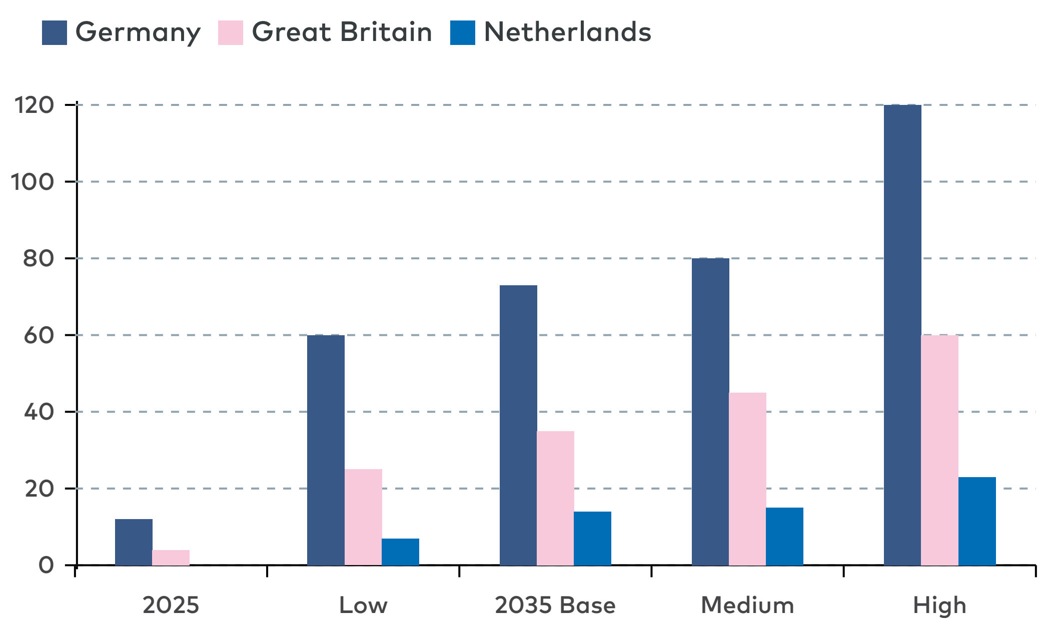
Figure 14. Solar capture prices and LCOEs for the solar PV capacity sensitivities



Comparing capture prices to solar LCOE reveals important implications for investment viability. In THEMA Base and All Low, capture prices in most Nordic zones remain above LCOE, allowing for market-driven solar investment in 2035. However, in the Medium and High sensitivities, capture prices fall below LCOE across all zones, making unsubsidised solar investment unprofitable in the Nordics.

It should be noted that while the All-High sensitivity reflects government targets for solar deployment, such capacity levels appear unrealistic unless matched by a corresponding increase in electricity demand. Solar curtailment in Germany rises dramatically under high solar penetration—increasing nearly tenfold from THEMA Base to All High. These results illustrate the market integration challenges associated with rapid solar expansion without corresponding demand growth: declining capture prices erode the business case for merchant investment, while rising curtailment represents lost renewable output. Although Norwegian hydropower flexibility provides some insulation, ambitious solar targets require corresponding growth in electricity demand and flexibility to avoid stranded renewable generation.

Figure 15. Operating battery capacity, GW



4.3.3 Battery capacity has limited impact on base prices but can reduce peak prices during Dunkelflaute events

We run three sensitivities for battery storage capacity in Germany, Great Britain, and the Netherlands. Figure 15 summarises the battery capacity assumptions. In all scenarios except High, batteries are assumed to have a 2-hour duration.

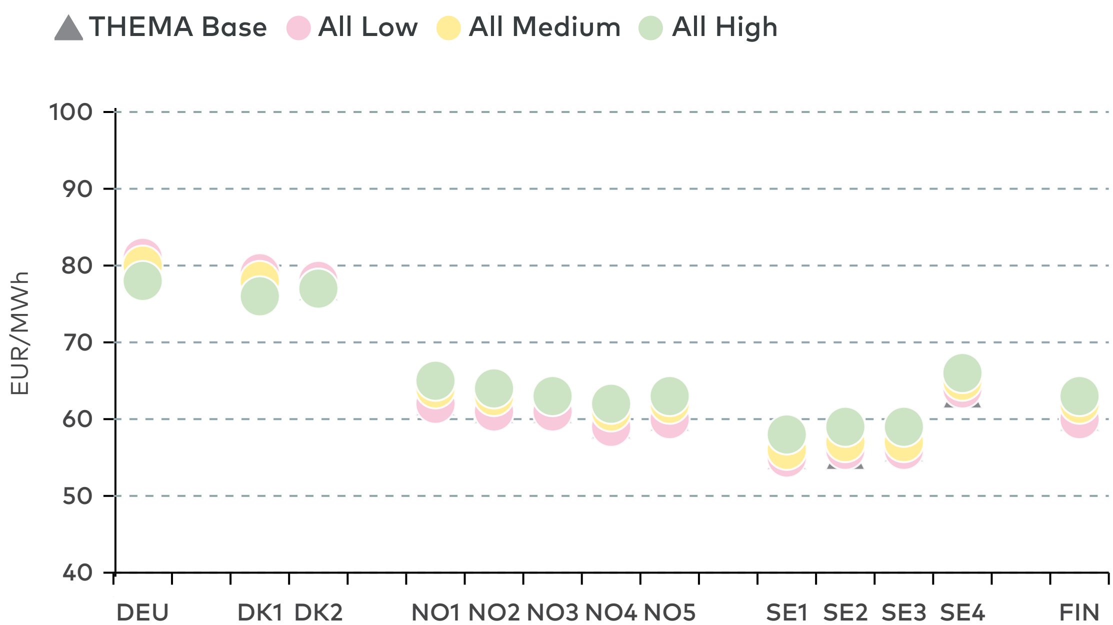
Low sensitivity: Deployment falls short of medium-term targets due to grid connection bottlenecks and insufficient subsidies as battery market revenues decline. Germany reaches 60 GW by 2035 (75% of the 80 GW expected in the government's monitoring report). Great Britain reaches 25 GW by 2035, meeting its 2030 target of 23–27 GW with delay. The Netherlands installs 7.9 GW, around half of the 15.8 GW projected by TSO TenneT for 2030.

Medium sensitivity: Countries meet their medium-term targets by 2035. Germany installs 80 GW, Great Britain reaches 45 GW (a linear extrapolation of its 2030 target), and the Netherlands reaches 15.8 GW.

High sensitivity: Deployment exceeds current targets due to falling technology costs and generous subsidy schemes. Germany installs 120 GW, including an additional 46.1 GW of 4-hour duration batteries on top of the 2-hour capacity in THEMA Base. Great Britain reaches 60 GW (130% of its extrapolated 2030 target), and the Netherlands reaches 23.7 GW (150% of its 2030 target).

We run the battery sensitivities for Germany, Great Britain, and the Netherlands. In these sensitivities, all three countries simultaneously reach their respective Low, Medium, or High capacity levels. Figure 16 shows baseload prices across Nordic and continental bidding zones for the battery sensitivities.

Figure 16. Base prices for the battery sensitivities, EUR/MWh



Battery capacity has limited impact on baseload prices across Nordic bidding zones, as Figure 16 highlights. Prices show minimal variation between the All Low, THEMA Base, All Medium, and All High scenarios. German baseload prices similarly reveal little sensitivity to battery capacity.

The muted effect on baseload prices reflects the dual role of batteries in price formation. Batteries reduce prices during peak hours by discharging stored energy, while increasing prices during low-price hours by charging and absorbing surplus generation. These opposing effects largely offset when averaged across all hours, resulting in minimal net impact on annual baseload prices.

However, the effects on price extremes are more pronounced. The 4-hour duration batteries included in the All High scenario substantially reduce peak prices during Dunkelflaute events—in zones well connected to Germany, peak price hours above 500 EUR/MWh completely disappear (see Figure 32 in the appendix). Continental battery capacity also reduces the number of zero and negative price hours, with Germany and Danish zones seeing the largest reductions (see Figure 33 in the appendix). Norwegian, Swedish, and Finnish zones exhibit limited sensitivity to continental battery deployment for both peak and low-price hours.

Interestingly, while German baseload prices decline slightly with higher battery capacity, Norwegian prices increase marginally. This divergence reflects how batteries affect the terms of trade: by reducing German price extremes, batteries narrow the price differentials that drive Nordic-German exchange, making exports less profitable while reducing cheap import opportunities. This terms-of-trade effect partially offsets the direct price benefits of continental flexibility for Nordic markets.

As a measure of price volatility, Figure 17 shows the annual mean daily spread across bidding zones. Higher battery capacity reduces price volatility, with the largest reductions in Germany and Denmark. Norwegian, Swedish, and Finnish zones exhibit only small changes, as these markets already benefit from the flexibility provided by hydropower reservoirs.

Figure 17. Annual mean daily spread for the battery sensitivities, %
Annual mean daily spread is defined as the difference between daily maximum and minimum prices divided by the annual mean price

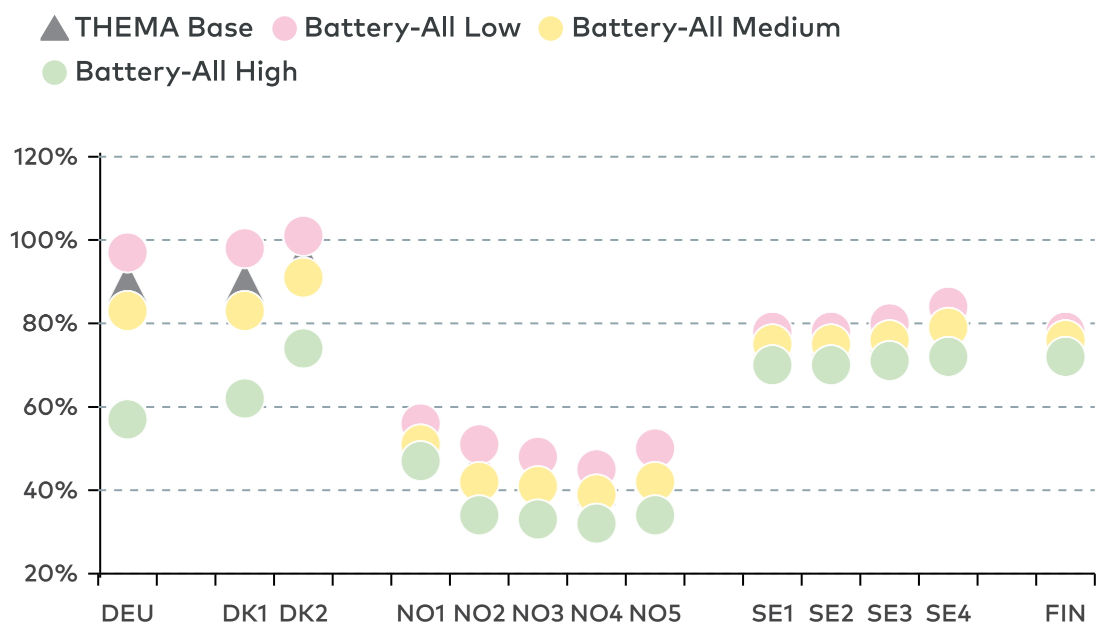
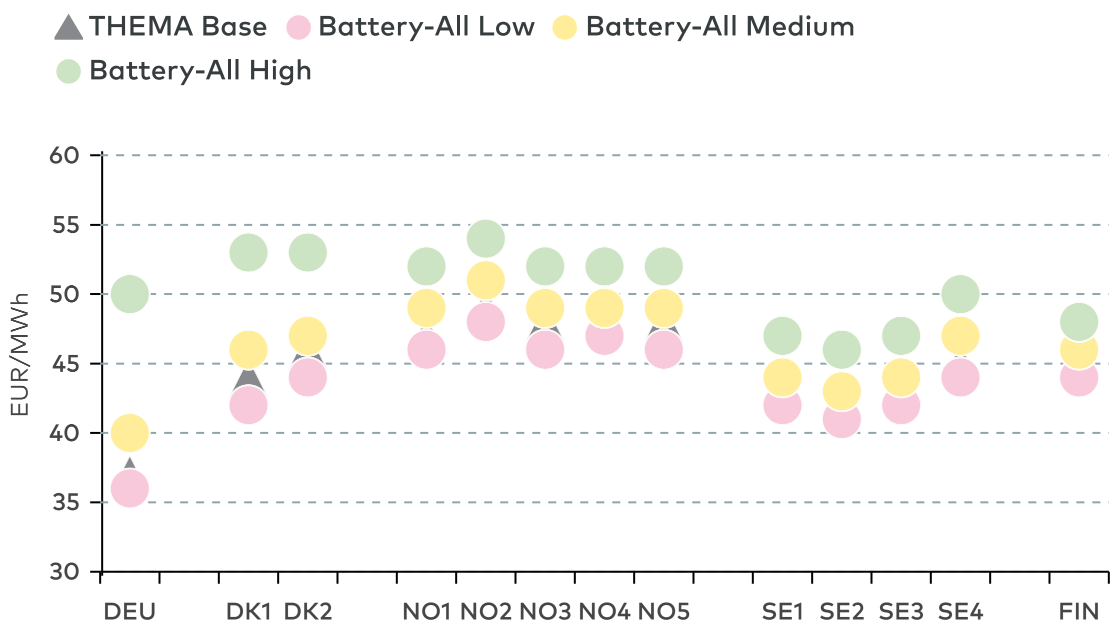


Figure 18 shows that higher continental battery capacity increases solar capture prices across Nordic markets by absorbing surplus solar generation during peak solar hours. Danish capture prices show the strongest response, followed by Norwegian and Finnish zones—reflecting the strength of interconnection with Germany. However, this improvement in capture prices comes at the cost of reduced revenue potential for the batteries themselves, as the price spreads they arbitrage decline with higher deployment.

Figure 18. Solar capture prices for the battery sensitivities, EUR/MWh



4.3.4 Batteries reduce solar curtailment but cannot fully offset solar integration challenges at high penetration

The solar sensitivities result in section 4.3.3 show that rapid solar expansion leads to declining capture prices, increasing low-price hours, and rising curtailment volumes, especially in Germany. Higher battery capacity could potentially mitigate these integration challenges by absorbing surplus solar generation during peak production hours. We therefore run additional sensitivities combining high solar and high battery capacity in Germany to assess whether batteries can effectively integrate larger volumes of solar generation.

Figure 19. Operating solar PV and battery capacity in Germany, GW

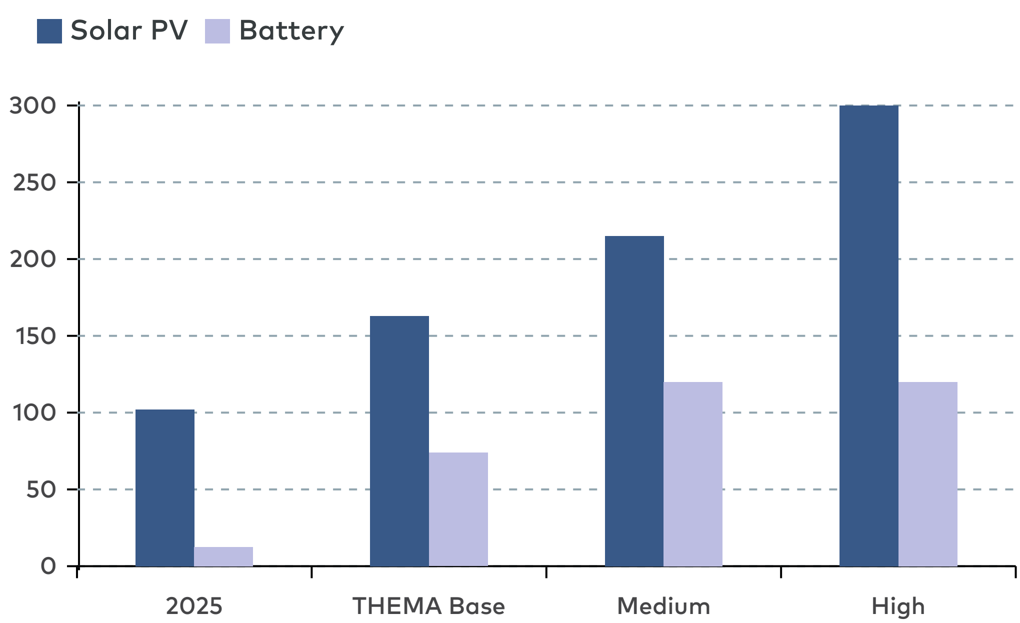


Figure 19 illustrates the capacity assumptions for the combined sensitivities. For the battery High sensitivity, we increased German battery capacity to 120 GW. The 120 GW comprises 73.9 GW of 2-hour duration batteries (as in THEMA Base) plus 46.1 GW of 4-hour duration batteries to further increase system flexibility.

We run two combined sensitivities for Germany:

Combined Solar Medium: Germany reaches 215 GW of solar capacity (the government's 2030 target) combined with 120 GW of battery capacity.

Combined Solar High: Germany reaches 300 GW of solar capacity (the government's 2035 target) combined with 120 GW of battery capacity.

Figure 20. Solar capture prices for the combined solar and battery sensitivities

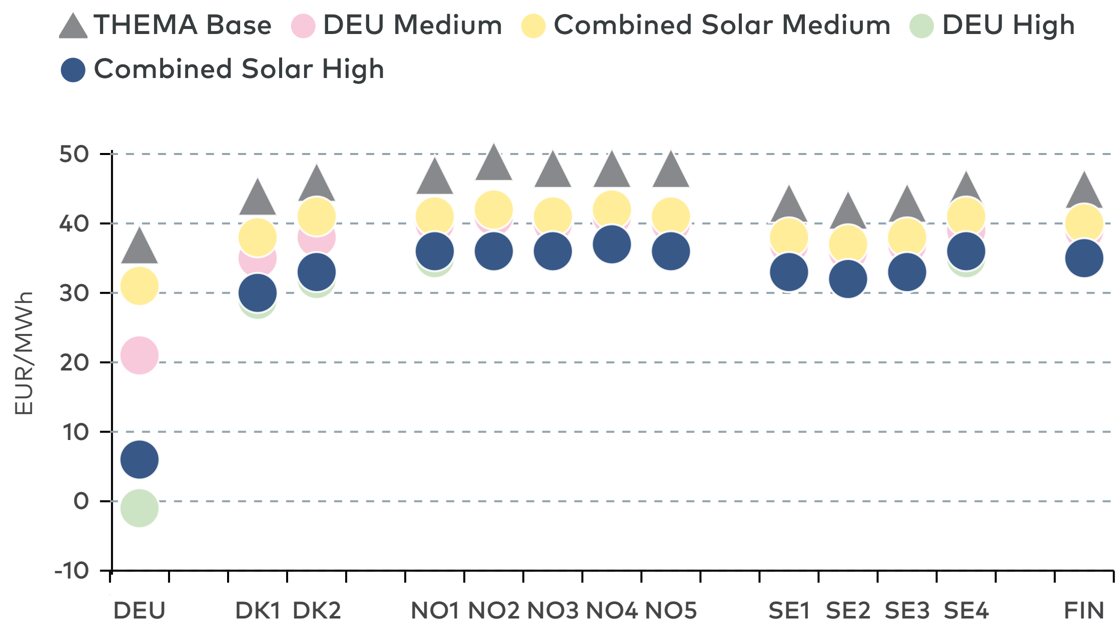


Figure 20 shows solar capture prices across bidding zone for the sensitivities that combine higher solar and battery capacities. Nordic solar capture prices show a muted response to German battery deployment. Comparing DEU High and Combined Solar High reveals only modest improvements in Nordic capture prices, indicating that German battery expansion provides limited additional benefit for Nordic solar generators beyond what interconnection constraints and domestic flexibility already offer. Figure 34 in the appendix highlights that the number of zero- and negative price hours in the Nordics also hardly change when combining the solar and battery sensitivities.

German solar market conditions improve more visibly when high battery capacity is added. Capture prices shift from negative values under high solar penetration to positive levels, and solar curtailment falls by roughly half. However, capture prices remain well below THEMA Base and substantial solar curtailment volumes persist, indicating that batteries can partially mitigate solar cannibalisation effects but cannot fully resolve the integration challenges of very high solar penetration.

These results should be interpreted in light of the assumed battery-to-solar capacity ratio. In Combined Solar High, battery capacity (120 GW) remains well below solar capacity (300 GW). If battery capacity were increased further, curtailment would likely decrease and capture prices improve. However, such high battery deployment relative to peak load would substantially erode the price spreads that batteries rely on for revenues, undermining the business case for battery investment.

4.4 Policies affecting interconnector availability and cross-border trade

In this section, we investigate the impact of changes to interconnector capacity and trade-restrictive policies on Nordic electricity markets. Further market integration of the Nordic countries is under consideration through new or upgraded interconnections, including EstLink3, new links via Bornholm, and upgrades around Kriegers Flak. However, the timing and realisation of these projects remain uncertain. Furthermore, internal grid constraints in continental Europe can limit the effective availability of existing interconnectors, reducing trade opportunities even without changes to nominal capacity.

Trade arrangements between Great Britain and the EU—and consequently with the Nordic region—also remain unclear. The UK and EU are negotiating a potential link between their emissions trading systems; should these negotiations fail, electricity imports from Great Britain could face CBAM charges. Broader protectionist pressures, while currently not permitted under EU internal market rules, cannot be entirely ruled out in the longer term.

Our sensitivities test what happens to Nordic prices under different outcomes: if planned interconnector projects are delayed, if internal grid bottlenecks reduce effective interconnector availability, if CBAM is applied to EU-GB electricity trade, or if general trade fees are introduced on Nordic-European interconnectors.

4.4.1 We run sensitivities for individual interconnectors, trade restrictions and availability of interconnectors

We test seven sensitivities related to interconnector capacities and cross-border trade:

Individual interconnector projects:

- **EstLink3:** The 700 MW interconnector expansion between Estonia and Finland does not come online as planned in 2035 due to construction delays.
- **Bornholm:** The 1,600 MW connection between Germany and Bornholm comes online earlier in 2035 rather than in 2037 as assumed in THEMA Base.
- **Kriegers Flak:** The interconnector capacity between Germany and Kriegers Flak is increased by 700 MW from 400 MW to 1,100 MW.

Trade restrictions:

- **CBAM:** This sensitivity studies the potential application of a Carbon Border Adjustment Mechanism to electricity trade between the EU and the UK. CBAM is set to apply from 1 January 2027, but the UK and EU governments have announced their commitment to link their emissions trading systems. If this agreement is reached, electricity flows from Great Britain to EU markets would not be subject to CBAM. However, should negotiations fail, exports from the UK to EU markets could face CBAM charges. We model CBAM as an import tax of 7 EUR/MWh on electricity flows from the UK to the EU, based on an assumed average emission intensity of 0.05 tCO_2/MWh and a carbon price of 134 EUR/tCO_2 in 2035.

- **Trade fee:** The general trade fee sensitivity captures a broader scenario of economic protectionism affecting electricity trade between European countries. A trade fee of 10 EUR/MWh applies to all flows via interconnectors between the Nordics and other European countries in both directions. Such a trade fee is not allowed under current EU internal market rules. However, we run the trade fee sensitivity as a proxy for more protectionist trade policies that might be implemented in the future.

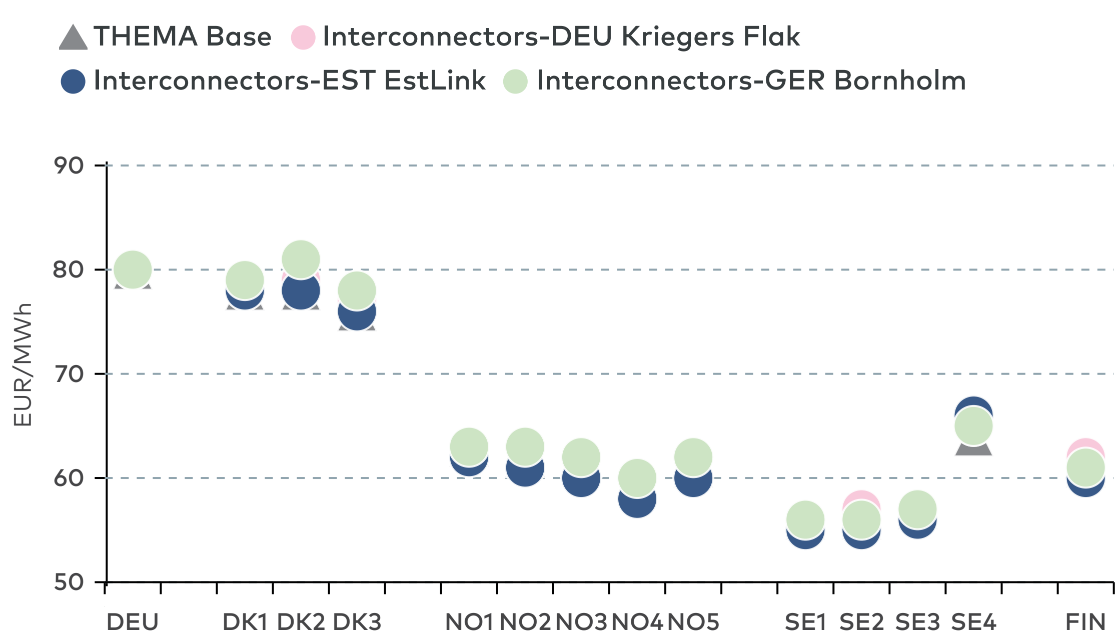
General availability reduction:

70% availability: The maximum availability of all interconnectors between the Nordics and the rest of Europe is reduced to 70% of nominal capacity to estimate the effect of internal grid bottlenecks in continental Europe.

4.4.2 Individual interconnector projects have limited price impact

Figure 21 shows baseload prices across Nordic and continental bidding zones under the individual interconnector sensitivities. Adding or removing individual interconnector projects has limited price impact—the Kriegers Flak, EstLink3, and Bornholm sensitivities produce only marginal changes. This reflects the relatively small capacity of these projects in the context of the overall Nordic-European transmission system: EstLink3 adds only 700 MW, while Bornholm and Kriegers Flak connect via offshore hubs rather than providing direct market-to-market capacity.

Figure 21. Base prices for the interconnector sensitivities, EUR/MWh



4.4.3 CBAM and trade fees have limited price effects, but reduced interconnector availability lowers Nordic prices

Figure 22 shows baseload prices under the CBAM, trade fee, and 70% availability sensitivities. The CBAM sensitivity produces virtually no price change across Nordic zones, as the mechanism only affects exports from Great Britain to the EU. The general trade fee sensitivity shows a more differentiated pattern. Most Nordic zones experience small price reductions as the trade fee makes imports more expensive, keeping more Nordic generation within the region and marginally depressing domestic prices. The 70% availability scenario has the most pronounced effect, reducing Nordic baseload prices by around 5–20% as constrained export capacity keeps more generation within the Nordic system.

Figure 22. Base prices for the trade and interconnector availability sensitivities, EUR/MWh

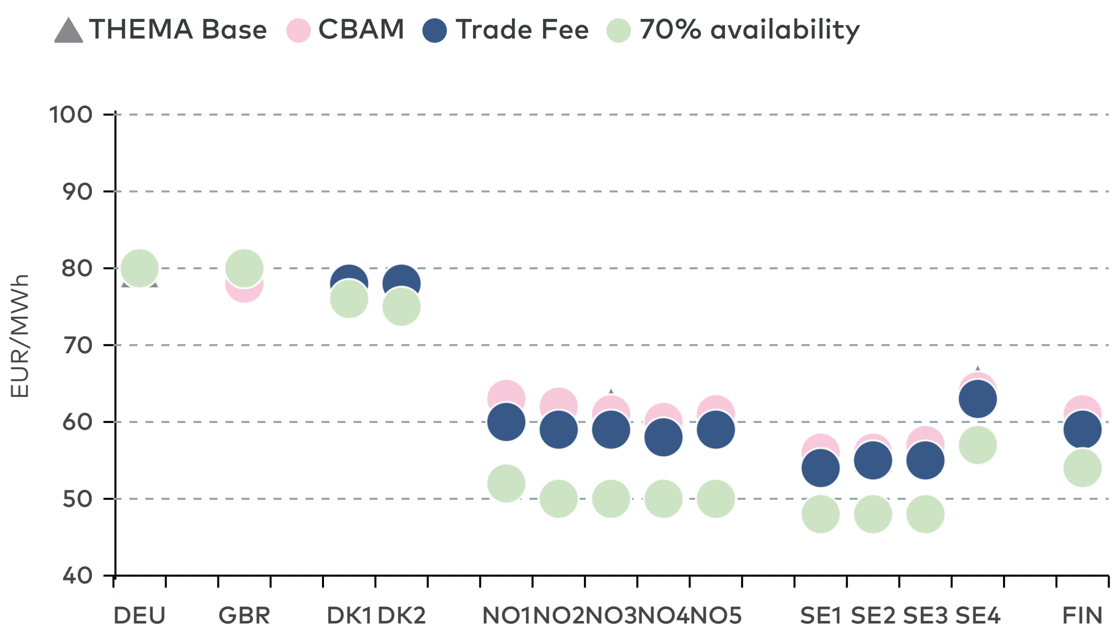


Figure 23. Annual trade volumes with Great Britain for the trade sensitivities and the THEMA Base scenario, TWh

Exports refer to trade flows from the Nordic zone to GB. Imports refer to trade flows from GB to the Nordic zone.

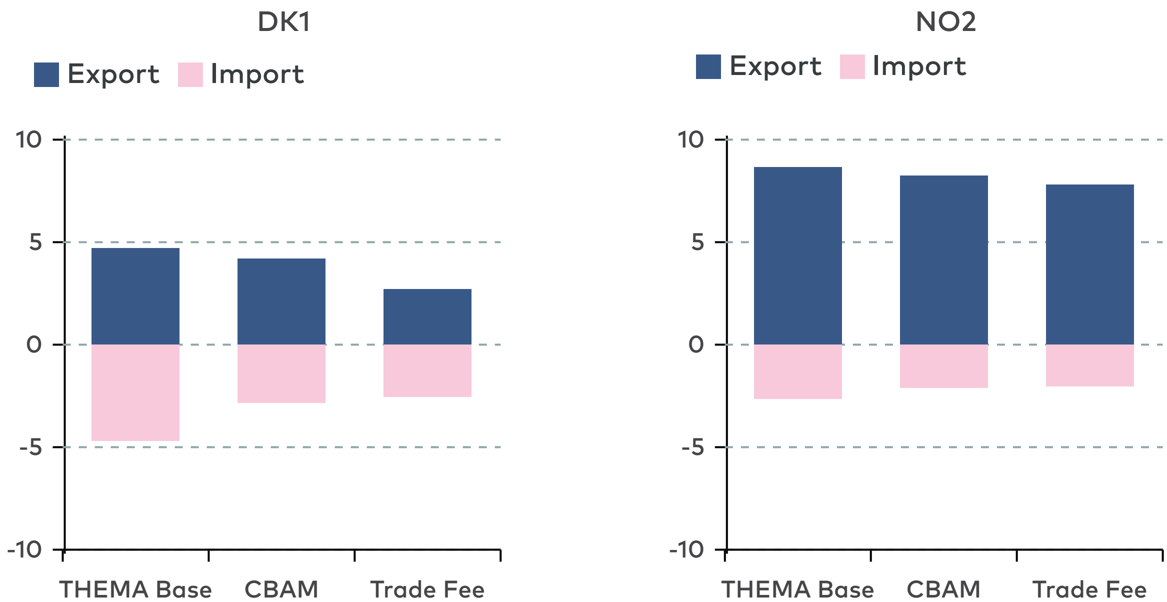
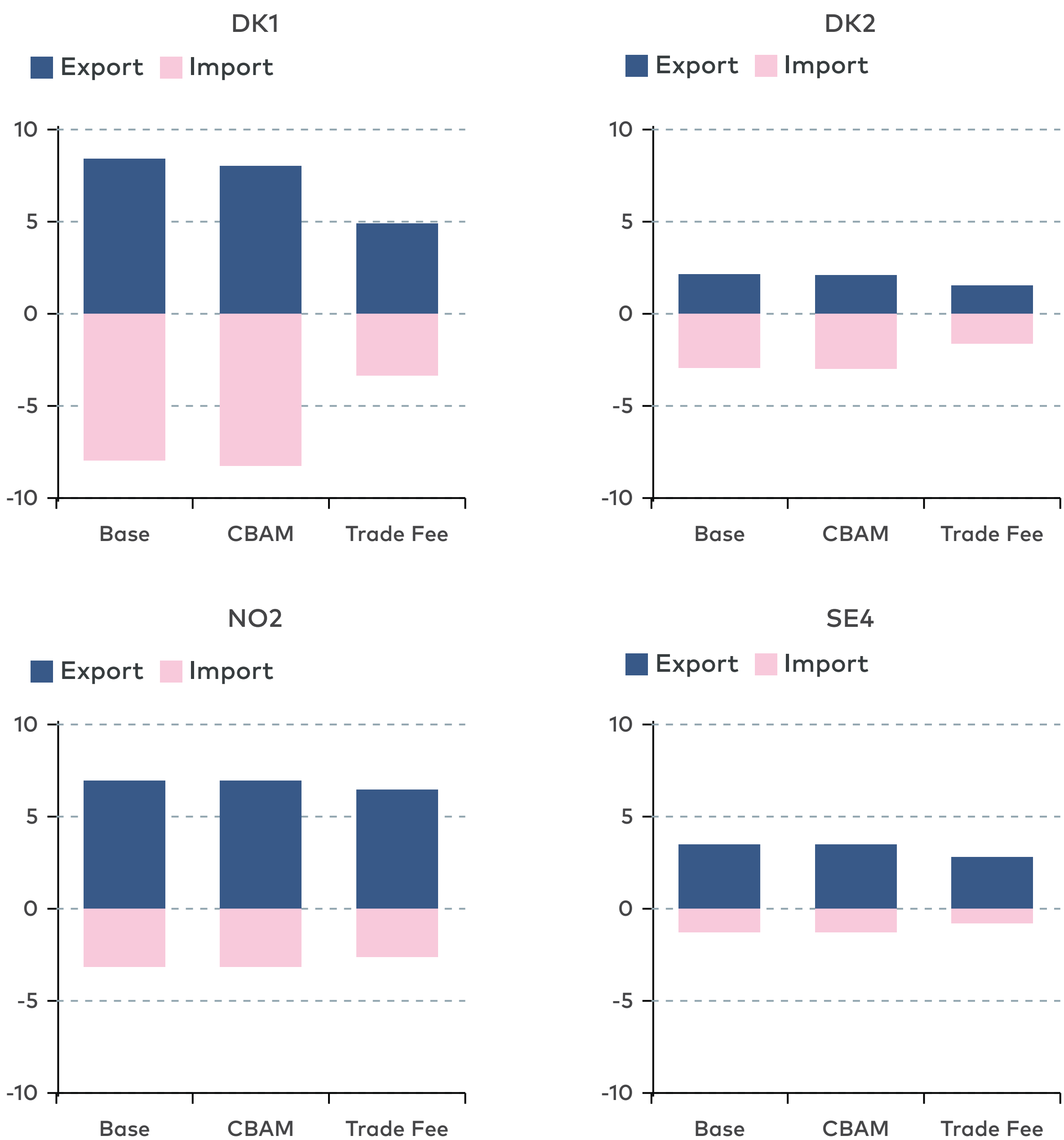


Figure 24. Annual trade volumes with Germany for the trade sensitivities and the THEMA Base scenario, TWh

Exports refer to trade flows from the Nordic zone to Germany. Imports refer to trade flows from Germany to the Nordic zone.



4.4.4 Trade restrictions reduce cross-border flows and congestion rents

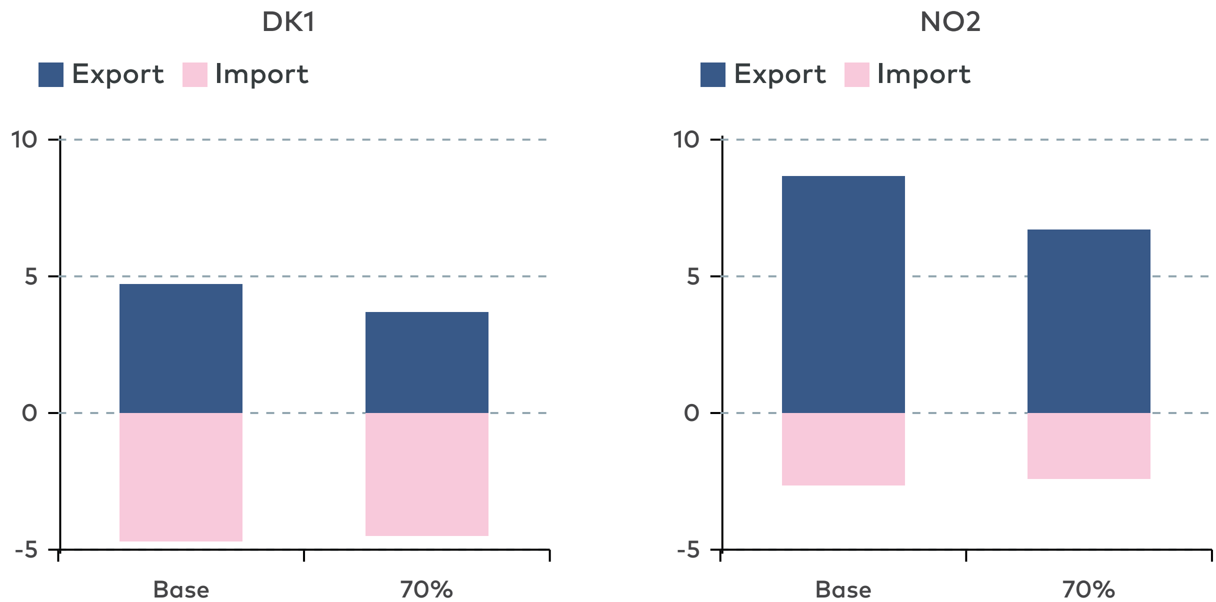
While price effects are modest, trade restrictions have more pronounced effects on cross-border electricity flows. Reduced trade volumes affect generator revenues, TSO congestion income, and overall market efficiency—impacts not fully captured by price changes alone.

Figure 23 and Figure 24 illustrate trade volumes between Nordic zones and Great Britain and Germany under the CBAM and trade fee sensitivities, while Table 8 provides a comprehensive breakdown of import and export flows for all remaining Nordic and continental price zones. The two sensitivities produce markedly different effects. CBAM primarily affects Nordic-British trade flows while leaving Nordic-German exchange largely unchanged—as expected, since CBAM applies exclusively to electricity imports from Great Britain to the EU. For British trade, CBAM reduces imports to both DK1 and NO2, with a notably stronger effect on Denmark where imports fall by approximately 40%. The stronger Danish impact reflects underlying price spread differences: Danish prices are typically closer to British prices, meaning the surcharge more frequently tips the balance against importing.

The general trade fee produces substantially larger trade volume reductions across all interconnectors. For German trade, the effects are particularly pronounced—DK1 experiences reductions of over 40% in both export and import volumes. Other Nordic zones with German connections show smaller but still significant declines.

Figure 25. Annual trade volumes with the Great Britain for the 70% availability sensitivity and THEMA Base

Exports refer to trade flows from the Nordic zone to Great Britain. Imports refer to trade flows from Great Britain to the Nordic zone.



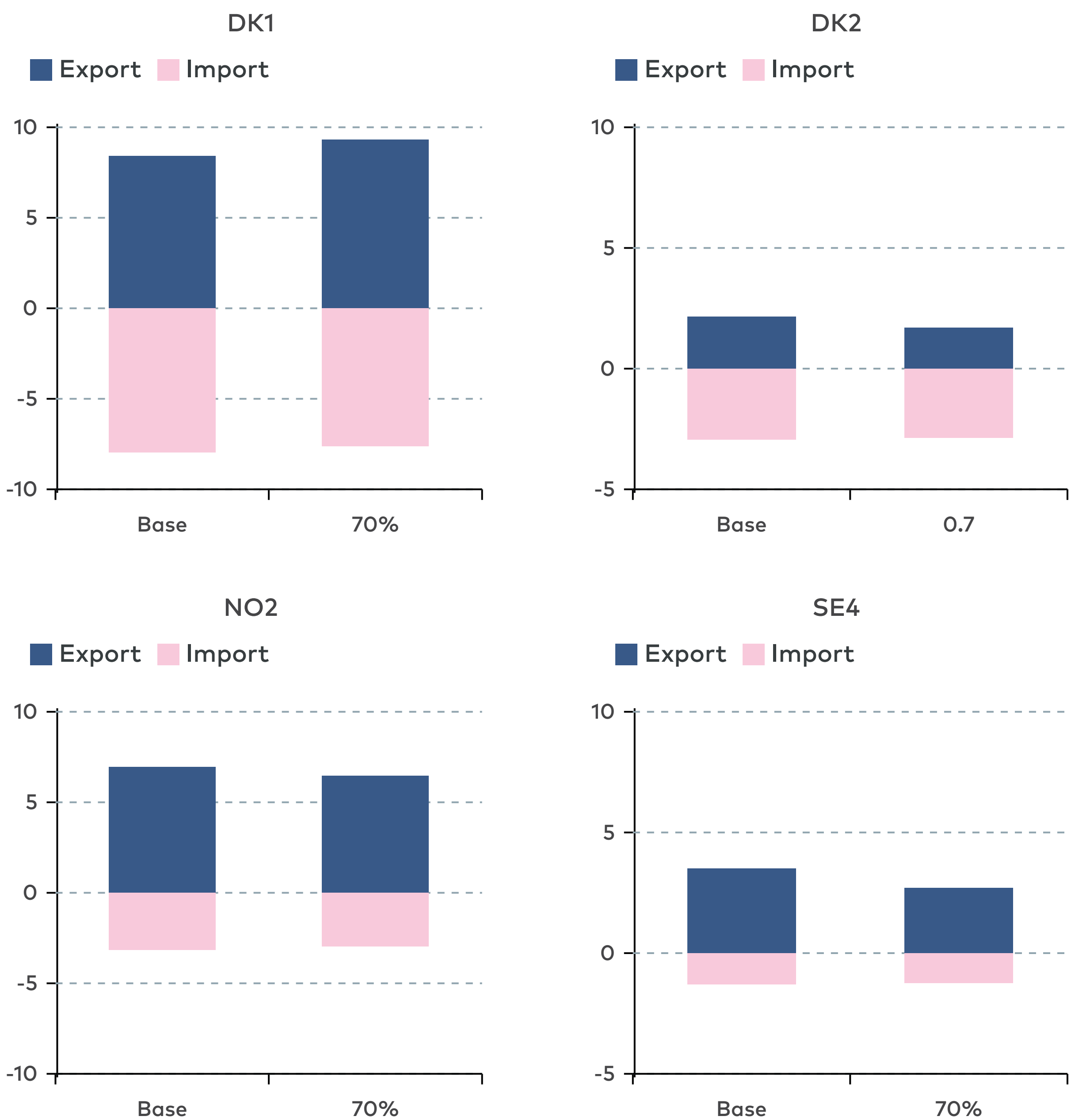
These trade volume changes translate directly into reduced congestion rents. CBAM modestly reduces congestion rents on British links while leaving German links almost unaffected. The general trade fee has a more substantial impact, with congestion revenues declining by at least 20% on key Nordic lines to both Great Britain and Germany. The divergence between the two sensitivities reflects their different scope: CBAM applies only to British exports to the EU with a lower surcharge, while the general trade fee applies symmetrically to all Nordic-European interconnectors with a higher surcharge.

4.4.5 Reduced interconnector availability benefits Nordic consumers but generates net regional welfare losses

The 70% availability scenario has the most far-reaching consequences, affecting not only prices but also trade patterns and overall welfare. Figure 25 and Figure 26 present annual trade volumes between selected Nordic zones and Germany and Great Britain, respectively, comparing THEMA Base with the 70% availability sensitivity. Table 8 in the appendix provides a full breakdown of import and export volumes across additional Nordic and continental price zones. Under 70% availability, total trade volumes between the Nordics and continental Europe decline as export capacity becomes constrained. DK1 captures a larger share of the remaining cross-border exchange with Germany due to its stronger direct connections, while other Nordic zones see declining volumes. Trade with Great Britain follows a simpler pattern—both DK1 and NO2 experience declining volumes in both directions, with no compensating increase on alternative routes.

Figure 26. Annual trade volumes with Germany for the 70% availability sensitivity and the THEMA Base scenario, TWh

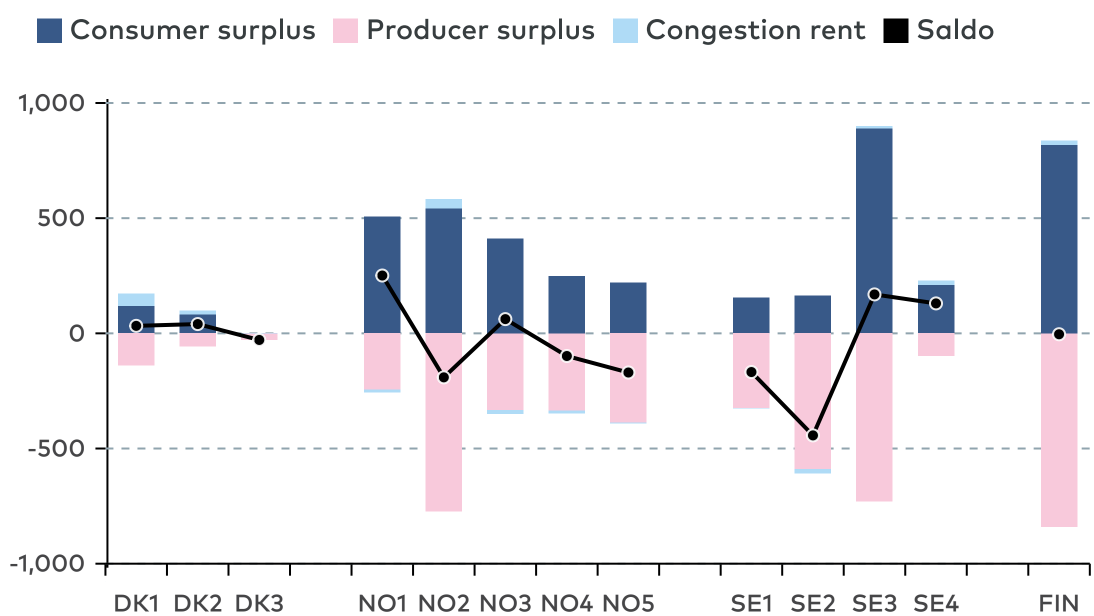
Exports refer to trade flows from the Nordic zone to Germany. Imports refer to trade flows from Germany to the Nordic zone.



The finding that reduced interconnector availability lowers Nordic prices while reducing trade raises an important question regarding overall distributional impacts. Lower prices benefit consumers but harm generators who lose access to higher-priced export markets. To assess these distributional consequences, we conduct a welfare analysis that accounts for consumer surplus, producer surplus, and congestion rents across all Nordic price zones.

Figure 27 shows the welfare impact by bidding zone and country under the 70% availability scenario compared to THEMA Base. Consumer surplus increases substantially across all Nordic zones, with the largest gains in zones with high consumption such as NO1 and SE3. These consumer benefits come directly at the expense of generators—producer surplus declines by a slightly larger amount than consumer gains, reflecting the Nordic region's position as a net exporter. Congestion rent changes are modest by comparison, with Denmark capturing the largest share of increased rents as reduced availability on links to Germany widens price differentials on remaining capacity.

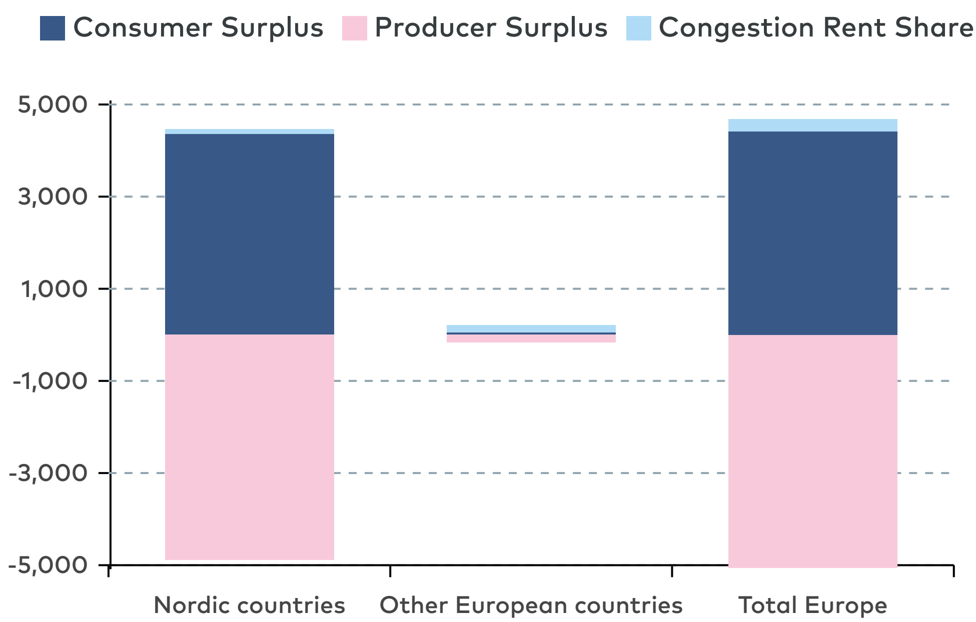
Figure 27. Difference in surplus between the 70% availability sensitivity and THEMA Base by category, Million EUR



Aggregating all components reveals significant regional variation. Denmark is the only country with a positive overall outcome, as congestion rent gains on its transit links more than compensate for modest producer losses. Sweden bears the largest loss, followed by Norway—where losses concentrate in NO2 with its high hydropower export capacity. Finland's impact is nearly neutral as consumer and producer effects largely offset. Overall Nordic welfare across all zones declines.

Figure 28 extends the analysis to all of Europe. Non-Nordic countries experience a small net welfare gain under the 70% availability scenario—Continental consumers face slightly higher prices, but this is offset by producer gains and increased congestion rents as scarcity on Nordic links raises the value of remaining capacity. However, these Continental gains are insufficient to offset Nordic losses. Total European welfare declines, confirming that reduced interconnector availability generates deadweight losses that harm the European market as a whole. In summary, while reduced interconnector capacity lowers Nordic prices, this comes at the expense of a significant welfare loss that is distributed unevenly across regions and between producers and TSOs.

Figure 28. Difference in total European surplus between the 70% availability sensitivity and THEMA Base, Million EUR



4.5 Potential German bidding zone split

4.5.1 Internal bottlenecks are driver for the discussion on bidding zones

Germany has internal transmission bottlenecks between the North of Germany, where many wind resources are located and where demand is generally lower, and the South, where there is less wind, but higher demand. This imbalance has caused a number of issues, including loop flows, trade restrictions, and high redispatch costs. To mitigate these effects, the introduction of bidding zones is often mentioned as an appropriate measure. But there are also reservations around the introduction of bidding zones (e.g. transaction costs, market liquidity).

4.5.2 A German bidding zone split faces strong political opposition and is highly unlikely

The discussion about the pros and cons of a bidding split has flared up again and again for more than a decade. The EU and its institutions are key proponents of a split. However, the German government and German TSOs are adamantly against splitting the national bidding zone. Germany has never come close to splitting up its bidding zone, and since the ultimate decision lies with the national government, a split remains unlikely.

The EU, and many power market economists, argue that a split would greatly enhance the efficiency of the underlying power market. Germany faces a structural bottleneck between its north and its south. There is currently not enough transmission capacity to bring all of Germany's northern wind power to its southern demand centres. The argument goes that splitting up the German bidding zone would make this bottleneck visible by inducing different prices in the north and south. Split power prices could reflect local production and demand and thereby help incentivise the more efficient placement and scheduling of demand and supply. A split would also reduce loop flows through neighbouring countries, lower redispatch costs, and improve price signals for dispatch decisions.

However, past and present German governments have been vehemently against a zonal split. They argue that it would be politically impossible to convince German industry to accept different power prices in the north and south. They also argue that a split risks compromising the liquidity of the German financial power market, undermining a trading hub used by a variety of European traders to manage power price risk.

In April 2025, the latest bidding zone review report was published, coordinated by ENTSO-E with the methodology and the alternative configurations decided by ACER. The Review found that splitting Germany into multiple bidding zones would increase social economic welfare. ACER, in a subsequent statement, argued that the study actually underestimates the welfare benefits of a split due to unrealistic assumptions in the underlying methodology. The German government and the four German TSOs, however, rejected the findings on different grounds—arguing that the study relied on outdated data, underestimated the costs of implementation, and failed to demonstrate sufficient efficiency gains to justify a split. Despite the study's positive welfare findings, strong political opposition means a split remains unlikely.

4.5.3 A German zonal split would reduce average Nordic power prices, but the effect depends on future grid developments within Germany

Given that a bidding zone split in Germany is highly unlikely until 2035, modelling it is technically complex, and the concrete definition of any future bidding zones remains highly uncertain, we have not conducted dedicated new simulations for this study. However, since such a split—however unlikely—could have significant implications for Nordic electricity markets, THEMA has modelled the impact of a German bidding zone split in detail in previous studies. The main findings from these earlier studies are:

- The price effect is subject to how the bidding zones are defined: Different layouts can have a different price effect
- The magnitude of price effect depends on the progress of internal grid developments. Germany is currently upgrading its internal infrastructure to address internal bottlenecks, with major HVDC transmission projects—SüdLink and SüdOstLink—scheduled for completion between 2027 and 2030. Should these investments come in time, the price effect of bidding zones may be small (hence questioning the purpose of bidding zones in this scenario); should the investments be delayed, the price effect could be significant (e.g. around 20% lower prices in Northern Germany compared to a Base line scenario)
- The price decline would be in particular driven by more frequent hours with zero or negative prices in hours where there is a lot of wind. This would also have an impact on capture prices for renewables, in particular wind.
- Some of the price effect may transmit into the Nordics. The pass-through, i.e. how much of the price decline in North Germany would transmit into Nordic bidding zones, could be between 40-70%, depending on scenario and other assumptions. That is, if prices in Northern Germany decline on average by say 10 EUR/MWh, the price decline in Nordic bidding zones can be between 4-7 EUR/MWh.

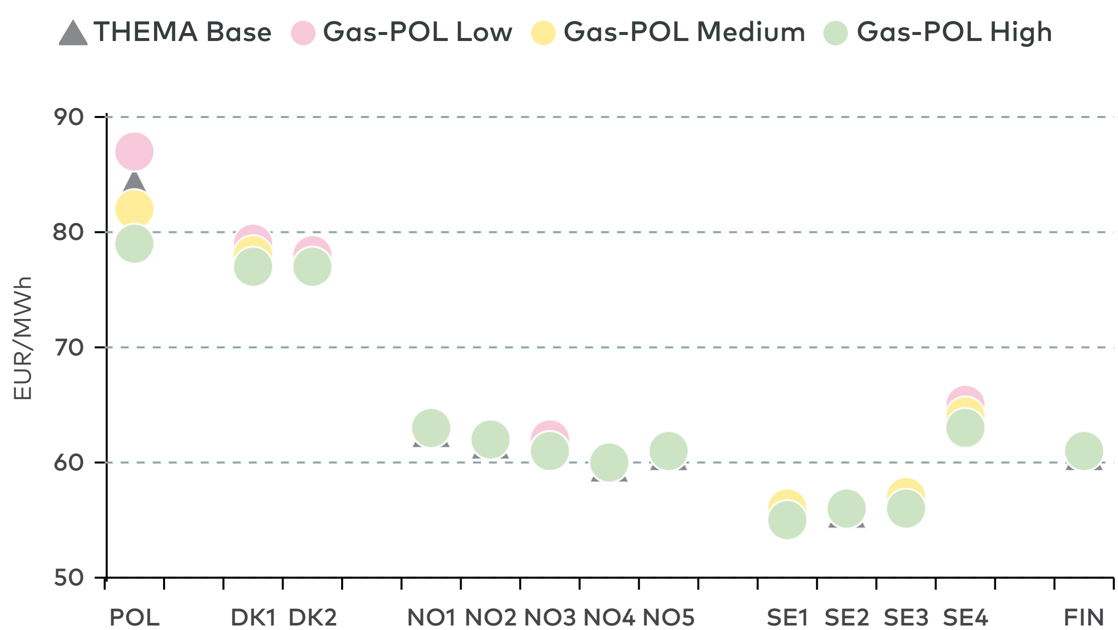
But all depends on the precise developments of internal grid upgrades, and how one would eventually define the bidding zones. And, last but not least, on what one assumes on how renewable capacities, demand and other factors impacting the power system in Germany will develop in the coming years.

Appendix 1. Additional simulation results on price impact

Impact of Polish gas capacity on Nordic prices

Figure 29 presents base prices in Poland and Nordic bidding zones under the sensitivities on Polish gas capacity. The Polish gas capacity sensitivities produce only negligible effects on Nordic prices. This limited impact reflects the weaker integration between Nordic and Polish markets compared to the strong coupling between the Nordics and Germany. Polish base prices, however, decline significantly when more domestic gas capacity is added.

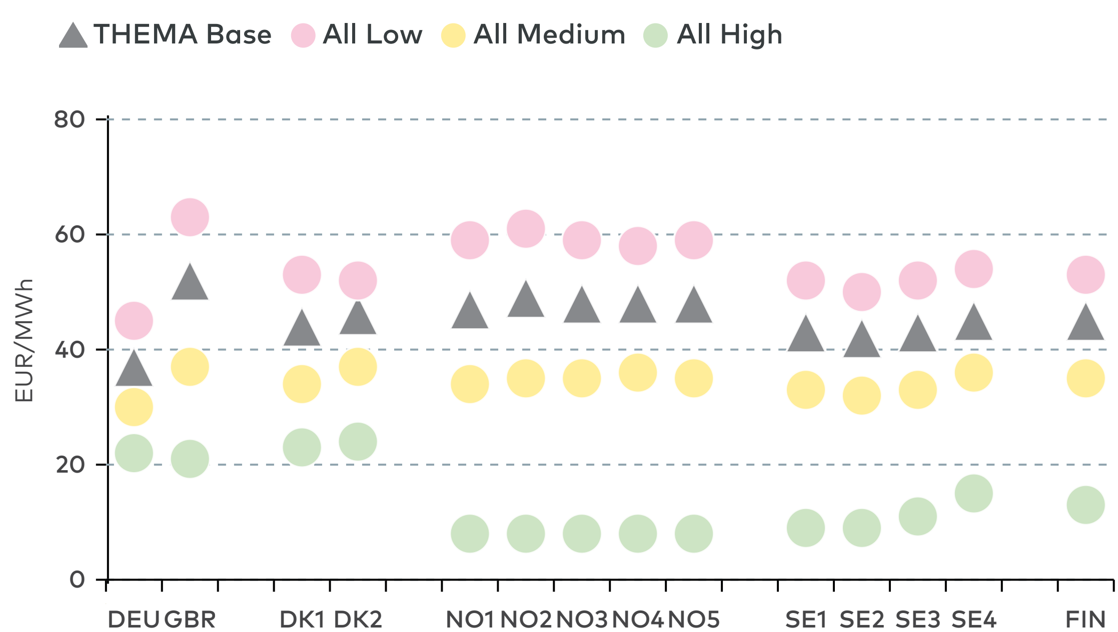
Figure 29. Base prices across bidding zones for the sensitivities on Polish gas capacities, EUR/MWh



Impact of different offshore wind capacities on solar capture prices

Figure 30 illustrates the solar capture prices under different offshore wind sensitivity scenarios. Solar capture prices decline significantly as continental offshore wind capacity increases. This decrease is primarily driven by a base-price effect: higher continental offshore capacity lowers electricity prices during daytime hours when solar generation is high, thereby reducing the capture prices for solar power.

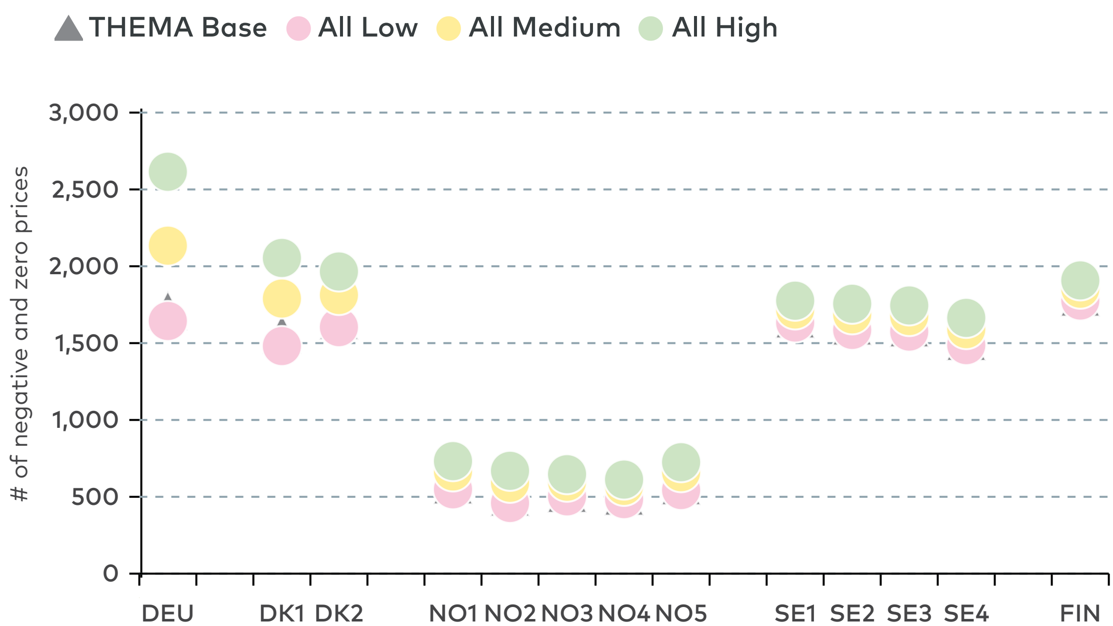
Figure 30. Solar capture prices for the offshore wind sensitivities, EUR/MWh



Development of zero and negative price hours for solar capture sensitivities

Figure 31 illustrates the frequency of zero and negative price hours across the analyzed price zones. While the rise in such hours contributes to lower capture prices, it is only one of several factors driving the decline. Most Nordic zones experience a moderate increase in low-price hours as solar capacity grows, with Danish bidding zones showing the greatest sensitivity due to their strong interconnection with the German market. The shift is considerably more pronounced in Germany, where low-price hours rise by over 50% between the THEMA Base and All High scenarios, reaching roughly 30% of total hours by 2035.

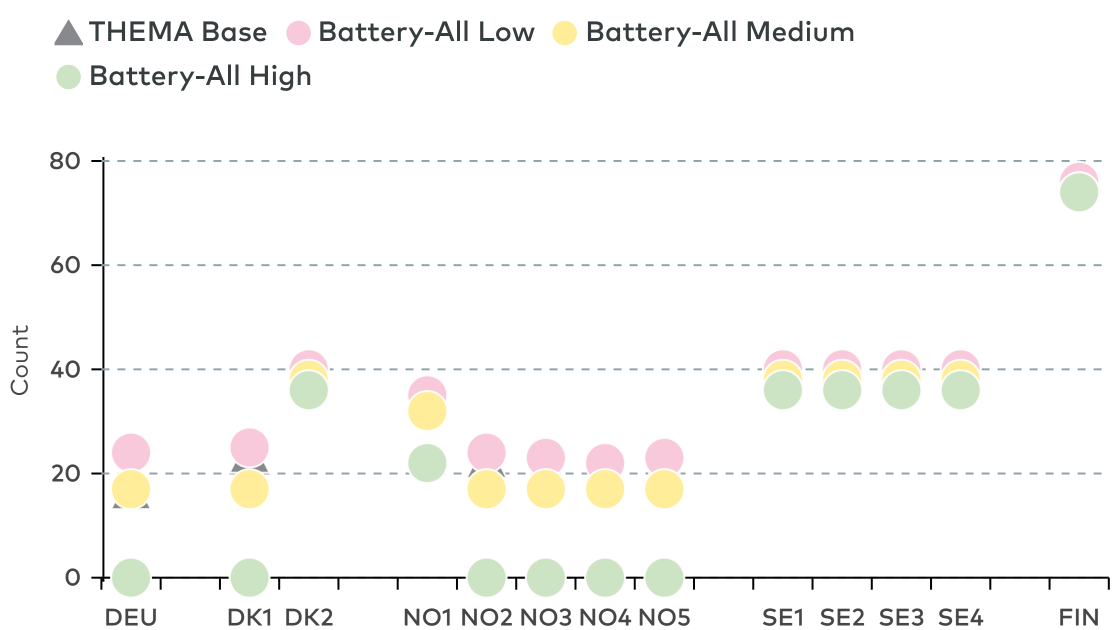
Figure 31. Number of zero and negative price hours for the solar capacity sensitivities



Battery impacts on price spikes

Figure 32 displays the occurrence of extreme price spikes exceeding 500 EUR/MWh across the battery sensitivity scenarios. Expanded battery deployment significantly curtails these episodes, particularly in zones with strong interconnection to Germany such as DK1 and the Norwegian bidding zones. The 4-hour duration storage assumed in the All High scenario proves especially effective at mitigating scarcity pricing during Dunkelflaute periods — in well-connected zones, hours above 500 EUR/MWh are virtually eliminated. By contrast, Swedish and Danish price zones show comparatively limited responsiveness to changes in continental battery capacity.

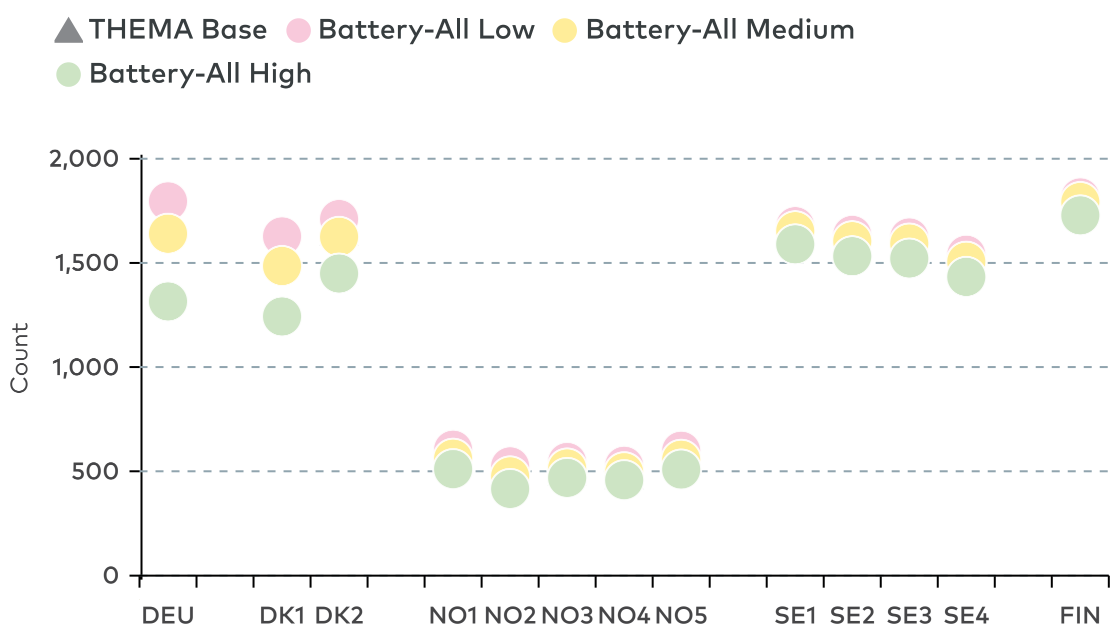
Figure 32. Number of peak prices above 500 EUR/MWh for the battery sensitivities



Battery impact on zero and negative price hours

Figure 33 displays the number of zero and negative price hours across the relevant price zones. Expanded battery storage capacity reduces the frequency of such hours, with the most substantial decreases observed in Germany and the Danish zones. By contrast, price zones in Norway, Sweden, and Finland show minimal responsiveness to changes in continental battery deployment, both in terms of high-price and low-price hour frequency.

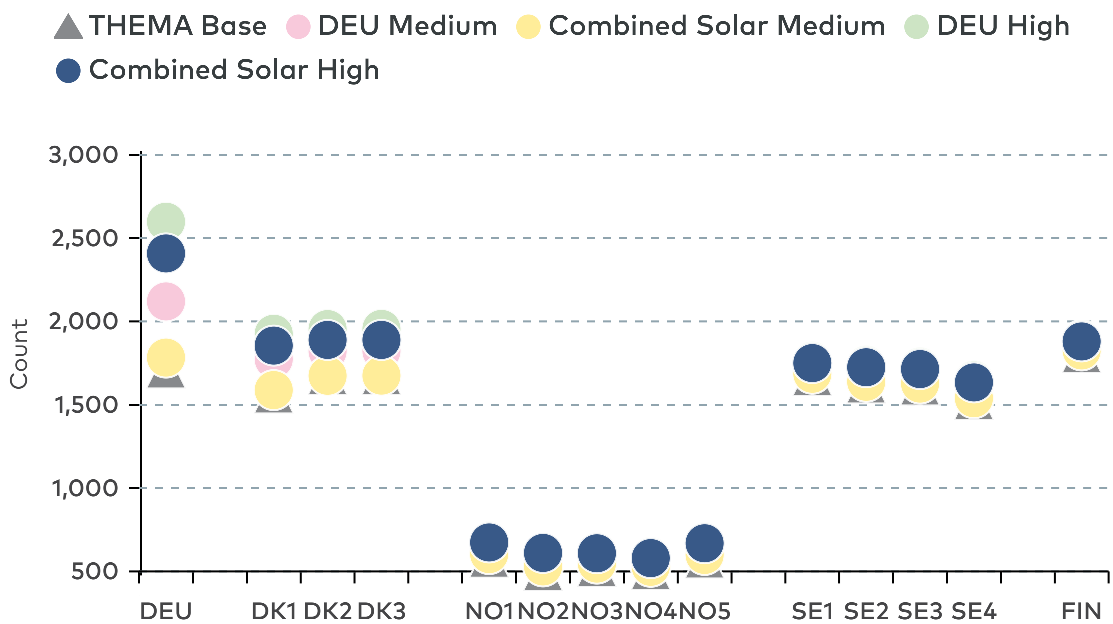
Figure 33. Number of zero and negative price hours for the battery sensitivities



Zero and negative price hours for combined solar and battery sensitivities

Figure 34 shows the number of zero and negative price hours for the combined solar and battery sensitivities. The figure illustrates that the number of zero- and negative price hours in most Nordic zones hardly change when combining the solar and battery sensitivities.

Figure 34. Number of zero and negative price hours for the combined solar and battery sensitivities



Appendix 2. Additional simulation results on trade volumes and congestion rents

Table 6. Annual Trade volumes for the offshore wind sensitivities. Table 6 displays annual import and export volumes between Nordic and continental electricity price zones for the offshore wind sensitivities.

Trade Zones		Absolute values (TWh)				Delta to THEMA Base (TWh)		
Export zone	Import zone	THEMA Base	All Low	All Medium	All High	All Low	All Medium	All High
GBR	DK1	4.7	3.8	6.1	8.0	-0.9	1.4	3.3
DK1	GBR	4.7	4.6	4.3	3.8	-0.1	-0.4	-0.9
Net	**GBR→DK1**	**0.0**	**-0.8**	**1.7**	**4.1**	**-0.8**	**1.8**	**4.1**
GBR	NO2	2.7	2.1	3.9	5.7	-0.6	1.2	3.1
NO2	GBR	8.7	9.0	7.5	5.9	0.3	-1.2	-2.7
Net	**GBR→NO2**	**-6.0**	**-6.9**	**-3.6**	**-0.2**	**-0.9**	**2.4**	**5.8**
DEU	DK1	8.0	7.1	8.9	10.0	-0.8	0.9	2.1
DK1	DEU	8.4	8.3	9.0	9.7	-0.2	0.6	1.3
Net	**DEU→DK1**	**-0.4**	**-1.1**	**-0.2**	**0.3**	**-0.7**	**0.3**	**0.8**
DEU	DK2	2.9	2.6	3.4	3.8	-0.3	0.4	0.8
DK2	DEU	2.1	2.3	1.9	1.8	0.2	-0.2	-0.3
Net	**DEU→DK2**	**0.8**	**0.3**	**1.4**	**1.9**	**-0.5**	**0.6**	**1.2**
DEU	NO2	3.2	2.9	3.6	4.0	-0.3	0.5	0.9
NO2	DEU	7.0	7.0	6.7	6.6	0.1	-0.2	-0.3

Net	**DEU→NO2**	**-3.8**	**-4.2**	**-3.1**	**-2.6**	**-0.4**	**0.7**	**1.2**
DEU	SE4	1.3	1.1	1.5	1.8	-0.2	0.2	0.5
SE4	DEU	3.5	3.7	3.3	3.2	0.2	-0.2	-0.3
Net	**DEU→SE4**	**-2.2**	**-2.6**	**-1.8**	**-1.4**	**-0.4**	**0.5**	**0.8**
NLD	DK1	2.1	1.6	2.9	3.8	-0.5	0.8	1.7
DK1	NLD	2.4	2.6	2.1	1.8	0.2	-0.3	-0.6
Net	**NLD→DK1**	**-0.3**	**-0.9**	**0.9**	**2.0**	**-0.7**	**1.1**	**2.3**
NLD	NO2	1.3	1.1	1.9	2.6	-0.2	0.5	1.3
NO2	NLD	3.8	4.0	3.4	2.8	0.2	-0.5	-1.0
Net	**NLD→NO2**	**-2.5**	**-2.9**	**-1.5**	**-0.2**	**-0.4**	**1.0**	**2.3**
POL	SE4	1.0	1.0	0.8	0.9	0.0	-0.2	-0.1
SE4	POL	3.8	3.7	4.0	4.2	-0.1	0.2	0.4
Net	**POL→SE4**	**-2.8**	**-2.7**	**-3.2**	**-3.3**	**0.2**	**-0.4**	**-0.5**
EST	FIN	2.9	3.0	2.8	3.1	0.0	-0.1	0.1
FIN	EST	7.1	6.8	7.6	8.1	-0.3	0.4	0.9
Net	**EST→FIN**	**-4.2**	**-3.9**	**-4.7**	**-5.0**	**0.3**	**-0.5**	**-0.8**
LTU	SE4	2.6	2.7	2.4	2.3	0.0	-0.3	-0.3
SE4	LTU	2.0	1.9	2.4	2.7	-0.1	0.4	0.7
Net	**LTU→SE4**	**0.6**	**0.8**	**0.0**	**-0.4**	**0.2**	**-0.7**	**-1.1**

Table 7. Annual congestion rents for the offshore wind sensitivities. Table 7 presents annual congestion rents between the Nordic price zones and selected continental price zones for the offshore wind sensitivities.

Trade Zones		Absolute values (Million EUR)				Delta to THEMA Base (million EUR)		
Export zone	Import zone	THEMA Base	All High	All Low	All Medium	All High	All Low	All Medium
GBR	DK1	51	52	110	188	2	59	137
DK1	GBR	77	80	63	48	2	-15	-30
Total	**GBR←→DK1**	**128**	**132**	**173**	**236**	**4**	**45**	**108**
GBR	NO2	93	89	126	61	-4	33	-32
NO2	GBR	280	232	289	354	-49	9	74
Total	**GBR←→NO2**	**374**	**320**	**415**	**416**	**-53**	**42**	**42**
DEU	DK1	47	50	36	12	4	-11	-34
DK1	DEU	60	62	78	116	1	17	56
Total	**DEU←→DK1**	**107**	**112**	**114**	**128**	**5**	**7**	**21**
DEU	DK2	37	23	43	31	-15	5	-7
DK2	DEU	37	43	32	34	7	-5	-3
Total	**DEU←→DK2**	**74**	**66**	**74**	**64**	**-8**	**0**	**-10**
DEU	NO2	120	123	113	36	3	-6	-84
NO2	DEU	260	222	310	465	-38	49	204
Total	**DEU←→NO2**	**380**	**345**	**423**	**500**	**-35**	**43**	**121**
DEU	SE4	38	28	43	25	-10	5	-13
SE4	DEU	110	110	110	140	1	1	30

Total	**DEU←→SE4**	**148**	**138**	**153**	**165**	**-10**	**5**	**17**
NLD	DK1	21	16	41	68	-6	20	47
DK1	NLD	30	33	23	19	3	-7	-11
Total	**NLD←→DK1**	**51**	**48**	**64**	**87**	**-3**	**13**	**36**
NLD	NO2	52	49	63	28	-3	11	-24
NO2	NLD	136	121	145	184	-15	9	48
Total	**NLD←→NO2**	**188**	**170**	**208**	**212**	**-18**	**20**	**24**
POL	SE4	33	47	31	20	14	-3	-13
SE4	POL	120	102	144	213	-18	23	93
Total	**POL←→SE4**	**154**	**149**	**174**	**234**	**-5**	**20**	**80**
EST	FIN	3	4	4	1	0	1	-2
FIN	EST	65	55	75	112	-11	10	47
Total	**EST←→FIN**	**68**	**58**	**79**	**113**	**-10**	**11**	**45**
LTU	SE4	37	45	33	26	8	-4	-11
SE4	LTU	8	5	12	24	-3	4	16
Total	**LTU←→SE4**	**45**	**51**	**45**	**50**	**5**	**0**	**5**

Table 8. Annual trade volumes for the interconnector availability and trade sensitivities. Table 8 shows annual import and export volumes for the sensitivities on interconnector availability and trade restrictions.

Trade Zones		Absolute values (TWh)							Delta to THEMA Base (TWh)					
Export zone	Import zone	THEMA Base	Kriegers Flak	Est Link 3	Born-holm	CBAM	Trade fee	70% availa-bility	Kriegers Flak	Est Link 3	Born-holm	CBAM	Trade fee	70% availa-bility
GBR	DK1	4.7	4.7	4.7	4.8	2.8	2.5	4.5	0.0	0.0	0.1	-1.9	-2.2	-0.2
DK1	GBR	4.7	4.7	4.7	4.6	4.2	2.7	3.7	0.0	0.0	-0.1	-0.5	-2.0	-1.0
Net	**GBR→ DK1**	**0.0**	**0.0**	**0.0**	**0.2**	**-1.4**	**-0.2**	**0.8**	**0.0**	**0.0**	**0.2**	**-1.3**	**-0.2**	**0.8**
GBR	NO2	2.7	2.7	2.6	2.7	2.1	2.0	2.4	0.0	0.0	0.0	-0.5	-0.6	-0.2
NO2	GBR	8.7	8.6	8.7	8.6	8.3	7.8	6.7	0.0	0.1	0.0	-0.4	-0.9	-2.0
Net	**GBR→ NO2**	**-6.0**	**-6.0**	**-6.1**	**-6.0**	**-6.1**	**-5.8**	**-4.3**	**0.0**	**-0.1**	**0.0**	**-0.1**	**0.2**	**1.7**
DEU	DK1	8.0	8.0	8.0	8.0	8.3	3.4	7.6	0.0	0.0	0.0	0.3	-4.6	-0.3
DK1	DEU	8.4	8.4	8.4	8.0	8.0	4.9	9.3	-0.1	0.0	-0.4	-0.4	-3.5	0.9
Net	**DEU→ DK1**	**-0.4**	**-0.4**	**-0.5**	**0.0**	**0.2**	**-1.6**	**-1.7**	**0.1**	**0.0**	**0.5**	**0.7**	**-1.1**	**-1.2**
DEU	DK2	2.9	2.9	3.0	3.0	3.0	1.6	2.9	0.0	0.0	0.0	0.1	-1.3	-0.1
DK2	DEU	2.1	2.1	2.2	1.8	2.1	1.5	1.7	0.0	0.0	-0.3	0.0	-0.6	-0.5
Net	**DEU→ DK2**	**0.8**	**0.8**	**0.8**	**1.2**	**0.9**	**0.1**	**1.2**	**0.0**	**0.0**	**0.4**	**0.1**	**-0.7**	**0.4**
DEU	NO2	3.2	3.2	3.2	3.2	3.2	2.6	3.0	0.0	0.0	0.0	0.0	-0.5	-0.2
NO2	DEU	7.0	6.9	7.0	6.9	6.9	6.5	6.5	0.0	0.0	-0.1	0.0	-0.5	-0.5

Net	**DEU→ NO2**	**-3.8**	**-3.7**	**-3.8**	**-3.7**	**-3.8**	**-3.9**	**-3.5**	**0.0**	**-0.1**	**0.1**	**0.0**	**-0.1**	**0.3**
DEU	SE4	1.3	1.3	1.3	1.3	1.3	0.8	1.2	0.0	0.0	0.0	0.0	-0.5	0.0
SE4	DEU	3.5	3.5	3.4	3.4	3.5	2.8	2.7	0.0	-0.1	-0.1	0.0	-0.7	-0.8
Net	**DEU→ SE4**	**-2.2**	**-2.2**	**-2.1**	**-2.1**	**-2.2**	**-2.0**	**-1.5**	**0.0**	**0.1**	**0.1**	**0.0**	**0.2**	**0.7**
NLD	DK1	2.1	2.1	2.1	2.2	2.1	1.1	2.1	0.0	0.0	0.0	0.0	-1.0	-0.1
DK1	NLD	2.4	2.4	2.4	2.3	2.4	1.5	1.9	0.0	0.0	-0.1	0.0	-0.9	-0.5
Net	**NLD→ DK1**	**-0.3**	**-0.2**	**-0.3**	**-0.2**	**-0.3**	**-0.4**	**0.2**	**0.0**	**0.0**	**0.1**	**0.0**	**-0.1**	**0.4**
NLD	NO2	1.3	1.4	1.3	1.4	1.4	1.1	1.3	0.0	0.0	0.0	0.0	-0.2	-0.1
NO2	NLD	3.8	3.8	3.9	3.8	3.8	3.5	3.3	0.0	0.0	0.0	0.0	-0.3	-0.5
Net	**NLD→ NO2**	**-2.5**	**-2.5**	**-2.5**	**-2.4**	**-2.5**	**-2.4**	**-2.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.4**
POL	SE4	1.0	1.0	1.0	1.0	1.0	0.5	0.8	0.0	0.0	0.0	0.0	-0.5	-0.2
SE4	POL	3.8	3.8	3.8	3.8	3.8	3.1	3.0	0.0	0.0	0.0	0.0	-0.7	-0.9
Net	**POL→ SE4**	**-2.8**	**-2.8**	**-2.8**	**-2.8**	**-2.8**	**-2.6**	**-2.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.2**	**0.7**
EST	FIN	2.9	2.9	1.9	2.9	2.9	1.0	2.3	0.0	-1.1	0.0	0.0	-2.0	-0.6
FIN	EST	7.1	7.1	4.9	7.1	7.1	4.2	6.0	0.0	-2.2	0.0	0.0	-2.9	-1.2
Net	**EST→ FIN**	**-4.2**	**-4.2**	**-3.0**	**-4.2**	**-4.2**	**-3.3**	**-3.6**	**0.0**	**1.2**	**0.0**	**0.0**	**0.9**	**0.6**
LTU	SE4	2.6	2.6	2.3	2.6	2.6	1.2	2.0	0.0	-0.3	0.0	0.0	-1.4	-0.6
SE4	LTU	2.0	2.0	2.2	1.9	2.0	1.0	2.0	0.0	0.2	-0.1	0.0	-1.0	0.0

Net	**LTU→ SE4**	**0.6**	**0.7**	**0.1**	**0.7**	**0.7**	**0.2**	**0.0**	**0.0**	**-0.5**	**0.1**	**0.0**	**-0.5**	**-0.6**

Table 9. Congestion rent for the interconnector availability and trade sensitivities

Trade Zones		Absolute evalues							Delta to THEMA Base					
Export zone	Import zone	THEMA Base	Kriegers Flak	Est Link 3	Born-holm	CBAM	Trade fee	70% availa-bility	Kriegers Flak	Est Link 3	Born-holm	CBAM	Trade fee	70% availa-bility
GBR	DK1	51	51	51	52	42	33	48	1	0	2	-9	-18	-3
DK1	GBR	77	76	78	74	72	57	74	-1	1	-4	-6	-21	-4
Total	**GBR← →DK1**	**128**	**127**	**129**	**126**	**113**	**89**	**121**	**-1**	**1**	**-2**	**-15**	**-39**	**-7**
GBR	NO2	93	94	91	94	82	71	74	1	-2	1	-11	-22	-19
NO2	GBR	280	276	291	276	263	228	292	-4	11	-5	-17	-53	12
Total	**GBR← →NO2**	**374**	**370**	**382**	**370**	**345**	**299**	**366**	**-4**	**8**	**-4**	**-29**	**-75**	**-7**
DEU	DK1	47	47	46	37	48	33	33	1	-1	-10	1	-14	-13
DK1	DEU	60	57	62	44	62	43	97	-4	1	-16	2	-18	37
Total	**DEU← →DK1**	**107**	**104**	**107**	**81**	**110**	**76**	**130**	**-3**	**0**	**-26**	**3**	**-31**	**23**
DEU	DK2	37	38	37	16	38	31	32	0	0	-21	0	-6	-5
DK2	DEU	37	29	37	10	37	28	35	-8	0	-27	0	-8	-1
Total	**DEU← →DK2**	**74**	**67**	**74**	**26**	**74**	**59**	**67**	**-7**	**0**	**-48**	**0**	**-15**	**-7**
DEU	NO2	120	121	117	119	119	92	96	1	-3	-1	0	-28	-23
NO2	DEU	260	256	270	256	266	219	312	-4	9	-5	5	-41	52

Total	**DEU←→NO2**	**380**	**377**	**386**	**374**	**385**	**311**	**408**	**-3**	**7**	**-5**	**5**	**-69**	**28**
DEU	SE4	38	39	38	32	38	31	33	0	-1	-6	0	-7	-5
SE4	DEU	110	107	102	104	111	84	105	-3	-8	-5	1	-26	-5
Total	**DEU←→SE4**	**148**	**145**	**140**	**137**	**149**	**115**	**138**	**-3**	**-8**	**-11**	**1**	**-33**	**-10**
NLD	DK1	21	22	21	21	22	14	20	0	0	-1	1	-8	-2
DK1	NLD	30	29	30	27	31	22	30	-1	0	-3	2	-8	0
Total	**NLD←→DK1**	**51**	**51**	**51**	**47**	**53**	**36**	**50**	**-1**	**0**	**-4**	**2**	**-15**	**-2**
NLD	NO2	52	52	51	52	52	40	42	1	-1	0	0	-12	-10
NO2	NLD	136	134	141	134	141	113	155	-2	5	-2	4	-23	19
Total	**NLD←→NO2**	**188**	**187**	**192**	**186**	**193**	**153**	**197**	**-2**	**4**	**-2**	**4**	**-35**	**9**
POL	SE4	33	34	33	30	33	28	29	0	0	-3	0	-5	-4
SE4	POL	120	118	114	116	121	92	114	-3	-7	-5	1	-28	-7
Total	**POL←→SE4**	**154**	**151**	**147**	**146**	**155**	**121**	**143**	**-3**	**-7**	**-8**	**1**	**-33**	**-11**
EST	FIN	3	4	31	3	3	2	3	0	28	0	0	-2	-1
FIN	EST	65	65	88	66	66	46	94	0	23	0	1	-19	28
Total	**EST←→F**	**68**	**68**	**119**	**69**	**69**	**48**	**96**	**0**	**51**	**0**	**1**	**-21**	**28**
LTU	SE4	37	38	33	36	37	27	28	1	-4	-1	0	-11	-10
SE4	LTU	8	8	16	8	8	6	19	-1	8	0	0	-3	10

Total	**LTU← →SE4**	**45**	**45**	**49**	**44**	**45**	**32**	**46**	**0**	**3**	**-1**	**0**	**-13**	**1**

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Dr. Arndt von Schemde

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