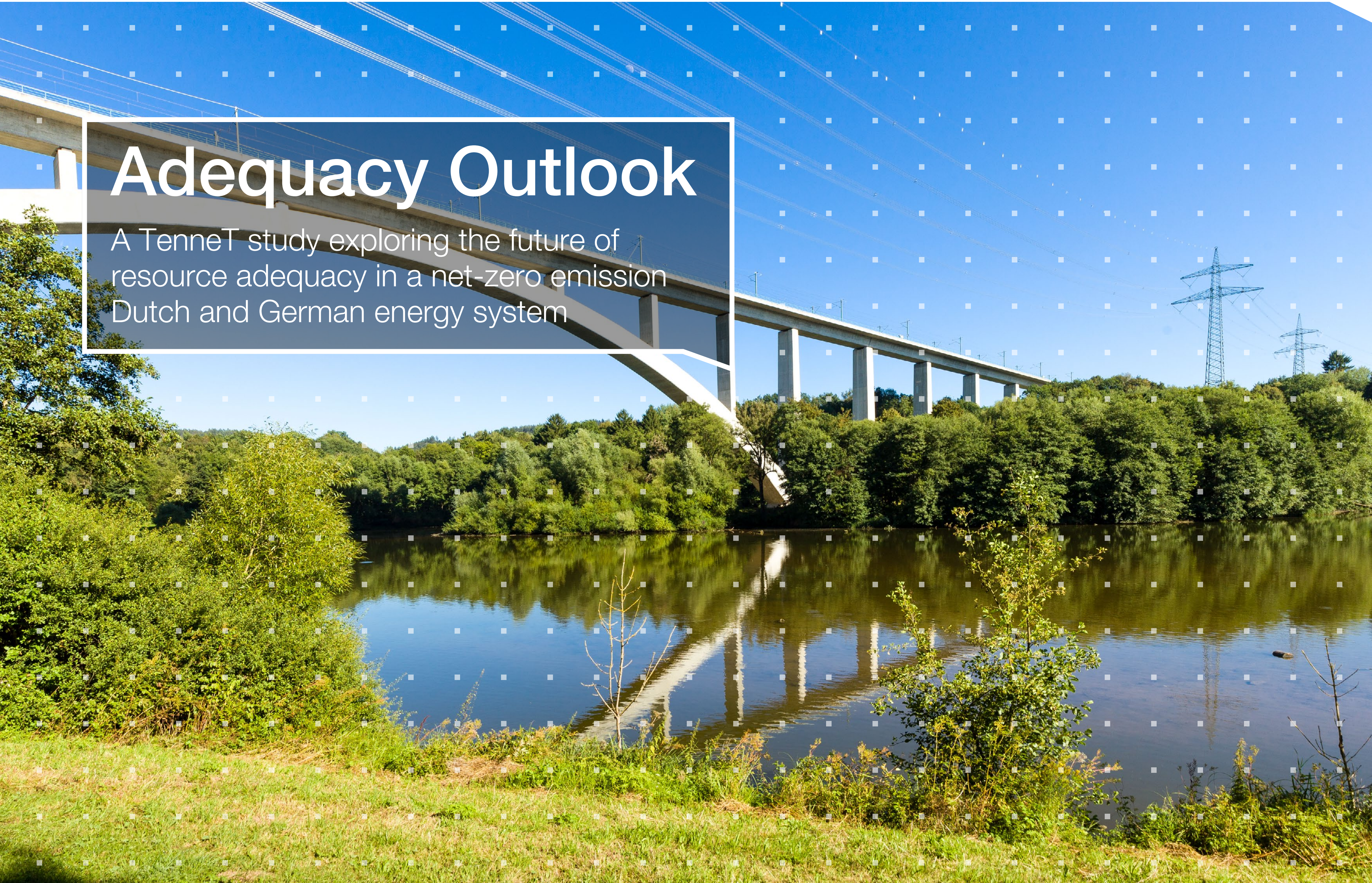
Adequacy Outlook

A TenneT study exploring the future of resource adequacy in a net-zero emission Dutch and German energy system



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Key Messages

Resource adequacy can be ensured in a net-zero emission power system providing sufficient investments are made in firm capacity from demand-side response, cross-border transmission capacity, storage, and zero-carbon thermal capacity.

- The most challenging adequacy situations in a net-zero emission system are likely to be long periods with limited renewable electricity generation and high demand, also known as *dunkelflaute* situations. These cannot be addressed by short-term battery storage or load shifting.
- Demand side response is likely the most cost-effective source of firm capacity to resolve short-term shortages in supply, and exploiting its potential should be the first priority for ensuring adequacy.
- Cross-border transmission plays a major role by providing access to capacity resources in foreign markets, and is particularly beneficial when connecting markets with complementary characteristics. Transmission capacity helps stabilise market prices, maximises the use of renewable energy sources and reduces the amount of firm production capacity needed. However, it is more uncertain than relying on domestic capacity as not only must the capacity in another country be available, but the transmission capacity to access it must also be available.
- Batteries with significant energy capacity and other long-duration storage technologies can contribute significantly to adequacy, while short-duration storages (e.g. 2-hour batteries) are unable to provide significant capacity in times of shortages in supply.
- Investments in capacity come at a cost, and it's important we build an energy system that society is willing to pay for.

Electricity generation from zero-carbon gases will be important for maintaining a secure electricity supply.

- Zero-carbon gasses such as hydrogen will be needed to support the electricity system, especially during regional '*dunkelflaute*' situations when the contribution of short-term storage, demand side response and cross-border exchange is limited.
- While significant capacities are required to cover '*dunkelflaute*' periods, these plants run only a limited number of hours throughout the year, and electricity generated from zero-carbon gas provides less than 10% of total electricity demand.
- Balancing the annual supply and demand of zero-carbon gasses across the energy system will require significant domestic storage volumes for hydrogen to cover seasonal variations in load and generation from renewables, or conversion to other energy carriers which are easier to store.

The current electricity market design works in a future net-zero emission system in theory. However, in practice there is a risk the investments needed to support the energy transition will not be realised in time without additional measures.

- We find that renewables, storage, hydrogen plants and significant industrial demand-side response could be economically viable in a future net-zero emission energy system, but only if:
  - some scarcity periods where electricity demand cannot be fully met by supply are accepted in challenging climate years, and the market price is allowed to reach high levels (approaching the Value of Lost Load) in these situations;
  - sufficient price-flexible demand is available in the system to absorb surplus generation from renewables, preventing market price collapse;
  - investment risks are minimised;
  - investment costs for renewable and battery technologies continue to fall.
- An unwillingness to accept periods of high market prices, risk of market invention, and urgency to decarbonise could make the transition to net-zero too uncertain for the market, making further intervention necessary.
- A market design which empowers consumers to decide their own electricity reliability level, and how much they are willing to pay for it would give consumers more control over their electricity bills, and also provide governments with better information on how to set the national reliability standard.

A net-zero emission energy system presents new challenges for operating the electricity grid, but these can be overcome.

- The specific nature and scale of the system operation challenges will depend on the makeup of the technologies in the net-zero emission system.
- The biggest challenge for system operation is likely to be maintaining system frequency and voltage stability.
- Many system operation challenges have a locational component and can be exacerbated or relieved depending on where future investments take place in the grid.
- System services currently provided by fossil power plants can be provided by other technologies in a future net-zero emission energy system, with the right incentives.
- Stable operation of a net-zero emission power system could be ensured with a mix of investments in new technologies to strengthen the grid, changing the way we operate and manage the grid, and potential market design reforms.

Key Policy Recommendations

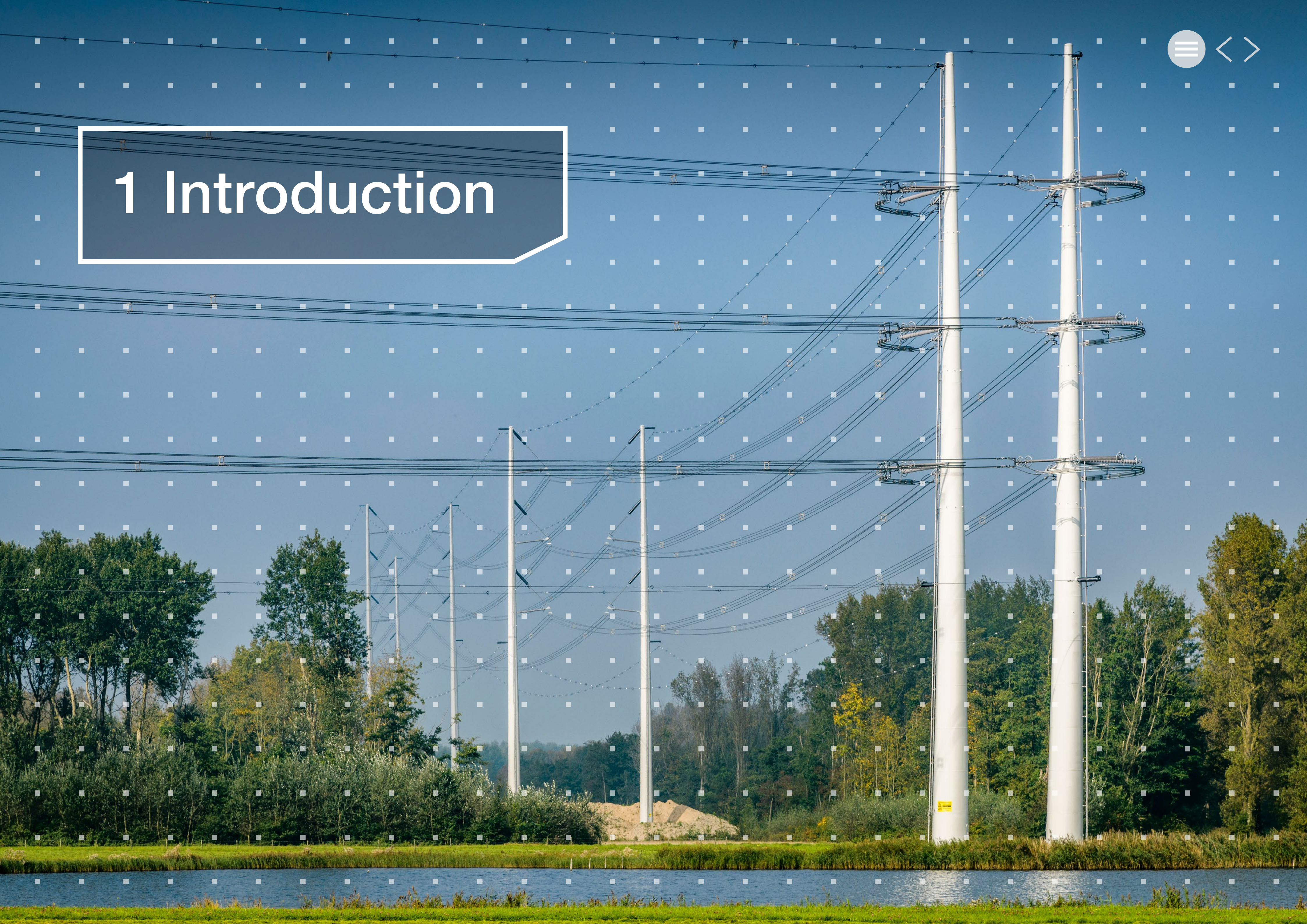
- Explore ways to facilitate consumer participation and increase demand-side flexibility in electricity markets at all time scales
- Consider options to improve the liquidity of long-term forwards and future markets, and increase access to Purchase Power Agreements to counterbalance the need for state-based support.
- Explore ways to simplify complex and lengthy permitting processes to accelerate infrastructure investments, reduce delays and costs.
- Limit interventions in the electricity market as much as possible to create a stable market environment which attracts investment.
- Ensure any subsidy schemes introduced for renewable and other zero-carbon technologies (e.g. P2X) retain their exposure to short-term market price signals.
- Introduce mechanisms to account for spatial challenges in support schemes and other investment measures
- Continue to monitor merchant investments in zero-carbon firm capacity over the coming years, alongside the expected demand and security of supply situation. If the pace of investment is insufficient to ensure timely decarbonisation while maintaining resource adequacy, additional measures to stimulate investments should be considered.
- Accelerate the rollout of advanced smart meters capable of providing real-time pricing, as well as remote control of consumption.
- Phase out net metering of solar production as soon as possible to encourage consumers to start self-balancing their production and consumption.

Inhoud

Abbreviations

ACER	European Union Agency for the Cooperation of Energy Regulators
BRP	Balance responsible party
BSP	Balancing service provider
CAPEX	Capital expenditure
CCGT	Combined-cycle gas turbine
CCS	Carbon capture and storage
CfD	Contract for Difference
CONE	Cost of new entry
CRM	Capacity remuneration mechanism
DA(M)	Day-ahead (market)
DE	Germany
DSO	Distribution System Operator
DSR	Demand-side response
ENS	(Expected) Energy not served
ENTSO-E	European Network of Transmission System Operators for Electricity
EOM	Energy-only market
ERAA	European Resource Adequacy Assessment
ETM	Energy Transition Model
EU	European Union
EV	Electric vehicle
FCR	Frequency Containment Reserve
FLH	Full load hours
FOM	Fixed operating & maintenance costs
FRR	Frequency Restoration Reserve
GHG	Greenhouse gas
HMMCP	Harmonised Maximum and Minimum Clearing Price methodology
HP	Heat pump
HVDC	High-voltage direct current
ID(M)	Intraday (market)
IHE	International Hydrogen Economy
II3050	Integrale Infrastructuur-verkenning 2030–2050
IMR	Inframarginal rent
IRR	Internal rate of return
LHV	Lower Heating Value
LLD	Load limiting device
LOLE	Loss of load expectation
MLZ	Monitoring Leveringszekerheid
NEL	National Electrification
NEP	Netzentwicklungsplan
NL	The Netherlands
NRA	National Regulatory Agency
NSWPH	North Sea Wind Power Hub
NTC	Net Transfer Capacity
OCC	Overnight capital cost
OCGT	Open-cycle gas turbine
P2G	Power to gas (hydrogen)
P2H	Power to heat
P2X	Power to X, used to collectively refer to P2G and P2H
PDC	Price duration curve
PECD	Pan-European Climate Database
PEID	Power electronic interfaced device
PPA	Power Purchasing Agreement
PV	(Solar) photovoltaic
RES	Renewable energy sources
RoCoF	Rate of Change of Frequency
RT	Reference technology
SRMC	Short-run marginal cost
STATCOM	Static synchronous generator
SVC	Static VAR compensator
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom
VOLL	Value of lost load
VOM	Variable operating & maintenance costs
WACC	Weighted average cost of capital

1 Introduction



1.1 Background

In order to meet the objective of the 2015 Paris Agreement and limit global warming to well below 2°C (preferably to 1.5°C) compared to pre-industrial levels, emissions of greenhouses gases (GHG) and in particular carbon dioxide (CO_2) must be reduced. As part of the European Green Deal and the European Climate Law, the European Union (EU) aims to achieve a 55% reduction in GHG emissions by 2030 compared to 1990 levels (i.e., the Fit for 55 Package), and aims to become the world's first climate-neutral continent by 2050 [1]. In order to achieve these ambitious goals, each member state will need to play its part. In Germany, the government has sharpened its national targets in the Climate Protection Act in 2021 which legislates a 65% reduction in GHG emissions by 2030, and carbon neutrality by 2045. In the Netherlands, the decarbonisation ambitions were set forth in 2019 with the Dutch Climate Agreement (Het Klimaatakkoord [2]) and legislated in the Dutch Climate Act. The target is to achieve a 95% reduction of GHG emissions by 2050 compared to 1990 levels.

These ambitious decarbonisation targets will transform the way energy is produced and consumed throughout the entire energy system. As part of this transition, the electricity sector is expected to play a major role in achieving these goals, and two key trends are expected over the coming years:

- Large-scale deployment of renewable energy sources (RES) such as onshore wind, offshore wind and solar photovoltaics (PV), For example in the Netherlands, RES are expected to supply nearly 80% of total Dutch electricity generation by 2030 [3] compared with 20% in 2020) [4]. In Germany RES are expected to supply 80% of the gross consumption by 2030 [5] (compared to 46% in 2020). Even more ambitious targets for the expansion of RES in Germany have recently been set with the goal to achieve climate neutrality for the whole energy system by 2045, and electricity generation to be almost completely driven by RES in 2035.

- A significant increase in electricity demand, both due to direct (direct end use of electrical energy) and indirect (conversion of electrical energy to another carrier first) electrification throughout demand sectors.

Compared to conventional electricity generation technologies such as natural gas and coal power plants, RES have the advantage that they are renewable, emit no direct GHG emissions, and in recent years have reached cost parity with conventional fossil technologies in many locations. On the other hand, due to their variable generation output and distributed nature, an increasing share of RES also poses new challenges for maintaining security of supply and stable operation of the electricity grid. Given the significant uncertainty as to how the future power system will develop in the coming decades, the full extent of these challenges remains unknown.

1.2 Aims of this study

In this context TenneT has performed the Adequacy Outlook in order to get further insights into the magnitude of the challenges related to the future adequacy in a net-zero emission system. With this study our aim is not to provide a detailed forecast of future system adequacy as in the MLZ or the ERAA, but rather to:

- explore what supply- and demand-side resources may be needed to ensure resource adequacy in a net zero-carbon emission energy system, and how resource adequacy could be achieved[1];

- understand how sensitive adequacy may be under different future energy system scenarios;

- analyse the role different technologies can play in supporting system adequacy;

- identify what types of adequacy challenges the system will face in the future and how these can be addressed;

- gauge the potential economic viability of capacity resources in a net-zero emission system; and

- reflect on the possible high-level implications for system operation and electricity market design of a net-zero emission system.

1 We use the term 'zero-carbon' in this study to mean that either the energy (or electricity) system emits no net direct emissions of CO_2. This would allow for a system with some CO_2 emissions so long as an equivalent amount of CO_2 is also removed from the atmosphere. However, we do not consider embodied or life-cycle emissions of CO_2 for different generation technologies.

With the insights of this study, TenneT aims to provide a long-term perspective on resource adequacy, and engage with policymakers, market parties and other stakeholders on how security of supply can best be maintained in this changing energy landscape.

1.3 What is resource adequacy?

When we consider adequacy in the context of security of supply, we usually refer to *resource adequacy*: the ability of the power system to ensure aggregate demand for electricity can be met at all times, at a price that consumers are willing to pay (Figure 1.1). The resources contributing to resource adequacy can be either on the supply side (e.g., conventional thermal power plants, solar PV, wind farms, hydro), on the demand side (e.g., flexible consumers), or both (e.g., storage). If we also bring in *transport adequacy* – the ability of the grid to deliver electricity from where it is produced to where it is consumed – we arrive at the wider definition of system adequacy. Ensuring *system adequacy* is a long-term process as it requires investments in new supply, demand, storage and transmission infrastructure. Along with more short-term phenomena related to the grid such as *system stability* and *system security*,[2] resource adequacy is one of the key aspects of overall *system reliability*.

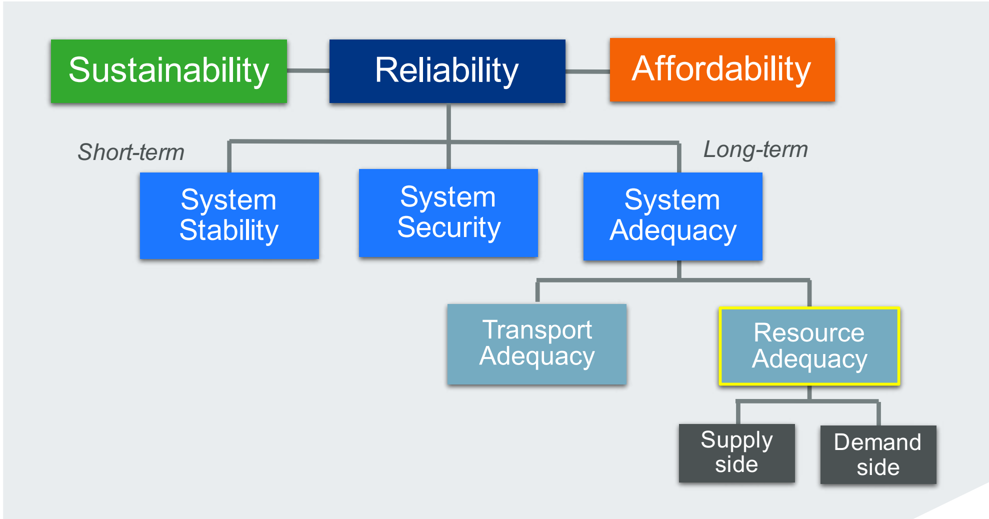


Figure 1.1 | Resource adequacy in the context of reliability and wider energy system objectives

2 System security is the ability of the electric power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements (e.g., generators, lines, transformers), while system stability is the ability to maintain a state of equilibrium during normal conditions and regain a state of equilibrium after abnormal system conditions or disturbances.

1.4 Resource adequacy and the Energy Trilemma

Having a reliable energy system is not the only goal: it should be sustainable and affordable too. The challenge of achieving all three goals is sometimes known as the *energy trilemma* and requires certain trade-offs. For example, if there are not enough capacity resources available in the system to meet the electricity demand, the transmission system operator (TSO) is usually forced to take the emergency measure of reducing some consumer load, in order to maintain the power system within safe operating limits. Nevertheless, this involuntary load shedding represents a cost to society, as electricity is a fundamental part of our daily lives and underpins the modern economy. We can always invest more in additional power plants to make the system more adequate, but such investments also come at a cost. According to economic theory, a point will be reached where the incremental cost of supplying an extra MWh of electricity, and the economic harm from shedding that MWh of load, are equal [6]. This implies there is some optimal level of capacity (and hence resource adequacy) where the total costs of capacity and load shedding are at a minimum for society (Figure 1.2). This is the principle behind the concept of a *reliability standard*, discussed further in Chapter 5.

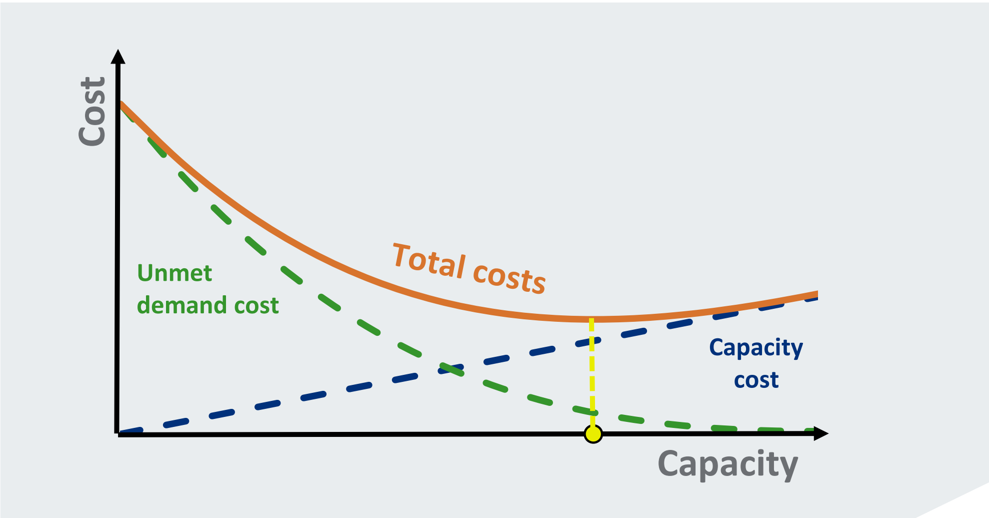


Figure 1.2 | Resource adequacy is a trade-off between capacity costs and unmet demand costs. Where the total cost is lowest is the theoretical optimum level of reliability.

Identifying the optimal level of capacity for a future net-zero emission energy system is not straightforward. For one thing, the economic damage associated with involuntary load shedding is difficult to assess, and likely to change over time as consumers adapt to changes in the electricity market, and new types of consumers emerge. The costs of capacity are also uncertain: some technologies may get cheaper over time as technology improves, while others may get more costly due to higher fuel prices. Completely new game-changing technologies may also emerge. Moreover, the contribution to resource adequacy of capacities in other countries via interconnectors should also be considered. Even if we could calculate the optimal level of reliability with any precision, another challenge is how the electricity market should be designed to deliver this level of capacity in a way that is economically viable.

1.5 Relation to other studies

Several previous studies have been performed on the topic of resource adequacy and the transition to a net-zero emission system in NL, DE and Europe as a whole (Table 1.1). Most existing adequacy studies typically:

- focus on the short- to medium-term (i.e., from 1 to 10 years ahead) rather than on the long term;
- focus on the needs only of a net-zero emission *electricity* system, without accounting for the additional implications of a completely net-zero emission *energy system*; or
- assume a specific level of reliability, without questioning the assumptions underlying this level of reliability, how these may change in the future, and exploring the trade-offs between adequacy and cost.

There are also net-zero emission energy system studies which focus on the bulk supply and demand for energy, and long-term infrastructure studies. However, adequacy is not the focus of these studies which typically ensure either a fully adequacy system or simulate only a small number of climate years.

With this Adequacy Outlook, we aim to fill a gap by providing a broader perspective on long-term resource adequacy in a net-zero emission energy system and identifying synergies with other aspects of long-term system design.

1.6 Scope of this study

While the Adequacy Outlook takes a broad look at future resource adequacy and the uncertainties surrounding it, several scope limitations should be kept in mind.

- The focus is the Netherlands (NL) and Germany (DE). Other European countries are considered as part of the modelling, but not analysed in detail.
- This study considers a point in the future once the transition to a net-zero energy system has taken place, without reference to any specific future target year, decarbonisation and climate policies at both EU and national level are becoming increasingly ambitious over time and coupled with the ongoing war in Ukraine and its impact on unprecedented high fuel prices, the need for decarbonisation in the EU has never been so urgent. For this reason, our study is not aimed at any specific future year (e.g., 2040, 2050) as the pace of the energy transition will ultimately be set by policymakers through regulations and targets, the design of the electricity markets, and the financial resources mobilised by market parties and governments to make investments.
- The focus is on resource adequacy, in the context of the broader energy trilemma. Transport adequacy is not considered, and transmission within countries is treated as 'copper-plate'. Ultimately the grid investments required to achieve a net-zero emission energy system will depend on where generation and demand will be located in the grid. These can be steered by different choices in grid tariffs and market design.

Focus region	Study	Study type
The Netherlands	Monitoring Leveringszekerheid [7]	Adequacy study (Medium term)
	100% CO_2-vrije elektriciteit in 2035 [8]	Net-zero emission electricity system
	Naar een CO_2-vrij elektriciteitssysteem in 2035 [9]	Net-zero emission electricity system
	Investeringsplannen [10]	Infrastructure study (Medium term)
	Integrale Infrastructuurverkenning 2030–2050 [11]	Infrastructure study (Long term)
Germany	Monitoring the adequacy of resources in the European electricity markets [12]	Adequacy study (Medium term)
	The impact of weather in a high renewables power system [13]	Adequacy study (Long term)
	Langfristszenarien [14]	Net-zero emission energy system
	Klimaneutrales Deutschland 2045 [15]	Net-zero emission energy system
	Klimapfade 2.0 [16]	Net-zero emission energy system
	Aufbruch Klimaneutralität [17]	Net-zero emission energy system
	Netzentwicklungsplan Strom [18]	Infrastructure study (Medium and long term)
The Netherlands and Germany	Infrastructure Outlook 2050 [19]	Infrastructure study (Long term)
Europe	Seasonal Outlook [20]	Adequacy study (Short term)
	European Resource Adequacy Assessment [21]	Medium term adequacy
	Ten Year Network Development Plan [22]	Infrastructure study (Medium and long term)

Table 1.1 | Overview of selected existing studies related to resource adequacy and the transition to a net-zero emission energy system

This rest of this report is structured as follows:

- **Chapter 2** describes the overall methodology applied in this study and underlying analysis steps;
- **Chapter 3** presents the scenarios for a future zero-carbon energy system which are analysed;
- **Chapter 4** details the main modelling and technology assumptions underlying the study;
- **Chapter 5** presents the main adequacy analysis for the scenarios considered, as well as insights on how various technologies contribute to adequacy;
- **Chapter 6** analyses the economic viability of the capacity resources in the considered scenarios;
- **Chapter 7** considers the implications for power system operation in a net-zero emission energy system;
- **Chapter 8** reflects on the electricity market design elements required to support a net-zero emissions energy system, and
- **Chapter 9** presents some high-level conclusions and recommendations.

Additional assumptions can be found in the Annex at the end of this report.

2 Methodology

2.1 High level approach

This study consists of four main steps, as shown in Figure 2.1.

- We first define a framework of **scenario storylines** for a future net-zero carbon emission energy system in NL and DE.
- An **energy system model** is then used to build quantified datasets of the demand and supply of all key energy carriers in NL and DE for each scenario defined.[3] The key output of this model is the hourly demand for electricity and hydrogen in NL and DE, which is used as an input for the next step.
- Next the quantified scenarios and load profiles for NL and DE are combined with net-zero emission scenarios for all other European countries, and **electricity market simulations** are performed for a large number of climate years and forced outage patterns to determine the hourly balance of supply and demand.
- Lastly, the scenario assumptions are combined with the detailed market simulation results in order to perform a set of ex-post **quantitative and qualitative analyses** focussing on (i) resource adequacy, (ii) economic viability, (iii) system operation, and (iv) market design.

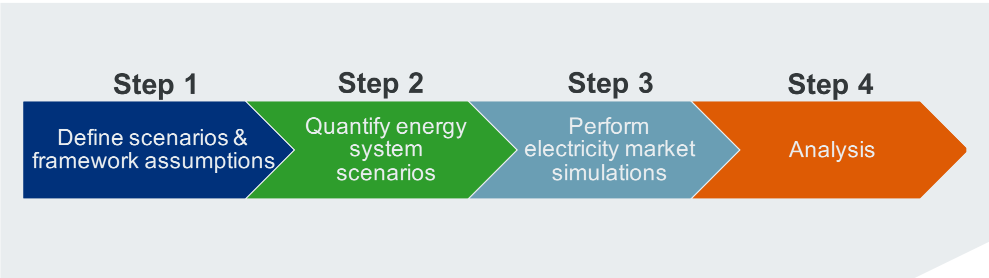


Figure 2.1 | High level overview of the Adequacy Outlook methodology

3 While the scope of the energy system model (ETM) covers the entire energy system, the geographic scope is a single country. Thus, the scenarios for NL and DE are quantified separately.

2.2 Scenarios and framework assumptions

The starting point for this study is a set of high-level storylines for a net-zero emission energy system in NL and DE. These storylines vary on key dimensions such as final energy demand, the extent of electrification, the amount of RES and the role of hydrogen in the energy system. Within these storylines several scenarios are also considered, to explore specific uncertainties such as the mix of generation technologies considered, and total electricity demand. Alongside the high-level scenario assumptions, various additional framework assumptions such as technology parameters and fuel prices are also required in different steps of the study.

2.3 Quantify energy system scenarios

The net-zero emission energy system scenarios for NL and DE are built and quantified using the open-source *Energy Transition Model* (ETM). [4] The ETM is an energy system model which allows the user to develop and explore balanced energy system scenarios, based on a set of user-defined and built-in assumptions, while considering all relevant energy carriers and sectors. By supplying the ETM with hourly RES capacity factors, temperature and solar irradiance profiles from 35 historical climate years (1982-2016) from the Pan-European Climate Database (PECD), the ETM is used to generate hourly electricity demand profiles for NL and DE for the market simulations in Step 3, which are consistent with the scenario assumptions for the wider energy system (Figure 2.2).

4 ETM is developed by Quintel and can be accessed here https://energytransitionmodel.com/.

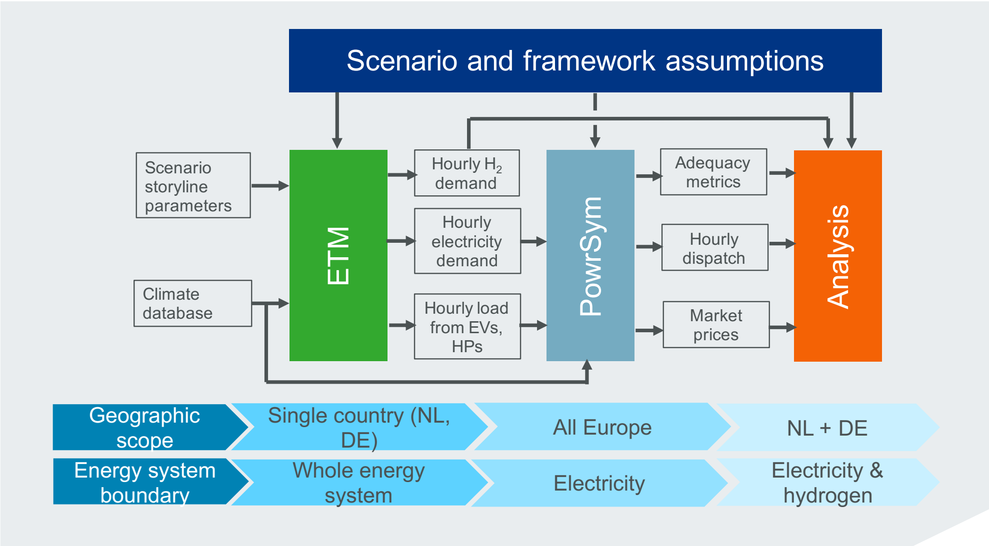


Figure 2.2 | Main inputs, outputs and interfaces between the modelling steps

In addition to the total hourly electricity demand profiles, the underlying electricity demand profiles for electric vehicles and heat pumps, as well as the hourly demand for hydrogen (excl. hydrogen for gas power plants) are extracted from the ETM. The demand profiles for electric vehicles and heat pumps are used to define flexible DSR capacities for these technologies, while the hydrogen demand profiles are used to determine the resulting hydrogen import/export in the post-processing analysis.

2.4 Electricity market simulations

For each net-zero emission scenario, detailed electricity market simulations are performed for the whole European market using the simulation tool *PowrSym*.[5] This tool optimises the dispatch of all supply- and demand-side resources to meet hourly demand, calculates the cross-border electricity exchange. Any electricity demand which cannot be supplied by generation, storage, imports or voluntary DSR indicates a potential resource adequacy issue and would imply some demand would need to be curtailed by the TSO. In order to capture the impact of climate variability and unplanned outages, each scenario is simulated for 35 historical climate years (1982-2016) and five forced outage patterns for dispatchable power plants and cross-border high-voltage direct current (HVDC) interconnectors in a large set of so-called probabilistic *Monte Carlo* simulations. The main outputs from the electricity market simulations are key resource adequacy metrics, the hourly dispatch of supply- and demand-side resources, and electricity market prices. These outputs are also used to derive additional indicators for the subsequent analysis steps.

2.5 Analysis

In the last step we analyse the simulation results of each of the considered net-zero emissions scenarios in terms of resource adequacy, as well as the related topics of economic viability, system operability, and electricity market design. These focus areas are analysed as they are either a necessary step for, or are an important consideration in the transition to a net-zero emission energy system. These analyses are based on a combination of the input assumptions, market simulation results, literature and other TenneT studies.

Several of these topics are naturally interrelated, and the analysis conducted in certain steps depends on the results from others (Figure 2.3). For example, an analysis of the performance of the market design first requires an assessment of economic viability, which depends on the market simulation results. An overview of these additional analyses is described briefly in this section.

5 While the ETM does perform hourly calculations, these are based on a simplified dispatch algorithm which is not as detailed as the unit commitment and economic dispatch performed by PowerSym. Exchange between countries is only modelled in a simplified way and technology constraints are not modelled.

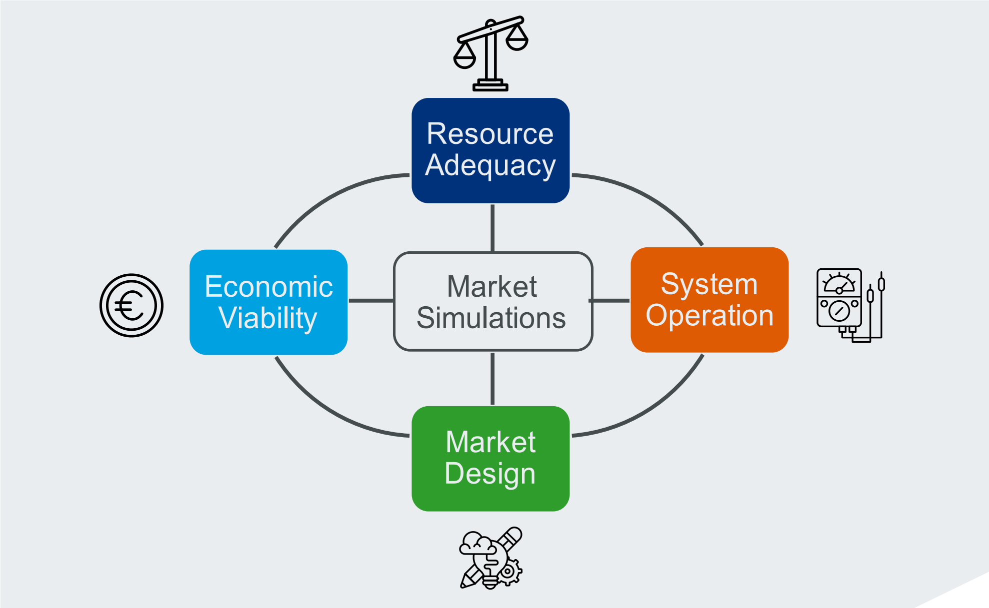


Figure 2.3 | Links between the analysis steps and the market simulations

2.5.1 Resource adequacy

The resource adequacy analysis considers security of supply in each of the net-zero emission scenarios by calculating key probabilistic security of supply indicators such as Loss of Load Expectation (LOLE), the average number of hours per year that some demand in a market area cannot be met, and expected *Energy Not Served* (ENS), the total amount of demand which cannot be met in a given year. As part of this analysis we also:

- estimate the cost of capacity resources and perform calculations on reliability standard;
- determine how much capacity is needed to make each of the net-zero emission scenarios (roughly) adequate;
- analyse the role of each technology in supporting system adequacy;
- explore what situations are most challenging for resource adequacy in net-zero emission energy system, and
- reflect on the dependence of zero-carbon energy carriers such as hydrogen.

2.5.2 Economic viability

The aim of the economic viability analysis is to check whether the portfolio of capacity resources assumed in each scenario could have a viable business case. This is done by comparing the calculated plant revenues from the model results with the estimated fixed costs of providing capacity. This high-level analysis is complemented by an assessment of more indirect economic indicators, such as the hourly market prices and annual full load hours achieved by different plant types.

The absence of a sound business case for a given technology could suggest that the capacity resource mix assumed in the scenario would not be viable under the modelled market assumptions. Thus, the capacity mix would need to be modified, or additional market design elements would be required to lead to support the assumed scenario.

2.5.3 System operation

The transition to a net-zero emission electricity system including large shares of RES presents new challenges not only for resource adequacy, but also system operation. While detailed grid calculations are beyond the scope of this study, we can gain some high-level insights into the operational challenges of a net-zero system by comparing different net-zero scenarios based on several qualitative and quantitative indicators.

2.5.4 Electricity market design

This study assumes the current European electricity market design – with some refinements – still prevails in a future net-zero emission electricity system. In this analysis we reflect on the performance of the electricity market design based on the simulation results and identify which key market design elements are needed to reach a net-zero emission energy system.

3 Scenarios

3.1 High-level energy system scenario storylines

In order to avoid dangerous climate change, GHG emissions from our energy system will have to fall to (at least) net zero within the next two to three decades. However, it is not exactly clear how this transition will be achieved, and whether it will be achieved in time. For example, on the demand side it is unclear to what extent zero-carbon electricity can and will be used to directly substitute fossil fuels in carbon-intensive industries, how much electricity will be needed to produce zero-carbon fuels such as hydrogen, how much the total demand for electricity will grow, and how this might be mitigated by energy efficiency measures. On the supply side, it is also not clear to what extent technology developments and cost reductions will impact future investments, and what mix of technologies will form the basis of the future energy system. Whichever way the transition unfolds, resource adequacy must be maintained, and for this reason we explore several scenarios for the future energy system.

Our scenario framework is based on two high-level storylines: the **National Electrification (NEL)** and the **International Hydrogen Economy (IHE)** storyline (Table 3.1).

- In the NEL storyline, it is assumed that both countries rely on energy efficiency improvements in all sectors, electrification of final energy demand and decarbonisation of electricity generation to achieve carbon neutrality. There is a preference to supply the bulk of national electricity demand with domestic RES, and a preference to produce hydrogen (and derived fuels) domestically to decarbonise sectors which are difficult to electrify directly (e.g., industrial processes, aviation). The latter leads to significant deployment of electrolysers in both NL and DE.

- In the IHE storyline, an international market for zero-carbon hydrogen is assumed to emerge with significant quantities of molecule-based energy available at a lower cost than in the NEL storyline. As a result, hydrogen is used to a greater extent and in more sectors than in the NEL storyline, and both NL and DE rely more on imported hydrogen to meet their total energy needs. As in the NEL storyline, significant energy efficiency improvements and electrification are assumed, but due to the wider availability and higher dependence on hydrogen, the degree of electrification is lower.

These two high-level scenario storylines are developed by combining different scenarios from existing Dutch, German and European studies:

- the *Integrale Infrastructuurverkenning* 2030–2050 (II3050) [24] for NL;
- the (draft) *Netzentwicklungsplan 2023* (NEP 2023) [19] for DE; and
- the *Ten-Year Network Development Plan* (TYNDP) *2022 edition* [25] for all other European countries.[6]

The specific scenarios from the original studies are selected and combined in order to be as consistent as possible with the high-level NEL and IHE storyline assumptions. For example, the storyline assumptions underlying the *National* scenario from II3050 for NL are broadly comparable to the *NEP B/C* scenario for DE and *Distributed Energy* scenario from TYNDP 2022, while the *International* storyline from II3050 is broadly comparable to the *NEP A* storyline for DE and *Global Ambition* scenario from TYNDP 2022 (Figure 3.1). Due to differences in the way the original scenarios were developed, there are some differences in how the final demand for electricity and hydrogen develops in different countries.

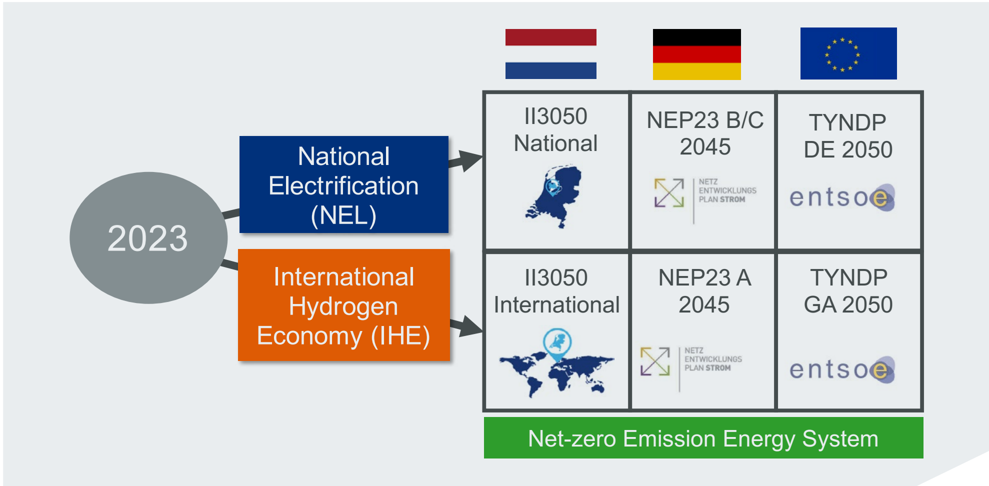


Figure 3.1 | Basis for the high-level scenario storylines considered

6 Note that the assumptions for NL are based on the first edition of the II3050 study published in April 2021, not the second edition of the II3050 study which is currently underway. The assumptions for DE are based on draft NEP 2023 scenarios available in early 2022. The scenarios were subsequently updated before approval by the German regulator [120], but these updates are not reflected in this study.

	Storyline	
Dimension	**National Electrification (NEL)**	**International Hydrogen Economy (IHE)**
CO_2 emissions	Approximately 100% reduction compared to 1990	
Renewable energy sources (RES)	Significant increase of domestic RES generation compared with today, much higher than in the IHE storyline.	Significant increase of domestic RES generation compared with today, but lower than in the NEL storyline.
Final energy demand	Significant reductions across most sectors compared with today due to improved building insulation, and a shift to more efficient technologies.	Similar to the NEL storyline.
Electrification of final demand	Significantly higher than today, and higher than in the IHE scenario due to significant requirements for domestic P2X	Significantly higher than today, but lower than in the NEL storyline since less P2X.
Role of hydrogen	Hydrogen is used mostly for (backup) electricity generation and for industry, and to a limited extent in the transport (e.g., heavy transport vehicles). Lower dependence on imported hydrogen than in the IHE storyline due to high domestic P2G capacity.	Hydrogen is used for electricity generation as well as for industry, transport and heating buildings. Higher dependence on imported hydrogen than in the NEL storyline due to lower domestic P2G capacity.

Table 3.1 | Assumptions underlying the energy system scenario storylines

3.2 Scenarios considered for NL and DE

The NEL and IHE storylines represent different realisations of what a future net-zero emission system could look like, from both the demand and supply side. In order to explore some additional uncertainties specific to the electricity sector, we consider several scenarios for DE and NL based on these storylines (Table 3.2).

- The combination of the two original 'II3050 National' and 'NEP B/C' scenarios, and 'II3050 International' and 'NEP A' scenarios for NL and DE we define as the **NEL-Wind** and **IHE-Wind** scenarios respectively, as both rely strongly on onshore and offshore wind to supply electricity.

- In the **NEL-Solar** scenario, we consider a system where solar PV provides a larger share of electricity than in the NEL-Wind scenario by reducing the capacity of wind and scaling up the capacity of solar PV.

- The **NEL-Demand** scenario assumes more demand for electricity than in the NEL-Wind scenario. An additional ~30 TWh/y of inflexible demand is added for NL based on the maximum potential for industrial electrification identified in a recent study [26], while an additional ~130 TWh/y demand is added in DE by applying the same increase in underlying industrial demand as in NL.

- In the **NEL-Baseload** scenario, 9 GW of firm baseload generation capacity in the form of nuclear capacity is added in NL, and the capacity of offshore wind is reduced by approximately 16 GW to compensate for the estimated generation of nuclear. [7] No changes are made in DE for this scenario.

7 This scenario reflects the coalition agreement in the NL in which additional nuclear capacity is considered for NL [85], and a follow-up study to II3050 commissioned which explored up to 9 GW of nuclear capacity in a climate-neutral Dutch energy system [86] [87]. However, it could represent any kind (or mix) of firm baseload technology such as deep geothermal, or bioenergy with carbon capture and storage. We assume nuclear replaces offshore wind as this is the costliest RES technology, and this effect is seen in other studies (e.g. [97]). However, the additional firm capacity could instead replace onshore technologies such as ground-based solar PV or onshore wind if this were preferred from a societal perspective.

	Region	
Scenario	NL (flag)	DE (flag)
NEL-Wind	**II3050 National scenario** • Approaching 100% RES • ~75%/20% wind/solar share[1] • Load approx. 220 TWh/y[2]	**NEP B/C 2045 scenario** • Approaching 100% RES • ~60%/35% wind/solar share[1] • Load approx. 1 000 TWh/y
NEL-Solar	Based on NEL-Wind, but **solar share increased to ~40%** by increasing solar and reducing wind capacity	Based on NEL-Wind, but **solar share increased to ~50%** by increasing solar and reducing wind capacity
NEL-Demand	Based on NEL-Wind, **with an additional 30TWh/y (~13%) inflexible demand added**	Based on NEL-Wind, **with an additional 130 TWh/y** (13%) inflexible demand added
NEL-Baseload	Based on NEL-Wind, **but 9 GW** of baseload capacity replaces ~16 GW of offshore wind.	Same as NEL-Wind
IHE-Wind	**II3050 International scenario** • Approaching 100% RES • ~70%/20% wind/solar share[1] • Load approx. 250 TWh/y[2]	**NEP A scenario** • Approaching 100% RES • ~60%/30% wind/solar share[1] • Load approx. 860 TWh/y[2]

[1] *Based on approximate share of gross electricity supply from ETM*

[2] *Excluding demand from P2X, which is modelled as fully price flexible*

Table 3.2 | Overview of the scenarios considered in this study for NL, DE and the rest of Europe

Alongside solar and wind, flexible zero-carbon technologies such as hydropower, battery storage, and zero-carbon gas power plants are considered in every scenario. Price-driven flexible DSR from industrial consumers, Power-to-Gas (P2G) and Power-to-Heat (P2H) (referred to collectively as P2X), as well as electric vehicles (EVs) and heat pumps (HPs) are also considered. The capacities of these technologies are mostly based on the original *II3050* and *NEP* scenarios, with the following exceptions:

- the capacity and price of industrial DSR is based on other studies, as the II3050 and NEP either did not explicitly consider industrial DSR, or did not include sufficient data to model it;
- the capacity of batteries is reduced from the original scenarios as the battery capacity was likely over-estimated in the II3050 study,[8] and to bring the ratio of assumed battery capacity to peak load in NL and DE closer together;
- the capacity of DSR from EVs and HPs is based on the underlying hourly demand profiles of these technologies from the ETM, assuming only a part of this demand is flexible; and
- the capacity of zero-carbon gas (hydrogen) plants is not taken from the original scenarios, but adjusted as part of this study in each scenario to meet a specific reliability standard (see section 5.4).

8 The approach used to estimate required flexible capacity in the II3050 study was highly simplified.

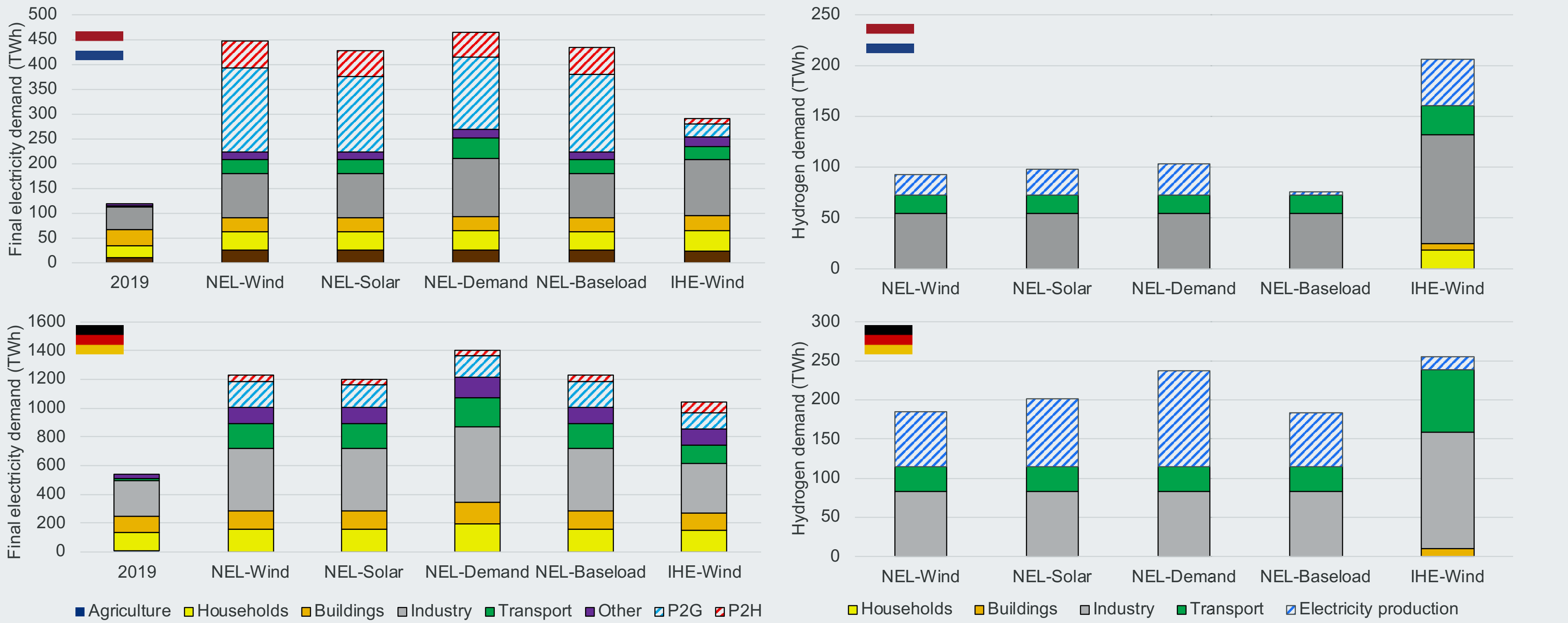


Figure 3.2 | Typical breakdown of electricity (left) and hydrogen (right) demand for NL (above) and DE (below) for each scenario based on the ETM model. Note that the demand for electricity and supply of hydrogen differs per climate year in the simulations depending on renewable temperature, temperature and electricity prices.

3.3 Demand assumptions

In terms of electricity demand, Figure 3.2 shows the underlying assumptions for NL and DE in each scenario. The historical load from 2019 is also shown for comparison. Compared to 2019 the main drivers increasing demand in our net-zero emission scenarios are: (i) electrification in industry (43-55 TWh/y increase in NL, 73-154 TWh/y in DE); (ii) additional demand for heating from HPs (10-12 TWh/y in NL, 30-46 TWh/y in DE), and (iii) charging of EVs (24-25 TWh/y in NL, 115-151 TWh/y in DE). While the impact of climate change may ultimately lead to lower demand for heating and an increase in demand for cooling, these effects are not considered in this study.[9]

Excluding demand for P2X, the total underlying annual electricity demand in the *NEL-Wind* scenario rises to approximately 220 TWh/y in NL and 1000 TWh/y for DE, while peak electricity demand in the *NEL-Wind* scenario reaches roughly 40 GW in NL, and 180 GW in DE in the most challenging climate year.[10] Including indirect electrical demand for P2X, the total demand for electricity rises to around 400 TWh/y in NL, and 1200 TWh/y in DE. In the IHE-Wind scenario, underlying demand reduces in DE but increases somewhat in NL compared with the NEL-Wind scenario.[11] Note that the electricity demand for P2X is not a fixed input assumption, but rather an outcome of simulations. The reason for this is that the production of hydrogen from P2G and heat from HPs and electric boilers and is assumed to be fully price responsive, and hydrogen/heat will only be produced from electricity if this is cost effective compared with alternatives.

The assumed demand for hydrogen for sectors other than electricity sector (e.g., industry and transport) is also shown in Figure 3.2 While the installed capacity of P2G per country is an input, the actual domestic production of hydrogen and annual import/export position is an outcome of the simulations. For each scenario, for each climate year, the hydrogen demand from other sectors coming from ETM is compared with the calculated annual net domestic hydrogen production (i.e., production from domestic P2G, less consumption in domestic hydrogen power plants): any resulting shortfall is assumed to be met by hydrogen imports, while any resulting surplus is exported. The hourly balancing of the hydrogen system is covered by respective hydrogen storages. Further details on how the hydrogen demand profiles are built up can be found in the documentation of the ETM [27].

3.4 Overview of installed capacities

An overview of the assumed capacities for all supply-side, demand-side and storage technologies for each scenario is shown in Table 3.3 and Table 3.4 for NL and DE respectively. The capacity installed in 2021 is also shown for comparison, for the closest corresponding (fossil) technology. The installed capacities in neighbouring countries are kept the same based on the original TYNDP scenarios.

It is important to highlight that the mix of technologies considered in each scenario is an assumption based on previous studies, and the adjustments outlined in section 3.2. These scenarios are not necessarily cost optimal from a system perspective, nor do they represent TenneT's view of how the power system should or is likely to develop. More variants of the NEL storyline are considered than for the IHE storyline as with less domestic RES capacity, a stronger reliance on hydrogen import and lower overall demand, maintaining resource adequacy is expected to be somewhat less challenging in the IHE storyline than in the NEL storyline.

9 The PECD does not current account for long-term future warming as a result of climate change. However, ENTSO-E is developing a new database based on simulations of the future climate to be able to consider these impacts in future studies
10 This corresponds to roughly a doubling compared to the recent average peak load of 18 GW in NL and 80 GW in DE [98].
11 The reason for this is that in the original scenario for NL (II3050 'International') an increasing industrial activity is assumed, resulting in higher energy consumption.

Technology		Reference	Net-zero emission scenario				
Category	Sub-type	2021	NEL-Wind	NEL-Solar	NEL-Demand	NEL-Baseload	IHE-Wind
Nuclear	-	0.5	0	0	0	9	0
Solid fuels	-	4	0	0	0	0	0
Zero-carbon gas (hydrogen)	OCGT	18.5	*Adapted as part of this study (see Section 5.4). but in the range of 4 to 16 GW to reach a reliability standard of 6 h/y*				
	CCGT						
Other conventional	-	0.6	0	0	0	0	0
Wind	Offshore [a]	2.5	51.5	38.6	51.5	35.7	27.5
	Onshore	4.5	20	15	20	20	10
Solar PV	Rooftop	10.7	49.8	49.8	49.8	49.8	17.7
	Ground-based		57.6	142	57.6	57.6	34.6
Biomass	-	0.4	0	0	0	0	0
Hydro	Run-of-river	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1	< 0.1
	Reservoir	0	0	0	0	0	0
	Pump storage	0	0	0	0	0	0
Other RES	-	0.6	0.6	0.6	0.6	0.6	0.6
Battery storage	Small-scale (4 h)	0	9.2	9.2	9.2	9.2	10
	Large-scale (8 h)	0	4	4	4	4	4.3
DSR	Other Industry	0.7	3.5	3.5	3.5	3.5	3.5
	Electric vehicles (EVs) [b]	0	1.1	1.1	1.1	1.1	1
	Heat pumps (HPs) [b]	0	2.2	2.2	2.2	2.2	1.6
	Power-to-gas (P2G)	0	51	51	51	51	16
	Power-to-heat (P2H)	0	8.8	8.8	8.8	8.8	3

(a)The offshore wind total excludes an additional 20 GW of offshore wind capacity in the NEL scenario variants that is dedicated to synthetic fuel production according to the original II3050 scenarios and therefore not considered in the modelling of the electricity system.
(b)The DSR available from HPs and EVs varies per hour depending on the demand. The value shown here is the maximum.

Table 3.3 | Assumed technology capacities in each scenario for the Netherlands (GW). The installed capacity in 2021 is also shown for reference.

Technology		Reference	Net-zero emission scenario				
Category	Sub-type	2021	NEL-Wind	NEL-Solar	NEL-Demand	NEL-Baseload	IHE-Wind
Nuclear	-	8.1	0	0	0	0	0
Solid fuels	-	39.9	0	0	0	0	0
Zero-carbon gas (hydrogen)	OCGT	31.7	*Adapted as part of this study (see Section 5.4). but in the range of 8 to 56 GW to reach a reliability standard of 6 h/y*				
	CCGT						
Other conventional	-	9.2	0	0	0	0	0
Wind	Offshore	7.8	70.8	53.1	70.8	70.8	63.3
	Onshore	55.3	150	112.5	150	150	125
Solar PV	Rooftop	56.2	148.1	148.1	148.1	148.1	148.1
	Ground-based		247	447	247	247	177
Biomass	-	9.4	2	2	2	2	2
Hydro	Run-of-river	4.7	4.7	4.7	4.7	4.7	4.7
	Reservoir	1.3	1.3	1.3	1.3	1.3	1.3
	Pump storage	9.8	10	10	10	10	10
Other RES	-	1	1	1	1	1	1
Battery storage	Small-scale (4 h)	0	39.6	39.6	39.6	39.6	30.8
	Large-scale (8 h)	0	17.4	17.4	17.4	17.4	13.2
DSR	Other Industry	3.6	17	17	17	17	17
	Electric vehicles (EVs) [a]	0	6.5	6.5	6.5	6.5	6.5
	Heat pumps (HPs) [a]	0	9.6	9.6	9.6	9.6	7
	Power-to-gas (P2G)	0	40	40	40	40	36
	Power-to-heat (P2H)	0	6.6	6.6	6.6	6.6	5.6

(a)The DSR available from HPs and EVs varies per hour (and climate year) depending on the demand. The value shown here is the maximum.

Table 3.4 | Assumed technology capacities in each scenario for Germany (GW). The installed capacity in 2021 is also shown for reference.

4 Technology and modelling assumptions

4.1 Considered technologies

Exactly which zero-carbon generation technologies will come to dominate in a net-zero emission energy system is not certain. Nevertheless, given current government ambitions in NL and DE, it seems that solar and wind, various types of zero-carbon thermal capacity and storage are all likely to play a role. Thus, the focus of the Adequacy Outlook lies on these technologies. Table 4.1 shows the main technologies considered, along with the key technical and economic assumptions taken for each technology. The key parameters are:

- the *nominal efficiency*, given in terms of lower heating value (LHV);
- the *short-run marginal cost* (SRMC), which for thermal generation technologies is the incremental cost of producing electricity and includes fuel costs, variable operating and maintenance costs (VOM).[12] For DSR technologies it is the opportunity cost of their production, and thus the price above which they will reduce demand;
- the *de-rating factor* – also known as the *firm capacity* – is the average fraction of total plant capacity which is likely to be technically available during scarcity situations (i.e. hours with ENS);
- the *overnight capital cost* (OCC) is the capital expenditure (CAPEX) required to invest in a technology if this were to be made as a lumped sum; and
- *fixed operating and maintenance* (FOM) costs, which are annual costs incurred whether a plant operates or not; and
- *construction time*, which is how long the plant takes to build from the moment an investment decision is made.

Note that some assumptions are required for the market simulations, while others are only required for certain ex-post calculations. For example, the SRMC is required for the market simulations to determine the marginal generation cost, which in turn defines the merit order, dispatch and market prices. These variable costs are also needed in the economic viability and system cost analysis. On the other hand, the FOM and OCC do not affect the market simulations, but are needed for the economic viability analysis in Chapter 6. For these parameters a *Reference* value is used for the main calculation, while *Low* and *High* values are also considered in order to capture uncertainties in these costs.

4.1.1 Renewable energy sources (RES)

Three types of variable RES technologies are considered in the simulations: onshore wind, offshore wind, and solar PV. Hourly capacity factors for these technologies are taken from the Pan-European Climate Database (PECD) developed by European Network of Transmission System Operators for Electricity (ENTSO-E). The version of the PECD used is based on 35 years of historical climate data (1982 to 2016), but accounts for expected improvements in wind and solar PV technology leading to somewhat higher capacity factors than observed today (Table 4.2).[13] Hydropower is accounted for in those countries where it is relevant. For example, run-of-river, reservoir, and pumped hydro storage is considered in DE, but no significant expansion in capacity or storage is assumed compared with today. The storage duration is approximately 75 hours for pure pumped storage, and 230 hours for open-loop pumped storage.

12 While SRMC typically includes carbon costs, there is no need for a carbon price in our study as no fossil fuel technology is considered. However, the carbon price in a net-zero emission scenario would have to be very high to ensure fossil fuels were not used unabated. Hydro and battery technologies don't have a fixed SRMC, which is typically based on opportunity costs. In our study their dispatch is based on longer term storage constraints (for hydro), and what leads to the least cost for the system across a weekly optimisation horizon (for batteries and pumped hydro).

13 The current PECD does not consider the impact of long-term future climate change on temperature, nor generation from solar, wind or hydro. To account for the fact that the climate has already experienced warming over the past decades, the database does include a linear detrending of historical temperatures to bring all years to the year 2025.

Category	Type	Efficiency (%)	Short-run marginal cost (€ MWh^{-1})		De-rating factor (%) [b]	Overnight Capital Cost (€ kW^{-1}) [c]			Fixed Operating & Maintenance (€ kW^{-1} y^{-1}) [c]			Construction time (y) [c]
			NEL	IHE		Reference	Low	High	Reference	Low	High	
Renewable energy sources (RES)	Onshore wind	-	0		8%	1000	700	1200	20	15	30	2
	Offshore wind	-	0		11%	2000	1500	2500	40	30	60	2
	Solar PV	-	0		2%	400	300	500	10	8	13	1
	Hydro run-of-river	-	-		-	-	-	-	-	-	-	-
	Hydro reservoir	-	-		90%	-	-	-	-	-	-	-
	Pumped storage	75%	-		-	-	-	-	-	-	-	-
Low-carbon thermal	Nuclear	33%	19		80%	5000	4000	6000	80	60	100	6
	Biomass	46%	89		90%	2000	1700	3000	30	20	40	4
	Hydrogen OCGT[d]	42%	183	105	95%	500	400	600	20	10	30	1
	Hydrogen CCGT[d]	60%	130	75	90%	650	600	750	20	15	35	3
Storage	4-hour	90%	-		70%	600	450	1000	15	8	20	1
	8-hour	75%	-		95%	1100	700	1500	15	8	20	1
Demand-side response (DSR)	Other industrial	-	See 4.1.3		100%	20	0	100	20	5	50	1
	EVs	-	700		-	-	-	-	-	-	-	-
	HPs	-	500		-	-	-	-	-	-	-	-
	P2G[a]	70%	49	26	-	120	100	140	2	-	-	-
	P2H	100%	76	43	-	60	50	70	-	-	-	-

These assumptions are based on an overview of literature studies, or other studies TenneT has conducted or been involved with such as II3050, North Sea Wind Power Hub (NSWPH). More details are available in the Technical Appendix.

(a) For P2G, the SRMC here refers to the maximum electricity price plants are willing to spend to generate hydrogen based on the assumed hydrogen price, an electrolyser efficiency of 76%, and an additional 8% losses due to hydrogen storage and compression.

(b) De-rating factors are based on National Grid ESO's calculations for the UK capacity market auction up until the year 2025 [81], and not necessarily representative of the de-rating factors in a net-zero emission system in the NL and DE in the long term. However, they give a rough indication for the cost of new entry calculations, and can be compared with the de-rating factors calculated as part of this study in section 5.6.

(c) Parameters related to fixed costs and investment costs are only relevant for the economic viability analysis and have no direct impact on the scenarios or simulations. For computing the annualised capital cost for the CONE and economic viability analysis, a reference WACC of 9% is assumed for all technologies together with the assumed construction time and economic life.

(d) We do not include any cost for hydrogen storage

Table 4.1 | Key technical and economic assumptions made for each technology

Technology						
	Min	Average	Max	Min	Average	Max
Solar PV	11%	12%	13%	9%	10%	11%
Onshore Wind	25%	30%	34%	24%	28%	32%
Offshore Wind	43%	49%	54%	44%	50%	55%

Table 4.2 | Annual capacity factors of solar PV and wind based on the PECD. The table shows the average annual capacity factor across all climate years, as well as the maximum and minimum value. Note these are the potential capacity factors before the impact of any curtailment.

4.1.2 Zero-carbon thermal technologies

Thermal technologies are those which require a fuel source to generate electricity. In this study we consider only zero-carbon thermal technologies such as hydrogen-fuelled open-cycle (OCGTs) and combined-cycle gas turbines (CCGTs), bioenergy, and nuclear power plants.[14] While fuel prices will not affect adequacy indicators such as LOLE and ENS, they do have an impact on the dispatch of power plants and market prices. In particular, the hydrogen price is an important assumption as it (i) determines the electricity market price when plants running on hydrogen are the marginal technology, and (ii) defines the willingness to pay for P2G and P2H, and hence the market price when these technologies are price setting.

The future price of hydrogen is highly uncertain (Figure 4.1). To be consistent with the assumptions behind the high-level NEL and IHE storylines, different prices for hydrogen are assumed in each storyline:,

- In the scenarios based on the NEL storyline, a price of 21 €/GJLHV is assumed based on a study by Aurora [28]. This price is comparable to the estimated future (levelised) cost of green hydrogen produced from domestic wind resources in NL and DE using the reference cost assumptions in Table 4.1 as shown in Figure 4.1. It is also the same price assumed for hydrogen in a recent study by Aurora [28] looking at flexibility options in a future net-zero emission Dutch power system.

- In the scenario based on the IHE storyline, a price of 12 €/GJLHV is assumed based on the most optimistic future hydrogen cost assumption applied in the TYNDP22 scenarios [25]. This price is comparable to the estimated future cost of green hydrogen produced from utility-scale solar PV under optimal climate conditions, such as those present in North Africa or Australia.

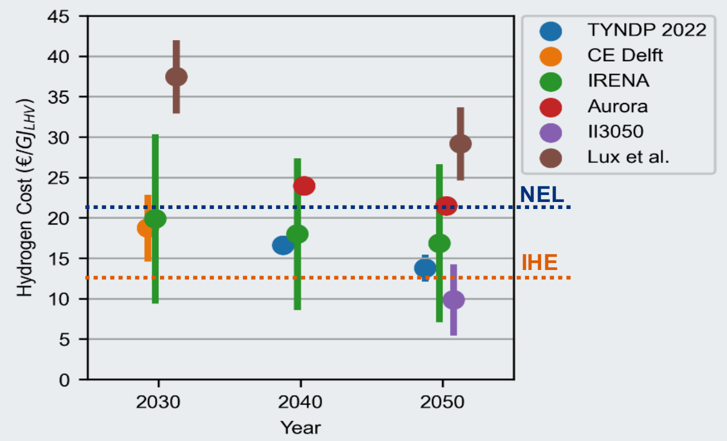


Figure 4.1 | Estimates of the future cost of hydrogen from various studies, compared with the assumed values for the NEL and IHE scenario storyline in this study (Sources: [89], [90], [91], [28], [11]).

14 We use the term 'zero-carbon' in this study to refer to technologies which emit no net direct CO_2 emissions upon generating electricity. This does not mean no indirect CO_2 emissions are emitted throughout the fuel supply chain or embodied in the technology; however, these life-cycle emissions are not considered. Under the right circumstances bioenergy emits no net carbon emissions and is also a renewable energy source, but we classify it here as zero-carbon thermal.

Note that no distinction is made in this study between 'green' hydrogen produced from renewables, 'grey' hydrogen produced from natural gas, or 'blue' hydrogen produced from natural gas with carbon capture and storage (CCS). Moreover, we do not explicitly account for other potentially zero-carbon gases such as biogas or biomethane, nor other energy zero-carbon carriers derived from green hydrogen such as synthetic methane, or ammonia. Instead, in this study we lump together all generation technologies using zero-carbon gaseous fuels and treat them simply as hydrogen. Thus, the hydrogen plants we model represent all plants burning zero-carbon gaseous (or liquid) fuels including not just hydrogen, but also ammonia, synthetic methane, biogas/methane. This simplification is made for several reasons:

- As derived energy carriers such as synthetic methane and ammonia require hydrogen as a feedstock and the conversion process involves losses [29], these will always be more costly than green hydrogen to produce, even though they have significant advantages compared to hydrogen in terms of storage and transport. Given this cost difference is small compared to the uncertainty in the future hydrogen price, and it makes no difference from an adequacy perspective whether the modelled gas is hydrogen, synthetic methane, or biomethane, treating these as separate fuels would not improve the accuracy of the study.

- Future cost estimates for biomethane are in the same region as hydrogen and – with only limited potential – is unlikely to be a key driver for future electricity prices.

- While continued use of fossil fuels is technically possible in a net-zero emission system when combined with CCS,[15] the original net-zero carbon emission scenarios for NL and DE do not include any generation technology using fossil fuels for electricity generation. For this reason, fossil fuels combined with CCS are not included, even though these may have a role to play in the transition to a net-zero emission power system.

Regarding other zero-carbon thermal technologies, nuclear power is considered in neighbouring countries including France, the United Kingdom (UK), and Czech Republic, consistent with the assumptions in the original TYNDP scenarios. Some nuclear capacity is considered in the *NEL-Baseload* scenario for NL, though no nuclear capacity is considered in DE in any scenario. The cost of nuclear fuel is taken as 0.5 €/GJ_{LHV} in all scenarios [25]. Electricity generation from biomass has a relatively limited role in the original scenarios, and the cost of biomass is kept the same in all scenarios at 11 €/GJ_{LHV} [30]. Bioenergy combined with CCS is also not considered.[16]

4.1.3 Demand-side response

Several kinds of DSR are considered including (i) P2G and P2H, (ii) other industrial DSR, and (iii) flexibility provided by EVs and HPs. The assumptions and modelling approach for these technologies are briefly explained below.

P2G is modelled as fully price-responsive load. This means that hydrogen will only be produced from electricity via electrolysis if the electricity price makes this economically attractive. For P2G, we assume electrolysers will only run if the cost of producing hydrogen from domestic electricity is cheaper than the assumed hydrogen import price, which depends on the scenario. Accounting for P2G conversion efficiency and additional variable costs to convert electricity to hydrogen, the indifference price for P2G is taken as 49 €/MWh and 26 €/MWh in the NEL and IHE scenarios respectively. P2H is modelled as fully price-flexible demand in the same way as P2G, with the alternative of burning hydrogen directly to produce heat. Assuming that electric boilers and hydrogen boilers are both approaching 100% efficiency, the calculated indifference prices are 76 €/MWh and 43 €/MWh in the NEL and IHE scenarios respectively.

15 CCS can significantly reduce emissions from coal and natural gas plants but has not yet been demonstrated at scale. Residual carbon emissions can also be offset by so-called 'negative emission' or carbon dioxide removal technologies including bioenergy with CCS, direct air carbon capture, or afforestation. However, the original scenarios do not rely on large-scale use of these technologies to achieve net zero emissions.

16 However, assuming such plants would be remunerated for the net carbon dioxide they remove from the atmosphere, they would likely operate as baseload and would play a similar role as nuclear does.

Additional DSR is assumed to be available from specific industries for NL and DE in the form of load shedding. We assume that the technical potential of industrial DSR will be fully exploited, as we find this to be one of the most cost-effective capacity resources (see 5.3). Industrial DSR potential is defined in price-volume pairs based on literature studies (Figure 4.2).[17] While some types of DSR are often modelled as load shifting (rather than shedding) and subject to certain constraints on how long or frequently they can be activated, model limitations prevent detailed modelling of load shifting load-shifting in this study.[18] When these constraints are modelled, they are typically based on perceived industry expectations and limitations in the current electricity market, while in the future industries will likely have incentives to change their behaviour and processes in response to price developments. Thus, rather than taking industrial DSR flexibility as a given constraint, we model DSR without activation or shifting constraints and reflect on how flexible DSR would need to be in the future based on the model results.

EVs have the potential to provide significant flexibility for the power sector, but there are significant uncertainties around (i) how much EV capacity will be connected to the system at any moment, depending on the charging patterns of consumers, (ii) how much of their capacity consumers will be willing to provide to the market for flexibility, and (iii) the compensation consumers will require for offering this flexibility. In this study, we take a simplified (conservative) approach and assume that 20% of the hourly demand for EV charging can be shed if the market price reaches a threshold value of 700 €/MWh.[19] This value is based on a rough calculation of the minimum willingness to pay, given the high fuel prices observed in Q2 2022. HPs are modelled in a similar way as EVs such that 20% of the hourly HP demand can be shed, assuming a willingness to pay threshold of 500 €/MWh. This value is based on the estimated cost of heating with natural gas at Q2 2022 prices, assuming this would be the maximum consumers would pay for heating with an electric HP. The capacity of EV and HP demand which can be shed varies per hour but the maximum is shown in Table 3.3 and Table 3.4.

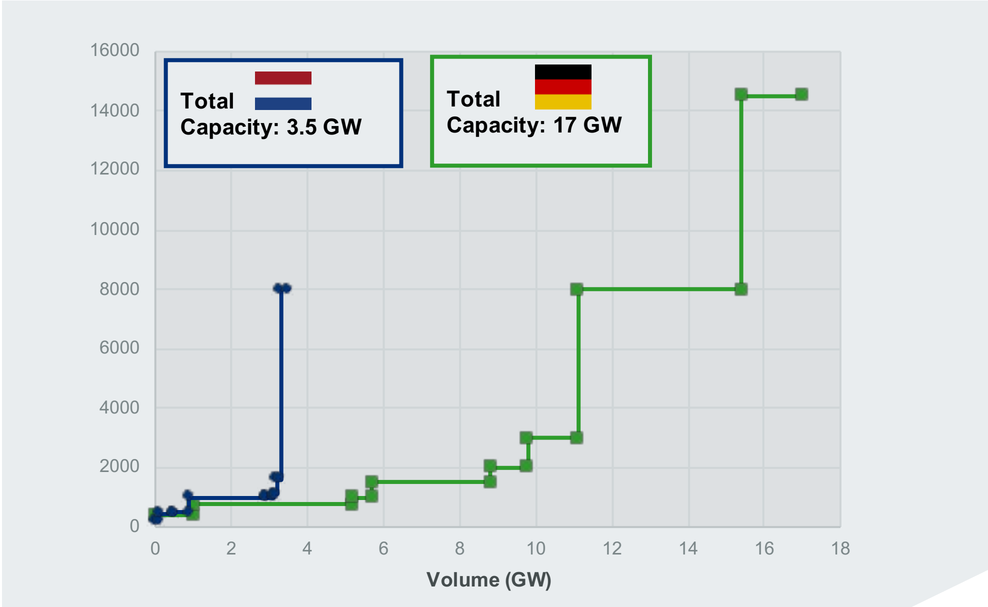


Figure 4.2 | Assumed capacities and prices of industrial load-shedding DSR in DE (above) and NL (below) (Sources: [92], [93]). Note the bid ladders in the original studies are simplified to reduce the number of DSR bands for the modelling.

17 We thus assume higher DSR capacity for DE than the original NEP scenarios (8.9 GW in A2045, 12.1 GW in B/C2045). The II3050 scenarios do not include any assumptions for industrial DSR in NL.
18 Some examples of DSR constraints are minimum and maximum operating hours per activation, and load shifting with recovery. See [100] and [101] for a more detailed overview of DSR constraints and the impact they can have.
19 This is likely an underestimate and would imply fully charging an EV with a 100-kWh battery would cost nearly €80, compared to €15 if charging at the average residential electricity price including tax (2020) of 0.13 €/kWh.

4.1.4 Batteries and storage

In addition to EV batteries, other battery and storage technologies have the potential to play an important role in a future zero-carbon power system. It is not clear which technologies will come to dominate the market as while some are already market mature (e.g. lithium ion batteries), others are still in the developmental or pilot phase (e.g. redox flow batteries, large-scale compressed air energy storage) [28] [31]. In this study we account for two types of generic battery storage technologies: one with 4 hours of storage, and one with 8 hours of storage.[20] Longer duration storages are not modelled as we assume these needs are covered by hydrogen.

4.2 Cross-border Exchange

Exchange of electricity between countries is modelled using the Net Transfer Capacity (NTC) approach. These exchange capacities are broadly consistent with grid investment plans for NL and DE, and kept constant in all scenarios (Table 4.3). This is a simplification compared to the flow-based capacity calculation approach, which is currently applied in operation, but is sufficient for the purpose of this study given all uncertainties.

4.3 Outages

Both planned and unplanned (forced) outages are considered for power plants and cross-border HVDC lines as part of the simulations. Five random forced outages patterns are considered for each climate year.

	Net Transfer Capacity (NTC) (GW)		
Border	Approximate current capacity (2020)	This study	Lower NTC sensitivity
NL Total	**9.1**	**18.8**	**15.9**
NL-BE	2.4	4.4	3.4
NL-DE	4.3	6.0	5.1
NL-DK	0.7	0.7	0.7
NL-NO	0.7	0.7	0.7
NL-GB	1.0	3.0	2.0
NL-NSWPH [a]	0.0	4.0	4.0
DE Total	**28.2**	**60.5**	**48.9**
DE-AT	4.9	10.5	7.7
DE-BE	1.0	2.0	1.5
DE-CH	1.7	6.8	4.3
DE-CZ	1.5	3.0	2.3
DE-DKE	1.0	2.6	2.6
DE-DKW	2.5	3.5	3.0
DE-FR	3.0	4.8	3.9
DE-GB	0.0	2.8	1.4
DE-LU	2.3	4.6	4.1
DE-NL	4.3	6.0	5.1
DE-NO	1.4	1.4	1.4
DE-PL	3.0	3.0	4.3
DE-SE	0.6	2.0	1.3
DE-NSWPH [a]	0.0	6.0	6.0

(a) We model the proposed North Sea Wind Power Hub (NSWPH) concept as separate offshore zones for NL, DE and DK. Aside from providing a route to bring electricity generated by offshore wind at the hub to shore, the hub also provides additional capacity to transfer power between NL, DE and DK, depending on wind generation.

Table 4.3 | Assumptions for cross-border capacities

20 These levels are based on an NREL study for the US showing that with increasing penetration of solar and wind, the optimal size of battery storage volumes increases, with around 50% of battery capacity having 4 hours of storage (or less) in 2050, with the remaining 50% having between 6- and 12-hours storage [94].

	Balancing capacity (GW)	
	NL	DE
Average balancing capacity procured in 2021 (upward)	1.4	3.7
ERAA 2021 (TY 2030)	0.8	4.9
TYNDP 2022 (DE/GA TY 2040)	0.8	4.6
Adequacy Outlook	2.1	4.6

Table 4.4 | Comparison between balancing capacities procured in 2021, assumed in ERAA 2021 and assumed in this study

4.4 Reserves

TSOs procure reserve capacity from the market in order to deal with short-term fluctuations in generation and load and maintain the system frequency within stable levels. As reserve capacity is required for operational stability at all times, it is not current practice to allow capacity allocated for reserve provision to contribute to resource adequacy.

While it can be expected that reserve capacities will not stay at current levels in a net-zero emission energy system, it is not fully clear how the reserve requirement will change. On the one hand there are developments that will drive increasing reserve requirements, such as increasing RES generation and load bringing higher forecasting errors. For NL, the new 2GW standard for offshore grid connections is also expected to increase the reference incident for dimensioning FRR [32]. On the other hand, reforms could decrease reserve requirements, such as increasing cross-zonal cooperation on reserves, larger Load-Frequency-Control blocks, or the use of dynamic balancing dimensioning methods. Given this uncertainty, only a modest increase in reserve requirements in NL and DE are assumed in this study compared with today's requirements (Table 4.4).[21]

21 Reserve requirements for neighbouring countries are taken from the original TYNDP 2022 scenarios.

Balancing capacity is modelled in a simplified manner as an additional fixed load. This means the capacity resources must be capable of meeting both the hourly load, as well as reserve requirement.

4.5 The value of lost load and market price cap

Two key assumptions for any adequacy study are the value of lost load, and the market price cap. The **value of lost load (VOLL)** is the estimated economic damage associated with involuntary load shedding when there is insufficient supply to meet demand, and the TSO is forced to disconnect consumers (i.e., curtail load) to maintain stable operation of the power system. Since 2020 there is a harmonised EU methodology which countries should apply to determine this value, based on estimating the willingness of consumers to pay for electricity [33]. In NL, the official VOLL is currently set at 68887 €/MWh [34], while in DE the current value is 12240 €/MWh [35]. The **market price cap** is the maximum clearing price applied to the electricity market price in periods where there is insufficient supply offered to the market to meet demand, and the market is unable to clear. This is then the price that demand bids pay for electricity, and the price received by suppliers in times of scarcity. This value is currently 4000 €/MWh for the day-ahead market [36].

In this study, we depart from the current official values above and assume a uniform VOLL of 15000 €/MWh for all EU countries, for several reasons. Firstly, there is a considerable difference between the official VOLL for NL and DE at this stage it is not clear whether this is a true reflection of a difference in the value consumers place on reliability in different countries, or differences in how the official methodology was applied [37]. Applying different VOLL values in different countries in the modelling would lead to a bias in which countries load is shed in shortage situations, and assuming a uniform VOLL across countries is a more robust approach. Secondly, the current official VOLL estimates are based on surveys of what the price-responsive component of consumers are willing to pay to avoid the types of supply interruptions which can be expected in the current market. However, in the long term the VOLL is likely to change in response to market developments such as changes in electricity prices, new patterns of consumption, new technologies allowing consumers (especially residential) to react to prices, and different types of supply interruptions. A VOLL of 15000 €/MWh is ultimately chosen in this study as this is more in line with the estimated VOLL estimates across other EU countries, and reflects higher market price caps applied in shorter term markets such as intraday (+/- 9999 €/MWh) and balancing.

In this study, we also deviate from the current market rules and assume that the market price cap is also set at 15000 €/MWh. The reason for this is that according to economic theory, in an ideal market the price cap should be set at the VOLL as this leads to the most cost-efficient outcome for the system [6], and this difference between the price cap and VOLL is considered a barrier for efficient price formation in the current EU electricity market design. With the aim of addressing this barrier, in 2017 the Harmonised Maximum and Minimum Clearing Price (HMMCP) methodology was implemented by which the maximum clearing price for the day-ahead market automatically increases by 1000 €/MWh after periods of scarcity are observed and the clearing price exceeds 60% of the maximum price in one hour. Due to concerns the mechanism would lead to too much volatility, the mechanism was adjusted in January 2023 and now a lower increase of 500 €/MWh is triggered if the market price exceeds 70% of the maximum price in at least two hours over two days [38]. Thus, an increase in the market price cap can be expected in the long term, albeit at a slower pace under the new rules.

5 Adequacy Analysis

Key takeaways…

Resource adequacy can be ensured in a net-zero emission power system providing sufficient investments are made in firm capacity from a mix of DSR, cross-border exchange, storage, and zero-carbon thermal capacity.

The most challenging adequacy situations in a net-zero emission system are likely to be long periods (exceeding one week) with very limited renewable electricity generation, especially wind. These '*Dunkelflaute*' situations cannot be addressed by short-term battery storage or load shifting. Managing these events requires investments in zero-carbon thermal capacity, long-duration energy storage, long-distance exchange capacity, or periods of load shedding lasting multiple days.

DSR is likely the most cost-effective source of firm capacity to resolve short-term shortages and mobilising existing untapped DSR potential should be the first priority for ensuring adequacy. DSR could also help to avoid longer term outages with multi-day load shedding, but more insights are needed on whether there will be industries for which this is feasible and cost effective.

Cross-border transmission plays a major role in ensuring resource adequacy by providing access to capacity located in other markets, and certain borders contribute more to adequacy than others. Based on our scenarios cross-border transmission provides roughly 25% of the capacity needed in scarcity situations. However, if nearby countries in Central Western Europe all rely significantly on wind resources in a future decarbonised power system, correlated wind patterns could lead to simultaneous scarcity events, and the ability of these countries to support each other during scarcity events will be limited. Countries located further afield with less correlated wind patterns and different generation mixes (e.g., Norway, France, the United Kingdom) are better able to support NL and DE in scarcity situations. On the other hand, relying on cross-border capacity is more uncertain than relying on domestic capacity as not only must the capacity in another country be available, but the transmission capacity to access it must also be available.

Batteries and other storage technologies can contribute to adequacy, if they have sufficient storage volume. Based on our results, batteries in a net-zero emission system can provide roughly 30% of their capacity during shortage event for a battery with 4 hours of storage, rising to 70% for batteries with 8 hours of storage, and 90% for batteries with 24 hours of storage. Very short-term storages (e.g., 2-hour batteries) will have only a minor contribution to adequacy.

Additional sources of future electricity demand (such as P2X) should respond flexibly to market prices, and reduce demand when prices are high. If new sources of industrial demand, P2X facilities and data centres etc. do not respond to market prices, maintaining resource adequacy in a future net-zero emission system will be significantly more challenging and costly. Next to that parties will have economic incentives to ensure their demand is flexible, as prices might be extremely high during shortages. More robust approaches are needed to estimate the VOLL.

Zero-carbon gas plays an important role in ensuring adequacy, especially during '*dunkelflaute*' events. Based on our scenarios, meeting a reliability standard of 6 hours per year will require between 4 and 16 GW of zero-carbon thermal capacity in NL, and 8 to 56 GW in DE. Without domestic zero-carbon gas capacity, a reliable system will require significantly more flexibility from DSR, long-duration storage technologies, or additional investments in cross-border capacity. While significant zero-carbon gas capacity is needed, the volumes of gas required are limited and can be covered by domestic hydrogen production in most cases.

Sufficient supply of zero-carbon gasses from both domestic sources and imports as well as a suitable gas transport and storage infrastructure are crucial to run gas power plants reliably and ensure an adequate power system. Due to limited national potentials, it is likely that an international market for zero-carbon gasses will be required.

Balancing the annual supply and demand of zero-carbon gasses throughout the energy system will require significant import and export capability, as well as domestic storage volumes. In the order of 24 to 44 TWh storage volume for zero-carbon gas is required for NL, and 44 to 90 TWh is required for DE, based on our scenarios. The technical and economic feasibility of storing this much hydrogen domestically remains unclear.

The future level of reliability should be based on the value of lost load, as the cost-effective level of reliability is determined by the costs assumed for shortages. Nevertheless, estimates of the VOLL very significantly and setting the reliability standard appropriately requires the best estimate of the VOLL as possible.

5.1 Introduction

Given the uncertainty surrounding how and when a net-zero emission energy system will be achieved, there is little value in attempting to accurately forecast the reliability level of such a system. Rather, this analysis of adequacy in a future net-zero emission energy system focusses on addressing the following questions:

- What might be the cost of capacity in a net-zero emission energy system?
- How do these costs affect the optimum level of resource adequacy?
- Approximately how much firm capacity would be needed in a net-zero emission energy system to ensure adequacy?
- How do different zero-carbon technologies support resource adequacy?
- Which situations present the greatest challenges for resource adequacy in the future, and what drives them?
- To what extent is the electricity sector dependent on imports of zero-carbon gases such as hydrogen for security of supply, and what are the implications for the sector?

5.2 Methodology

To answer the above questions, we take a multi-step approach (Figure 5.1).

- Using the technology assumptions presented in Section 4 we estimate the future cost of capacity resources according to the EU methodology. Using these results and the VOLL, we explore what level of resource adequacy could be cost effective in a future net-zero emission power system by calculating the reliability standard following the same methodology.

- Using an iterative approach, we simulate our net-zero emission scenarios for many climate years and outage patterns and adjust the capacity of the marginal technology until each scenario is roughly adequate.

- Based on the market dispatch results and some additional sensitivity analysis, we examine the role each technology plays in the system.

- We take a closer look at the periods where adequacy challenges are identified to better understand the types of adequacy issues we might expect in a net-zero emission energy system, and what drives them.

- Establish the impact of the use of carbon free gasses on the sector for carbon free gasses to ensure that this dependence is feasible.

5.3 Cost of New Entry and Reliability Standard

Many countries in Europe currently maintain a reliability standard which sets the acceptable level of resource adequacy, usually defined in terms of LOLE. For NL this standard is 4 h/y [7], while for DE the standard is 2.77 h/y [35].[22] In some countries the reliability standard is a binding target defined in law which governments aim to ensure with a policy instrument known as a *capacity remuneration mechanism* (CRM).

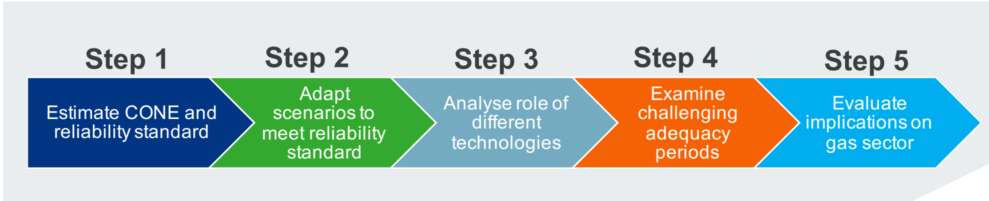


Figure 5.1 | Steps applied in the adequacy analysis

22 The German reliability standard of 2.77 h/y was defined in 2021 by the Bundesnetzagentur according to the official ACER methodology, and thus has legal weight. The Dutch reliability standard of 4 h/y was not defined according to this methodology and has no strict legal weight, but has been applied by TenneT for many years as a reference value for monitoring Dutch security of supply in the MLZ.

A CRM is an out-of-market payment made to various capacity resources based on the firm capacity they can guarantee will be available to the system in times of scarcity to support resource adequacy. The types of technologies which can participate, the volume awarded and price paid for firm capacity depend on the design of the CRM.

According to EU law, any country wishing to implement a CRM must determine their reliability standard according to a common EU methodology [33].[23] In essence, this methodology aims to find the LOLE level (in h/y) where the marginal cost of investing in additional capacity resources – also referred to as the Cost of New Entry (CONE) – and the marginal costs of unmet demand are equal [33]:

$$RS \approx marginal(LOLE_{RT}) = \frac{CONE_{fixed,RT}}{VOLL - CONE_{var,RT}}$$

The CONE consists of two components: (i) a fixed component ($CONE_{fixed}$) which includes annualised CAPEX and FOM, and (ii) a variable component ($CONE_{var}$) based on the SRMC. For each reference technology (RT) considered in the system, a separate LOLE value is calculated indicating what the cost-effective reliability standard would be ($LOLE_{RT}$), if that technology would be used to add additional capacity. However, as some technologies such as DSR have a limited potential, the methodology requires that all the cheapest sources of capacity are considered first, and the reliability standard is based on the CONE of the marginal reference technology.

After calculating the $LOLE_{RT}$ values for a selection of the technologies in Figure 5.2 assuming a VOLL of 15000 €/MWh, Table 5.1 shows that DSR is the cheapest capacity resource, as it has the lowest $LOLE_{RT}$ value based on the reference assumptions – even at activation prices up to 10000 €/MWh. Following DSR come hydrogen OCGTs and CCGTs with $LOLE_{RT}$ in the range of 5 to 7 h/y, and then battery storage technologies with $LOLE_{RT}$ above 8 h/y. It is important to highlight that the CONEfixed for DSR is more uncertain than for the other technologies as the costs for realising DSR vary significantly across different processes and industries, and limited data are available on the investment and annual operating costs for DSR.[24] In spite of this, even taking the high CONEfixed assumptions for DSR, the $LOLE_{RT}$ for DSR with activation price at 3000 €/MWh would be roughly comparable with the reference $LOLE_{RT}$ for hydrogen OCGTs, and thus the finding that DSR is likely to be the cheapest capacity resource seems robust. While DSR and hydrogen technologies all have a relatively low $LOLE_{RT}$ below 10 h/y, all RES technologies have $LOLE_{RT}$ values exceeding 100 h/y. The main reason for this is their low de-rating factor (see Table 4.1) as RES tend to have low generation during scarcity periods.

Technology	$CONE_{fixed}$ (€/kW/y)			$LOLE_{RT}$ (h/y)		
	Low	Reference	High	Low	Reference	High
DSR 3000 €/MWh	5	24	69	0.4	2.0	5.8
DSR 10000 €/MWh	5	24	69	1.1	4.9	13.8
Hydrogen-OCGT	57	79	101	3.8	5.3	6.8
Hydrogen-CCGT	96	109	139	6.5	7.3	9.3
Storage. 4-hours	91	128	206	6.1	8.5	13.7
Storage. 8-hours	100	159	217	6.7	10.6	14.5
Nuclear	710	893	1076	47.4	59.6	71.8
Onshore wind	1118	1580	1971	75.0	105.0	131.0
Offshore wind	1723	2298	2963	115.0	153.0	198.0
PV (utility-scale)	1927	2536	3195	128.0	169.0	213.0

Table 5.1 | LOLE thresholds for selected technologies, calculated using the range of CAPEX and FOM estimates in Table 4.1. DSR is shown for two different activation prices. A weighted average cost of capital (WACC) of 9% is assumed, and a VOLL of 15000 €/MWh.

23 Technically this methodology only needs to be applied if a country wishes to implement a CRM.

24 For example, some industrial consumers may not need to make any significant investments to be capable of reducing load in periods of high prices, but may incur additional annual costs for managing their energy consumption. Other industries may need to invest in storage or backup technologies to provide flexibility. Based on the data countries have used to calculate the CONE and provided to ACER, the CAPEX for DSR is negligible, and fixed costs range between 0 and 30 €/kW/y [37].

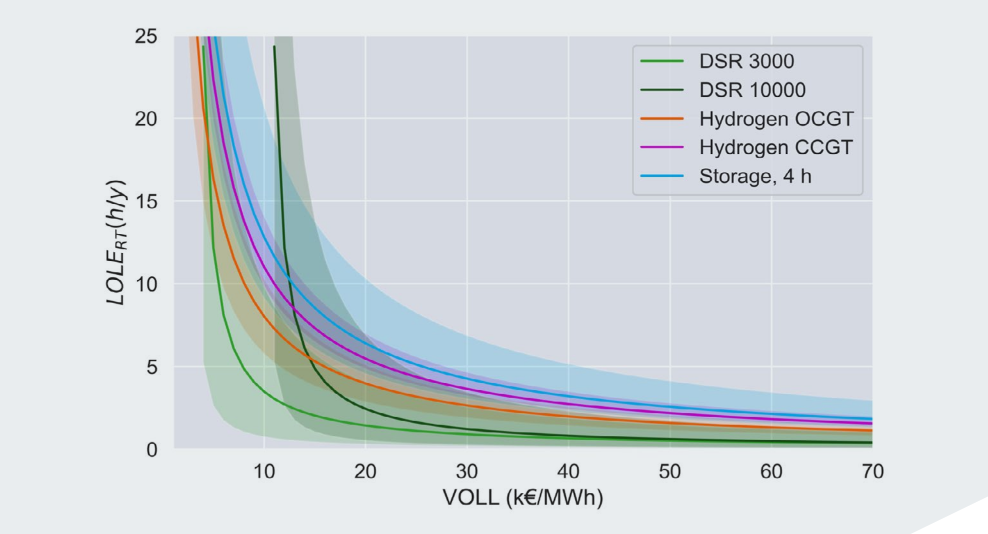


Figure 5.2 | Calculated LOLERT as a function of VOLL for several technologies with the lowest $LOLE_{RT}$ from Table 5.1. The solid line is calculated at the reference $CONE_{fixed}$, while the coloured bands show the uncertainty in $CONE_{fixed}$ based on the Low and High ranges.

While the equation to estimate the reliability standard seems simple, in practice it is difficult to estimate what the cost-effective reliability level in a future net-zero emission power system could be for two main reasons. Firstly, the future CONE of different net-zero emission technologies is uncertain due to underlying uncertainty in the CAPEX and FOM. This is especially true for heterogeneous technologies like DSR, and maturing technologies like battery storage. Secondly, the VOLL itself is uncertain and hard to estimate, which is evident from the range of VOLL values estimated in different countries.

To illustrate the impact of uncertainty in the CONE and VOLL on the reliability standard, Figure 5.2 shows the calculated $LOLE_{RT}$ as a function of VOLL for several technologies with the lowest $LOLE_{RT}$ values. From this figure it can be seen that:

- As the VOLL decreases the $LOLE_{RT}$ for all technologies increases as the cost of unserved energy reduces compared to the cost of capacity. This means it would be more cost effective for society to experience some additional load curtailment than invest in additional capacity. At lower VOLL values (e.g., 10000 €/MWh) the impact of CONE differences between technologies is also higher and the $LOLE_{RT}$ is more sensitive to the CONE.

- As the VOLL increases the cost of unmet demand becomes the driver, and the $LOLE_{RT}$ falls for all technologies below 3 h/y. The differences in $LOLE_{RT}$ between technologies and for different cost assumptions becomes smaller as the impact of uncertainty in the CONE diminishes when compared with very high VOLL values.

Notwithstanding the above points, Figure 5.2 shows that if the activation cost of DSR is sufficiently lower than the VOLL, DSR has a lower $LOLE_{RT}$ than either hydrogen or storage, and thus would be preferable as the marginal technology to define the reliability standard. Still, as DSR has a limited capacity which we assume is fully exploited in the future, it cannot be flexibly adjusted to meet the reliability standard and is thus not suitable to use as the marginal technology. The technologies with the next lowest $LOLE_{RT}$ are Hydrogen OCGTs and CCGTs and 4-hour battery storage, although the difference between the calculated $LOLE_{RT}$ values for OCGTs and CCGTs is relatively minor given uncertain technology costs and investment risks.[25]

Given the uncertainty around the future VOLL and CONE, it is not possible to calculate exactly what the cost-effective reliability standard should be for each future scenario. Instead, in this study we explore how much capacity would be needed in each scenario to deliver roughly the same level of adequacy, and how sensitive these capacity needs are to different levels of reliability. To ensure all scenarios are roughly comparable, we simulate each scenario iteratively and adjust the total hydrogen capacity (CCGT + OCGT) in NL and DE until an average LOLE of roughly 6 h/y in both countries is reached. This value is based on the average calculated $LOLE_{RT}$ for Hydrogen OCGTs and CCGTs at a VOLL of 15000 €/MWh (see section 4.5).

25 The CAPEX for OCGTs and CCGTs also depends on the installed capacity of the unit, which we don't account for in this study [79]. Moreover, due to the higher marginal cost and fewer activation hours of OCGTs compared with CCGTs, these may be considered a higher risk investment and attract higher financing costs, which would lead to higher $CONE_{fixed}$ and $LOLE_{RT}$ values for OCGTs more comparable with CCGTs.

Note that as we do not use a cost-based investment model, the capacity mix of CCGTs and OCGTs is not optimised in each scenario but set at roughly a 50:50 split. Moreover, a future net-zero emission power system will likely include a mix of zero-carbon gas technologies with different efficiencies and marginal costs (e.g., retrofitted natural gas plants, older plants, newer plants), and including a mix of mid-merit and peaking capacities should lead to more realistic market prices.

With a LOLE of 6 h/y achieved in all scenarios, we then analyse the resulting capacities, the role played by each technology, and the challenging periods for adequacy.

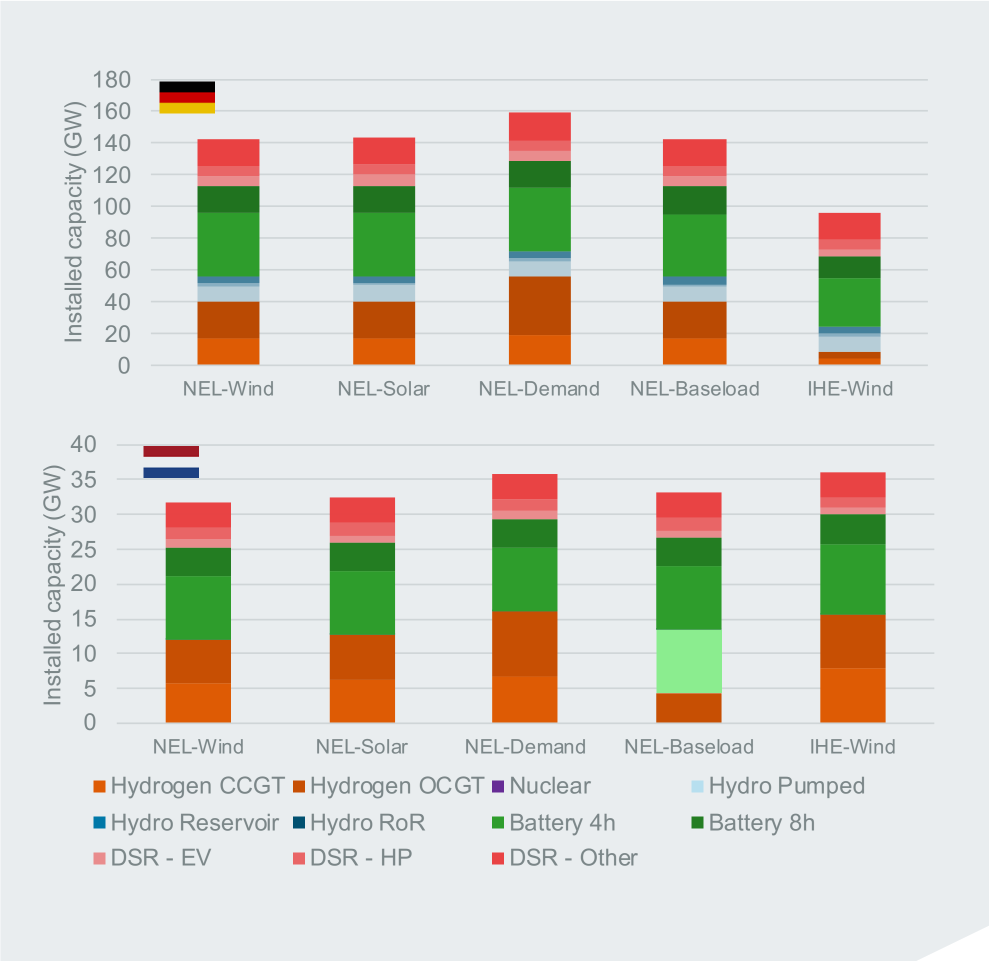
5.4 Adaptation of hydrogen capacities

The installed dispatchable capacities in each scenario after adjusting the hydrogen capacity to achieve a reliability standard of roughly 6 h/y in both NL and DE in shown in Figure 5.3. We find that between 4 and 16 GW of hydrogen capacity is needed in NL, and between 8 to 56 GW in DE, depending on the scenario assumptions. In particular, the lowest capacities are needed in the NEL-Baseload and IHE-Wind scenarios for NL and DE respectively. The former is due to the 9 GW of nuclear capacity included in the scenario which reduces the need for hydrogen capacity in NL, while the latter is mostly due to the lower demand in DE in IHE-Wind. The highest capacities are needed in the NEL-Demand scenario given the higher demand. In terms of thermal power plants, the required capacity is less than half the installed thermal capacity in today's power system.

Figure 5.4 shows boxplots of the two key adequacy indicators of LOLE and ENS for each scenario, across all simulated climate years and forced outage situations. This figure shows that while an average LOLE across all simulations of roughly 6 h/y is achieved in both countries in all scenarios, the expected outage hours in any specific year can vary significantly. The reason for this is that while LOLE is typically less than 3 h/y in most years, there are some years in which the LOLE reaches higher values, up to nearly 50 h/y in DE and 60 h/y in NL. However, as the reliability standard is always defined as a long-term average, it is to be expected that the standard is exceeded in some years, and not reached in others. The causes for these more challenging years for adequacy are discussed in section 5.7.

The results for the expected ENS also show differences across climate years and outage iterations. As the demand for electricity is typically higher in DE than in NL, the total ENS experienced in DE in more challenging years is higher than NL for the same reliability standard. Nevertheless, the total amount of unserved demand is limited, and on average more than 99.99% of load is met (or reduced voluntarily by DSR) across all scenarios.

It is important to highlight that the hydrogen capacities resulting from this adjustment process are a consequence of the underlying assumptions for the capacities of cross-border interconnection, DSR, storage and other technologies in each scenario. If additional capacities were available from these technologies, the same reliability standard could be achieved with fewer investments in domestic zero-carbon thermal capacity. Given our assumption of 20% flexibility from HPs and EVs may be on the conservative side, maximising the flexibility from these technologies in future could yield significant system benefits.



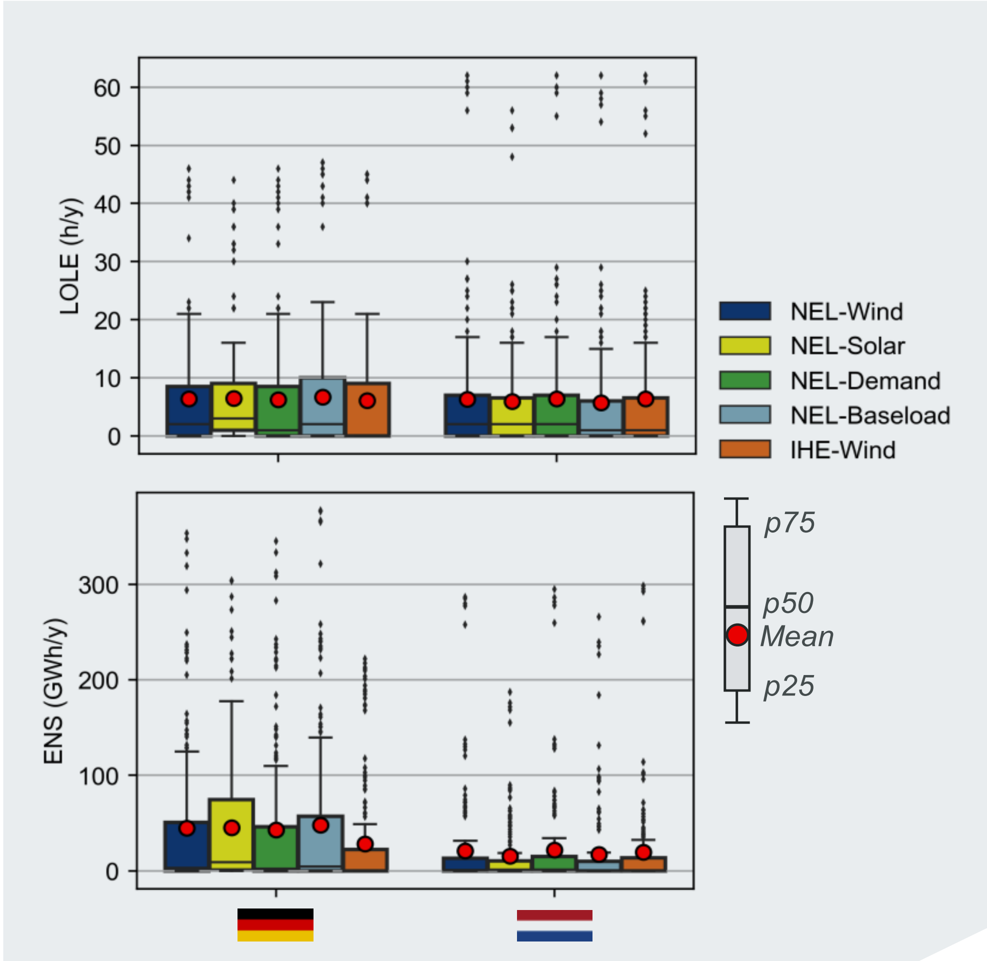


Figure 5.3 | Installed dispatchable capacities per scenario for DE (upper) and NL (lower), after calibration to 6 h/y reliability standard. The installed dispatchable capacity in 2021 is also shown for comparison, with all gas shown as 'Hydrogen CCGT', and solid fuels as 'Other'.

Figure 5.4 | LOLE and ENS per scenario after calibrating the hydrogen capacity to reach 6 h/y reliability standard. The box plots show the distribution across all simulated climate years and outage iterations.

5.5 Impact of reliability standard and VOLL on firm capacity requirements

In the previous section we showed how much capacity would be required in each scenario in order to achieve an adequacy level of roughly 6 h/y LOLE. Given that policymakers may wish to target a more stringent reliability standard in the future, it is relevant to also analyse how much additional capacity would be required to achieve a lower LOLE in both NL and DE, and the potential impact on overall system costs. We can do this in a simplified way by using the hourly profiles of ENS resulting from the market simulations with 6 h/y LOLE, and seeing how these profiles would change if more hydrogen capacity were available in the system.[26] In effect, this approach mimics each country implementing a CRM in the form of a national strategic reserve closed to cross-border participation. Figure 5.5 presents the results of this analysis for the NEL-Wind scenario, assuming (a) the reference VOLL of 15000 €/MWh and (b) a higher VOLL of 70000 €/MWh.

This figure shows that in order to reach the current reliability standards of 4 h/y in NL and roughly 3 h/y in DE, approximately 2 GW of additional capacity would be needed in NL and 6 GW in DE, compared with the calibrated hydrogen capacities. Assuming this capacity is provided by hydrogen would imply additional capacity costs of roughly 160 million €/y in NL and 480 million €/y in DE to cover fixed costs (FOM and annualised CAPEX) of this additional capacity.[27] Whether this would be a cost-effective option or not depends what the true VOLL is. While the cost of ENS falls as more hydrogen capacity is added, the additional capacity costs increases at a faster rate in the case where the VOLL is 15000 €/MWh (Figure 5.5a). Therefore, the total net costs (capacity costs + ENS costs) goes up, confirming that the calibrated hydrogen capacity leading to 6 h/y LOLE is the cost optimal level given these assumptions. In the case where the VOLL is 70000 €/MWh (Figure 5.5b), the decrease in ENS costs initially outweighs the additional capacity costs and total costs fall until LOLE reaches approximately 1 h/y, which would then be the cost optimal LOLE for a VOLL of 70000 €/MWh. Achieve this reliability level would require roughly 7 GW additional capacity in NL and 13 GW in DE, implying annual capacity costs of 560 million €/y in NL and just over 1 billion €/y in DE.

26 This simplified ex-post calculation does not fully capture the impact of forced outages or cross-border effects, and a more accurate approach would be to run additional simulations while incrementally increasing the capacity of hydrogen turbines. However, this simplified calculation is sufficient for our purposes.

27 This calculation is based on the 'reference' FOM and CAPEX for hydrogen OCGT and CCGTs which, when annualised using a 9% discount rate and 20 year economic lifetime, result in total annual fixed costs of roughly 80 €/kW/y. Assuming a lower discount rate of 3% would reduce these costs by roughly 30%.

This analysis shows how sensitive the optimal reliabilty standard is to the VOLL, and that setting the reliability standard appropriately requires the best estimate of the VOLL as possible. For example, if the estimated VOLL is higher than its true value, the reliability standard would be set too strictly. If this reliability standard is enforced through a CRM, this would lead to over-investment in capacity and higher costs for society. On the other hand if the estimated VOLL is lower than its true value, the societal costs of unmet demand would be much higher and additional investments in firm capacity would be justified.

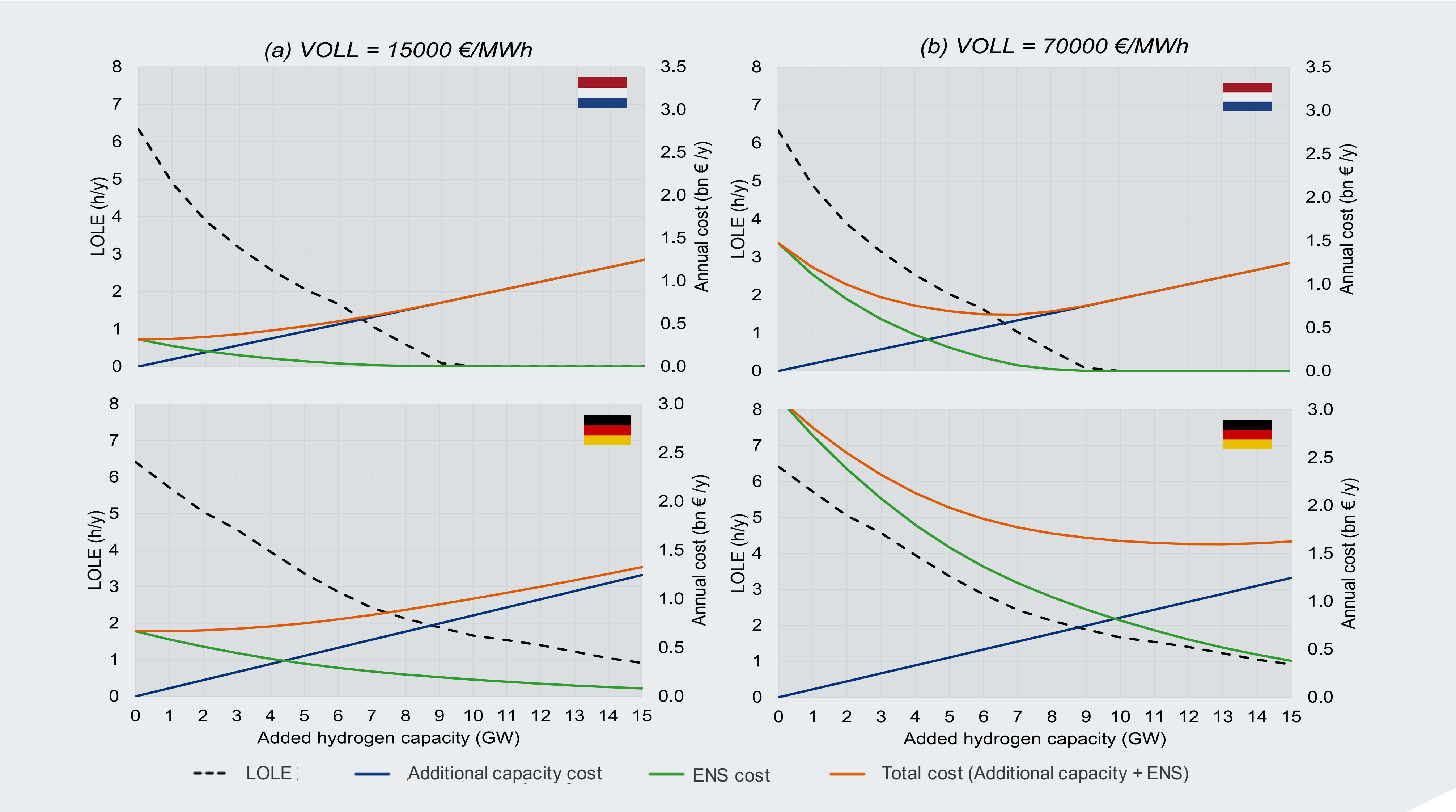


Figure 5.5 | Impact on LOLE and annual costs of adding additional hydrogen OCGT capacity to the levels calibrated for 6 h/y LOLE for the NEL-Wind scenario. In the left figure (a) a VOLL of 15000 €/MWh is used to calculate ENS costs, while in the right figure (b) a VOLL of 70000 €/MWh is used. Capacity costs are based on the reference CAPEX and FOM assumptions for hydrogen CCGTs and OCGTs, levelised using a WACC of 9% and economic lifetime 20 years.

5.6 What role do different technologies play in ensuring adequacy?

In this section, we look a bit deeper into how different groups of technologies contribute to adequacy in our net-zero scenarios, namely (i) zero-carbon thermal technologies, (ii) demand-side response (DSR), (iii) storage and (iv) cross-border exchange. As a starting point for this analysis, one indicator for assessing how a technology contributes to adequacy is its firm capacity, in relative terms also known as the derating factor.[28] For each scenario and modelled climate year, derating factors are calculated for selected technologies based on their average generation during periods with ENS (Figure 5.6). From these results we see that:

- **Hydrogen CCGTs and OCGTs have a derating factor above 90%** and thus can be considered almost fully firm;
- **The derating factor of RES approaches zero.** Solar PV has a derating factor of less than 1% as it practically never generates during periods with ENS, while wind has factors of 3 to 6%;
- **The derating factors of DSR from HPs and EVs are roughly 40% and 80% respectively**, based on their underlying hourly load profiles.
- **P2G, P2H and industrial DSR have a derating factor of 100%** as these are assumed to be fully price flexible and without technical constraints. This may be optimistic and not technically feasible for all industries. Nevertheless, if the price of electricity in scarcity situations is high enough there will be significant incentive for industrial consumers not to consume.
- **The derating factors of batteries depends on the storage volume**, with 8-hour batteries having roughly double the firm capacity of 4-hour.

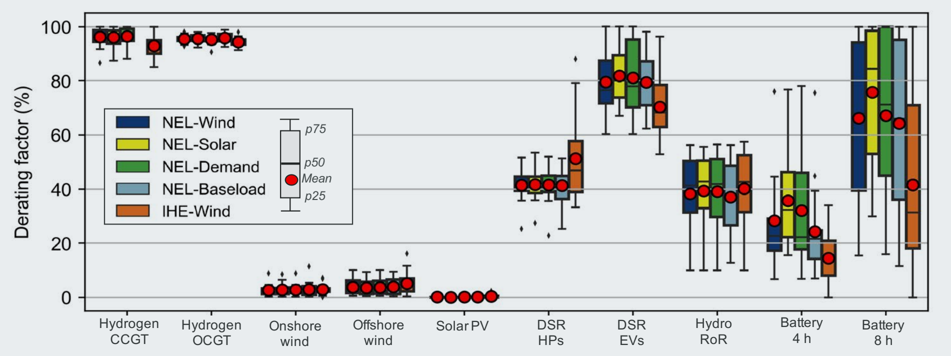


Figure 5.6 | Calculated derating factors for selected technologies per scenario for NL. The calculated values for DE are very similar to NL and hence not shown.

The calculated derating factors show some differences compared with values from other studies, in particular for RES and battery storage for which we find somewhat lower values. This is likely due to the fact that the firm capacity of RES typically declines as the share of RES generation in the system increases [39], and our scenarios are for a net-zero emission power system with significantly higher share of RES than today. Differences in derating factors to a large extent dictate the role each technology can play in ensuring resource adequacy, and the average firm capacity contribution provided by each group of technologies in both NL and DE is shown in Figure 5.7. In the following sections we analyse in more detail the role each technology plays in contributing to resource adequacy.

28 Technically the firm capacity has units of MW or GW and is calculated by multiplying the total installed capacity (in MW) by the derating factor (%). However, in this study we use the terms 'firm capacity' and 'derating factor' interchangeably. In this study we estimate the derating factor using the simplified approach of calculating the average dispatch of each technology during hours with ENS, and dividing this by the installed capacity. More detailed methods are also possible, as summarised in [121].

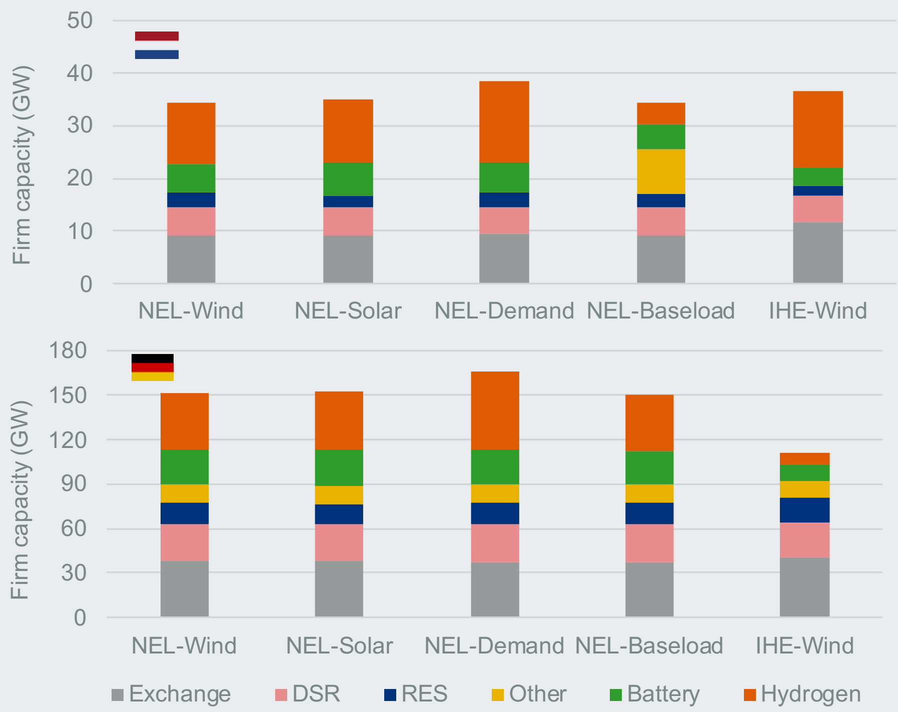


Figure 5.7 | Amount of firm capacity delivered to the system in all scenarios by the different technologies.

5.6.1 The role of zero-carbon thermal capacity

Low-carbon gas power plants play a special role in the scenarios as their capacity has been adjusted to achieve a reliability standard of 6 hours (see section 5.4). As shown in Figure 5.6 these plants have an availability of more than 90% in times of shortages and are almost always available to generate, except when they are forced offline due to an unplanned outage. Thus, zero-carbon thermal plants play a critical role in providing firm backup capacity to support resource adequacy, especially during periods of low RES generation. This backup role can be seen in Figure 5.8 for a typical winter and summer week in DE for the NEL-Wind scenario. In the winter week, generation from RES (especially wind) in the first few days is not sufficient to fully cover demand. To meet the shortfall, all available hydrogen capacity is dispatched, as well as batteries, some DSR, and significant imports. After the wind lull, RES generation is sufficient to cover demand and produce hydrogen, which could be stored and used to generate electricity at later time. During the summer week, batteries take the main role of meeting night-time demand the by discharging the electricity stored during the day from solar PV. However a small amount of hydrogen capacity is sometimes dispatched during still nights if demand cannot be fully met by batteries.

To further highlight the role of hydrogen as backup, we can compare the share of firm capacity it provides to the system with the share it contributes to total electricity generation. Figure 5.7 shows that hydrogen capacity provides around 25% of the firm capacity in DE and 35% in NL for the NEL-Wind and NEL-Solar scenarios. The contribution varies in the other scenarios depending on the installed capacity. By contrast, Figure 5.9 shows that in terms of total annual electricity generation hydrogen only contributes a minor share (<5%), far less than its share in firm capacity in both NL and DE. The reason for this is that overall, hydrogen OCGTs and CCGTs have relatively low capacity factors (~20% for CCGTs and ~3% for OCGTs). This highlights that hydrogen's key role is providing backup capacity during low RES periods, and covering night-time demand.

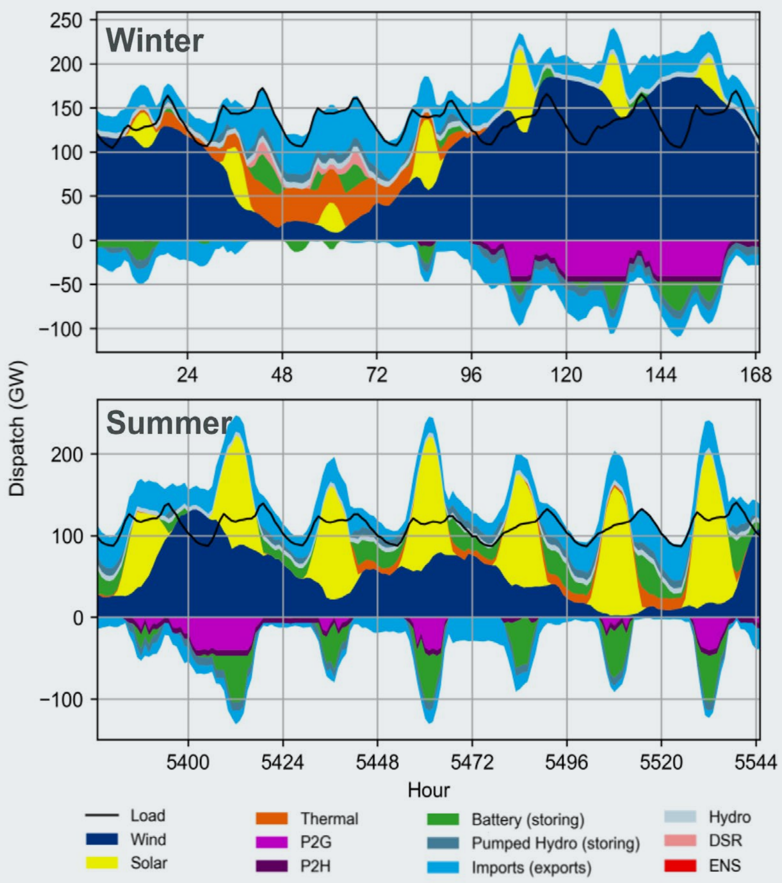


Figure 5.8 | Hourly dispatch in DE during a week in winter (upper) and summer (lower) in climate year 1996. Discharge of storage technologies and imports are shown as positive, while charging of storages and exports shown as negative. The black line shows underlying load (without P2X), including reserves.

To show the impact of having more or less hydrogen capacity in the system, additional sensitivity runs were performed for the NEL-Wind scenario with 50% less hydrogen capacity in both NL and DE (26 GW) than in the reference case (i.e. the capacity needed to reach 6 h/y LOLE), and no hydrogen capacity. Figure 5.10 shows that reducing the capacity by 50% from 52 to 26 GW increases the LOLE from 6 h/y up to 70 h/y in both countries, while a further reduction from 26 GW to 0 GW sees LOLE increase to nearly 300 h/y. This shows that domestic firm capacity is indispensable for ensuring adequacy but that the incremental adequacy contribution reduces as more capacity is added, a feature also seen in Figure 5.5 when more hydrogen capacity was added.

Aside from hydrogen, nuclear is another zero-carbon thermal technology which also plays a role in the NEL-Baseload scenario in NL. Nuclear has a similarly high derating factor and thus also supports adequacy in this scenario by providing significant firm capacity to the system (see Figure 5.7). Unlike hydrogen plants though, it is dispatched more frequently thanks to its low marginal cost and essentially provides baseload generation. Despite ramping down generation during high RES periods, nuclear is able to manage approximately 7000 full load operational hours per year. How nuclear can achieve this in a system with significant variable RES is further discussed in Chapter 6.

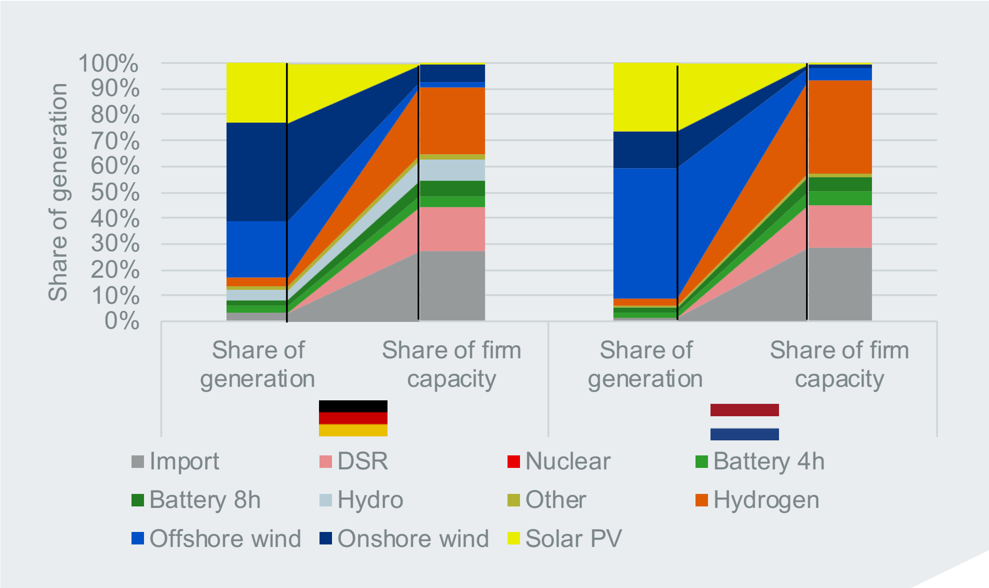


Figure 5.9 | share of firm capacity and total electricity generation by various sources for the NEL-Wind scenario both for Germany (left) and the Netherlands (right).

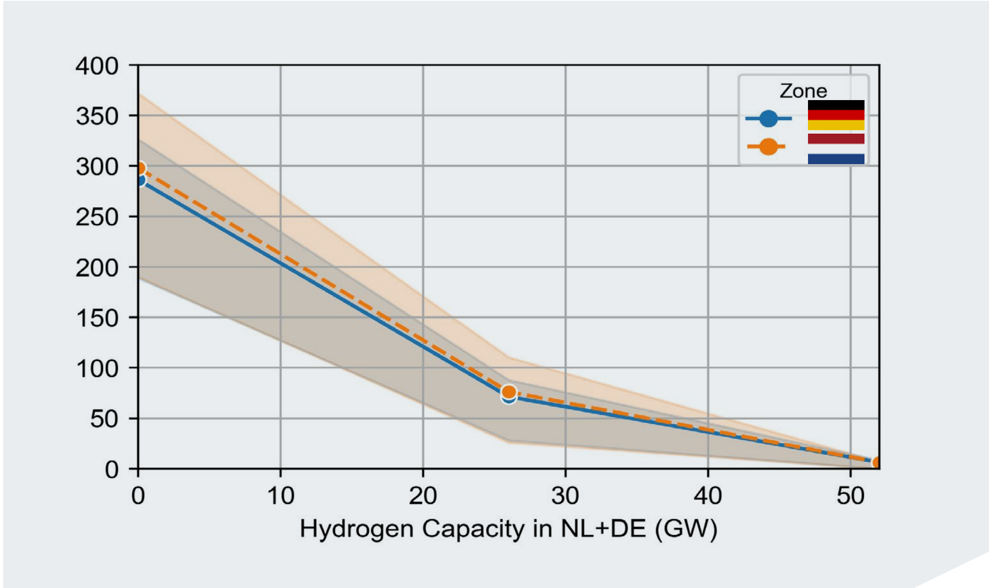


Figure 5.10 | Impact on LOLE of reducing the total installed hydrogen (CCGT and OCGT) capacity by 50% and 100% from the calibrated level in NL (12 GW) and DE (40 GW) for the NEL-Wind scenario

5.6.2 The role of DSR

As explained in section 4.1.3, several different forms of DSR are considered per country including P2X, HPs, EVs as well as other industrial DSR. As each form of DSR is associated with a different price, these follow a specific order of activation with lower cost DSR being activated before higher cost DSR. Figure 5.11 shows a duration curve of the average activated DSR in DE for the NEL-Wind scenario, stacked in order of activation price. The amount of ENS (involuntary load shedding) is also shown at the top of the curve with the highest price. On average, DSR is activated in roughly 120 h/y (1.4% of the time), and the total volume of load voluntarily reduced by DSR is roughly 1 TWh. The combined voluntary and involuntary curtailed load represents only very small fraction (0.1%) of the total annual load. As we assume most DSR has a firm capacity of 100%, DSR capacity strongly reduces the number of hours with shortages as each MW of available DSR can prevent up to 1 MWh of ENS. While the LOLE in this scenario is roughly 6 h/y, this would increase to 122 hours if no DSR would be present and load would remain inflexible at all prices. This shows that DSR plays an important role in supporting adequacy by providing firm capacity, without necessarily requiring significant volumes of demand to be shed. The total activation of DSR is given for all scenarios in Figure 5.12, showing that DSR activation is roughly comparable in all scenarios.

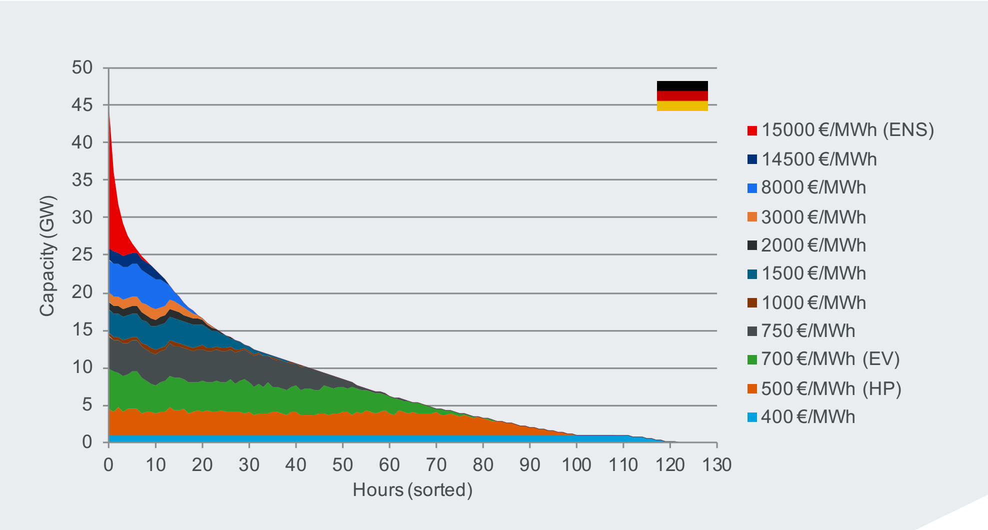


Figure 5.11 |

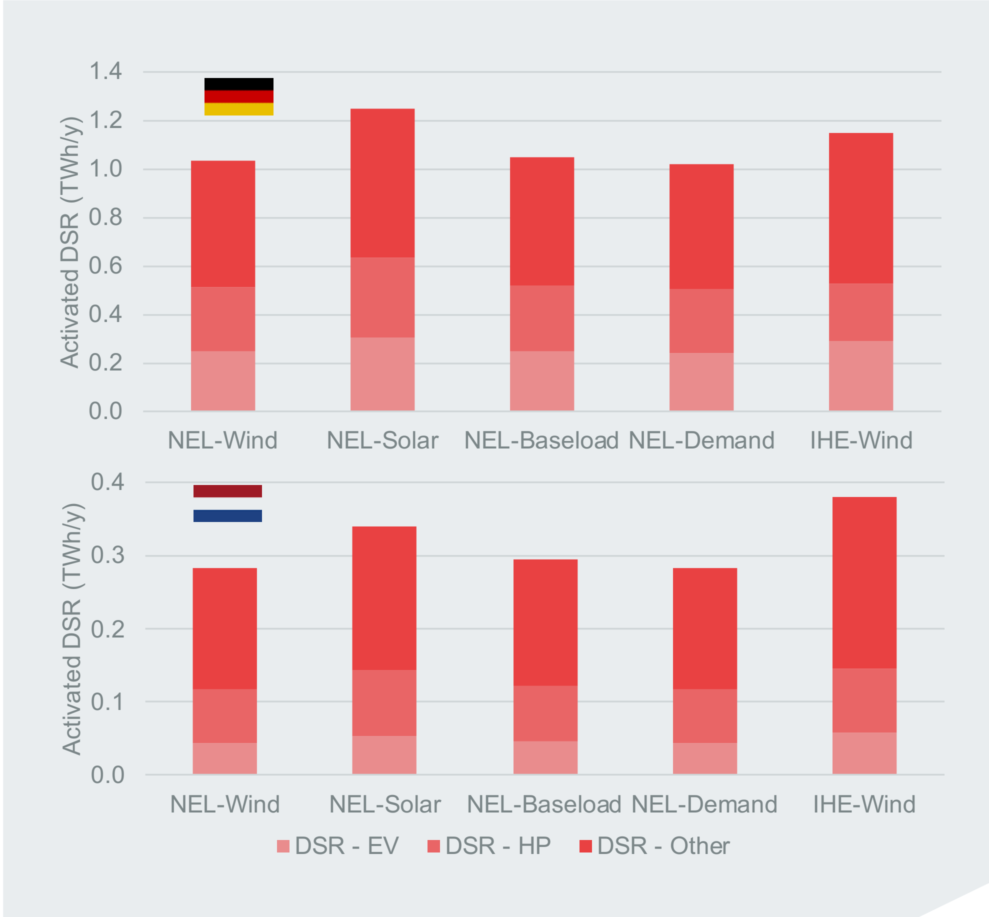


Figure 5.12 | Total DSR activation in all scenarios in DE and NL averaged over all climate years and outage iterations.

From an adequacy perspective, these results shows there is a strong case to support the development of DSR as by making some relatively modest investments in industry and introducing the necessary market conditions to ensure price-responsive behaviour of EVs and HPs, significant benefits for the adequacy of the system could be realised. Namely, we show that if load can be reduced by only 0.1%, LOLE can be reduced drastically from roughly 120 h/y to 6 h/y. While DSR plays an important role in our scenarios, there are several uncertainties regarding its role in the future zero-carbon energy system:

- From a technical perspective both the **maximum potential and flexibility of DSR, and thus the firm capacity it can provide are uncertain**. For HPs and EVs this will depend on how many of these devices are deployed, how they are operated (e.g. when EVs are connected to the grid), and how much consumers are willing to pay to consume, or be paid to reduce demand. For industrial DSR, reducing load by shedding or shifting production can be complex or even impractical, and the economics of this will vary from industry to industry.

  From an economic perspective, the **cost-effectiveness** of investments in DSR is also uncertain, especially for DSR with high variable (opportunity) costs. For example, for certain industries it may be cost effective to reduce demand in high price hours if the electricity cost savings outweigh the opportunity costs of not producing their output. On the other hand, industries with a very high opportunity cost of e.g. 14500 €/MWh would only save 500 €/MWh in the rare hours when the market cap price reaches 15000 €/MWh. For industries in which electricity costs are a large share of their total production costs, high electricity prices are more likely to outweigh opportunity costs and justify the investments necessary to operate more flexibly. On the other hand, certain producers may be contractually bound to supply fixed volumes to their clients, and have limited flexibility to shift or shed load. Nevertheless, more volatile electricity prices in the future will increase the incentive for industries to invest in DSR, and seek for more flexibility in their contractual arrangements.

5.6.3 The role of storage

While electricity can be stored in many ways, in this section we focus on the role of battery storage. What sets storages like batteries apart from other technologies is that they are an energy-constrained technology. This means that generation is not only limited by the installed capacity (i.e. MW) available, but also by the amount of energy (i.e. MWh) available in the storage. Due to this fact, battery storage operators will plan their consumption and generation of electricity in order to maximise their profits, also taking into account other potential revenue sources such as ancillary services. As a result, price-driven batteries will tend to consume electricity when prices are low (typically during periods with an abundance of RES), and generate electricity when prices are high.

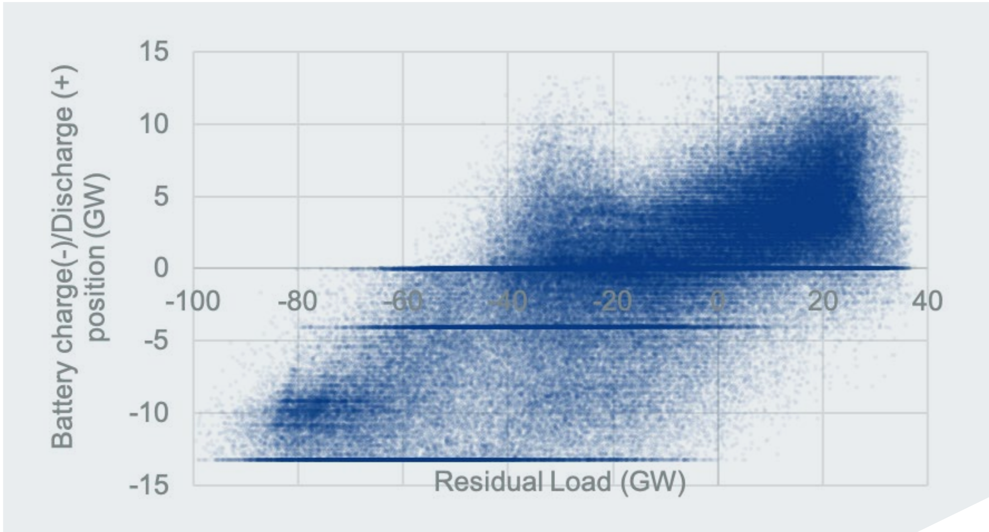


Figure 5.13 | Scatterplot of total battery charging and discharging positions versus the residual load for NL in NEL-Wind.The line indicates the roling average of the battery positions over 0,5 GW of residual load.

To further highlight this behaviour of batteries, Figure 5.13 shows a scatterplot of the net charging/discharging position of batteries against the *residual load* for NL, i.e. the demand minus the electricity generation from RES. It shows that batteries are mostly charged during hours with a negative residual load (i.e. surplus RES and low prices), and discharged during hours with a positive residual load. Batteries are still sometimes charged during hours with a positive residual load when a costlier technology (e.g. hydrogen CCGT or OCGT) is setting the price, as this can avoid the need for dispatching more costly technologies such as DSR, or even avoid ENS at a later stage. Given prices will be highest during periods of scarcity, battery operators will have a clear incentive to optimise their charging and discharging decisions so they can produce as much as possible during periods of (expected) scarcity, even if this means charging at relatively high prices on occasion. Thus, by seeking to optimise their own profits, they support resource adequacy in the process.

As a result of daily patterns in demand and solar PV generation and their impact on prices, batteries tend to exhibit a daily pattern of charging and discharging. Figure 5.14 shows this average charging and discharging pattern of batteries for NL, as well as the residual load. Due to the residual load pattern, charging of batteries on average takes place during the afternoon in hours with sun, while they are discharged mostly during the evening peak. This can also be seen in the dispatch in Figure 5.8.

As with other technologies, the contribution batteries can make to resource adequacy depends on their ability to discharge during situations of scarcity. While the firm capacity of thermal plants depends mostly on forced outages, there are several additional reasons why batteries may not always be able to discharge during scarcity periods. Firstly, as they are energy constrained, batteries may not be fully charged at the onset of a scarcity period if the period was not foreseen, and the charging state not fully optimised. Secondly, if the scarcity period is very long and/or severe, battery storages may simply run empty if they discharge all their stored energy and have no opportunities to charge. This effect can be seen in Figure 5.6 which shows that the derating factor of batteries with 8 hours of storage (~70%) is higher than that of batteries with 4 hours of storage (~30%). This highlights that the more energy a battery can store, the more it can contribute to resource adequacy. To explore the potential of

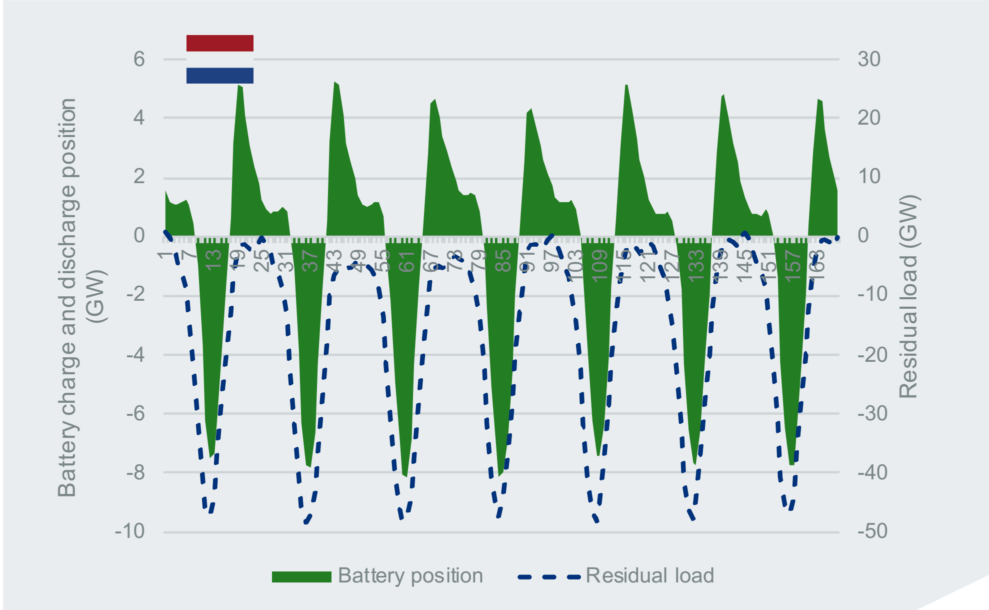


Figure 5.14 | Average weekly pattern of battery charging and discharging and residual load for NEL-Wind for NL over all climate years and outage scenarios.

batteries with even larger storage volumes, additional simulations were performed for the NEL-Wind scenario with batteries having 12, 24 and 48 hours of storage. As shown in Figure 5.15, the calculated derating factor for these larger batteries increased to roughly 80%, 90% and nearly 100% respectively. This shows that for batteries to achieve a similar level of firm capacity as zero-carbon thermal plants (~95%), longer storage durations of at least 24 to 48 hours would be needed, which would come at significantly higher cost. At the same time, the trend in Figure 5.15 also suggests that batteries with less than 4 hours of storage are unlikely to provide a significant contribution to resource adequacy.

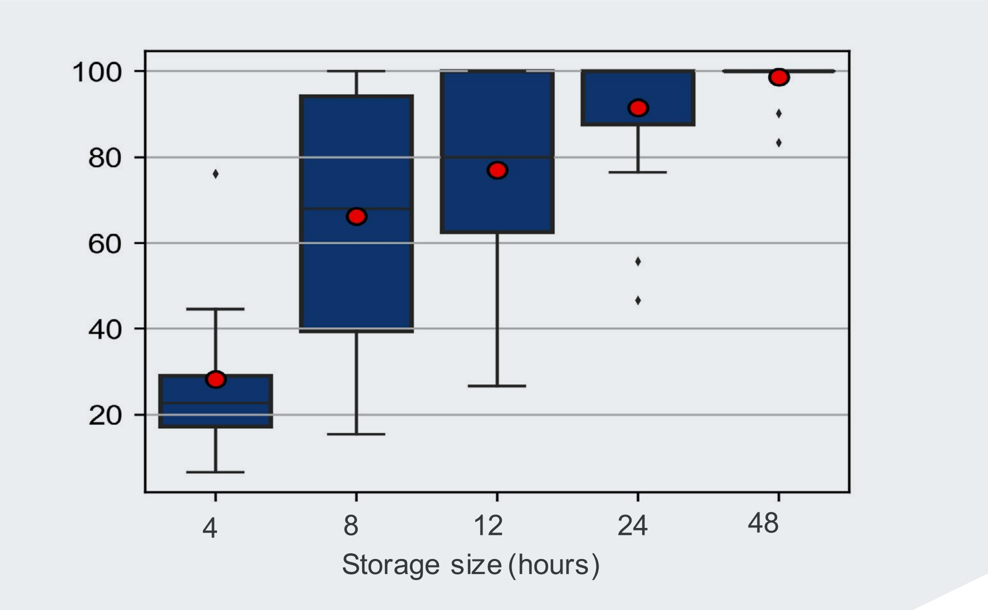


Figure 5.15 | Impact of battery storage size on firm capacity for the NEL-Wind scenario.

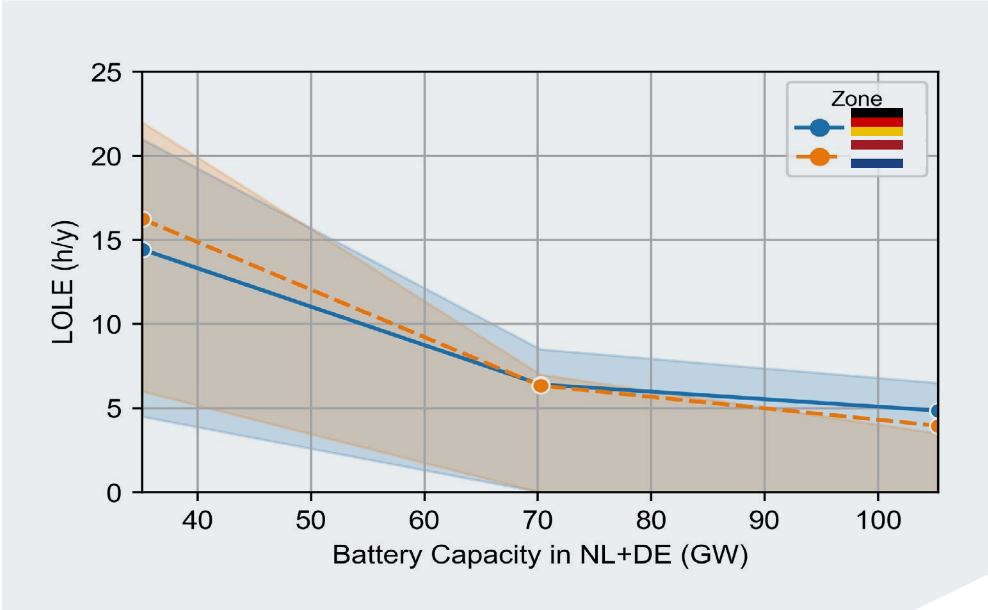


Figure 5.16 | Impact on LOLE of varying the total installed battery (4-hour and 8-hour) capacity by -50% and +50% from the assumed level in NL (13 GW) and DE (57 GW) for the NEL-Wind scenario. The x-axis shows the summed capacity for the two countries.

To further understand the impact of battery capacity on resource adequacy, additional sensitivity simulations were performed for the NEL-Wind scenario with 50% higher and 50% lower battery capacity installed in both NL and DE. The results are given in Figure 5.16 showing that reducing battery capacity by 50% (~35 GW) increases LOLE in both countries from 6 h/y to roughly 15 h/y, while increasing capacity by 50% reduces LOLE to between 4 and 5 h/y. Comparing these results for batteries with the sensitivity to hydrogen capacity (Figure 5.10) shows that as a result of its lower (marginal) derating factor, resource adequacy is far less impacted by the capacity of batteries (at least those with 4 and 8 hours storage) than the capacity of thermal capacity. It also shows that assuming higher battery capacities in the scenarios (e.g. due to greater uptake of residential batteries) would not leads to significantly different conclusions regarding level of firm thermal capacity required.

5.6.4 The role of cross-border exchange

Unlike domestic thermal capacity, DSR or storage, the ability of cross-border exchange capacity to contribute to resource adequacy depends on the situation in neighbouring markets, and the European market as a whole. Cross-border capacity does not provide capacity in itself, but rather provides the ability to access capacity (energy) located in other markets. For capacity in one country to be able to support resource adequacy during periods of scarcity in another country, two key prerequisites must be met. Firstly, the foreign country should have enough capacity to be able to cover their own demand and still have energy available to export. Secondly, sufficient cross-border capacity needs to be available between the two countries (or perhaps via 3rd countries) to transport the electricity. The latter can be affected by many factors including unplanned interconnector outages and internal grid bottlenecks in either country.

Figure 5.17 shows the calculated derating factors for all of the cross-border interconnectors available to NL and DE. For NL it shows that imports from Norway, the UK and Belgium contribute significantly during periods of scarcity, while on average Denmark and Germany contribute less. For DE it shows that imports from the Nordic countries and the UK are similarly important during scarcity periods, as well as countries including France, Switzerland, Austria and Poland. There are two main reasons for these differences. Firstly, as both electricity demand and weather conditions (e.g. wind speeds, temperature) across a geographic area tend to be highly correlated, low wind production in one country will tend to coincide with low wind generation in neighbouring countries. If these countries all rely significantly on wind generation to provide electricity, the risk of them all experiencing simultaneous scarcity issues is higher, and in such situations they cannot support each other. This is reason for the low derating factors for the Dutch, German and Danish borders, as the underlying scenarios assume significant deployment of wind capacity in a net-zero emission system in all three countries. This affect is less pronounced for countries located further away, as RES generation (and demand) profiles are less correlated at greater distances.

A second reason behind the difference in derating factors across borders is that countries with different generation portfolios are more likely to be able to support each other during scarcity periods. For example, if one country relies heavily on wind but its neighbours rely more on solar PV, zero-carbon thermal, or hydropower for electricity supply, the chance that they will have spare capacity and be able to support during a scarcity situation is higher. This explains why the Nordic, Austrian and Swiss borders have a high derating factor for DE, as these countries have significant hydro capacity. The French and Polish borders also have a high derating factor as these countries rely less on wind and have significant thermal capacity (see Annex A1).

To gauge the sensitivity of resource adequacy to the cross-border capacity assumptions, additional simulations were performed with the total Dutch and German interconnection reduced by roughly 15 GW (20%) from nearly 08 GW to 65 GW (see Table 4.3). As shown in Figure 5.18, this leads to a significant increase in LOLE in both countries, reaching by a total of 14.5 GW increases the LOLE from 6 h/y to almost 45 h/y in both countries. The sensitivity of resource adequacy to the level of cross-border capacity is thus higher than to the assumed level of batteries, which only increased the LOLE to 15 h/y when even more capacity (35 GW) was removed.

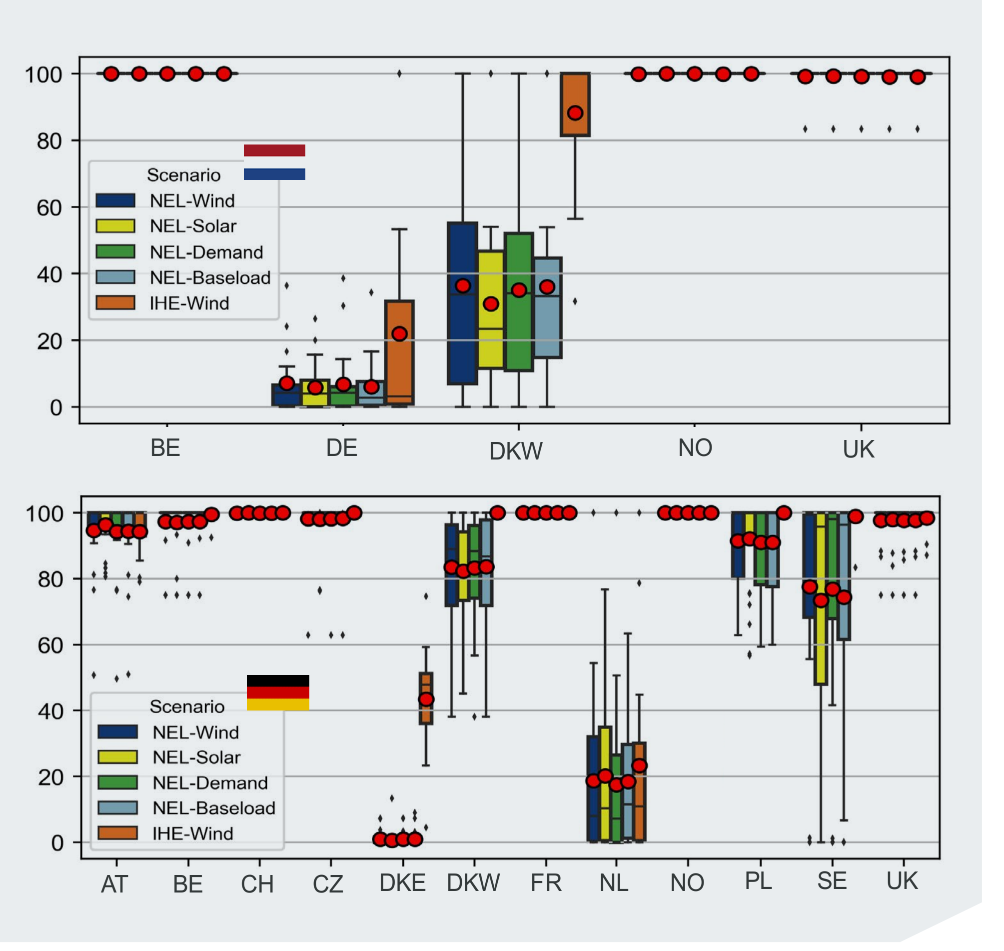


Figure 5.17 | Boxplot of the calculated derating factors for the cross-border interconnectors available to NL (upper) and DE (lower). The boxplot contains yearly averages values and shows the spread over all scenarios, outage iterations and climate years.

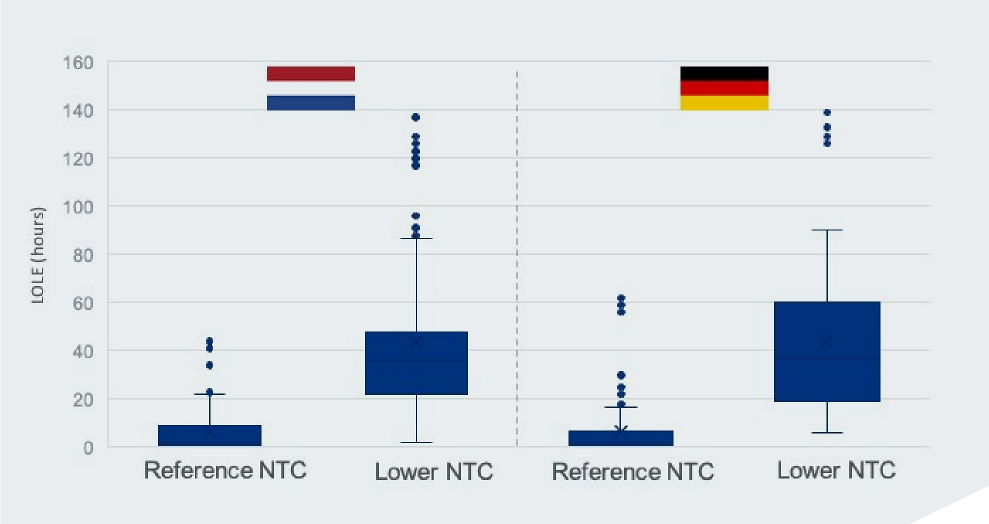


Figure 5.18 | Boxplot for LOLE levels versus the NTC used in NEL-Wind scenario. In 'Low NTC' the total interconnection capacity was reduced from 79.3 GW to 64.8 GW.

Thus, we conclude that while cross-border capacity can contribute significantly to adequacy in a net-zero emission energy system, it is inherently more uncertain than other forms of capacity as it depends on only on having the cross-border capacity built in time and available when needed, but also developments in foreign countries.

5.7 Analysis of shortage situations

Assuming the future power system will be operated at a cost-effective reliability standard above 0 h/y, there will always be challenging periods in certain years where it is expected that demand cannot be fully met by supply, and some situations with ENS will occur. In this section, we look deeper into the simulation results and analyse these challenging periods and their causes for several reasons:

- LOLE and ENS are very high-level adequacy indicators which are unspecific about the nature of the underlying outage events;
- Following the official methodology, our modelling assumes that the VOLL is a single value (i.e., the same cost per MWh of demand not met) irrespective of the type of outage. In reality though, outages which are longer, deeper, more frequent, or at specific times may represent higher costs for society which are not captured by a single VOLL value;
- By analysing the ENS events faced across scenarios we can better understand the sort of adequacy challenges which could be faced in future; and
- Evaluating the types of ENS events encountered gives insights on which technologies may be better suited to addressing them. Given that the capacities of certain technologies such as DSR, storage and exchange have been fixed in the scenarios in this study, one can reflect to what extent these scenario assumptions impact the results.

We analyse the challenging periods for adequacy from two perspectives. Firstly, we analyse the hourly results from all the market simulations and identify all the shortage events: consecutive hours where the model finds that demand cannot be fully met in each zone. Each shortage event is then characterised by three metrics (Figure 5.19): (i) the duration of the event (in hours), (ii) the maximum capacity shortfall or depth of the outage (in GW), and (iii) the total energy shortfall across all hours of the ENS event (in GWh). Secondly, we identify the most challenging climate years for adequacy (i.e., the outliers with the highest LOLE in Figure 5.4) and examine the detailed hourly dispatch to see which kinds and combinations of shortage events drive the LOLE higher in these years, and the reasons behind that.

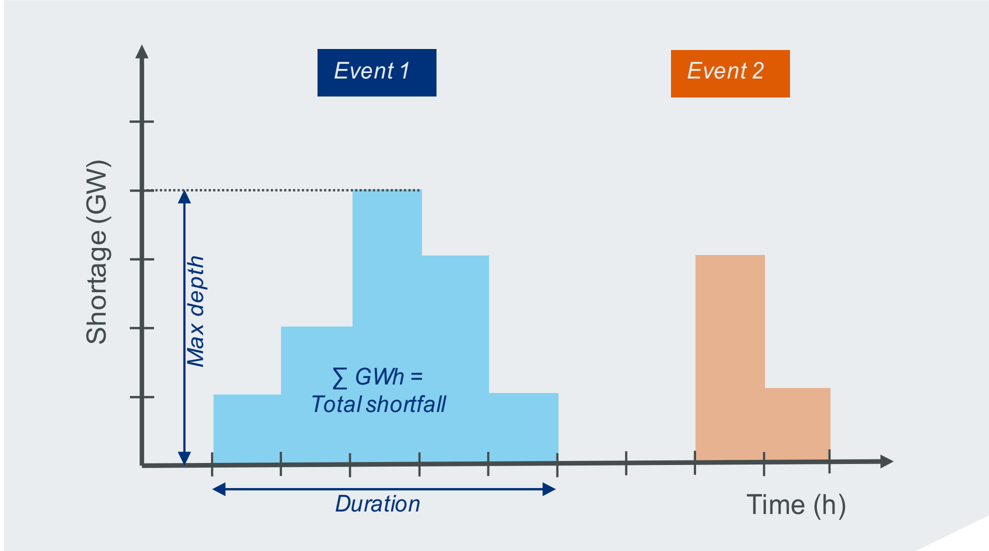


Figure 5.19 | Metrics by which shortage events are characterised

5.7.1 Characterisation of shortage events

Figure 5.20 presents an overview of all the shortage events for the NEL-Wind scenario. While shortages of one and two hours constitute the majority of ENS events, these are relatively minor and together result in only 15% of the total volume of ENS across all simulations. By contrast, longer outages of 7 hours or more constitute only 10% of the ENS events but are responsible for 50% of the total unmet demand. The maximum shortage depth reaches 20% of peak demand in NL, and a similar value in DE.

From a system perspective, shorter events could likely be resolved at minimal cost with some additional load shifting from HPs, EVs, industrial DSR, but it is unlikely these loads could be shifted by more than a few hours, and moreover load shifting would not be able to resolve the longer duration outages which represent the largest volume of ENS. Handling these types of shortages requires technologies such as firm zero-carbon thermal capacity, cross-border exchange, long-duration storage, or load shedding.

The approach applied to characterise the shortages in Figure 5.20 treats individual ENS events across all hours and simulations separately, but does not account for the fact that these shortage events can occur successively forming a chain of ENS events over a longer period, which may be more critical from an adequacy perspective. To identify these types of events, we need to look in more detail at specific challenging climate years.

5.7.2 Challenging climate years

The results of the simulations showed that certain climate years are more challenging for resource adequacy than others, at least in terms of the LOLE and ENS indicators. But what makes one year more challenging than another can be defined in different ways depending on the adequacy indicators used, the interpretation of those indicators, and what type of outage events are considered more severe than others. For instance, even using traditional indicators the most challenging year could be based on the highest LOLE (i.e., most hours with ENS), the highest total ENS (i.e., most unmet demand), or the highest observed hourly ENS (i.e., deepest outage). However, if the VOLL is not constant – as assumed in most adequacy studies – but depends on the duration and depth of outages, new indicators may need to be developed to identify challenging adequacy years which instead reflect the types of ENS events observed. This kind of analysis would need to account for the emergency load shedding procedures of TSOs, the order and manner by which load is curtailed in different sectors, and data on the VOLL of different outage types for these consumers.[29]

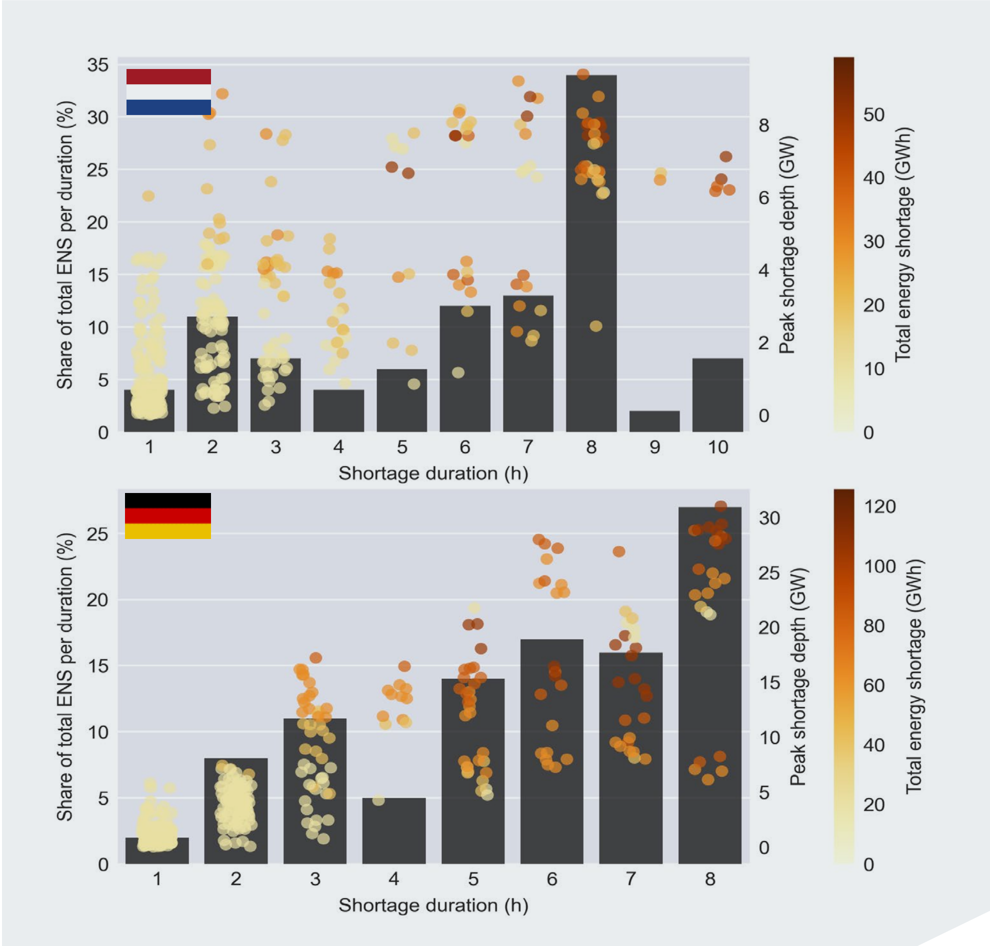


Figure 5.20 | Overview of all ENS events in the NEL-Wind scenario for NL (upper) and DE (lower). Each dot is a separate ENS event characterised by the shortage duration (h) on the x-axis, maximum shortage depth (GW) on the right y-axis, and total unserved energy during the event (GWh) visualised in colour coding. The bar graph shows how shortage events of different durations contribute to the total ENS read on the left y-axis.

29 According to the official VOLL methodology these data should in principle be collected by NRAs in setting the VOLL, but the available studies for NL and DE do not report on (all) these detailed parameters (e.g., dependence of VOLL on outage duration), or exclude some consumer types from the survey (e.g., residential).

Scenario	NL	DE
NEL-Wind	1996, 1984,1987	1997,1996, 2001
NEL-Solar	1996,1984,1987	1997,1996,1984
NEL-Demand	1996,1984,1987	1997,1996,1984
NEL-Baseload	1996,1984,1987	1997,1996, 2001
IHE-Wind	1996,1991, 1997	1996,1997, 2001

Table 5.2 | Top 3 climate years with the highest average LOLE per scenario per country

Looking at the years with the highest LOLE per country per scenario, we find that climate years 1996, 1997, 1984, 1987 and 2001 are the most challenging for adequacy across the scenarios considered (Table 5.2). Climate year 1996 stands out as the most challenging for NL in all scenarios, and the second most challenging for DE. At first glance, one would not expect these years to be especially challenging from an adequacy perspective based on typical indicators. For example, these are typically not the years with especially low generation from RES, nor the highest peak demand, nor even peak residual demand.

Looking in more detail at climate year 1996, we find the main reason for the high LOLE in this year is an extended period of roughly eight days in December where ENS event are observed almost every day (Figure 5.21). During this period a combination of very low offshore wind generation, lower solar generation and cold, dark conditions (meaning higher demand for electricity for heating and lighting) results in a severe example of a so-called *kalte dunkelflaute* (further addressed as *dunkelflaute*) situation. This combination of low generation from renewables (*dunkel*=dark, *flaute*=low wind) and high demand due to cold conditions (*kalte*=cold) create a critical situation for adequacy, as in this period the power system must rely to a larger extent on cross-border exchange, storage, zero-carbon thermal capacity and DSR to keep supply and demand in balance. Still, looking at the hourly dispatch during this period, we can see why even these technologies have challenges:

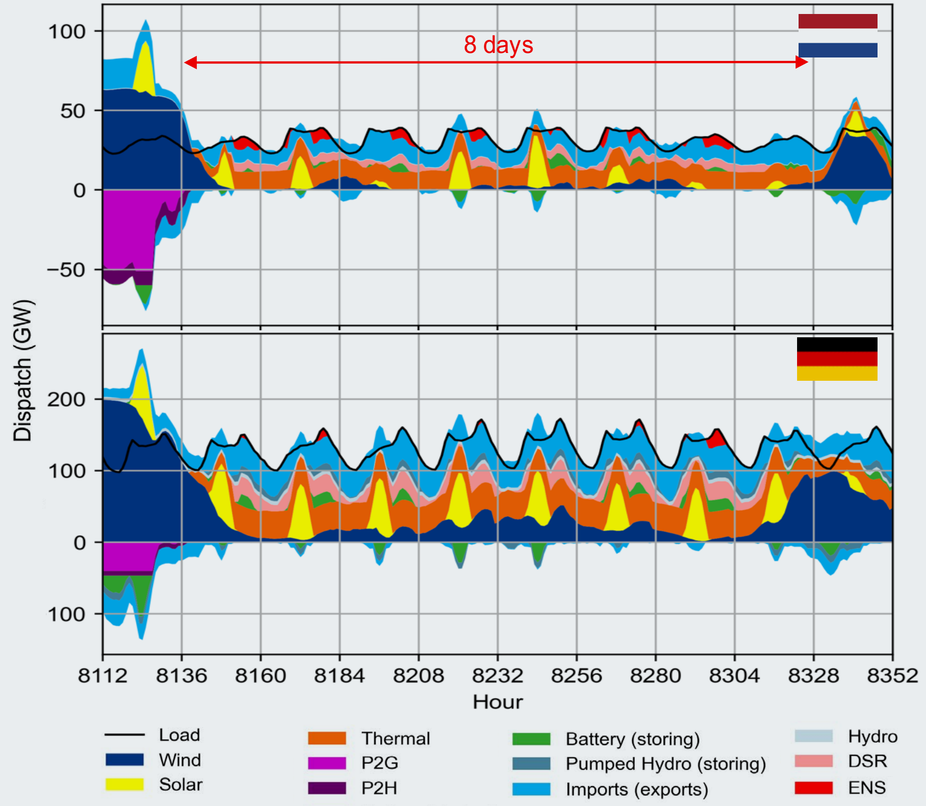


Figure 5.21 | Hourly dispatch during a challenging adequacy period in December (week 50/51) climate year 1996. Discharge of storage technologies and imports are shown as positive, while charging of storages and exports shown as negative. The black line shows underlying load (without P2X), including reserves.

- As wind generation is low in both in NL and DE and both face scarcity, the possibilities to support each other with cross-border exchange is limited. Moreover, wind generation in this period is not only low in NL and DE, but also across the whole North Sea region (Figure 5.22). As a result, **nearby wind-dependent countries also have challenges satisfying their own demand and cannot support** with cross-border exchange. Import from countries further away (with less correlated RES generation), and those with less wind-dependent generation portfolios still continues and used to its full extent (e.g., Poland, Switzerland, France, Norway).

- With limited generation from wind and solar (particularly in NL), b**attery storages are quickly depleted**, and have limited opportunities to charge from surplus RES, thermal power or imports. Moreover, due to high prices charging storages is very costly.

- Despite some minor outages **all available thermal capacity is used** to its full extent during this period and cannot contribute any further.

- **DSR from HPs, EVs and industry is (partly) activated almost continuously** throughout this entire 8-day period in both NL and DE, but the assumed load flexibility is not enough to fully avoid ENS. Even if additional load shifting from EVs and HPs were assumed, these loads could only be shifted a few hours, while the *dunkelflaute* lasts multiple days. Completely shedding loads from HPs and EV charging throughout this period would largely resolve all the ENS issues, but this would have major consequences for consumers and the economy.

A further point to highlight is that given our assumption that P2X is fully price flexible, and the market price during this *dunkelflaute* period is very high (the price is set by either hydrogen, DSR or the price cap), P2X does not operate at all during this 8-day period. If P2X were not fully price flexible, additional demand from P2X would further increase LOLE and ENS. Thus, it is important that as we move towards a net-zero emission system, **significant new sources of demand such as P2X should fully respond to the market price** or be curtailable by the TSO in emergency situations.

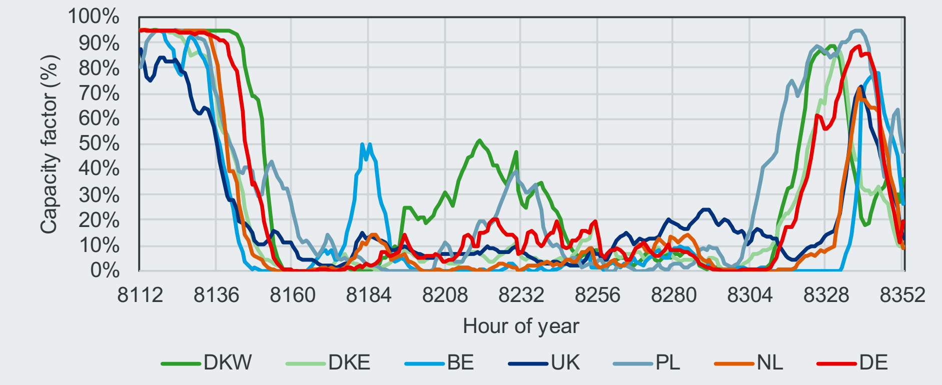


Figure 5.22 | Hourly capacity factors for offshore wind in NL, DE and selected neighbouring countries during week 50/51 of climate year 1996. While not shown, onshore wind generation is similarly low.

Looking at the other challenging climate years, we find that the high LOLE in these years is also driven by (shorter) *dunkelflaute* events across NL and DE.[30] Thus, the reliability of a future net-zero emission power system will largely be driven by how it fares during *dunkelflaute* events, which in turn will depend on how rare and severe they are.

Recent studies of the historical weather in DE show that short *dunkelflaute* events (up to 3 days) may occur up to several times a year, while extended *dunkelflaute* events (8 days and more) may occur only once a decade, and perhaps even less frequently in winter when they are harder for the power system to manage [40] [41]. While the database of historical climate years used in this study covers a period of almost four decades up to 2016, this does not preclude the possibility that even more severe *dunkelflaute* events can occur.[31] Looking to the future, it is also not clear what impact climate change may have on the frequency and severity of *dunkelflaute* events in NL, DE and Europe as a whole.

30 For example, 1997 had a severe *dunkelflaute* event in January, 1984 had one in December, and 1987 one in January and December.
31 Low generation from wind has also been seen in more recent years [99].

5.8 Zero-carbon gasses and resource adequacy

In a future net-zero emissions energy system the use of fossil fuels will have been largely phased out, and zero-carbon gases such as green hydrogen will likely play an important role delivering a net-zero emission energy system. This is also reflected in current national and EU energy and climate policy discussions and action plans (e.g. REPowerEU [42]). By providing a means to decarbonise sectors that are too difficult or costly to electrify directly, and the potential to store significant volumes of electrical energy in molecules across weeks, months or even seasons, zero-carbon gases are likely to play a key role in providing flexibility to the power system both on the demand (i.e. P2G) and supply side (i.e. hydrogen power plants).

Given our scenarios assume significant P2G capacity and the results from section 5.4 showing that significant capacities of firm zero-carbon thermal plants are required in a net-zero emission power system, it is relevant to also consider the implications of depending on zero-carbon gases for adequacy – especially if a significant quantity of these gases must be imported. The following sections elaborate briefly on the requirements, possible challenges and implications for adequacy. For the sake of simplicity we use the term 'hydrogen' as a proxy for all types of zero-carbon gasses (see 4.1.2).

5.8.1 Supply and demand of zero-carbon gasses

Based on the simulation results, an analysis of the annual hydrogen balance is performed. The main source of hydrogen supply in the assumed scenarios is domestic supply from P2G. On the demand side, hydrogen is consumed either by gas power plants to generate electricity, or used in other non-electricity sectors (e.g. industry). If the calculated domestic hydrogen supply is lower than domestic consumption this indicates hydrogen must be imported from other countries, while a surplus of domestic hydrogen can be exported.

Figure 5.23 shows an overview of the calculated annual hydrogen balance averaged across all modelled climate years for all scenarios, while Figure 5.24 shows how this balance varies per climate year for the NEL-Wind scenario. Following the scenario storylines, domestic hydrogen production from P2G plays a significant role in all the NEL scenarios in both NL and DE. In NL for example, as a result of the significant RES and P2G capacities assumed in the NEL scenarios, the total demand for hydrogen in both the power sector and other (e.g. industry)

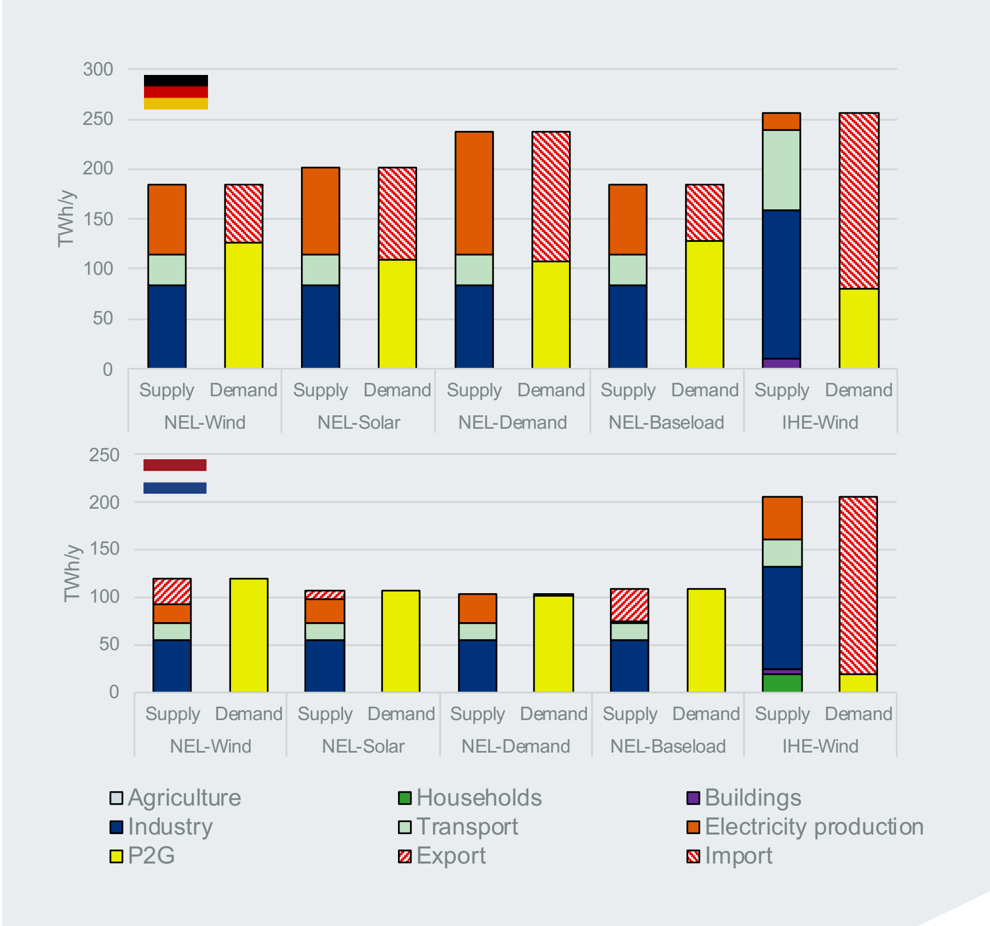


Figure 5.23 | Overview of hydrogen supply and demand balance per scenario for DE (upper) and NL (lower) as average of modelled climate years. Values are averaged across all climate years.

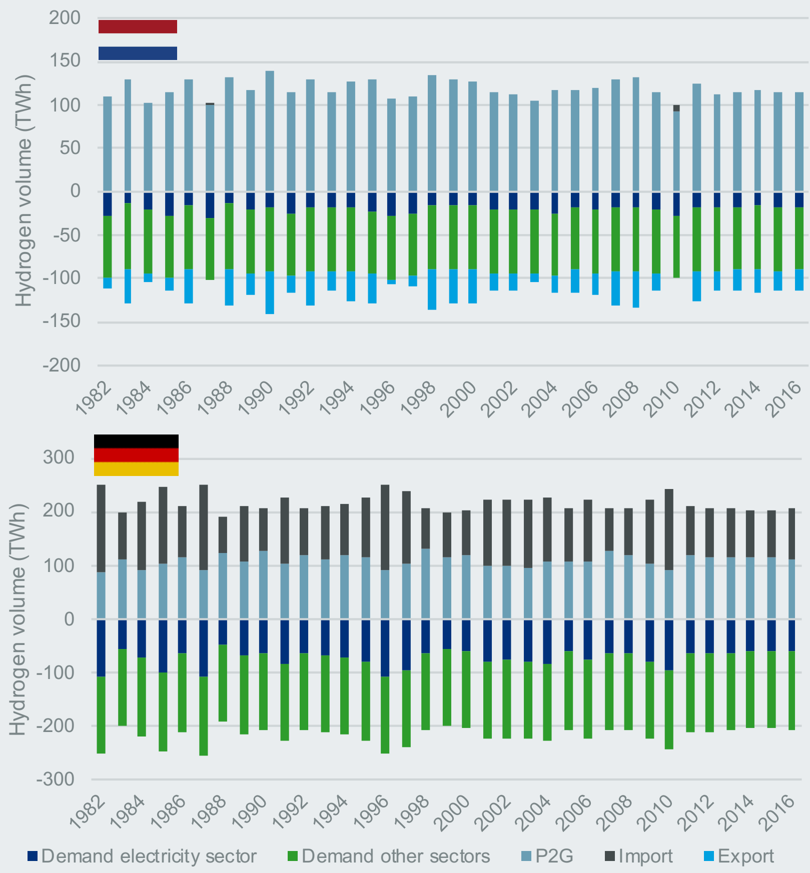


Figure 5.24 | Hydrogen supply and demand balance in all climate years for the NEL-Wind scenario. Positive number represent demand, negative numbers represent supply.

sectors can be fully met by domestic hydrogen production from P2G, and even allows for some limited export to other countries. In DE the assumed domestic P2G capacity in the NEL scenarios produces enough hydrogen to roughly cover what is used for electricity generation, but not enough to meet demand for hydrogen from other sectors. Thus, DE would still be a net importer of hydrogen in all the NEL scenarios. The P2G production is somewhat higher in the NEL-Wind and NEL-Baseload scenarios compared to both the NEL-Solar and NEL-Demand scenarios. This is mostly driven by the higher average full load hours of wind compared to solar PV, and the lower electricity prices (see 6.4.1). As a consequence of the higher electricity demand in the NEL-Demand scenario, more electricity is generated by gas power plants, requiring increased import of hydrogen. In the NEL-Baseload scenario, nuclear generation replaces some generation from gas-fired power plants in NL, reducing the domestic hydrogen demand and at the same time increasing hydrogen exports. In line with the scenario storyline assumptions the demand for hydrogen is higher and P2G capacity lower in the IHE-Wind scenario compared to the NEL scenarios, and both countries become significant net importers of hydrogen in this scenario.

The annual supply and demand balance of hydrogen varies between climate years as a result of several factors including the interannual variability in RES generation, temperature-dependent electricity and hydrogen demand, the dispatch of hydrogen power plants, and resulting electricity market prices. For example, Figure 5.24 shows that in certain climate years (e.g. 1996), the volume of hydrogen imports required in DE could be twice as high as in other years (e.g. 1988).

Note that the volume of zero-carbon hydrogen used for generating electricity in all the net-zero scenarios is lower than the volume of natural gas used for electricity generation today. For example, in the NEL-Wind scenario the average annual consumption of hydrogen for electricity generation is roughly 20 TWh/y in NL, significantly lower than the ~140 TWh of natural gas used for electricity generation in NL in 2020 [43]. For DE, approximately 70 TWh/y of hydrogen is required in the NEL-Wind scenario for electricity generation, compared with ~160 TWh used in 2020 [44].

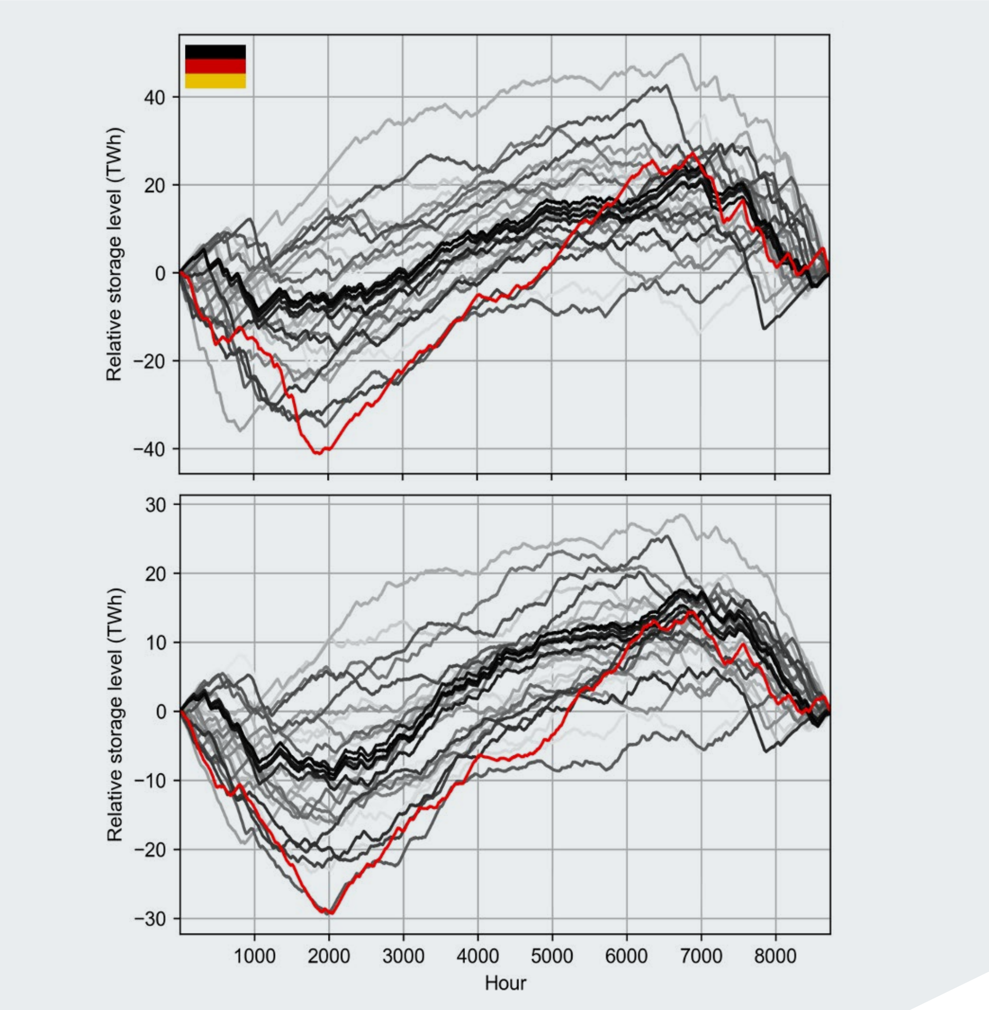


Figure 5.25 | Hydrogen storage requirements in DE in the NEL-Wind (upper) and IHE-Wind (lower) scenarios. The traces show the implied relative storage level across all climate years. The red trace indicates the climate year with the largest seasonal difference in storage levels.

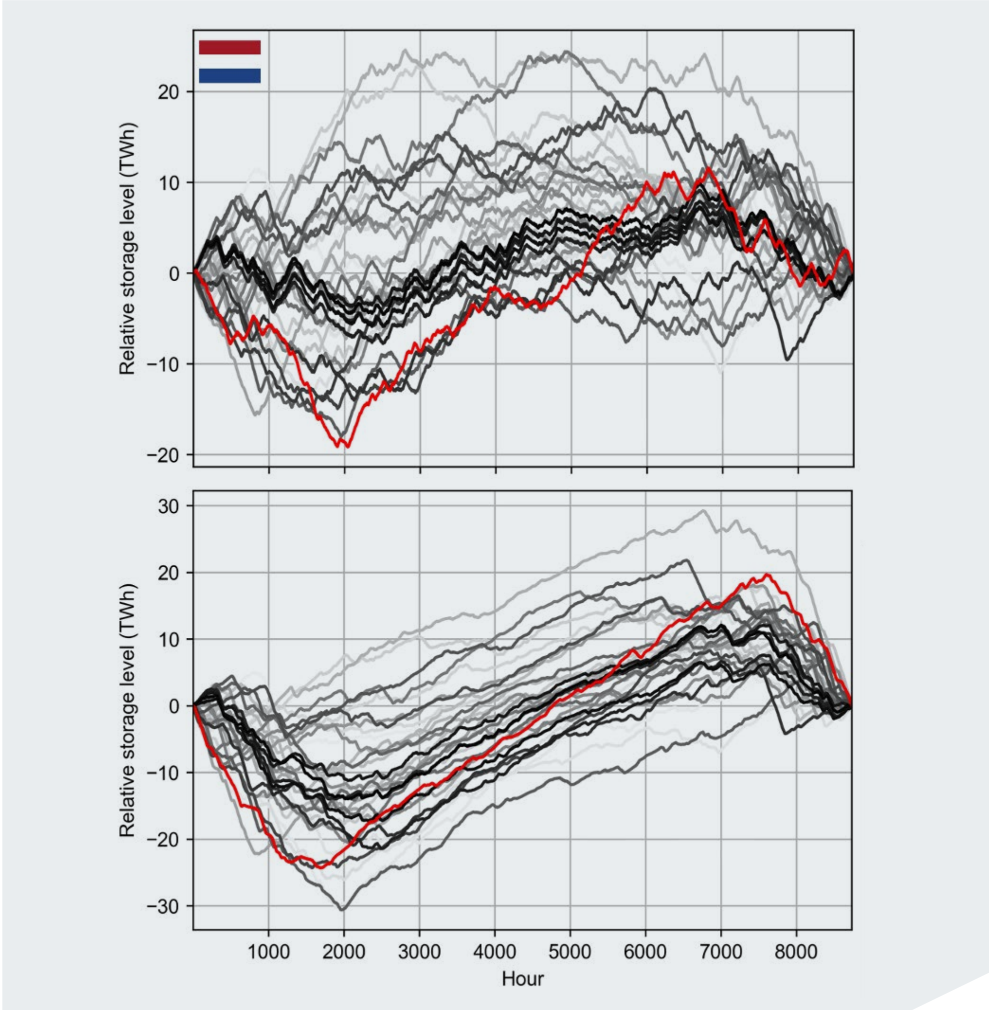


Figure 5.26 | Gas storage requirements in NL in the NEL-Wind (upper) and IHE-Wind (lower) scenarios. The traces show the implied relative storage level across all climate years. The red trace indicates the climate year with the largest seasonal difference in storage levels.

5.8.2 Storage of carbon-free gasses

While imports of zero-carbon gas from foreign countries can help to balance supply and demand on a yearly basis, the ability to store zero-carbon gas (e.g. as gaseous hydrogen, liquid hydrogen, or ammonia) is another important prerequisite for resource adequacy to ensure that hydrogen produced domestically can be stored across longer timescales (e.g. weeks, months, years), and to provide a buffer for efficient management of hydrogen imports and exports. Based on the scenario assumptions and market simulation results, the relative need for domestic hydrogen storage can be estimated by:

- calculating the difference between total annual domestic hydrogen production and consumption (i.e. the annual net hydrogen imports required) for each climate year;
- distributing this maximum annual net import across all hours of the year, essentially assuming a fixed maximum import capacity for hydrogen through pipelines, ships, etc. which is used at full capacity throughout the year, and
- for each hour of the year, calculating the cumulative sum of the differences between hourly domestic hydrogen production, consumption, and net imports i.e. the relative storage level.
- the climate year which show the largest difference between the lowest and highest relative storage level across the year can provide a rough estimation of the minimum domestic storage requirement.[32]

Figure 5.25 and Figure 5.26 show for NL and DE (respectively) the resulting relative hydrogen storage levels for each of the modelled climate years for both the NEL-Wind and IHE-Wind scenarios.[33] While there is a relatively clear pattern visible of filling the storages mostly in the summer period and empty them in the winter months, the exact storage filling profile and storage volumes implied differ significantly between the modelled historical climate years as results of the different RES generation patterns, temperature-dependent demand profiles, and dispatch of hydrogen power plants. In NEL-Wind, the minimum delta in storage volume reaches nearly 70 TWh in DE and 31 TWh in NL. While these values are lower than the current domestic storage capacities for natural gas of approximately 140 TWh in NL and 250 TWh in DE [45], storage volumes for hydrogen and natural gas are not directly comparable.[34]

An important question from an adequacy perspective is thus if the necessary volumes of domestic hydrogen storage could be realised in the future. While storage of hydrogen in underground salt caverns and depleted gas fields is often presented as a solution, it remains to be seen if sufficient geologically suitable locations can be found with the correct technical characteristics to storage hydrogen at reasonable cost. The issues of public acceptance and security would also need to be addressed. Other studies elaborate in more detail on these aspects and indicate that large-scale deployment of hydrogen storages poses major challenges and will require significant efforts [46].

From the analyses in this section we find there will be a close link between electricity and low-carbon gases in a future zero-carbon energy system. While the dependency on gaseous fuels to generate electricity is significantly lower in the net-zero scenarios compared with today's power system, ensuring an adequate supply of zero-carbon gas for the electricity and other demand sectors would be contingent on (i) the availability of sufficient zero-carbon gas supply from domestic P2G, (ii) the ability to import (significant) zero-carbon gasses from international markets, where domestic supply is insufficient to meet demand, and (iii) sufficient domestic storage capacities for zero-carbon gas.

32 This approach only gives an indication on domestic storage requirements, assuming just enough import capacity is built to balance yearly demand. However, lower storage volumes could be possible by investing in greater import capacity, and allowing hydrogen import volumes to vary throughout the year. In this case imports and storage levels would need to be more carefully managed due to lower working volume, and supply of hydrogen would be more vulnerable to supply interruptions.

33 For visualisation purposes the storage level is each set to zero at the beginning and the end of the respective year, in practise the starting volume levels would differ per year

34 Storage sites currently used for methane are not necessarily suitable for storing hydrogen, and storage volumes strongly differ between the two gasses as hydrogen requires about 3.2 times as much volume for the same amount of energy at equal pressure.

6 Economic Viability

Key takeaways…

The viability of hydrogen (zero-carbon gas) plants is driven by scarcity revenues, average market prices, and annual operating hours. However, as long as scarcity revenues are high enough to cover fixed costs, a reduction in operating hours compared to today would not be a major barrier to the viability of hydrogen plants.

The viability of storage is driven by price volatility, scarcity revenues, annual operating hours and capital costs, which will need to fall by roughly 50% compared with current costs for the assumed battery capacities to be viable.

The viability of RES is driven by the capture rate (cannibalisation), baseload price, and the investment costs. Onshore and offshore wind are viable in practically all scenarios, while the viability of solar PV is mixed due to the stronger impact of revenue cannibalisation. Revenue cannibalisation can be reduced by adding flexible demand in the system (e.g. from P2X), or installing less capacity. Scarcity revenues do not significantly affect the viability of RES as scarcity mostly occurs during hours of low wind and solar generation.

Hydrogen plants, DSR and batteries have significantly more volatile revenues than solar or wind. More volatile revenues represents higher investment risk, higher financing costs, but also higher expected returns.

DSR from industries with high activation costs (> 8000 €/MWh) are unlikely to be viable due to insufficient operating hours. The current market price cap (4000 €/MWh) would also pose a barrier for these industries entering the market.

Wholesale electricity markets could theoretically provide sufficient revenues for investments in RES, storage, hydrogen plants and industrial DSR (< 8000 €/MWh) to be market viable in a net-zero emission energy system, but only if:

- resource adequacy is maintained at the reliability standard (on average), accepting that periods of scarcity are to be expected in challenging years;
- the market price cap is set at the VOLL, or at least approaching it;
- the market price is allowed to reach high levels during scarcity periods without intervention;
- sufficient flexible demand is available to absorb RES generation and prevent market price collapse;
- investment risks are kept as low as possible; and
- and the investment costs of RES and battery technologies continue to fall

In a future power system with large-scale deployment of RES, it is important this goes hand in hand with flexible demand to prevent price collapse and mitigate the effect of RES cannibalisation. If the supply of electricity from RES outpaces demand from (flexible) loads such as EVs, HPs, P2X and storage, low market prices pose risks to the economic viability of many technologies.

A power system with a higher share of solar PV is likely to see higher average prices than one with a higher share of wind. With solar generation available during daylight hours only, costlier generators have to be dispatched more often during evening hours than in a wind-driven scenario.

The price of imported hydrogen will have a major impact on domestic electricity prices in an energy system with significant domestic P2G capacity, as hydrogen based supply will often set the market price when adapting to available RES generation.

6.1 Introduction

In the previous chapter we showed how different technologies can support resource adequacy, and approximately how much firm capacity would be needed in each net-zero emission scenario. In order for the required investments in zero-carbon thermal, storage and DSR capacities to be made without government support, these capacities must be economically viable for market parties to invest in them. In this chapter, we use the results of the adequacy simulations together with additional economic assumptions to perform a simplified assessment of the economic viability of the assumed technology capacities in each scenario. With this analysis we seek to understand:

- What are the main factors driving the economic viability of different capacity resources in a net-zero emission energy system?
- Are the assumed thermal, storage and DSR capacities required to meet the reliability standard in our net-zero emission scenarios potentially economically viable?
- How sensitive are the results to different technology costs and market conditions, and under what conditions are capacities more likely to be viable?

6.2 Methodology

The economic viability analysis follows a stepwise approach (Figure 6.1). First, we define several indirect and direct indicators of economic viability, and the set of criteria used to assess the likelihood of viability. Second, we analyse the indirect viability indicators as these are typically the underlying drivers of economic viability, and can help to understand and interpret the results of step 3, where we use the hurdle rate method to perform a direct evaluation of viability based on the internal rate of return. A sensitivity analysis is then performed to check the impact of certain assumptions, before making a final evaluation and reflection on economic viability.

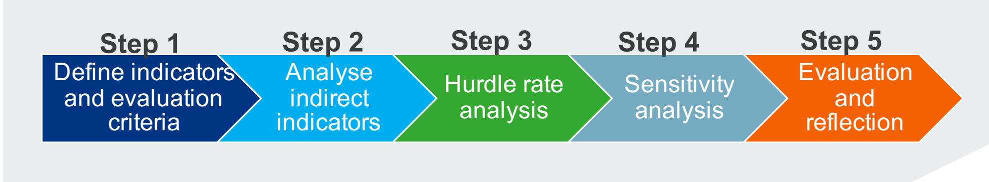


Figure 6.1 | Steps applied in the economic viability analysis

Note that in performing the economic viability analysis, several key assumptions and simplifications are made:

- We assume an energy-only electricity market (EOM) with marginal cost-based bidding, and pay-as-cleared pricing.
- Our simulations assume perfect foresight of load and RES, and thus represent the combined dispatch outcome after the futures, day-ahead and intraday markets have closed.
- We assume all electricity is bought and sold on the combined day-ahead/intraday market at the (hourly) prices resulting from the dispatch model, while in reality market parties would typically sell (buy) a portion of their expected generation (consumption) on futures and forward markets to lock-in revenues (costs) ahead of time and hedge against volatile prices. Moreover, depending on their asset portfolio, market parties can take advantage of market price volatility and generate additional (extrinsic) value by optimising their positions over time and e.g. buying electricity back from the spot market if the price falls below their marginal cost. However, as we only model a single future year we cannot account for the impact of forward trading and hedging, but instead reflect on this as part of the analysis.
- Only wholesale electricity market revenues are included. Revenues from the provision of ancillary services (e.g. balancing reserves), subsidies, optionality (see above) and CRMs are also not included. In the absence of feed-in type subsidies, RES plants will also not bid into the market at negative prices.

- As the modelling of power plants is simplified and individual power plants cannot be distinguished, economic viability is only assessed per technology type per country, treating all the installed capacity of each plant type as if it were a single plant.

- The mix and installed capacity of each technology is based on scenario assumptions, and not optimised for the system as a whole. Assuming higher (lower) capacity for a given technology would reduce (increase) the specific profitability, as total market revenues must be spread across more plants.

It is important to state that given the above simplifications and uncertainty in the future long-term electricity market design, technology costs, financing costs, fuel and electricity prices, the results of the economic viability analysis are only intended to give a rough indication of economic viability and its drivers, not an accurate assessment of whether any particular capacity or plant is viable.

6.3 Definition of economic viability indicators and evaluation methodology

Definitions of the main indicators used to perform the economic viability analysis are shown in Table 6.1. The market price, capture rate, full load hours, and annual marginal rent are indirect indicators of economic viability. These provide insights on the underlying drivers of economic viability for different technologies, but do not provide a direct indication of their profitability. For example, the starting point of the economic viability analysis is the annual inframarginal rent (IMR), which is calculated by determining the revenue from electricity sales in each hour, subtracting the variable cost for producing that electricity, and summing this across all hours in the year the plant is operating (Figure 6.2).[35] While a positive IMR indicates positive revenues from the sale of electricity, it does not give any insights whether capacity may be profitable in the long term. To ensure long-term profitability, the annual IMR needs to be high enough to also cover (i) FOM; (ii) the annualised CAPEX required for investing in the plant; and (iii) a reasonable return on investment given the particular risk level associated with investing in and operating the plant. For this purpose, two direct indicators of economic viability are commonly calculated: the specific gross margin, and the internal rate of return (IRR).

Indicator	Unit	Description
Electricity market price	€/MWh	The wholesale price of electricity output from the market simulations, based on marginal costs. We consider the baseload (annual average) price, as well as hourly prices.
Capture rate	%	The percentage of the baseload price a technology would receive for selling its electricity, if sold on the spot market. This effect is also known as market value or *hourly shaping*, as the hourly price depends on the shape of the hourly generation curve.
Full load hours (FLH)	h/y	The number of hours per year a technology is expected to operate, expressed as equivalent hours at full capacity.
Annual inframarginal rent (IMR)	€/kW/y	The difference (net) between revenues from the sale of electricity on the wholesale market and annual variable costs (fuel, VOM and start-up costs), calculated for each year
Internal rate of return (IRR)	%	The discount rate that makes the net present value (NPV) of future cash flows equal to zero, based on the median (50th percentile) value of the annual IMR across all simulated climate years.

Table 6.1 | Definition of the direct and indirect indicators of economic viability analysed

35 The IMR calculation is modified for storage and DSR technologies reflecting their different cost and revenue streams as explained in the annex. Moreover, economic viability is only analysed for a subset of technologies.

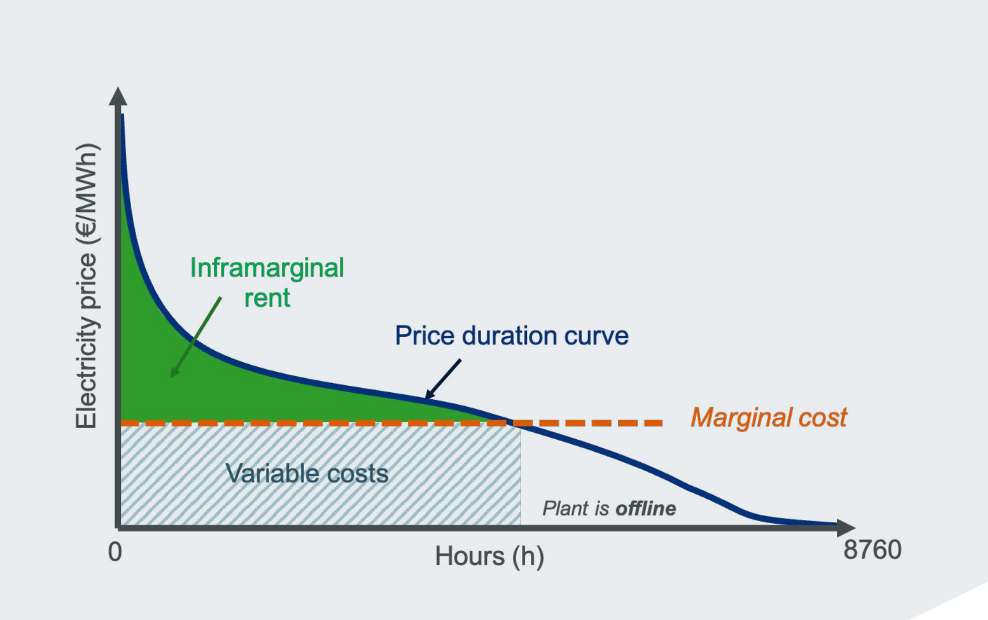


Figure 6.2 | The annual inframarginal rent (IMR) is calculated by subtracting the variable generation costs from the electricity market revenue for each hour of the year the plant is operating. A plant will only be dispatched if the electricity price is higher than (or equal to) its short-run marginal cost.

The main difference between these two indicators is how they incorporate the discount rate. In this context, the discount rate represents the rate of return the investor in a plant expects to achieve on the capital invested in a project and depends both on the type of investor, and the type of investment. For example, companies usually have to finance their investments with a mix of equity and debt, and the weighted average cost of capital (WACC) from these two sources determines their overall financing costs. While equity is typically sourced internally, debt must be sourced from financial institutions such as banks, and the cost of debt will be higher for a commercial investor than for a government or state-backed investor, as the latter has much lower risk of defaulting. Moreover, some types of technologies are subject to higher risks than others, and lenders will demand a higher interest rate for riskier investments. Thus, when it comes to defining what a reasonable return on investment should be, the following generally applies (i) higher risk investors require higher returns than lower risk investors, and (ii) riskier investments imply higher required returns than less risky investments. Returning to the two indicators and how they treat the discount rate:

- the specific gross margin is calculated by subtracting the assumed FOM and annualised capital costs from the IMR with the capital costs annualised assuming a *fixed discount rate*, and hence implies an assumption about the type of investor, whereas

- the IRR is the *discount rate* which makes the net present value of projected future project cash flows equal to zero, without making an assumption on the type of investor.

While the gross margin can provide insights on the expected distribution of returns for a certain type of investor investing in a specific capacity resource, the IRR provides more insight on how investable different capacity resources are likely to be for different investors. For these reasons, the overall economic viability evaluation in this study is based on the IRR indicator.

To account for the fact that riskier investments require higher returns we use the concept of the hurdle rate, which is the minimum IRR an investment needs to deliver to be considered economically viable [47].[36] The hurdle rate (H) is comprised of two components: the *WACC of a reference investor* (WACC*), and *(ii) a technology-specific hurdle premium* (h).

36 This approach has also been applied in other studies including Elia's Adequacy and Flexibility Study for Belgium 2022-2023 [79].

$$H = WACC^{*} + h$$

The WACC of a reference investor (%) represents the weighted average industry-wide cost of capital for a private investor, and can be seen as the absolute minimum return on investment required. This value is taken as 5% (real, pre-tax) based on [47]. For the technology-specific premia, we take a simplified approach and define a set of three technology risk categories, representing a range of hurdle premia (Table 6.2).[37] Technologies are assigned to each category based on a qualitative evaluation of the relevant investment risks such as policy risks and revenue volatility. Further explanation is provided in the Annex.

Risk Category	Included Technologies	Hurdle Premium (%)	Hurdle Rate (%) (including WACC* of 5%)
Low	- Solar PV - Onshore Wind - Offshore Wind	0% ≤ h < 5%	5% ≤ H < 10%
Moderate	- Hydrogen CCGT - Battery 4-hour - Battery 8-hour	5% ≤ h < 10%	10% ≤ H < 15%
High	- Hydrogen OCGT - DSR ≥ 200 €/MWh - Nuclear	≥10%	≥15%

Table 6.2 | Definition of the direct and indirect indicators of economic viability analysed

To perform the viability evaluation, the IRR is calculated for each technology based on the median (50th percentile) IMR from the simulations, as well as the reference OCC, FOM and economic life assumptions. The range in which the IRR falls is then compared with the hurdle rate corresponding to its assigned risk category (Table 6.3).

- If the IRR < 0%, the assumed capacity of that particular technology is deemed *unviable* as the total returns are less than the initial investment, irrespective of the assumed discount rate.

- If the IRR > 0% but significantly below the minimum required hurdle rate, the assumed capacity of that particular technology is deemed *unviable* without support as the return is considered too low for a private investor without state support.

- If the IRR falls just below the indicated hurdle rate, we deem this *marginally market viable*. Viability in this case may still be possible for investors with a particularly low risk profile (i.e. lower than the reference private investor), access to low-cost finance, other measures to reduce the cost of capital, or if the investment costs are lower than assumed in the reference case (see section 6.6).

- If the IRR is in the same range as the hurdle rate, the assumed technology capacity is deemed *likely market viable* as the expected returns are comparable to the required hurdle rate.

- If the IRR is significantly higher than the hurdle rate, we deem this as strongly *market viable*, as it indicates a robust return above the minimum required.

37 Other studies perform more detailed technology-specific calculations, but given the long-term nature of this study and significant uncertainties involved, a simplified approach seems more appropriate without introducing false accuracy

Calculated IRR range	Technology Risk Category & Hurdle Rate: Low 5 ≤ H < 10	Moderate 10% ≤ H < 15%	High H ≥ 15%
IRR < 0%	Unviable	Unviable	Unviable
0% ≤ IRR < 5%	Marginally market viable	Unviable without support	Unviable without support
5% ≤ IRR < 10%	Likely market viable	Marginally market viable	Unviable without support
10% ≤ IRR < 15%	Strongly market viable	Likely market viable	Marginally market viable
IRR > 15%	Strongly market viable	Strongly market viable	Likely market viable

Table 6.3 | Evaluation of economic viability based on the difference between the calculated IRR and technology hurdle rate

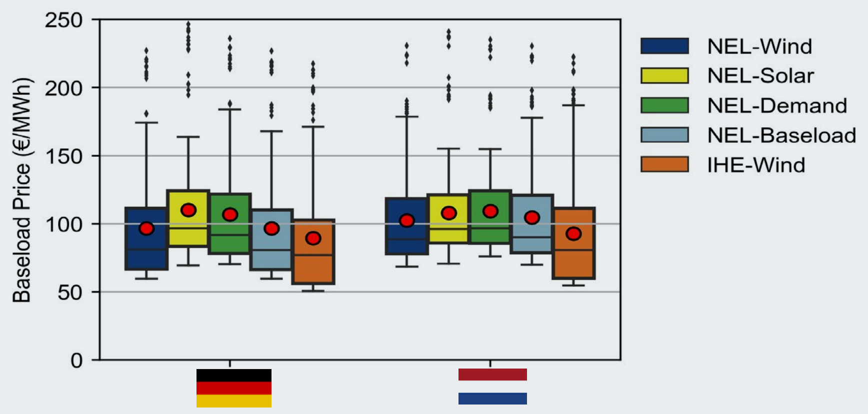


Figure 6.3 | Annual average (baseload) market prices for all scenarios. The boxplot shows the distribution of average annual prices across all climate years and outage iterations. The red circle indicates the mean value.

6.4 Indirect viability indicators

6.4.1 Electricity prices

The distribution of annual (baseload) market prices across all scenarios is depicted in Figure 6.3, showing that the median price varies between 75 and 100 €/MWh, depending on the scenario. In all scenarios the mean price across all simulations is higher than the median price. This is due to the fact that while the baseload price in most years is in the range of 50 to 125 €/MWh, all scenarios show some years with very high prices above 200 €/MWh. These years correspond to the most challenging years for adequacy with higher LOLE and ENS (see Table 5.2), and hence more hours where the market price is set by the price cap and DSR.

In order to understand the differences in prices between scenarios, we need to look more closely at the underlying hourly market prices, which are shown in Figure 6.4 as price duration curves (PDC).[38] Also shown in this figure is an indication of which technology is typically setting the market price in different regions of the PDC, based on the underlying marginal costs. At the far left of the PDCs the highest prices are observed during hours with ENS where the price is set at the VOLL (15000 €/MWh), followed by up to ~100 hours in which load shedding from industrial DSR, EVs and HPs sets the price at levels between 500 and 14500 €/MWh. Following this, hydrogen plants set the market price in around 2000 h/y when there is insufficient generation from RES to meet demand, and cheaper electricity cannot be imported from abroad.

38 A PDC shows the hourly market prices for all 8760 hours of the year, sorted from highest to lowest price

This is followed by a large region of the PDC where flexible demand from P2X follows the available generation from RES both domestically and abroad, and the market price is set by the willingness to pay of P2G and P2H. The last section of the PDC is where the market price is zero. Zero-price hours occur when surplus RES is available domestically but there is insufficient interconnection, battery or P2X capacity to utilise it, and RES must be (partially) curtailed. The number of zero-price hours is lower in NL than DE as the assumed capacity of P2X in the Dutch scenarios compared to the installed RES capacity is relatively higher than in the German scenarios.

The highest prices overall are seen in the NEL-Demand and NEL-Solar scenarios. Higher prices in the NEL-Demand scenario are a result of the higher assumed demand, which requires costlier generators such as hydrogen to be dispatched more frequently to meet demand. Higher prices in the NEL-Solar scenario are also due to more hours where hydrogen (and storage) sets the price compared the NEL-Wind scenario, particularly during the evening and night when solar does not generate. Lower prices in the IHE-Wind scenario are due to the lower assumed hydrogen price, which reduces not only the marginal cost of hydrogen power plants, but also the maximum price at which P2X is willing to consume.

Analysis of the PDCs shows that P2X has a significant impact on price formation in the net-zero emission scenarios. In particular, price-flexible demand from P2X prevents the market price from collapsing to zero in periods with surplus RES by establishing a kind of plateau for the market price. The extent of the plateau depends on how much P2X capacity is available, while the price level depends on the hydrogen import price. This effect has also been identified in other studies [48].

6.4.2 Capture rate

The capture rate varies considerably between technologies, as shown in Figure 6.5. Hydrogen plants capture prices significantly higher than the baseload price as they tend to generate when supply from RES is low, and when prices are set by DSR or the market price cap. While batteries capture more than the baseload price, their storage is typically depleted before they can capture the same price levels as hydrogen. Due to their higher storage capacity, 8-hour batteries have roughly 10% higher capture rate than 4-hour batteries.[39]

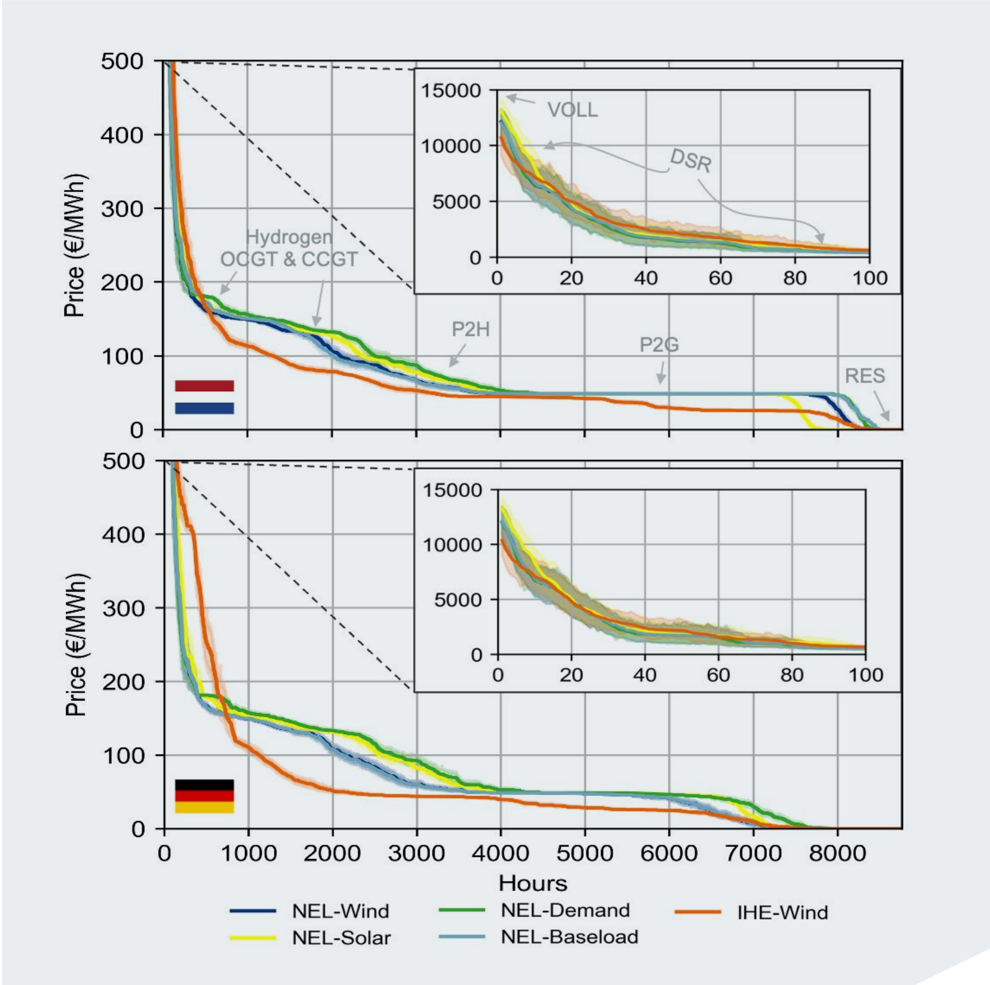


Figure 6.4 | Price duration curves for all scenarios for NL (upper) and DE (lower), averaged across all simulations. The insets zoom in on the market prices in the highest 100 hours per year. The grey annotations indicate which technology is typically price setting in a given region of the curve.

39 The longer storage duration means they can also arbitrage across larger price differentials in general.

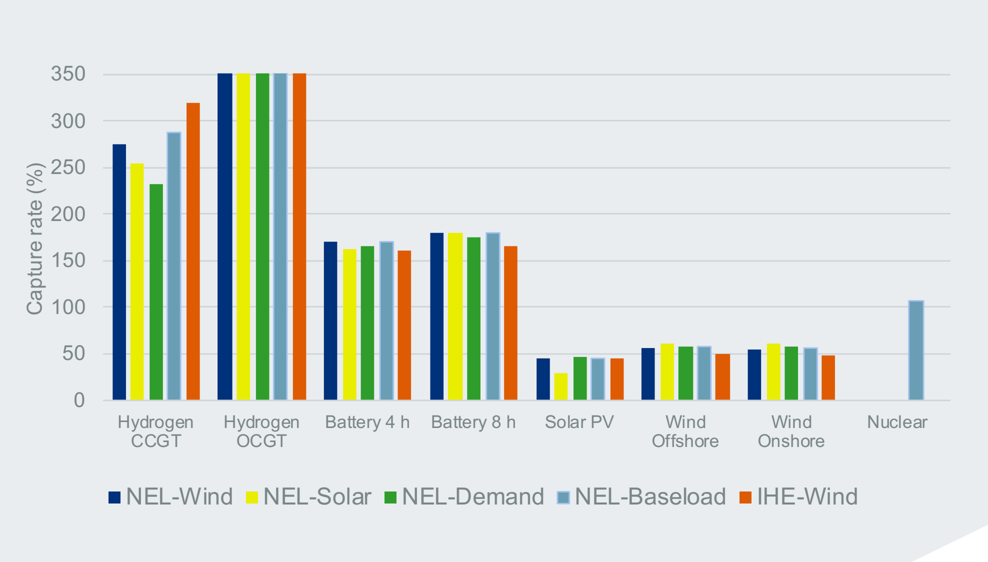


Figure 6.5 | Average capture rate for selected technologies across both NL and DE. The capture rate of OCGTs exceeds 500% in all scenarios, but not shown in this figure for visibility.

Unlike hydrogen and storage, RES technologies only capture roughly 50% of the baseload price in most scenarios. This is due to the so-called merit-order effect of RES. As RES have practically zero marginal cost and bid into the market accordingly, they are dispatched before costlier thermal generators in the merit order such as hydrogen. If the generation from RES is high enough to meet demand without thermal plants, they can be pushed out of the merit order and technologies with lower marginal cost such as P2X, nuclear, or even RES can set the price. As a result, market prices are typically lower during times of high RES generation. The merit-order effect is particularly evident with solar PV as generation only takes place during daylight hours, and the generation profiles of different solar farms are strongly correlated. This effect can be clearly seen in the NEL-Solar scenario where the higher capacity of solar PV lowers the market price to such an extent that the capture rate falls to nearly 25%, representing significant revenue cannibalisation. On the other hand, the generation profiles of different wind farms tend to be more temporally and geographically diverse, allowing wind to capture somewhat higher prices than solar. This shows that the future volume of RES capacity bidding into the market and the shares of solar and wind will have a significant impact on price formation and ultimately on their economic viability.

6.4.3 Full load hours

Full load hours (FLH) reflect how often a plant is dispatched and earning revenues from electricity sales. Without revenues, plants cannot cover their fixed costs which are incurred whether they generate or not. FLH are also important for the viability of other technologies such as DSR, as these must also cover their fixed costs by avoiding consuming (i.e. saving electricity costs) during hours with very high electricity prices. The FLH for selected technologies in NL are shown in Figure 6.6. We find that hydrogen CCGTs achieve around 2000 FLH/y per year, while hydrogen OCGTs achieve only a few hundred operating hours per year in most scenarios. However, as the split between hydrogen CCGT and OCGTs is fixed in all scenarios at roughly 50/50 (see section 5.4), these FLH are only indicative.[40] Batteries achieve 1000 to 2000 h/y with 8-hour batteries attaining more FLH than 4-hour batteries, as they can take advantage of price differentials across a longer period.

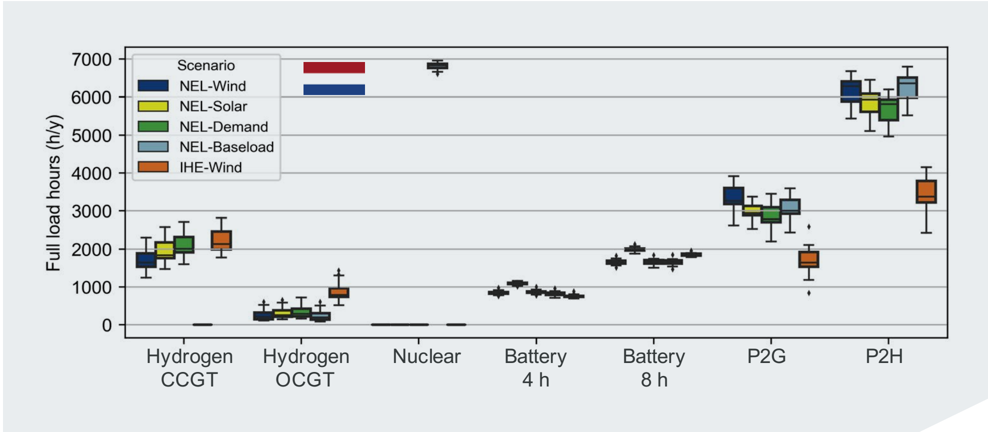


Figure 6.6 | Calculated annual full load hours (FLH) for selected technologies per scenario for NL. The box plots show the distribution of annual FLH across all simulated years.

40 Considering all hydrogen CCGT and OCGT capacity together, the total FLH would be approximately 1000 h/y.

Electrolysers achieve on average 3000 FLH/y in most scenarios, apart from the IHE-Wind scenario where a combination of lower installed RES capacities, lower assumed hydrogen import price, and lower threshold price for P2G reduce the number of hours where domestic P2G is cost effective to run. The large domestic P2G capacity also leads to significant import of electricity in both NL and DE when prices are low in neighbouring countries. A point to highlight here is that P2G never operates when hydrogen sets the market price, as this would never make sense from a cost perspective. Thus, in a future energy system with significant hydrogen and P2G capacity, there will always be a trade-off between the operating hours of hydrogen power plants and the operating hours of electrolysers.

The nuclear capacity assumed in NL in the NEL-Baseload scenarios operates for almost 7000 h/y. These FLH are achievable in our scenarios for several reasons. Firstly, we assume nuclear replaces 16 GW of offshore wind, so there is less RES supply than in the NEL-Wind scenario. Secondly, nuclear is lower in the merit order than hydrogen and thus preferentially dispatched before hydrogen, and can also be exported to neighbouring countries. Lastly, the marginal cost of nuclear is low enough that it is still below the indifference price of both P2G and P2H, thus nuclear power is also dispatched to generate hydrogen and heat, which is not the case for hydrogen plants.

The FLH of DSR depend on the assumed activation price. Load from relatively low-cost price bands (i.e. 200 to 400 €/MWh) is typically curtailed in around 100 hours per year, while the most costly DSR type (i.e. 14500 €/MWh) is typically activated only once a year. In extreme adequacy years, low-cost DSR activation can exceed two weeks, while the most costly DSR bands can reach up to two days.

6.4.4 Inframarginal rent (IMR)

Analysing the distribution of calculated IMRs across all simulated years (Figure 6.8), we find that average revenues are highest for zero-carbon thermal capacity, wind, 8-hour storage, and low-cost DSR. Due mainly to lower FLH and lower capture rates, the revenues for onshore wind are somewhat lower than for offshore wind, and 4-hour batteries also lower than for 8-hour batteries. Low FLH and capture rates are also the reason why solar PV has some of the lowest specific revenues of all technologies at 20 to 40 €/kW/y. DSR bands with high activation prices also have very low revenues due to their infrequent activation, and the fact that the savings when they do activate are lower than for cheaper DSR bands.

While the average revenues for thermal capacity, 8-hour storage, and low-cost DSR are relatively high, the volatility of these revenues is significantly higher than for RES. Hydrogen plants and DSR have particularly volatile revenues, with the rents in peak years being up to 8 times the median (i.e. 50th percentile, or most likely) value for CCGTs, and even higher for some lower cost DSR bands. As with the baseload price, this volatility is mostly due to scarcity prices in challenging climate years driven by the VOLL and DSR activation. As a result of these outlier years with higher prices the average IMR for all technologies is (significantly) higher than the median. While having some years with very high returns would lead to higher average revenues in the long term (i.e. across many climate years), averages are not typically considered by market parties when planning to invest in new capacity, who rather consider the 'most likely' revenue scenario instead of relying on infrequent years with high revenues to cover their costs [49]. This is the reason we use the median value of the IMR across all simulated climate years to calculate the IRR instead of the mean. There are also a number of years – particular for technologies like OCGTs and high-cost DSR – which see very low or even zero revenues. In contrast to thermal, storage and DSR plants, revenues from RES display much lower volatility from year to year. This might seem counterintuitive given the variable nature of RES, but while RES generation can vary significant across hours, days, or even weeks, the total annual generation of RES is typically quite consistent, mostly driven by the type of technology and where the plant is installed. The differences in revenue volatilities between technologies are largely consistent with the technology risk categories defined in Table 6.3, highlighting the importance of this risk from an investor perspective.

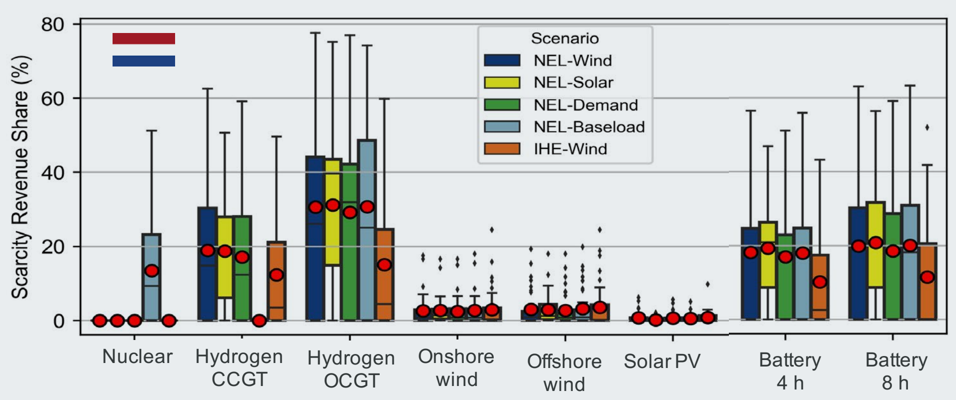


Figure 6.7 | The share of electricity revenues from hours with ENS (and price at the price cap) as a percentage of total IMR for NL

Given that we assume a future market price cap which is significantly higher than the current level and this drives the revenue volatility for several types of plants, it is relevant to see how much impact this assumption has on total revenues. By looking at the revenues plants accrue during hours with ENS (Figure 6.7), we find that these scarcity revenues on average contribute 30% of the total revenues for hydrogen OCGTs, and roughly 20% of the revenues for CCGTs and storage. While not all generation would necessarily be remunerated at this price (capacity is typically hedged beforehand), it does indicate a higher dependence on peak prices, which we consider further in section 6.6.

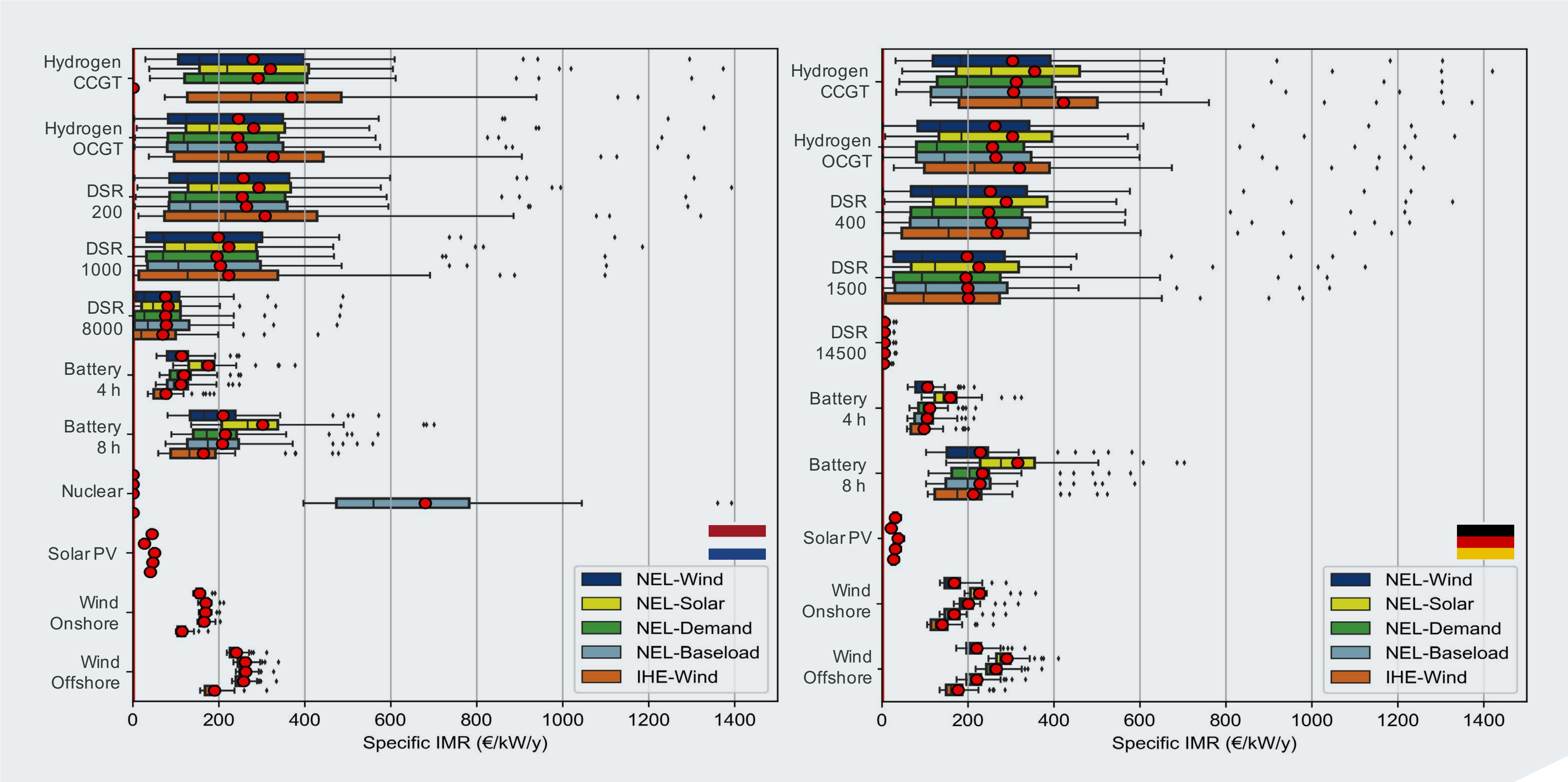


Figure 6.8 | Distribution of inframarginal rents (IMR) per scenario for selected technologies in NL (left) and DE (right).

6.5 Hurdle rate evaluation

The calculated IRR for selected technologies across all five scenarios are shown in Figure 6.9. Based on the hurdle rate evaluation matrix presented in Table 6.3, the key IRR thresholds for viability of 0%, 5%, 10% and 15% are indicated with vertical bars. Comparing the calculated IRR with the required hurdle rate for viability leads to the following conclusions regarding viability, summarised in Table 6.4:

- Both **hydrogen CCGTs and OCGTs** achieve an IRR above their hurdle rate of 15% and are deemed ***likely market viable***. Profitability is higher in the NEL-Solar and IHE-Wind scenarios as a result of higher market prices in NEL-Solar, and higher hydrogen FLH in IHE-Wind.

- Both **4-hour and 8-hour batteries** achieve an IRR in the range of 10-15% for most scenarios matching their technology hurdle rate, and are thus also deemed ***likely market viable*** overall. Despite this, the viability of batteries is lower in the IHE-Wind scenario to the point where viability is at risk as the difference between the charging and discharging price of batteries in this scenario (~100 €/MWh) is significantly lower than in other scenarios (~140 €/MWh in NEL-Wind). A higher price differential together with higher FLH is also the reason for stronger economic performance of batteries in the NEL-Solar scenario, showing that these two technologies support each other in a way that (short-duration) batteries and wind do not.

- We find that all **DSR bands with activation price 8000 €/MWh** or below have an IRR above 30% in all scenarios apart from IHE-Wind, and thus considered ***likely market viable***. Lower-cost bands have IRR significantly higher than this (>200%), and thus would likely be strongly viable. **Price bands above 8000 €/MWh** are found to have a negative IRR, and thus ***unviable***.

- **Onshore wind** achieves an IRR of between 10 and 15% in most scenarios across NL and DE. With a hurdle rate in the low risk category we thus deem this ***strongly market viable***. Returns from onshore wind are somewhat higher in the NEL-Solar scenario, and lower in the IHE-Wind scenario due to the higher and lower electricity prices in these scenarios respectively.

- **Offshore wind** achieves an IRR or between 5 and 10% in most scenarios and deemed ***likely market viable***. Similar to onshore wind, returns are somewhat higher and lower in NEL-Solar and IHE-Wind respectively. The overall IRR is lower for offshore than onshore wind mainly due to the higher up-front investment cost. Note that the reference CAPEX assumed for offshore wind includes the cost for connection to the onshore grid, which in NL and DE is a cost met by the TSO.

- The results for **solar PV** vary depending on the scenario and country. In NL, solar achieves an IRR between 5% and 10% for all scenarios apart from NEL-Solar, indicating ***likely market viable, and marginally market viable*** in the latter. In DE, solar PV is mostly marginally market viable in the majority of scenarios but unviable in the others. The main reason for these differences is that the scenarios themselves likely contain an overcapacity of solar PV capacity compared with the other assumed scenario parameters (e.g. storage, demand, P2X). This leads solar PV to cannibalise its own revenues, and also more curtailment which reduces the effective FLH of solar PV. This is especially the case in the NEL-Solar scenario, where additional battery capacity would be warranted due to the high IRR. Solar PV also performs worse in DE than in NL due to fewer FLH and a lower capture rate.

- **Nuclear** achieves a IRR of between 5 and 10% in the NEL-Baseload scenario which, given its high risk and hurdle rate of >15%, is thus deemed ***unviable without support***. This is despite nuclear achieving the highest specific IMR of all considered technologies. The reason is the high investment cost of nuclear which, for a discount rate of 9% (a typical market-based hurdle rate), leads to total annualised fixed costs of approximately 900 €/kW/y (including FOM), significantly higher than the median IMR of 550 €/kW/y. To bring the fixed down costs to this level a WACC of roughly 5% would be necessary.

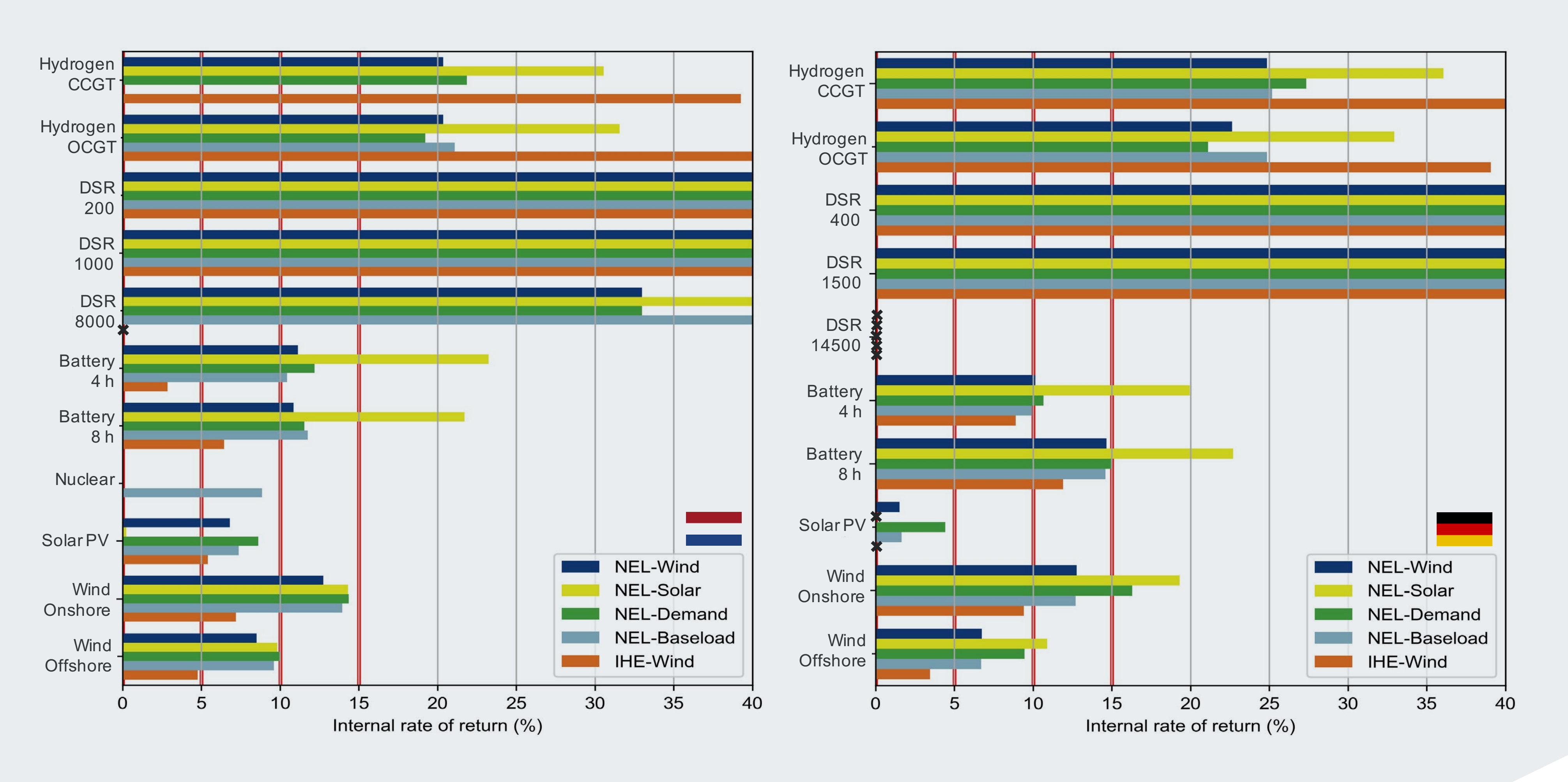


Figure 6.9 | Calculated internal rate of return (IRR) for selected technologies per scenario for NL (left) and DE (right). The red vertical lines indicate viability thresholds at IRR levels of 0%, 5%, 10% and 15%. An 'x' indicates a negative IRR. IRR values higher than 40% are not shown.

Calculated IRR range	Technology Risk Category & Hurdle Rate: Low 5 ≤ H < 10	Moderate 10% ≤ H < 15%	High H ≥ 15%
IRR < 0%			DSR > 8000 €/MWh
0% ≤ IRR < 5%	Solar PV (DE)		
5% ≤ IRR < 10%	Offshore Wind Solar PV (NL)		Nuclear
10% ≤ IRR < 15%	Onshore Wind	Battery 4-hour Battery 8-hour	
IRR >15%		Hydrogen CCGT	Hydrogen OCGT DSR ≤ 8000 €/MWh

Table 6.4 | Overview of the economic viability result per technology based on the hurdle rate approach

6.6 Sensitivity analysis

Analysis of the indirect and direct economic viability indicators shows that periods of high prices, the level of flexible demand, and investment cost assumptions strongly affect the profitability of several technologies. Moreover, the recent intervention to cap market revenues of certain technologies as part of the EU's response to the energy crisis may also have an effect on profitability [50]. To understand these potential impacts, additional sensitivity analysis is performed exploring the impact of these parameters for several technologies based mainly on the NEL-Wind scenario.[41] In particular, the sensitivities consider:

a. a lower market price cap of 3000 €/MWh, compared with the reference assumed price cap of 15000 €/MWh;
b. a cap on the hourly IMR of 180 €/MWh applied to solar PV, onshore wind, offshore wind, and nuclear capacities; [42]
c. 50% lower P2G capacity in both NL and DE than in the reference case; and
d. alternative CAPEX assumptions for selected technologies, based on the low and high levels given in Table 4.1.

The calculated IRR for the first three sensitivities are given in Figure 6.10 showing that:

- **A lower price cap of 3000 €/MWh significantly reduces the IRR and hence viability of hydrogen plants (especially OCGTs), DSR and battery storage** as these technologies derive a significant share of their IMR from scarcity revenues (see Figure 6.7). On the other hand, the viability of solar and wind is hardly impacted as these technology derive only a small share of their IMR from scarcity prices.

- **The 180 €/MWh cap on IMR has a minor impact on the viability of RES, but a significant impact on nuclear**, which sees the IRR fall from 8% to less than 3%, which would render it less market viable than in the reference NEL-Baseload scenario.

- **Reducing the P2G capacity by 50% reduces the viability of RES, as well as hydrogen plants**. RES plants are most strongly effected, with the calculated IRR falling below 5% in NL for both solar and wind. The reason for this is twofold: (i) reducing P2G capacity leads to lower electricity prices as there are more hours with RES oversupply and prices at zero, and (ii) with lower demand from P2G, RES curtailment increases.[43] This highlights that future large-scale RES deployment would need to go hand-in-hand with higher flexible demand to avoid market price collapse. If not, the significant RES deployment assumed in the scenarios would not take place based on market-driven behaviour if market revenues were too low to cover RES investment costs.

41 Except for the lower P2G capacity sensitivity, no additional simulations are run. Instead, we take the hourly results from the NEL-Wind scenario, adapt the hourly prices and market revenues (where necessary), and recalculate the economic viability indicators without changing the dispatch. This is a simplified approach as in reality the market dispatch would be different (i.e., DSR bands > 3000 €/MWh would not activate with a price cap of 3000 €/MWh), but sufficient for our purpose.

42 This is in line with the minimum requirements included in the regulation [50]. We assume that hydrogen, battery storage, and DSR are not impacted by a revenue cap.

43 RES curtailment is below 5 TWh/y in NL and 40 TWh/y in DE in all scenarios (mostly solar PV) but rises to 20 TWh/y and 80 TWh/y respectively in the NEL-Solar and lower P2G sensitivity.

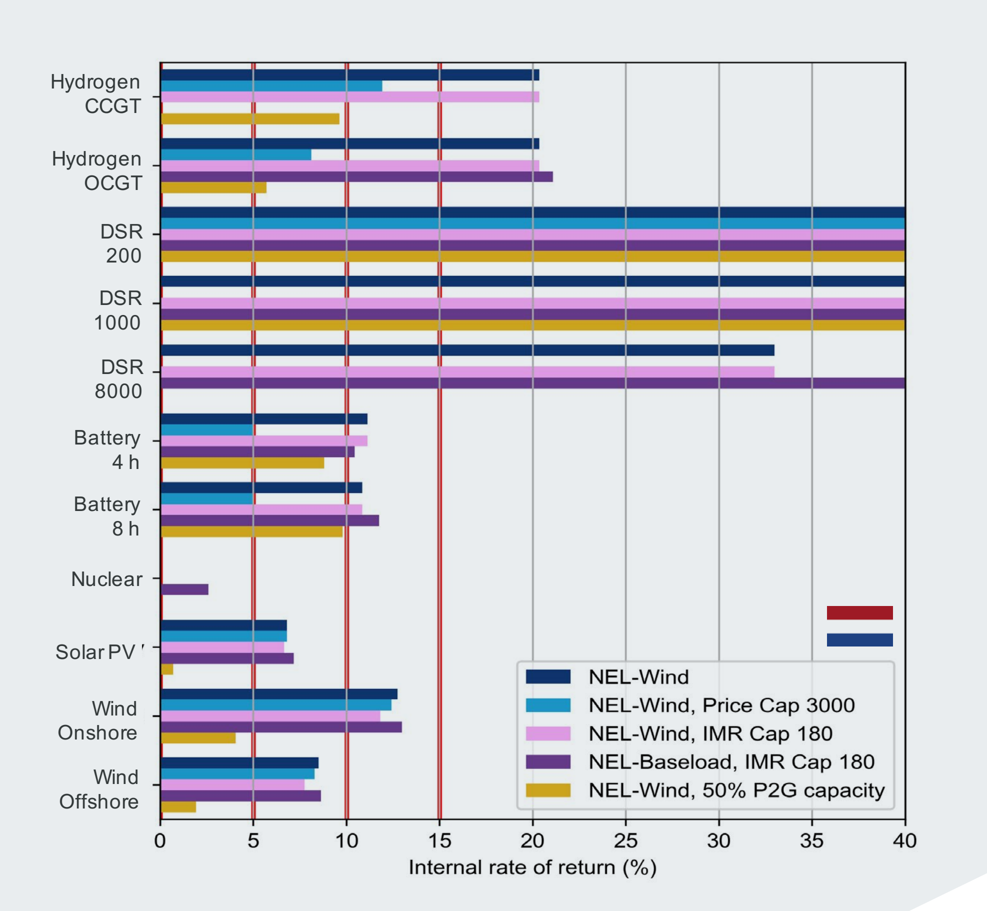


Figure 6.10 | Calculated IRR in the sensitivity runs for selected technologies in NL.

Turning to the last sensitivity (d), the impact of the assumed CAPEX varies per technology (Figure 6.11):

- **Hydrogen CCGT and OCGT viability is not strongly impacted by the CAPEX**, as the IRR for both technologies remains above 15% even if the CAPEX is increased by 100 €/kW (roughly 20%) from the reference level. This shows the CAPEX would have to be significantly higher than assumed to seriously affect viability and assuming the cost uncertainty of hydrogen turbines is similar to conventional gas turbines, this seems unlikely.

- **Battery storage viability is strongly affected by the assumed CAPEX**. Our reference cost assumption for 4-hour batteries assumes battery costs fall roughly 50% from today's costs.[44] The future cost of batteries is more uncertain than other technologies as technology improvements and scale-up offer greater opportunities for cost reduction, though increasing demand for scare materials (e.g. lithium) may increase costs in the long term. If battery costs do not fall significantly as assumed, their economic performance and viability decline.

- **At the capacities assumed, solar PV viability is contingent on further cost reductions if deployed at utility-scale**. The reference CAPEX for solar PV (400 €/kW) is lower than the current cost of utility-scale installations (~500 to 700 €/kW in NL, depending on size [51]). As smaller-scale residential rooftop PV system cost more than larger utility-scale systems, these may struggle to be viable without support.

- **Offshore wind viability is affected by CAPEX, but the risk to viability is low**. The reference offshore wind cost includes the cost of connecting the wind farm to the onshore grid (roughly 500 €/kW), however in NL and DE this cost is currently born by the state via the TSO. Reflecting this with a lower CAPEX of 1500 €/kW would indicate even stronger viability. Even if offshore wind costs remain at recent levels (roughly 2500 €/kW [52]) and do not decline further, offshore wind would still be viable in all scenarios apart from IHE-Wind.

44 Europe's largest battery (50 MW capacity, 100 MWh storage) was recently commissioned in Belgium at a cost of €30 million or 600 €/kW for a 2-hour battery [106], while our reference assumption is 600 €/kW for a 4-hour battery.

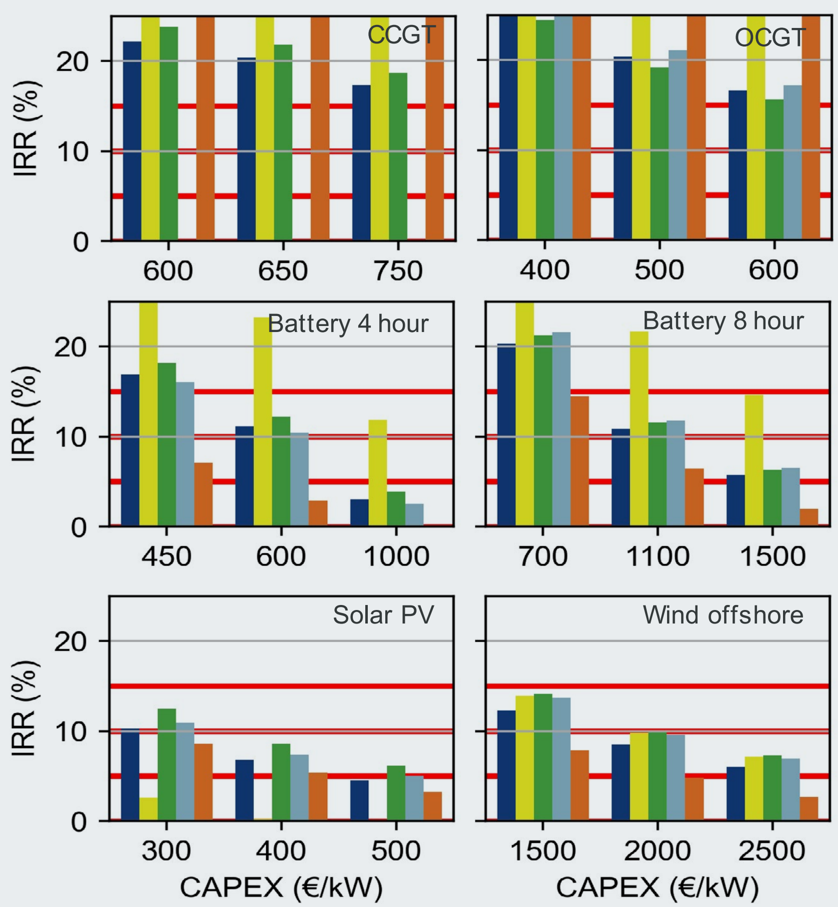


Figure 6.11 | Calculated IRR for selected technologies in NL with lower and higher CAPEX assumptions, on either side of the reference value

6.7 Evaluation and reflection

The analysis performed in this chapter identified several key drivers for the economic viability of different technologies in a net-zero emission power system, as summarised in Table 6.5. For hydrogen plants, DSR and storage technologies, the main factors determining economic viability are scarcity prices and price volatility, FLH, investment risk, and CAPEX. For RES, the main drivers are the effect of the capture rate (i.e. revenue cannibalisation), and CAPEX. Based on the model results and economic assumptions, the capacities assumed in the zero-carbon emission scenarios could be economically viable on the whole, with the exception of high cost DSR (>8000 €/MWh), nuclear, and solar PV in certain situations. Nevertheless, the results of the economic viability analysis should be viewed in the context of the assumptions and simplifications outlined in 6.1, and the following caveats:

- **The mix and installed capacity of technologies is not optimised, but based on the original scenario assumptions** and adaption of hydrogen to meet the reliability standard. As a result, the capacities of individual technologies may be higher or lower than what would be the cost efficient from a system perspective. In the long term, supply and demand dynamics in a free market will trend towards an equilibrium as low prices incentivise more demand for electricity, while high prices incentivise new capacity investments.[45]

- The analysis is based on a system **operating at the marginal level of reliability** at the reliability standard of 6 h/y. This means accepting there will be some years with ENS, leading to high scarcity prices in some hours. Operating the system artificially at a de facto higher reliability standard (i.e. without increasing the VOLL and price caps to reflect a lower LOLE target) would reduce the prevalence of these prices, and negatively affect the viability of those technologies for which scarcity revenues are a major driver.

- Our modelling assumes **all electricity is traded at the hourly spot price**, meaning both producers and consumers would be fully exposed to volatile prices. However, in practice generators (retailers) typically sell (buy) a significant portion or their generation (consumption) months or even years ahead on futures and forwards markets and hedge a significant

45 In an ideal market at long-term equilibrium (including investments and retirements), profit-making generators will incentivise competitors to enter the market which reduces profits, while lossmaking plants will leave the market, and ultimately the average revenue that generators receive from the market exactly covers their costs. [57]

fraction of their revenues (costs) ahead of time, depending on their asset portfolio and risk appetite. As a result, the volumes traded on day-ahead, intraday and balancing markets and their ability to capture (exposure to) volatile short-term prices would be lower than modelled in this study. Nevertheless, as we use the median IMR to determine the IRR and not the mean, our conclusions on economic viability do not assume scarcity prices are fully captured.

- At the same time, certain flexible 'at-the-money' power plants which have a marginal cost close to the spot price (e.g. CCGTs) could derive additional value from the price volatility in futures markets by selling electricity (and buying fuel) when spreads are positive, then buying electricity (and selling fuel) when spreads turn negative again. This additional ***extrinsic* value is not considered** in this study.

Key driver
Additional driver

	Scarcity revenues	Price Volatility	Baseload price	Capture rate (shaping)	FLH	Investment risk	CAPEX
Hydrogen CCGT	Additional driver	Key driver	Additional driver		Key driver	Additional driver	Additional driver
Hydrogen OCGT	Key driver	Additional driver	Additional driver		Additional driver	Key driver	
DSR	Key driver	Additional driver			Key driver	Key driver	
Battery 4 hour	Key driver	Key driver				Additional driver	Key driver
Battery 8 hour	Key driver	Key driver				Additional driver	Key driver
Nuclear			Additional driver		Additional driver	Key driver	Key driver
Solar PV			Additional driver	Key driver	Additional driver		Key driver
Onshore wind			Additional driver	Key driver	Additional driver		
Offshore wind			Additional driver	Key driver	Additional driver		Additional driver

Table 6.5 | Summary of key economic drivers for selected technologies. Note that all factors play some role for most technologies, even if they are not indicated as a key or additional driver.

7 System Operation

Key takeaways…

A net-zero emission energy system presents a paradigm shift and new challenges for operating the power system, but these can be overcome by investing in new technologies to strengthen the grid, changing the way we operate and manage the grid, and market design reforms.

The specific nature and scale of the system operation challenges will depend on the makeup of the technologies in the net-zero emission system. For example, a higher dependence on solar PV might require more flexibility to deal forecasting errors, but could reduce the impact of significant transmission flows from offshore and coastal regions in scenarios with significant deployment of offshore wind.

The biggest challenge for system operation is likely to be maintaining frequency and voltage stability, driven by a reduction in system inertia and short-circuit power compared with the current system. However, mitigating measures exist and could partially be provided by renewable generation. Investments in grid-strengthening technologies such as synchronous condensers would likely be needed in all foreseen scenarios to provide inertia and short-circuit power.

Many system operation challenges have a locational component, and can be exacerbated or relieved depending on where future investments take place. Locational aspects should therefore play a role in investment decisions and should potentially be steered by a combination of market mechanisms (e.g. price incentives), grid tariffs, and regulations.

System services currently provided by fossil-fuel power plants can be provided by other technologies in a future net-zero emission energy system. In particular, upward balancing reserves could be provided by power to gas, DSR, zero-carbon thermal capacity, while downward reserves could be provided by RES and zero-carbon thermal plants.

7.1 Introduction

Aside from system adequacy, system stability and security are two other key aspects of system reliability which TSOs manage in the both the long- and short-term by investing in technologies to strengthen the grid, and procuring various ancillary services such as balancing reserves, reactive power support, redispatch, and black start facilities. While market simulations can show if supply and demand can be matched on an hourly basis, they shed no light on the operational stability of the power system, and other practical considerations of operating the power grid. As grid operator, ensuring the power system can be operated stably is of vital importance to TenneT, especially as we move towards a net-zero emission electricity system in which solar and wind provide the majority of the energy supplied to the grid.
While a detailed analysis of grid security and stability in a net-zero emission energy system is out of scope of this study, by combining the scenarios, the results of the market simulations and expert assessment, we can gain some high-level insights on future system operability. With the analysis in this chapter, we aim to identify:

- What are likely to be the most significant challenges for transmission system operation going towards a net-zero emission energy system?
- To what extent are these challenges affected by the net-zero emission scenarios considered for NL and DE?
- What mitigating measures can be taken to reduce these challenges?, and
- Which technologies can provide the essential ancillary services to enable stable operation of the power grid?

7.2 Methodology

The basis for the system operability evaluation in this chapter is a paper by Sewdien et al. *System Operational Challenges from the Energy Transition* [53]. This paper, to which TenneT was a contributor, identifies 27 system operational challenges resulting from the transition to a net-zero emission energy system. Based on this paper, the following steps were followed to analyse the implications for operating a future net-zero emission power system (Figure 7.1):

- First, the number of challenges in the original paper was reduced to a shorter list of (11) key challenges based on expert discussions by excluding those that were not expected to pose a significant challenge, or that were not considered to be affected differently based on the net-zero emission scenarios considered in this study;

- Secondly, a largely qualitative assessment was made as to how each challenge might be affected in each net-zero emission scenario. Additionally, the challenges were scored based on their potential impact to system operational stability;

- Third, a list of measures were identified that could help mitigate one or more of the assessed challenges in the future; and

- Lastly, an assessment made on which low-carbon technologies could be used to provide ancillary services in a net-zero emission power system when the (largely) fossil based plants which currently provide these services are no longer available.

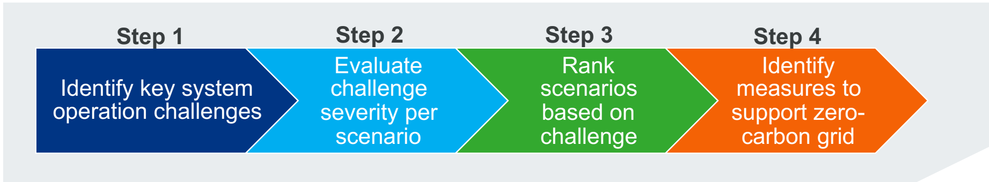


Figure 7.1 | Approach taken in the system operability analysis

7.3 Operational challenges going towards a zero-carbon grid

Following discussions with experts, a list of eleven system operation challenges were identified for further analysis. In this section, a brief description of each challenge is provided, as well as an explanation of the key driving factor(s) behind each challenge, and how these are affected in different net-zero emission scenarios.[46]

7.3.1 Reduction of transient stability margins

Transient stability is the ability of the power system to maintain synchronism when subjected to a severe disturbance such as a power plant outage, or a short-circuit event triggered by a lightning strike or equipment failure. The increasing contribution of non-synchronous power electronic interfaced devices (PEIDs) such as solar PV farms, offshore wind farms and batteries in the grid influences the stability with different compounding factors. Critical situations affecting transient stability margins include large phase angle differences in the system due to high transmission flows. In DE this can be the result of large offshore wind power generation in the north combined with large power consumption in the south. Generally, phase angle differences are less of a problem in NL due to the smaller size of the power grid.

7.3.2 Increasing RoCoF

The Rate of Change of Frequency (RoCoF) is a metric of frequency stability (Figure 7.2). It measures to what extent (i.e. the gradient) the system frequency initially responds to an imbalance between generation and demand, usually due to a disturbance such as an unplanned power plant outage. The RoCoF is mainly driven by the system inertia, i.e. the amount of rotating masses in the system, and the size of an imbalance. As the inertia of the system is expected to fall over time as synchronous generation is replaced by non-synchronous renewable generation, the RoCoF following a disturbance in the system will increase, affecting frequency stability. Higher RoCoF can cause more frequent triggering of anti-islanding protection, misfunctioning of low frequency demand disconnection protection, and can trigger a generator trip to prevent mechanical damage. These may lead to cascading

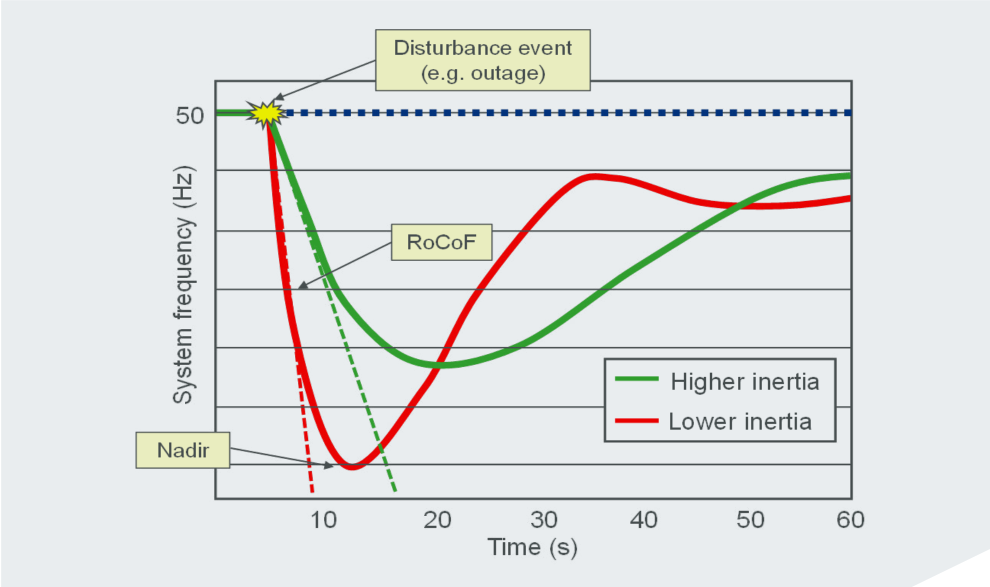


Figure 7.2 | Typical response of system frequency to a disturbance event in a power system with higher (green) and lower (red) inertia.

events and ultimately a blackout if emergency measures are not taken. Inertia in the current system is mostly provided by synchronous generators such as thermal power plants. Critical situations for RoCoF are therefore periods with **low synchronous generation** as a result of high solar and wind generation. A worst case situation could be a disturbance event that leads to a system split, combined with low inertia and high transmission flows. The system split would interrupt the power flow and immediately cause a very large imbalance in the disconnected grids, resulting in a very high RoCoF.

46 The remaining 16 system operational challenges described in [53] are not considered as they are not as strongly affected by the different scenarios, or because they are strongly related to another challenge already included. This does not imply they pose no challenge to system operational stability. In particular, being able to restart the power system from a complete system outage (i.e. system restoration, or black-start capability), resonances due to cables and power electronics, resonance (harmonic) instability, and decreased damping of existing power oscillations are seen as significant challenges which will need to be managed in any RES-driven power system.

7.3.3 Decreasing frequency nadir

Another metric of frequency stability is the nadir. The frequency nadir indicates the lowest value the system frequency reaches following a disturbance such as an outage of a large generator, before it is stabilised by frequency control mechanisms (e.g. FCR, FRR). Like the RoCoF, the nadir is affected by a reduction in the system inertia. During periods of high participation of RES, and therefore low inertia, the system is more vulnerable to low frequency nadir. Low nadirs can cause triggering of under-frequency load shedding responses. The frequency nadir is mainly affected by the system inertia, the magnitude of an imbalance after a disturbance, and the available amount of frequency containment reserves. As with the RoCoF, critical situations include moments with low inertia, i.e. **low synchronous generation**, especially when a system split would occur.

7.3.4 Excessive frequency deviations

The system frequency is constantly varying around the target frequency of 50 Hz, reflecting imbalances between electricity generation and demand. However, unlike the RoCoF and nadir this is not specifically related to disturbances, but rather the result of imperfect forecasting of generation and consumption. As the electricity generation based on variable RES is less predictable than conventional generation, frequency deviations are expected to become larger and more frequent. Frequency deviations cause more wear on conventional synchronous generators, and in the long run can endanger the system's ability to remain stable. The key driving factor for this challenge is thus the **forecasting errors** of renewable generation.

7.3.5 Estimation of operating reserves

Operating reserves are procured by TSOs in order to be able to balance electricity generation and demand in the system and keep the system frequency on target. Reserve sizing is determined amongst others by the potential forecasting errors in electricity demand, as well as electricity generation from RES. As the penetration of RES increases, so will the associated forecasting errors. Given that the procurement of operating reserves represents a cost for TSOs, these reserves should be kept as low as possible, potentially requiring closer to real-time dimensioning. This complicates operational procedures. Driving factors for this challenge thus also include RES **forecasting errors**.

7.3.6 Ramps management

Given that generation and demand in the power system must always be in balance, generation must typically ramp up and down in response to changes in load. Historically, ramping needs were mostly determined by thermal generators ramping up and down to follow the daily pattern of demand. With the increasing penetration of RES, ramp management is becoming more challenging due to the fluctuating generation of solar and wind, and more volatile residual demand profile. Thus, drivers for ramp management in the future include the installed capacity of solar and wind, and the resulting **high ramp rates** expected in a net-zero emission system.

7.3.7 Voltage dip induced frequency dip

This challenge refers to the active power recovery of wind turbines following a short-circuit event. Synchronous generators used in conventional power plants restore practically instantly active power generation upon fault clearance. On the contrary, wind turbines may recover active power slower in order to relieve mechanical stress on the drive train. Hence, with high penetration of wind generation the loss of energy may introduce frequency stability problems. Critical situations for this challenge include moments with **high wind generation** as well as moments with **low short-circuit power**, as this would lead to larger and wider spread voltage dips.

7.3.8 Static reactive power balance

Reactive power is required in a power system to control the voltage at target levels, and the reactive power balance in the future power system will be affected by many developments. Some developments are expected to increase the reactive power in the system, such as the deployment of more underground cables instead of overhead power lines, and operating power lines below their surge impedance loading as a result of lower transmission flows due to solar generation being located near consumption. On the other hand, certain situations may lead to shortfall in reactive power. One example is when a grid with high penetration of RES is operated at fixed leading power factor, and the grid operator may be faced with a reactive power shortage if there is a lack of synchronous generation capacity which can supply (and sink) reactive power more easily. One of the driving factors for this challenge is a **high range in the power flows through the transmission grid**. The reactive power balance must be ensured both in moments with high loading of transmission lines as well as low loading of transmission lines.

7.3.9 Dynamic reactive power balance

During a short-circuit event, the voltage close to the short circuit will drop to zero. In the current system, synchronous generators near the fault will immediately inject large short-circuit currents and reactive power, which stabilise the voltage and prevents the low voltage from propagating too far through the power grid. However, RES as solar and wind can only provide limited amounts of short-circuit power, generally no more than 1.25 times the rated current as opposed to synchronous generators that might supply 5 to 7 times their rated current. Therefore, during periods of high solar and wind generation in a future RES driven power system, the risk is higher that a short-circuit event could lead to large voltage dips which propagate further through the power system, triggering cascading failures due to too undervoltage. Critical situations for this challenge thus include moments with **low short-circuit power** in the system, which are expected to coincide with periods of high solar and wind generation.

7.3.10 Operation of protection relays

Protection relays are used to detect short circuits in the power grid and control protection equipment. Certain protection relays require sufficient fault currents (short-circuit power) for their correct operation. As RES can only provide limited amounts of short-circuit power, protection relays might not correctly operate during periods of high solar and wind generation. As with dynamic reactive power balance, critical situations for this challenge are also moments with **low short-circuit power** in the system.

7.3.11 Increased congestion / Decrease of redispatch possibilities

Congestion occurs in the grid when the expected power flow through a line exceeds the allowed available capacity. When significant RES capacity is installed far from where the electricity is consumed (e.g. offshore wind farms), this can result in large power flows through the transmission grid and increase the likelihood of congestion. To relieve congestions, TSOs typically instruct power plants on one side of the congestion to reduce generation, and plants on the opposite side to increase generation in a process known as *redispatch*. In an increasingly RES-dominated power system however, less dispatchable capacity may be present in the system and available for the TSO for redispatch. Critical situations for this challenge includes moments with **high transmission flows**, driven by periods of high RES infeed.

7.4 Evaluation of operational challenges across net-zero scenarios

Table 7.1 presents an overview of the driving factors identified for the challenges described in the previous section, and an indication as to whether each factor is expected to be more or less prominent than in the NEL-Wind scenario. Note that this qualitative assessment is based not on detailed grid calculations, but on the underlying scenario assumptions, and additional assumptions about how the installed capacity in each scenario is distributed throughout the grid. Thus, the assessment in Table 7.1 only provides a high-level relative indication of the expected system operation challenge between scenarios. The assumptions and rationale behind the impacts on each driving factor are briefly discussed in the following subsections.

Driving factor	NEL-Wind	NEL-Solar	NEL-Demand	NEL-Baseload	IHE-Wind
High transmission flows	n/a	▼	▲	▼	▼
High transmission flow range	n/a	▲	0	▼	▼
High forecasting error	n/a	▲	0	▼	▼
High ramp rates	n/a	0	0	▼	▼
High wind generation	n/a	▼	0	▼	▼
Low synchronous generation (inertia)	n/a	0	0	▼	▼
Low short circuit power	n/a	0	0	▼	0

Table 7.1 | Overview of how the identified driving factors for system operation are expected to compare with the NEL-Wind scenario. A ▲ symbol indicates that a specific driving factor is expected to be more prominent compared with the NEL-Wind scenario, while a ▼ symbol indicates less prominent. A '0' indicates the same.

7.4.1 High transmission flows

For the NEL-Solar scenario, it is assumed that the replacement of especially offshore wind generation with solar generation will reduce the strain on the transmission grid compared to the NEL-Wind scenario, as solar generation will be more geographically spread out and located closer to electricity demand.

In the NEL-Demand scenario, the additional demand has to be met with additional generation. Assuming this additional demand would not be located (exclusively) near the additional generation capacity but throughout the grid, transmission grid flows are expected to increase.

The additional nuclear capacity in the NEL-Baseload scenario replaces some offshore wind capacity in the NEL-Wind scenario. Assuming this baseload capacity is installed at strategic locations in the grid (e.g. in the vicinity of load centres), the NEL-Baseload scenario should lead to lower transmission flows than in the NEL-Wind scenario. Note however that if the additional baseload capacity is installed at suboptimal locations, or concentrated in a single location in the grid, transmission flows may even be more challenging than in the NEL-Wind scenario.

For the IHE-Wind scenario, as the installed RES capacity in this scenario is overall lower than in the NEL-Wind scenario, lower transmission flows are expected. Moreover, lower electricity demand is assumed in DE which should also lead to lower transmission flows.

7.4.2 High transmission flow range

The range of transmission flows – difference between the lowest transmission flows and the highest transmission flows – is expected to be higher in the NEL-Solar scenario than in the NEL-Wind scenario due to the lower capacity factor of solar generation compared to wind, and in particular stronger fluctuations between night and day-time flows.

In the NEL-Demand scenario, the range of transmission flows is expected to be largely the same as in the NEL-Wind scenario, as the additional demand is expected to be constant (baseload).

The range of transmission flows is assumed to go down in the NEL-Baseload and IHE-Wind scenarios, as these scenarios contain additional either additional baseload or hydrogen generation, and lower fluctuating RES generation.

7.4.3 High forecasting errors

In the NEL-Solar scenario, part of the onshore and offshore wind capacity is replaced by solar PV generation. Due to the lower capacity factor for solar PV (~10%) compared to wind (~40%), 1 GW of wind capacity requires roughly 4 GW of solar capacity to generate the same amount of electricity throughout the year. While it cannot be said that forecasting errors are generally higher for solar PV than for wind generation, due to the additional solar capacity required, even a similar relative forecast error is likely to lead to larger absolute power imbalances. Thus, this factor is considered more challenging in the NEL-Solar scenario than in NEL-Wind.

For the NEL-Demand scenario, the same amounts of installed wind and solar capacity is assumed as compared to the NEL-Wind scenario. Therefore, the forecasting errors are expected to be similar. The contribution of the additional baseload demand on the overall forecasting error is assumed to be negligible.

Forecasting errors are assumed be lower in the NEL-Baseload and IHE-Wind scenarios as installed RES capacity is lower, and thermal capacity is higher than in NEL-Wind.

7.4.4 High ramp rates

It is unclear what the effect of the additional solar capacity in the NEL-Solar scenario would be on the ramps management in the system. While ramps related to wind generation might generally be steeper, the additional capacity required for solar generation – due to lower capacity factors – could be higher. On the other hand, ramps caused by solar PV might be more predictable (occurring always in the morning and afternoon) and thus easier to manage than ramps caused by wind. Given this uncertainty, the NEL-Solar is evaluated the same as NEL-Wind in this case.

For the NEL-Demand scenario, the installed wind and solar capacity is the same as in the NEL-Wind scenario, and thus a similar level of ramping is expected.

Ramp rates are assumed to go down in the NEL-Baseload and IHE-Wind scenarios as installed RES capacity is lower, and thermal capacity is higher than in NEL-Wind.

7.4.5 High wind generation

High wind generation was described as a driving factor for the *Voltage dip induced frequency dip* challenge. Wind generation capacity is lower in NEL-Solar, NEL-Baseload and IHE-Wind scenarios.

7.4.6 Low synchronous generation (inertia)

The system inertia is generally understood to be a system (synchronous area) wide phenomenon. As the Dutch and German power grids are interconnected with the entire synchronous grid of Continental Europe, the system inertia is to a large extent determined outside the Dutch and German borders, and does not have to be provided locally. However, critical situations may occur – such as a system split – in which local inertia will indeed be an important factor for system stability.

As described in section 3.1, all NEL scenarios assume the same installed generation capacity in the rest of Europe. Only the IHE-Wind scenario reflects a different scenario outside NL and DE. Global inertia is therefore only different in the IHE-Wind scenario, where more synchronous generation leads to higher global inertia levels in the system.

Locally, inertia is higher in the NEL-Baseload scenario, although this only affects the Dutch power grid. On the other hand, DE has a higher baseline of synchronous generation across all scenarios, where NL has many periods of no synchronous generation in all but the NEL-Baseload scenario. Thus, overall higher inertia is expected in the NEL-Baseload and IHE-Wind scenarios.

7.4.7 Low short-circuit power

Short-circuit power contributions are expected to be the same for solar and wind generation, as both systems would be connected through power electronic converters. Only in the NEL-Baseload scenario is significantly more synchronous generation assumed, implying a higher short-circuit power contribution.

7.4.8 Overall evaluation

Table 7.2 shows an overview of the effects of the different scenarios on the various challenges compared, based on the underlying driving factors described in this section. Additionally, the table shows an impact severity score given to each challenge based on expert discussions. Three red dots (•••) indicate the challenge is expected to have a relatively high impact, while one yellow dot (•) indicates a relatively low impact to system operational stability. As with Table 7.1 the challenges for each scenario are evaluated relative to NEL-Wind, which is why this scenario is not evaluated. However, this does not mean this scenario itself is not challenging, and significant operational challenges will need to be overcome for system stability to be ensured in this scenario.

Overall, Table 7.2 shows that the NEL-Baseload (for NL) and the IHE-Wind scenarios are expected to be less challenging from an operational perspective than the NEL-Wind scenario. This result is largely driven by the lower installed capacity of RES, and higher synchronous generation capacity in these scenarios. The NEL-Solar scenario is in certain ways less challenging, while in other aspects more challenging than the NEL-Wind scenario. Thus, it is difficult to draw a strong conclusion on this scenario without more detailed analysis, beyond the scope of this study.

Challenge	Challenge Severity	Driving factors / critical situations	Scenarios					Comment
			NEL-Wind	NEL-Solar	NEL-Demand	NEL-Baseload	IHE-Wind	
1 Reduction of transient stability margins	•••	High transmission flows	n/a	▼	▲	▼	▼	The impact of the reduction of transient stability margins is expected to be more problematic in DE compared to NL. Problems are expected to occur with large phase angle differences that are the result of large power flows through the transmission grid. In DE, these are mostly related to north-south flows, where (offshore) wind energy has to be transported to the south. These problems are less prominent in the smaller transmission grid of NL.
2 Increasing RoCoF	•••	Low synchronous generation (inertia)	n/a	0	0	▼	▼	
3 Decreasing frequency nadir	•••	Low synchronous generation (inertia)	n/a	0	0	▼	▼	
4 Excessive frequency deviations	•	High forecasting errors	n/a	▲	0	▼	▼	
5 Estimation of operating reserves	••	High forecasting errors	n/a	▲	0	▼	▼	
6 Ramps management	•	High ramping	n/a	0	0	▼	▼	Where ramps are currently mostly managed with conventional generators, in the future they will increasingly have to be supported by battery storage and demand side response from for example electrolysers.
7 Voltage dip induced frequency dip	•	High wind generation, low short-circuit power	n/a	▼	0	▼	▼	This issue is mainly found with doubly-fed induction generator (DFIG) wind turbines. As the penetration of DFIG wind turbines is expected to be limited in the future this challenge was given a low severity score.
8 Static reactive power balance	••	High transmission flow range	n/a	▲	0	▼	▼	
9 Dynamic reactive power balance	•••	Low short-circuit power	n/a	0	0	▼	0	
10 Operation of protection relays	••	Low short-circuit power	n/a	0	0	▼	0	
11 Increased congestion / Decrease of redispatch possibilities	•••	High transmission flows	n/a	▼	▲	▼	▼	Scoring of this challenge was mostly based on the increased congestion. The effect that renewable generation replaces conventional generation that is traditionally used for redispatch was not considered.

Table 7.2 | Evaluation of the system operation challenges for each scenario in comparison to NEL-Wind. The ▲ symbol indicates that the scenario is expected to be more challenging than NEL-Wind , while the ▼ symbol indicates less challenging. A '0' indicates the same. The perceived severity score of each challenge is also indicated as having either a relatively low (•), medium (••), or high (•••) impact.

7.5 Measures to support a zero-carbon grid

The previous section showed that there will be significant challenges operating a net-zero emission power system, and that the nature of these challenges is likely to vary depending on how demand and supply evolve in the future system, and where new generation capacity and load will be located in the grid. However, in the future these challenges can be addressed with a combination of measures ranging from (i) grid infrastructure investments, (ii) changing regulations and the way we operate and manage the grid, and (iii) wider market design reforms (Table 7.3). Some examples of these measures are briefly explained in the following sections.

		System operation challenge										
Category	Measure	1	2	3	4	5	6	7	8	9	10	11
Infrastructure investments	Upgrading transmission capacity											✓
	Installing phase-shifting transformers											✓
	Installing synchronous condensers	✓	✓	✓	✓			✓	✓	✓	✓	
	Installing (adjustable) reactive power compensators (e.g. STATCOMs, SVCs, Capacitor banks)		(✓)	(✓)					✓	(✓)		
	Adopting more complex protection schemes										✓	
Grid management and regulations	Reforming balancing reserve products, allowing full market integration of RES				✓		✓					
	Improving reserve dimensioning and sharing procedures				✓		✓					
	Reduce imbalance settlement periods				✓	✓	✓					
	Adopting grid supporting control schemes in power electronics interfaced devices (e.g. grid forming control)	✓	✓	✓	✓			✓	✓			
	Improve transmission capacity utilization											✓
Regulatory and market design	Strengthening of imbalance markets and pricing				✓	✓	✓					
	Locational signals in grid connections and tariffs											✓
	Stronger locational pricing											✓

Table 7.3 | Overview of measures which could support a zero-carbon grid, and which main system operation challenges they can address

7.5.1 Infrastructure investments

Several operational challenges can be addressed by the TSO by investing in various kinds of grid infrastructure and new technologies which can help to strengthen the grid. Some examples of these investments are:

- Upgrading transmission capacity
- Installing phase-shifting transformers
- Installing synchronous condensers
- Installing (adjustable) reactive power compensators
- Adopting more complex protection schemes

Upgrading transmission capacity is the standard approach to alleviate congestion in the power grid in the long term. This can be done by upgrading the capacity of existing power lines, or by building new power lines or cables. Nevertheless, building new power lines is not always the best solution as new investments come at significant cost, can take several years to plan and construct, and face local opposition in built-up areas.

Phase-shifting transformers are specialised transformers that can be used to control the flow of active power through the transmission grid, redirect flows, and help alleviate congestion.

Synchronous condensers are synchronous machines that are not connected to a generator, but that are driven by energy from the grid. By controlling the field excitation in the rotor, synchronous condensers can either absorb or inject reactive power. The rotating mass of the synchronous condenser can, if attaching a flywheel, also contribute to the system inertia. Moreover, synchronous condensers can also provide short-circuit power.

Other reactive power compensators exist aside from synchronous condensers, that can help control the reactive power balance in the grid. These devices can be fixed, like shunt reactors or capacitors, or adjustable, like a switchable capacitor bank, static VAR compensator (SVC), or static synchronous compensator (STATCOM). By controlling the reactive power they absorb or inject, they can help control the voltage in the power grid. With the exception of the STATCOM, these devices do not operate fast enough for dynamic reactive power support. If equipped with energy storage and grid forming control, a STATCOM would also be able to support frequency stability with synthetic inertia.

Adopting more complex protection schemes can mitigate challenges related to the operation of protection relays under reduced short-circuit power conditions. Short-circuit power mainly affects the operation of overcurrent or distance protection schemes that rely on the measurement of high fault currents. Line differential protection does not rely on high fault currents, but rather on the difference between the current measured at either side of a transmission line. This requires data communication between the two substations connected by the transmission line and is therefore more complex than the aforementioned protection schemes.

7.5.2 Grid management and regulations

Grid investments come at a cost which is ultimately passed down to consumers in grid fees. Certain investments also come with significant lead time. Thus, relying only on grid investments alone is unlikely to be the most cost-effective or timely way of ensuring a stable net-zero emission system solution in the long run. However, changing the way we operate and manage the grid can also make it easier to integrate RES, and potentially reduce the need for grid investments. Some examples are:

- Reforming balancing reserve products, allowing full market integration of RES
- Improving reserve dimensioning and sharing procedures
- Reduce imbalance settlement periods
- Adopting grid supporting control schemes in PEIDs (grid forming control)
- Improve transmission capacity utilisation

Reforming existing balancing reserve products will go a large way to allowing full market integration of RES and storage. Some reserve products are currently difficult for zero-carbon and DSR resources to provide due to stringent technical requirements. For example, FRR capacity products in NL have a contract duration of 24 hours. While these are portfolio products, meaning that they are not contracted based on a single technology, they can be difficult to provide with portfolios consisting largely of solar generation not available at night, or batteries with limited storage capacity. Alleviating market entry barriers by lowering the requirements for these services could encourage more reserve capacity to become available at lower cost.

Improve reserve dimensioning and sharing procedures. Increasing sharing of reserves between different load frequency control areas and between TSOs would make reserve provision more secure, while ensuring costs for reserve procurement are as low as possible. Additionally, improved reserves dimensioning e.g. closer to delivery would allow for the inclusion of RES generation forecasts in the dimensioning process, thereby avoiding over-dimensioning in times of low RES generation and corresponding forecasting errors.

Reducing imbalance settlement periods and thereby the market time unit allows for more accurate portfolio balancing of Balance Responsible Parties, and thereby to a reduction of imbalances encountered in operation. The increased market granularity might also have a positive effect on ramps management.

Adopting grid-supporting control schemes in PEIDs can provide important contributions to the stability of a zero carbon emission power system. Current PEIDs generally use a so-called grid-following control mechanism, through which active and reactive power output can be controlled. Such a control mechanism relies however on a stable grid voltage and sufficient system strength for correct operation, and can therefore show poor dynamic performance and possibly even exacerbate stability issues during a system disturbance (e.g. a voltage dip-induced frequency dip). Alternative grid-forming control mechanisms can support the system stability during a disturbance by having an inherent response that is independent of the grid voltage. Additionally, if combined with some (battery) storage capacity, PEIDs equipped with grid-forming control can provide frequency support through synthetic inertia or fast frequency response. However, providing the ability for grid-forming control typically requires additional investments. For grid-forming control from HVDC systems, these investments would likely be made by the TSO. To enable grid-forming control from solar and wind generation, these investments will need to be made by market parties. To incentivise these investments, new ancillary service products might have to be developed e.g., for (synthetic) inertia. Creating new markets for these products can be an efficient and transparent way for the TSO to communicate the need for these services through price signals, ensure that they are correctly valued, and compensate market parties for their investments. Where markets for ancillary services are not suitable, or do not provide sufficient incentives for grid-supporting investments by market parties, regulation could be used e.g. to mandate grid-forming control mechanisms on PEIDs.

Improve transmission capacity utilisation. In addition to investing in more transmission capacity, existing transmission capacity can also be utilised more fully by operating closer to security limits, and reducing operational security margins where possible. For example, rather than determining maximum line ratings based on thermal limits with a conservative safety margin, *dynamic line ratings* can be applied where the allowed current flow through a line depends on the real-time temperature and wind speed. While these measures can help to alleviate congestions they can also complicate operational procedures and lead to other challenges, and may only be justified in certain situations.

7.5.3 Market design

The rules by which Europe's electricity markets operate govern not only commercial and economic flows, but can have a significant impact on the physical flows of electricity through the grid. These impacts can have both positive and negative implications for operating a stable grid and given the challenges posed by moving toward a net-zero emission power system, all options should be considered if these can help ensure stable operation of the grid, taking into account any potential trade-offs. Moreover, several of the infrastructure and grid operation measures presented in the previous sections imply additional investments or higher operational costs for TenneT. These are ultimately passed down to consumers in grid fees, and should therefore be kept as low as possible. Thus, any synergies where wider regulatory and market design reforms can also address operational challenges present a significant opportunity. In discussion with experts, several aspects of the regulatory environment and electricity market design are identified as having a significant impact on system operation, which could be considered for reform in the long term. These measures are discussed further in Chapter 8.

7.6 Provision of ancillary services

Ancillary services are services provided to the TSO to keep the system stable, within security limits or to help restore the system in case of a blackout. They are currently procured mostly from conventional fossil fuel generation plants. While the net-zero emission scenarios still contain a significant amount of thermal generation in the form of hydrogen and other low-carbon thermal capacities, many ancillary services require these plants to be dispatched in order to provide them. However, as was seen in section 6.4.3, these thermal plants will generally have few full-load hours per year and thus not necessarily available to provide ancillary services. Luckily, many other technologies are already, or will be technically capable of providing these ancillary services as well in future (Table 7.4).Exactly which technologies will ultimately provide these services will depend on the ultimate capabilities, installed capacities, and costs involved.

In terms of balancing reserves, Frequency Containment Reserves (FCR) are already today provided by battery systems, and will likely be so in the future. Downward Frequency Restoration Reserves (FRR) could also be provided from storage systems as well as RES curtailment. For upward FRR, storage and demand reduction from P2G could play a role, as could RES under the right circumstances. Also, HPs and EVs could potentially provide balancing services when represented by an aggregator, such as is piloted in the TenneT-backed project Equigy.[47]

Black start facilitation could be provided in the future by solar or wind generation, if equipped with grid-forming control. Low-carbon thermal plants would also be well positioned to provide this service, in much the same was as fossil plants do now. Practically any PEID, such as solar, wind, or batteries, can control their reactive power output and potentially provide voltage support. Redispatch services could be provided by almost any technology, as long as the exact location of the connection is known to the grid operator.

	Balancing Reserves					Black start facilitation	Reactive power (voltage support)	Redispatch	
	FCR	aFRR		mFRR				Upward	Downward
Technology	Symmetric	Upward	Downward	Upward	Downward				
Solar	Yes [a]	Unlikely [a]	Yes	Unlikely [a]	Yes	Potentially [c]	Yes	Unlikely [a]	Yes
Wind	Yes [a]	Unlikely [a]	Yes	Unlikely [a]	Yes	Potentially [c]	Yes	Unlikely [a]	Yes
Batteries	Yes	Yes [g]	Yes [g]	Yes [g]	Yes [g]	Potentially [c]	Yes	Yes [g]	Yes [g]
Hydro	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
P2X	Yes	Yes [e]	Yes [af]	Yes [e]	Yes [af]	No	Potentially	Yes [e]	Yes [af]
HPs	Potentially [d]	Potentially [d]	Potentially [d]	Potentially [d]	Potentially [d]	No	No	Potentially [d]	Potentially [d]
EVs	Potentially [d]	Potentially [d]	Potentially [d]	Potentially [d]	Potentially [d]	No	No	Potentially [d]	Potentially [d]
Other industrial DSR	No	Yes [e]	No	Yes [e]	No	No	No	Yes [e]	No
Hydrogen CCGT	Yes [b]	Yes [b]	Yes [b]	Yes [b]	Yes	Yes	Yes	Yes	Yes
Hydrogen OCGT	Yes [b]	Yes [b]	Yes [b]	Yes	Yes	Yes	Yes	Yes	Yes
Other zero-carbon thermal	Yes [b]	Yes [b]	Yes [b]	Yes [b]	Yes	Yes	Yes	Yes	Yes

(a) If operated below nameplate capacity, implying an opportunity cost, or if combined with storage; (b) If online (spinning); (c) With grid-forming control; (d) through aggregators; (e) by reducing consumption; (f) By increasing consumption; (g) limited by storage capacity or availability

Table 7.4 | Overview of which system services could technically be provided by different low-carbon technologies

47 https://equigy.com/

8 Market Design

Key takeaways...

A key requirement of liberalised electricity markets is that they provide sufficient market-based incentives for investment in capacity resources to meet demand with an acceptable level of reliability. In a zero-carbon energy system where RES supply the bulk of electricity demand, firm dispatchable resources will play a vital role in meeting electricity demand when supply from RES is scarce. From a market design perspective, the question that needs to be addressed is **how to finance firm capacity which will be used relatively rarely**. This question has become increasingly relevant as revenues from wholesale markets have become more volatile and less certain, making long-term investment decisions riskier.

For this reason, **reducing investment risk is an important enabler for new investments**. One of the major risks for new investments is changes in government policies and regulatory environment. Changing market conditions create uncertainties for investors planning to make long-term investment decisions, and undermine the long-term price signals created by the market. Thus, **a stable policy environment and market design are key ingredients for reducing investment risk**.

In the long-term, investments in zero-carbon technologies (RES, storage, DSR) should primarily be driven by **free-market price signals capturing all externalities** (fuel prices, carbon prices). To maximise the flexibility of demand, electricity markets will need to be designed to unlock the existing potential of DSR, ensure new sources of electricity demand (e.g. P2G) are as flexible as possible, and allow consumers to react to market price signals.

Improving access to market-based risk hedging such as power purchase agreements (PPAs), **and increasing liquidity of long-term futures markets** should be the first priority for reducing investment risk and financing costs for RES and zero-carbon thermal capacity respectively, and providing consumers with more price stability.

Encouraging consumers to better respond to price signals can help ensure resource adequacy in a cost-efficient way. A market design which **empowers consumers to decide their own electricity reliability level and how much they are willing to pay for it** would not only give consumers more control over their electricity bills, but also provide national governments with a more robust way of monitoring the VOLL.

Over the longer term, the market should be designed in such a way that it ensures that required investments in new resources are made in due time. **In theory, an energy-only electricity market should incentivise the required investments in new resources. However, in practice there is a risk that security of supply is not ensured without additional measures**. An unwillingness to accept periods of high market prices, (risk of) market inventions, and societal urgency to quickly decarbonise could make the transition to net-zero too volatile and uncertain for suppliers, consumers and governments, making further intervention likely and consequently increasing risks for investors. If investments in firm and dispatchable capacities cannot be achieved in the pace and volume required via an energy-only market, additional capacity remuneration mechanisms are likely to be needed in order to achieve these investments.

Moreover, an efficient system development requires an effective spatial coordination of those market-driven activities with infrastructure investments and operation. **In a future system market participants should account at least for costs of structural congestions in their (investment) decision making**. In the context of the current market design we see especially a value in (i) adequate bidding zones to better reflect structural congestion as well as (ii) locational incentives for supported technologies.

Finally, a future-proof market design ensures an **integration of markets across national borders, across time frames, as well as across energy carriers**.

8.1 Introduction

Electricity market design has a key role to play in ensuring resource adequacy. Electricity markets should facilitate an efficient dispatch of supply- and demand-side resources in the short-term, as well as provide adequate incentives for investment in new capacity in the long-term. a net-zero emissions energy system brings many new challenges, and from a market design perspective markets should be designed such that they have the best chance of addressing these challenges in the long term, while enabling a liquid and competitive market environment and avoiding market distortions.

Given the energy transition will affect so many aspects of how electricity markets and power systems function, it is important to take advantage of any potential synergies to ensure that market design is coherent. For example, as a TSO responsible for both monitoring resource adequacy, developing the electricity grid, and maintaining stable operation of the power system, market design elements which affect system adequacy, transmission adequacy, and system operation are of key concern. In this respect, it is important that market design elements are implemented to ensure resource adequacy, transmission adequacy, as well as system operation reinforce (rather than conflict with) each other. This will give the best chance of reaching a net-zero emission system sooner, more efficiently, at lower cost, and with a more stable grid.

With this chapter, we discuss which elements of electricity market design can play a key role in meeting many of the objectives of a net-zero emission power system, and set us on the right path to getting there.

8.2 Key market design elements for a net-zero emission electricity system

Based on the results of this study as well as wider discussions with internal and external experts, we outline several key features which should be part of a future-proof electricity market design (Figure 8.1):

- Resource adequacy as a product in the market
- Demand which follows price signals
- Unbiased price signals
- Location, location, location
- Integrated electricity markets

Each of these features is supported by a number of market design elements, which are described in the following sections.

Resource adequacy as a product in the market

- **Scarcity periods with high prices** are a key incentive for investments in DSR, storage and other firm capacity.
- **Ensuring a stable market and policy environment** with minimum intervention is key to reduce investment uncertainty.
- If there is a long-term security of supply risk, a **technology-neutral CRM with locational components** could be an effective and efficient option to support resource adequacy.
- Retail contracts should **allow consumers to choose their reliability level, and how much they pay for it.**

Demand follows price signals

- Unlock the **demand-side response potential of existing consumers** as key priority.
- Ensure **future new demand sources are flexible** to avoid exacerbating the adequacy challenge.
- **Greater access to real-time price signals** (i.e. intraday and imbalance) would allow consumers more control over their energy costs.
- **Aggregators** allow residential prosumers to provide flexibility from EVs, HPs and other devices to electricity markets

Unbiased price signals

- **Strong carbon pricing** is the best incentive for low-carbon generation: let the market do its job.
- Investment risks should primarily be reduced **with market-based hedging measures** such as Purchase Power Agreements (PPAs) and liquid futures markets.
- In case of RES profitability issues, **state-based support** that incentivises market and system integration of RES should be considered, ensuring RES remain exposed to market price signals to avoid distortive behaviour.
- **The imbalance price** is the most important price signal for short-term adequacy which propagates back to all prior market segments, and which should be transparently and directly visible for market parties closer to real time.

Location, location, location

- **Strong locational signals** are needed to ensure investments in capacities are deployed efficiently, and where they are most needed.
- An **adequate bidding zone configuration** is a prerequisite for cost-reflective market prices.
- **Locational incentives in subsidy schemes** contribute to better coordination of network expansion with new investments in support technologies and achieve a more diversified RES portfolio across space and time.

Integrated electricity markets

- **Cross-border interconnection and market integration is an enabler** to successfully integrate variable RES across time and space, to ensure operational security as well as resource adequacy across Europe.
- **Cross-sectoral integration** of the market design and regulatory framework is a key element to seamlessly exploit the flexibility potential across of molecule- and electron-based energy carriers.

Figure 8.1 | Key features of a future-proof electricity market design

8.3 Resource adequacy as a product in the market

In order to reach a reliable net-zero emission energy system, Chapters 3 and 5 showed significant investment are needed in low-carbon electricity sources such as RES, as well as zero-carbon thermal plants, storage, and DSR. In an increasingly weather-dependent energy system, dispatchable resources will play an important role in meeting electricity demand when supply from RES is scarce. From a market design perspective, a key challenge to address is how to incentivise and finance investment in firm capacity which may only be in a limited number of hours (e.g. several hundred for OCGTs or even fewer for costly DSR, see section 6.4.3). In literature, this is often referred to as 'the missing money problem'.

For investors this question has become more relevant than ever before since revenues from energy markets are becoming more volatile than in the past, making future investment decisions much riskier. In addition, we've seen from the turbulence on electricity markets in 2022 that periods of high prices may be politically and socially unacceptable, increasing the risk of market intervention. This leads investors to doubt whether sufficiently high scarcity prices will ever materialise in the future. These risks are particularly high for resources which are dispatched relatively infrequently (e.g. hydrogen OCGTs, DSR), but also for RES which can face revenue cannibalisation. Chapter 6 showed that risk considerations have a major impact on investment decisions as higher risks typically translate to higher financing costs, which have a significant impact on the economic viability of these resources in the future energy system.

For the above reasons, and the risk-averse behaviour of private investors, it has to be discussed whether or not there will be a need for additional risk hedging mechanisms as part of a future-proof market design to help market parties and investors to efficiently manage their investment risks. In our study, investment risk and investment decisions are not explicitly modelled. Nevertheless, based on literature and the current debate around market designs, it is clear that ensuring the future electricity market provides sufficient opportunities for reducing risk will be a key requirement for the required investments in dispatchable capacities to be realised by the market. With this in mind, we identify four key elements that should be part of the future market design in order to incentivise investments in firm dispatchable capacities: (i) strengthening scarcity pricing, (ii) ensuring a stable market and policy environment, (iii) CRMs, and (iv) letting consumers choose their level of reliability, and how much they pay for it.

8.3.1 Scarcity prices could work, if you let them

The results of the economic viability analysis (Chapter 6) suggest that under the assumptions taken in this study, the EOM could provide sufficient revenues for peaking capacity from hydrogen CCGTs, OCGTs and most DSR types to be economically viable, without the need for a CRM. However, the analysis also highlighted a dependence on scarcity revenues and our assumption that the market price cap is set at a high level equal to the VOLL, and that the system is at the reliability standard. These assumptions are directly linked to the design and operation of electricity markets, as explained below.

Price caps are administrative limits on the minimum and maximum price that market parties can bid on exchanges to either sell or buy electricity. They are a necessary feature of electricity markets and serve several purposes, such as limiting the amount of financial collateral that market parties need to provide to trade on markets, and protecting market parties when accidental erroneous bids are entered into market platforms. Price caps essentially limit how much generators can earn during scarcity periods, substantially impacting the profitability of resources needed to cope with scarcity situations such as peaking generator units (e.g. OCGTs) as well as high-cost DSR technologies. Thus, **it is important that price caps do not hinder efficient price formation**. According to economic theory, this is achieved by aligning the price cap with the VOLL [6]. One of the key benefits of aligning the price cap with the VOLL is that it helps improve the viability of peaking generation units by allowing them to capture high scarcity prices while still providing effective financial incentives for DSR capacities to engage in voluntary load reductions/shedding. While the current market price caps for the day-ahead and intraday market are likely below the VOLL and hence not at the efficient level, the current HMMCP methodology should see these prices rise over time (see section 4.5) and create a price signal for investments in peaking capacity and DSR. However, this signal will only materialise if price caps can rise without further intervention, and providing that the electricity system is allowed to operate at the reliability standard, as explained below.

Currently, many countries with a reliability standard treat their standard as a hard limit: any exceedance is treated as a sign that the system is not adequate, which can trigger calls for market design reform or government intervention. This treatment of the reliability standard as a limit inhibits the formation of scarcity prices as the system tends to operate below the reliability standard on average in the long term. In order for scarcity price signals to materialise, the electricity system would need to operate on average at the reliability standard (Figure 8.2). In practice, this would mean **treating the reliability standard more like a target than a limit** and accepting that in some years, in some hours, supply and demand would not be able to clear, spot prices would reach the market price cap, and the TSO would need to curtail some consumer load. These scarcity prices would provide an incentive to the market to invest in new capacity such as DSR, storage and thermal plants, which over time would return system reliability to target levels. If this option is not politically or socially acceptable, other market design elements could be introduced to provide the market with the same scarcity price signals, without actually needing to operate the system at its physical limits. One such mechanism could be a CRM in the form of a strategic reserve (such as currently in place in DE), and administratively setting the market price to the price cap whenever the strategic reserve is activated. Another example could be the implementation of an operating reserve demand curve, in which a percentage of the VOLL is added onto the imbalance price in periods when capacity is scarce [54]. Nevertheless such a mechanism would introduce additional complexities and risks, and not necessarily provide a guaranteed solution for resource adequacy [55].

8.3.2 No guarantees on a stable market and policy environment

One of the major risks for new investments is changes in government policies and regulatory environment. Changing market conditions create uncertainties for investors planning to make long-term investment decisions, and undermine the long-term price signals created by the market. Thus, a **stable policy environment and market design is a key prerequisite** for reducing investment risk. This also means it is essential to limit state interventions in the electricity market to where they are really needed, as these create further uncertainty in the market and increase investment risks. However, given recent experience in Europe where high prices and potential scarcity have invoked various market interventions (e.g. the introduction of revenue caps) and debate on electricity market design, a **risk of further market interventions is clearly present** (see section 8.8).

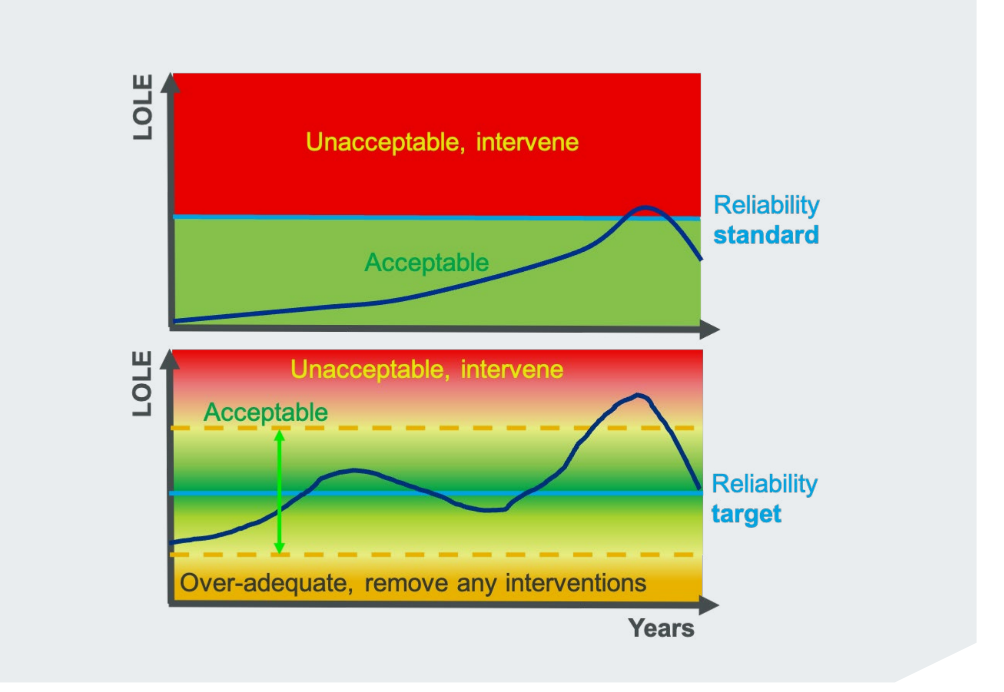


Figure 8.2 | Treating the reliability standard as a limit (upper) and the way it would need to be treated in an effective energy-only market (lower).

8.3.3 Capacity remunerations mechanisms (CRMs)

If the investments in new capacity resources cannot be achieved at the required pace and volume with the current EOM – despite improvements to long-term market-based risk hedging measures (see section 8.5.2) – **additional cost recovery mechanisms such as CRMs** may need to be adopted. By providing more predictable revenue streams these mechanisms can be used to further reduce investment risks, and encourage more investments.

According to current EU regulation and national policies, the introduction of CRMs is only justified if adequacy concerns are identified which cannot be resolved within the EOM design. In this study, we find that most capacities could be economically viable under the assumed EOM design (see Chapter 6), but this result is contingent on the assumed market developments and economic parameters. In particular, assumptions such as the VOLL and price cap, reliability standard (6 h/y), technology costs and discount rate drive the economic viability results to a large extent, and adapting any one of these parameters impacts the results and the conclusion around the suitability of the EOM. For example, assuming a higher VOLL closer to 70000 €/MWh would imply a more stringent reliability standard closer to 1 h/y (see section 5.3), increase the amount of firm hydrogen capacity required, and reduce the overall FLH of the hydrogen capacity in the system. This would in turn increase investment risk, as the economic viability would be driven by revenues from even fewer scarcity hours, requiring an even higher market price cap. Thus, a very strict reliability standard driven by a high VOLL would make it more likely that a CRM is needed to reduce investment risks, and incentivise the additional capacity required to achieve stricter reliability levels.

It remains to be seen whether both market parties and policymakers are willing to accept the risks involved in a more volatile EOM in the future, whether more liquid futures markets and better access to market-based hedging instruments can reduce these risks enough to lead to the investments required, and whether additional measures such as CRMs are necessary. If policymakers decide the risk of delivering a reliable net-zero emission power system in time is too high with the current EOM design and that CRMs are necessary, it is crucial these be designed in an effective and efficient way. This is no easy task given the many different CRM designs which are possible, representing varying levels of intervention in the electricity market. One example is a targeted out-of-market scheme like a strategic reserve, such as the *Kapazitätsreserve* currently in place in DE. Under this design, the TSO contracts a certain volume of capacity resources which is kept in reserve outside the electricity market, and receives annual payments for being available to supply electricity upon request from the TSO during scarcity periods. The costs for the strategic reserve are typically passed on to consumers in grid connection charges. As it only applies to the plants held in reserve, a strategic reserve causes only minimal market distortions. However, if the volume of capacity held in the reserve gets too large, it may become inefficient and costly if too much capacity is kept outside the market. In such cases, a strategic reserve may not be suitable and a market-wide capacity auction may preferable, such as that applied in the UK. While some studies suggest that the overall costs to consumers of different CRM designs do not necessarily differ significantly compared to an EOM,[48] an important precondition for this is that any **CRM should be technology neutral** to avoid biases towards certain types of technologies, and ensure that all technologies (including cross-border plants) such as DSR, storage, thermal capacity and RES are incentivised to contribute to resource adequacy depending on the firm capacity they can provide.

Whichever type of CRM is applied, designing and implementing an efficient CRM is not a straightforward solution, and does not necessarily eliminate all the risks associated with maintaining security of supply. For example, a major challenge is dimensioning the volume of capacity to be contracted. This should be based on the reliability standard determined from the VOLL and the CONE, which as explained previously are difficult to estimate, highly uncertain, and may change over time (see section 5.3). Moreover, de-rating factors for different technologies must also be estimated and updated as the market develops, as well as contributions from cross-border participation. Uncertainties and errors in these calculations can result in either over- or under-dimensioning of the CRM, and hence higher costs to consumers.

Another important aspect to consider when designing CRMs is the **inclusion of locational components/incentives** to ensure that any new investments in dispatchable capacities contracted under the scheme not only support resource adequacy, but also system operation. These locational components should ensure that any new investments supported by CRMs should be deployed at locations in the grid where they can help address the system operation challenges faced by the transition to a net-zero emission energy system discussed in Chapter 7, and provide ancillary services such as redispatch, voltage support, inertia etc. where they

48 For example, CRMs can lead to reduced costs for consumers by reducing investment risk and hence financing costs for new capacity, while costs for consumers can be higher if the CRM is designed inefficiently and the capacity contracted is over-dimensioned. However, these two risks work in opposite directions, and can cancel each other out to some extent [117].

are most needed (see section 7.6). Not including locational components in a CRM risks exacerbating the challenges and costs for TSOs in building and operating a stable grid, and ultimately higher costs for consumers.

8.3.4 Consumers choose their level of reliability, and how much they pay for it

In the future, alternative market-based options to a CRM as described in the previous section may become available which could help make the volume of capacity needed for a reliable electricity supply – as well as the willingness to pay for it – more explicit, and thus provide a more robust of ensuring resource adequacy. For example, aided by technological developments such as the rollout of advanced smart meters with load limiting devices (LLD), concepts like *interruptibility* contracts and *capacity subscriptions* are promising and could be a smart way to let consumers choose how much capacity they need and at what price [56]. An *interruptibility* contract is essentially a real-time (dynamic) pricing contract (see section 8.4.3) in which consumers specify the maximum price they would be willing to pay per kWh of electricity as part of their retail contract, and consent to having their demand reduced remotely by their supplier (with pre-notification and opt-out) if prices exceed their pre-defined threshold level. Such contracts would reduce the exposure of both consumers and retailers to extreme high prices, but the total energy bill and reliability level would depend on their level of consumption and communicated price preferences. Alternatively, for consumers wanting more certainty in their energy bills and reliability level, a capacity subscription model may be preferred. Under a capacity subscription, consumers would subscribe to a certain (minimum) level of capacity (e.g., 4 kW) that they would be guaranteed to be able to consume at all times, but in times of high prices their electricity provider could remotely limit the consumer load to their subscription level via their LLD. These products could translate consumer preferences for a certain level of resource adequacy into explicit revenue streams for providers of firm capacities. Through capacity subscriptions, the need and willingness of consumers to pay for reliability would become explicit, allowing this demand to be met in a competitive, market-oriented approach that maximises the contribution of the demand side (via load shedding, shifting or reduction) to resource adequacy.

As *interruptibility* contracts and capacity subscriptions would empower consumers to explicitly **choose their desired level of reliability and how much they are willing to pay for it**, widespread adoption of these types of contracts would bring two additional benefits for electricity markets. Firstly, as consumers would provide their preferences on the their desired reliability and/or price level ahead of time, retailers would be better placed to be able to hedge the necessary volumes and prices for their peak consumption on long-term forwards, futures and options, improving the liquidity of these long-term markets, and creating an important long-term price signal for investments (see section 8.5.2). Secondly, the consumer price (and volume) preferences collected by retailers would provide a more robust way of estimating the underlying VOLL for consumers, as explained below.

The analysis in Chapter 5.5 showed how sensitive the optimal reliability standard is to the estimated VOLL, and how important it is to estimate correctly. Establishing the VOLL is the task of member states (usually via National Regulatory Authorities (NRAs)), which according to the ACER methodology should be estimated by surveying different types of consumers [33]. Despite this requirement, surveys are unlikely to be a robust way of establishing the VOLL in the long term for several reasons. Firstly, consumers may respond strategically to surveys if they think it will be used for policy decisions and secondly, the VOLL is defined based on the share of demand from consumers which does not respond to market prices. However, the ability of consumers to react to prices should increase in the future thanks to increased rollout of smart meters, allowing consumption patterns to adapt (or be adapted). In the long term, a more robust approach to assess the VOLL would be to let the underlying VOLL of consumers manifest directly on wholesale electricity markets, or in the data collected by retailers. For retail consumers, this could be achieved by widespread adoption of interruptibility or capacity subscription contracts. By analysing (anonymised) data collected from long-term markets and retailers, NRAs would be able to estimate the VOLL more accurately and dynamically than from surveys, and thus have more confidence in estimating the cost-effective reliability standard. This method of estimating the VOLL would be especially valuable if a CRM were in place to ensure the volume of contracted capacity is set correctly.

Note that the retail contracts mentioned in this section would require consumers to have advanced smart meters equipped with LLDs allowing grid operators to remotely reduce consumer loads, and the necessary communication channels between grid operators and retailers to perform the load management based on consumer preferences. Unfortunately, smart meters capable of remote load management are not yet widely available. Significant rollout of smart meter technology in DE is not expected until 2024. While more than 80% rollout of smart meters has been achieved in NL, the current meters only provide access to peak/off-peak or real-time pricing contracts, and do not provide the grid operator the capability of modulating consumer loads remotely [70]. Potential social and legal barriers may also exist which would need to be addressed to provide for this capability.

8.4 Demand follows price signals

In a future net-zero emission energy system the demand for electricity is expected to be two to three times higher than what it is today, as the use of carbon-emitting fossil fuels is replaced by zero-carbon electricity (see section 3.3). As an increasing share of energy demand is electrified, these applications can also provide significant flexibility to the power system, which will be important to effectively manage and absorb the fluctuating generation of RES. In this study we assume significantly higher capacity from industrial DSR will be available than today, and the adequacy analysis showed the crucial contribution DSR can make as one of the lowest cost providers of firm capacity (see section 5.6.2). In order for DSR to play this role, electricity markets will need to be designed to (i) unlock the existing potential of DSR, (ii) ensure new demand sources are as flexible as possible, (iii) provide greater access to real-time pricing, and (iv) allow aggregators to optimise the flexibility from EVs and HPs.

8.4.1 Unlock existing industrial DSR potential

The demand side can and should play a decisive role in providing flexibility to the future energy system. The primary driver for consumers to utilise their flexibility is expected to be based on consumers aiming to reduce their overall costs for energy. In this optimisation, they are expected to take the electricity price into account for when best to consume electricity, as well as their opportunity costs for not consuming electricity (i.e. how much they stand to lose from lost production). In general, this should incentivise demand to consume more in hours with RES generation and low prices, and less during scarcity situations with high prices, thus improving the adequacy of the system.

Existing industrial demand is less designed to incorporate and utilise flexibility capabilities. For many industrial consumers, the opportunity costs – especially for demand reduction – are likely at a level much higher than the peak prices reached in the past decades, and higher than the current day-ahead price cap of 4000 €/MWh. This indicates that the need (at least from an economic perspective) for significant industrial flexibility has been low until now. Nevertheless, there are already some industries with lower opportunity costs making full use of their flexibility capabilities to reduce costs for electricity consumption, and some industrial consumers have a long history of providing balancing reserves. Also, during the period of high prices in 2022 where electricity prices were in the range of 200-600 €/MWh, it was observed that several industries significantly reduced their electricity demand. This indicates that the market design is already to a large extent capable of unlocking industrial DSR. In section 6.5 we show that in the long-term, investments in DSR should be economically viable for industries with a willingness to pay up to roughly 8000 €/MWh. So long as the rules outlined in the revised HMMCP methodology are followed and maximum prices are allowed to rise over time without intervention (see section 4.5), **additional DSR capacity from existing industrial consumers** with higher opportunity costs should be incentivised to participate in the market.

Further improvements to the participation of flexible industrial DSR can be gained with grid tariff reform. For example, **certain grid tariff structures** in NL and DE incentivise large consumers to have a constant (i.e. baseload) consumption pattern or maximise their full load hours. These type of structures are a disincentive to providing DSR and should be reconsidered.[49]

8.4.2 New demand sources should be as flexible as possible

The net-zero emission scenarios considered in this study assume significant additional demand from P2G and P2H will arise in the future, which will make valuable products for the net-zero emission economy. These technologies can bring benefits to the electricity system by utilising low-priced hours with high RES infeed (see 6.4.1), supporting the business case of RES (see 6.5), and providing ancillary services (see 7.6).[50] A key assumption made is that P2G and P2H will respond fully to market price signals, not consume electricity during hours with high scarcity prices, and hence not pose a risk to adequacy. This is a logical assumption given companies will always have an incentive to reduce their costs. While future P2X facilities would have significant financial incentives to respond to price,[51] certain market developments or restrictions by subsequent (industrial) processes could reduce price responsiveness and lead to future situations where P2X may exacerbate adequacy issues. Examples of such potential situations are (i) energy-based subsidies for P2X which would increase their effective willingness to pay for electricity, (ii) smaller P2X installations not participating in wholesale electricity markets subject to fixed price contracts, and (iii) P2X capacity integrated in industrial processes that cannot easily be switched off due to a lack of flexibility from (on-site) storage or backup supply. Thus, it is important that the future policy environment and market design does not incentivise these kinds of situations, to ensure new demand sources are as flexible as possible.

49 In NL, large consumers currently receive a volume discount on their grid charges if they have a stable base load profile in peak hours, while in DE large consumers receive a fee reduction if their energy consumption exceeds 7,000 full load hours per year and 10 GWh [110]

50 Another potential future demand source could be direct air carbon capture which could capture CO_2 from the air when electricity prices are low. However, this technology is not considered in this study.

51 P2X facilities would likely hedge their costs ahead of time on futures and forwards markets, or via PPAs. If prices reached very high values on intraday or balancing markets, it would be attractive for P2X plants to sell their pre-bought electricity on the spot market instead of consuming. Other studies also show that flexible P2X can operate flexibly, and that flexible price-responsive operation is more profitable than operation with a fixed dispatch pattern [116].

8.4.3 Greater access to real-time pricing

The demand-side flexibility of small consumers has for a long time been limited to reducing costs by shifting consumption from peak to off-peak hours.[52] This has been made possible through price differentiation between peak and off-peak hours in metering and retail contracts. Real-time pricing contracts in which consumers are informed one day ahead of time what the hourly price of electricity will be can provide consumers with even more granular control over their energy bills than peak/off-peak contracts. Recent developments in the Dutch market show a significant increase in suppliers offering these real-time contracts, most likely in response to the current EU energy crisis, as well as a rising share of consumers wishing to switch to these contracts. However, real-time pricing contracts also require smart meters, which are not widely available yet in the German market. Thus, **greater access to real-time pricing contracts** – which ideally also include consumer price preferences for a certain reliability level (see section 8.3.4) – would allow consumers even greater control over their energy costs by avoiding consuming during periods of relatively high prices (but below their maximum willingness to pay) and shifting it to lower price periods.

A related issue is net metering for solar PV. While this has helped support deployment of solar PV, it also leads to distorted price signals as the netting of annual solar PV generation against annual consumption effectively remunerates households with a higher price for the electricity they inject into the grid than the actual market value, which is typically lower during the day. Thus, households are not incentivised to adapt their consumption to match their solar PV generation, nor install batteries.

8.4.4 Aggregators maximise flexibility from EVs and HPs

In order to decarbonise transport and heating, the future energy system will need to contain millions of EVs and HPs. Most of these devices will be owned by households and small businesses subject to retail contracts and connected 'behind the meter' in distribution grids. While individual devices represent only a relatively small share of the load on the grid, they can pose a challenge for future resource adequacy if their consumption is unmanaged and concentrated in similar periods. To ensure these devices contribute to rather than endanger system adequacy, it is important they are integrated into electricity markets where they can both provide, and respond to market price signals. In our study, this type of DSR is modelled in a simplified way by assuming a relatively conservative contribution from EVs and HPs, which is triggered when the market prices exceeds a predefined threshold price level for the activation of these small-scale flexibilities (see section 4.1.3). These technologies should have significant inherent flexibility (e.g. in the EV battery, thermal storages), and hence significant potential to optimise costs. A balance responsible party (BRP) will need to support consumers in unlocking these flexibility opportunities by developing both fixed-price and dynamic pricing contracts with the ability to steer and optimise the operation of EVs and HPs based on consumer preferences.[53] By **aggregating and optimising the flexibility provided by many HPs, EVs** and other devices, these parties could contribute significantly to resource adequacy by reducing demand in scarcity situations, and mitigate the impact by spreading load reductions across many consumers in an optimal way.[54] In addition to market access, TSOs need to ensure that aggregated demand and supply are allowed to be part of the portfolios of balancing service providers (BSPs) and congestion service providers.

52 Peak hours are 8:00 to 20:00 weekdays, and off-peak hours are before 8:00 and after 20:00 (weekdays) and weekends.

8.5 Unbiased price signals

Price signals are an important outcome of markets which ensures that producers and consumers respond to supply and demand dynamics. In order for the electricity market to be fit-for-purpose for a net-zero emission energy system, it is important that four key price signals are established and strong enough to steer both long- and short- term market behaviour: (i) scarcity, (ii) carbon, (iii) real-time (real-time), and (iv) location. Price signals need time to work by manifesting and filtering through markets, and be sustained long enough for market parties to take them into account in future investment decisions. Thus, it is important these price signals are in place early enough for the transition to net-zero emissions to be affected in a timely manner. Price signals should also be adjusted in a gradual way to avoid destabilising the market.

8.5.1 Strong carbon pricing drives low-carbon investments, not subsidies

As we transition towards a carbon-neutral energy system it is important to define emission limits which decline over time, and pricing mechanisms which encourage emitters to reduce their CO_2 emissions. According to economic theory, carbon emissions are known as an externality as the emission of carbon results in damage and costs (in the form of climate

53 There is no formal role of an 'aggregator' in the electricity market, but this function could be taken by many types of business such as (smart) electricity retailers, EV and HPs manufacturers, or EV charging station operators, so long as they are themselves (or nominate) a BRP.

54 For example, an aggregator providing 100 MW of load reduction for 1 hour from HPs could spread this across all devices in its portfolio based on price preferences, or initiate rolling reductions every 15 mins so individual consumers do not notice the difference.

change) which are born by everyone, but the emitters themselves do not incur a cost for doing so. For this reason, the EU Emissions Trading System (ETS) was established in Europe to internalise the externality of carbon emissions, and create a price signal for which makes releasing carbon (in the form of CO_2) into the atmosphere more expensive over time. Ideally, this carbon price should reflect the socio-economic cost of the damage each tonne of emitted carbon does to the climate. Today, the ETS covers all carbon emissions from the electricity and heating sectors, energy-intensive industries as well as aviation, and will be gradually extended to maritime transport, buildings, road transport, and fuels as part of the "Fit for 55"-package.[55] On the ETS, an emission cap is defined that can be emitted by all participating installations. Emission certificates allow market parties to trade emissions, and the price of carbon is determined by the balance between the supply of certificates (set by the mechanism), and the demand for certificates (the amount of emitted carbon). As the price of carbon increases fossil-fuel based generation – in particular coal, lignite and natural gas – becomes more expensive as operators of these plants have to buy emission certificates for every tonne of carbon they emit. This increases their marginal cost for generating electricity which they reflect in their bids on the electricity market. Over time this has a direct impact on the merit order and tends to increase the electricity market clearing price, as fossil plants are most commonly the price-setting marginal generation units in the current market. As the market price increases when fossil plants are dispatched, low-carbon technologies such as RES benefit from higher inframarginal rents, creating an incentive for market participants to invest more in low-carbon technologies like RES. Over time, these low-carbon investments put downward pressure on market prices, which is good for consumers.

While government support schemes for RES have played a major role in the large-scale adoption of RES, they also have the effect of weakening carbon price signal as RES investments are driven mostly by the subsidy, rather than their advantageous position in the merit order and resulting inframarginal rent. In the long term, this leads to RES cannibalising their own revenues, and a reduction in the market value of RES. However, studies have shown that relying on the carbon price as the main driver for RES – rather than subsidies or quotas – can allow for high shares of RES to be achieved without cannibalising their own revenues, as the higher carbon price leads to higher rents for RES plants when fossil plants are generating [57]. For this reason, a **robust market design should aim for full market integration of RES driven by strong carbon pricing**. Thus, measures aimed at strongly driving up the ETS price over the coming years such as a faster reduction in the emission cap, market stability reserve, and extending the ETS to more sectors will be crucial to achieving decarbonisation targets, incentivising RES investments and stabilising their market value. The reforms outlined in the Fit for 55 package are a positive step in this direction, but it remains to be seen whether additional measures will be required over the coming years.

8.5.2 Market-based risk management

To hedge against future price uncertainty and reduce financing costs, electricity producers and consumers have two main options available in the marketplace: (i) trading (hedging) on forwards and futures markets, and (ii) purchase power agreements (PPAs). **Market-based risk management** measures such as hedging and PPAs are important as they provide more transparent revenue streams for investors and reduce investment risk. Moreover by letting market parties manage their own risks these mechanisms foster competition and innovation, and more prudent investment decisions.

Today, most market-based hedging is done using long-term supply contracts through futures and forwards. While these markets allow electricity to be bought and sold up to 10 years ahead, the most liquid markets are for electricity delivered up to 3 years ahead. For existing plants, this is generally long enough to effectively hedge their production against price volatility and effectively manage financial risks. While forward markets are an effective risk management tool for existing capacities, they are less effective at reducing investment risks for the significant long-term investments needed in zero-carbon capacity over the coming decades. This is because lenders are unlikely to offer favourable financing rates to projects with only short-term revenue transparency. Therefore, in today's electricity market the options to effectively reduce investment risks in the long term are rather limited. **Improving the liquidity of long-term futures and forward markets** will be important if these are also to provide a sufficient signal for long-term investments.

Another market-based risk hedging option is corporate bilateral *power purchase agreements* (PPAs). These are generally direct (i.e., over-the-counter) agreements between a RES supplier and a consumer of RES electricity such as large industrial user. In the future, PPAs may also provide important for investments in P2X facilities. As the demand for renewable electricity is

55 The Fit for 55 package is a set of proposals to revise and update EU legislation and to put in place new initiatives with the aim of ensuring that EU policies are in line with the climate goals agreed by the Council and the European Parliament.

growing while the subsidies provided for RES are decreasing or being phased out, the role of PPAs in financing RES projects is becoming more important. PPAs can hedge both sellers and buyers against future price uncertainty and create stability, thus increasing the financial viability of the RES projects. Combined with Guarantees of Origin, PPAs could secure RES power consumption and help consumers to support investments in new RES capacities and achieve net-zero targets. Nevertheless, there are some challenges related to PPAs such as the complexity of aptly pricing/setting up a contract, access to financing and collateral, and engagement for large volumes and longer PPA periods. **Addressing these issues should drive further growth of the PPA market** and reduce the need for state-based support.

8.5.3 State-based support

Government support schemes, such as the feed-in-tariffs and feed-in-premium schemes provided by the German *EEG* and Dutch *SDE++*, have been used by governments to incentivise RES deployment since the early 2000s. By protecting investors from full exposure to market price risks, these support schemes were able to accelerate RES deployment while these technologies were not yet competitive with fossil-based generation due to high investment costs, and the carbon price signal from the ETS was not strong enough to incentivise investments. More recently, the increasing cost competitiveness of RES – reflected in the very low and even subsidy-free auction results for new solar and wind in recent years – has led governments to introduce more competitive support schemes, and in some cases plans to remove support completely. For example, the Dutch government announced its intention not to subsidise new RES installations after 2025 [2].

Removing subsidies is a key step to the full market integration of RES. Nevertheless, whether market forces will incentivise sufficient and timely RES investments, or whether additional support schemes will still be needed in the future to drive RES development remains unclear. On the one hand, there is a risk that the growing share of RES will depress market prices (due to the merit-order effect, see section 6.4.2) and cannibalise revenues to such an extent that some sort of financial support providing stable revenues will be necessary to attract the required investments in RES capacities. On the other hand, the results of this study show that as long as increasing RES capacity goes hand-in-hand with increasing storage capacity and flexible demand, the market value and economic viability of RES can be maintained, and subsidies should not be needed (see section 6.5).[56] If electrification is outpaced by RES deployment and/or market price signals do not lead to sufficient investment in flexible demand and storage, the risk of revenue cannibalisation will increase, and a need for state support becomes more likely.

If state support is needed for RES, the design of support schemes is critical to ensure RES are supported in a way that fosters competition, allows for **the gradual market integration of RES** without unduly creating market distortions, nor exacerbating the challenges for operating the electricity network. In this respect, it is important that any support mechanism should provide system-beneficial investment incentives for RES generation and flexibilities (e.g., generation, storage, flexible DSR). For example, support schemes should be designed in such a way that RES are not insulated from the market and incentivised to follow a 'produce-and-forget' strategy (as is the case with feed-in tariffs), but instead ensure that RES are fully exposed to market price signals (e.g., day-ahead, intraday, balancing) and incentivised to adapt their generation based on market prices, and contribute to providing ancillary services such as balancing reserves and redispatch. One approach could be capacity-based (rather than energy-based) support schemes which limit payments to a maximum number of full load hours (MWh/MW) over the lifetime of the asset, but which offer no payments when market prices are negative. Support schemes should also be auction-based to ensure price competition, and that state support is limited to the minimum level necessary. If there is a political desire to combine support schemes with mechanisms that prevent "windfall profits", approaches such as two-sided contracts for difference (CfD) could be considered as a basis.[57] The inclusion of locational incentives in RES support schemes could also contribute to the spatial steering of investments at the right locations in the grid where they are most needed (see section 8.6.2). Ultimately, the design of any support scheme is a political decision based on the long-term vision for the energy system, but this decision should be made carefully considering potential negative impacts on the functioning of electricity markets, system operation, and interactions with other state support measures.

56 In addition to income from wholesale markets, additional revenues from provision of balancing reserve capacity and/or other ancillary services could also support the business case of RES in future (see section 7.5.2), as could business models combining RES with storage or P2X technologies to better align the weather-dependent RES output with market prices and demand patterns

57 To ensure RES are still exposed to market price signals it is important that any CfD design decouples the payments from actual generation. Several designs have been proposed such as Schlect et al.'s 'financial CfD' [118] and Newbery's 'yardstick CfD' [119].

8.5.4 Imbalance price

We consider the imbalance price as the most important price signal, and balancing markets should be designed in such a way that they provides market parties with incentives for system-friendly behaviour. Furthermore, we see balancing not as a process but as a real-time equilibrium determined by supply and demand. The balancing market design should be fit for all connections to be balancing responsible and anchor responsibility in the market. Balancing should be an integral part of the market (i.e. reflect the real-time price for energy), not only a cost recovery system. The imbalance price is the last and most important price signal which propagates back to all prior market segments and which should be transparently and directly visible for market parties as close to real time as possible.

8.6 Location, location, location

An efficient system development requires sufficient revenues for required generation and storage capacities, as well as incentives for an effective spatial coordination of these market-driven activities with infrastructure investments and grid operation. The current market design and regulatory framework provides several ways in which locational aspects can be differentiated including network charges, electricity market prices, and support schemes. These elements they can be designed to include prohibitive limitations, or positive/negative price incentives so market parties can account for them in their investment and/or dispatch decisions. In a future net-zero emission system, market participants should (at least) account for the costs of structural congestions in their decision making. In this respect, two key aspects of electricity market design are ensuring (i) an adequate bidding zone configuration to better reflect congestion costs, and (ii) locational incentives for supported technologies.

8.6.1 Definition of adequate bidding zones

Strong locational signals are needed to ensure investments in firm capacity and system services are deployed efficiently, and where they are most needed. Despite the significant grid investments planned, there will always be periods when expected flows exceed the limits of the grid infrastructure, leading to congestions which must be resolved with remedial actions by the TSO. Thus, a cost-efficient and future-proof market design must include elements to ensure the grid is used as efficiently as possible, and that investments are made at the right location. In this respect, price signals with a finer granularity in space could support a cost-efficient system development by providing locational incentives that indicate to market participants where investments in new capacity resources would be most valuable for the system. This allows for a better coordination of where new investments in resource capacities are located with the available grid capacity and/or planned grid investments.

Appropriate spatially-differentiated price signals are needed to ensure future demand and generation are located closer together to reduce transmission flows, redispatch and the need for grid reinforcements, while improving dynamic stability. **An adequate bidding zone configuration** is a prerequisite for such cost-reflective price signals to give incentives from the system, as the (average) price in a bidding zone reflects whether there is a need for investments in more generation (high electricity prices), or an opportunity for investments in flexible demand or storage (low prices). Significant and sustained price deltas between bidding zones also reflect structural congestions in the grid, and transparently show where additional investments in grid infrastructure would allow for more exchange between bidding zones, better price convergence, and greater overall welfare. Without an adequate bidding zone configuration where the bidding zone borders are located at the points of structural congestions in the grid, maintaining the current zonal model in the European electricity market would likely result in the need for significant redispatch measures to alleviate congestions, the need to remunerate market parties for these services, and ultimately higher costs for consumers. An inefficient bidding zone configuration will also fail to provide the necessary price signals to steer investments to locations in the grid where they can alleviate, rather than contribute to congestions.

The zonal market design offers many advantages and is the fundamental basis on which the current European electricity markets have been built. Still, if congestions become more substantial and variable in time and space, it may become difficult to define a robust bidding zone configuration, and the ability to efficiently deal with congestions with bidding zone reconfiguration in the current zonal model may become limited. In such a situation, a market model with more granular price signals – such as a nodal market design – may ultimately be a more effective solution.

8.6.2 Locational incentives for supported technologies

In addition to market prices coming from adequately defined bidding zones, **including location-based incentives as part of any state-based support scheme** could further steer new investments to locations in the grid where they are most needed, and away from locations where they would exacerbate challenges. This is especially relevant if existing state support schemes are extended, or new schemes are introduced (see section 8.5.3) to accelerate the deployment of RES, storage, zero-carbon thermal capacity, or even P2X due to perceived investment risks, high technology costs, or a desire to transition to a net-zero emission system more rapidly than the market seems capable of achieving alone. As part of these support schemes, it can be meaningful to provide additional spatial/locational components to achieve either a better alignment between technology deployment with required infrastructure investments, or to diversify the renewable generation portfolio. Spatial/locational aspects could take the form of explicit limitations such as expansion regions, or through location-dependent financial incentives. While spatial limitations might be seen as more effective, they come at the risk of slowing the development of supported technologies. Thus, financial incentives might be better suited to account for infrastructure costs which normally are not (or cannot) be taken into account by investors, without necessarily limiting the ramp-up of those technologies.

Moreover, if (new) CRMs are deemed necessary and implemented (see section 8.3.3), there should be a possibility to include locational components in these as well in order to simultaneously address transmission adequacy and system operation challenges, as well as resource adequacy.

8.7 Integrated electricity markets

For a future-proof market design it is important to integrate electricity markets across national borders, and also across timeframes. The challenge for power system operation is to facilitate these markets, and be able to deal with changes in the market preferences to trade. This requires frequent iterations with the market in which network information is exchanged with market parties, and where the TSO can incorporate the reaction of the market to the network information. The frequency of that iteration increases closer to real time as it becomes more critical to monitor the status of the grid. Another challenge is to provide the same operational speed both within bidding zones and at bidding zone borders to allow for a level playing field in the market. This requires very close cooperation between neighbouring TSOs. Several aspects of integrated electricity markets are seen as key to enabling a net-zero emission energy system: (i) increasing cross-border interconnection and market integration, (ii) market integration across time frames, and (iii) cross-sector integration with other zero-carbon energy carriers.

8.7.1 Cross-border interconnection and market integration are key

The results of this study show the important role interconnection capacity can play in a future net-zero emission energy system in contributing to resource adequacy, particularly between countries with different generation mixes, and those further away with less correlated RES generation patterns (see section 5.6.4). In order to scale-up RES capacity while ensuring resource adequacy as well as operational security, ongoing efforts at the EU level to **integrate national markets are key** to establishing an efficient and well-functioning internal electricity market. Better use of existing interconnectors, and investments in new interconnector capacity will increase the efficiency, flexibility and robustness of the system by allowing surplus RES generation in one location in Europe to be used elsewhere (instead of curtailed), and allow countries to support each other during scarcity situations. To facilitate this, effective market integration also requires: (i) efficient management of the network as a whole, and an increasing need for operational harmonisation at regional and EU level, (ii) a regulatory framework that provides the right incentives for the use of and investments in a highly interconnected European power grid, (iii) a market design which better takes into account the physical constraints of the network in order to facilitate efficient trading between market participants and a level playing field, and (iv) investment in domestic grids, to avoid internal grid bottlenecks becoming a limiting factor on the use of cross-border interconnectors.

8.7.2 Market integration across all market time frames

As a growing share of total generation becomes driven by weather-dependent RES, **enabling closer to real-time trading** will allow market parties (in particular BRPs) to optimise their portfolios/trading positions to changing market conditions, ahead of physical delivery.[58] This would allow market parties to better adjust to extreme (e.g. scarcity) situations, facilitate more RES participation in balancing and other ancillary services markets, and reduce schedule deviations which would improve the balancing process. Through price signals on short-term markets, such as intraday or imbalance prices, the need for flexibility can be made transparent so that market participants get the right price signals to know how and when to act. In this way, trading closer to real time can support the development of a flexible and reliable electricity system. Individual local market solutions should be avoided as they introduce market fragmentation and increase complexity. Instead, access to markets should be as easy as possible and (decentralised) energy resources should be used where it gives the highest

58 A trend toward shorter term trading can already be seen in traded market volumes, which have grown by 15% annually over the past 5 years [114].

system value, and not reserved by a certain party. As with closer market integration, closer to real-time trading will require an even higher degree of cooperation between TSOs and automation of operational processes across borders.

8.7.3 Cross-sector integration with other zero-carbon energy carriers

A net-zero emission system will rely not only on electricity, but also on other zero-carbon energy carriers. This study shows that hydrogen in particular has significant interactions with the electricity sector, and coupling these sectors can lead to significant benefits. For example, low-cost generation from RES is used by P2G to generate hydrogen, which plays a major role in ensuring a secure supply of electricity (see Chapter 5), and is also used to decarbonise other sectors. At the same time, P2X plays an important role in maximising the utilisation of RES, and supports the business case of RES and other technologies by setting the market price during periods of high RES production, and stabilising market prices (see Chapter 6). P2X can also support system operation by providing certain ancillary services in the future (see Chapter 7). This level of sectoral integration will require the necessary hydrogen infrastructure to develop at pace with developments in the electricity sector. For example, a potential hydrogen backbone, partly based on the existing gas network and with access to underground gas storages, is a promising solution for shifting significant energy amounts of stored energy across space and time, and providing flexibility both sectors. In this regard, the market design and regulatory frameworks for both energy carriers must be developed in a coherent way to support the necessary infrastructure investments, and efficiently exploit the flexibility potential provided by both sectors.

8.8 Discussion

The European wholesale electricity market we have today has developed incrementally since market liberalisation began more than 20 years ago. In their recent assessment of the ongoing crisis on Europe's electricity markets, ACER concluded that while improvements can be made, the current market design is not to blame for the crisis, but rather the gas price shock triggered by Russia's war on Ukraine, and subsequent withholding of gas supplies [58]. The current energy crisis has had profound impacts on the electricity sector and energy markets in general:

- In response to high electricity prices the demand for electricity has decreased. This occurred despite higher economic activity [59];
- High prices for other fuels – especially natural gas, petrol and oil – have triggered energy savings in many sectors, and triggered households to look to electrical solutions for road mobility and heating [60];
- Significant price volatility has been a trigger for investments in storage technologies, and in the course of 2022 TenneT received an unprecedented number of requests from market parties to connect new batteries to the grid;
- In certain cases, low-carbon electricity generation technologies have been able to secure significant inframarginal rents, which would provide capital for further RES investments.[59] With (near) record-high electricity and carbon prices, the price signal for investments in RES has never been so strong;
- The relevance and attractiveness of natural gas as a transitional fuel on the way to net-zero emissions has changed significantly. To decrease the dependency on individual suppliers as well as to foster decarbonisation of the system, the desire for a national and European hydrogen economy gained more political attention; and
- The low degree of supplier diversification for some commodities (e.g., gas, coal) and the impact of commodity price volatility on the energy system has brought more attention to the resilience of the energy system, and dependence on imports. In this setting, stronger ambitions to expand domestic RES capacities are being seen as a no-regret measure.

In order to cope with the energy crisis, market interventions have been announced in several EU countries such as the gas price cap for electricity generation in Spain and Portugal, and subsidies (price caps) to support households from high electricity and gas bills have been provided in many countries. Wider ranging interventions have also been announced at EU level

59 Not all plants would have profited from high prices as (i) significant generation would've been hedged ahead of time, (ii) plants under a two-way CfD support scheme would have to pay the difference back, and (iii) some countries will apply the revenue cap retroactively.

such as the inframarginal rent cap on generation from RES and nuclear plants, a cap on natural gas prices, and mandatory reduction in electricity consumption during peak demand hours. Moreover, the current EU electricity market design has also been called into question, triggering the European Commission to launch a consultation on the EU electricity market design.

It is not clear whether the impacts of the energy crisis on electricity markets will only be short lived, or if markets have changed structurally. Nevertheless, one should never let a crisis go to waste, and it is important we learn the most we can from this period going forward. For example:

- The measures EU member states must take to reduce electricity during peak hours by between 5% (mandatory) and 10% (voluntary) will hopefully highlight the importance and trigger longer-term exploitation of DSR, even though the announced measures are intended to be temporary [50]; and

- Not all risks to adequacy can be foreseen, assessed and fully quantified. Thus, diversifying sources of energy supply (and hence risks) can bring benefits for adequacy and may lead to lower costs in the long run, even if this may come at a higher cost in the beginning.

Where the current discussion on the electricity market design will land – and which reforms (if any) will be agreed and finally implemented – remains to be seen. However, it is important we don't 'throw the baby out with the bathwater' with the current market design, and decisions on long-term market design (e.g., CRMs, support schemes, etc.) should not be made rashly in reaction to the energy crisis, but rather in a calm and considered way taking into account all the available evidence, in consultation with stakeholders. Implementing significant market design changes in a hurried way can lead to unforeseen consequences, market instability, and increased investment risks. Relying on markets to drive the energy transition to a low-carbon energy system will require (i) setting the right market conditions and price signals to steer the market in the desired direction, (ii) limiting further interventions to keep market conditions stable and reduce investment uncertainty, and (iii) time for market parties to adapt and respond to signals in their investment decisions. While this study finds that the current EOM (with some reforms) could lead to a reliable net-zero emission power system in theory, there are a number of reasons why the current EOM design may not lead to a stable and timely transition to a net-zero emission system in practice, which could necessitate further measures:

- **Recent experience shows that the appetite of consumers and governments for high market prices is very low**. Under these conditions the risk of government intervention in the market to shield customers and local industries is high. This risk of price intervention increases uncertainty and reduces the willingness of market parties to invest in technologies which rely on higher price levels and volatility, such as peaking plants and DSR.

- **Many zero-carbon technologies are still maturing or under development, and characterised by rather high technology costs and/or investment risks**. While this is less the case for RES, it is true for hydrogen power plants and P2X which depend on wider infrastructure investments, as well as long-duration storage, and innovative solutions in electrifying industrial processes. In order to foster technological improvements and cost reductions through learning and economies of scale, state-based support may be needed.

- **The time required for EOM price signals to trigger sufficient investments in zero-carbon technologies may not be fast enough** to bring about the transition to a reliable net-zero emission carbon system in the time required to avoid dangerous climate change.

- As the process of redefining and adapting to a new bidding zone configuration is likely to take a number of years,[60] **it is questionable whether bidding zone reform is a sufficiently agile mechanism** to ensure that the market receives the right price signals to invest dynamically on the transition to a net-zero emission system. In this case, other means of strengthening spatial (dis)incentives for investments such as spatial planning, location-based grid tariffs and connection charges, or potentially a nodal market design may eventually become a more efficient and effective solution.

60 A bidding zone reform requires time for (i) TSOs to propose and analyse alternative bidding zone configurations, (ii) member states to agree unanimously on a new configuration, (iii) the new configuration to be implemented in the field, and (iv) market parties to react to the new price signals and take them into account in their investment decisions. This process could take 3 to 5 years from beginning to end.

Thus, going forward it is imperative that policymakers set the framework conditions for market design in a way that reduces regulatory risks, in order for market parties to have confidence in the regulatory and market environment when making their future investment decisions. To this end, any interventions in the market should be tailored and limited to specific causes or crisis situations, and avoided under normal circumstances to reduce market uncertainty. If state-based support is deemed necessary to scale-up deployment of zero-carbon technologies (e.g., RES, P2G and hydrogen plants) to achieve climate targets, these mechanisms should be designed carefully so as not to distort short-term price signals for market dispatch. Moreover, if a greater share of zero-carbon investments are triggered by state actions, the willingness of the market to make investment decisions may decrease, potentially delaying the overall speed of the energy transition.

9 Conclusion and Recommendations

9.1 Conclusion

The Netherlands and Germany have historically enjoyed very high levels of security of supply. However, this supply has relied on the unsustainable use of fossil fuels such as coal and natural gas to generate electricity, a reliance which must cease if the worst effects of climate change are to be avoided in the future. As we transition towards a net-zero emission energy system based largely on renewable energy sources (RES), security of supply must be maintained at the same time as electricity demand is expected to increase significantly. Recent resource adequacy studies at national and European level also suggest that the medium- to long-term risks for security of supply are increasing in the Netherlands, Germany and other EU countries, and how to ensure security of supply can be maintained in a net-zero emission energy system at a reasonable cost to society has become a key concern for many countries.

Almost every chapter of this study has explored a different piece of the puzzle of how we can get to a cost-effective, reliable, net-zero emission energy system:

- **Chapter 3** showed that demand for electricity is going to increase significantly, and significant investments in low-carbon electricity sources – in particular RES – will be needed to generate enough green electricity to meet the needs of a future net-zero economy;

- **Chapter 5** showed that resource adequacy can be ensured in a net-zero emission power system providing sufficient investments are made in a mix of demand-side response (DSR), cross-border exchange capacity, storage, and zero-carbon firm capacity. It also showed we need a more robust way of knowing the true value of electricity supply to society so we can target the right level of reliability, and avoid under- or over-investing in the electricity system.

- **Chapter 6** showed that under certain assumptions a future net-zero emission power system could be economically viable if we allow market price signals in an energy-only market to function as intended, investment risk is kept as low as possible, and market interventions are kept to a minimum. However, there is debate ongoing on the future electricity market design and it is unlikely that in the future such an undistorted energy-only market will be in place;

- **Chapter 7** showed that the transition to net-zero emissions presents new challenges for operating the power system, but these can be addressed with a mix of technical solutions, new ways of operating the power system, and market design reforms; and

- **Chapter 8** showed the key role electricity market design has to play in meeting many of the objectives of a net-zero emission power system, and our vision of what the key elements are for a future-proof electricity market design.

Based on these insights a number of recommendations for policymakers have been identified.

9.2 Recommendations for policymakers

Based on the results of this study, several key recommendations are made for both national and EU policymakers:

Explore ways to facilitate consumer participation, and increase demand-side flexibility in electricity markets at all time scales (day-ahead, intraday, balancing etc.). For example, allowing a greater share of consumers to communicate their willingness to (not) pay for electricity and have this manifest on markets through direct participation (via aggregators) or new forms of retail contracts would not only give consumers more control over their energy costs by allowing them to choose their level of reliability, but also reduce the uncertainty faced by regulators in estimating the VOLL. To ensure no one is left behind in the energy transition, vulnerable consumers may need targeted support.

Consider options to improve the liquidity of long-term forwards and future markets, and increase access to PPAs to counterbalance the need for state-aid support. Large-scale increase in variable RES capacities to levels considered in these scenarios will only be manageable if demand increases too, and in a flexible way. While periods of low prices should provide an incentive for some investment in additional load and storage technologies in the short-term, the large-scale investments needed in RES and P2X require longer-term revenue certainty. If these market-based measures are not timely, further targeted measures may be needed to accelerate and coordinate investments in RES and P2X.

Explore ways to simplify complex and lengthy permitting processes to accelerate infrastructure investments, reduce delays and costs. Infrastructure is both a prerequisite for the internal grid and a possible source of firm capacity for interconnectors. Cross-border interconnection should be taken into account as an important additional measure to support both system adequacy and security, next to investments in generation capacity, storage and DSR.

Limit interventions in the electricity market as much as possible to create a stable market environment which attracts investment. Interventions distort the proper functioning of electricity markets, erode price signals for investment in zero-carbon technologies, and may adversely affect the economic viability of capacity providers on both the supply and demand side.

Ensure any subsidy schemes introduced for RES and any other zero-carbon technologies (e.g. P2X) retain their exposure to short-term market price signals. This will reduce the risk of distortions, encourage 'system-friendly' behaviour, and facilitate their long-term integration into the market.

Include mechanisms to account for spatial challenges in support schemes and other investment measures. An efficient system development requires a better alignment of market activities with infrastructure investments. Infrastructure investments often face long lead times and can therefore not always react to the pace and dynamics of investment from the market, leading to delays in the energy transition and higher costs (e.g. redispatch) in the meantime. Additional locational incentives can help to achieve a better alignment of market activities with infrastructure needs.

Continue to monitor merchant investments in zero-carbon firm capacity over the coming years, alongside the expected demand and security of supply situation. If the market does not lead to the pace of investment required in DSR, storage and zero-carbon thermal capacity (either new-build plants or retrofitting of existing fossil plants to reduce emissions) to ensure timely decarbonisation while maintaining resource adequacy, additional (or strengthened) measures should be considered such as a technology-neutral capacity remuneration mechanism with locational components, open to both existing and new capacity.

Accelerate rollout of advanced smart meters capable of providing real-time price signals, as well as remote control of consumption. These will pave the way for retailers to offer more real-time pricing contracts, allow consumers to react voluntarily to market prices, and allow grid operators (via retailers) to reduce consumption in emergency situations based on consumer price preferences. Other technical and legal barriers preventing retailers from requesting local grid operators to reduce consumer demand in high price periods would also need to be addressed, without compromising the data, privacy and wellbeing of end consumers.

Phase out net metering of solar production as soon as possible (for the Netherlands), as this removes incentives for consumers to start self-balancing their production and load. Even small changes in behaviour by a large number of electricity producing households due to this incentive could help to reduce the evening demand peaks and use the afternoon production peaks.

9.3 Caveats and future work

Security of supply is a broad, complex and evolving topic. While certain uncertainties and risks can be quantified, others cannot (yet). In this section we outline a number of caveats to this study results, in particular with regards to scenario uncertainties, other adequacy risks, and required infrastructure developments. Some of these may be addressed in future studies.

9.3.1 Scenario uncertainties

- The *assumed energy efficiency measures might not be reached*, leading to a higher than expected load and increased need for additional (thermal) capacity. However, the NEL-Demand scenario can be seen as a sensitivity to cover this uncertainty.

- The geographical focus of this study is Germany and the Netherlands. While the rest of Europe has been considered in the modelling, no variations in the installed capacities are considered. *Different developments in the generation* portfolios of neighbouring countries – in particular less firm capacity – would have a significant impact on reliability in the Netherlands and Germany. Going forward it will be important to monitor future developments in neighbouring countries to identify potential risks early.

- *Game-changing technologies* could have a major impact on how resource adequacy is ensured, and the required capacities. For example, reversible P2G technologies, such as reversible fuel cell-based electrolysers [61] which can produce hydrogen when electricity prices are low, and generate electricity when prices are high, could have a major impact on the energy system. From an economic perspective, such technologies would have the advantage of being able to operate with significantly higher operational hours compared to stand-alone electrolysers or hydrogen plants. If deployed at large scale, such technologies could avoid the need for a dedicated fleet of hydrogen CCGT and OCGT plants (like assumed in this study), leading to much better utilisation of capital and infrastructure. Also, low-cost long-duration storage technologies could in theory change the storage duration of batteries, strongly improving their ability to serve as firm capacity and possibly even providing solutions to seasonal discrepancies in supply and demand.

9.3.2 Other adequacy risks

While this study considers adequacy risks such as forced outages of thermal plants, interconnectors, and climate uncertainty, certain adequacy risks are not quantified. These may be considered in future studies. For example:

- *Reliance on (imports) of zero-carbon fuels*. Most scenarios in this study rely to some extent on hydrogen (or other zero-carbon fuel) to achieve net-zero emissions. If these markets do not develop as assumed, domestic production falls short of expectations, or potential import volumes are limited due to limited international supply, the use of these fuels in the power sector could become very costly. Thus, it is important to ensure a diverse supply of zero-carbon fuels to the economy.

- *Correlated outage events*. While outages are typically modelled as uncorrelated events, certain (mostly) weather-driven events can result in simultaneous adequacy issues. For example, warm dry weather can lead to reduced availability of hydropower plants, as well as restrictions in thermal plant capacity due to insufficient cooling water. Major storms or cold spells may also trigger high demand for electricity, coupled with low RES generation, and simultaneous equipment failures in both the (zero-carbon) gas and electricity networks, as observed in the Texas outages in 2021 [62].

- *Implementation of nationalistic policies* aiming to e.g. cap or reduce exports have the potential to limit the value of interconnectors in challenging adequacy situations, and require more domestic investments. Security of supply will be higher for all Europeans in a free, integrated, price-driven market.

- *The impact of climate change* on the power system is not considered. The climatic conditions considered in this study are based on 35 historical climatic years (1982-2016), while climate change may have significant impacts on the energy system such as (i) heat waves which increase demand from air conditioning, (ii) long-term changes in rainfall patterns which could limit availability of hydro power in neighbouring countries, and (iii) increasing frequency or severity of major storms which damage critical infrastructure. TenneT is working with TSOs and other partners to consider climate change in future studies.

9.3.3 Infrastructure investment and modelling

- The analysis relies on the Net Transfer Capacity approach for modelling cross-border exchanges, while **underlying grid constraints** and congestion with flow-based market coupling is not considered.

- Solar and wind energy are modelled as being fully connected to the grid at their full capacity, while it is current practice (in NL) to **limit the capacity of new grid connections** for solar farms to 50% of the installed PV capacity. Different connection capacities due to economic or technical reasons could change their production patterns significantly.

- All the scenarios considered in this study depend on **significant infrastructure investments** in both electricity and zero-carbon fuels. If grid capacity is not sufficient to allow the introduction of newly connected flexible load and RES development as described, the pace of the energy transition will be slowed and transport adequacy could become a more limiting factor in ensuring security of supply than it is today. TenneT, together with other TSOs and infrastructure companies - is continually planning for a zero-carbon future and investing significantly in the grid. Future infrastructure requirements are covered in other products such as the Investment Plan, *Integrale Infrastructuurverkenning 2030-2050, Target Grid Netzentwicklungsplan* and the *Ten-Year Network Development Plan*.

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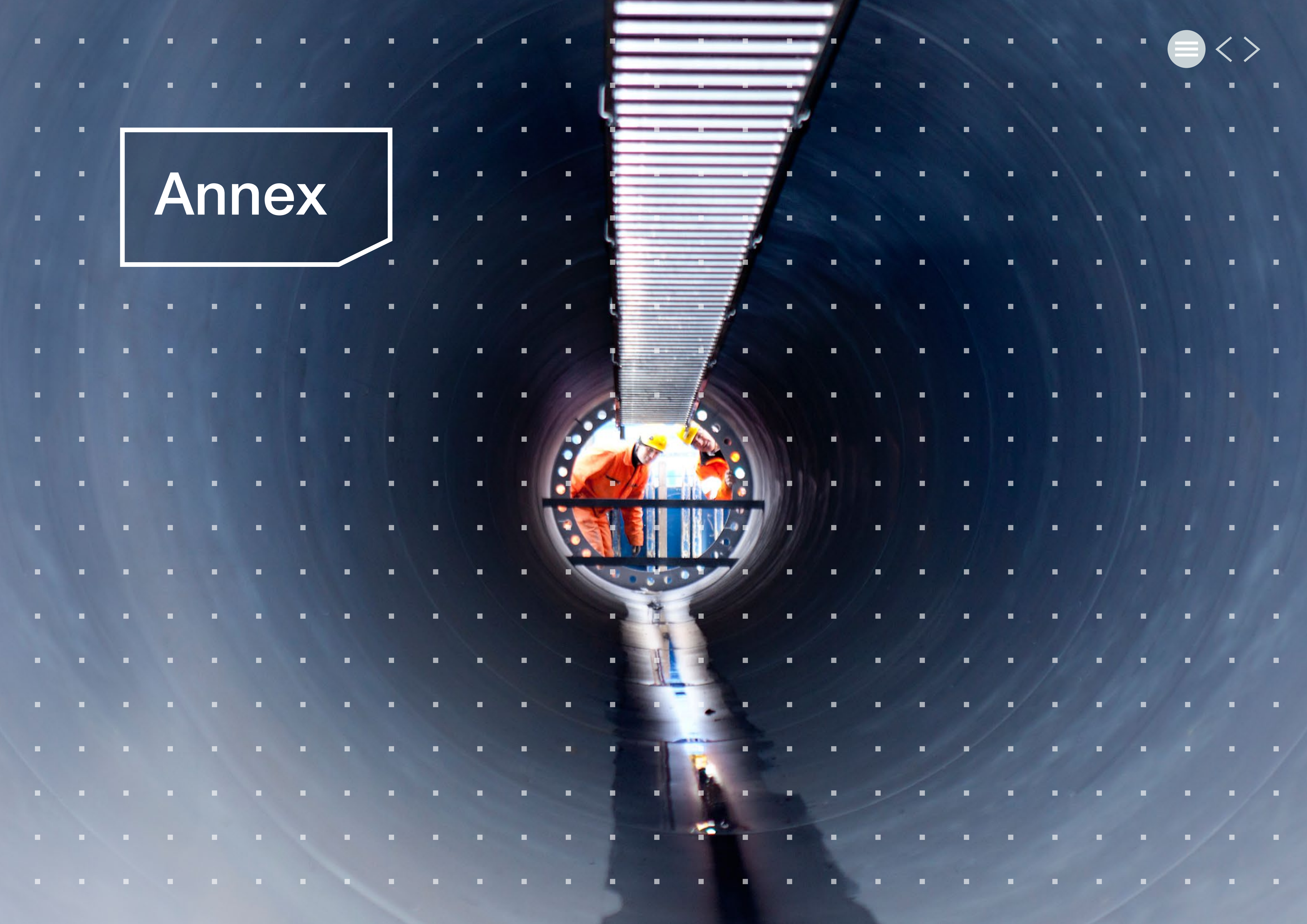
Annex



A1 Additional scenario assumptions for neighbouring countries

Technology		NEL-Wind							
Category	Type	BE	UK	DK	FR	PL	AT	CH	CZ
Zero-carbon thermal (GW)	-	24.0	78.6	7.7	63.9	36.6	0.8	3.6	14.1
Wind (GW)	Offshore	6.9	79.6	17.5	39.6	15.6	0.0	0.0	0.0
	Onshore	10.4	59.4	8.4	116.1	57.2	25.3	3.0	15.1
Solar PV (GW)	-	40.3	110.2	29.8	193.0	39.9	55.9	9.9	30.0
Hydro (GW)	Run-of-river	0.1	2.1	0.0	13.6	0.5	6.1	4.2	0.4
	Reservoir	0.0	0.0	0.0	9.8	0.3	2.5	0.0	0.7
	Pump storage	1,2	2.7	0.0	3.8	1.5	6.1	12.9	1.2
Other RES (GW)	-	0.5	6.3	0.2	2.4	0.6	0.6	0.4	0.7
Battery storage (GW)	-	10.9	30.9	0.5	4.4	6.5	14.9	3.9	3.8
DSR (GW)	Industry	2.0	4.3	0.0	5.5	0.8	0.5	0.0	0.0
	Power-to-gas (P2G)	5.6	30.9	10.7	42.0	16.8	2.5	0.0	2.8
Yearly demand (TWh) (excl. P2X)	-	141.7	618.8	100.1	657.0	242.6	115.8	76.3	91.5

Table A1 | Installed capacities in GW and yearly demand in TWh/y for selected countries in the NEL scenarios (i.e. NEL-Wind, NEL-Solar, NEL-Demand, NEL-Baseload)

Technology		IHE-Wind							
Category	Type	BE	UK	DK	FR	PL	AT	CH	CZ
Zero-carbon thermal (GW)	-	43.7	83.2	7.0	97.1	47.7	2.0	2.4	15.4
Wind (GW)	Offshore	6.6	86.1	32.7	66.2	20.0	0.0	0.0	0.0
	Onshore	9.1	44.8	7.3	85.4	20.3	22.2	0.5	10.9
Solar PV (GW)	-	28.7	62.5	12.5	196.2	20.1	50.7	0.0	19.7
Hydro (GW)	Run-of-river	0.1	2.1	0.0	13.6	0.5	6.1	4.2	0.4
	Reservoir	0.0	0.0	0.0	9.8	0.3	2.5	0.0	0.7
	Pump storage	1.2	2.7	0.0	3.8	1.5	6.1	12.9	1.2
Other RES (GW)	-	0.5	6.3	0.2	2.4	0.6	0.6	0.4	0.7
Battery storage (GW)	-	5.0	13.3	0.6	5.9	3.0	9.0	2.2	2.0
DSR (GW)	Industry	2.0	4.3	0.0	5.5	0/8	0.5	0.0	0.0
	Power-to-gas (P2G)	3.0	31.2	18.5	49.3	0,5	1.5	0.0	1.6
Yearly demand (TWh) (excl. P2X)	-	115.9	577.2	64.3	563.9	212.9	111.7	76.3	81.2

Table A2 | Installed capacities in GW and yearly demand in TWh/y for selected countries in the IHE scenario (i.e. IHE-Wind)

A2 Additional technology assumptions and sources

Category	Type	Efficiency (LHV) (%)	VOM (€/MWh)	Outage Rate (%) [b]		OCC (€ kW^{-1})			FOM (€ kW^{-1} y^{-1})			Economic lifetime (y)	Build time (y) [s]
				Planned	Unplanned	*Ref*	*Low*	*High*	*Ref*	*Low*	*High*		
Low-carbon thermal [i]	Nuclear	33% [b]	14 [g]	15%	5%	5000 [c]	4000 [c]	6000 [c]	80 [g]	60 [b]	100 [c]	30	7
	Biomass	46% [b]	3 [g]	7%	10%	-	-	-	-	-	-	-	-
	Hydrogen OCGT	42% [b]	2.5 [eg]	4%	5%	500 [h]	400 [b]	600 [e]	20 [e]	10 [b]	30 [b]	20 [p]	1
	Hydrogen CCGT	60% [b]	2.5 [eg]	7%	5%	650 [egh]	600 [b]	750 [m]	20 [g]	15 [mn]	35 [e]	20 [p]	3
RES	Onshore wind	-	0	-	-	1000 [c]	700 [d]	1200 [c]	20 [c]	15 [c]	30 [c]	25 [g]	2
	Offshore wind	-	0	-	-	2000 [f]	1500 [c]	2500 [c]	40 [c]	30 [c]	60 [c]	25 [g]	2
	Solar PV	-	0	-	-	400 [cg]	300 [c]	500 [c]	10 [c]	8 [c]	13 [c]	25 [g]	1
Hydro	Run-of-river	-	0	-	-	-	-	-	-	-	-	-	-
	Reservoir	-	0	-	-	-	-	-	-	-	-	-	-
	Pump storage	X	0	-	-	-	-	-	-	-	-	-	-
Storage	4 hour	90% [gj]	0.5 [g]	-	-	600 [cg]	450 [eg]	1000 [ce]	15 [b]	8 [g]	20 [e]	15 [g]	1
	8 hour	75% [gj]	0.5 [g]	-	-	1100 [k]	700 [k]	1500 [k]	15 [b]	8 [g]	20 [e]	15 [g]	1
DSR	Industry	-	Various	-	-	20 [l]	0 [l]	100 [l]	20 [l]	5 [l]	50 [l]	10	1
	EVs	-	700	-	-	-	-	-	-	-	-	-	-
	HPs	-	500	-	-	-	-	-	-	-	-	-	-
	P2G[a]	76%	NEL: 49 IHE: 26	-	-	120	-	-	-	-	-	20	1
	P2H	-	NEL: 76 IHE:43	-	-	60	-	-	-	-	-	20	1

Table A3 | Additional technology assumptions and sources

Footnotes for Table A3

(a) For P2G, the VOM here refers to the maximum electricity price plants are willing to spend to generate hydrogen, and thus the 'VOM' for DSR provided by P2G. For the economic calculations of actually producing hydrogen from P2G, a VOM of 4 €/MWh electric input is assumed, together with the quoted efficiency, OCC and FOM.

(b) Own assumptions

(c) Based on a range of estimates identified from the literature (Sources: [63] [64] [65] [66] [67] [68] [69] [70] [71])

(d) Based on II3050 [72]

(e) Based on Pöyry study for North Sea Wind Power Hub [69]

(f) Offshore wind costs are difficult to compare between studies, depending on whether connection costs to the onshore grid are included or not. Our reference level assumes 1000 €/kW for the turbines from II3050 [73] , and roughly 1000 €/kW for grid connection cost to the shore based on a study by Berenschot and Guidehouse [74]. Cost uncertainty is also higher due to impact of water depth and distance to shore on costs.

(g) Based on Aurora (2021) [28]

(h) Similar to current investments costs for natural gas units based on published CONE studies (e.g. [75] [76]) assuming costs for hydrogen-fired turbines will not be considerably different

(i) For Nuclear (in NL) we assume unit blocks of 1000 MW, representing a potential mix of both larger Gen III+ nuclear units (~1600 MW), and smaller modular reactors (~300 MW) [28]. Hydrogen OCGT (50 MW) and CCGT (400 MW) units sizes are based on typical block sizes for natural gas plants. For units in other countries, the size depends on the original data provided by TSOs in the TYNDP dataset.

(j) Roundtrip efficiency for storage technologies

(k) Based on Aurora 2022 [77]

(l) Literature estimates for CAPEX and FOM for DSR vary widely. The values assumed here are based on published national CONE studies across Europe which suggest a range of costs, but an average total fixed CONE in the order of 20 €/kW/y. However, costs may be higher or lower in different industries, thus a wider range is assumed than for the other technologies.

(m) CREG 2020 [75]

(n) Terna 2021 [76]

(o) Taken from National Grid ESO 2021 [78]. These de-rating factors are calculated as part of the UK capacity auction up until the year 2025, and not necessarily representative in a net-zero emission system in the Netherlands and Germany in the long term. However, they give a rough indication for the cost of new entry calculations, and can be compared with the de-rating factors calculated using the simplified methodology presented in the main report.

(p) Based on Elia 2021 [79]

(q) The economic lifetime is the investment lifetime considered in the economic assessment for financing a project, and is usually equal to or less than the technical lifetime. A longer economic life is assumed for nuclear given these typically have longer lifetimes than other thermal plants, and represent a more long-term investment. A lower lifetime is assumed for industrial DSR given a shorter payback time would likely be expected for an operating facility.

(r) Construction times are very project dependent. Nuclear construction time is based on the expectation that the new nuclear plants announced for NL will begin construction in 2028, and be operational by 2035 [80]. Offshore wind construction time is typically 2 to 3 years, depending on the size of the farm. Two years is assumed here based on expectations for the Hollandse Kust Zuid farm [81]

A3 Revenue streams, technology risks and hurdle rates for the economic viability assessment

Technology Type	Revenues	Costs
Low-carbon thermal (all)	Based solely (wholesale) electricity sales. Revenues from ancillary services or capacity markets are not considered.	Costs include variable generation costs (fuel and VOM), FOM, and annualised CAPEX.
RES	Based solely (wholesale) electricity sales.	Costs include FOM, and annualised CAPEX.
Hydro	*Not evaluated*	*Not evaluated*
Storage batteries	Based solely (wholesale) electricity sales. Revenues from ancillary services or capacity markets are not considered.	Costs for batteries include electricity charging costs, VOM, FOM and annualized CAPEX.
Industrial DSR	Taken as the total 'savings' in electricity costs for each industry sector due to DSR, by comparing the total annual cost for electricity consumption with and without load shedding	Costs for other DSR include (i) FOM, (ii) annualized CAPEX, and (iii) the implied cost of lost production due to load shedding. As a proxy, the latter is calculated as the volume of load shed, multiplied by the DSR activation price, assuming this is the indifference price at which the cost of consuming the electricity is equivalent to the value of the good/service produced by the industry sector.

Table A4 | Revenue and cost types considered as part of the economic viability analysis of the different capacity types

		Risk rating (L=Low, M=Medium, H=High, - = n/a)								
Risk category (Hurdle premium range)	Technology	Construction	Volume	Shaping/ Profile	Revenue Volatility	Fuel related	Balancing	Technology	Policy/Legal	Comments
Low (0 ≤ h ≤ 5 %)Solar PV	Solar PV	L	L	H	L	-	M	L	L	Relatively predictable revenues, risks mostly due to shaping effects, revenue cannibalisation, and balancing.
	Onshore wind	L	L	M	L	-	M	L	L	Similar to solar PV, but somewhat lower shaping risks as generation profile more constant.
	Offshore wind	M	L	M	L	-	M	L	L	Similar to onshore wind but somewhat higher construction and technology risks.
Moderate (5 ≤ h ≤ 9 %)	Hydrogen CCGT	L	M	L	M	H	L	M	L	More volatile revenues than RES due to mid-merit operation, more dependent on high prices. Additional risk of future price and availability of hydrogen.
	Battery 4 hour	L	M	L	M	M	L	L	L	Similar to hydrogen CCGT, but lower fuel and technology risks. Some 'fuel risk' due to uncertain electricity prices for charging.
	Battery 8 hour	L	M	L	M	M	L	M	L	Similar to 4 hour battery, but with higher technology risks given large-scale deployment not yet achieved.
High (h>9 %)	Hydrogen OCGT	L	H	L	H	M	L	M	M	Rare activation, significant downside risk as reliant on few hours of activation at high prices, susceptible to market intervention to reduce high prices. Less susceptible to fuel risks than CCGT due to lower operating hours and fuel use.
	DSR (all bands)	L	H	L	H	-	L	L	M	Similar to hydrogen OCGT but with even more volatile revenues, though without fuel risks
	Nuclear	H	H	L	M	M	L	M	H	High-capital intensive, long-term projects with significant construction risks, fuel related risks, and major policy uncertainty.

Table A5 | Assumed technologies per risk category and hurdle premium

A4 Links to scenarios in the Energy Transition Model (ETM)

Links to the energy system scenarios developed using the ETM as the basis for Dutch and German scenarios can be found in the table below. The resulting load profiles for electricity and hydrogen demand can also be downloaded via the ETM. Note that the NEL-Demand scenarios were not built in the ETM, but simply based on the NEL-Wind scenarios with adapted load profiles.

Country	Scenario	Variant	ID	ETM link
NL	NEL	Wind	NL_NEL_Wind	https://pro.energytransitionmodel.com/saved_scenarios/11506
NL	NEL	Solar	NL_NEL_Solar	https://pro.energytransitionmodel.com/saved_scenarios/11519
NL	NEL	Baseload	NL_NEL_Nuclear	https://pro.energytransitionmodel.com/saved_scenarios/11522
NL	IHE	Wind	NL_IHE_Wind	https://pro.energytransitionmodel.com/saved_scenarios/11509
DE	NEL	Wind	DE_NEL_Wind	https://pro.energytransitionmodel.com/saved_scenarios/11507
DE	NEL	Solar	DE_NEL_Solar	https://pro.energytransitionmodel.com/saved_scenarios/11521
DE	IHE	Wind	DE_IHE_Wind	https://pro.energytransitionmodel.com/saved_scenarios/11508

Table A6 | Links to Energy Transition Model scenarios

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