Flexibility Needs Assessment report for the Netherlands

July **2026**

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Executive summary

Introduction

This report presents the first Dutch Flexibility Needs Assessment (FNA), prepared pursuant to Regulation (EU) 2024/1747. The assessment evaluates future flexibility needs of the Dutch electricity system for the target years 2030 and 2035.

The Dutch FNA was prepared by TenneT, acting as the designated entity for the Netherlands, in close cooperation with the Dutch distribution system operators Coteq, Enexis, Liander, RENDO, Stedin and Westland Infra. It brings together system flexibility needs, transmission network flexibility needs and distribution network flexibility needs into a single national assessment of future flexibility requirements.

The assessment distinguishes between three complementary categories of flexibility needs. First, system flexibility needs assess the flexibility required to accommodate renewable generation, manage residual load variability and address short-term forecast errors. These system needs are evaluated at national level, without considering the constraints of the underlying electricity grid. Second, transmission network flexibility needs assess the flexibility required to manage congestion and transport constraints within the TenneT transmission network. Third, distribution network flexibility needs assess the flexibility required to manage local constraints in the distribution networks operated by the Dutch DSOs.

Methodology and scenario assumptions applied

TenneT and the Dutch DSOs have conducted the FNA in accordance with the official methodology for the FNA approved by the Agency for the Cooperation of Energy Regulators (ACER). This required several new features to be implemented in TenneT's electricity market models including detailed power plant flexibility constraints, day-ahead forecast errors for solar and wind, and coupled simulations between day-ahead and real-time models. Further methodological developments were also needed to analyse and interpret the results for system needs, transmission network flexibility needs and distribution network flexibility needs.

This FNA is based on the *Verkenning Vertraagde Transitie* (VVT) or "Delayed Transition" scenario, developed jointly by the Dutch grid operators in consultation with stakeholders. This scenario incorporates the latest insights into the pace of the energy transition in the Netherlands but does not assume full achievement of all longterm energy and climate targets. Nevertheless, the scenario assumes continued electrification, strong growth in renewable electricity generation and substantial deployment of flexibility resources. For example, under this scenario the total electricity demand in the Netherlands is assumed to increase from roughly 120 TWh/y in 2025 up to 156 TWh/y in 2030 and 196 TWh/y in 2035. The installed capacity of renewable energy sources (RES) is expected to more than double by 2035 compared to 2025, with the total installed capacity of wind (onshore and offshore) and solar photovoltaics reaching 28 GW and 52 GW respectively. At the same time, by 2035 the installed battery capacity is assumed to increase to approximately 16 GW, Power-to-X capacity to approximately 6.5 GW, and interconnection capacity to approximately 12.6 GW.

These developments substantially increase the variability of the Dutch electricity system, resulting in larger fluctuations in residual load (i.e. electricity demand minus RES generation), stronger hour-to-hour variations and more frequent periods of surplus RES generation.

Key results of the FNA

The table below shows an overview of the high-level quantified uncovered flexibility needs for the Netherlands for target years 2030 and 2035. The key results for system needs, TSO and DSO network needs are further explained below.[1]

Type	Flexibility need	Indicator	Total Volume (TWh)	
			2030	2035
System needs	RES integration	RES integration needs	0	0
	Ramping needs	Upward needs	0	0
	Short-term needs	Upward needs	0.02	0.02
Network needs	TSO network needs	Downward needs	7.8	5.2
		Upward needs	13.8	5.6
	DSO network needs	Downward needs	0.08	0.02
		Upward needs	0.14	0.04

System-level flexibility needs can be met under the assumed scenario conditions

Despite the increase in variability, no structural uncovered flexibility needs are identified at system level in either 2030 or 2035 after taking into account the flexibility resources assumed in the VVT scenario. This does not imply that no flexibility is required. Instead, the assumed portfolio of flexibility resources in the VVT scenario is sufficient to manage hourly ramping requirements and short-term flexibility needs, while still meeting national RES integration targets. The flexibility portfolio in the VVT scenario should not be interpreted as a forecast of future flexibility deployment, but as a scenario assumption used to assess covered and uncovered flexibility needs. The key results for RES integration are summarised below.

RES integration assessment (TWh)	2030	2035
Net RES generation	85	150
RES integration target	81	150
RES integration needs	0	0

Despite RES curtailment, net RES generation remains sufficient to meet the national RES integration targets in both 2030 and 2035, resulting in zero RES integration needs.

The absence of uncovered system-level needs is supported by a diverse portfolio of domestic and cross-border flexibility resources. The analysis indicates that domestic flexibility resources provide the primary contribution to managing additional short-term variability, while cross-border exchanges provide an important additional source of flexibility and contribute to maintaining system balance. At the same time, the results show that the Dutch electricity system increasingly relies on the availability of flexibility in neighbouring countries.

[1] Averaged across the simulated climate years

However, the results should not be interpreted as evidence that sufficient flexibility will automatically be available in the future. The identified absence of uncovered system needs is conditional upon the availability of the domestic and foreign flexibility resources assumed in the VVT scenario, including storage, demand-side flexibility, dispatchable thermal capacity, as well as interconnection capacity. Ensuring that sufficient volumes of these flexible resources are available in the system – including both existing and new sources of flexibility - will therefore remain an important consideration in the years ahead. Mechanisms aimed at safeguarding resource adequacy and maintaining investment incentives for flexible and dispatchable capacity may contribute to supporting these assumptions.

Significant transmission-network flexibility needs remain despite planned grid reinforcements

When transmission and distribution network constraints are considered, significant network-related flexibility needs emerge. These needs differ fundamentally from system-level flexibility needs, as they are location-specific and directly linked to physical limitations in the electricity grid. A substantial share of the identified network flexibility needs is transitional in nature and decreases as planned network reinforcements are commissioned.

The largest network-related flexibility needs are identified in the transmission network. These needs are concentrated in a limited number of regions and are primarily associated with transport constraints in the 110–150 kV and 220–380 kV networks. The identified needs are often characterised by large energy volumes and long activation durations, indicating that flexibility is likely to complement rather than replace network reinforcement. Although planned reinforcement projects reduce these needs between 2030 and 2035, significant flexibility requirements remain. Additional transmission investments expected to be commissioned after 2035 are anticipated to further reduce these flexibility needs, particularly in the 220–380 kV network.

The transmission-network results should be interpreted in the context of the underlying scenario assumptions. In particular, the flexibility needs identified in the 220–380 kV network are strongly influenced by cross-border power flows and the assumed development of demand, renewable generation and flexibility resources in neighbouring countries. Consequently, the magnitude and location of the identified transmission-network flexibility needs are sensitive to assumptions regarding the pace of electrification, renewable deployment and deployment of flexible capacity both within and outside the Netherlands. The results should therefore be interpreted as flexibility needs under the analysed scenario assumptions rather than as forecasts of future congestion volumes.

Distribution-network flexibility needs are more local and decrease substantially towards 2035

Compared with transmission network needs, distribution network needs are generally characterised by lower volumes, shorter activation durations and clearer temporal patterns. These needs are concentrated around specific substations and network areas and are typically associated with local demand growth or renewable generation. Compared with transmission-network needs, distribution-network needs occur during more limited periods and are generally better suited to targeted flexibility measures such as demand response, local storage and other decentralised solutions. Similarly as for TSO network needs, the analysis shows that many identified DSO flexibility needs diminish significantly between 2030 and 2035 as planned reinforcement projects are realised, leaving only a limited number of local residual constraints. It should be taken into account however that only the flexibility needs for networks with a voltage level of 25kV and higher have been determined. Networks at lower voltage levels might have flexibility needs as well.

While many identified DSO flexibility needs appear technically suitable for flexibility solutions, practical experience to date shows that the availability of upward flexibility remains limited in many areas. Realising the flexibility potential identified in this assessment may therefore require further development of flexibility markets, products and participation by flexible resources.

Key conclusions and insights

No single solution can address all flexibility needs

The assessment demonstrates that flexibility needs differ significantly across system levels, locations and timeframes. System-level needs are primarily driven by temporal mismatches between electricity demand and renewable generation, whereas network-related needs are strongly location-specific and depend on local grid constraints. Different types of needs therefore require different combinations of solutions, including grid reinforcement, storage, demand response, redispatch and sector coupling.

An effective approach to flexibility therefore requires a coordinated portfolio of measures tailored to the specific characteristics of each need, rather than reliance on a single technology or policy instrument.

Flexibility needs remain dependent on future investments

The absence of structural uncovered system-level flexibility needs in this assessment should be interpreted in the context of the underlying scenario assumptions. The results rely on substantial growth in batteries, demand-side flexibility, and interconnection capacity, both in the Netherlands and abroad. The extent to which these resources are realised will depend on future market conditions, policy frameworks and investment incentives. Consequently, ensuring that sufficient flexibility is delivered to the system may require continued attention to market design, resource adequacy measures and potential support mechanisms for non-fossil flexibility.

Policy support may be needed to support flexibility if the scenario assumptions are not realised.

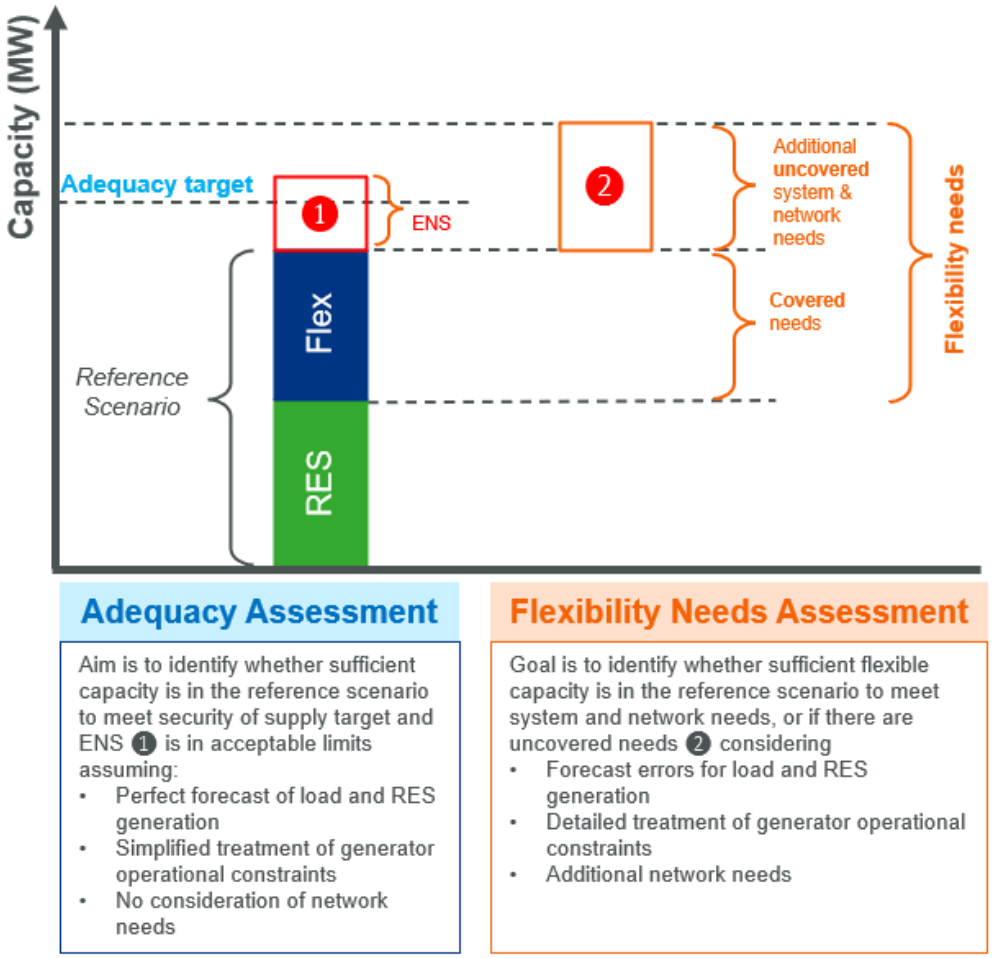
The finding that system-level flexibility needs are largely covered should not be interpreted as evidence that sufficient flexibility will automatically be delivered by the market. The assessment of covered and uncovered flexibility needs is inherently linked to the flexibility portfolio assumed in the scenario. While the VVT scenario assumes substantial growth in batteries, demand-side flexibility, Power-to-X facilities and interconnection capacity, the realisation of these investments remains subject to uncertainties related to technology costs, market revenues, financing conditions and future regulatory frameworks. If flexibility resources are deployed more slowly, or at a lower scale than assumed, a larger portion of the identified flexibility needs would become uncovered. In such circumstances, policymakers may consider whether existing market arrangements continue to provide sufficient investment incentives or whether additional measures, such as the planned capacity remuneration mechanism or targeted support schemes for non-fossil flexibility, could help ensure that the required flexibility resources are realised in a timely manner.

Scope FNA and comparison to other studies

The results should be interpreted within the scope of the FNA methodology. The network-related flexibility needs presented in this report are not directly comparable to flexibility volumes identified through congestion management studies or congestion forecasts. The FNA is a long-term scenario-based assessment intended to identify future flexibility needs under a consistent European methodology. Congestion studies are typically conducted for operational or planning purposes using different assumptions, methodologies and levels of detail. Consequently, the volumes reported in this assessment should not be interpreted as forecasts of future congestion management procurement volumes.

The FNA complements rather than replaces Dutch and European adequacy assessments. While adequacy studies such as the Monitor Voorzieningszekerheid (MVZ) and the European Resource Adequacy Assessment (ERAA) focus on whether sufficient generation and interconnection capacity is available to maintain security of supply, the FNA assesses whether sufficient flexibility is available to accommodate renewable integration, forecast errors, operational constraints and network-related flexibility needs. Figure 1 illustrates how the FNA builds on adequacy assessments and assesses both covered and uncovered flexibility needs.

Figure 1 | Relationship between adequacy assessments and the flexibility needs assessed in the FNA.



The FNA assesses both covered and uncovered flexibility needs. The system-needs results presented in this report primarily relate to uncovered flexibility needs after taking into account the flexibility portfolio assumed in the VVT scenario. In addition, the FNA assesses network-related flexibility needs for both the transmission and distribution networks.

Finally, the results remain dependent on the underlying scenario assumptions. Future flexibility needs will be influenced by the pace of electrification, renewable energy deployment, the availability of flexibility resources, developments in neighbouring countries and the timely completion of network investments. Deviations from these assumptions may result in lower or higher flexibility requirements than identified in this assessment.

The findings of this first Dutch Flexibility Needs Assessment provide a common basis for discussions on future flexibility developments and support policy makers, regulators, network operators and market participants in facilitating a reliable, affordable and decarbonised electricity system.

Unlocking flexibility potential is important for addressing identified network-related flexibility needs.

While system-level flexibility needs can be met with the assumed flexibility portfolio, the assessment identifies significant network-related flexibility needs. Addressing these needs will require not only sufficient technical flexibility potential, but also the ability to mobilise that flexibility in practice. Barriers related to DER participation, new investments, grid connection constraints and risk exposure may limit the deployment of flexibility services. Reducing these barriers is therefore important to enable flexibility to contribute effectively to congestion management and the mitigation of network-related flexibility needs.

1. Introduction

This report marks the first Dutch **Flexibility Needs Assessment** (FNA), introducing a new reporting obligation that every Member State of the European Union (EU) must fulfil every two years.[2] The primary aim of the FNA is to assess the flexibility needs of the Dutch electricity system over a 5- to 10-year horizon. This time horizon is relevant as it aligns with typical investment cycles in the energy system and provides forward-looking insights into expected system developments.

The assessment aims to identify when, where, and to what extent additional flexibility will be required to ensure a secure, reliable and cost-efficient electricity system, particularly in the context of increasing shares of renewable energy. The results of the FNA are intended to support policymakers, regulators, system operators, and market participants. For example, they can inform the development of policies and regulatory frameworks, including potential measures to stimulate non-fossil flexibility, improve market design, and address barriers to flexibility. In particular, the outcomes of the FNA are intended to support countries in setting targets for non-fossil flexibility and can serve as a basis for introducing support schemes to ensure that sufficient non-fossil flexibility is deployed. In addition, the FNA provides transparency to market parties and investors regarding expected future flexibility needs, thereby supporting potential investment decisions in flexible solutions such as storage, demand response, and other innovative technologies. Ultimately, this contributes to a more efficient functioning of electricity markets and facilitates the integration of renewable energy at least cost to society.

In the Netherlands, the Dutch Ministry of Economic Affairs (EZK) has appointed Transmission System Operator (TSO) TenneT as the designated entity for drafting the FNA. TenneT has performed this task with support of the regional Distribution System Operators (DSOs) Coteq, Enexis, Liander, Rendo, Stedin, and Westland Infra. The findings have been jointly compiled by the grid operators into this national FNA report.

In the remainder of this introductory chapter we present the legal and regulatory background to the FNA, how the FNA has been developed and organised at national level, and several key concepts and terms which are important for understanding the rest of the report.

1.1. Legal and regulatory context

The FNA is a newly-mandated national assessment established under Regulation (EU) 2024/1747 of the European Parliament as regards improving the Union's electricity market design as part of the Electricity Market Design Reform (EMDR), [3] which amended Regulation (EU) 2019/943 (recast) on the internal market for electricity (hereafter the "Electricity Regulation").[4] This update to the regulatory framework aims to enhance the resilience, efficiency, and integration of electricity markets across the Union, with a particular focus on accommodating the increasing penetration of variable renewable energy sources (RES) such as wind and solar photovoltaics (PV). The FNA is designed to systematically identify and quantify the flexibility requirements necessary to ensure the secure and reliable operation of the electricity system, both at national and cross-border levels. Article 19e of the recast Electricity Regulation requires all EU countries to carry out a biennial assessment of the electricity system's flexibility needs over a 5-to-10-year time horizon, which must be submitted to the European Commission and the European Union Agency for the Cooperation of Energy Regulators (ACER).

The type and format of data and the methodology for TSOs' and DSOs' flexibility needs analysis (hereafter the **"FNA methodology"**) was developed jointly by the European Network of Transmission

[2] Formally the Regulation refers to *Member States*, but we use the term *country* throughout this report for simplicity.
[3] (Regulation (EU) 2024/1747 of the European Parliament and of the Council of 13 June 2024 amending Regulations (EU) 2019/942 and (EU) 2019/943 as regards improving the Union's electricity market design, 2024)
[4] (Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast), 2019)

System Operators for Electricity (ENTSO-E) and the EU DSO Entity and formally adopted by ACER in July 2025 (ACER, 2025). Following the ACER's decision on the FNA methodology, each country is required to conduct a national flexibility needs assessment using the new methodology by July 2026. Pursuant to Article 19e(7) of the recast Electricity Regulation, once all the national FNA reports have been submitted to ACER, the Agency shall issue a report analysing the national reports on the estimated flexibility needs and providing recommendations on issues of cross-border relevance (expected in July 2027).

In accordance with Article 19f of the recast Electricity Regulation, the FNA forms the analytical basis for subsequent policy actions at national level. Within six months following the submission of the FNA report pursuant to Article 19e, countries are required to define an **indicative national objective for non-fossil flexibility**. This objective is based on the flexibility needs identified in the FNA and includes, where relevant, the expected contributions of key flexibility sources such as demand response and energy storage. Countries may achieve this objective through different means, including the removal of identified market and regulatory barriers to flexibility, thereby enabling market-based investment. Where such measures are not sufficient to realise the required level of flexibility, Article 19g provides the possibility for countries to introduce **non-fossil flexibility support schemes**.

1.2. Governance: designated bodies involved in the FNA report

Article 4(1) of the FNA methodology requires TSOs and DSOs within each country to agree with each other and with the respective designated authority or entity (and where an entity is designated, also with the regulatory authority) on the national organisation of the FNA process. This includes agreement on the scope of data and analyses to be provided, the respective roles and responsibilities, and the timelines for delivering inputs to the FNA report. In line with these requirements, the TSOs and DSOs conduct the agreed analyses and deliver their results to a designated entity, which is responsible for compiling the national FNA report. For the Netherlands, the following forming roles and responsibilities have been established regarding the FNA in accordance with Article 19e(1) of the Electricity Regulation:

- the Dutch Ministry of Economic Affairs (EZK) has appointed TenneT as the designated entity for drafting the FNA (Ministerie van Klimaat en Groene Groei, 2025);
- The Netherlands Authority for Consumers and Markets (ACM) is tasked with approving (or amending) the FNA report submitted by TenneT.

As designated entity, TenneT has prepared this report together with the Dutch DSOs Coteq, Enexis, Liander, Rendo, Stedin, and Westland Infra. The FNA methodology prescribes several types of flexibility needs that must be assessed as part of the FNA. Following discussions between TenneT, the DSOs and ACM in the second half of 2025, the following responsibilities were agreed as summarised in Table 1:

- TenneT would be responsible for conducting the assessment of the system flexibility needs, transmission network flexibility needs, as well as the analysis of market barriers.
- The DSOs would be responsible for assessing the distribution network needs and, together with TenneT, fine-tuning those needs (where necessary) with the system and transmission network flexibility needs.

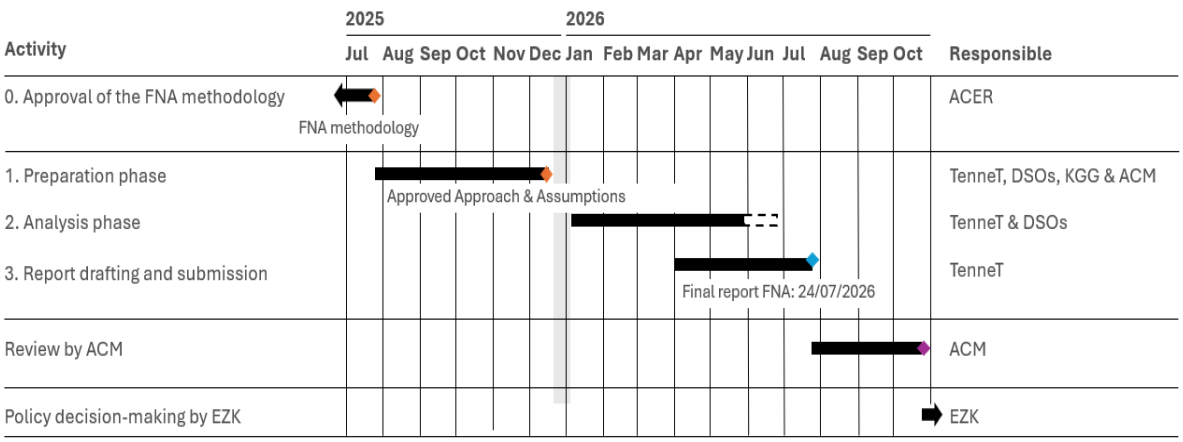
Table 1 | Assignment of responsibilities for the various FNA analyses between TenneT and the Dutch DSOs

Need / Analysis Type	Relevant FNA Methodology Article(s)	Primary Responsible
System Needs, including • ***RES integration needs*** • ***Ramping needs*** • ***Short-term flexibility needs***	Articles 7, 8, 9, 10	TenneT
Distribution Network Needs	Article 11	DSOs (Coteq, Enexis, Liander, Rendo, Stedin, and Westland Infra)
Transmission Network Flexibility Needs	Article 12	TenneT
Fine-Tuning System Needs with Network Needs	Article 14	TenneT, DSOs
Market Barriers & Digitalisation	Article 15	TenneT

TenneT and the DSOs have worked in close cooperation and alignment since July 2025 to ensure efficient and timely exchange of the necessary data and results and facilitate timely delivery of this first FNA report (

Figure 2). Pending approval by ACM, the final FNA report will be published and submitted to ACER and the European Commission.

Figure 2 | Overview of the process and timeline for TSO and DSO cooperation in drafting the FNA report



1.3. Relationship between the FNA and resource adequacy assessments such as the Monitor Voorzieningszekerheid

The Electricity Regulation (Article 19(e) paragraph 1(a)) requires that the FNA shall be consistent with the European Resource Adequacy Assessment (ERAA) and the National Resource Adequacy Assessments (NRAA). In line with the FNA methodology, this consistency is ensured by basing the FNA on (at least) one of the central reference scenarios of the ERAA (see section 3.1) and performing the analysis on a subset of climate scenarios consistent with the ERAA (see section 2.2). Starting from this consistent input data, but having a different scope, the FNA complements the adequacy assessment by assessing different aspects of the power system by[5]:

- Accounting for technical constraints or capabilities that are less relevant for adequacy studies, such as ramping, start-up and/or shut-down constraints.
- Accounting for load and RES forecast errors, which are typically not considered in resource adequacy studies which assume 'perfect forecast' of load and RES generation.
- Accounting for network needs or 'transmission adequacy' considerations, which are out of scope of resource adequacy studies which rely on a simplified network model and consider only a limited number of critical network elements and contingencies.

Thus, by ensuring the FNA is both consistent with and complementary to the input adequacy assessment, it ensures that any additional capacity (or energy) needs for flexibility which are identified are conceptually distinct from any potential capacity needs for adequacy.

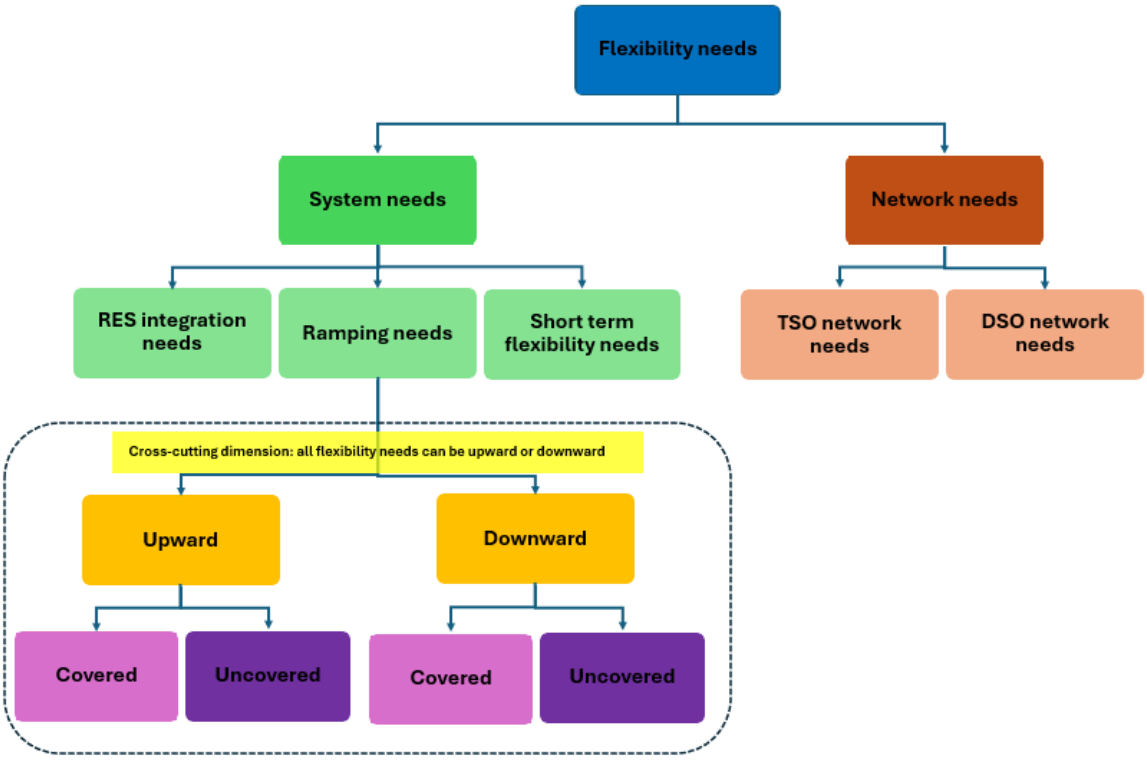
1.4. Key definitions

Flexibility is defined in the Electricity Regulation (Article 2(79)) as *"the ability of an electricity system to adjust to the variability of generation and consumption patterns and to grid availability, across relevant market timeframes"*. More concretely, it refers to the ability of electricity resources in the power system — such as storage, demand response, flexible generation and interconnection — to increase, decrease or shift electricity production or consumption in response to system or local grid conditions. **Flexibility needs** on the other hand describe how much, when and where such flexibility is required to operate the electricity system securely and efficiently, integrate renewable electricity to desired levels, while ensuring local grid limits such as congestion or voltage problems are managed.[6] While there is already significant flexibility in the power system provided by flexible consumers and Demand Side Response (DSR), existing fossil thermal power plants,[7] interconnection and storage technologies such as batteries, flexibility needs are expected to increase in the future as the power system accommodates an increasing share of RES.

Flexibility needs can be **upward**, requiring more electricity injection or less demand on the grid; or **downward**, requiring less injection or more demand on the grid. The FNA methodology formally distinguishes between two main types of flexibility needs: **system flexibility** needs and **network flexibility** needs, each of which is further sub-divided, as summarised in Figure 3. The upward/downward split, and the distinction between covered and uncovered needs introduced below, apply across all categories.

[5] *The principles of this complementarity are outlined in the Recitals of the FNA methodology (e.g. Recitals 11, 12, and 17)*
[6] *Neither the Electricity Regulation nor the FNA methodology provide a formal definition of flexibility needs; the definitions provided here are simply for understanding.*
[7] *The focus of the FNA is on non-fossil sources of flexibility, such as that provided by batteries, DSR, and interconnection.*

Figure 3 | Categories of flexibility needs as defined in the FNA methodology. Note that the sub-categorisation into upward and downward needs and covered and uncovered needs applies to all types of needs but is shown here only for ramping needs for simplicity.



System needs are defined in the FNA methodology as *"flexibility needed by the electricity system to adjust to the variability of generation and consumption patterns, across relevant market timeframes"*. Put simply, these needs reflect the system-wide ability required to manage changes in **residual load**: the electricity demand left after wind, solar and other variable renewable generation have been subtracted. This residual load must be managed by flexible resources in the system such as storage, demand response, flexible generation and interconnection, as shown in Figure 4. In situations where the generation from RES would exceed the demand for electricity i.e. negative residual load, **curtailment** of RES (voluntary or directed) can also be a flexibility solution, though this lowers overall net generation from RES in the system.

For system needs, a distinction is made between RES integration needs, ramping needs, and short-term flexibility needs:

- **RES integration needs** indicate the amount of flexibility required in the system to accommodate RES to the target level. For example, rather than curtailing RES generation, additional storage capacity can provide flexibility by charging from the grid during periods of surplus RES generation and discharging it at a later point in time.
- **Ramping needs** refer to flexibility needed in the system to manage fluctuations in residual load. These needs are shown also in Figure 4. The more quickly the residual load changes from one hour to the next, i.e. the higher the residual load 'ramps', the more flexibility is required in the system (see Figure 4).
- **Short-term flexibility needs** refer to the flexibility needed to manage unexpected fluctuations in residual load because of forecast errors in load or RES generation that materialize shortly before real time and hence can only be provided by operational (i.e. spinning) or fast-starting resources (see Figure 5).

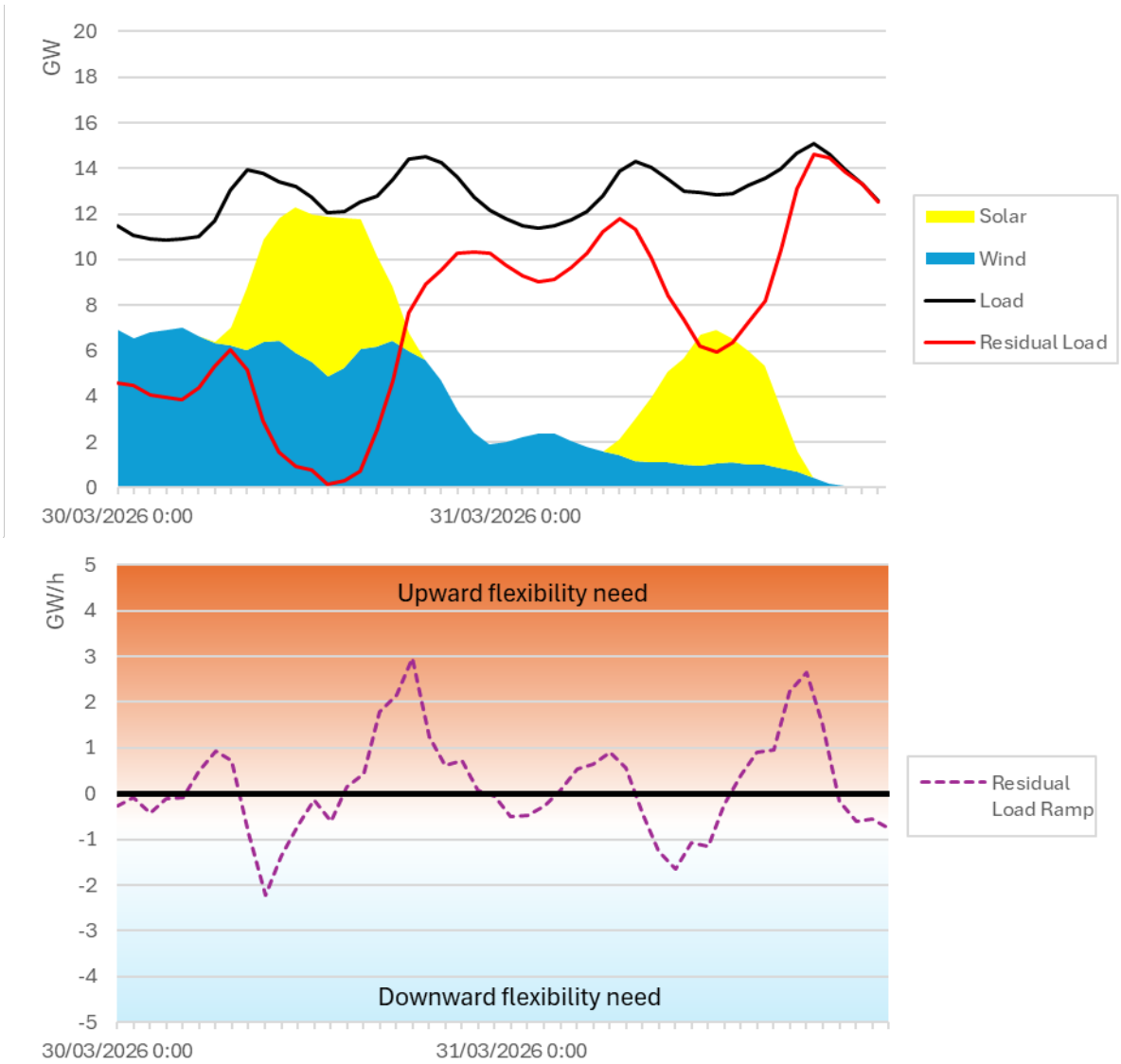
For network flexibility needs, a distinction is made between **transmission or TSO network needs**, which are flexibility needs located in the (extra) high voltage grid of TenneT, and **distribution or DSO network needs,** which are needs located in the lower voltage grids of the DSOs.

One further distinction in the FNA methodology is between covered and uncovered flexibility needs:

- **Covered flexibility needs** refer to the portion of the flexibility needs that are expected to be met by the flexibility sources assumed to be available in the scenario; and
- **Uncovered flexibility needs** refer to flexibility needs that are not expected to be met by the existing flexible resources or resources expected to be deployed in the system, based on ERAA or NRAA input assumptions.

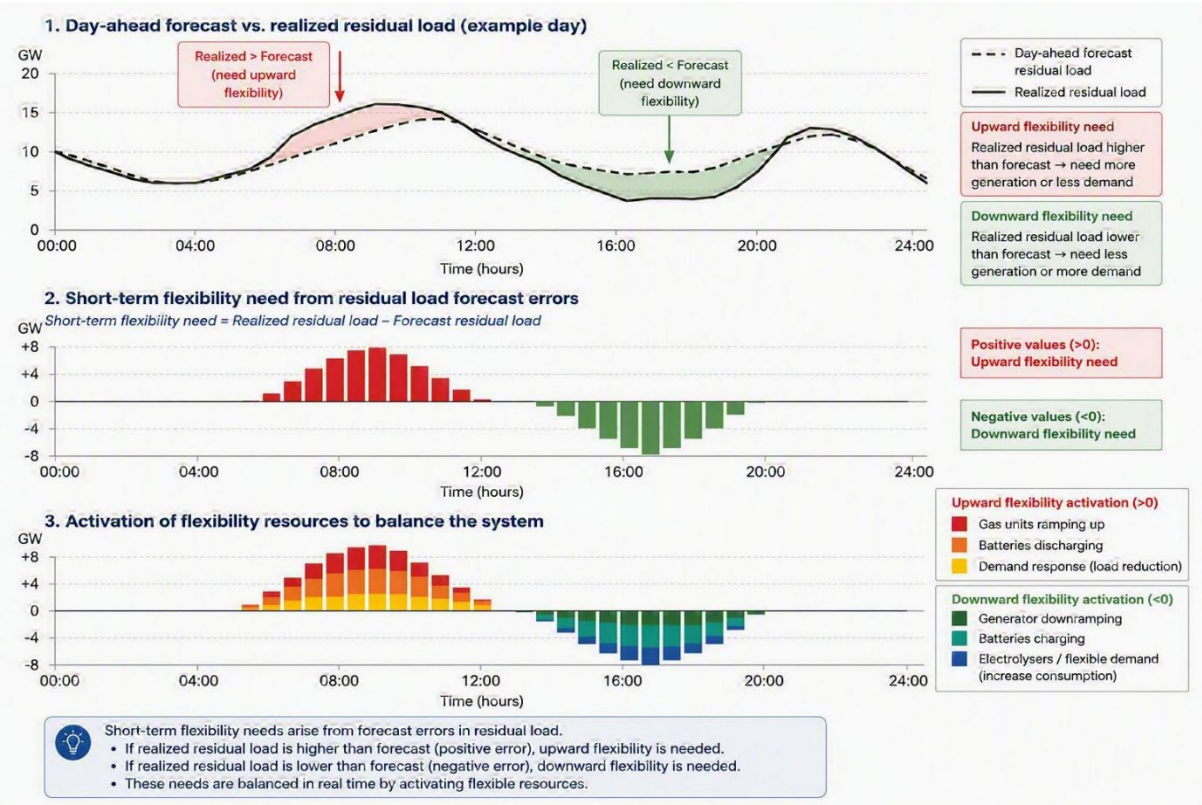
Figure 4 makes the residual-load concept concrete for two days in March 2026. The upper panel shows residual load as the gap between demand and RES generation: it is high when RES output is low and falls to zero when RES fully covers demand. The lower panel shows the hour-to-hour ramps in that residual load — downward flexibility is needed as residual load falls (for example, as solar rises in the morning) and upward flexibility as it climbs (as solar falls off in the evening).

Figure 4 Illustration of residual load and residual-load ramps for two days in March 2026. (Source: TenneT, based on data from Montel EnAppSys.)



Short-term needs arise from a different mechanism, shown in Figure 5: not from the shape of the residual load itself, but from the error between the day-ahead forecast and what actually materialises. Where realised residual load turns out higher than forecast, upward flexibility is needed; where it turns out lower, downward flexibility is needed. These deviations are balanced in real time by activating resources such as fast-starting generation, storage and flexible demand.

Figure 5 | How short-term flexibility needs arise from forecast errors in residual load, and how flexible resources are activated to balance them in real time.



A final distinction runs across all of these categories. Covered flexibility needs are the portion expected to be met by the flexible resources assumed available in the ERAA or NRAA; uncovered flexibility needs are those not expected to be met by existing or resources expected to be deployed. These uncovered needs are relevant as these indicate what additional flexibility is required in the future energy system and for which new policies or support schemes may be needed to realise this flexibility.

A summary of the definitions of all the various types of needs referred to in the FNA methodology is provided in Table 2. A glossary of further technical terms and abbreviations is also provided at the end of the report. For a complete list of official definitions, the reader is referred to the FNA methodology.

Table 2 | Key concepts and definitions used in this report. Definitions are based on either the Electricity Regulation or FNA methodology (Recital or Article 2) where available.

Term	Definition
System flexibility needs	The flexibility needed by the electricity system to adjust to the variability of generation and consumption patterns, across relevant market timeframes. System flexibility needs reflect the flexibility needed to adjust to the variability of generation and consumption for the Netherlands (i.e. the single Dutch bidding zone) as a whole and – following the FNA methodology – are estimated based on three indicators (i) ramping needs, (ii) short-term flexibility needs, and (iii) RES integration needs.
RES integration needs	The quantity of flexibility required for a country to achieve its annual RES integration target. RES integration needs are typically downward flexibility needs, to accommodate surplus RES generation.
Ramping needs	Needs associated with variations of the residual load assuming perfect forecast conditions. Ramping needs are identified by measuring or modelling the flexibility required to accommodate net-load variations from one hour to the next. Ramping needs can be both upward and downward.
Short-term flexibility needs	Needs associated with unexpected variations of the residual load such as forced outage of assets during the intra-day or balancing timeframe. These needs can be both upward and downward.
Network flexibility needs	The flexibility needed to adjust for grid availability, by means of preventing or solving congestion or voltage issues, across relevant timeframes. Network flexibility needs are further broken down into: - TSO network flexibility needs: flexibility needs which are required in the (extra) high voltage grid operated by TenneT. - DSO network flexibility needs: flexibility needs which are required in the lower-voltage grids operated by the DSOs.
Downward flexibility needs	Downward flexibility needs indicate less injection of power (or higher demand) is required from the network
Upward flexibility needs	Upward flexibility needs indicate more injection of power (or lower demand) from the network is required
Covered flexibility needs	The portion of the flexibility needs that are expected to be met by the assumed available sources of flexibility (in accordance with Article 19e(4)(b)(i) and (ii) of the Electricity Regulation)
Uncovered flexibility needs	The additional flexibility needs identified by the FNA methodology, not expected to be met by new or existing resources based on ERAA or NRAA.

1.5. Structure of this report

This report is structured as follows:[8]

- Chapter 2 outlines the high-level methodological framework underpinning the flexibility needs assessment,
- Chapter 3 describes the main scenarios and underlying assumptions used,
- Chapter 4 presents the key results for the various types of flexibility needs identified,
- Chapter 5 outlines the barriers for flexibility and contribution of digitalisation, and
- Chapter 6 presents the main conclusions, key findings and next steps.

This report also includes several annexes including more details on the methodologies applied and results. These can be found at the end of the report.

[8] TenneT has largely followed a template for the national FNA reports provided by ACER.

2. Methodological aspects

This chapter outlines the methodological framework underpinning the FNA including the main data sources used, target years considered, and high-level overview of how the FNA methodology has been implemented in the Dutch context to evaluate the national flexibility needs. The detailed scenario assumptions are elaborated further in Chapter 3.

2.1. Data sources

The analysis performed as part of this FNA is underpinned by several key data sources, chosen to ensure the FNA is based on transparent, consistent and up-to-date data sources for the Dutch context:

- The 2025 edition of the *European Resource Adequacy Assessment* (ERAA) (ENTSO-E, 2026), published by ENTSO-E in draft version in late 2025 and approved (with amendments) by ACER in early 2026.
- The *Monitor Voorzieningszekerheid* (MVZ) 2026 edition, which is the latest version of the Dutch National Resource Adequacy Assessment (NRAA) conducted annually by TenneT (TenneT, 2026)
- TenneT's national grid investment plan for the Netherlands, or *Investeringsplan* (IP) in Dutch. The most recent version is the IP 2026 published in April 2026 covering the period 2026-2040, which includes both an onshore grid investment plan *Net op Land* (TenneT, 2026), and an offshore grid investment plan *Net op zee* (TenneT, 2026).
- An additional scenario report published by the Dutch grid operators outlining an additional *'Verkenning Vertraagde Transitie'* (VVT) scenario, which serves as the basis for the FNA 2026 calculations as explained in Chapter 3 (Netbeheer Nederland, 2026).
- The latest National Energy and Climate Plan (NECP) for the Netherlands for the period 2021-2030, referred to as the *Integraal Nationaal Energie- en Klimaatplan* in Dutch. The most recent version is from June 2024 (Ministerie van Economische Zaken en Klimaat, 2024).
- The MVZ 2026 scenario incorporates information collected through TenneT's market participant consultation, which provided input on expected developments in generation capacity, storage and demand-side flexibility (TenneT, 2026).
- Historical data on Dutch load and RES production from the *Montel EnAppSys Web Service* platform, used to derive and synthesize load and RES forecast errors for the economic dispatch simulations (Montel, 2026).

2.2. Target years considered

In this edition of the FNA, the target years 2030 and 2035 have been analysed. These years were chosen to align with pivotal target years considered as part of the ERAA 2025 as per FNA Methodology Article 4(1)(d) and Article 6(1).

In addition, the analyses in this first edition of the FNA are based on the same set of three future-oriented climate years as applied in the ERAA Economic Viability Assessment (EVA)[9]. These climate years capture a representative range of weather conditions and therefore provide a robust basis for assessing the impact of variability in renewable generation and demand patterns on flexibility needs.

[9] These three climate years are referred to as "WS23", "WS27" and "WS35" in the ERAA.

For the system needs assessment, all three climate years are considered. However, for the TSO network needs analysis, only one of these climate years is used due to computational limitations.

For this edition of the FNA, the DSO network needs assessment is based on the most recent available historical measurement data (2025). This reflects common DSO practice for network studies, which are based on observed load and generation patterns in the distribution network. For the TSO analyses, climate years from the ERAA studies are used, as these analyses rely on European market simulations and therefore require a consistent set of weather and market input data across countries. The different climate year choices are therefore driven by methodological and data availability considerations and should not be interpreted as a preference for one approach over the other.

2.3. Methodological and modelling approach

This section briefly describes the main modelling approaches applied for the estimation of system needs, TSO network needs, and DSO network needs.

2.3.1. Methodology for System Needs

The assessment of system flexibility needs was carried out by TenneT in accordance with the FNA methodology based on three complementary indicators:

1. RES integration needs,
2. Ramping needs, and
3. Short-term flexibility needs.

Together, these indicators reflect the flexibility needed to adjust to the variability of generation and consumption for the Netherlands as a whole. Flexibility needs are categorised as upward needs when more injection into or less demand from the network is required, and as downward needs when less injection or more demand is required.

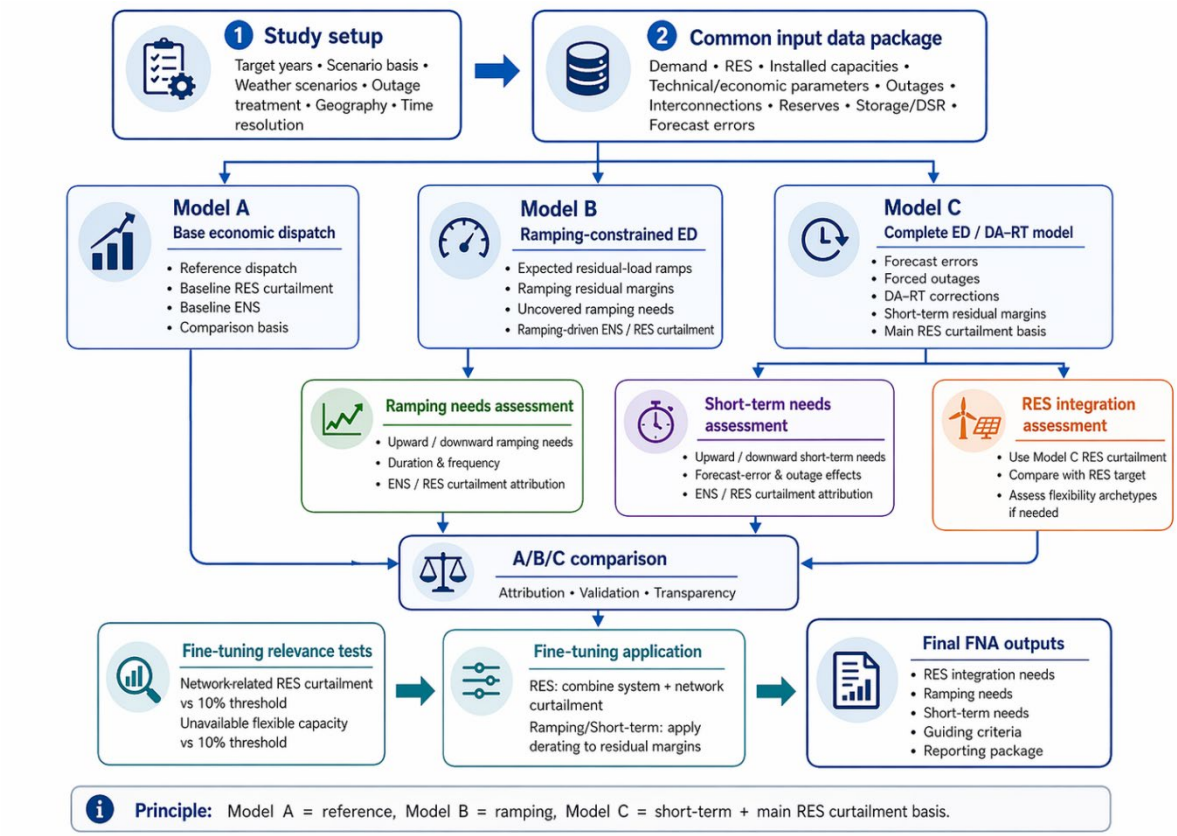
Pursuant to Article 7(3)(b) of the FNA methodology, TenneT has performed a separate set of economic dispatch simulations specifically for the FNA to estimate system needs, rather than relying on a post-processing of results from the ERAA or NRAA. The economic dispatch modelling uses as basis the MVZ2026 market models, which provide a consistent European framework and up-to-date national adequacy insights. For each target year (2030 and 2035), multiple simulations are performed in three modelling steps to isolate and quantify the different types of flexibility needs prescribed by the methodology as shown in Figure 6. Each modelling step builds on the last by introducing more features to capture the flexibility needs in a granular way. These steps are explained in the following sub-sections.

2.3.1.1. Base case simulation (Model A)

In the first step, a reference base case model is created which reflects the ideal outcome of the market if there would be unlimited ramping capability of the various assets in the system, and assuming stochastic parameters such as load and RES generation can be forecasted perfectly. In order to create this base case, market simulations are performed by TenneT with the PLEXOS Energy Market Simulation Software, developed by Energy Exemplar. This software tool is used to perform market simulations that involve a chronological optimisation of unit commitment and economic dispatch decision with an hourly granularity. The market simulations are performed on the basis of the market models developed for and used in the MVZ2026, without considering technical ramping constraints on

generating units[10]. In these market simulations, electricity generation, electricity demand, electricity storage, electricity conversion and the exchange of electricity between countries are optimised for every hour of the year across the whole of Europe (the market model contains approximately 60 bidding zones).

Figure 6 | Overview of the stepwise economic dispatch modelling approach for estimating system needs



2.3.1.2. Simulation with technical ramping constraints (Model B)

In the second step, additional power plant operational constraints such as ramp-rate limits, minimum up/down times, and minimum stable generation levels are added to the base 'Model A' and the simulations are repeated, again assuming perfect forecasts of load and RES generation. By comparing outcomes between the base case simulations (Model A) and the simulations with operational constraints (Model B), the impact of ramp-rate limitations of generators on the need for flexibility can be identified.

As input for the technical constraints, specific values for individual generators are used where those values have been confidentially obtained by TenneT as part of the periodic data exchanges between TenneT and market parties for the sake of this study and/or planning studies in general. For those generators where no specific values were provided/available, standard values from ERAA have been used which vary depending on the asset class.

[10] Ramping and flexibility constraints such as hourly ramping limits, minimum stable level, and minimum up/down times add significant computational complexity, while in TenneT's experience do not substantially impact the results of the adequacy simulations performed for the MVZ and are typically excluded.

2.3.1.3. Simulation with technical ramping constraints and forecast errors (Model C)

In the third step, synthetic day-ahead forecast errors for load and RES generation are added to Model B to represent real-time deviations from day-ahead schedules, resulting in Model C. The 'interleaved mode' of PLEXOS is applied, where the unit commitment, storage levels and generator states obtained in Model B are passed to Model C as initial conditions and then the model needs to optimise for the new situation accounting for the day-ahead forecast errors. Comparing the results of the simulation with technical constraints (Model B) and the simulation including forecast uncertainty (Model C) quantifies the additional short-term flexibility needs required to manage forecast deviations. The methodology for synthesising the day-ahead forecast errors is outlined in Annex 1.

The availability of short-term flexibility in future power systems is inherently uncertain. While the installed portfolio of flexibility resources can be estimated based on scenario assumptions, the extent to which these resources are available to respond to forecast errors in real time is less certain. In particular, uncertainties exist regarding the availability of non-committed generation and potential support from neighbouring systems. To assess the sensitivity of the results to these uncertainties, a stepwise approach is applied through three Model C configurations (C1–C3), representing progressively higher levels of available flexibility.

- **C1**: In the first configuration, conservative assumptions are applied. Cross-border exchanges are fixed at day-ahead levels, implying no additional flexibility from neighboring countries. Flexibility is limited to the upward dispatch capability of generators included in the day-ahead unit commitment, while non-committed units cannot provide additional flexibility. Other flexibility sources, such as batteries and demand-side response, remain fully available as they are not subject to unit commitment constraints. This configuration represents a lower-bound estimate of the system's capability to respond to forecast errors, in addition to ramping requirements of residual load.
- **C2**: In the second configuration, additional domestic flexibility is introduced by allowing a subset of Dutch gas-fired power plants (CCGTs) that were not committed day-ahead to start up and provide balancing flexibility. Cross-border exchanges remain fixed.
- **C3**: In the third configuration, the contribution of cross-border flexibility is assessed in accordance with Article 10(3) of the FNA Methodology. Available flexibility from neighbouring countries is assumed to be accessible through interconnection capacity, except during scarcity situations corresponding to the 1% highest electricity price hours. In these hours, cross-border flexibility is assumed to be unavailable, reflecting the likelihood that neighbouring systems are simultaneously experiencing tight market conditions. This configuration provides an indication of the extent to which cross-border flexibility can contribute to covering the remaining short-term flexibility needs identified in configuration C2.

This stepwise approach allows for a structured assessment of the potential contribution of domestic and cross-border flexibility in addressing flexibility needs in the Netherlands, ensuring compliance with Article 19e(1) of the Electricity Regulation and Articles 9(3)(c) and 10(3)(c) of the FNA Methodology, by explicitly considering the role of cross-border exchanges and their effect on system flexibility and market liquidity.

2.3.1.4. RES integration assessment

If the modelled curtailment of renewable energy sources (RES) in the simulations with ramping constraints and forecast errors exceeds the maximum allowable level derived from national RES targets (see Section 3.3), an additional analysis should be performed to quantify the downward flexibility required to limit curtailment to acceptable thresholds.

2.3.1.5. Derivation of system need indicators and output of the system needs assessment

The three system-needs indicators are calculated as follows:

- **Ramping needs** (upward flexibility): Determined by the hourly differences in Energy Not Served (ENS) between the simulations from Models A and B. Any increase in ENS due to generator ramp constraints indicates insufficient ramping capability.[11]
- **Short-term flexibility needs** (upward flexibility): Calculated by comparing ENS outcomes between simulations from Models B and C. ENS represents electricity demand that cannot be served within the modelled hour. Additional ENS resulting from forecast errors reflects the need for faster-responding flexibility to mitigate short-term deviations.
- **RES integration needs (downward flexibility):** Based on the modelled RES curtailment time series resulting from Model C.[12] Model C does not include flexibility from neighboring countries to absorb surplus generation resulting from forecast errors and can therefore be considered conservative. If curtailment exceeds the threshold derived from national RES targets, the required downward flexibility is estimated based on the hourly curtailment volumes and durations. This provides an indication of the amount of (non-fossil) flexibility required to accommodate excess RES generation.

The outcome of this process consists of hourly upward and downward flexibility needs for each indicator, reflecting:

- the magnitude of flexibility required (MW),
- the energy volumes involved (MWh), and
- temporal patterns across seasons and representative days.

2.3.1.6. Consideration of resource unavailability due to grid prequalification and temporary limits

According to Article 13 of the FNA Methodology, the analysis should include a consideration of potential limitations on the availability of flexible resources due to grid prequalification requirements and temporary operational constraints.

In the Dutch context, reliable data on the availability impacts of grid prequalification and temporary limits are currently not available, and their potential effect on system flexibility in the future cannot be estimated with confidence. As a result, the effect of grid prequalification and temporary limits on the availability of flexible resources has been neglected in this edition of the FNA, in accordance with Article 13(2)(a)(ii) of the methodology. As a result, all flexible resources are assumed to be fully available within their technical constraints.

2.3.1.7. Fine-tuning of system needs with network needs and unavailability of flexible resources

The fine-tuning step aims to ensure a consistent integration of the results from the system needs and network needs analyses while avoiding double counting, in line with Article 14 of the FNA Methodology. Pursuant to Article 14(1) of the FNA methodology, this involves fine-tuning:

- all three components of the system needs (i.e. short-term needs, ramping needs and RES integration needs) based on the unavailability of flexibility resources (where applicable), and

[11] *In the context of the FNA, any additional ENS resulting from the economic dispatch simulations in Model B and Model C does not indicate a resource adequacy shortfall as is typically the case in adequacy studies like the ERAA or MVZ. Rather, it should be interpreted as additional flexibility needs.*

[12] *The selection of the configuration (C1–C3) for assessing RES curtailment is arbitrary, as these configurations differ only in the availability of upward flexibility and not in downward flexibility.*

- the RES integration needs based on the identified downward network flexibility needs.

As explained in Section 2.3.1.6, the impact of grid prequalification requirements and temporary operational limits on resource availability could not be quantified with sufficient confidence in this edition of the FNA. As a result, no fine-tuning on the basis of unavailability has been performed. However, given the system-level nature of the analysis, the omission of these effects is not expected to materially alter the overall conclusions as: (i) temporary operational constraints are (by definition) temporary and often location-specific; (ii) such constraints are therefore unlikely to systematically affect all flexible resources simultaneously; and (iii) the results (see section 4.4.2) already indicate sufficient flexibility to meet RES integration, ramping, and short-term flexibility needs, providing some margin against potential availability reductions.

Regarding the fine-tuning of RES integration needs, system-level and network-induced curtailment are treated as mutually exclusive. The network simulations use the dispatch outcomes of the market simulations as input, meaning that any RES generation curtailed at system level has already been removed to preserve the energy balance of the power flow scenarios. As a result, any additional curtailment identified in the network needs assessment is solely attributable to network constraints. System-level and network-induced curtailment can therefore be aggregated without double counting and are jointly used to assess overall RES integration and compliance with national RES targets.

2.3.2. Methodology for TSO network needs

The TSO network flexibility needs have been determined using load-flow calculations for the Dutch high-voltage grid (110 – 380 kV). These calculations have been performed using the same toolchain as applied for the IP (2026) analyses. A detailed description of the calculation methodology, assumptions, regionalization and modelling approach is provided in the IP 2026 documentation, including Annex 7 of the IP, which describes the load-flow calculation process in detail (TenneT, 2026).

The load flow calculations for the TSO network have been performed using so-called ‘N-1’ contingency analyses of high voltage circuits and transformers for the years 2030 and 2035 under the VVT scenario. The term ‘N-1’ refers to the security criterion that the power system must be able to remain within safe operational limits even after the unexpected loss of any single relevant network element (e.g. such as a line, transformer, generator, or interconnector). Whether the ‘N-1’ criterion can be met also during maintenance has not been assessed. This assumes that maintenance activities can be scheduled during periods of relatively low grid loading. In addition, the detailed maintenance schedules for 2030 and 2035, which would be required to explicitly model maintenance intervals, have not yet been determined.

The portfolio of TenneT consists of projects in different phases, not all these projects have a concrete defined scope yet.[13] For the network needs calculations, all projects with a concrete scope with impact on the load flow calculations have been included. These projects are generally in the basic design phase or in later phases. This differs from the normal IP calculations where only projects in the realization phase have been included.[14] This means that more projects are included in the calculations of the FNA compared to the IP calculations. The IP only uses projects in the realization phase, which generally have an in service date of up to 2030. If this selection were to be used, TSO grid reinforcement between 2030 and 2035 would not be included, resulting in over-estimations of the flexibility need for 2035 and to a lesser extent also for 2030. This also results in a more uniform approach with the DSO

[13] This includes projects where several technical alternatives are yet studied. A cable from substation A to B or from B to C can both solve the same constraint. When no choice has been made, the projects are not included in the FNA calculations.

[14] Projects in the basic design phase are projects for which the need for initiation is proven, a preferred technical alternative has been chosen (thus having a concrete scope) and are currently in the phase where a basic engineering design is being carried out. Compared to these projects, projects in the realization phase have additionally passed the basic design phase and a final investment decision has been taken.

Network Needs as the DSOs also take into account these projects in the network needs calculations. Using a more reinforced grid will lead to lower overloads as compared to the results of IP2026.

Because these projects are in an earlier project phase, the planning and scope of the projects are less sure, which means that there is a larger probability of delay. If the projects are delayed, the flexibility needs will become larger.

In the grid model a distinction has been made between the summer (April-October) and winter loading limits (November-December). Overhead lines have a higher rating in the winter due to the more favourable weather conditions with respect to temperature and wind speed. Higher (static) loading limits of assets is being investigated within TenneT by the MaxLimit programme. At the start of the FNA calculation not all assets were investigated. Higher loading limits have therefore not been included in the FNA network needs. Higher loading limits of the grid will result in a lower flexibility need.

For each overloaded asset, both the maximum instantaneous overload (in megawatts, MW) and the total energy associated with overload conditions (in megawatt hours, MWh) have been determined. In the load flow analysis, a distinction is made between the direction of power flows. In the 110/150 kV network and at the coupling with the 220/380 kV transmission grid, the direction of the flow generally corresponds to the nature of the constraint. Power flows from the 380 kV grid towards the 150 kV grid are typically driven by electricity demand, whereas flows in the opposite direction are predominantly associated with electricity generation feeding into the higher voltage grid. This characterization is strengthened by use of the seasonal/ intra-day patterns of the constraints. Based on this characterization, the upward and downward flexibility needs can be analysed and reported separately.

For the 380 kV grid itself, however, such a distinction cannot be made. The flows in this grid are primarily driven by spatial mismatches between generation and demand, as these are not necessarily co located at the same substations. In addition, international cross border flows and loop flows have a significant impact on observed overloads in the 380 kV grid. For this reason, overloads in the 380 kV network are not attributed separately to load driven or generation driven causes. To translate the identified overloads into corresponding flexibility needs, several additional steps are required to arrive at a realistic estimate of network related flexibility requirements. These steps are described in the following paragraphs.

Note that while the FNA methodology includes voltage issues within the definition and scope of network flexibility needs, this assessment excludes voltage control from the quantified TSO network needs. The reason is that in the Dutch transmission system, voltage is managed primarily through reactive power and system control measures (e.g. capacitor banks, shunt reactors (compensation coils), and contracted reactive power from connected assets) rather than through the activation of active power flexibility. As the FNA requires flexibility needs to be expressed in MW and MWh, voltage control does not translate into a quantifiable active power flexibility requirement. The TSO network needs presented in this report therefore focus on congestion-related needs that require active power flexibility, which can be addressed through redispatch, curtailment, or other flexibility measures.

2.3.2.1. Critical asset identification

The high voltage transmission grid operated by TenneT is designed and operated as a meshed network. Within such a meshed grid, power flows are distributed across multiple parallel circuits in order to reach their destination. As a result, overloads may occur simultaneously on several interconnected assets, potentially giving rise to a need for flexibility. However, the total network related flexibility need is not equal to the simple sum of all individual asset overloads. Flexibility activated at an appropriate location can reduce power flows across multiple overloaded assets at the same time. To avoid double counting flexibility needs, critical assets are therefore identified on a regional basis, building on insights from earlier studies and network analyses. This analysis has been done for 2030 and 2035 separately.

Critical assets are defined as those assets that exhibit the highest overload within a cluster of electrically related overloaded assets along the same transport corridor or system axis. For example, if one circuit within a given transport axis is overloaded by 20 MW while adjacent or electrically connected circuits are overloaded by 5 MW, only the maximum overload of 20 MW is considered for the determination of

flexibility needs. Solving the overloads on the critical asset (20 MW) would also solve the 5 MW overload.

The data has been aggregated based on the regions used in the IP 2026. These regions are electrically connected and network needs within these regions are thus highly interdependent. Using these regions ensures consistency in the reporting between 2030 and 2035. In this period the grid is being expanded, thus mitigating a large part of the identified overloads. This grid expansion combined with the increased growth from 2030 to 2035, however, also changes the load flows, which can result in other constraints becoming the new critical asset within that region. By using the regions as used in IP2026 the results of 2030 and 2035 can be compared.

2.3.2.2. Meshed grid effectiveness

In a meshed transmission grid, power can flow in several multiple parallel paths. When one of these paths becomes overloaded, this may give rise to a need for flexibility. Such flexibility must be activated at one or more substations within the affected network area. However, when flexibility is activated at a given location, it influences power flows across all electrically connected circuits—not only the overloaded circuit, but also parallel and adjacent ones. As a result, not all activated flexibility directly contributes to relieving the overload on the constrained asset. The effectiveness of flexibility in a meshed grid is therefore less than 100%. To account for this effect in the network flexibility needs assessment, each critical asset has been evaluated to determine whether it is located in a meshed or a non-meshed network configuration. For overloaded transport axes in a meshed grid situation, a generic correction factor of 1.4 is applied. This implies that, on average, resolving an overload of 1 MWh requires 1.4 MWh of flexibility activation in meshed grid conditions. This factor is based on the average grid effectivity of redispatch in the Dutch 380 kV ring. This factor is used as the highest flexibility needs are observed in the 380 kV grid.

2.3.2.3. Determination of flexibility need metrics

A set of metrics has been defined to report flexibility needs:

- Annual flexibility volume (MWh)
- Peak flexibility demand (MW)
- Annual duration of flexibility activation (hours)
- Seasonal and intra-day deployment patterns

All metrics are reported at regional level, rather than per (critical) asset.

The annual flexibility volume is based on the Energy Not Transported (ENT) of each critical asset. After applying a correction factor for meshed grid effectiveness, regional flexibility volume is calculated as the sum of ENT across all relevant critical assets, separately for upward and downward flexibility.

Peak demand and annual duration are derived from a regional hourly ENT profile (with meshed grid effectiveness correction), created by aggregating the hourly profiles of all critical assets. The maximum value defines the regional peak, while the number of non-zero hours determines the annual duration. These are also assessed separately for upward and downward flexibility.

Using the same regional hourly profile, heatmaps are generated to identify seasonal and intra-day activation patterns by flexibility direction. These patterns are reported as follows:

- Seasonal pattern: Summer, Winter, or both (if no clear concentration)
- Intra-day pattern: Morning, Afternoon, Evening, Night, or multiple periods; if no clear pattern emerges, it is classified as spread-out

2.3.2.4. DSO network needs correction

The network-related flexibility needs identified by TenneT are initially derived from market simulations based on the VVT scenario, without explicitly accounting for capacity constraints in the underlying DSO grids. As a result, there are situations in which the simulated power exchange between the TSO grid and a substation exceeds the available capacity of the downstream DSO network. In such cases, the DSO is assumed to activate local flexibility to prevent overloads on DSO assets, thereby reducing the power exchange with the TSO grid. This reduction in TSO-DSO exchange may, in certain hours, also contribute to alleviating overloads in the TSO network. To account for this interaction and to avoid double counting of flexibility needs, the network-related flexibility needs identified by DSOs are therefore subtracted from the initially calculated TSO network needs.

This adjustment takes into account both the specific grid locations affected and the typical timing of DSO flexibility activation. DSO network needs at locations or at times where there is no significant effect on the TSO needs are therefore not subtracted from the initially calculated TSO network needs. While this approach does not reduce the overall flexibility need across system levels, it ensures a consistent allocation of flexibility requirements between the TSO and DSO domains and prevents double counting of network needs.

2.3.3. Methodology for DSO network needs

The DSO network flexibility needs have been assessed for distribution networks with voltage levels of 25 kV and above, corresponding to the scope of the so-called ‘major investments’ included in the IP (2026).[15] For this assessment, the same network models were used as those applied by the DSOs for the IP (2026) analyses. The analysis was performed on the basis of the VVT scenario, as described in section 3.1. This scenario was regionalised to derive expected electricity demand and generation levels for the years 2030 and 2035. The regionalisation is done in the same way as for the Koersvaste Middenweg (KM) scenario in the IP2026. This regionalisation is described in the report Netbeheer Nederland Scenario’s Editie 2025 (Netbeheer Nederland, 2025) and in the individual investment plans of the DSOs. These regionalised demand and generation profiles from the scenario are combined with the forecast of new clients and are added to the current load profiles to create future load profiles for 2030 and 2035. With these load profiles and the detailed network models, load-flow simulations were carried out at an hourly temporal resolution, resulting in network loading profiles for all relevant assets.

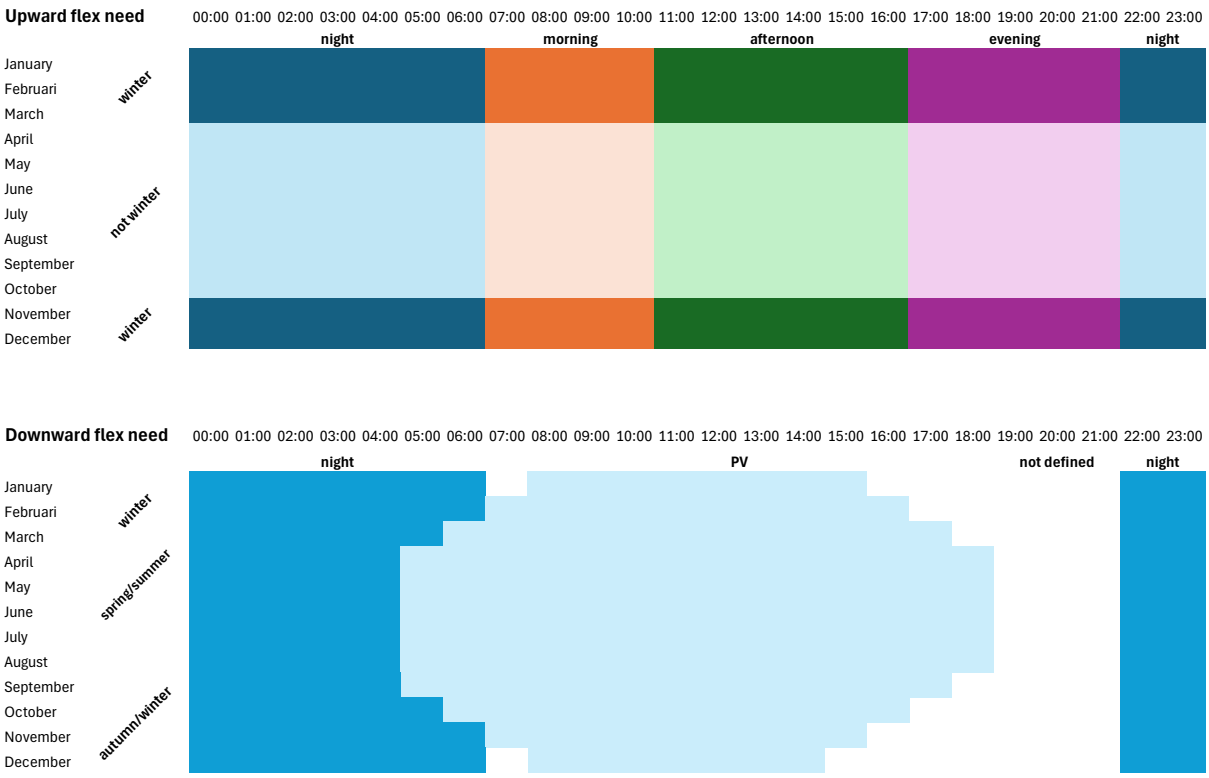
For each relevant network component, the simulated loadings were compared against the applicable technical capacity limits. This enabled the determination, for each hour, of the portion of demand or generation that could not be accommodated due to network capacity constraints (i.e. non-transportable capacity). The simulations explicitly incorporate all network reinforcements included in IP2026 (these are the investments that the DSOs expect to realize, taking into account shortage of staff, timely availability of permissions, etc.). Consequently, once an investment is assumed to be commissioned, the associated increase in network capacity is reflected in the simulations, resulting in a reduction or elimination of non-transportable capacity.

The DSO network needs are analysed to indicate typical time periods of non-transportable capacity. The analysis distinguishes between multiple temporal patterns, including seasonal variation, differences in day-type (weekend versus weekday), and intra-day patterns (morning, midday, evening and night). The results indicate either a representative typical period in which network needs arise or show that no pattern can be identified.

[15] This includes cables from 25 kV up to 66 kV and DSO-owned transformers with a primary voltage of 25 kV up to 150 kV.

The definitions for the seasonal and intraday time periods for upward and downward flexibility needs are shown in . The colours are used solely for visual differentiation of the defined time periods and have no quantitative meaning. For the upward flexibility need there is a seasonal distinction between wintertime and non-wintertime, for the downward flexibility need the intraday pattern is focused on solar energy production, which varies per month, and nocturnal energy production.

Figure 7 | Definitions of the seasonal and intraday timeframes for upward (upper figure) and downward (lower figure) flexibility needs



Both demand and generation levels in the VVT scenario are lower than those assumed in the KM scenario applied in the IP. As a result, no additional network prohibitive barriers were expected to emerge in the context of the FNA beyond those already identified in the IP analyses. Nevertheless, a validation check was carried out to confirm that all relevant prohibitive barriers identified under the FNA framework were indeed covered by the IP2026 assessments.

For more complex DSO network configurations, such as meshed grid structures, the resulting network flexibility needs were aggregated at the TSO–DSO interface (feeder point). Network needs identified for individual components were combined taking the network topology into account, ensuring that flexibility needs were not double counted for assets located downstream of one another.

Note that flexibility needs for voltage control are not quantified as part of the DSO network flexibility needs presented in this report, for similar reasons as for the TSO network needs. Namely, the Dutch DSOs typically address voltage constraints through other measures such as transformer tap-changing and reactive power control. As these solutions do not require the activation of active power flexibility, no corresponding flexibility need in MW or MWh can be defined within the framework of the FNA methodology. Thus, the DSO contribution to network needs focuses on congestion-related flexibility requirements that can be expressed in terms of active power and energy.

2.3.4. Methodology for the analysis of market barriers

Chapter 5 '*Barriers for flexibility and contribution of digitalisation'* addresses the relevant topics from ACER's recommendation for evaluation of Dutch electricity markets and the barriers for entry and participation of assets that can provide upward or downward flexibility. (ACER, 2026) The information from the chapter builds upon existing reports from research institutes and the EC, documentation from system operators' websites on procedures and requirements, the Dutch Energy Act, letters to parliament and TenneT's 'Business Roadmap' of planned IT changes (TenneT, 2026). The information was collected in collaboration with experts from system operators in their respective fields. The chapters on balancing markets and electricity markets were led by TenneT's experts. The chapter on congestion management also included experts from different DSOs and GOPACS, the coordination platform used by Dutch grid operators to alleviate grid congestion by activating bids from market parties.

3. Scenarios and assumptions

This chapter outlines the scenarios, targets, and key assumptions underpinning the FNA, building upon the data sources and methodological framework described in Chapter 2. While Chapter 2 focuses on how the assessment is conducted—covering data sources, modelling approaches, and analytical techniques—this chapter specifies what inputs are applied to those methods. It details the scenarios used for system and network needs, the relevant RES integration targets, and the critical assumptions that shape the analysis. Together, these elements ensure transparency in the baseline conditions and the factors influencing the assessment outcomes.

3.1. Scenarios used to assess system and network needs

The FNA report—presenting the Dutch Flexibility Needs Assessment for the period 2030–2035—is closely linked to, and builds upon, the most recent European Resource Adequacy Assessment (ERAA 2025) as well as the Dutch National Resource Adequacy Report 2026 (MVZ 2026), which itself is derived from ERAA 2025 (ENTSO-E, 2026). This is in line with the FNA methodology which requires that system needs and (where applicable) TSO network needs must be based on the most recently approved ERAA.[16] DSO network needs should be based on the most recent Distribution Network Development Plan (DNDP), which for the Netherlands is also the IP2026.

For the Dutch FNA, a deliberate choice was made to harmonize scenario assumptions across system needs, TSO network needs, and DSO network needs, as much as possible. To achieve this, all three assessments are anchored in the same *Verkenning Vertraagde Transitie* (VVT) or "Delayed Transition" scenario (Netbeheer Nederland, 2026) as shown in Table 3. This VVT scenario, recently developed by the grid operators, incorporates the latest insights into the energy transition and does not assume full achievement of all long-term energy and climate targets. This scenario was not included in the original scenario set developed by Netbeheer Nederland (Netbeheer Nederland, 2025) or simulated as part of the IP2026 calculations, but has been calculated separately using the same toolchain and similar assumptions as in the IP2026. For other countries, the ERAA 2025 reference scenario is used.

Table 3 | Overview of the scenarios, grid model and interconnection capacity used for each type of flexibility needs assessed

Analysis	Region	Applied Scenario	Applied grid model	Interconnection capacity
System Needs	The Netherlands	MVZ 2026 'High demand scenario' [a]	N/A	ERAA 2025 Flow-based Domains
	Other countries	ERAA 2025 - Central Reference Scenario 'without CMs'	N/A	
TSO Network Needs	The Netherlands	VVT	IP 2026	ERAA 2025 Flow-based Domains
	Other Countries	ERAA 2025 - Central Reference Scenario 'without CMs'	IP 2026	
DSO Network Needs	The Netherlands	VVT	IP 2026	N/A

[a] *This scenario is based on the VVT scenario with a few downward changes to the load, as explained in the MVZ 2026 report* (TenneT, 2026)

[16] ACER approved the ERAA 2025 in April 2026. (ACER, 2026)

With this approach, all three components of the FNA—system needs, TSO network needs, and DSO network needs—are grounded in a single underlying scenario framework that is as close as possible to the newly-developed VVT scenario, while maintaining strict compliance with the FNA requirement regarding consistency with ERAA-derived assumptions. This ensures that the FNA report is fully aligned with the most up-to-date Dutch adequacy insights (MVZ 2026) and the latest network scenarios applied by the Dutch grid operators in the IP 2026.

Note that for this first edition of the FNA only one scenario – the VVT scenario – has been assessed. This is due to the need for a consistent scenario across the three components (i.e. system needs, TSO network needs and DSO network needs), and the compressed timeline for conducting the study.[17] In future editions of the FNA, additional scenarios may be considered to better explore the impact of uncertainties in future developments on flexibility needs.

3.2. Description of the Verkenning Vertraagde Transitie (VVT) scenario

The VVT scenario is an additional scenario developed by Netbeheer Nederland to represent a slower, more realistic short- to medium-term energy transition pathway than the regular IP 2026 scenarios. Whereas the IP scenarios are target-oriented scenarios in which climate and energy objectives are assumed to be met, the VVT scenario explicitly lets go of the interim climate targets for 2030 and 2040 and instead reflects a delayed transition based on current policy, market developments and observed implementation challenges. For the period up to 2030, the VVT is closely aligned with the PBL Klimaat- en Energieverkenning (KEV), while for 2035 and beyond it uses the IP 2026 scenario Koersvaste Middenweg (KM) as a starting point, with sector-specific adjustments based on recent insights.

Compared with the KM and other IP scenarios, the VVT generally assumes slower electrification, lower renewable generation growth, delayed hydrogen development, lower deployment of large-scale flexibility assets, and a slower phase-out of conversion of fossil capacity. Based on the VVT scenario, total electricity demand in the Netherlands is assumed to increase from roughly 120 TWh/y in 2025 up to 156 TWh/y in 2030 and 196 TWh/y in 2035 (Netbeheer Nederland, 2026).18

Table 4 shows the assumed installed capacity of flexible and non-flexible resources in the Netherlands in the VVT scenario in target years 2030 and 2035, as well as the installed capacity in 2025. Alongside a significant increase in the installed capacity of RES, the installed capacity of flexibility is also assumed to increase significantly from roughly 35 GW in 2025 up to 50 GW in 2035.

Figure 8 further breaks down the assumed developments in installed flexible capacities between 2025 and 2035 highlighting that most of this increase in flexible capacity is assumed to come from batteries (+14.5 GW), Power-to-X (+6.5 GW), as well as cross-border interconnection (+3.4 GW). While there is a significant reduction in fossil-based flexibility from coal (-4 GW) and gas (-5.5 GW) assumed, the increase in non-fossil flexibility more than compensates for the reduction in fossil capacity. As a result, there is roughly 15 GW (43%) more flexible capacity assumed to be available in the Netherlands in 2035 than in 2025.

Note that the VVT scenario does not replace the IP scenarios for long-term infrastructure planning, but provides a complementary scenario for analyses where a more realistic view of near-term developments is important. Also, while the VVT scenario assumes generally slower growth in electrification and RES deployment than the IP scenarios, the actual growth rate realised in the future at both national and regional level may be even lower still, due to e.g. grid congestion and challenges for connecting new

[17] The first implementation of the FNA report had a timeline of one year, during which significant methodological, tool and model developments were needed to analyse new requirements such as ramping needs and short-term flexibility needs. Future editions of the FNA can be performed every two years.

[18] Excluding demand from Power-to-X

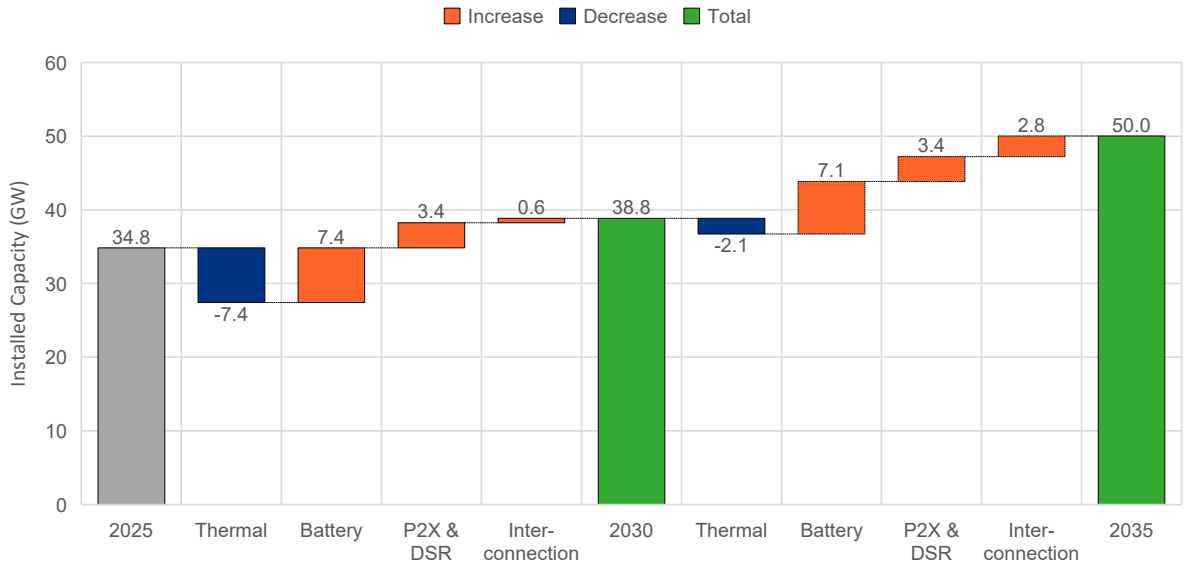
customers to the distribution and transmission grids. The VVT scenario does not take these aspects into account.

Table 4 | Assumed installed capacity of flexible and non-flexible resources in the Netherlands in this FNA assessment in comparison with the installed capacity in 2025 (GW) (Sources: (Netbeheer Nederland, 2026), TenneT)

Technology	Reference (2025)	2030	2035
Variable Renewable Energy Sources (GW)			
Onshore Wind	6.8	7.6	8.2
Offshore Wind	4.7	8.9	19.8
Solar PV	23.6	42.2	52.4
Flexible resources (GW)			
Nuclear	0.5	0.5	0.5
Natural Gas	17.9	14.4	12.4
Coal	4.0	0	0
Biomass	0.5	0.6	0.7
Waste	0.7	0.7	0.5
Hydro	0.04	0.04	0.04
Battery [a]	1.3	8.7	15.8
DSR	0.7	0.8	1.0
Power-to-gas	0	1	4
Power-to-heat	0	2.3	2.5
Interconnection	9.2	9.8	12.6
Total Flexible	**35**	**39**	**50**
Of which non-fossil	*13*	*24*	*38*

[a] *includes small-scale household storage, V2G, as well as large grid-scale battery storage*

Figure 8 | Overview of the assumed development in flexible capacities in the Netherlands until 2035 according to the VVT scenario. The blue and orange boxes show the incremental decrease and increase (respectively) in assumed flexible capacities between 2025, and the two target years of 2030 and 2035.



3.3. Target for RES integration

The RES integration target defines the level of renewable generation that the system must accommodate and serves as the basis for assessing RES integration needs in line with Article 8(7) of the FNA Methodology. The applied RES targets and underlying assumptions outlined below have been agreed with EZK and ACM.

For 2030, the RES target is primarily derived from the latest National Energy and Climate Plan (NECP) for the Netherlands for the period 2021–2030, also known as the *Integraal Nationaal Plan Energie en Klimaat* (INEK) in Dutch (Ministry of Economic Affairs and Climate Policy, 2024). The target is defined differently for onshore and offshore RES:

- Onshore RES: 42 TWh/year of net generation, consisting of 35 TWh/year from onshore wind and utility-scale solar PV and 7 TWh/year from rooftop solar PV.
- Offshore RES: 8.9 GW of installed offshore wind capacity.

While the NECP defines a policy ambition of approximately 21 GW of offshore wind by 2030, the applied value of 8.9 GW reflects the most recent realization outlook. This value was defined in alignment with EZK and is based on updated national projections (KEV 2024/2025 and government update of August 2025) and is consistent with the assumptions used in the MVZ 2026 scenario.

For 2035, no official RES target is defined in the Dutch NECP. In alignment with EZK, the RES integration target is defined as 95% of unconstrained RES generation, corresponding to a maximum of 5% annual curtailment of RES. This threshold is consistent with Article 13(5)(a) of Regulation (EU) 2019/943, which requires that the curtailment of renewable generation is minimized. The absolute value for RES integration target is then derived from the RES capacities assumed to be installed in 2035 in the VVT / MVZ 2026 scenario. Across the selected climate years, average unconstrained RES generation amounts to approximately 158 TWh, ranging from 146 to 164 TWh. Consequently, the absolute RES integration target, defined as 95% of unconstrained RES generation, is approximately 150 TWh. Table 5 summarizes the resulting RES integration targets applied in the assessment for 2030 and 2035.

Table 5 | RES integration targets applied in the assessment

	2030	2035
Onshore RES target (TWh)	42	–
Offshore wind capacity (GW)	8.9	
Offshore wind generation (average, TWh)	39	–
Average unconstrained RES generation (TWh)	–	158
Target definition	NECP-based	95% of unconstrained RES
RES integration target (TWh)	**81**	**150**

3.4. Uncertainty in the assumed portfolio of flexibility and other resources, and the impact on covered and uncovered needs

The flexibility capacities included in the VVT scenario should not be interpreted as a forecast of future flexibility deployment in the Netherlands. During the development of the VVT scenario, sufficient flexibility is assumed to be available to operate the energy system and accommodate the variability resulting from projected electrification, renewable generation and cross-border exchanges. The resulting flexibility portfolio therefore reflects scenario assumptions used in the modelling process rather than an evidence-based projection of future flexibility availability.

Consequently, the distinction between covered and uncovered flexibility needs presented in this report depends on the assumed availability of these flexibility resources. If flexibility resources develop differently from the assumed portfolio, the amount of uncovered flexibility needs may increase or decrease accordingly.

While the VVT scenario reflects the latest expectations regarding the pace of the energy transition in the Netherlands, it should not be interpreted as a prediction of future investment outcomes. As shown in Table 4 and

Figure 8, the scenario assumes substantial deployment of both renewable generation and flexibility resources, requiring continued investment throughout the assessment horizon. Whether these investments ultimately materialise will depend on a range of factors, including technology costs, market revenues, financing conditions, regulatory frameworks, future policy developments, and the ability to connect new customers to the grid.

The results of the FNA are therefore subject to two important sources of scenario-driven uncertainty. Firstly, the pace of electrification and RES deployment influence the overall magnitude of flexibility needs. Higher levels of renewable generation will generally increase variability in residual load, forecast errors, and the occurrence of surplus generation periods, resulting in greater demand for flexibility. Conversely, slower growth in renewable generation may reduce the level of flexibility required.

Secondly, the assumed deployment of flexibility resources in the VVT scenario influences the extent to which identified flexibility needs are assessed as covered or uncovered. As outlined in Section 1.4, a flexibility need is considered *covered* if it can be met by the flexibility resources assumed to be available in the scenario and *uncovered* if the assumed portfolio is insufficient to meet that need. Consequently, the level of covered and uncovered flexibility needs depends not only on the flexibility requirement itself, but also on the amount, type and availability of flexibility resources assumed to be present in the system.

These two dimensions interact. For example, faster-than-expected deployment of RES will generally increase flexibility needs, while slower-than-expected deployment of batteries, demand-side flexibility, Power-to-X facilities or interconnection capacity would reduce the availability of flexibility to meet those needs. Both developments could therefore lead to a larger volume of uncovered flexibility needs than identified based on the VVT scenario. Conversely, faster deployment of flexibility resources or lower growth in RES could reduce uncovered needs.

The results of the FNA should therefore be interpreted in the context of the underlying VVT scenario assumptions for the Netherlands, as well as the assumptions for other countries. In addition to future market conditions (e.g. electricity price developments, technology costs etc.), future market and policy developments including changes to grid tariffs, the planned introduction of a capacity remuneration mechanism in the Netherlands[19] , as well as potential future support schemes for non-fossil flexibility, may influence the pace at which both flexible capacities and RES resources are deployed.

[19] The Dutch government announced its decision to introduce a market-wide Capacity Remuneration Mechanism with a letter to parliament in June 2026. A Capacity Remuneration Mechanism is a market intervention aimed at ensuring sufficient (ongoing) investment in capacity to ensure sufficient resource adequacy according to a national reliability standard. However, new investments in flexible capacities which result from a capacity mechanism will likely contribute to system flexibility as well.

4. Results of the Flexibility Needs Assessment

This chapter presents the assessment of flexibility needs in accordance with Regulation (EU) 2019/943 and the FNA Methodology (Articles 8–12).

It evaluates the flexibility required to maintain system balance and support RES integration across seasonal, daily and hourly timescales. The role of non-fossil flexibility resources — such as demand response, storage and interconnection — is considered from both transmission and, where relevant, distribution perspectives.

The chapter first identifies flexibility needs and subsequently assesses the resources required to address them.

4.1. System-wide flexibility needs

This section presents the system-wide flexibility needs of the Dutch electricity system across the relevant timeframes: hourly, daily and seasonal. The assessment distinguishes between **covered needs**, which are met by the flexibility resources assumed to be available in the MVZ scenario (including storage, dispatchable generation, demand response and interconnection capacity) and represented in the economic dispatch, and **uncovered needs**, where the system is unable to fully accommodate the identified flexibility requirement under the scenario assumptions.

System-wide flexibility needs are assessed through three indicators:

- RES integration needs;
- ramping needs;
- short-term flexibility needs.

These indicators represent different dimensions of system flexibility. RES integration needs primarily capture the ability of the system to accommodate renewable generation and avoid excessive curtailment. Ramping needs capture expected changes in residual load between consecutive time steps. Short-term flexibility needs capture unexpected deviations from forecast errors and other short-term uncertainties.

The analysis distinguishes system-wide needs from network-driven needs. System-wide needs are derived from the market and economic-dispatch results and describe the ability of the electricity system as a whole to balance demand, renewable generation, dispatchable generation, storage, demand-side response, Power-to-X and interconnection. Network-driven needs, including transmission- and distribution-related curtailment or redispatch needs, are assessed separately in the network-needs sections and are considered in the final synthesis and fine-tuning step.

The key system-level finding is that flexibility requirements increase between 2030 and 2035 due to stronger variability in residual load, deeper surplus periods and more pronounced intraday patterns. However, under the analysed assumptions, most system-wide flexibility needs are covered by the available resource portfolio. No uncovered RES integration needs are identified at system level, and ramping needs are also covered. Short-term uncovered needs are assessed separately in Section 4.1.3 and depend on the assumed availability of domestic and cross-border flexibility.

4.1.1. RES integration

RES integration needs reflect the quantity of flexibility required for the electricity system to integrate renewable generation while respecting the national RES integration targets. In this assessment, RES integration is evaluated using the economic-dispatch results, with particular attention to residual load

patterns, RES curtailment, and the extent to which curtailment remains compatible with the RES target.

The RES integration assessment is structured in four steps:

1. characterization of the residual load time series;
2. characterization of RES generation curtailment;
3. assessment of uncovered RES integration needs;
4. assessment of flexible resources needed to meet uncovered needs.

The main conclusion is that system-level RES curtailment increases between 2030 and 2035 but remains limited relative to total RES generation. Curtailment is strongly concentrated in specific hours and seasons, especially around midday in spring and early summer, and is dominated by solar PV. Based on the system-level assessment, no uncovered RES integration needs are identified.

RES integration needs reflect the amount of flexibility required to integrate renewable generation into the electricity system while respecting the national RES integration targets. These needs are assessed based on the outcomes of the economic dispatch simulations described in Chapter 2.

4.1.1.1. Characterisation of residual load time series

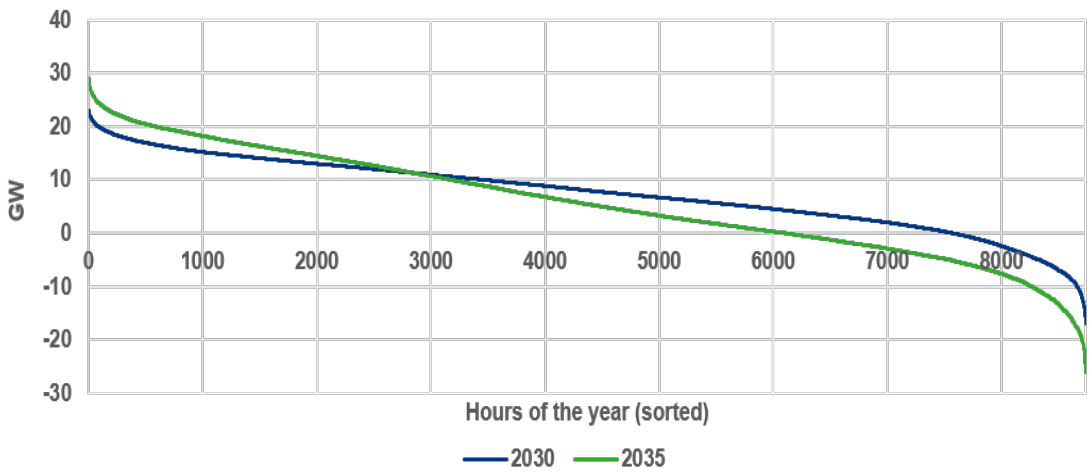
Residual load is defined as electricity demand minus non-dispatchable renewable generation. It represents the part of demand that must be met by dispatchable generation, storage, demand-side response, Power-to-X, interconnection and other flexible resources. Residual load is therefore a key indicator for identifying the timing, direction and magnitude of system-wide flexibility needs.

The residual load time series is characterised across three dimensions:

- **hourly**, using the distribution of residual load values, minimum and maximum values, and duration curves;
- **daily**, using average intraday profiles and the difference between daily minimum and maximum residual load;
- **seasonal**, using monthly and seasonal average residual load patterns.

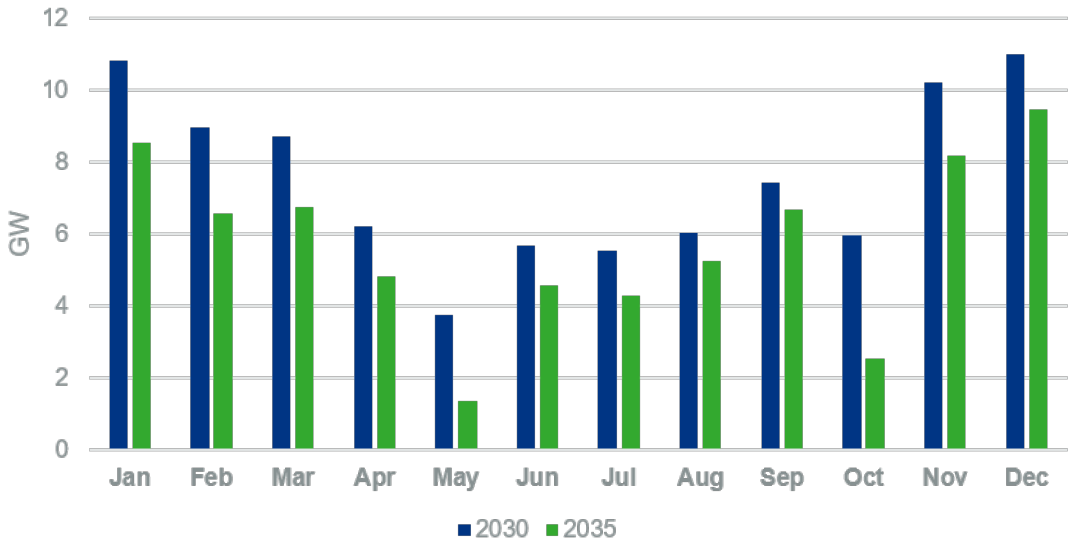
Negative residual load values indicate periods where renewable generation exceeds demand before the full contribution of flexible resources is considered. These periods are particularly relevant for downward flexibility, because surplus renewable generation must either be absorbed by storage, flexible demand, Power-to-X or exports, or curtailed if insufficient downward flexibility is available.

Figure 9 | Residual load duration curves in 2030 and 2035



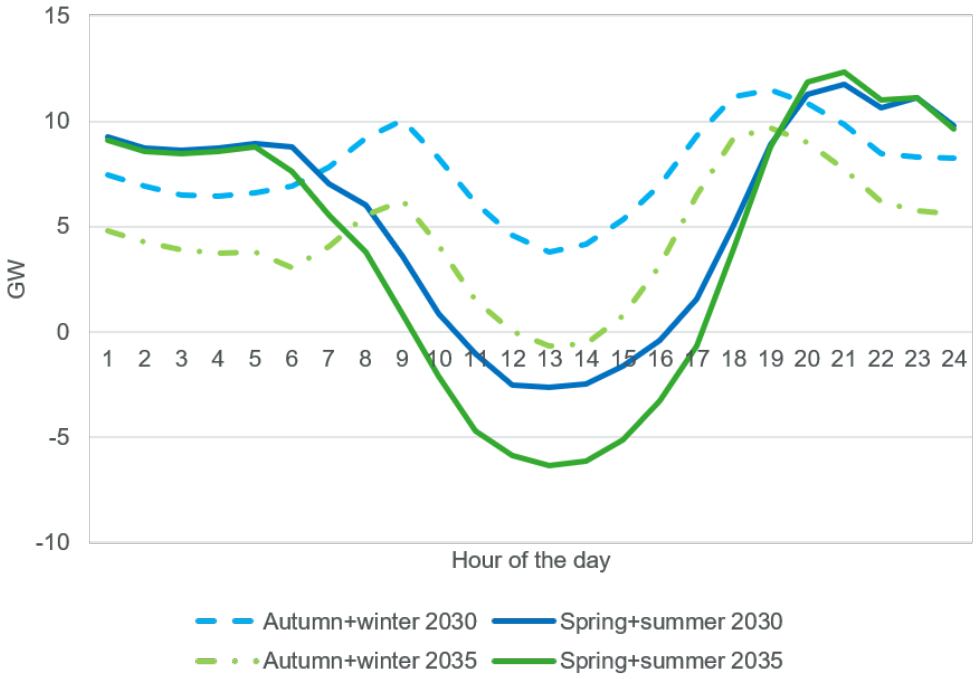
The residual load duration curves show a widening range between high positive and negative residual load values between 2030 and 2035. Peak residual load increases from approximately +23 GW in 2030 to approximately +29 GW in 2035, while minimum residual load decreases from approximately −17 GW to approximately −25 GW. This indicates that both high residual-load conditions and surplus renewable conditions become more pronounced. The system therefore requires flexibility in both directions: upward flexibility during high residual-load periods and downward flexibility during surplus renewable periods.

Figure 10 | Monthly average residual load in 2030 and 2035



At seasonal level, residual load remains higher in winter and lower in spring and summer. This pattern reflects the combination of higher demand during winter months and increased renewable generation, particularly solar PV, during spring and summer. Compared with 2030, monthly average residual load is lower in 2035 across most months, reflecting the growth of renewable generation. The reduction is most visible in spring and summer, but is also present in winter due to the contribution of wind generation.

Figure 11 | Average hourly residual load by season in 2030 and 2035



At intraday level, residual load shows a clear daily pattern. Morning and evening peaks are mainly driven by demand, while midday troughs are driven by solar generation. These intraday dynamics become more pronounced in 2035, with deeper midday troughs and sharper transitions toward evening residual-load peaks. This points to an increasing need for resources that can absorb surplus generation during midday hours and provide upward flexibility during evening hours.

Overall, the residual-load analysis shows that system-wide flexibility needs become more pronounced, particularly in spring and summer. The system experiences deeper midday troughs and sharper transitions towards the evening.

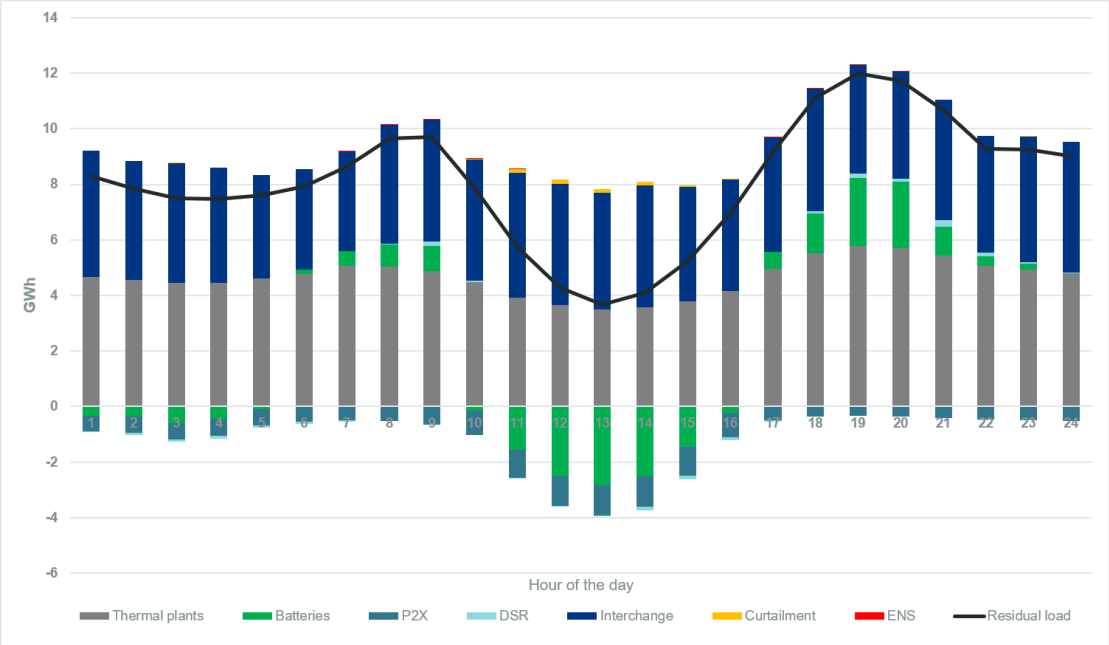
4.1.1.2. Contribution of flexibility resources

The contribution of flexibility resources is assessed using the economic-dispatch results. The objective is to understand how different resources respond to the residual-load patterns described above and how they contribute to upward and downward flexibility.

Different flexibility resources contribute in different system conditions:

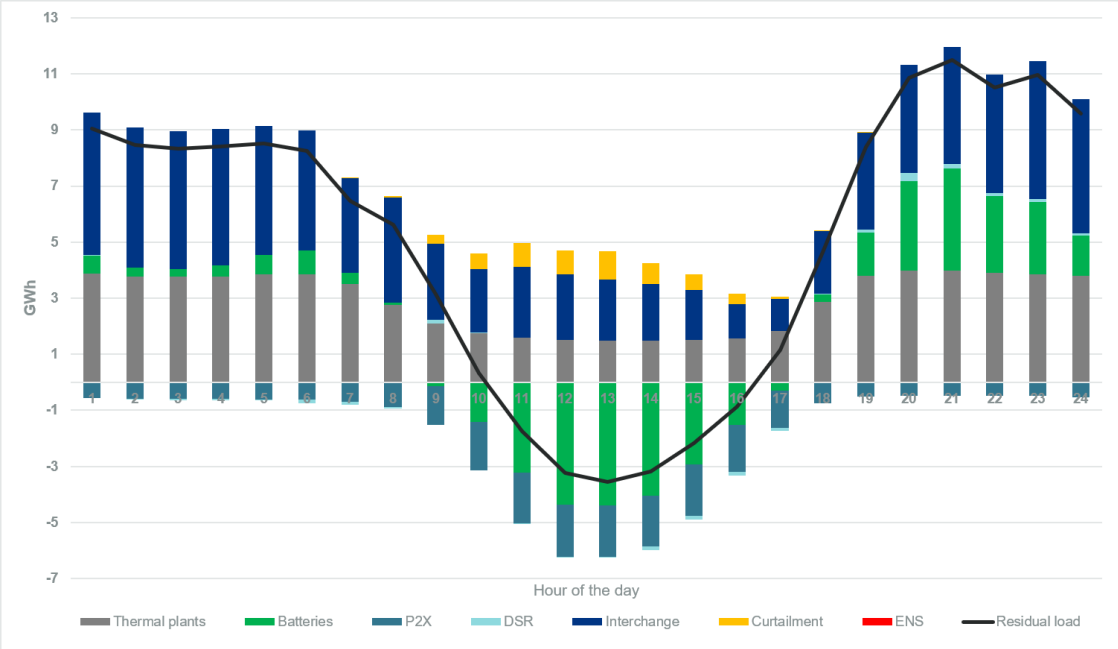
- Dispatchable generation and interconnectors provide most upward flexibility during periods of high residual load;
- Battery storage contributes to both upward and downward flexibility;
- Power-to-X mainly contributes to downward flexibility during surplus generation periods;
- Demand-side response provides a smaller but complementary contribution in both directions;
- RES curtailment occurs when available downward flexibility is insufficient to fully accommodate renewable surplus.

Figure 12 | Average hourly contribution of flexible resources in autumn and winter



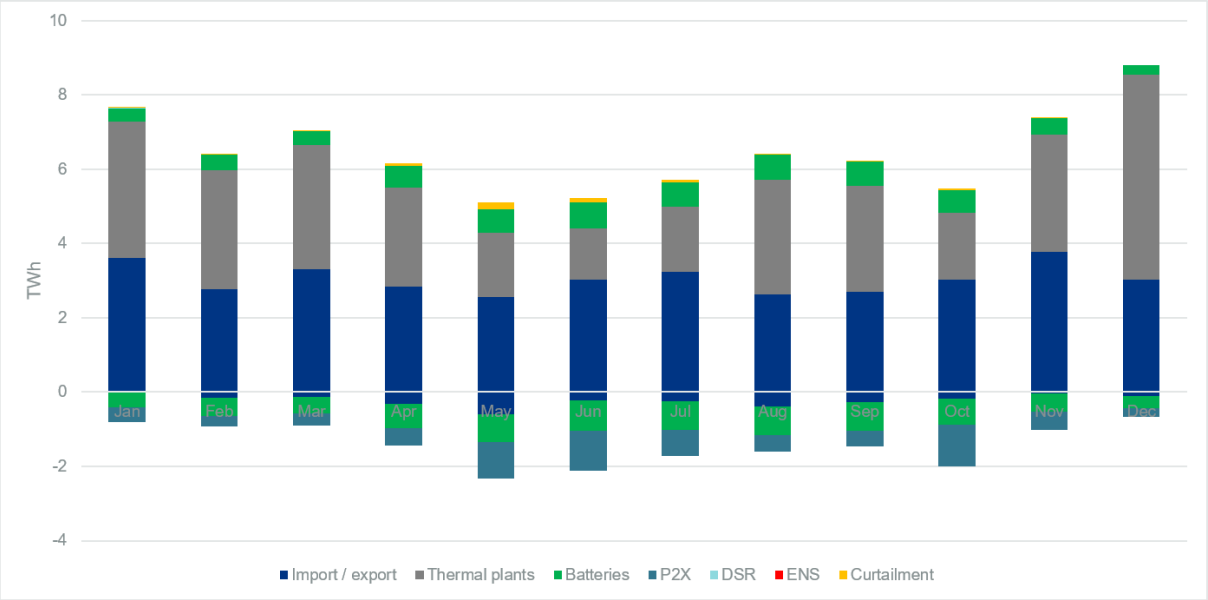
In autumn and winter, residual load is generally positive throughout the day. Flexibility provision is therefore mainly upward-oriented. Dispatchable generation and interconnectors cover most morning and evening residual-load peaks, while batteries provide intraday balancing. Contributions from Power-to-X and demand-side response are more limited in these periods, and RES curtailment is negligible.

Figure 13 | Average hourly contribution of flexible resources in spring and summer



In spring and summer, midday residual load frequently becomes low or negative due to high solar generation. During these hours, battery charging, Power-to-X and flexible demand contribute to downward flexibility. In the evening, the system transitions back toward upward flexibility, mainly covered by dispatchable generation, interconnectors and battery discharge. This confirms that flexibility provision is strongly time-dependent and follows the residual-load structure.

Figure 14 | Monthly contribution of flexibility resources to upward and downward flexibility in 2030



At seasonal level, upward flexibility is more prominent in winter months, while downward flexibility becomes more important in spring and summer. Batteries play a dual role by charging during surplus periods and discharging when residual load increases. Power-to-X contributes mainly during surplus renewable periods. Interconnectors and dispatchable generation provide the majority of upward flexibility.

The main implication is that no single flexibility resource covers all system needs. Upward and downward flexibility are provided by different combinations of resources, and their contribution depends strongly on the season and hour of day. During the most pronounced surplus periods, available downward flexibility is not always sufficient, leading to RES curtailment. This is analyzed in the next subsection.

4.1.1.3. Characterisation of RES curtailment

RES generation curtailment represents renewable electricity that cannot be accommodated by the system and is therefore not injected into the grid. In the system-wide assessment, curtailment is derived from the economic-dispatch results and reflects the interaction between renewable generation, demand, interconnection, storage, flexible demand and dispatchable resources.

In the economic-dispatch model, curtailment occurs when available renewable generation can no longer be absorbed by demand, storage, Power-to-X, interconnection capacity or other flexibility resources. Electricity prices in the model are based on marginal costs and are not modelled as negative. Consequently, curtailment occurs once surplus renewable generation can no longer be accommodated by the available flexibility options within the modelled system.

Curtailment is characterised using the following indicators:

- total curtailed energy;
- maximum curtailed capacity;
- number of hours with curtailment;
- duration curve of curtailed capacity;
- distribution by RES technology;
- monthly and intraday curtailment patterns.

Figure 15 | RES generation and curtailment in 2030 across climate years

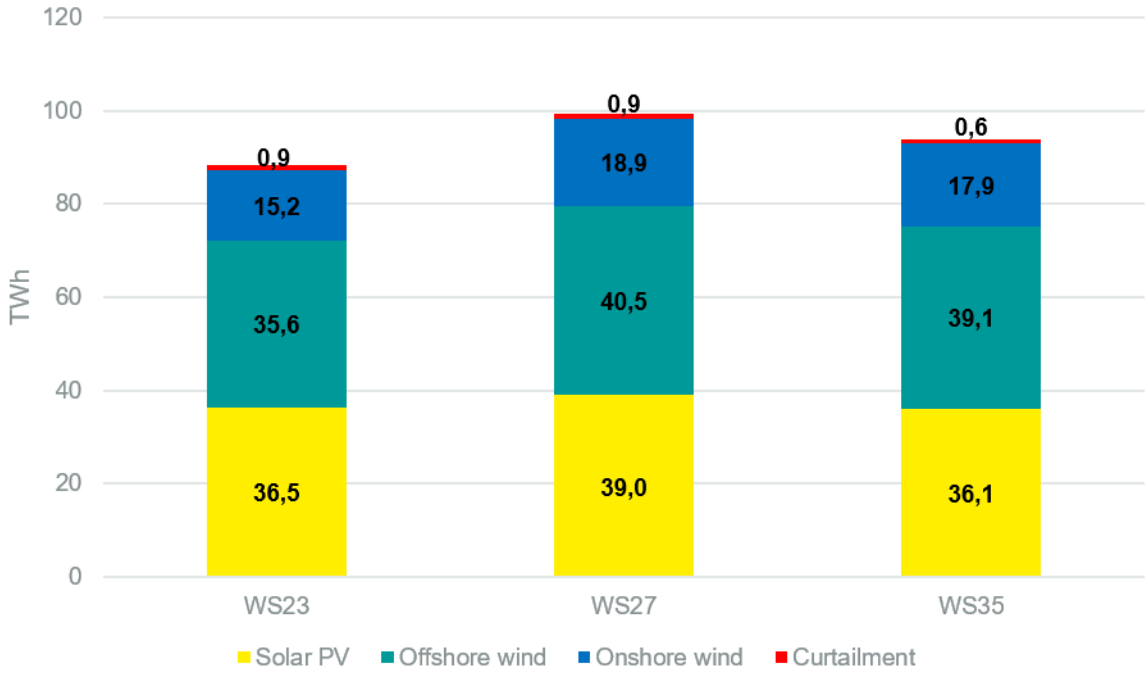


Figure 16 | RES generation and curtailment in 2035 across climate years

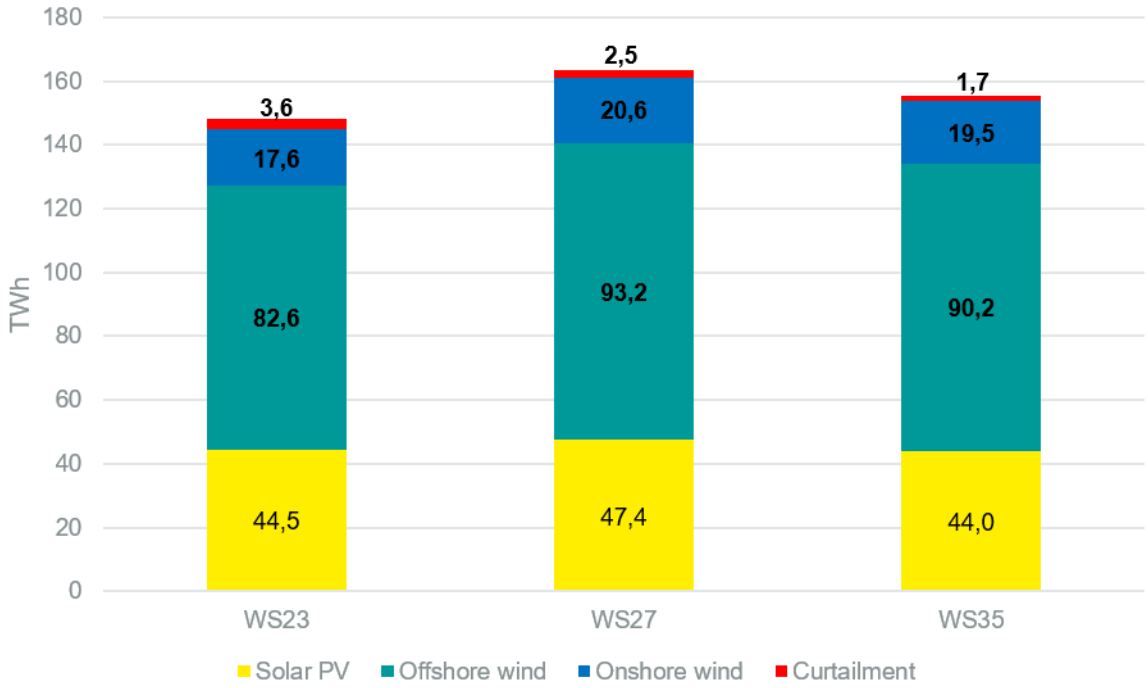
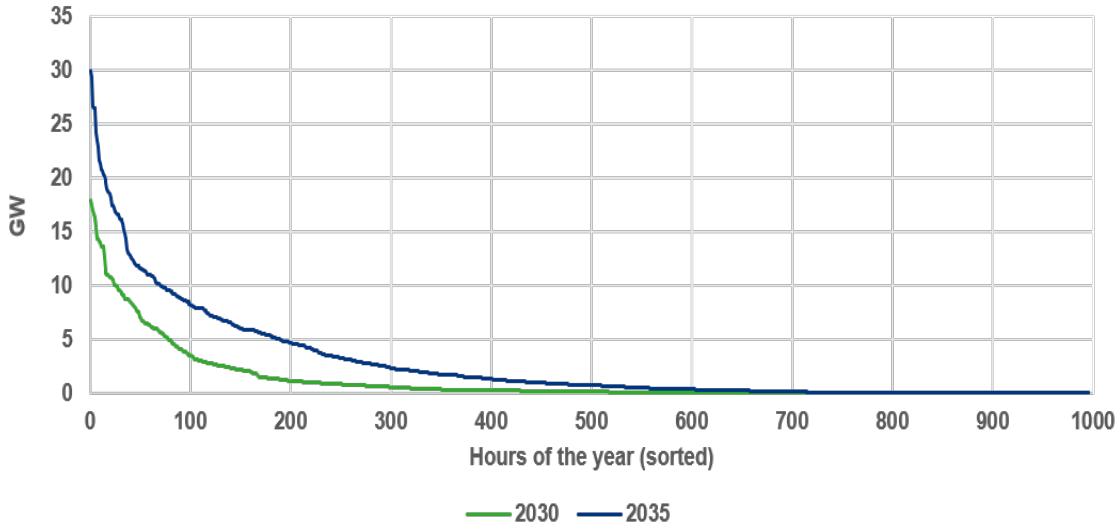


Figure 15 and Figure 16 present the results across the three ERAA climate years used in this assessment (WS23, WS27 and WS35). System-level RES curtailment remains limited in both target years, but increases toward 2035. Across the climate years considered, curtailment amounts to approximately 0.6–0.9 TWh in 2030 and approximately 1.7–3.6 TWh in 2035. The increase reflects higher renewable penetration and more frequent surplus-generation periods. However, curtailment

remains concentrated in a limited number of hours rather than being distributed evenly throughout the year.

Figure 17 | RES curtailment duration curves in 2030 and 2035



The curtailment duration curves show that the highest curtailment levels are concentrated in a relatively limited number of hours. The peak curtailed capacity increases from approximately 18 GW in 2030 to approximately 30 GW in 2035. This indicates that the main challenge is not continuous renewable surplus across the year, but short, high-intensity surplus events that require well-timed downward flexibility.

Table 6 | Distribution of RES curtailment by technology in 2030, average across climate years

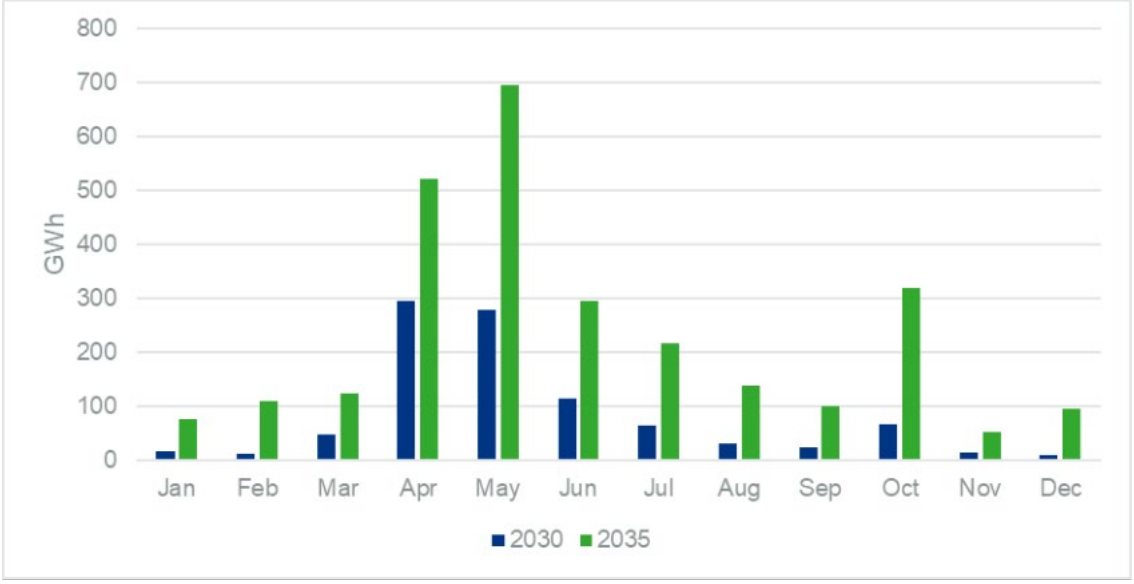
Technology	Curtailment [GWh]	Share of total [%]	Curtailment ratio [%]	Available energy [GWh]
Solar PV	654	67	1.8	37,062
Wind offshore	211	22	0.5	38,409
Wind onshore	115	12	0.7	17,310

Table 7 | Distribution of RES curtailment by technology in 2035, average across climate years

Technology	Curtailment [GWh]	Share of total [%]	Curtailment ratio [%]	Available energy [GWh]
Solar PV	1,334	49	3.0	44,906
Wind offshore	1,125	41	1.3	88,725
Wind onshore	286	10	1.5	18,855

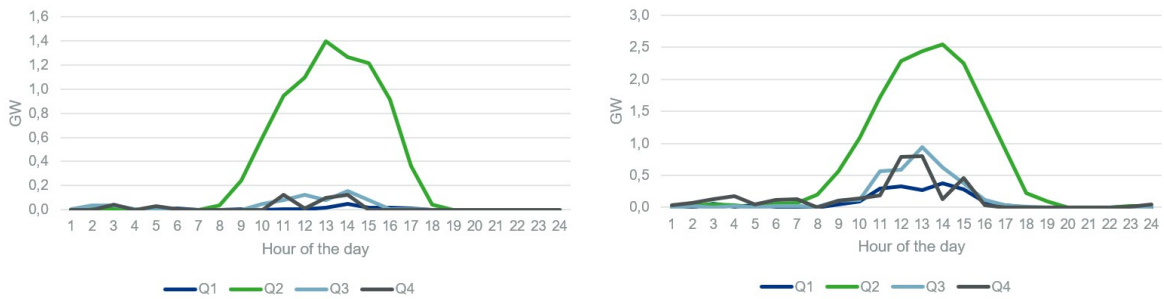
Solar PV remains the largest contributor to RES curtailment in both target years, indicating that system-level curtailment is strongly linked to solar generation patterns. At the same time, the contribution of wind curtailment increases towards 2035, especially for offshore wind, as renewable generation volumes continue to grow.

Figure 18 | Monthly RES curtailment in 2030 and 2035



At seasonal level, curtailment is strongly concentrated in spring and early summer months. These are periods with high solar generation and moderate demand, creating surplus conditions when available downward flexibility is insufficient to absorb renewable output. Curtailment remains limited in autumn and winter, when demand is higher and solar generation is lower.

Figure 19 | Average intraday RES curtailment by quarter in 2030 (left) and 2035 (right)



At intraday level, curtailment occurs mainly around midday, especially in Q2. This reflects the concentration of solar PV output around late morning and early afternoon. In 2035, the midday curtailment peak becomes more pronounced, indicating that surplus conditions become stronger as renewable capacity increases.

Overall, curtailment is not caused by a continuous lack of system flexibility across the year. It is concentrated in specific hours and seasons, mainly linked to solar-driven surplus periods. This means that the relevant flexibility challenge is not only the total volume of downward flexibility, but also its timing, availability and ability to absorb short-lived surplus peaks.

4.1.1.4. Uncovered needs

In accordance with the FNA Methodology, uncovered RES integration needs arise when simulated RES curtailment exceeds the level compatible with achieving the RES integration target. The assessment therefore compares the simulated level of system-level curtailment with the maximum acceptable curtailment implied by the RES integration target. At system level, RES curtailment remains limited:

- 2030: approximately 0.6–0.9 TWh;
- 2035: approximately 1.7–3.6 TWh.

Based on these system-level results, RES curtailment remains below the level that would indicate an uncovered RES integration need. The RES integration target is achieved in both target years under the analyzed assumptions. Therefore, no uncovered RES integration needs are identified at system level.

Network-induced curtailment is assessed separately in the network-needs sections. When system-level and network-induced curtailment are considered together in the final synthesis, the margin to the RES target becomes smaller, particularly in 2035. However, this combined assessment does not change the system-level conclusion that the economic-dispatch results do not indicate uncovered RES integration needs at national system level.

The interpretation is therefore twofold:

- from a system-wide perspective, RES curtailment remains limited and compatible with the RES integration target;
- from a wider system-and-network perspective, network-induced curtailment reduces the margin to the target and is therefore relevant for the final synthesis and guiding-criteria assessment.

4.1.1.5. Flexible resources needs to meet uncovered needs

Since no uncovered RES integration needs are identified at system level, no additional flexibility resources are required to achieve the RES integration target under the analysed assumptions.

The curtailment analysis nevertheless provides insight into the types of flexibility that support RES integration. Curtailment is concentrated in spring and early summer, primarily during midday hours with high solar generation. This highlights the value of downward flexibility resources such as battery charging, flexible demand, Power-to-X, demand-side response and cross-border exports.

The results indicate that reducing curtailment further would primarily require flexibility that is available during these high-surplus periods rather than a year-round increase in flexibility capacity. Network-induced curtailment and the suitability of flexibility measures to address it are assessed separately in the network-needs sections.

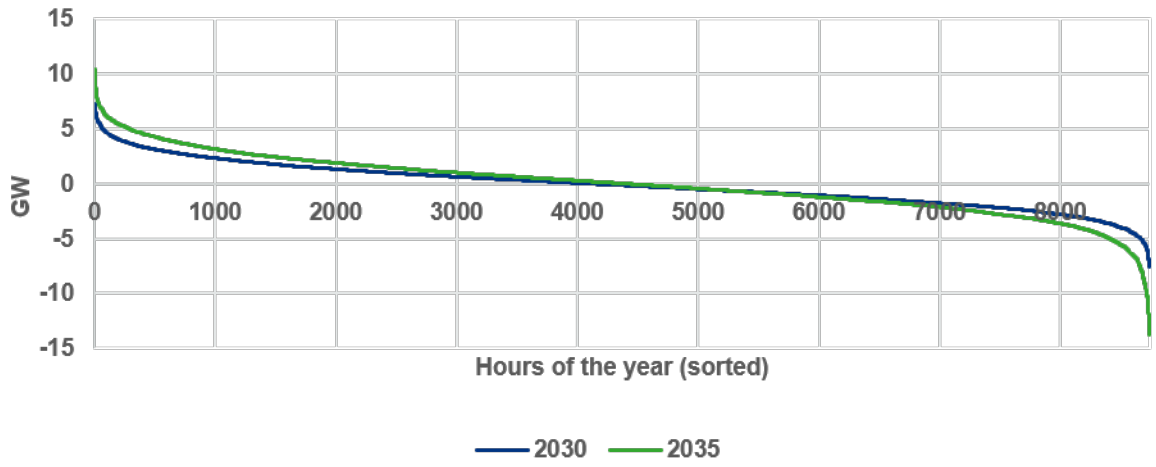
4.1.2. Ramping needs

Ramping needs reflect the ability of the electricity system to follow expected changes in residual load between consecutive time steps. While the RES integration assessment focuses on whether renewable generation can be accommodated, the ramping assessment focuses on how quickly the system must adjust generation, demand, storage, interconnection and other flexible resources in response to changes in residual load.

In this assessment, ramping needs are derived from the variation in residual load between consecutive modelled time steps. A positive value represents an upward ramping need, where the system must increase net supply or reduce demand. A negative value represents a downward ramping need, where the system must reduce net supply or increase demand.

Ramping needs are characterised by their magnitude, direction, frequency and timing. The analysis distinguishes between upward ramps and downward ramps and assesses their distribution across the year, within the day and across seasons.

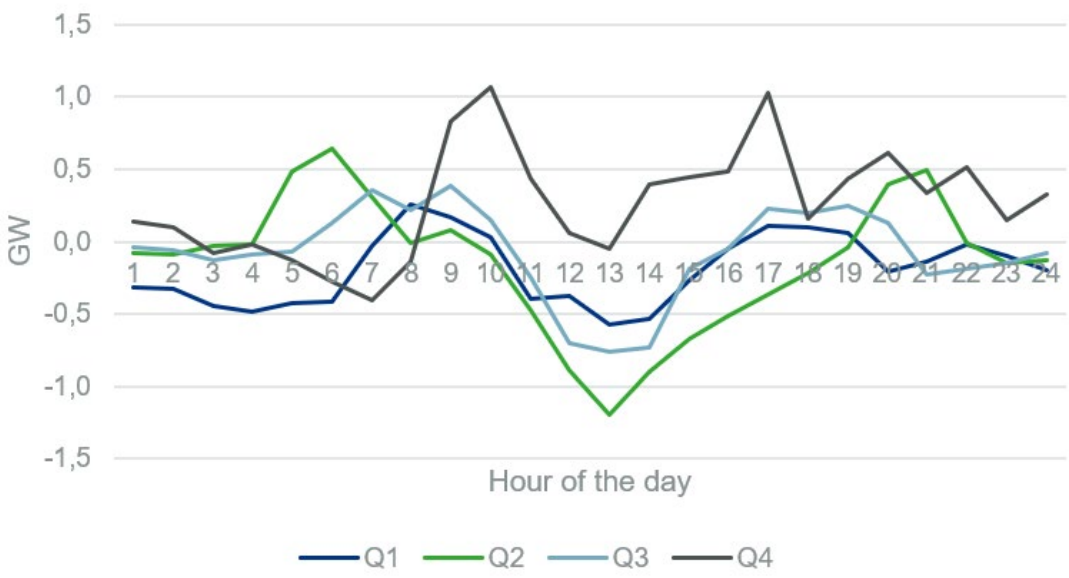
Figure 20 | Duration curves of upward and downward ramping needs in 2030 and 2035



The ramping duration curves show that both upward and downward ramping requirements increase toward 2035. The distribution becomes wider, indicating that the system faces more frequent and more pronounced changes in residual load, particularly during the most extreme upward and downward ramping events.

This indicates that the system does not only need sufficient flexible capacity in absolute terms; it also needs resources that can adjust their output or consumption quickly enough to follow changes in residual load.

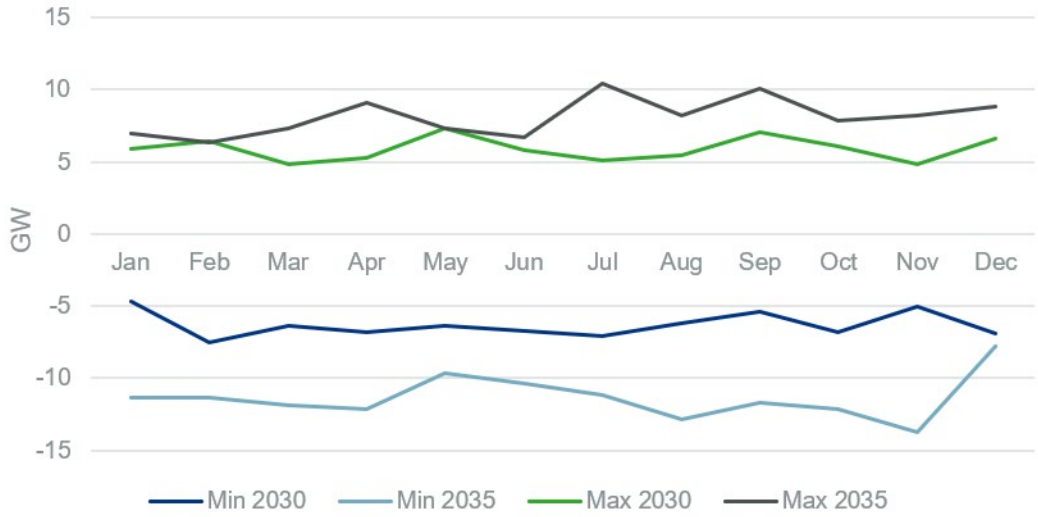
Figure 21 | Intraday ramping profile by quarter



At intraday level, ramping needs follow a clear daily pattern. Downward ramps are most visible during late morning and midday hours, when solar PV generation increases and residual load decreases. Upward ramps are most visible during late afternoon and evening hours, when solar generation decreases while demand remains relatively high.

This pattern is strongest in spring and summer, when solar generation has the largest impact on the residual-load profile. In autumn and winter, ramping needs are generally less pronounced and are more closely linked to demand-driven variations.

Figure 22 | Monthly minimum and maximum ramping needs in 2030 and 2035



At seasonal level, ramping requirements occur throughout the year. The difference between minimum and maximum ramping values widens in 2035, especially for downward ramps. This reflects the increasing role of solar generation and the stronger variation between low midday residual load and higher evening residual load.

Overall, the ramping analysis shows that expected short-term variability increases between 2030 and 2035. The main driver is the growing impact of variable renewable generation on the residual-load profile, particularly the solar-driven transition from midday surplus conditions to evening upward ramps.

4.1.2.1. Characterisation of ramping capacity

Ramping capacity refers to the ability of flexibility resources to increase or decrease their output or consumption in response to changes in residual load. Upward ramping capacity corresponds to an increase in generation and/or a reduction in electricity consumption, while downward ramping capacity corresponds to a reduction in generation and/or an increase in electricity consumption.

As a first step, the ramping behaviour of the main flexibility resources was analysed using the results of Model B. For each resource category, the upward and downward ramping capability was determined based on the maximum observed change in dispatch between two consecutive hourly time steps in the economic dispatch simulations. The results are shown in Table 7.

Table 8 | Maximum observed upward and downward hourly ramping capability by resource [GW]

Resource	2030 downward	2030 upward	2035 downward	2035 upward
Interconnection	-10.7	16.4	-15.3	16.4
Batteries	-8.9	8.7	-14.9	15.8
Dispatchable generation	-8.9	8.4	-9.1	8.8
Power-to-X	-2.8	2.8	-5.7	5.7

The results show that multiple flexibility resources contribute to accommodating ramping requirements. Interconnection provides the largest observed upward ramping capability in both assessment years, while batteries play an increasingly important role in both upward and downward ramping. Battery ramping capability increases significantly between 2030 and 2035, reflecting the strong growth in storage capacity in the underlying scenario assumptions. Dispatchable generation continues to provide a stable contribution, while Power-to-X increasingly contributes to downward flexibility through additional electricity consumption during periods of surplus generation.

The utilisation of these resources follows the intraday pattern of ramping needs. Downward ramping is primarily provided during late-morning and midday periods through battery charging, flexible demand and reductions in generation. Upward ramping is mainly provided during late-afternoon and evening periods through dispatchable generation, battery discharge and adjustments in cross-border exchanges.

As a second step, the ability of the modelled flexibility portfolio to accommodate all ramping requirements was assessed. This is discussed in the next section.

4.1.2.2. Uncovered needs

Uncovered ramping needs occur when available ramping capability is insufficient to meet the required upward or downward change in residual load. In this assessment, uncovered ramping needs are evaluated by comparing the more constrained dispatch in Model B with the baseline economic-dispatch in Model A.

This comparison shows that no significant uncovered upward or downward ramping needs are identified in either 2030 or 2035. The system is able to accommodate both upward and downward ramping requirements under the analysed assumptions.

This conclusion is supported by the absence of additional:

- Energy Not Served;
- RES curtailment;

Therefore, no uncovered ramping flexibility needs are identified at system level.

This result should be interpreted within the modelling scope. The ramping assessment is based on hourly time resolution, fixed cross-border exchanges as represented in the model, perfect foresight and full availability of modelled flexible resources. These assumptions may underrepresent some real-time operational constraints and uncertainty. Forecast errors and other unexpected deviations are therefore assessed separately under short-term flexibility needs in Section 0.

4.1.2.3. Flexible resources needed to meet the uncovered needs

Since no uncovered ramping needs are identified, no additional flexibility resources are required to meet uncovered ramping needs under the analysed assumptions.

However, the results highlight the importance of maintaining sufficient fast-response capability in the system. Ramping capability is mainly provided by a combination of interconnection, battery storage, dispatchable generation and flexible demand. Interconnection provides a large upward ramping contribution, while batteries become increasingly important in both directions, especially in 2035.

The main implication is therefore not that additional ramping capacity is required at system level, but that the system's ability to manage ramping depends on the continued availability and coordination of fast-response resources. This includes:

- sufficient interconnector availability and cross-border operational coordination;
- battery charging and discharging capability;
- dispatchable generation that remains technically available to ramp;
- flexible demand and Power-to-X that can respond during surplus periods.

The ramping assessment therefore shows that expected residual-load variations can be covered under the analysed assumptions. Remaining flexibility challenges are more closely linked to uncertainty, forecast errors and real-time availability of resources, which are assessed in the short-term flexibility section.

4.1.3. Short-term flexibility needs

Short-term flexibility needs arise from deviations between day-ahead schedules and real-time system conditions. These deviations are mainly driven by forecast errors in renewable generation and electricity demand, and can create a need for additional upward or downward flexibility after the day-ahead market clearing.

In this assessment, short-term flexibility needs are quantified by comparing Model B, which includes technical constraints under perfect foresight, with Model C, which introduces forecast uncertainty. The detailed modelling approach, including the interleaved Model B–Model C setup and the synthesis of forecast errors, is described in Chapter 2 and Annex 1.

Because the availability of short-term flexibility is uncertain, Model C is assessed through three configurations. These configurations are described in detail in the methodology chapter and are only recalled here for interpretation of the results:

Table 9 | Explanation of model configurations C1, C2 and C3 used to assess the impact of uncertainties in the (in)flexibility of domestic capacity and available cross-border flexibility on short-term flexibility needs

Configuration	Interpretation in the results
C1	Conservative flexibility availability: no additional cross-border flexibility and limited access to non-committed domestic generation.
C2	Additional domestic flexibility: up to 5 GW of additional Dutch CCGT capacity is made available, taking into account capacity already committed in the day-ahead market.
C3	Additional domestic and cross-border flexibility: remaining needs can also be covered by indicative cross-border flexibility, except during scarcity conditions in neighbouring systems.

The three configurations should not be interpreted as separate forecasts. They provide a sensitivity range for the availability of short-term flexibility resources. This allows the results to distinguish between flexibility needs that reflect a structural shortage of resources and needs that arise mainly because flexibility is not assumed to be available in specific hours.

The analysis is based on an hourly market model. As a result, the quantified results explicitly represent the 1-hour timescale, corresponding to slow short-term flexibility needs in the FNA Methodology. Very fast and fast flexibility needs, covering the 5–60 minute range, are not explicitly modelled. The assessment therefore does not represent balancing-market processes, reserve activation or other sub-hourly operational actions.

The main conclusion is that uncovered short-term flexibility needs are highly sensitive to assumptions regarding flexibility availability. Under conservative assumptions, uncovered upward needs remain material. These needs are strongly reduced when additional domestic flexibility is made available and decrease further when indicative cross-border flexibility is included. No uncovered downward short-term flexibility needs are identified under the assessed configurations.

4.1.3.1. Characterisation of short-term upward and downward flexibility

The short-term flexibility assessment starts from forecast errors in the main drivers of residual load: native load, solar PV, wind onshore and wind offshore. Forecast errors are defined as the difference between day-ahead forecasts and realised values.

Historical forecast errors for 2024 and 2025 were obtained from Dutch market data and used as the basis for generating synthetic forecast error time series for the target years 2030 and 2035.

To preserve key statistical characteristics observed in historical forecast errors, including temporal correlations and seasonal patterns, a SARIMA-based approach was applied. A detailed description of this methodology is provided in Annex 1.

The resulting error distributions were scaled to 2030 and 2035 to reflect the projected development of electricity demand and renewable generation capacities in the underlying scenario.

Table 10 summarises the resulting forecast error distributions for the historical reference period (2024–2025) and the modelled target years 2030 and 2035.

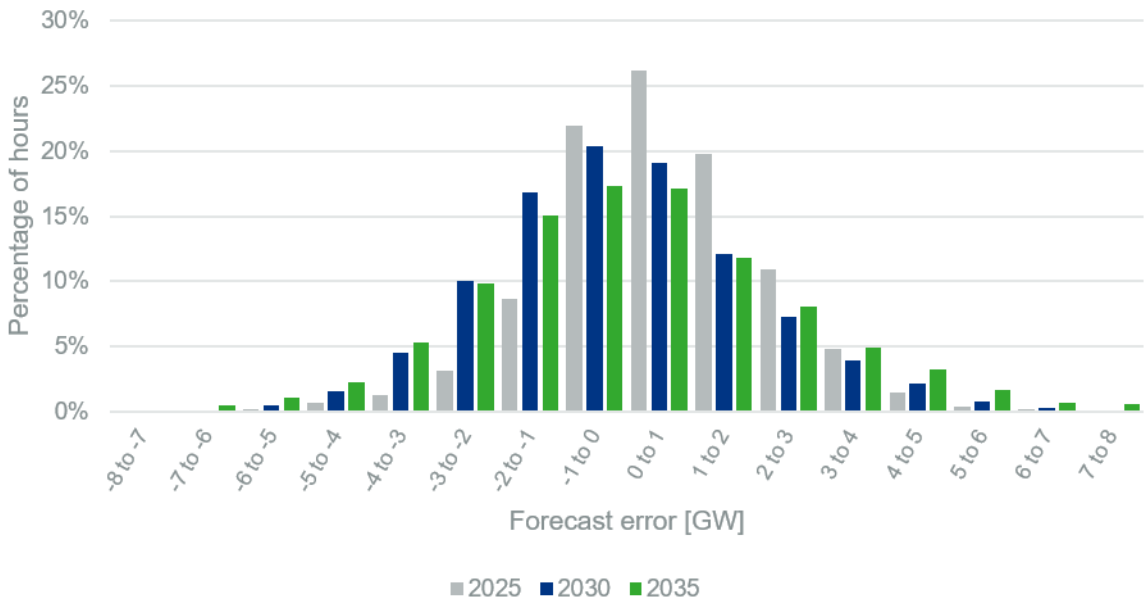
Table 10 | Forecast error statistics for the main drivers of residual load

	Variable	P90 abs. forecast error (GW)	P95 abs. forecast error (GW)	P99 abs. forecast error (GW)	Max. abs. forecast error (GW)
2024/2025	Native load	1.3	1.7	2.4	4.7
	Solar PV	1.6	2.4	4.0	7.8
	Wind onshore	0.8	0.9	1.2	4..5
	Wind offshore	0.8	1.1	1.8	3.1
	Residual load	**2.1**	**2.9**	**4.6**	**8.3**
2030	Native load	1.6	1.9	2.6	4.9
	Solar PV	1.7	2.3	3.6	9.3
	Wind onshore	2	2.2	2.7	6
	Wind offshore	1.5	1.9	2.6	8.2
	Residual load	**3.3**	**3.9**	**5.3**	**10**
2035	Native load	1.9	2.3	3.1	5.4
	Solar PV	2.2	3	5.3	21
	Wind onshore	2	2.3	2.9	7.5
	Wind offshore	2.6	3.4	4.9	19.1
	Residual load	**3.7**	**4.6**	**6.3**	**10.8**

Note: P90 abs., P95 abs. and P99 abs. represent the 90th, 95th and 99th percentiles of the absolute forecast error, irrespective of whether the forecast deviation is positive or negative.

Forecast uncertainty increases towards 2035 as electricity demand and renewable generation capacity grow. Individual forecast errors for native load, solar PV and wind generation are considerably smaller than the resulting residual-load forecast errors, reflecting the combined effect of simultaneous deviations in demand, wind generation and solar generation. The P95 residual-load forecast error increases from 2.9 GW in 2025 to 4.6 GW in 2035, while the P99 value rises from 4.6 GW to 6.3 GW. These results highlight the growing importance of flexible resources capable of responding to short-term imbalances.

Figure 23 | Distribution of residual load forecast errors in 2030 and 2035



Most residual-load forecast errors remain concentrated around zero. At the same time, the distribution has pronounced tails, with forecast errors above ±4–6 GW occurring less frequently but still representing relevant stress events. The distribution widens towards 2035, reflecting the increasing scale of variable renewable generation and electricity demand.

The next step is to see how different technologies respond to the forecast-error in the C1 configuration.

Figure 24 shows a representative day from the market simulation and illustrates how short-term flexibility is activated in response to residual-load forecast errors.

In the early hours, the realized residual load is higher than forecasted, creating a need for upward flexibility. This deviation is mainly accommodated by increased battery discharge, supplemented by demand-side response and additional generation from dispatchable units.

Later in the day, the realized residual load falls below the day-ahead forecast, creating a need for downward flexibility. This is accommodated through changes in dispatch relative to the day-ahead schedule: generators reduce their planned output, while P2X facilities increase electricity consumption. Together, these adjustments restore system balance without requiring significant additional curtailment.

Figure 24 | Illustrative example of short-term flexibility activation during a representative simulation day in 2030.

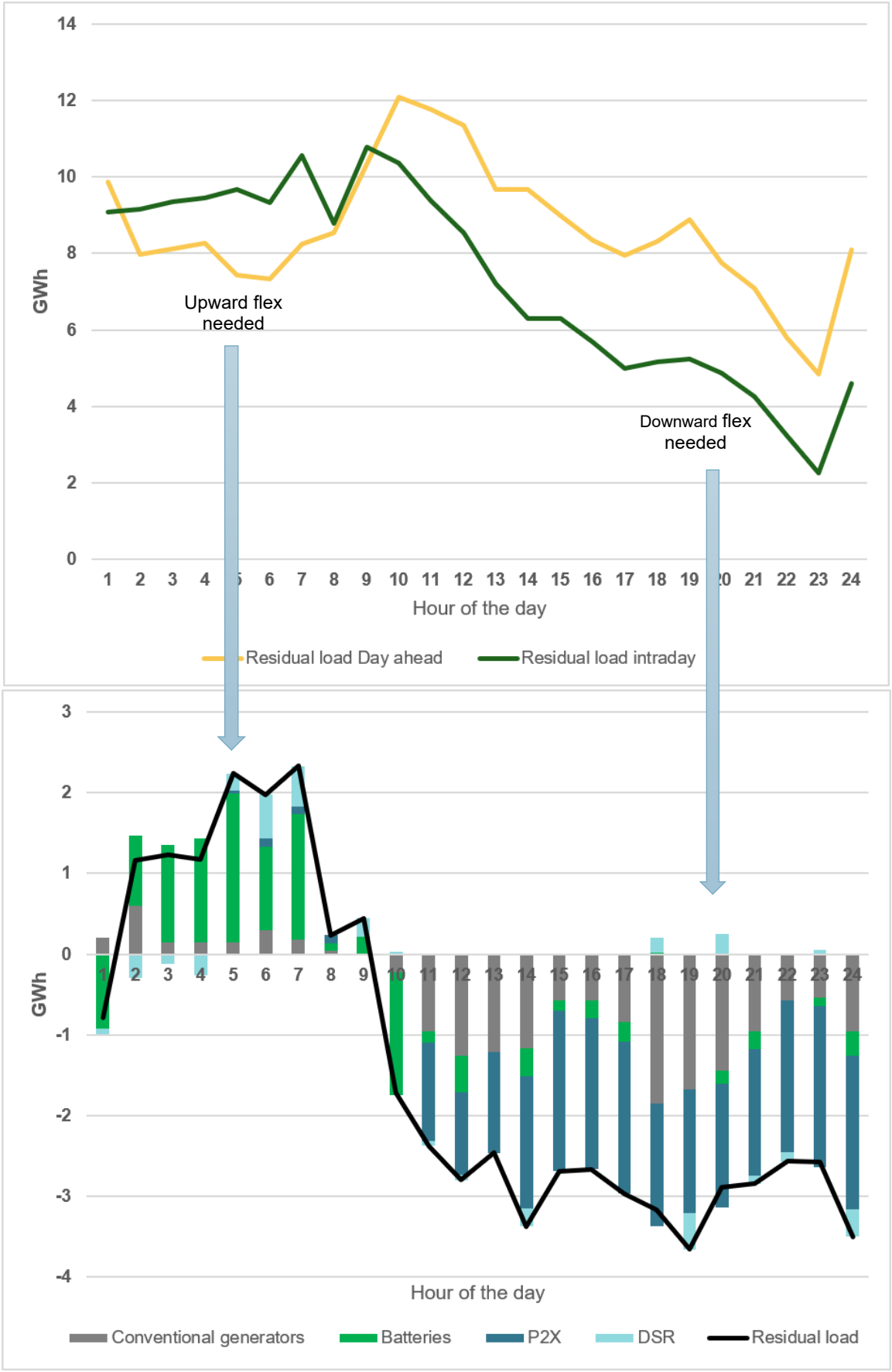


Figure 25 | Cumulative upward and downward ramping delivered in the market simulations (configuration C1 and climate year 27)

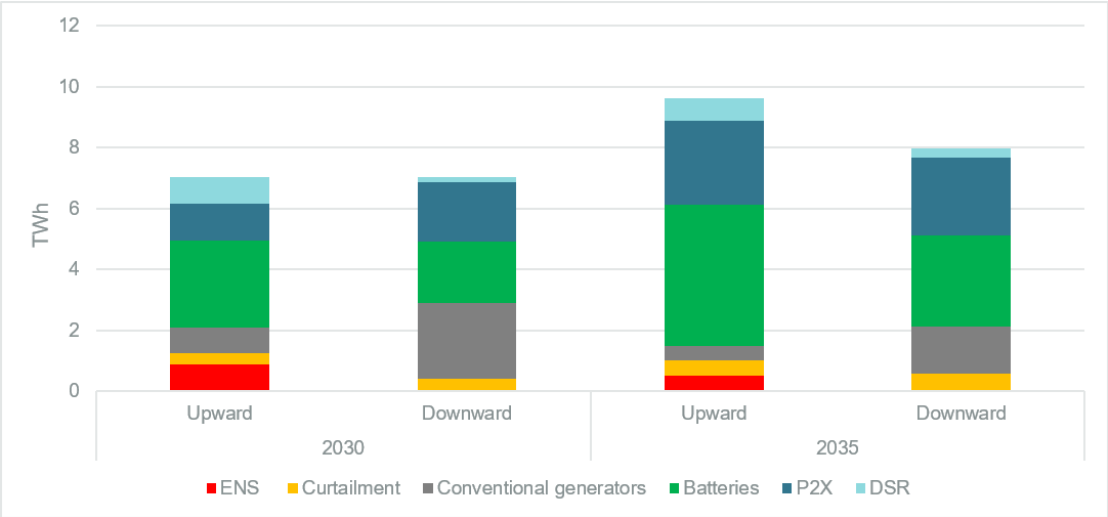


Figure 24 shows the cumulative upward and downward flexibility delivered over the simulation year. The overall volume of balancing actions increases between 2030 and 2035, consistent with the wider forecast-error distributions. Batteries remain the dominant source of upward flexibility, while the contribution of P2X increases significantly, particularly for downward flexibility. Generator redispatch continues to play an important role, whereas DSR contributes only a limited share.

Table 11 provides additional insight into the magnitude of individual balancing events by showing the P50, P95 and P99 activation volumes for each technology.

Table 11 | Distribution of activated short-term flexibility per technology (GW) (average of 3 climate years)

		2030			2035		
Technology	**Up/Down**	**P50 (GW)**	**P95 (GW)**	**P99 (GW)**	**P50 (GW)**	**P95 (GW)**	**P99 (GW)**
Batteries	Upward	0.3	2.3	3.3	0.6	3.4	5.0
	Downward	0.2	1.8	2.8	0.3	2.8	4.1
Thermal generators	Upward	0.05	0.8	1.0	0	0.8	1.1
	Downward	0.	2.3	3.5	0	2.0	3.5
P2X	Upward	0	1.6	2.5	0	3.5	5.3
	Downward	0	2.0	2.5	0.03	3.1	4.3
DSR	Upward	0.05	0.7	1.0	0	0.8	1.1
	Downward	0	0.3	0.5	0	0.4	0.8

Table 11 shows that balancing events become larger between 2030 and 2035. This is reflected by the higher P95 and P99 values across most flexibility technologies.

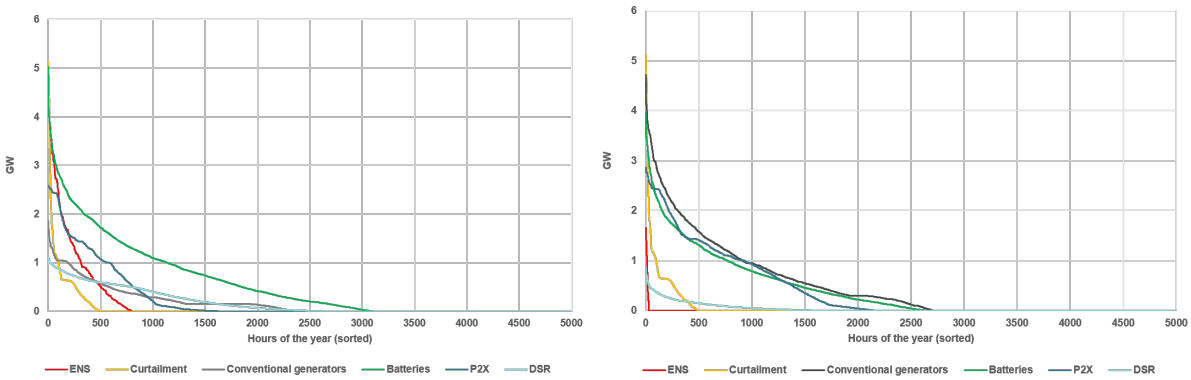
Batteries remain the main source of upward flexibility and are increasingly activated during large forecast-error events. P2X shows the strongest growth, particularly during extreme upward and downward balancing events, highlighting the increasing value of flexible electricity demand.

For downward flexibility, generators continue to play an important role, but batteries and P2X account for an increasing share of the balancing requirements in 2035.

Overall, the results indicate that future balancing requirements are met through a combination of storage, flexible demand and dispatchable generation, with batteries and P2X becoming increasingly important towards 2035.

Figure 26 shows the full distribution of activated short-term flexibility throughout the year. For upward flexibility, batteries are the dominant source of flexibility. For downward flexibility, the provision is shared more evenly between conventional generators, batteries and P2X. The duration curves also show that the highest activation volumes occur only during a limited number of hours, while lower activation levels are sufficient for most of the year.

Figure 26 | Delivered upward ramping in 2030 for configuration C1 in climate year 27 (left: upward, right: downward)



4.1.3.2. Uncovered needs

The previous section showed that forecast errors can generally be accommodated by the available flexibility portfolio. However, uncovered short-term flexibility needs occur when forecast errors coincide with insufficient available flexibility in the same hour. This section therefore assesses the hourly coincidence of forecast errors and flexibility availability under configurations C1, C2 and C3.

Figure 27 | Duration curves of uncovered upward short-term flexibility needs under configurations C1-C3 (2030)

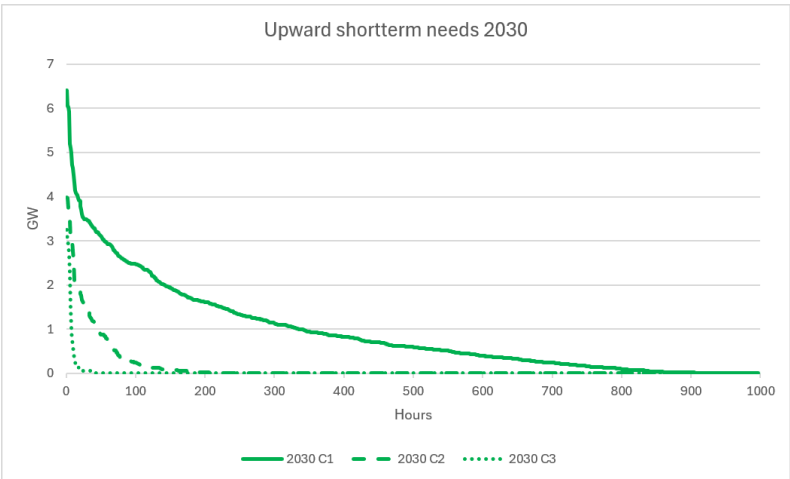
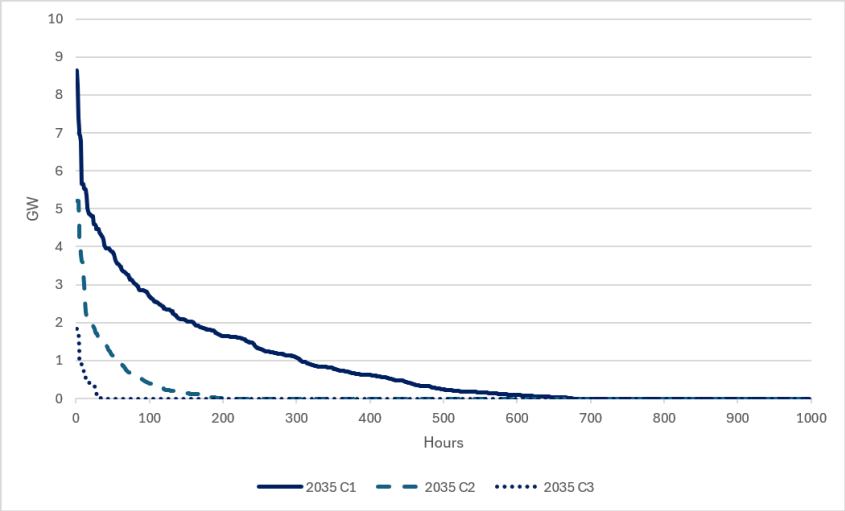


Figure 28 | Duration curves of uncovered upward short-term flexibility needs under configurations C1-C3 (2035)



Under the conservative assumptions of C1, substantial uncovered upward needs remain in both target years. These needs can reach several gigawatts in the most stressed hours and occur during a material number of hours throughout the year.

Introducing additional domestic flexibility in C2 significantly reduces both the magnitude and duration of uncovered needs. The duration curves become substantially steeper, indicating that most shortages are resolved by making additional domestic flexibility available.

Including cross-border flexibility in C3 further reduces the remaining uncovered needs. However, small residual shortages remain in the results, indicating that cross-border flexibility strongly mitigates but does not completely eliminate all uncovered upward needs in the assessed configurations.

Table 12 | Uncovered short-term upward flexibility needs in 2030 and 2035 under model configurations C1-C3

	2030			2035		
Metric	**C1**	**C2**	**C3**	**C1**	**C2**	**C3**
Peak uncovered need (GW)	6.4	3.5	3.2	8.6	5.2	1.8
Total uncovered energy (GWh)	931	110	21	892	163	19
Hours with uncovered needs (h)	929	216	18	675	201	16
Share of year (%)	10.6%	2.5%	0.2%	7.7%	2.3%	0.2%

The results show that uncovered needs are highly sensitive to assumptions regarding flexibility availability. Under C1, uncovered energy amounts to 931 GWh in 2030 and 892 GWh in 2035, occurring during approximately 8–11% of the year. Under C2, uncovered energy decreases by around 80–90%, showing that a relatively limited increase in available domestic flexibility can resolve most of the identified shortages. Under C3, remaining uncovered needs are reduced to very low levels, with around 16–18 hours of uncovered needs per year.

Although forecast errors increase towards 2035, uncovered needs do not increase proportionally. This is because the flexibility portfolio also expands, partly offsetting the larger forecast-error distribution. The remaining uncovered needs should not be interpreted as evidence of insufficient short-term flexibility in the system. The results are highly sensitive to assumptions regarding the availability of flexibility resources, as illustrated by the substantial reduction in both the magnitude and duration of uncovered needs between configurations C1, C2 and C3. Furthermore, the assumptions in C2 are

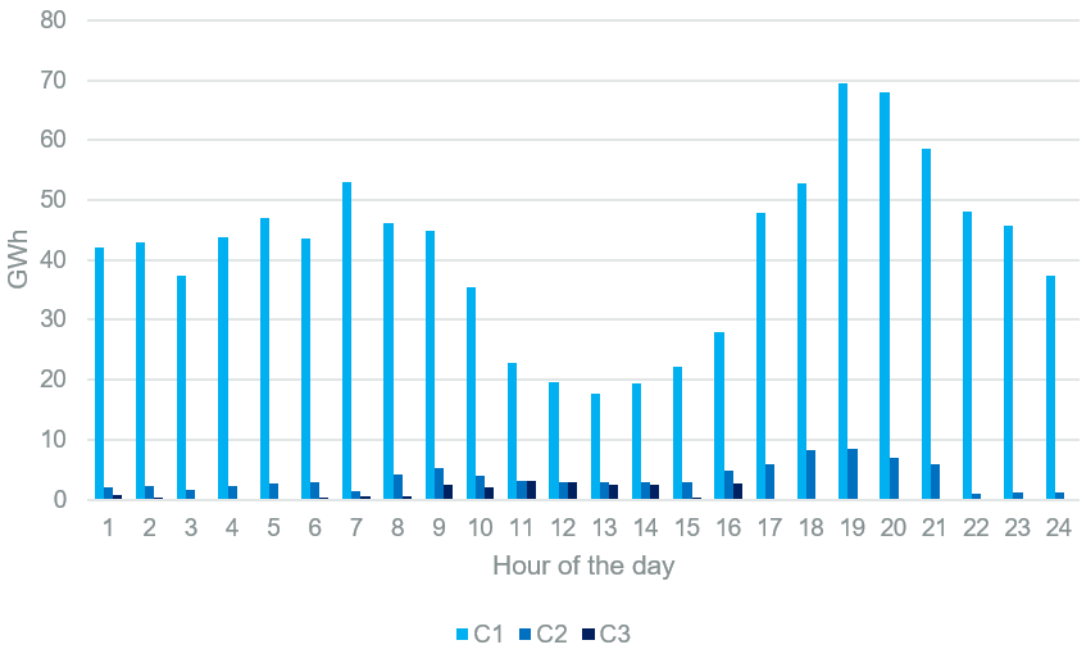
relatively conservative, as only part of the available CCGT capacity is assumed to contribute to flexibility.

No uncovered downward short-term flexibility needs are identified under any of the assessed configurations. This reflects the relatively large portfolio of downward flexibility resources, especially battery charging, Power-to-X and flexible demand. Generators and cross-border flexibility that are not fully represented in the conservative configurations may further reduce these residual shortages in practice.

Temporal characteristics

Beyond the magnitude of uncovered needs, their *timing provides insight into the system conditions in which shortages emerge.*

Figure 29 | Distribution of annual uncovered short-term flexibility needs by hour of day (2030)



Under C1, uncovered needs occur throughout the day but are clearly concentrated in the morning and evening periods. The largest concentration occurs during the evening hours, approximately between 18:00 and 22:00, when solar generation declines and residual load increases. A secondary concentration occurs in the morning, when demand increases and upward flexibility is also required.

Under C2, the annual volume of uncovered needs decreases substantially across all hours, but the remaining shortages remain concentrated around the same morning and evening periods. This indicates that these hours represent the most critical periods for upward short-term flexibility.

Under C3, only limited residual shortages remain. Their concentration around morning and evening periods suggests that uncovered short-term needs are driven by the coincidence of forecast errors with already tight system conditions, rather than by forecast errors alone. Overall, the uncovered-needs assessment shows that short-term flexibility challenges are primarily associated with upward flexibility during morning and evening hours. The critical issue is not only the total amount of flexibility in the system, but whether sufficient flexibility is available at the right time.

4.1.3.3. Flexible resources needed to meet the uncovered needs

The results show that the magnitude of uncovered short-term flexibility needs depends strongly on the assumed availability of flexibility resources. Under conservative assumptions, uncovered upward needs are material. These needs are substantially reduced when additional domestic flexibility is made available and decrease further when cross-border flexibility is included.

The strong reduction from C1 to C2 indicates that a large share of the identified shortages can be addressed by increasing the availability of domestic flexibility. In the assessment, allowing approximately 5 GW of non-committed CCGT capacity to provide short-term flexibility resolves most of the uncovered needs identified under C1. This highlights the importance of operational availability, not only installed capacity.

The remaining shortages are reduced further under C3, where neighbouring systems provide an indicative contribution through interconnection. This suggests that cross-border flexibility can complement domestic resources during hours in which domestic flexibility is already heavily utilised.

The assessment does not indicate a structural shortage of downward short-term flexibility. Downward needs are covered by the available portfolio of battery charging, Power-to-X, flexible demand and generation reduction.

For upward short-term flexibility, the results point to the following resources as most relevant:

- dispatchable generation that can be made available at short notice;
- battery discharge and other fast-response storage resources;
- demand-side response and flexible demand reduction;
- cross-border flexibility through interconnection;
- operational arrangements that improve access to flexibility during critical hours.

Since the remaining uncovered needs under C3 are limited in both energy and duration, the results do not indicate a need for a large structural increase in installed short-term flexibility capacity at system level. Instead, they indicate that the main requirement is to ensure that existing and future flexibility resources are accessible and operationally available during critical morning and evening hours.

The key conclusion is therefore that short-term flexibility needs are mainly an availability and coordination challenge. The system contains substantial flexibility resources, but the ability to manage forecast errors depends on whether those resources can be mobilised in the specific hours where forecast errors coincide with high residual load and limited flexibility margins.

4.2. TSO network needs

This section presents the flexibility needs arising from congestion in the Dutch transmission network for the target years 2030 and 2035. The analysis quantifies the required flexibility to resolve transmission constraints under expected system conditions, expressed in volume (MWh), peak (MW), duration (hours), and seasonal & intra-day pattern (season/hour of occurrence).

The assessment is based to a large extent on the same modelling framework and tooling as the IP (2026), ensuring consistency with network development assumptions and planned reinforcements.

The results provide:

- A quantitative basis for identifying transmission-driven flexibility needs,
- Insight into their regional and seasonal/hourly characteristics
- Input for policy design and integration with system and DSO level needs.

4.2.1. Overview of results

An overview of the TSO flexibility needs is presented in Table 13. This data is aggregated based on the grid regions as used in the IP2026. The values in this table are adjusted to avoid double-counting of the DSO needs. A generation related overload could be solved by reducing generation or increasing demand in that region. This type of flexibility will be referred to as downward flexibility. Similarly, flexibility related to solving demand related overloads will be referred to as upward flexibility.

When interpreting the table, it is important to note that the scenarios applied in this study are aligned with the methodology defined by ACER. The projected growth and geographical distribution of future customer connections, whether new connections or expansions of existing ones, are based solely on the underlying scenario assumptions. These projections do not account for the potential impact of congestion management measures on connection growth (e.g. connection queues).

As a result, the reported flexibility needs should be understood as an upper bound and are likely to represent an overestimation of the actual needs that will materialise in 2030 and 2035. This nuance is also essential when comparing the outcomes of this study with those of other national or international analyses addressing flexibility requirements.

The network needs are reported on the voltage level at which the overloads occur. Flexibility at lower voltage levels can also be used to reduce these overloads, e.g. flexibility at the medium-voltage level can be used to reduce overloads at the high-voltage level. The other way around is not possible; flexibility at the high-voltage level has no effect on the medium-voltage level.

Additional clarifications on differences in assumptions, starting points, and methodologies are provided in Annex 2.

The “Seasonal / intra-day pattern” column indicates the representative periods in which flexibility needs arise. Winter is defined as November-March and summer as April-October. The intra-day categories are night (21:00-06:00), morning (06:00-10:00), afternoon (10:00-16:00) and evening (16:00-21:00). “Spread-out” indicates that flexibility needs occur across multiple periods of the day and cannot be attributed predominantly to one or two specific intra-day categories.

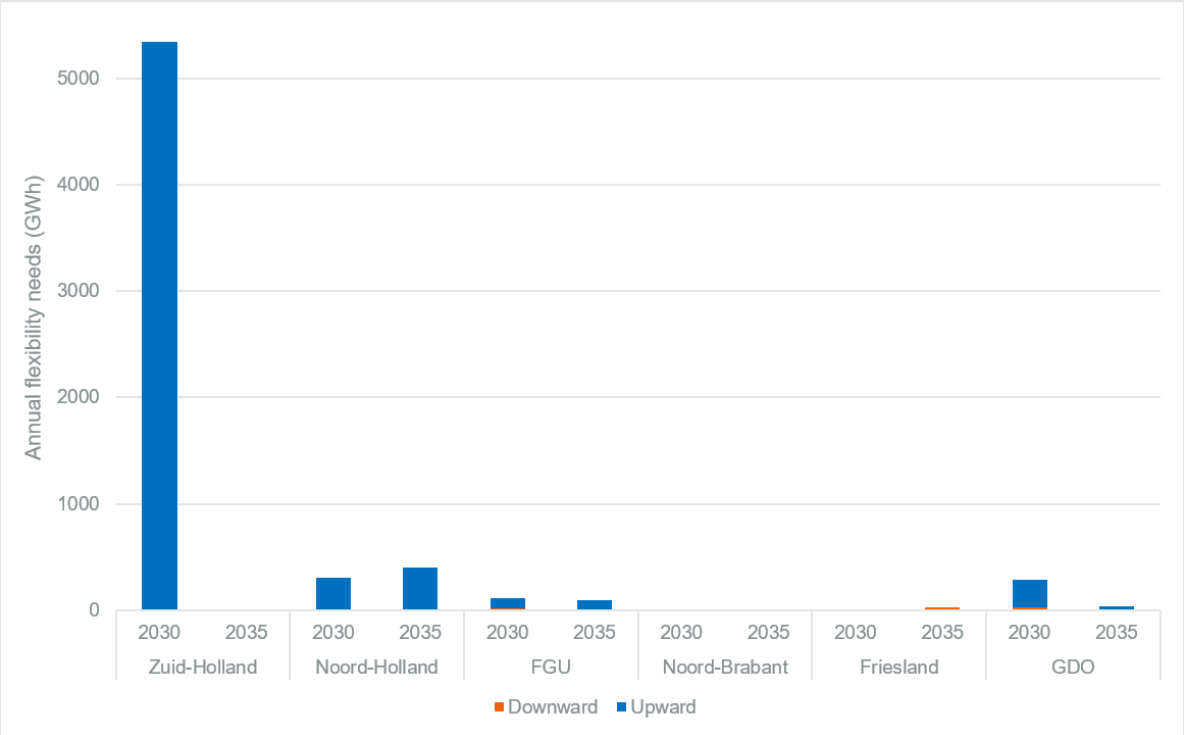
Table 13 | Overview of the identified TSO network needs per region, direction, and target year

Region	Voltage level	Direction	Year	Volume (GWh)	Peak (MW)	Duration (h)	Seasonal / intra-day pattern
220/380	220-380	Downward	2030	7,766.6	7,162	3224	Winter & Summer / Spread-out
		Upward	2030	7,766.6	7,162	3224	Winter & Summer / Spread-out
		Downward	2035	5,136.6	7,654	3745	Winter & Summer / Spread-out
		Upward	2035	5,136.6	7,654	3745	Winter & Summer / Spread-out
Friesland	110	Downward	2030	8.4	58	516	Summer / Morning & Afternoon
		Upward	2030	0	0	0	NA
		Downward	2035	31.2	110	951	Summer / Morning & Afternoon
		Upward	2035	0	0	0	NA
Groningen, Drenthe and Overijssel (GDO)	110	Downward	2030	26.2	158	546	Summer / Morning & Afternoon
		Upward	2030	266.3	325	4377	Winter / Spread-out
		Downward	2035	0.2	20	29	Summer / Morning & Afternoon
		Upward	2035	37.0	118	1717	Winter / Spread-out
Flevopolder. Gelderland and Utrecht (FGU)	150	Downward	2030	22.1	388	492	Summer / Afternoon
		Upward	2030	96.0	548	2452	Winter & Summer / Spread-out
		Downward	2035	0	0	0	NA
		Upward	2035	100.0	927	981	Winter / Spread-out
Noord-Brabant	150	Downward	2030	0.3	46	16	Summer / Afternoon
		Upward	2030	2.2	45	146	Winter / Spread-out
		Downward	2035	0	0	0	NA
		Upward	2035	0	0	0	NA
Limburg	150	Downward	2030	0	0	0	NA
		Upward	2030	0	0	0	NA
		Downward	2035	0	0	0	NA

		Upward	2035	0	0	0	NA
Noord-Holland	150	Downward	2030	0	0	0	NA
		Upward	2030	307.1	375	4151	Winter & Summer / Morning & Afternoon
		Downward	2035	0	0	0	NA
		Upward	2035	400.1	239	6008	Winter / Spread-out
Zuid-Holland	150	Downward	2030	0	0	0	NA
		Upward	2030	5,337.6	1,267	8619	Winter & Summer / Spread-out
		Downward	2035	0	0	0	NA
		Upward	2035	7.1	76	369	Winter / Morning & Afternoon
Total		**Downward**	**2030**	**7,824**	**-**	**-**	**-**
		Upward	**2030**	**13,776**	**-**	**-**	**-**
		Downward	**2035**	**5,168**	**-**	**-**	**-**
		Upward	**2035**	**5,681**	**-**	**-**	**-**

Figure 30 shows the regional distribution of the identified 110/150 kV transmission-network flexibility needs in 2030 and 2035. Upward flexibility needs are substantially higher than downward flexibility needs in both target years. In 2030, upward flexibility needs are strongly concentrated in Zuid-Holland, with additional contributions from Noord-Holland, GDO and FGU. By 2035, the overall flexibility needs decrease substantially as a result of planned network reinforcements, and the remaining upward needs are primarily concentrated in Noord-Holland and FGU, while most other regions exhibit only limited flexibility needs.

Figure 30 | Identified 110/150 kV transmission-network flexibility needs in 2030 and 2035



At system level, the following general conclusions can be drawn:

- The extra-high-voltage system (220/380) accounts for the largest share of flexibility needs, this is related to the higher voltage level that allows for higher power transfer, but also the meshed topology and high interconnection with neighbouring countries, which can lead to substantial amounts of transit flows.

  The combined 220/380 kV needs amount to approximately 15.5 TWh in 2030 and 10.3 TWh in 2035, with peak needs of roughly 7.2 GW in 2030 and 7.7 GW in 2035. These magnitudes are far larger than most of the regional 110/150 kV needs and indicate that the extra-high-voltage layer reflects broad transmission-system transport patterns rather than a small number of isolated local bottlenecks.

- In most regions and/or voltage levels, the upward needs are higher than the downward needs. That results in higher upward flexibility needs than downward. In the few cases where downward flexibility needs are dominant, these are related to large amounts of renewable generation connected in those regions.

  In 2030, upward needs are strongly concentrated in Zuid-Holland, with additional material needs in Noord-Holland, GDO and FGU. Downward needs are much smaller in total volume and are concentrated mainly in FGU, GDO and Friesland.

  In 2035, the remaining upward needs are more clearly concentrated in Noord-Holland, FGU and GDO, while the Zuid-Holland upward profile becomes relatively limited. Downward needs in 2035 are more limited overall and remain concentrated mainly in Friesland, with only minor residual downward needs elsewhere. This indicates that some regional bottlenecks persist, while others appear more temporary or are materially reduced over time.

- In most regions, the trend shows a reduction in flexibility needs (upward and downward) from 2030 to 2035. This is primarily related to grid reinforcements which increase the capacity of the region. However, there are some exceptions in which the flexibility needs increase in 2035.

This can be attributed to scenario and regionalization assumptions that lead to steeper increases in demand and/or renewable generation in some areas, which do not match exactly the timing of grid reinforcements. Additionally, inclusion of new reinforcements introduced for the first time in IP2026 have not been included in this analysis since their scope is still being worked out. These could lead to a further reduction of flexibility needs in or after 2035.

- Downward at the 110/150 kV-level are mostly identified in the summer period. This is partially due to the fact that solar generation is higher in the summer period and the load is lower. This effect is amplified because TenneT uses seasonal ratings for overhead lines. In the winter period the ambient temperature is lower and therefore more power can be transported by the overhead lines.
- Most of the upward needs at the 110/150 kV-level occur in the winter-period when the load of households, utilities and other sectors is higher combined with lower solar generation. The load in the winter-period is the highest. Because of the seasonal-ratings some minor upward needs occur in October and April. In these months the load is lower than in the winter-period, but for overhead lines the lower summer rating is used, and therefore less grid capacity is present.
- For the 220/380 kV-grid needs are identified throughout the year. These overloads are mostly caused by national and international transports due to the fact that load and generation are not located at the same location in the grid. The effects of solar generation on the needs in the 220/380 kV-grid are very limited, which is one of the reasons why seasonal patterns are absent. Moreover, all 380 kV circuits are assumed to be upgraded to maximum of 4.000A. Because this 4.000A is limited by substation components and stability requirements, a higher winter-rating is not used.

Figure 31 | Peak flexibility requirement versus annual activation duration

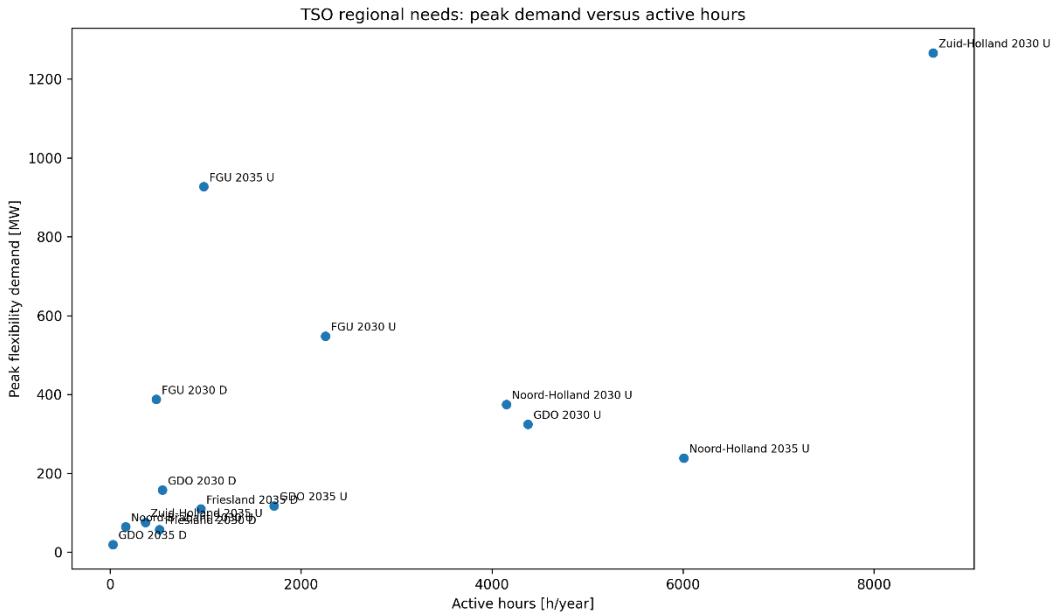


Figure 31 compares the peak flexibility requirements and annual activation durations of the identified transmission-network flexibility needs. The results show substantial variation between congestion areas. Some needs are characterised by high peak requirements and long activation durations, such as Zuid-Holland in 2030, while others combine relatively high peak requirements with more limited durations, such as FGU. This illustrates that flexibility needs with comparable annual volumes can exhibit very different characteristics.

The relationship between peak requirement and activation duration is an important determinant of the cost-effectiveness of potential solutions. A flexibility need that occurs during only a few hundred hours per year is fundamentally different from a need that remains binding during several thousand hours. In addition, the seasonal and intra-day occurrence patterns influence the suitability of different flexibility solutions. While some needs are concentrated in specific months and hours of the day, others are distributed more evenly throughout the year.

For this assessment, needs that primarily occur between April and October are classified as summer needs, while needs occurring predominantly during the remaining months are classified as winter needs. Intraday patterns are classified according to the period of the day in which flexibility activation is concentrated. Needs that occur across multiple dayparts are characterised as spread-out. This classification describes when flexibility is required, rather than how frequently it is activated.

Consequently, flexibility solutions must be capable of providing:

- high peak capacities (MW)
- significant annual energy volumes (MWh); and
- operation during both extended periods and short high-demand intervals.

These characteristics suggest that no single flexibility technology or market design can efficiently address all identified transmission-network flexibility needs.

Despite the expected reduction in flexibility needs towards 2035 and the commissioning of additional reinforcements beyond 2035, some level of transmission-network flexibility is expected to remain necessary. The main reason is that non-structural overloads occurring during a limited number of hours are often more cost-effectively resolved through operational measures, such as the employment of flexibility, rather than by investing in localised grid reinforcements. Such a cost-benefit analysis is part of the national IP, in which the financial impact of solving an overload with operational measures is compared to that of investing (along with other non-financial factors).

4.2.2. Regional distribution of needs

Network flexibility needs are location-specific, with significant variation across regions. Their nature (downward / upward) and temporal patterns also can vary. The variation can be attributed to the network topology of each region (meshed or pocket), but is primarily related to the type and amount of connections in the region and the localized balance of demand and generation.

4.2.2.1. The 220/380 kV grid

The 220/380 kV region is not a geographical region in the strict sense. It spans across the whole country. However, it is reported as a separate region, since it is substantially different from the 110/150 kV grids in terms of purpose, design principles and type of connections.

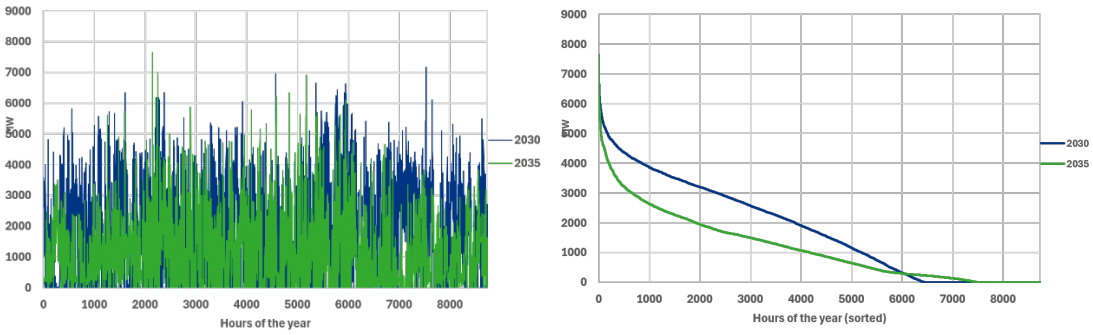
The nature of the power transport taking place in the 220/380 grid cannot be fully attributed to excess of generation or demand. Most of the connections transport power on both directions which in some instances are dominated by the transport of excess generation or demand, but on a yearly basis do not show a clear dominant behaviour. Additionally, due to the meshed nature of this grid, transit and international exchange flows often use up a substantial amount of the 220/380 kV grid capacity making the categorisation on purely generation and/or demand related, impossible.

Therefore, the flex needs are determined as a whole and the reported upward and downward needs are a result of an (50/50) split of the total flexibility needs. That is the reason the reported upward and downward needs of the 220/380 kV grid are identical. In practice that is also the case. Sometimes the overload on a line is solved by upward redispatch and sometimes, for the same line with downward redispatch. For every upward redispatch action and similar down redispatch action is required to maintain the system balance. Therefore the TSO network needs are balanced as well.

Comparing the flexibility needs of the 220/380 grid in 2030 and 2035, it can be concluded that the flex needs reduce in terms of volume in 2035. However, they do remain comparable to 2030. In terms of peak requirements, those remain more or less unchanged.

This is related to the fact that some major reinforcement projects on major constraints in the 220/380 kV grid (e.g. Diemen-Lelystad-Ens 380, Geertruidenberg-Krimpen/Crayestein 380) are not yet commissioned in 2035. Their commissioning is expected between 2035 and 2040 and could reduce substantially the need for flexibility. However, a total elimination of flexibility needs is not expected even after major reinforcements take place as also indicated in the IP2026. The remaining overloads after grid reinforcements will have to be solved with redispatch or additional grid reinforcements, which will be described in the IP2028.

Figure 32 | Downward and upward needs 220-380 kV during year (left) and sorted by hour (right)



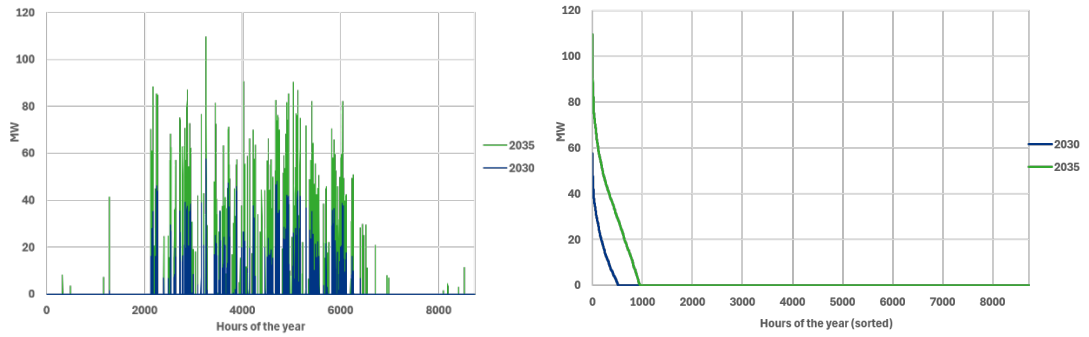
4.2.2.2. The 110/150 kV grid

The trends in the network needs differ per 110/150 kV region. For most regions, the flexibility needs decreases or disappears because of the effects of the grid reinforcements at the 110/150 kV level, most of which take place in the period before 2035.

Some increases in 2035 or changes of the critical assets in some regions are observed. Although the grid is reinforced, the growth of demand and generation can cause new overloads in the 2035 case. The change in grid configuration can also shift overloads from one critical asset to another critical asset.

- **Friesland:** In Friesland the overloads are caused by renewable energy. In 2035 the calculated network needs are higher. This is caused by the increased generation in the VVT-scenario compared to 2030. Projects have been initiated to mitigate these overloads, but as the scope of these projects have not yet been finalized, the effects of these projects have not been included in the calculations of the FNA. The reported flexibility needs for 2035 are therefore likely an overestimation.

Figure 33 | Downward needs Friesland during year (left) and sorted by hour (right)



- **Groningen, Drenthe en Overijssel (GDO):** The projects in IP2026 solve almost all of the generation related overloads in the 2035 situation, thus reducing the flexibility needs for generation. For demand, overloads exist in both 2030 as well as 2035. Several of these overloads are solved by the projects, but other constraints are increased because of the increase in demand in the scenarios. Solutions have been investigated for these overloads, but as the scope of these projects are not yet definitive, these projects have not been included in the calculations. Considering that the VVT scenario for 2035 are lower than the scenarios as used in the IP and that the projects needed to solve these overloads have an in service date in or before 2035, it is estimated that these projects can reduce the flexibility in 2035 to 0.

Figure 34 | Upward needs GDO during year (left) and sorted by hour (right)

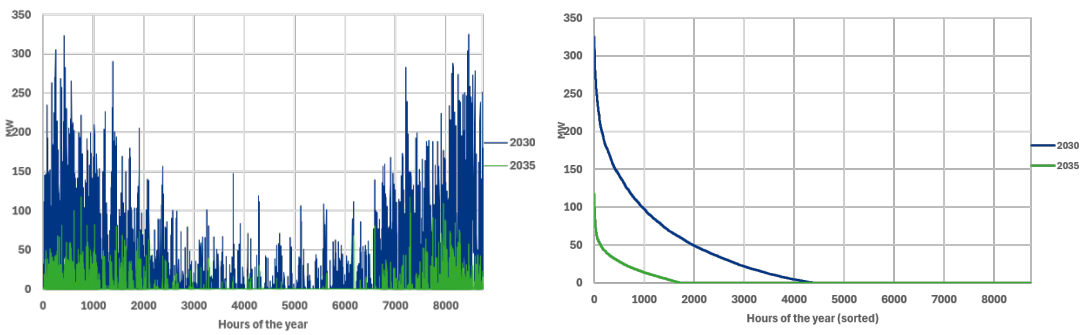
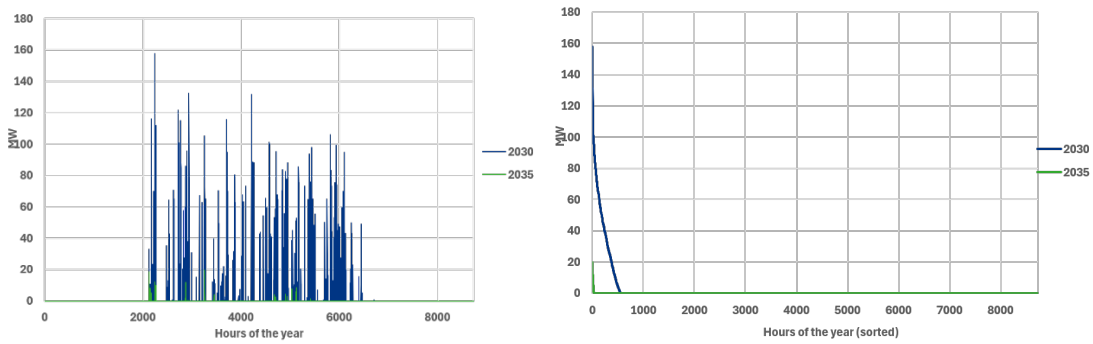
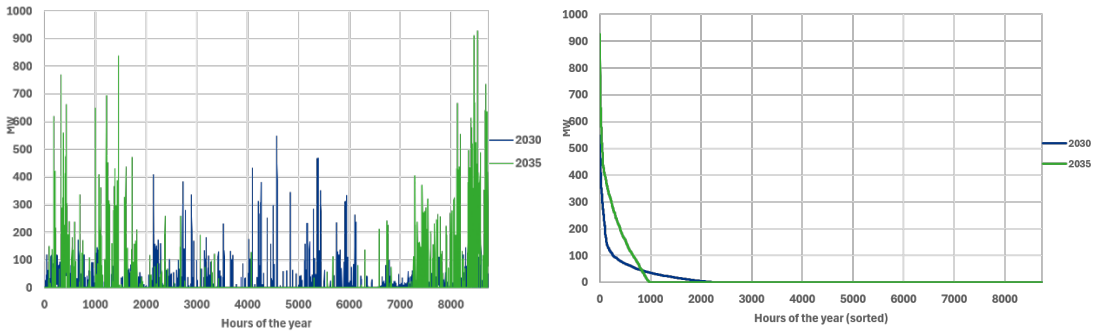


Figure 35 | Downward needs GDO during year (left) and sorted by hour (right)



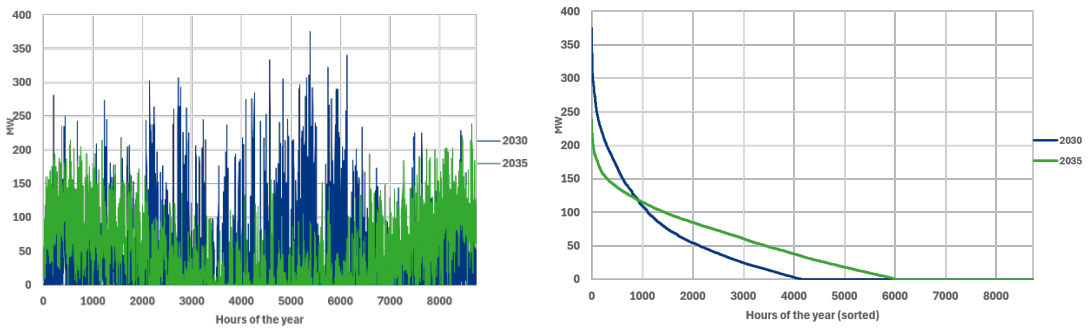
- **Flevopolder, Gelderland and Utrecht (FGU):** In the 2030 situation, the FGU grid is operated in a meshed operation, because of this meshed configuration several overloads are caused by a combination of demand, generation and transit flows. Several overloads have therefore been not classified as a demand or production overload and the network need is distributed 50-50 over demand and production. The overloads of the 2030 network are solved in the 2035 network, but other overloads occur. Because the necessary grid reinforcements to solve these constraints have an in service date past 2035, flexibility needs persist after 2035 in the VVT scenario.

Figure 36 | Upward needs FGU during year (left) and sorted by hour (right)



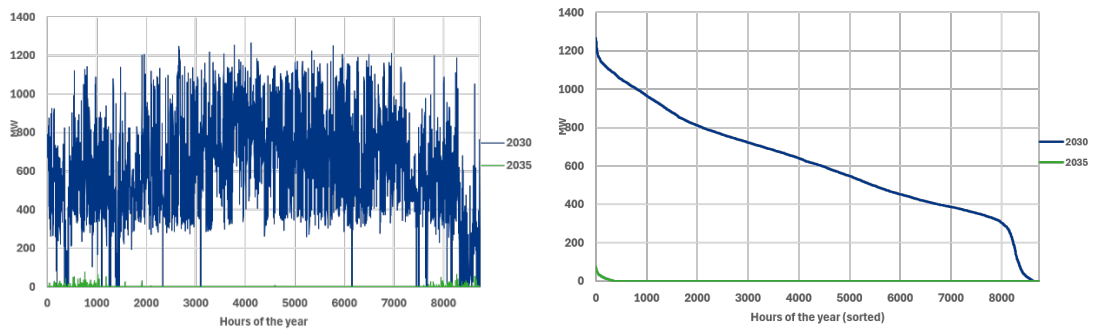
- **Noord-Brabant:** In 2030 there are flexibility needs of both demand and generation, where the demand overloads are significantly higher than the generation overloads. Because of grid reinforcements between 2030 and 2035, no network needs exist in the 2035 situation.
- **Limburg:** In Limburg no flexibility needs have been identified in 2030 and 2035. The lower growth of the VVT scenario combined with a significant increase in transport capacity in 2030 (Boxmeer 380), results in no flexibility needs. Towards 2035 the demand grows further, but the construction of the Einighausen 380 substation increases the available capacity substantially.
- **Noord-Holland:** No generation overloads occur in Noord-Holland, because the 2030 grid is already substantially reinforced. The demand related overloads are significant. The grid reinforcements solve most of these overloads. The remaining overloads increase, causing a net increase of demand network needs. These are mostly concentrated in one specific area and are caused by assumptions about data centre development. These developments could be an overestimation of the actual growth, which also means that the 2035 demand network needs are an overestimation as well.

Figure 37 | Upward needs Noord-Holland during year (left) and sorted by hour (right)



- **Zuid-Holland:** The demand network needs in 2030 for Zuid-Holland are significant. Most of these needs are centered around the port area, where the industrial growth results in demand related overloads combined with transit flows from the 380 kV grid. However, a lot of these industrial developments are currently on the waiting queue because of congestion. In 2035 this part of the grid is reinforced and operated in several pockets thus solving the overloads. The remaining overloads are to be solved by a newly initiated project from IP2026 which has not yet been included in the grid calculations.

Figure 38 | Upward needs Zuid-Holland during year (left) and sorted by hour (right)



- **Zeeland:** The network needs in Zeeland are zero in all years. This is caused by the slower growth of demand in the VVT scenario combined with a grid reinforcement in 2030. In 2035 the grid is further reinforced with the grid investment of 380 kV Zeeuws-Vlaanderen.

4.2.3. Seasonal & intra-day patterns

Flexibility needs exhibit both seasonal and intra-day patterns, which are directly related to the nature of the constraints they are deployed for. In general, upward flexibility occurs often in winter, driven by high demand. On the other hand, downward flexibility occurs often in summer, driven by high RES generation.

Regarding intra-day patterns upward needs might occur in morning and evening hours or could be constant or spread-out throughout the day. This depends on the type of demand or mix thereof, in each region (e.g. primarily household demand or data centres or other industrial demand or any combination).

Downward needs occur mainly during morning and midday hours, since in most regions (especially on the 110/150 kV voltage levels) the generation excess is caused by high amounts of solar-PV connections in the regions.

Of course, there can be deviations from the above mentioned patterns, which are closely related to the amount of critical assets in each region and the different drivers that lead to their overload. For example, in Zuid-Holland, in 2030, before the pocket structure is introduced, the critical assets are primarily overloaded due to industrial load in the port area and transit flows from the 380 kV grid. In that case, a clear pattern attributed to a single type of demand cannot be distinguished and there is no specific seasonal or intra-day pattern.

Additionally, it should be noted that in the winter-period (November-March) the ratings of some overhead lines are higher than in the summer. The transition from winter to summer-period at the beginning of April also results in a slightly higher demand for flexibility in April compared to March.

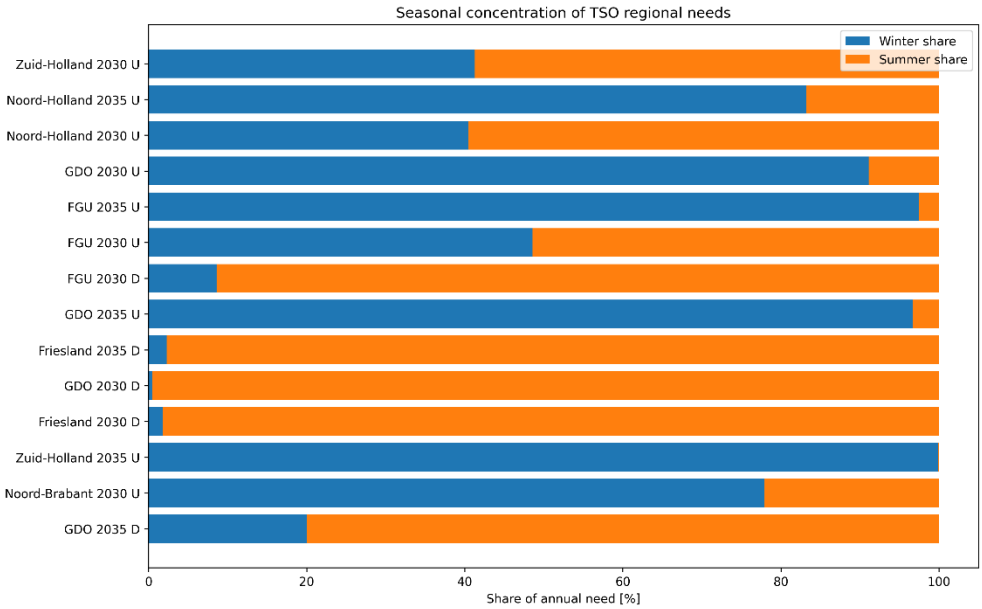


Figure 39 | Seasonal concentration of TSO regional needs

Looking at the seasonal concentration shows that downward profiles are generally much more seasonally concentrated than upward profiles (Figure 39). Downward needs in Friesland, FGU and GDO are strongly summer-weighted, which is consistent with generation-driven congestion and particularly with local renewable surplus. Upward needs are more mixed. Some are clearly winter-oriented, especially GDO and FGU in 2035, while others are more spread out or more strongly weighted toward 2030 summer conditions, notably the very large Zuid-Holland 2030 upward profile. This confirms that the Dutch TSO need profiles should not be interpreted through one uniform seasonal logic.

4.3. DSO network needs

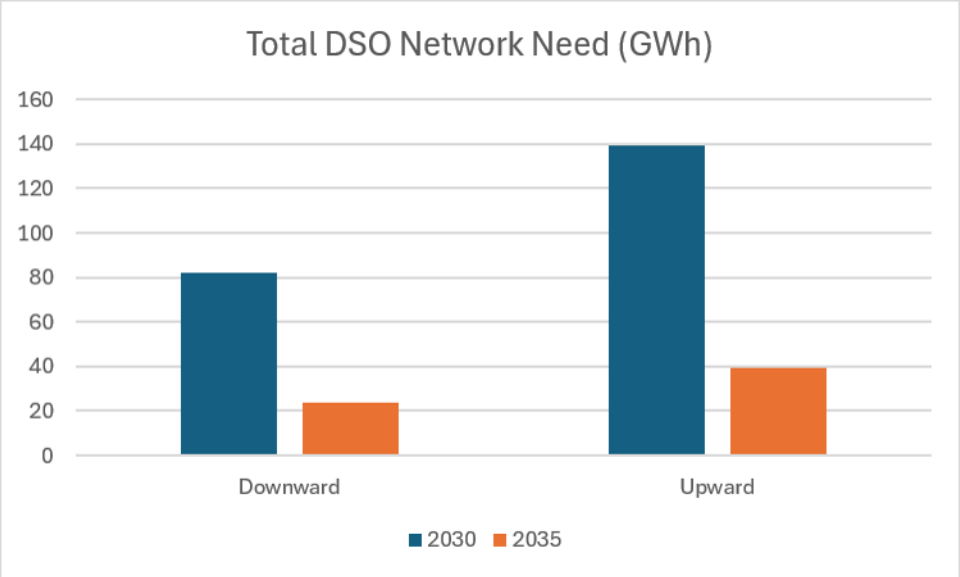
This section presents the flexibility needs arising from congestion in the Dutch distribution networks of 25kV and higher for the target years 2030 and 2035. The analysis quantifies the flexibility required to manage projected network constraints under the VVT scenario, taking into account all planned network reinforcements included in IP2026. The identified DSO network flexibility needs are generally local in nature and substantially smaller than the transmission-network flexibility needs presented in Section4.2. Nevertheless, they provide important insight into locations where network development is unable to fully keep pace with projected growth in electricity demand and renewable generation.

The analysis evaluates these needs in terms of flexibility volumes, peak requirements, duration and temporal occurrence patterns. This provides insight not only into the magnitude of the identified needs, but also where and when flexibility is required within the distribution networks.

4.3.1. Overview of results and general trends

Figure 40 provides an overview of the identified DSO network flexibility needs for networks with a voltage level of 25kV and higher in 2030 and 2035. The results show that both upward and downward flexibility needs decrease substantially towards 2035. Downward flexibility needs decrease from approximately 82 GWh to 24 GWh, while upward flexibility needs decrease from approximately 139 GWh to 39 GWh. This reduction is primarily driven by the network reinforcements included in IP2026, which relieve a large share of the identified congestion points.

Figure 40 | Summary of DSO network needs



Although the overall trend is strongly downward, the evolution differs between regions. Most regions experience a significant reduction in flexibility needs as additional network capacity becomes available. However, a limited number of regions continue to exhibit flexibility needs in 2035, indicating that demand growth and renewable generation can locally outpace the effect of planned reinforcements.

Table 14 summarises the regional distribution of the identified flexibility needs for networks with a voltage level of 25kV and higher.

Table 14 | DSO Network needs per region

Region	Downward need (GWh)		Upward need (GWh)	
	2030	2035	2030	2035
Friesland	6.03	1.99	0	0
Groningen	5.68	0	42,77	0
Drenthe	31,99	0	1,69	0
Overijssel	0	0	6.66	0
Flevoland	0.01	0	0	0
Gelderland	9.72	9.46	0.29	3.41
Utrecht	0.04	0.07	0.2	7.98
Noord Brabant	1.7	0	70.2	0
Limburg	0.02	2.16	5.09	0
Noord-Holland	11.2	2.47	2.18	0
Zuid-Holland	0	7.58	0	27.74
Zeeland	15.43	0	10.01	0.11
Total	**81.8**	**23.7**	**139.1**	**39.2**

In 2030, the largest upward flexibility needs are concentrated in Groningen and Noord-Brabant, while downward flexibility needs are mainly observed in Drenthe,, Zeeland, Friesland and Gelderland. Towards 2035, most identified needs reduce significantly, with the remaining flexibility needs increasingly concentrated in Gelderland and Zuid-Holland.

The identified flexibility needs also exhibit clear temporal patterns. In general, downward flexibility needs are associated with periods of high solar PV generation and therefore occur predominantly during spring and summer daylight hours. Upward flexibility needs are more frequently observed during winter periods with elevated electricity demand, although the exact timing varies between regions and congestion points. A more detailed analysis of these temporal characteristics is provided in Section 4.2.3.

4.3.2. Regional distribution of needs

While Section 4.2.1 presented the overall magnitude and distribution of DSO network flexibility needs, the identified needs differ considerably between regions and congestion areas. This section highlights the main regional characteristics and drivers of the identified flexibility needs.

FGU (Flevoland, Gelderland, Utrecht)

There is no flexibility need in Flevoland in 2035 due to timely reinforcements. In 2030, a limited downward flexibility need is identified during periods of high PV generation combined with relatively low residential and industrial demand, predominantly during weekends.

Gelderland exhibits both upward and downward flexibility needs in 2030 and 2035. The upward flexibility need increases towards 2035 due to growing electricity demand and occurs primarily during winter periods, without a clearly dominant intraday pattern. This suggests that the identified need is driven by a combination of industrial and residential demand. The downward flexibility need is associated with periods of high solar generation during spring and summer daylight hours and decreases following planned network reinforcements.

In 2030, Utrecht has a limited need for upward flexibility. This need is fairly evenly distributed across a limited number of stations and is mainly concentrated in winter. The downward flexibility need is limited and confined to a single coupling point. In 2035, the need for upward flexibility increases significantly, but is concentrated across fewer coupling points than in 2030. The downward flexibility need remains limited in 2035.

Overall, the FGU region remains one of the regions with persistent flexibility needs in 2035, primarily due to increasing demand-driven congestion in Gelderland and Utrecht.

Friesland:

Friesland is characterised exclusively by downward flexibility needs. These needs are primarily driven by high levels of solar PV generation and occur during PV production hours in spring and summer, both on weekdays and weekends. Despite continued growth in PV generation, the identified flexibility needs decrease substantially between 2030 and 2035 as a result of planned network reinforcements. The remaining needs continue to be associated with periods of high renewable generation relative to local demand.

GDO (Groningen, Drenthe, Overijssel)

The provinces Groningen and Drenthe are characterised by both upward and downward flexibility needs in 2030. More than half of the identified flexibility need is downward and is associated with the high penetration of solar PV generation. These downward needs occur primarily during PV production hours and are therefore concentrated in spring and summer periods. Significant upward flexibility needs are also identified in these provinces. These needs do not exhibit a single dominant intraday pattern, suggesting that they are driven by a combination of industrial and residential demand.

In Overijssel, flexibility needs are more limited and concentrated in two specific regions, where upward flexibility is required during morning-afternoon and morning-evening periods.

Planned network reinforcements substantially reduce both upward and downward flexibility needs, with all identified flexibility needs expected to be resolved by 2035.

Limburg

Limburg exhibits only limited flexibility needs. In 2030, flexibility needs are identified at seven substations and are predominantly upward in nature, with afternoon periods being the most dominant activation window. While the needs at some substations are relatively small, several locations exhibit more substantial flexibility requirements.

Planned network reinforcements substantially reduce the identified flexibility needs. As a result, no upward flexibility needs remain in 2035. Only a downward flexibility need is identified at a single substation, associated with local generation-related congestion.

Overall, the results indicate that most identified flexibility needs in Limburg are resolved by 2035 through the planned network reinforcements included in IP2026.

Noord-Brabant

Noord-Brabant is characterised primarily by upward flexibility needs in 2030, driven by growing electricity demand. The identified needs are distributed across almost twenty congestion points, although a limited number of congestion points account for a large share of the total flexibility requirement. Only a limited number of locations exhibit downward flexibility needs associated with PV generation. Most identified needs disappear by 2035 as a result of planned network reinforcements.

Noord-Holland

Noord-Holland is characterised by both upward and downward flexibility needs in 2030. The upward flexibility need is concentrated around the Haarlemmermeer region and is primarily driven by increasing electricity demand from datacentres in combination with residential demand. The downward flexibility need is located in the northern part of the province, where high levels of solar and wind generation can lead to periods of local congestion. Planned network reinforcements substantially reduce the identified flexibility needs towards 2035.

Zeeland

For the province of Zeeland, there is both a downward flexibility need and an upward flexibility need in 2030, distributed across a limited number of stations. As a result of planned investments, almost all flexibility needs at these stations disappear by 2035.

Zuid-Holland

Zuid-Holland is characterised primarily by upward flexibility needs. In the part of Zuid-Holland where the network is operated by Stedin, these needs are distributed across multiple stations in 2030 but are dominated by a limited number of major congestion points. The identified needs are largely demand-driven and reflect continued growth in electricity consumption.

Unlike most other regions, the flexibility need in the Stedin service area increases towards 2035. While planned network reinforcements reduce congestion at most stations, growth at a limited number of locations results in higher flexibility needs at these stations. As a result, Zuid-Holland remains one of the main contributors to DSO network flexibility needs in 2035.

In the part of Zuid-Holland where the network is operated by Liander, no flexibility needs are identified in either 2030 or 2035 as a result of the planned network reinforcements.

4.3.3. Congestion area characteristics and duration patterns

The previous sections presented the DSO network flexibility needs at national and regional level. Detailed results for all identified congestion areas are provided in Annex 3. This section analyses the characteristics of these congestion areas in more detail, focusing on the magnitude, duration and temporal occurrence of the identified flexibility needs.

As described in section 2.3.3, the DSO network flexibility needs have been assessed for distribution networks with voltage levels of 25 kV and above, corresponding to the scope of the so-called 'major investments' included in the IP. The tables in the appendix quantify the required flexibility to resolve distribution constraints under expected system conditions, expressed in volume (MWh), peak (MW), duration (hours) and seasonal & intra-day pattern (season/hour of occurrence). A recommendation is given for type of contract to mitigate the expected overload per type of flex need.

From the results in the tables it can be noticed that there is a wide variation in the volume, peak and duration of the flex needs. Volumes vary from 1MWh to more than 30GWh, peaks from 1 to more than 70MW and durations from 1 to more than 2000 hours. The major part of the grid is expected to have no flex need in the VVT scenario however, due to reinforcements in the grid. In total 64 regions with a need for flexibility are identified in 2030, out of a total of about 250 regions. In 2035 this drops to 27 regions.

The duration curves for one typical province presented in this section illustrate how frequently flexibility is required and whether the identified needs are characterised by a small number of extreme events or by recurring congestion over longer periods.

Figure 41 | Upward flexibility duration curve

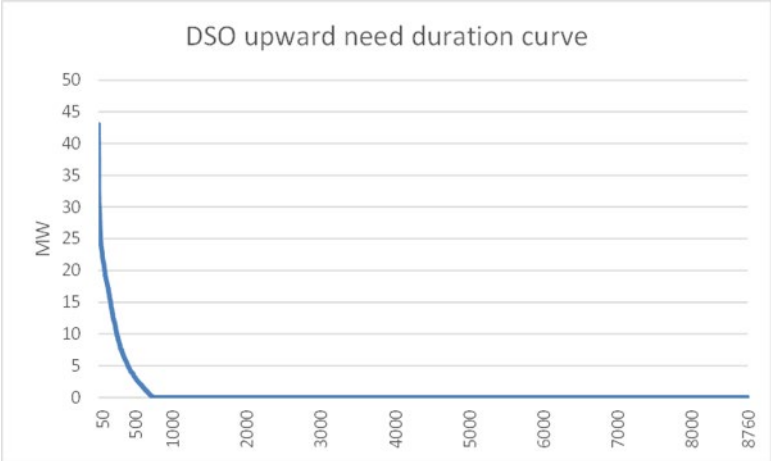
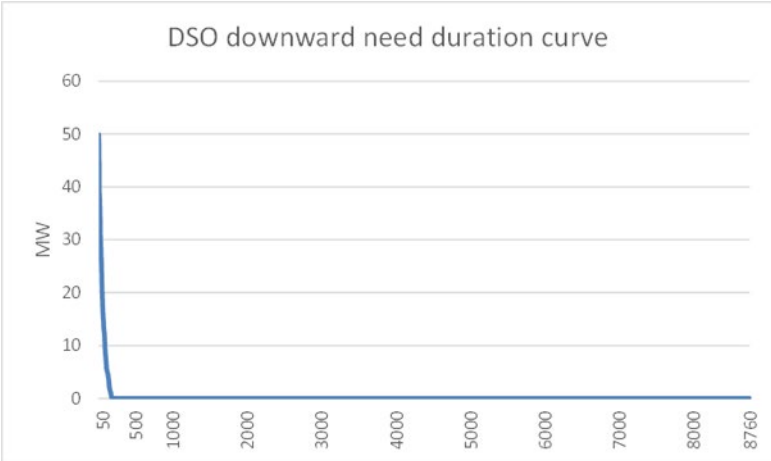


Figure 42 | Downward flexibility duration curve



The curves for other regions show similar behaviour. The curves show that flexibility need only occurs for a small number of hours. This holds for upward need but even more for downward need.

To further characterise the identified congestion patterns, individual congestion areas were classified according to their dominant time period of occurrence.

For each congestion area the typical timeframe is given. The downward need in almost all cases (expect one) is dominated by PV and occurs in spring and summer time. Thus the downward need is related to solar power generation and low load. There is a difference between congestion areaspoints whether these moments typically occur during the week or in the weekends. This is related to the load of these congestion sareas, whether the load has high contribution of industry-related load during the week. The upward need is always in the winter period, but the time periods differ over the different congestion areas, from a specific period (for example the evening) to divers (i.e. spread out over a significant part of the day). An overview of how often there is a downward flex need on a certain part of the day is given in Table 15. The evening is the most dominant part of the day for which there is a flex need, but also other parts of the day have a considerable flex need.

It can be assumed that the clear evening peaks are due to household consumption whereas congestion areas where the need is spread out over the days also have a significant share of industrial load.

Table 15 | Number of congestion areas per part of the day

Time of the day	Number of congestion areas
Winter night	16
Winter morning	12
Winter afternoon	15
Winter evening	41

4.3.4. Archetypes and proposed solutions

The congestion patterns underlying the DSO network needs follow a clear structure. The upward need is generally driven by high electricity demand during winter days, primarily due to a higher heating demand. The downward need is caused by a high production of RES, typically during sunny days in spring and summer. These archetypes correspond to the TSO archetypes B and C, respectively, presented in Table 17.

The solution families for the DSO network needs are comparable to those for TSO archetypes B and C. These families are given in the column ‘solution pathways’ in Appendix 3. For upward congestion (type B) the most suitable solution is a combination of capacity steering contracts (CSC) and redispatch. For type C (downward congestion) redispatch and curtailment are the most suitable.

As mentioned above, CSC and redispatch are the most favourable solutions for upward flexibility needs. Experience to date shows that securing sufficient volumes of this flexibility remains challenging. Therefore, policy measures should incentivize participation in these flexibility mechanisms.

For the downward flexibility need, curtailment of renewable energy production is expected to provide the flexibility need. The resulting curtailment volumes are limited relative to total renewable generation and are therefore not expected to materially affect the achievement of the RES targets for 2030 and beyond.

4.4. Synthesis - Guiding criteria application outcomes

4.4.1. Scope and application of the guiding criteria

Article 16 of the Electricity Regulation requires identified flexibility needs to be addressed in a cost-effective manner, taking into account all available solution options. This implies that identified needs should not be directly translated into new flexibility resources, but should first be assessed against alternative measures such as grid development, curtailment, redispatch and contractual arrangements.

In this assessment, the guiding criteria are applied to the results of the system-wide flexibility analysis (Section 4.1) and the transmission- and distribution-level network constraints identified in Sections 4.3 and 4.2.

At system level, the results show that flexibility needs are largely covered and do not indicate structural shortages. However, the inclusion of network constraints reveals additional flexibility requirements, particularly at transmission level, which are not visible in the system-wide analysis alone.

The interaction between system-level results and network constraints is considered where relevant. In particular, for RES integration, system-level curtailment is combined with network-induced curtailment in the fine-tuning step in order to assess the impact on RES targets.

Applying the guiding criteria therefore focuses on understanding the nature and origin of the identified needs, specifically their magnitude, duration and spatial concentration, and assessing appropriate solution pathways. A key aspect in this assessment is distinguishing between system-wide limitations and network-driven constraints, as this determines the most cost-effective response.

4.4.2. Guiding criteria on system needs

The application of the guiding criteria to system-wide flexibility needs is based on the system needs assessment presented in Section 4.1, complemented by the fine-tuning step in which network-induced curtailment is combined with system-level curtailment to ensure a consistent overall assessment.

For **RES integration**, system-level curtailment remains limited and does not prevent the achievement of national RES targets. Curtailment occurs during relatively short periods of high renewable generation, primarily driven by solar PV, and reflects temporal mismatches between supply and demand rather than a structural shortage of flexibility. As explained in 4.1.1.4, the curtailment identified in the network needs assessment is added as part of the fine-tuning step to the system-level curtailment, as these components do not overlap since network needs are derived from simulations in which system-level curtailment has already been accounted for. The total curtailment from the system and the network reduces the margin to RES targets, which are only just met, indicating that the remaining constraints are primarily driven by network limitations.

System-level RES curtailment remains limited, ranging from 0.9–1.3 TWh in 2030 and 2.3–3.3 TWh in 2035. To obtain a complete assessment of RES integration, this curtailment is combined with network-induced curtailment identified in the TSO network needs assessment. As these components do not overlap, their aggregation provides an estimate of total RES curtailment.

The resulting combined curtailment amounts to approximately 8.9 TWh in 2030 and 8.1 TWh in 2035.

Table 16 | Realisation RES integration targets

	2030	2035
Gross RES generation (TWh)	94.0	158.1
RES curtailment – system needs (TWh)	1.1	2.7
RES curtailment – network needs (TWh)	7.8	5.4
Net RES generation (TWh)	85.1	150.0
RES integration target (TWh)	81.0	150.0

Table 16 shows that the RES integration targets defined in Section 3.3 are achieved in both 2030 and 2035. Although combined system-level and network-induced curtailment reduces the available RES generation, net RES generation remains sufficient to meet the applicable targets. Consequently, **no uncovered RES integration needs are identified**.

For **short-term flexibility**, where next to ramping needs also forecast errors are assessed, uncovered needs are only observed under the restrictive assumptions of configuration C1, where available flexibility is limited to units committed in the day-ahead market. When additional operational flexibility is included (C2), these needs are largely resolved. Including cross-border flexibility (C3) further reduces the remaining needs, which become negligible in the assessed cases. This suggests that short-term flexibility needs primarily arise under conservative assumptions regarding resource availability.

Applying the guiding criteria defined in Article 16 indicates that no additional system-level flexibility resources are required. The existing flexibility portfolio appears sufficient to manage system-wide variability under the assessed assumptions, while the remaining short-term needs are mainly driven by restrictive assumptions regarding flexibility availability.

Overall, the analysis demonstrates that system-wide flexibility needs can be effectively managed by the flexibility resources assumed in the assessed scenarios, without structural investments in new flexibility resources

4.4.3. Guiding criteria on DSO network needs

This section provides further insight into DSO network needs. Based on the applied scenarios, both generation and consumption are expected to continue increasing over the coming decades, resulting in a sustained rise in network loading. Consequently, relatively limited congestion levels — and corresponding flexibility needs — are projected to evolve into more substantial and structurally embedded requirements over time.

In this context, network expansion is often considered the most cost-effective solution for addressing structural and persistent congestion. However, this general observation requires important qualification. While investments tend to be efficient in resolving continuous and widespread capacity shortages, they are less suited to addressing short-duration peaks or localised constraints. In such cases, flexibility can provide a more targeted and cost-efficient response. For example, short-lived peak loads during specific hours or seasons may not justify large-scale infrastructure investments, whereas the deployment of flexibility can effectively mitigate these peaks at lower system cost.

Moreover, flexibility is expected to remain an inherent and permanent component of the electricity system. Even in a significantly expanded grid, variability in generation (e.g. solar and wind) and demand patterns will continue to create temporal mismatches that require operational solutions. Flexibility is therefore not merely a transitional measure, but a structural element required to absorb fluctuations and optimize network utilization.

On shorter time horizons, the role of flexibility becomes even more pronounced. Given the time required to realize grid investments, flexibility is essential to bridge the gap between current capacity constraints and future system reinforcement. In practice, this implies that DSOs will need to rely on a combination

of measures: investments to structurally increase capacity, and flexibility to manage interim shortages and residual peaks. These two approaches should therefore be seen as complementary rather than substitutive.

This combined perspective is also reflected in the network developments presented in Section 4.2, where planned investments significantly reduce congestion levels between 2030 and 2035, while flexibility remains necessary to manage peak situations and transitional constraints.

Operational experience further nuances the role of flexibility. In particular, experience so far has shown that the availability of upward flexibility is often limited, which implies that additional instruments such as capacity steering contracts (CSC) and redispatch will remain necessary to develop upward flexibility where needed. At the same time, downward flexibility — for instance through curtailment of renewable generation during peak production hours — is generally more often available and offers a practical solution in situations of local oversupply, although it entails system trade-offs.

The underlying scenario used for this FNA assumes significant volumes of flexibility to meet system-level flexibility needs. If available and effectively deployed in the relevant constrained areas, this flexibility could also contribute to addressing the identified DSO network needs. This observation is particularly relevant in light of operational experience indicating that the availability of upward flexibility can be limited in practice.

Finally, several developments may influence future flexibility needs. The introduction of variable network tariffs is expected to incentivize peak reduction behaviour, thereby lowering the need for upward flexibility. Similarly, changes in market conditions, such as the phase-out of net metering for PV and the increasing occurrence of negative prices during periods of high solar generation, are likely to reduce downward flexibility needs. However, these effects remain subject to uncertainty and should be interpreted with caution. The DSO assesses these developments continuously and reevaluates the effects to determine the most cost-effective solution.

In summary, while network investments are indispensable for addressing structural capacity needs, flexibility will continue to play a critical role both in the short term — to mitigate immediate constraints — and in the long term, as an integral part of an efficient and resilient energy system. To ensure this, the availability for the upward flexibility need has to increase to ensure a sustainable system that is based on a good trade-off between the use of flexibility and network reinforcement.

4.4.4. Guiding criteria on TSO Network needs

This section presents the application of the guiding criteria to TSO network flexibility needs. Building on the results from Section 4.3, it provides a structured interpretation of the identified needs, linking their temporal and spatial characteristics to appropriate solution pathways. The analysis is further elaborated in the subsequent sub-sections.

4.4.4.1. Objective and scope

This section interprets the TSO network needs presented in Section 4.3 using the guiding criteria. The analysis combines:

- quantified congestion volumes and temporal patterns derived in Section 4.3,
- duration-curve analysis,
- screening-curve logic.

The interpretation follows three sequential steps:

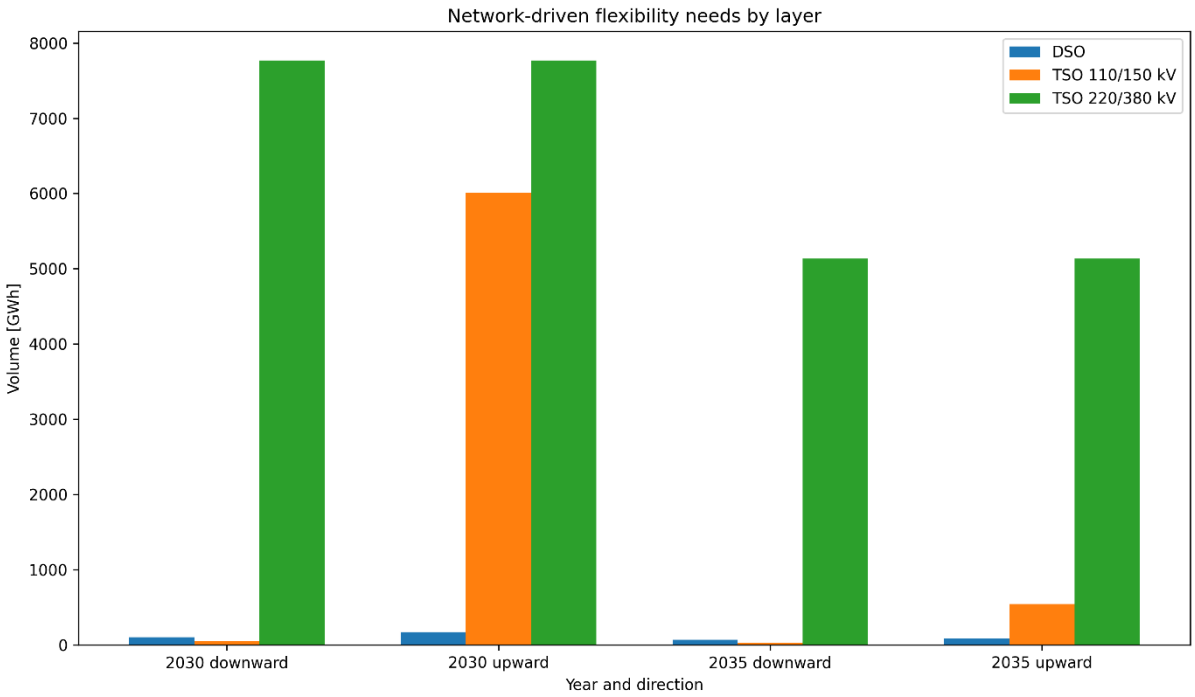
1. identification of structural patterns in the observed network needs,
2. mapping of these patterns to duration-curve and screening-curve logic,
3. classification and refinement into archetypes and corresponding solution pathways.

4.4.4.2. Key characteristics of TSO network needs

The results in Section 4.2.1 show that TSO network needs in the Netherlands are not uniform, but exhibit a clear layered structure across voltage levels and timeframes.

Figure 43 shows an aggregated view of network-driven flexibility needs across system levels and directions.

Figure 43 | Bar chart network flexibility needs by voltage layer



Three key observations follow:

- The **220/380 kV transmission** grid dominates the overall flexibility need, with volumes of approximately 15.5 TWh in 2030 and 10.3 TWh in 2035, and peak values in the order of 7–8 GW. This layer reflects system-wide congestion patterns driven by long-distance transport and meshed network interactions, where flows are distributed across a wide geographical area.
- The **110/150 kV** grid forms an intermediate layer, with significant regional needs in 2030 that reduce towards 2035 as planned grid reinforcements are realised. These needs typically amount to several hundred GWh per region, with peak values in the range of hundreds of MW. This layer reflects regionally concentrated congestion, which varies across areas and evolves over time.
- **Distribution-level (DSO)** needs are comparatively smaller in total volume, typically in the order of tens to low hundreds of GWh, but are highly localised and time-specific. These needs arise at substation and are often concentrated in specific hours or seasons, reflecting local imbalances between demand and generation.

This empirical distribution already suggests a decomposition into different layers of network needs with distinct characteristics and solution requirements. This layered structure suggests that congestion occurs at different temporal scales, which can be further analysed using duration-curve decomposition.

4.4.4.3. Conceptual framework: duration curves and screening curves

To interpret the identified network needs in a structured and consistent way, a conceptual framework is applied that combines duration-curve analysis with screening-curve logic.

This framework links the observed temporal patterns of congestion to their economic interpretation, without pre-determining specific solutions.

Duration-curve interpretation

A duration curve is constructed by ranking hourly flexibility needs from the highest to the lowest value.

Unlike a chronological time series, the duration curve represents:

- the **magnitude** of congestion (MW), and
- the **frequency** of occurrence (hours),

thereby providing a direct view of how often and how intensively the network is utilised beyond its limits.

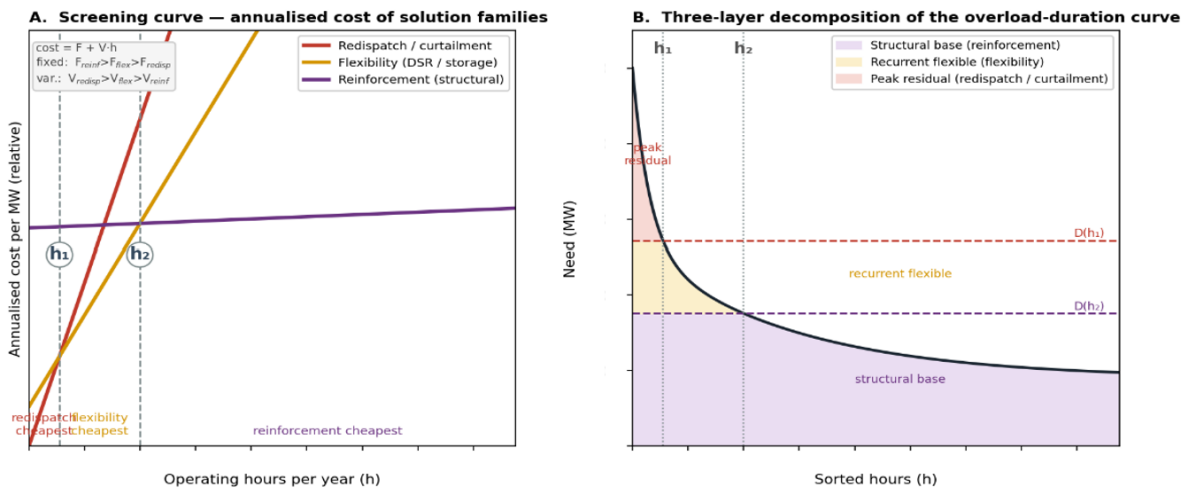
This allows the flexibility need profile to be decomposed into distinct layers with different analytical meaning:

- a structural component, corresponding to persistent congestion across many hours,
- a recurrent component, corresponding to regularly occurring but time-limited congestion, and
- a peak component, corresponding to short-duration and high-intensity events.

Screening-curve logic

To provide an economic interpretation of these temporal patterns, screening-curve logic from power system planning is applied.

Figure 44 | Screening curve and overload duration curve decomposition



Screening curves represent different solution categories as annualised cost structures, typically consisting of: *Cost = fixed cost + (variable cost × operating hours)*

This reflects the fundamental trade-off between:

- high fixed / low variable cost structures,
- moderate fixed and variable cost structures, and
- low fixed / high variable cost structures.

The intersection points between these cost structures define characteristic operating-hour thresholds at which one category becomes relatively more cost-effective than another.

These threshold hours can be mapped onto a duration curve, where they translate into capacity thresholds that separate the structural, recurrent, and peak components of congestion.

Analytical role of the framework

The combination of duration-curve and screening-curve logic provides a consistent way to:

- interpret congestion profiles across regions and voltage levels,
- distinguish between persistent, recurrent, and peak-driven needs, and
- relate observed patterns to economically meaningful utilisation regimes.

Importantly, this framework is not used to determine a least-cost solution mix, nor to derive exact cost outcomes. Instead, it provides an indicative and transparent analytical structure that supports consistent interpretation of network needs.

The framework is applied in the subsequent sections to decompose Dutch network needs into temporal layers and to support their classification into archetypes.

4.4.4.4. Duration-curve interpretation of Dutch network needs

Building on the conceptual framework introduced in the previous section, the duration-curve logic can be applied to the Dutch TSO network needs to interpret their temporal structure.

Clear differences in duration and frequency are observed across voltage levels and regions.

At the **220/380 kV level**, congestion occurs during a large share of hours and reflects persistent utilisation of the network. This corresponds to a dominant structural base layer, consistent with system-wide flows in a meshed transmission grid.

At the **110/150 kV level**, congestion is more regionally concentrated and occurs during a subset of hours. These profiles typically correspond to a recurrent layer, although in some cases they approach structural behaviour, while in others they are more limited in duration.

In contrast, downward congestion profiles are generally restricted to specific periods and occur during a limited number of hours. These profiles correspond to a peak-dominated layer, reflecting short-duration and time-specific constraints.

Overall, the duration-curve decomposition shows that Dutch TSO network needs consist of a combination of structural, recurrent, and peak-driven components.

This highlights that the temporal distribution of congestion is a key characteristic of network needs, in addition to their total volume.

This interpretation provides the basis for the archetype classification in the following section.

4.4.4.5. Archetypes classification

Building on the duration-curve interpretation, TSO network needs can be grouped into a limited number of archetypes that capture their key structural characteristics.

These archetypes are defined based on:

- the directionality of the need (upward, downward, or both),
- the spatial scope (system-wide or regional), and
- the temporal structure as identified through duration-curve decomposition.

Four archetypes of TSO network needs are identified:

- **A. Structural meshed congestion (EHV grid)**
- **B. Regional upward congestion**
- **C. Regional downward congestion**
- **D. Bidirectional or cycling congestion**

The archetypes provide a consistent basis for comparing congestion patterns across regions and voltage levels.

Further detail on their characteristics and interpretation is provided in the following sections.

4.4.4.6. Archetypes, indicators and solution pathways

Table 17 summarises how the guiding criteria, duration-curve interpretation and screening-curve logic translate into solution choices.

Table 17 | Archetypes applied for different types of congestion

Archetype	Key indicators	Interpretation (duration & drivers)	Implication for solution choice	Lead solution families
A – Structural meshed congestion	Large-scale transmission constraints, meshed grid flows	High share of hours → structural base layer	**Grid-first approach**	Grid reinforcement, redispatch, RES curtailment (complementary)
B – Regional upward congestion	Demand-driven peaks, spatial concentration	Recurrent patterns → mid-load layer	**Hybrid approach**	DSR, redispatch, local supply
C – Regional downward congestion	RES-driven surplus patterns	Primarily short-duration peaks → primarily peak layer	**Flexibility-first approach**	DSR, redispatch, RES curtailment, Storage, Power-to-X,
D – Bidirectional congestion	Both upward and downward needs	Cycling behaviour → multiple layers	**Symmetric flexibility required**	Storage combined flexibility

4.4.4.7. Detailed archetype definition and refinement

Building on the archetype framework presented above, each archetype is further refined using additional indicators and illustrated with Dutch system examples. This provides a more detailed basis for interpreting network needs in practice.

Archetype A — Structural meshed transmission congestion

Defined by: system-wide or transit-driven transport constraints in a meshed grid, driven by long-distance transport and transit flows. The scale and pattern of the need are shaped primarily by which reinforcements are commissioned and when.

Refined by: flex-need volume (annual energy and peak) is the most informative secondary dimension at this scale, taken directly from the quantified results in paragraph 4.3 — which already embed network (meshed) effectiveness in the need calculation, so it is not reconsidered here. Reinforcement outlook from the IP determines whether the need is likely to be addressed by planned infrastructure investments and on what timescale (structural vs. temporary). Market-access sensitivity is of lower weight here than in Archetypes B–D because the scale of the need generally exceeds what targeted local markets can deliver.

In the Dutch FNA, the 220/380 kV combined profile is the primary example of Archetype A. The large annual energy and broad spatial extent of this need make it structurally dominant across the assessment horizon, even as the load factor decreases between 2030 and 2035. The duration-curve decomposition and solution families follow from this characterisation.

It should be stressed out that the large 2030 and 2035 EHV volumes reflect a period in which not all major planned reinforcements are in operation, and future FNA iterations may find a different distribution of needs across voltage levels. Direction is not a defining criterion at EHV scale: the meshed topology means that injections interact across a wide area, so the precise directional distinctions that apply in the sub-transmission grid are less operationally meaningful here.

Archetype B — Regional upward congestion

Defined by: upward-dominant congestion concentrated in one or a limited number of sub-transmission grid regions. These indicators are sufficient to assign the archetype. Whether the profile is “structural” or “recurrent” is deliberately left open at this stage: that distinction is the output of the duration-curve step, not an input to the classification.

Refined by: active hours and annual volume feed the duration-curve decomposition and determine whether the structural base or recurrent flexible layer dominates. Driver type — load-driven, generation-driven, or mixed — informs whether upward needs are winter-oriented or more spread across seasons, which affects the predictability and timing of flexibility. Market-access sensitivity determines whether suitable providers can realistically be contracted in the relevant area. Reinforcement outlook from the IP applies as the cross-cutting modifier.

Dutch examples include Zuid-Holland 2030 upward (near-permanent, ~94% structural base layer — reinforcement dominant), Noord-Holland upward (both years, recurrent flexible layer dominant), and GDO 2030 upward (recurrent, reducing sharply in 2035). The same archetype classification applies to all three; it is the duration-curve step that differentiates their solution screening.

Archetype C — Regional downward congestion

Defined by: downward-dominant congestion concentrated in one or a limited number of sub-transmission grid regions. The label “generation-driven” from the original name is important context but is technically a secondary indicator (driver type), not a primary one: in principle, downward congestion could also be driven by low-demand conditions rather than renewable surplus. In practice, all identified Dutch downward profiles in the 110/150 kV grid are generation-driven, so the descriptor is accurate for this assessment but should not be embedded in the definition itself.

Refined by: driver type (renewable surplus generation) confirms the seasonal and intra-day pattern — predominantly spring/summer and daytime hours — which shapes the duration-curve structure. Active hours and seasonal concentration feed the layer decomposition directly, and for short-duration profiles the peak residual layer is expected to dominate. Market-access sensitivity focuses on the availability of local demand-side absorption, storage charging or Power-to-X capacity. Similarly to archetype B, the reinforcement outlook from the IP applies as the cross-cutting modifier.

Dutch examples include FGU 2030 downward (483 active hours, redispatch/curtailment dominant) and Friesland downward (present in both years, growing from 2030 to 2035). GDO 2030 downward is also Archetype C but reduces to near-zero by 2035, making it a clear candidate for the temporary modifier.

Archetype D — Bidirectional or cycling regional congestion

Defined by: both upward and downward needs present in the same sub-transmission grid location, with the minority direction exceeding a material share of the dominant direction's annual energy, **and** the active hours being largely non-overlapping (directional-complementarity check). The second condition is essential: if upward and downward needs co-occur in the same hours, a single two-way asset cannot serve both directions simultaneously, and the situation is better characterised as co-existing Archetype B and C needs rather than a cycling opportunity. Only where the directions are temporally separated does a bidirectional asset provide genuine two-way value.

Refined by: intra-day and seasonal cycling pattern is the most important secondary indicator for Archetype D, because it determines the required storage duration and the operational cycle count. Hourly or daily alternation between upward and downward needs points toward short-duration storage, whereas a weekly or seasonal swing points toward longer-duration options. Market-access sensitivity and the reinforcement outlook modifier apply as in the other regional archetypes.

In the current Dutch FNA dataset, no region presents a clear and evidenced Archetype D profile at 110/150 kV level once the directional-complementarity check is applied. Regions that show both upward and downward needs (such as GDO and FGU) do so across different years rather than within the same year with complementary timing, and the downward needs are generally much smaller than the upward ones. Archetype D is therefore retained as a framework category for completeness and for future FNA iterations, but is not the primary driver of solution screening in this assessment.

4.4.4.8. Cross-cutting modifier: temporary versus persistent needs relative to planned reinforcement

A final distinction applies across all four archetypes: whether the identified need is expected to remain material after planned reinforcement is completed, or whether it is likely to reduce significantly once planned investments become operational.

This distinction does not define a separate archetype, but acts as a cross-cutting modifier. Where a need is temporary relative to expected reinforcement, implementation speed and contract duration become more relevant than long-term optimisation, and interim or bridging solutions are more appropriate than structural measures.

The Dutch data between 2030 and 2035 illustrate this clearly, with several profiles showing large reductions over the five-year horizon:

- **Zuid-Holland upward** decreases from 5.34 TWh in 2030 to 7 GWh in 2035 (~100% reduction). Despite its size in 2030, this profile is almost entirely resolved, indicating a temporary need driven by reinforcement timing.
- **GDO upward** decreases from 271 GWh to 37 GWh (~86% reduction). This represents a material but transitional need, which diminishes strongly as planned grid developments take effect.

- **GDO downward** falls from 21.6 GWh to 0.2 GWh (−99%), indicating a fully temporary profile that is expected to be resolved with high confidence.
- **FGU downward** similarly reduces from 41.9 GWh to zero, showing a peak-driven but temporary congestion pattern.

By contrast, some profiles do not decline within the look-out period and therefore represent persistent needs:

- **Noord-Holland upward** increases from 307 GWh in 2030 to 401 GWh in 2035 (+30%), indicating a growing and persistent profile.
- **Friesland downward** grows from 8.4 GWh to 31.2 GWh (+271%), reflecting increasing congestion driven by renewable expansion, despite ongoing network development.

These examples show that the persistence of congestion depends on the timing of network reinforcements and the evolution of underlying system drivers, rather than on the archetype itself. As a result, both temporary and persistent patterns can occur within each archetype, and the evolution of needs over time becomes a key factor in their interpretation.

In application, this modifier should be assessed against the IP for each profile prior to solution screening. Where planned reinforcements are expected to resolve or substantially reduce a need within the assessment horizon, the temporary modifier applies, and solution considerations should focus on short-duration, rapidly deployable, and bridging arrangements.

4.4.4.9. Duration-curve interpretation and screening-curve thresholds

Once an archetype is identified, the need profile within it is interpreted through a flexibility-needs duration curve, which ranks the hourly required flexibility from the highest to the lowest active hour. Unlike a chronological time series, the duration curve represents the magnitude and frequency of congestion, enabling a decomposition into layers with distinct analytical meaning.

Three layers are distinguished:

1. **Structural base layer:** The portion of congestion related flexibility need occurring across a large number of hours. Although lower in instantaneous capacity than peak values, it is persistent and can represent a substantial share of total energy.
2. **Recurrent flexible layer:** The part of congestion related flexibility that occurs regularly but not continuously, reflecting repeated patterns over time, typically linked to seasonal or intra-day dynamics.
3. **Peak residual layer:** The highest congestion related flexibility levels occurring during a limited number of hours, representing short-duration and time-specific constraints.

Screening-curve thresholds

To define the boundaries between these layers in a consistent and reproducible way, the screening-curve logic is applied, following the framework illustrated in Figure 47 in subsection 4.4.4.3. The intersection points between the cost structures of different solution categories define threshold operating hours at which one category becomes relatively more cost-effective than another.

Projecting these threshold hours onto the duration curve translates them into capacity thresholds, which separate the structural, recurrent, and peak layers.

Role in the analysis

This approach does not determine a least-cost solution. Instead, it provides a transparent framework for distinguishing between structural, recurrent and peak-driven constraints and for identifying suitable solution families.

For bidirectional archetypes, upward and downward needs are assessed separately using the same methodology.

4.4.4.10. Summary of decision rules

Below is a summary of the decision rules for the guiding criteria:

1. **If the structural base layer is dominant,** reinforcement remains the reference solution and flexibility is assessed mainly as a complement or bridge.
2. **If the recurrent flexible layer is dominant,** flexibility-based solutions are screened first, provided locational precision and market access are sufficient.
3. **If the peak residual layer is dominant,** redispatch, curtailment or highly targeted measures are likely to be more cost-effective than dedicated new flexibility assets.
4. **If the profile is mainly upward,** the preferred families reduce net load on the constrained asset, by increasing local supply or reducing local demand.
5. **If the profile is mainly downward,** the preferred families reduce local injections or increase local consumption.
6. **If the profile is bidirectional,** solutions with two-way capability or complementary portfolios are preferred over one-directional solutions, subject to the directional-complementarity check
7. **If the need is temporary relative to planned reinforcement** — assessed against the IP — contract duration, implementation speed and timing relative to reinforcement become more important than long-term standalone optimisation.

If provider liquidity or contractability is weak, even a theoretically suitable flexibility option may not be robust enough to act as the primary solution In practice, provider liquidity and contractability may be affected by the market barriers described in Chapter 5.. This rule is currently applied qualitatively; it should be substantiated by a regional provider-availability assessment before it carries the same weight as rules 1–7.

4.4.4.11. Methodological note

The duration-curve decomposition is an interpretive screening framework, inspired by classical load-duration and screening-curve approaches, not a formal least-cost optimisation. The cost parameters and the resulting threshold hours used in the illustrative examples are non-binding and should be refined with Dutch cost ranges in future FNA iterations. Because the thresholds are derived from cost crossovers, the layer shares reported for each profile move with the cost assumptions; sensitivity to those assumptions should be reported alongside the headline shares.

Another important clarification is that the identification of constraints and the selection of appropriate mitigation measures are the primary focus of the IP and its subsequent activities. Within this formal process, each constraint is systematically assessed at both component and regional levels, and the most suitable solution is selected based on a range of indicators, including cost-optimality. In this analysis more scenarios are used as well as a further time horizon (15 years). As this will result in different load profiles the overloads as identified in the IP will differ from the FNA, which also means that different solutions might be chosen.

Consequently, the methodology presented here should not be interpreted as the formal approach for distinguishing between investment and operational solutions to constraints. Rather, it serves as a transparent framework for categorising flexibility needs per region and identifying relevant solution families.

5. Barriers for flexibility and contribution of digitalisation

The results of the FNA indicate that the Dutch power system will require new sources of both upward and downward flexibility from supply- and demand-side resources. In principle, practically all energy resources – including generation, demand-side and storage assets – can provide flexibility. Attention is paid to both large-scale renewable resources as well as small-scale distributed energy resources (DER[20]), potentially with aggregation. However, many market participants do not currently make their full flexibility potential available to the market. Meeting future flexibility needs will therefore require a combination of new investments and the unlocking of flexibility from existing assets. This chapter assesses the extent to which existing market frameworks are capable of integrating flexible energy resources and providing the investment signals needed to deliver the flexibility required for future system and network needs. The chapter addresses the barriers to flexibility based on the indicators suggested by ACER in its recommendations to NRAs' for reporting on barriers for non-fossil flexibility (ACER, 2026), based on the high-level categories outlined in Article 15 of the FNA methodology:

- Lack of proper legal framework for market access to new entrants and small actors
- Lack of enablers and incentives to provide flexibility
- Restrictive requirements to provide balancing services
- Restrictive requirements to provide congestion management
- Complex, lengthy, and discriminatory administrative requirements
- Lack of regulatory incentives to system operators to consider non-wire alternatives.

The market barriers evaluated in this chapter focus on entry and participation barriers for non-fossil energy resources and the role of digitalisation. The chapter elaborates on the most relevant barriers, labelling them as either **prohibitive barriers** that effectively exclude market participation or severe **hurdles** that, while theoretically surmountable, in practice significantly constrain effective participation. The list of hurdles is non-exhaustive, as different market parties can experience different hurdles.

This chapter explains market roles in the electricity system, explains how the balancing markets, congestion management and electricity markets are organized, and what the barriers are for unlocking flexibility in these markets and services. The chapter is structured per segment, first focussing on cross-market participants and cross-market barriers (section 5.1), followed zoom-ins on balancing markets (section 5.2), congestion management (section 5.3) and wholesale electricity markets (section 5.4), finalizing with an overview of the identified barriers and a qualitative reflection on the barriers from ACER (section 5.5).

Note that several of the barriers or design flaws discussed in this chapter relate to the functioning of the Information Technology (IT) systems of the grid operators, many of which are already being worked on by the DSOs and TenneT. For example, an overview of all planned IT changes that have an impact on TenneT's customers and markets can be found in the *Business Roadmap* (TenneT, 2026).

Also note that all products described in this chapter are procured from the market as under the *Energiewet* (Dutch Energy Law), system operators are generally not permitted to own any production assets (Energiewet, 2026). However, system operators are allowed to own storage facilities if they use them as a fully integrated network component (FINC) subject to approval by the ACM.

The barriers and references presented in this chapter reflect the situation as of 1 June 2026, unless indicated otherwise.

[20] *Distributed Energy Resources (DERs) are decentralized generation, storage, and demand-side flexibility assets connected to the distribution network that can support energy supply and grid operation. This includes the flexibility that can be unlocked from household-owned distributed energy resources, such as rooftop solar PV, home batteries, electric vehicles, and flexible demand. For some markets or services, their individual capacities are too small to participate, but they can participate in aggregation.*

5.1. Across markets

This section describes the different market parties that participate across balancing markets, congestion management and wholesale electricity markets, cross-market requirements for participation, and the barriers for market participation that were identified as being present for all the above markets and services.

5.1.1. Market roles

Participation in the electricity markets involves a range of actors, each with specific roles, responsibilities, and requirements. Those roles and responsibilities are stipulated by law and regulation. In principle, each role can be fulfilled by a separate player. In practice however, companies often perform several roles simultaneously. A distinction can be made between physical roles (connected parties and the system operators) and administrative roles. For more information, also see TenneT's information page on market roles (TenneT, Market roles, 2026).

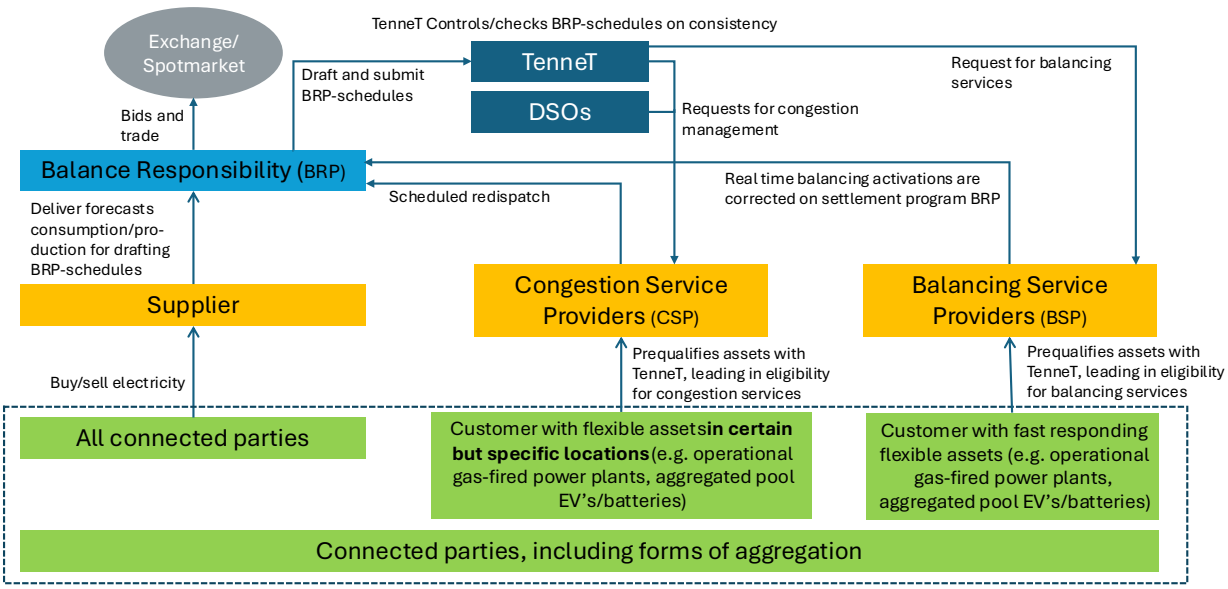
In this report, we zoom in on the administrative roles; administrative market roles that participate across markets or services are explained in the current section, being balance responsible parties, aggregators and energy communities. Administrative market roles that are more specific for a particular market or segment are explained in the sections focussing on these segments:

- Balancing Service Party (BSP) for balancing markets (in 5.2.1)
- Congestion Service Party (CSP) for congestion management (in 5.3.1)
- Energy supplier for wholesale electricity markets (in 5.4.1)

These roles are intermediaries that link and steer a grid user with the respective market or service.

A simplified overview of the different market roles explained and their responsibilities and relations can be found in Figure 45.

Figure 45 | Simplified overview of market roles



5.1.1.1. Balance Responsible Party

All grid connections fall under a balance responsible party (BRP) by law. Therefore, all parties that offer their flexibility potential to the various markets – either separate or in aggregation – fall under a BRP. Also, all service providers operate under a BRP, meaning that operation in wholesale electricity markets, balancing markets and congestions managements requires interaction with a BRP.

A BRP is responsible for maintaining the balance of its own portfolio. To do so, it submits a BRP-schedule (*"E-programma"* in Dutch) after closing of the day-ahead market. The BRP schedule reflects the BRP's net position resulting from all commercial transactions with other market parties for each 15-minute market time unit (MTU). This schedule is based on the cumulative impact of all the BRP's commercial transactions, portfolio adjustments and resulting obligations across the forward/futures, day-ahead and intraday markets. The sum of all BRP positions in the system should net to zero for each MTU, meaning that total scheduled injections equal total scheduled withdrawals. After the initial submission, the BRP can update the schedule to reflect additional intraday trades. After delivery, deviations between scheduled and actual volumes are settled at the imbalance price (see section 5.2).[21] This framework is embedded in national grid codes and enforced by TenneT, which assesses whether each BRP meets the technical and organizational requirements for onboarding and ongoing operation.

Every grid connection has one BRP, but BRPs may operate either with or without physical connections. Those without connections act purely as trading entities, optimizing their position exclusively through market transactions. BRPs with connections take on added obligations linked to metering, allocation, and reconciliation for end-users or generators. They can also physically balance their portfolio with real-time asset steering.

The prequalification process for BRPs with TenneT focuses primarily on a party's IT and communication systems, financial guarantees and administrative capabilities. In practice, this process typically takes three to four months for entities that already have experience in energy markets and possess the necessary operational infrastructure. Becoming a BRP with physical connections is significantly more demanding requiring robust data-handling capabilities, as well as the ability to process operational and settlement data from DSOs.

5.1.1.2. Aggregators and aggregation

Assuming market resources are compliant with prequalification requirements, the main reason actors may not be able to participate in balancing markets or congestion management is because the flexible capacity they offer is too small (e.g. 1 MW is a frequently occurring minimum capacity for balancing markets or congestion management). To solve that problem, there is the possibility to aggregate these participants into larger pools, or 'aggregators'. As a result, aggregation can significantly broaden market access and enable the participation of smaller flexibility resources that would not be able to participate on a standalone basis. While there are no markets or products that exclude aggregation, access is still subject to product-specific prequalification, technical and organizational requirements.

In the Dutch Energy Act, **aggregation** is defined as *"the combining of demand response or injected electricity from different active customers with a view to resale",* and an **aggregator** is the market participant who carries out the aggregation (Rijksoverheid, 2026).

In practice, market participants often fulfil multiple roles simultaneously. For example, an aggregator may also operate as a CSP, BSP and/or electricity supplier. This allows the aggregated portfolio of assets to participate directly in congestion management, balancing markets, or wholesale electricity

[21] Deviations in the BRP-schedule from services provided by the CSP and BSP are settled in such a way that the financial implications do not fall on the BRP.

markets. When the aggregator is not the supplier of those customers, it is referred to as an independent aggregator.

Alternatively, an aggregator may focus solely on pooling the flexibility of active customers and then make this aggregated flexibility available to another market participant, such as a CSP, BSP or supplier, which subsequently offers the flexibility in the relevant market or service.

Aggregators can conclude a pooling contract with various market participants, but it is primarily relevant for active customers. Aggregators don't need consent from any other legal entities.

5.1.1.3. Energy communities

Energy communities are legally-recognized entities under the Dutch Energy Act enabling citizens, small and medium-sized enterprises (SMEs), as well as local authorities to jointly generate, consume, store, share or trade energy. Energy communities may generate profits, but profit-making may not be their primary objective. Instead, they are intended to deliver environmental, economic or social benefits to their members or the local area. An energy community has four main characteristics:

1. It is a legal entity (registered as such)
2. It has more than one member
3. It is controlled by its members
4. Its primary goal is to provide social, economic, or environmental community benefits rather than financial returns

An energy community is a legal entity that has the same rights for market participation as any other potential aggregator and can offer the capacity of jointly owned or managed assets on electricity markets, balancing markets, or for congestion management.[22]

When an energy community seeks to offer services based on multiple assets connected at different connections or allocation points, aggregation is required. Aggregation is therefore possible but not inherent to operating as an energy community. Energy sharing is discussed in more detail in paragraph 5.4 on wholesale electricity markets.

Depending on the structure of energy sharing, aggregation or supplier relationships, participation in an energy community may require additional metering solutions or allocation points, particularly where multiple suppliers or aggregators are involved.

Although an energy community is a separate legal entity, participation in an energy community does not remove the individual status of members as end-customers. Connections, metering, allocation and consumer protection continue to apply at the individual customer level.

In the Netherlands, an energy community has only been recognized as a distinct legal concept under the Energy Act since 1 January 2026. As a result, there are currently no initiatives that are formally structured and identified as energy communities under this legal framework. Before the Energy Act entered into force, Dutch energy law did not recognize energy communities as a separate category of market actor with specific rights and obligations. Historically, parties that jointly undertook activities now associated with energy communities typically organized themselves through energy cooperatives or similar civil-law entities. Energy cooperatives have existed for decades and provided a legal vehicle to collectively develop, own and operate energy projects, organize participation and distribute benefits among members. In practice, many cooperatives already pursued local ownership, democratic governance and community benefit, even without a dedicated status under energy legislation.

Energy communities are effectively controlled by their members (often households) with active participation as a requirement. The barriers in initiating and running an energy community are thus more

[22] *In addition, an energy community in the Netherlands can take up certain supplier activities without holding a full supply license, but must have a contractual arrangement with a BRP for imbalance settlement and reconciliation.*

organizational than legal. A recent report from TNO highlights that there are four conditions necessary for energy communities that would need improvements (TNO, 2025):

1. **Better integration of generation, use, and storage**: Stronger links between production, consumption, and storage (e.g. storage and demand response) are needed to improve the viability of renewable energy projects, including for energy communities.
2. **Targeted financial support across project phases**: There is a need for higher start-up subsidies, funding for feasibility studies, loan guarantees (especially for heat networks), lower interest rates, and operational support to address long-term low price periods.
3. **Structural cooperation with governments**: Ongoing collaboration with local authorities is essential, particularly for energy savings, sustainability measures, and renewable electricity production, to increase affordability, sustainability, and participation.
4. **Inclusive expansion of energy communities**: Energy communities should be accessible to everyone; governments and communities can learn from each other to support development in different locations and promote inclusivity.

5.1.2. Physical market participation requirements

In order to participate in electricity markets, balancing markets and congestion management, there are two key physical requirements which apply for all:

- having a smart meter installed, and
- having a grid connection.

These requirements are described in more detail below.

5.1.2.1. Smart meters

A bare minimum for market participation is having a smart meter for each participating grid user, as this provides the market party with the ability to respond to price signals. Approximately 95% of households in the Netherlands have one, and nearly all commercial connections (Rijksinspectie Digitale Infrastructuur, 2026). These smart meters can be read by the system operator and energy supplier and provide:

- Access to non-validated near real-time consumption through a standardized interface, made available free of charge for the consumers.
- Access to validated historical consumption data, including visualization, on request and at no additional cost. However, not all historical data is stored in detailed resolution. For example, system operators remove 15-minute data after 12 working days.
- Separate measurements for electricity fed into the grid and electricity consumed from the grid by active customers.
- Data on final customers' electricity consumption and the electricity that they fed into the grid. This is made available to them on request or to a third party acting on their behalf at no additional cost, through a standardized communication interface or through remote access.
- Possibility for metering and settling at the same time resolution as the imbalance settlement period (15 minutes) in the national market, in most cases.[23]

Since May 1st 2026, for approximately 90% of allocation points in the Netherlands, actual 15-minute smart meter data is used for allocation instead of estimated load profiles. This significantly increases the accuracy of volume allocation to BRPs.

[23] There are some older smart meters installed for which this was not yet the standard.

5.1.2.2. Obtaining a new grid connection

For market participants requesting a new DSO grid connection, there are standardized procedures, and information is provided online (see three largest DSOs Enexis, Stedin and Liander). The request for a new grid connection can be carried out online at 'mijnaansluiting', a joint platform for various new connection requests (including electricity, gas and water). These procedures can be run in parallel with other authorizations, but there can be dependencies for example for permits. System operators can then give an indication for the procedure time until grid connection. For small connections (< 3x80A) there is a simple-notification procedure.

Obtaining a new TenneT grid connection goes via a more tailored approach. TenneT will discuss the options and determine the best connection option for the specific situation - in collaboration with the regional grid operator where necessary.[24]

As discussed in more detail in 5.1.3, unfortunately sufficient grid capacity is not available everywhere to accommodate new grid connections in all locations. Netbeheer Nederland, the organization representing all gas and electricity system operators in the Netherlands, compiles information from system operators on available grid capacity and makes this information publicly accessible in a *Capaciteitskaart* or capacity map for the Netherlands (Netbeheer Nederland, 2026), explained further in the next section.

5.1.3. Cross-market barriers

In this section, we discuss the most important barriers for the entry of non-fossil energy resources, relevant across balancing markets, wholesale electricity markets and congestion management combined.

Business case uncertainty for large-scale renewables and batteries (hurdle)

Most large-scale dispatchable power plants, renewable installations (e.g. solar and wind farms), and batteries have already found their way to the electricity markets to which they can contribute. It is not so much the market participation of these assets that is the challenge, but ensuring enough investments in these assets are made in the first place.

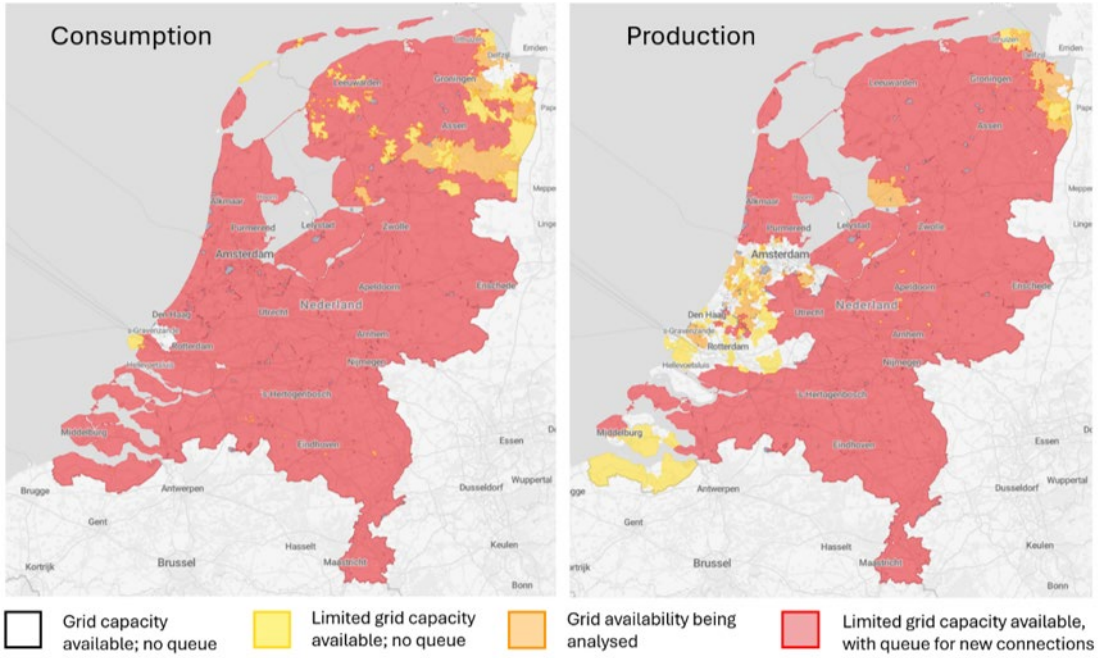
Market parties must assess whether their existing assets, as well as prospective new investments, will be profitable. A detailed analysis on future business cases for flexibility and other technologies is out of scope for this report, but TenneT does perform an economic viability assessment as part of the MVZ study (TenneT, 2026). For example, the latest MVZ 2026 indicates that battery storage may be economically viable in the Netherlands under the analysed scenarios towards 2035, reflecting the increasing value of flexibility in the electricity system. However, the results also show that the viability of batteries remains sensitive to assumptions regarding technology costs, future market developments, trading strategies, grid tariffs, and the evolution of balancing and wholesale market revenues. As a result, there remains uncertainty regarding the extent to which the flexibility resources assumed in long-term scenarios will materialise under purely merchant market conditions. The topic of business case consideration is also explained in the literature, such as reports by TNO on challenges towards a climate neutral electricity system (TNO, 2024), or the addendum the letter to Parliament on the strategic approach for batteries (Rijksoverheid, 2024). Part of this assessment is the extent to which the flexibility provided by the asset aligns with system and network needs and can therefore be monetized. By helping to articulate the expected flexibility needs from a system and network perspective in the future Dutch power system, FNA report is also an important step in providing more visibility to the market that investors may take into account in their future decisions.

[24] *For more details, see TenneT 'Aansluiten op het Nederlandse hoogspanningsnet'.*

Lack of grid capacity for new grid-connected large-scale renewables and batteries (prohibitive barrier)

Next to business case considerations, there are physical and administrative limitations for making investments. Currently, one of the biggest barriers in the Netherlands is the scarcity of new grid connections. Due to physical congestion and forecasted congestion (also called transport scarcity), both TenneT and the DSOs have introduced a queue for new grid connections in congested areas, until more grid capacity becomes available. Transport scarcity is announced to avoid physical congestion, and currently the majority of the waiting queue is induced by transport scarcity. See Figure 46 for an overview of the current *Capaciteitskaart* of the Netherlands (as of April 2026).

Figure 46 | Capacity map of the Netherlands for new connections with DSO and TSO grids combined, as of April 2026 (Netbeheer Nederland, 2026)



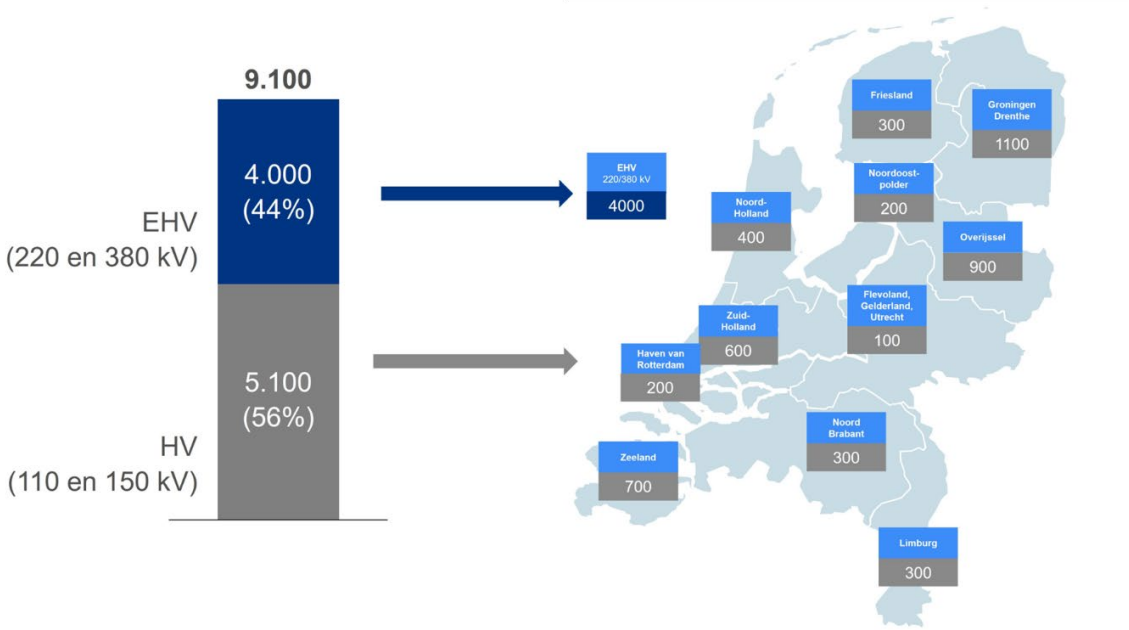
Reducing or solving the waiting queues can be achieved by making better use of the grid (see paragraph 5.3 on congestion management) or after new physical investments in the grid are made. Although it cannot be said with certainty when the current queues will be addressed, it is expected that they will remain in place until at least the 2030s. Not obtaining a grid connection can be a major barrier for the new investments.

These problems are recognized by the Dutch government and system operators. In February 2026, the Dutch government published a grid connection offensive ('Aansluitoffensief') see the letter to parliament and the report with eight measures that should alleviate the congestion problems and result in a (flexible) grid connection offer to everyone on the waiting list. Next to that, there is national action program for congestion (LAN) where the system operators jointly work on congestion problems. For enterprises that cannot grow due to congestion, the government has introduced the Flex-E subsidy (RVO, 2026) to analyze how they can better utilize their grid connection and possibly make investments (e.g. in batteries) to facilitate this optimization.

System operators are already taking measures to make more efficient use of their existing grid infrastructure. Some examples include the use of dynamic line rating, the use of congestion management contracts (see section 5.3), and by offering flexible contracts, such as time-dependent transport rights (TenneT, 2026), under which the grid user can receive a grid connection in exchange

for accepting restrictions on their capacity usage during periods when this is necessary to maintain grid security. In November 2025 for example, TenneT granted 9 GW of flexible contracts, where the connected party has firm capacity for at least 85% of the year. Figure 47 shows the distribution of flexible contracts that were made available.

Figure 47 | Distribution of available capacity for flexible grid connection contracts with 85% firm capacity on the EHV and HV-grid (TenneT, 2026)



Lack of automation (hurdle)

Not all assets that could potentially offer their flexibility are currently automated or can respond timely for functioning in balancing markets. Especially older DER often need additional investments for (aggregated) participation in markets where their assets must be steered by a third party, or as a response to an external factor. Many of these assets can become steerable through additional investments. This is mainly a technical matter that falls outside of the scope of the system operator.

Limited awareness, knowledge and trust among consumers (hurdle)

Limited awareness, knowledge and trust among consumers remains an important hurdle to unlocking demand-side flexibility. Many households are unfamiliar with flexibility opportunities, dynamic tariffs, aggregators and flexibility services, and often do not understand how participation could benefit them. For many commercial parties, participation on electricity markets is not part of their core business, making them hesitant to participate.

In addition, concerns about comfort, autonomy and control reduce willingness to participate. Households often prioritise comfort and convenience over potential financial benefits and may be reluctant to allow automated control of assets such as electric vehicles (EVs), heat pumps or home batteries (CE Delft, 2026). Similar concerns also exist among commercial consumers. Companies may be hesitant to provide flexibility when this is perceived to reduce comfort levels, limit operational control, or interfere with core business processes, such as the timely charging of electric vehicle fleets in the logistics sector (Common Futures, KWA, & EV Consult, 2026).

Concerns about losing control, facing unexpected outcomes, or sharing data with third parties can reduce trust in flexibility services and limit participation, even where the technical and commercial

conditions are already in place. Increasing flexibility participation therefore requires not only financial incentives and market access, but also greater awareness, clearer consumer information, and confidence that flexibility can be provided without materially affecting comfort or convenience.

5.2. Balancing markets

This section first elaborates on the functioning of balancing markets, followed by barriers for participation.

5.2.1. About balancing markets

The obligation for the TSO to balance the electricity system follows from the Dutch Energy Act, which is primarily governed by European legislation and implemented through national network codes and regulatory approval.

For understanding market functioning and barriers in the balancing market, it is important to first understand which products are used in the balancing market, and how they are procured and activated. Balancing products can be broadly divided into balancing capacity and balancing energy. Balancing capacity refers to the reservation of flexible resources that are kept available for activation by the TSO, while balancing energy refers to the actual increase or reduction in supply or demand delivered by those resources when activated. Balancing products therefore require assets either to be available for the TSO or to respond to a signal to increase or decrease their supply or demand.

Restoring balance is done through several standard products, which are provided by a balancing service provider (BSP). A BSP can represent various parties, can have multiple assets in its portfolio to provide balancing services, and there is no legislation hindering any market participant joining a BSP and offering its services. The main balancing market products are (i) Frequency Containment Reserve (FCR), (ii) Automatic Frequency Restoration Reserve (aFRR), and (iii) Manual Frequency Restoration Reserve (mFRR).[25] These products differ in their response time, how they are activated, how long they must be activated for, and in their minimum bid sizes. The balancing capacity and the balancing energy of each product are auctioned separately, and therefore remuneration differs per product. The FCR auction is symmetrical for both upward and downward direction, while aFRR and mFRR have separation auctions for upward and downward reserve provision. Each product is 100% procured from the market, in which no TSO or DSO owned assets are active.

Balancing products such as FCR, aFRR and are activated when the system is in imbalance. TenneT has a reactive balancing approach, which means that the products are only activated in response to actual power imbalances. FCR is activated automatically and stabilizes frequency immediately. aFRR and mFRR are used to restore balance to the target frequency and take over from FCR.

The costs for balancing capacity (i.e. the reservation) are paid through the grid tariffs. The costs for balancing energy (i.e. the activation) are paid by the BRPs which contribute to the imbalance. They pay the imbalance price if they contribute to the net imbalance of the system during a certain imbalance settlement period (ISP) of 15 minutes. BRPs that are in balance pay nothing, while BRPs that have an imbalance position that is beneficial for the system get rewarded. This mechanism may incentivize BRPs to activate their own flexible demand or supply to optimize balancing income, thus helping the system and reducing the need for balancing products.

TSOs need to contribute proportionally to the European market for FCR and must be able to cope with imbalances even when disconnected from neighbouring countries. The amount of FCR needed in the Netherlands is a fraction of the total FCR volume determined for the entire Continental Europe (CE)

[25] mFRR has two products: (1) a mFRR standard product that is integrated in the European market, and (2) a mFRR specific product which is only used in the Netherlands.

synchronous area level (ENTSO-E, 2026). In 2026, the Netherlands needs to procure 136 MW of FCR, of which 30% of the connections must be located in the Dutch control block (TenneT, Ancillary Services, 2026). The amount of aFRR and mFRR needed is based on calculations from TenneT, following European guidelines. Procurement and activation are as follows:

- FCR (which is a capacity-based product) is procured via a daily European auction with symmetric four-hour products, and activated automatically and autonomously based on local frequency deviation.
- aFRR capacity is procured in a Dutch national day-ahead capacity auction for both four-hour and 24-hour products and its energy is activated through TenneT's load-frequency controller through setpoint sending. This activation includes the correction received through the European PICASSO platform, which uses imbalance status and bid offers in all connected areas to activate the most economically efficient bids on a European level. The plan is to transition to four-hour products only.
- The mFRR specific product (also called "noodvermorgen" or "Incident Reserve") capacity is procured in a Dutch day-ahead capacity auction for 24-hour products. As of September 2026, TenneT will be selecting energy bids based on a merit order list. For mFRR activation, TenneT only makes use of the national mFRR specific product.
- The mFRR standard product (also called MARI product) only has energy bids, and no capacity bids. TenneT currently does not make use of MARI for its own imbalances. TenneT provides the opportunity for BSPs to participate in the European mFRR market (MARI) by submitting their bids that can be selected.

Each balancing product can be fulfilled by generation, demand and storage. A summary of the Dutch balancing market and its products is displayed in Table 18.

Table 18 | Summary of the balancing market products and requirements. A cell with 'N/A' indicates not applicable.

Product or market design element	EU target model requirement	FCR	aFRR capacity	aFRR energy	mFRR capacity standard product	mFRR energy standard product	mFRR capacity specific product	mFRR energy specific product
Minimum bid size	≤ 1 MW	1 MW [a]	1 MW	1 MW	N/A	1 MW	1 MW	1 MW
Validity period of balancing energy bids	15 min	N/A	N/A	15 min	N/A	15 min	N/A	15 min
Procurement of upward / downward capacity	Separate	Combined (symmetric product)	Separate	N/A	N/A	N/A	Separate	N/A
Price settlement rule	Marginal pricing	Marginal pricing	Pay as bid	Marginal pricing	N/A	Marginal pricing	Pay as bid	Marginal pricing
Non-contracted balancing energy bids	Allowed	N/A	N/A	Allowed	N/A	Allowed	N/A	Not Allowed

[a] The BSP must inform TenneT which reserve providing unit (RPU) or reserve providing group (RPG) will supply the allocated FCR capacity. This must be specified in increments of 100 kW per RPU/RPG used.

5.2.2. Barriers in balancing markets

TenneT contracts volumes for its services from BSPs, and the BSPs can choose which assets from their portfolio they'll steer up or down when activated. This is called portfolio bidding. An asset can be included in only one BSP's portfolio, which can be used for FCR, aFRR and mFRR. Portfolio bidding

also makes it possible for assets that would individually not comply with requirements (e.g. due to too slow response times) to compensate for their flaws in a portfolio, and make balancing markets very inclusive markets. The prequalification period takes approximately one to three months, but this is not harmonized on European level yet. That said, there are barriers for the entry of non-fossil energy sources in balancing markets, discussed in the next sections.

Participation of distributed energy resources (DER) (prohibitive barrier and hurdles)

Although TenneT does not publish which assets are active in offering different products, it is observed that the FCR market is dominated by large-scale batteries as they can easily offer upward and downward flexibility. However, there is limited participation of DER. Often caused by TenneT's existing procedures and requirements for information exchange, which were set up within a system dominated by larger units.

A **key barrier** to DER participation stems from limitations in **TenneT's IT systems**. The current information exchange platforms only support messages up to 20 MB, which may constrain the participation of larger aggregations of distributed energy resources. The message size directly relates to the amount of assets, which creates a limitation to declaration of a few hundred assets. In the past, TenneT has had to reject BSP prequalification requests due to this limitation, and it is expected that some BSPs have not sought prequalification due to this limitation. This is particularly affecting the aFRR energy-related message flows. However, TenneT is currently developing an update to its information exchange channels. To overcome the 20 MB message size limitation of the MMCHub communication platform, TenneT is implementing a solution that enables information to be segmented across multiple messages within the same exchange. This will allow BSPs to register and manage substantially larger portfolios of assets. The update is expected to go live by the end of 2026 and is anticipated to support BSP portfolios of up to 35,000 assets.

Aside from IT-related barriers, there are two severe **hurdles** for participation of DER in balancing markets:

1. **Asset requirements:** BSPs must prequalify one or multiple assets or a pool of aggregated smaller assets before they can offer them for balancing services.[26] These include IT, product-specific, and technical requirements. Already DER can participate through aggregation, offering demand response. However, in practice, the prequalification criteria pose an entry barrier for DER, as the criteria are better suited for larger assets than for smaller assets offering demand response.
2. **High liability clause:** There is a fixed liability clause of €5 million for aFRR (TenneT, 2025), independent of the bid size. This is disproportionately high for smaller bids of only a few MW.

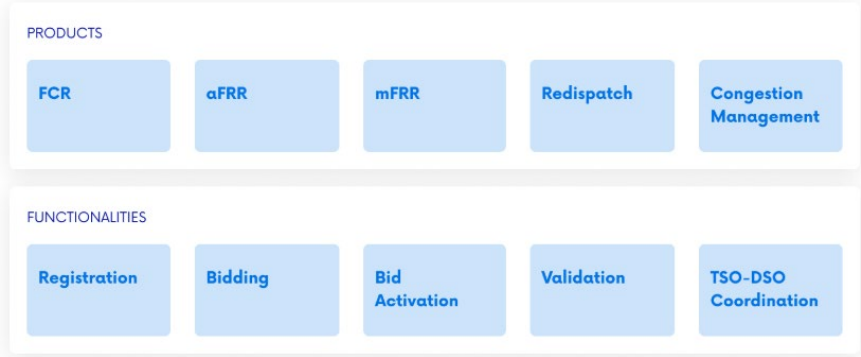
There are currently two main initiatives that strive to overcome these hurdles and make it easier for BSPs to participate with DER.

1. **Equigy, for IT communication requirements:** the difficulty for participation of DER was recognized by TenneT (and other European TSOs) several years ago. This led to the initiation of the TSO subsidiary Equigy in 2020, a data platform that enables aggregators to participate with smaller flexibility devices in markets for ancillary services including balancing markets and congestion management, mostly through support in fulfilling the IT communication requirements (Figure 48). Equigy indicates that through their platform, they have facilitated more than 3 GW of DER flexibility in the Netherlands.
2. **Adaptation of the network code on demand-side response, for IT and technical requirements and a legal framework:** the hurdles for offering DER in various electricity markets have also analyzed by ACER in 2023 (ACER, 2023), and put into European legislation through the *European network code on demand side flexibility*, which is currently under review by the

[26] *For more information on the process, see the prequalification procedure documentation*

European Union and expected to be adopted in 2027. The aim of this network code in relation to balancing markets is a harmonized European prequalification and participation model, simplifying market entry for smaller energy players and enabling standardization of demand response measurement across Europe. This harmonized European framework will simplify the qualification and verification system, and create standardization across countries.

Figure 48 | Equigy products and functionalities (Source: Equigy)



aFRR and mFRR cannot be delivered simultaneously at the same allocation point (prohibitive barrier)

There is currently a restriction that only one BSP can be active per allocation point. That BSP can deliver aFRR or mFRR at the same time. FCR can be combined with either of these products. These limitations are not driven by technical constraints of the underlying assets, but by insufficient observability and control at the level of service delivery. This is a technical barrier on TenneT's side, where TenneT cannot adequately verify whether the same capacity is simultaneously committed to different balancing products.

A key underlying issue is the lack of harmonization of sanctioning and settlement rules across balancing products. Differences in activation, non-delivery and penalty methodologies complicate enforcement when multiple products are delivered from one connection.

While this issue has been identified and analyzed, no concrete implementation timeline for resolving it has yet been defined. Harmonizing sanctioning frameworks across balancing products would reduce this barrier and enable greater stacking of balancing services, thereby unlocking additional flexibility potential.

Long contract durations for mFRR availability (hurdle)

A barrier in the mFRR market relates to the use of long availability blocks. Currently the specific mFRR product "incident reserve" is contracted in 24-hour blocks. This is not driven by market preferences, but by limitations in the underlying operational tooling, which does not yet support shorter contracting periods. As a result, providers offering incident reserve are required to guarantee continuous availability over a full 24-hour period.

This requirement limits participation, as some flexibility providers may only be able to offer capacity during a limited number of (specific) hours. aFRR already uses shorter availability of 4-hour blocks, and there is an intention to move towards shorter blocks for mFRR as well. Shorter availability blocks would lower entry barriers for variable and weather-dependent resources, such as renewable-based flexibility with reliable forecasts. However, reducing contract durations also involves trade-offs: beyond a certain point, further shortening can reduce product value and increase operational complexity. Progress

towards smaller block sizes is ongoing, but the pace of implementation is constrained by system capabilities.

Strict sanctioning conditions for FCR (hurdle)

Sanctioning conditions for non-compliance with the requirements associated with FCR delivery are currently relatively strict, which increases the risk exposure for BSPs and can deter market entry or expansion.

To mitigate this effect and stimulate additional participation, the sanctioning conditions have been temporarily relaxed. This temporary measure aims to attract more capacity to the FCR market. Work is ongoing to develop a more permanent and structurally balanced solution; however, no definitive implementation timeline has yet been established.

5.3. Congestion management

Congestion management plays an increasingly important role in facilitating access to the electricity grid and managing network constraints in the Netherlands. By activating flexibility from market participants, congestion management can help alleviate local grid bottlenecks and complement traditional grid reinforcement measures. This section provides an overview of the Dutch congestion management framework, discusses its role relative to network expansion, and identifies the main barriers affecting participation in congestion management.

5.3.1. About congestion management

Congestion management is needed when the grid cannot accommodate the forecasted electricity flows. Articles 3.28 and 3.29 of the Dutch Energy Act empower system operators to procure and apply flexibility services, including congestion management services. It is needed by both TenneT and the DSOs. System operators can indicate that an area is congested if there is actual physical congestion, or if there is transport scarcity leading to administrative congestion. Transport scarcity means that the grid investment prognosis indicates that an area will become congested through expected developments or if there are new grid users. System operators do not allow new grid connections in congested areas, or only small new grid connections.

Because of this precautionary measure, many areas in the Netherlands are congestion areas. Although currently the amount of congestion that needs to be managed is limited, a sharp increase in the amount of congestion that needs to be managed in the future is foreseen.

Products to tackle congestion are always location-specific, as the action must alleviate expected or forecasted congested lines. Congestion management is paid for by the system operators, which are passed on to the grid tariffs paid by grid users. Congestion is managed both before day-ahead gate closure (with capacity steering contracts) and during the intraday time domain (with redispatch):

1. **Through capacity steering contracts (CSCs).**

These are contracts that system operators have with asset owners or congestion service providers (CSPs, Dutch equivalent of flexibility service providers, specifically for congestion management), in which it is agreed that the counterparty has to adjust their production or consumption up or down when requested by the system operator, possibly constrained by when or how often the system operator can make this request. The remuneration can have a fixed component for the availability and a variable component for the activation. The CSC is activated before the balancing market auctions are cleared and before the day-ahead market closes, which means that the BRP-schedules can be adjusted and there is no need for a counter-action in the opposite direction. Then

the choice to activate CSCs is based on the congestion forecast of the system operator and follows the contractual agreements. The CSCs are registered and activated through Grid Operators Platform for Congestion Solutions Dutch congestion management platform GOPACS.

These CSCs can be concluded with a single asset or market participant or with an aggregated portfolio of assets. Participation takes place either directly by an active customer, or via representation by a CSP.

The Dutch system operators have jointly drafted a standard CSC contract (Partners in Energie, 2025), but the agreements made are bilateral by each system operator. It is possible for system operators to activate a CSC contracted by another system operator to solve their congestion problem via GOPACS. This provides system operators with access to vertical flexibility.

2. Through redispatch

After the day-ahead market is closed, system operators model whether the grid can facilitate all electricity flows. If these models indicate that some electricity cannot be delivered because components are congested, there is a need for redispatch.

Redispatch is used to solve problems identified in the intraday timeframe. These problems are partly due to the increased feed-in of renewable generation into the energy mix, and partly due to the trading volumes in the intraday domain. For the latter we see an increasing trend. As a consequence of the increase of renewables in market parties' portfolios, the likelihood of congestion arising within the intraday timeframe is increasing. The only way to make adjustments during intraday is through redispatch.

Redispatch always requires activation of an upward and downward bid of the same volume to avoid creating scheduled imbalances.

TenneT currently uses both the GOPACS and RESIN platforms to select redispatch bids in the day-ahead and intraday timeframes to resolve transmission and congestion issues. This leads to inefficiency, as bids intended to resolve transmission issues are spread across two systems. TenneT and the regional transmission system operators view GOPACS as the future central platform for congestion services. As a last resort, TenneT can also order redispatch via phone calls. DSOs only make use of the GOPACS platform for redispatch actions.

GOPACS is a foundation with 50% TenneT ownership and 50% DSO ownership. They operate a communication platform used by all system operators where they can do requests for redispatch. GOPACS collects information from various order books containing bids with geo-tags, and creates an optimal redispatch outcome. It is possible that system operators announce 1 hour before clearance that they will make a request, such that bids can be placed.

Redispatch can be offered both through parties that have contracts for bid obligations and through free bids.

In the current situation, in most cases, activation of CSC contracts is sufficient to avoid congestion and no other measures are needed in the intraday domain. Whilst contracting CSCs with market participants, the system operators also aim to have these market participants offer their flex intraday through redispatch.

In the future, with more flexibility being offered in both CSCs and in redispatch markets, activation would ideally be a mix of CSCs and redispatch. CSCs for the predictable congestion, and redispatch for the congestion arising in the intraday domain.

All market-based redispatch actions are executed via a CSP. BRPs and suppliers are or will always be informed by the system operator when their active customers are activated via GOPACS, both for CSC and for redispatch actions. Their schedules are corrected with the redispatched volume. There is no

interaction between the BRPs, CSPs and the suppliers. Redispatch can be offered both through parties that have contracts for bid obligations and through free bids.

In theory, the minimum period for CSC or redispatch activation is 15 minutes, but usually a line is congested for multiple hours (or more), and therefore the request is also for multiple hours. The latest time for redispatch requests is 45 minutes before delivery.

Ideally, congestion management is on a voluntary basis. However, in some cases, system operators can make congestion management mandatory. In areas without grid congestion, this can only be required from grid user with a grid connection larger than 60 MW. In areas with grid congestion, this can be required from grid users with a grid connection larger than 1 MW. The system operator then decides which type of contract (CSC or redispatch bid obligation) is most suitable for the situation.

System operators can, in theory, require parties to offer congestion management, for solving physical congestion, resulting in capacity steering or non-market based redispatch (see system code electricity 2026, §9.2.2.). The connectee gets a cost-based compensation. This mandate has historically never been put into practice, meaning that all congestion management today is market-based.

The prequalification process for a CSP is limited, but in order for controllable units to be activated, TenneT requires physical prequalification tests to ensure the connections can respond properly.

5.3.2. Congestion management compared to grid expansion

Congestion management, especially CSCs, can be effective non-wire measures to reduce the waiting list, and allow grid connections that would not have been made possible with only firm contracts. A good example is from Zeeland in November 2025 (TenneT, 2025), where Air Liquide transformed its firm contract into various flexible contracts, which reduced the waiting list for the new grid connections by 87%.

By Dutch law (see Energieregeling article 3) system operators have to publish an investment plan, containing a prohibitive barrier analysis, planned investments, and planned procurement of congestion and system operation services to prevent or bridge investments. In most cases, congestion management should not be considered as a non-wire alternative to grid expansion, but as a non-wire remedial action to optimize the grid in constrained periods. Usually, grid expansion is the cheaper option, but it is not always possible within the desired time horizon.

To incentivize grid users to utilize the grid better, system operators have introduced time-dependent grid fees. They are already applicable for large-scale consumers at the TenneT grid and are expected to become applicable for large-scale users on the distribution grid from 2028 onwards for small-scale consumers in 2029[27].

5.3.3. Barriers in congestion management

Most congestion management products are relatively new, as well as the need for this amount of congestion services. GOPACS estimates that multiple gigawatts of flexible assets is not yet active in providing congestion services. An indicator that there are indeed entry barriers is that nearly all congestion management contracts are concluded through proactive initiatives by system operators rather than through services offered proactively by market participants.

Improving congestion management is a top priority of the system operators, with frequent developments. For example, CSC standard contracts were updated in Q2 2026 (Partners in Energie, 2025). Until recently, CSC contracts included liability provisions with penalties that are perceived by market parties as extremely high, notably because these penalties are not capped. This created a

[27] *Both are under review at the ACM. See the proposals for large-scale consumers on the distribution grid and for small-scale consumers*

significant risk for flexibility providers, especially in contracts where only limited amounts of flexibility are unlocked. In the revised standardized contract, the penalty regime is substantially relaxed.

The barriers for an efficient market are both for the system operators and the parties that (can) offer congestion services. The prohibitive barriers and the most prominent hurdles identified for participation in congestion management markets and mechanisms are outlined below.

The financial compensation for CSCs and redispatch is too uncertain (hurdle)

Congestion management contracts (CSC and redispatch with bid obligation) come on top of a connection agreement. Most parties getting one do so to facilitate their electrical growth or expansion. For most parties, the financial incentive is thus secondary to the growth incentive. However, congestion management contracts are also offered to grid users without growth or expansion plans. Closing congestion management contracts with these parties is much more difficult, and driven by financial incentives.

It is uncertain when and how frequently the CSCs will be activated or redispatch will be requested. Part of the reason is that CSCs and redispatch bid obligation contracts are concluded both in regions with physical and in regions with administrative congestion. In areas with only administrative congestion, congestion management activation is not needed yet, but will probably be in the future. This makes it difficult to make a business case estimation for their income streams from congestion management, and greatly limits parties offering congestion management. These challenges result in high price markups for activation, or not participating in congestion management, especially when participation requires investments: as participation in congestion management requires some IT investments, it is observed that the income uncertainty is a hurdle for making these investments, as parties don’t know if they can earn them back.

These uncertain income streams are both hurdles for the parties offering their controllable assets, as well as for CSPs that need to make investments in order to offer their services.

Currently, system operators publish their redispatch requests on GOPACS even when it is known that no flexibility is being offered in the area. The purpose of this is to attract market participation. Next to that, historical and forecasted data for congestion is being prepared by the system operators, allowing models to be trained, helping with business case analyses.

Also in the Flevoland-Gelderland-Utrecht (FGU) region, this hurdle is addressed by offering by CSPs an attractive fixed fee for a four-year period.

Risk exposure for BRPs in the CSP - BRP - supplier information exchange (prohibitive barrier)

A key barrier in the use of flexibility for congestion management lies in the interaction between independent CSPs and BRPs. BRPs carry responsibility for portfolio balance and therefore face a significant risk when third parties activate flexibility without their control or timely knowledge, as uncoordinated actions lead to unanticipated imbalances and negative financial exposure for the BRP. Also suppliers can experience an impact on their purchase portfolios. The risk is that CSPs are hesitant in offering flexibility, as there the potential risks of communication mistakes are too high, also making it difficult or impossible for (potential) assets that can deliver flexibility to find a CSP.

For connection larger than 1 MW, this information exchange has already been implemented. For connections smaller than 1 MW, national agreements on information exchange are made, but they have not yet been planned nor implemented. More information can be found at Energiedatawijzer (Energiedatawijzer, 2026).

Unlocking capacities smaller than 1 MW in CSCs and redispatch currently not possible (prohibitive barrier)

From a system operator perspective, it is necessary that all active customers can participate in congestion management services. Currently, only connections larger than 1 MW can offer their flexibility for congestion management. System operators are working on facilitating the market such that all active customers will be able to offer their flexibility via a CSP, for Group-CSCs and redispatch through aggregation.[28]

Also for this topic, agreements have been made but there is not yet a planning for implementation (Energiedatawijzer, 2026). For winter 2026, a first version of group-CSC is foreseen for the Province of Utrecht (Partners in Energie, 2026)

The minimum size for activated congestion management is 100 kW.

Restrictions for participation in congestion management in PPAs and supplier contracts (hurdle)

In the market, there are restrictive clauses in Power Purchase Agreements (PPAs) and supplier contracts, where flexibility may explicitly not be used by parties other than the BRP or affiliated supplier.

At the same time, parties are required to make flexibility available under regulatory obligations, creating a complex situation where contractual arrangements (PPAs and supplier contracts) and grid codes do not always align.

There is currently a lack of effective incentives and enforcement mechanisms to ensure active contribution to congestion management. While flexibility could in principle be made available, market parties may prioritize established revenue streams under PPAs or supplier contracts, and face additional transaction costs and operational complexity when participating in congestion management. Without clear economic incentives or enforced obligations, there is limited motivation for these parties to proactively offer flexibility to system operators.

Mismatch between CSC product requirements and needs (hurdle)

Current CSC contracts are largely sector-wide standardized agreements, applied uniformly across all system operators. While this ensures consistency, the contract design offers limited adjustability, particularly in how prices are set: market parties are required to submit a fixed price per MWh for long contract durations (up to ten years), meaning that all operational and market risks must be priced in advance.

This approach works reasonably well for predictable assets such as wind and solar, but poses a major barrier for more flexible assets like batteries. These assets depend on dynamic market conditions and uncertain activation moments, making long-term fixed pricing extremely difficult.

A solution that is being worked on is moving away from a fixed pricing mechanism towards a daily ex-ante mechanism where the price is not fixed upfront, but is instead determined at the moment a congestion action is actually activated.

Legal entities that cannot yet participate in the congestion market (prohibitive barrier)

Individual large connections (>1 MW) are able to participate in congestion management for redispatch and CSC. However, closed distribution systems (CDS) and Multiple suppliers at a single connection

[28] *See Energiedatawijzer on Aggregation*

(MLOEA) can only participate when they act as a single customer, but not as the individual parties behind the grid connection. A solution is under development.[29]

5.4. Wholesale electricity markets

The Dutch electricity market is a liberalized and mature market in which electricity is freely traded between buyers and sellers, either bilaterally or through organized exchanges. System operators in the Netherlands do not participate in wholesale electricity trading.

Balancing and congestion management services, which are discussed in the previous paragraphs, exist to ensure system balance and operational security. These services are organized by the TSO or DSO and involve a single buyer (the system operator or a subsidiary), which makes them fundamentally different from wholesale electricity markets.

Overall, the Dutch electricity markets can be characterized as mature and well-functioning. Legal prequalification criteria for market participants are limited, and there is a clear legal framework for participation. Barriers lie mainly in the interaction between market actors, and the organization of structures in which electricity is shared, but they are not prohibitive barriers or severe hurdles for market participation. Therefore, this chapter has no section dedicated to barriers, but rather highlights challenges that market participants face in their operations related to the wholesale electricity market. For that reason, this chapter focuses on the description of the wholesale electricity market and its specific roles, including local electricity use optimization.

5.4.1. About wholesale electricity markets

The Dutch wholesale electricity market is operated by several designated Nominated Electricity Market Operators (NEMOs) such as EPEX SPOT, Nord Pool, EXAA and ETPA. Within this wholesale environment, participation is open to entities registered as market participants, subject to legal, technical and financial requirements:

All electricity trading that leads to physical delivery must be covered by balance responsibility. The BRP is the only entity that has access to the wholesale market platforms, but there are multiple BRPs that provide a service to their clients where they can themselves ‘trade’ through the BRP on these wholesale markets, meaning that the BRP provides a platform where the clients can sell or buy electricity, and the BRP executes this action for them. In that case, the BRP is the interface to the wholesale markets. Most electricity suppliers, aggregators, or large producers are either a BRP themselves or contract a BRP to carry balance responsibility for their positions.

Households or energy communities that participate in day-ahead or intraday markets typically do so via their supplier or an aggregator. These households don’t do trading but have a contract that states their measured consumption is billed on the day-ahead price. Due to such a contract, they can utilize demand-side response or electricity infeed from their own generation or batteries.

Market participants can trade across multiple time horizons, from long-term forward contracts to products traded close to real-time, and can include ex-post settlement after delivery. Product design is flexible, particularly in bilateral markets, but standardized products apply in organized day-ahead and intraday markets, which are jointly called the spot market. In the day-ahead market, the market clears at 12:00 PM, with a European pay-as-cleared price formation. The day-ahead price is usually referred to as the electricity price, and is different in European countries if interconnector capacity is congested.

[29] A solution is not very straightforward: if individual parties with a shared connection in a CDS or MLOEA could participate in congestion management, the effectiveness would be limited. This is because other parties connected to the connection point can still freely utilize the unrestricted available capacity on the connection point.

The intraday market also has a European clearing with different intraday markets. There are various clearances at set times, with price formation based on marginal cost pricing. There is also a continuously cleared market with price formation based on pay-as-bid. In the spot markets, bid sizes are typically at least 0.1 MW, and trading intervals correspond to the imbalance settlement period of 15 minutes.

Assets participating in wholesale electricity trading do not require asset-level prequalification; operating under a BRP and having a valid connection agreement with the system operator are sufficient. Consumers are free to choose their energy supplier and may select suppliers offering different contract types, including dynamic electricity pricing. These dynamic contracts are a requisite for demand side response. Publicly available data on the distribution of consumers across contract types is limited.

Zoom in: Suppliers

Energy suppliers sit at the commercial interface with end-users. They contract with households and businesses, invoice them and manage retail price arrangements. To participate in the market, a supplier must be registered and must be connected to a BRP, which assumes balancing responsibility for the supplier's portfolio. Many smaller suppliers do not require a license from ACM; a license becomes mandatory only when supplying more than 500 small consumers. All suppliers, however, must complete a market-role qualification with Energy Data Services Netherlands (EDSN) to ensure they can exchange metering and allocation data correctly.

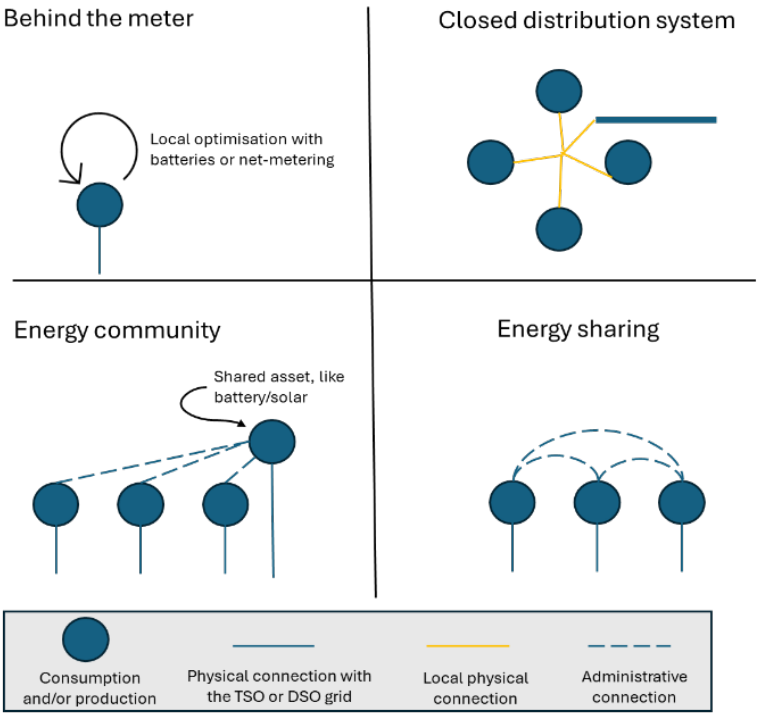
One of the most significant challenges for new suppliers is the need to secure a contract with a BRP, without which a supplier cannot enter the market. These contracts are commercially negotiated, unregulated and often strict, because BRPs assume financial exposure for any imbalance caused by the supplier's customers. This economic risk can result in high contract prices for the supplier. Under the Energy Act 2026, BRPs may in principle terminate a contract with a supplier, reducing the risk for a BRP. If a supplier is unable to find a BRP willing to contract them under the desired conditions, a supplier can become a BRP themselves.

Once active, suppliers must also manage the implications of regulatory schemes such as net-metering. Until 31 December 2026, suppliers remain obliged to settle excess household solar production through net-metering arrangements. Once net-metering is phased out, households will require separate contractual arrangements for selling surplus electricity. Some suppliers already provide dynamic tariffs that allow customers to respond to real-time price signals or to sell surplus generation.

5.4.2. Local electricity use optimization

Within the Dutch electricity market, there are several possibilities for market participants to optimize electricity use and production locally, thereby reducing the need for electricity to be transported over the public grid or administratively settled through wholesale markets. These forms of optimization take place either behind the meter, or through specific legal arrangements that modify how electricity flows and transactions are organized, displayed in the figure below, and elaborated in more detail in Figure 49.

Figure 49 | Different options for local electricity use optimization



Behind the meter

All producers and consumers are free to optimize electricity management behind the meter. This includes, for example, the installation of batteries, smart energy management systems, electric vehicles, or demand-side response solutions. Behind-the-meter optimization does not constitute market participation and therefore does not require registration as a market participant or coverage by a BRP, as long as no electricity is injected into or withdrawn from the public grid beyond the connection point.

A key limitation to behind-the-meter optimisation is the lack of interoperability between devices. Different manufacturers often use proprietary communication protocols and closed ecosystems, preventing flexible assets from being coordinated optimally. This limits the amount of flexibility that can be unlocked behind the meter (CE Delft, 2026).

Households that both produce and consume electricity are currently eligible for net-metering arrangements. Under net-metering, electricity fed into the grid is offset administratively against electricity withdrawn from the grid on a yearly basis. This mechanism reduces the need for households to actively trade electricity on wholesale markets. Net-metering will end on 1 January 2027, after which households will get financial incentives for better utilization of their own production.

Closed distribution systems

Within a closed distribution system, electricity distribution is organized on a private network with limited access to the public grid. CDSs can reduce grid charges and allow for greater internal optimization, but they require formal designation and approval and remain subject to specific regulatory obligations.

Energy communities

Energy communities provide a framework through which groups of consumers and producers can jointly manage generation, consumption and flexibility, as described in section 5.1.1.3. Energy communities may organize collective self-consumption and/or shared assets (such as communal batteries).

Energy sharing

Energy sharing arrangements allow electricity to be shared between multiple consumers or producers based on predefined allocation rules. Energy sharing typically remains an administrative construct layered on top of the existing grid structure, with electricity still physically flowing through the grid and subject to balancing responsibility at system level. A challenge for participants in energy sharing is that the administrative costs might be higher than the gains.

5.5. Summary of the identified barriers for participation of flexibility and potential mitigation measures

The goal of this Chapter 5 was to evaluate if the various electricity markets properly function for attracting and integrating assets that can provide upward or downward flexibility and, if this is not the case, identifying any causative barriers and potential solution directions. Table 19 summarizes the identified prohibitive barriers and severe hurdles on entry and participation for non-fossil energy resources identified in chapter 5. As explained in section 5.4, no significant barriers for flexibility were identified in the wholesale electricity markets.

According the FNA methodology (Article 15) (ACER, 2025), the evaluation of market barriers should consider indicators based on six categories. A reflection on the barriers in the context of these categories is provided in the sections below.

Table 19 | Summary of the identified hurdles and prohibitive barriers on entry and participation barriers for non-fossil energy resources in general, balancing markets and congestion management

Across markets (5.2.3)	
Description	**Solution direction / action**
Grid congestion delaying new or expanded grid connections, limiting new investments in assets that can offer flexibility	• Better grid utilization • Grid expansion • Alternative connection agreements
Business case uncertainty for large-scale renewables and batteries, limting new investments	• Articulation of expected developments • Eventually responsibility of the market
Assets lack of automation or compliance to other market requirements, excluding them from market participation	There are technical solutions, but often not economically viable.
Limited awareness, knowledge and trust among consumers	Not only focussing on financial incentives, but also on communication.
Balancing markets (5.3.2)	
TenneT IT Systems limiting the amount of assets that can be aggregated, effectively excluding DER from balancing markets	Updating TenneT IT information exchange channels
Existing procedures and requirements for market participation are relatively strict for DER	• Support on IT integration via Equigy • Adaptation of the network code on demand-side response for simplifying market participation and harmonizing it across Europe.
aFRR and mFRR cannot be delivered simultaneously at the same allocation point	Recognized, but no concrete solution plan
Strict sanctioning conditions applicable to FCR delivery, increasing risk exposure for BSPs	Temporarily relaxation of sanctioning conditions. Work is ongoing for a structural solution

mFRR availability incident reserve is only contracted at 24-hours, limiting participation of flexibility providers that can only offer capacity during specific hours	Intention to move towards shorter availability time blocks
Congestion management (5.4.2)	
The financial compensation for capacity steering contracts (CSCs) and redispatch is too uncertain	• More real time and historical data is being published, helping business case analyses • Predictable remunerations offered in some regions
Shortcomings in CSP – BRP - supplier information exchange can lead to high financial risk, limiting CSPs in willingness to offer flexibility for congestion management	National agreements on information exchange are made, but still need an implementation plan
Restrictions for participation in congestion management in PPAs and supplier contracts	Responsibility of the grid user. Possible solution is changing the contract
Mismatch between CSC product requirements and needs, e.g. with fixed multi-year remunerations not relevant for batteries	Moving away from a fixed pricing mechanism towards a daily ex-ante mechanism
Only connections larger than 1 MW can offer their flexibility for congestion management	System operators are working on facilitating the market such that all active customers will be able to offer their flexibility through aggregated solutions
Closed distribution systems (CDS) and Multiple suppliers at a single connection (MLOEA) can only participate when they act as a single customer, but not as the individual parties behind the grid connection	A solution is under development

5.5.1. Lack of proper legal framework for market access to new entrants and small actors

The legal framework for market access to new entrants is in place for participation in wholesale electricity markets, balancing markets and congestion management. Both for connection larger than 1 MW, and smaller connections offering their flexibility through aggregation. Barriers for participation relate mainly to market access for distributed energy resources. Because the introduction of aggregated flexibility from DER is relatively new, there are unfortunately some situations where it unattractive or impossible to offer their flexible capabilities:

- Balancing markets through aggregation. The legal framework is in place, but there are IT barriers for unlocking the assets. There are some restrictions for offering balancing services in complex constructions with multiple balancing providers behind a single allocation point. This is being worked on.
- Congestion management is legally possible through aggregation. Currently however, only connections larger than 1 MW can offer their flexibility for congestion management. System operators are working on facilitating the market such that all active customers will be able to offer their flexibility via a CSP, for Group-CSCs and redispatch through aggregation.
- Wholesale electricity markets through demand side response. All active customers can get contracts with variable prices, being able to respond to day ahead market prices. Next to that, various options for local energy optimization are possible, among which energy communities and energy storage behind-the-meter.

5.5.2. Lack of enablers and incentives to provide flexibility

Enablers: Smart meters are needed for participation in the electricity markets and operation services. The majority of households has a smart meter, and practically every large customer.

Incentives: Participation in wholesale electricity markets and balancing markets is mainly financially driven, and market data for markets is shared transparently. However, it is seen that households and commercial parties often have concerns about losing control, facing unexpected outcomes, or sharing data with third parties can reduce trust in flexibility services and limit participation. Increasing flexibility participation therefore requires not only financial incentives and market access, but also greater awareness, clearer consumer information, and confidence that flexibility can be provided without materially affecting comfort or convenience.

A large share of participants offering their flexibility for congestion management do so because it was a condition of their grid connections. System operators have a challenge in attracting more voluntary participation, with one of the reasons being that there is still too much uncertainty on the expected financial compensation.

5.5.3. Restrictive requirements to provide balancing services

Balancing services are procured in mature markets, and in theory all assets can participate; either directly or through aggregation. All services are fully market-based. The identified prohibitive barriers are technical, relating to IT-systems and monitoring. However, it is also recognized that there are conditions and market design choices that are experienced as hurdles in participation (see also Table 19): relatively strict participation requirements for DER, strict sanctioning conditions for FCR delivery, and availability for mFRR capacity too long for battery participation.

5.5.4. Restrictive requirements to provide congestion management

The contracts signed and products procured in congestion management are being improved whilst operational, for example through updated standard contracts for capacity steering contracts. All congestion management used is market-based, although for the D-2 solution, providers have bilateral congestion management contracts, and there are situations in which it is mandatory to participate in congestion management. As congestion management is evolving, there are still various hurdles and prohibitive barriers for participation, see Table 19.

5.5.5. Complex, lengthy, and discriminatory administrative requirements

Grid connection procedures are transparent, simple enough such that small users can make requests and grid connections are realised within reasonable time if not impacted by limitations through congestion or transport scarcity – which is a severe problem for many regions in the Netherlands. Also, there are no disproportionate procedures and requirements for participation in wholesale electricity markets.

5.5.6. Lack of regulatory incentives to system operators to consider non-wire alternatives.

System operators can procure flexibility services as an alternative for grid expansion, and are legally obliged to evaluate whether (foreseen) grid limitations can best be solved via expansion or procurement of services. Any costs made are eventually paid by the grid users, and therefore the system operator has the responsibility to solve grid limitations cost effectively whilst ensuring grid safety.

6. Conclusions

This report presents the results of the first Dutch Flexibility Needs Assessment (FNA), conducted in accordance with the methodology approved by ACER under the Electricity Regulation. The assessment evaluated the future flexibility needs of the Dutch electricity system for 2030 and 2035, covering system-wide flexibility needs, transmission network flexibility needs, distribution network flexibility needs, and barriers to the participation of flexibility resources.

This chapter present the high-level conclusions from the report and is structured as follows. Section 6.1 presents the main findings and key insights from the assessment. Section 6.2 discusses the main caveats and limitations of this first FNA and identifies areas for further methodological development in future editions. Lastly, section 6.3 outlines the next steps following publication of the FNA, including the relevant policy, regulatory and system-operator actions.

6.1. Key findings

System-level flexibility needs can be met with the assumed flexibility portfolio in the VVT scenario.

The market simulation results indicate that, for the analysed VVT scenario, the assumed portfolio of flexibility resources is sufficient to meet the identified system-level flexibility needs in 2030 and 2035. This includes managing hourly residual demand ramps, short-term flexibility needs, and achieving national RES integration targets. Under the assumptions of the VVT scenario, demand for electricity and installed capacity of RES in the Netherlands and abroad grow strongly through to 2035, significantly increasing the variability in the power system. This results in a wider range of residual load values, stronger hour-to-hour variations, and more frequent periods of surplus generation from RES, leading to higher flexibility needs than today. Despite this increase in variability, on a system level these needs may be covered by the additional flexible capacity deployed in the Netherlands (and abroad) including battery storage capacity (reaching 9 GW in 2030 and 16 GW in 2035), Power-to-X (reaching 6.5 GW in 2035), and interconnection capacity with neighbouring countries (reaching 12.6 GW by 2035). There are no uncovered needs at system level and even you include both system-level and network-related RES curtailment, the net RES generation remains sufficient to meet the national RES integration targets, resulting in no uncovered flexibility needs at system level.

Domestic flexibility resources assumed in the VVT scenario provide the primary contribution to meeting system-level flexibility needs.

The market simulation results indicate that domestic flexibility resources provide the primary contribution to managing additional short-term system variability. Although there are substantial cross-border exchanges in the VVT scenario, the analysis indicates that additional flexibility needs arising from forecast errors and generator constraints can largely be covered by domestic flexibility resources assumed in the scenario. Cross-border flexibility provides an additional safeguard but is not the main source of flexibility required to manage short-term system variations. This finding reflects the assumptions embedded in the assessed scenario and should not be interpreted as evidence that these flexibility resources will automatically become available in practice.

Grid analysis results indicate that, despite planned reinforcements, uncovered network-related flexibility needs are identified in both the TSO and DSO grids, with higher needs in the transmission grid.

Increasing load and deployment of RES puts additional strain on the grid, which cannot be fully addressed by the planned network reinforcements expected by 2035. Thus, when network constraints are taken into account, significant network-related flexibility needs emerge in both the TSO and DSO grids, in particular the 220–380 kV and 110–150 kV networks of TenneT. However, the volume of both TSO and DSO needs reduces in 2035 compared with 2030 as additional network reinforcement projects are brought online. Major investments (especially in the 220-380 kV grid) expected to be commissioned after 2035 are expected to bring the flex needs to even lower levels.

Transmission network flexibility needs are concentrated in a limited number of regions and are predominantly driven by structural transport constraints rather than system-wide flexibility shortages.

The identified needs are strongly location-dependent, with the largest needs occurring in the 220–380 kV grid and regions such as Zuid-Holland. These needs are typically characterised by high energy volumes and long durations, indicating that they are structural in nature and cannot be resolved through flexibility measures alone.

DSO network needs are generally smaller in magnitude and more locally concentrated, reflecting constraints at specific substations and feeders.

In contrast to TSO network needs, DSO needs for networks of 25kV and higher are typically less structural in nature, occurring during more limited periods and with lower volumes. As a result, they are generally more suitable for targeted flexibility solutions, such as demand-side response, local storage or other decentralised measures. Similar to the TSO needs, DSO-related needs decrease from 2030 to 2035 as a result of planned grid reinforcements. By 2035, DSO needs for networks of 25kV and higher are largely resolved, with only limited and local residual constraints remaining. While many identified DSO flexibility needs appear suitable for flexibility solutions, practical experience to date shows that the availability of upward flexibility remains limited in many areas. This implies that additional instruments such as capacity steering contracts (CSC) and redispatch will remain necessary to develop upward flexibility where needed.

The need for additional flexibility depends on the pace of electrification, RES deployment, and successful commissioning.

The flexibility needs identified in this assessment depend strongly on the underlying scenario assumptions. In particular, the level of electrification and renewable energy deployment determines the overall volume of flexibility required by the electricity system, while the deployment of flexibility resources determines the extent to which those needs are assessed as covered or uncovered. Under the VVT scenario, flexibility needs at system level can largely be met by the assumed portfolio of flexibility resources, which increases by approximately 15 GW between 2025 and 2035. However, this outcome is contingent on the successful deployment of batteries, demand-side flexibility, Power-to-X facilities, interconnection capacity and other flexibility resources. In addition, the Dutch electricity system increasingly relies on flexibility from neighbouring countries, meaning that developments outside the Netherlands also influence national flexibility needs. Deviations from these assumptions, whether due to changes in demand growth, renewable deployment, or the availability of flexibility resources, may result in different flexibility needs and a larger share of uncovered needs than identified in this assessment.

There's no one-size-fits-all solution to flexibility needs.

The results show that flexibility needs differ significantly across system levels, locations and timeframes. At system level, flexibility needs are primarily driven by temporal mismatches between demand and renewable generation, resulting in pronounced intraday and seasonal patterns. In contrast, network-related flexibility needs are highly location-specific and depend on local grid constraints, with distinct characteristics observed across the transmission and distribution networks. The concept of flexibility archetypes further illustrates that different types of congestion—such as structural transmission constraints, regional demand-driven shortages, or localised surplus generation—require different combinations of solutions, including grid reinforcement, demand response, storage, and redispatch. As a result, an effective approach to flexibility requires a coordinated portfolio of measures tailored to the specific characteristics of each need, rather than reliance on a single technology or policy instrument.

Additional policies may be needed to support flexibility if the scenario assumptions are not realised, or national objectives for non-fossil flexibility are not met.

The finding that system-level flexibility needs are largely covered should not be interpreted as evidence that sufficient flexibility will automatically be delivered by the market. The assessment of covered and uncovered flexibility needs is inherently linked to the flexibility portfolio assumed in the scenario. While the VVT scenario assumes substantial growth in batteries, demand-side flexibility, Power-to-X facilities and interconnection capacity, the realisation of these investments remains subject to uncertainties related to technology costs, market revenues, financing conditions and future regulatory frameworks. If flexibility resources are deployed more slowly than assumed, a larger share of the identified flexibility needs would become uncovered. Furthermore, the flexibility requirements identified in this FNA do not automatically determine the level of flexibility that may ultimately be targeted through a indicative national objective for non-fossil flexibility (see 6.3.1), which should take into account the findings of the FNA as well as broader policy considerations. In such circumstances, policymakers may consider whether existing market arrangements will provide sufficient investment incentives or whether additional measures, such as targeted support schemes for non-fossil flexibility or the planned Dutch capacity remuneration mechanism, could help ensure that the required flexibility resources are realised in a timely manner.

Nearly all assets that can provide flexibility have options to offer their services for balancing markets, congestion management and wholesale electricity markets

However, there are situations where there are barriers for unlocking the flexibility potential. The most important ones can be summarized as follows:

- **Barriers in unlocking potential from distributed energy resources (DER)**: The introduction of aggregated flexibility from DER is relatively new, creating situations where it is difficult, unattractive or impossible to offer their flexible capabilities, especially for balancing markets and congestion management. Next to that, limited awareness, knowledge and trust among consumers reduces participation of DER. System operators are working on updating IT-systems and adjusting participation requirements for balancing markets and congestion management.
- **Barriers in making new investments:** Areas with grid congestion or transport scarcity have put constraints on the amount of new grid connections. This can make it impossible to develop new assets that can offer their flexible capabilities. Next to that, participation in congestion management (which requires upfront investment costs) is held back by lack of insight in the expected financial compensation for offering the flexibility capabilities at certain locations.

- **High risk exposure by offering flexibility.** There are various examples:
  - For FCR, a balancing product, there are relatively strict sanctioning conditions
  - For DER, there are relatively high liability clauses for balancing services
  - For congestion management, there are significant financial risk when parties activate connections smaller than 1 MW without proper communication with involved market roles. Resulting in hesitation from congestion service providers (CSPs) in offering flex, making it difficult assets that can deliver flexibility to find a CSP.

6.2. Caveats and limitations

The findings presented in this edition of the FNA should be interpreted in light of several methodological limitations and simplifications.

- The system needs assessment depends on the flexibility resources assumed in the VVT scenario. The flexibility portfolio included in the scenario should not be interpreted as a forecast of future flexibility deployment. Rather, it represents a scenario assumption used to assess covered and uncovered flexibility needs. Consequently, the absence of uncovered flexibility needs should not be interpreted as evidence that the required flexibility resources will automatically become available in practice. **Uncertainty** remains regarding the **availability of generation assets** that could contribute to flexibility provision in **day-ahead markets**. In this edition of the FNA, this uncertainty is represented through the C1, C2 and C3 sensitivity cases, which illustrate the impact of different availability assumptions on the identified flexibility needs.
- Uncertainty remains regarding the availability of flexibility from neighbouring countries through **interconnectors**. The contribution of cross-border flexibility depends on market conditions, network availability and simultaneous flexibility needs in surrounding countries. As a result, the extent to which imported flexibility can be relied upon remains subject to uncertainty.
- The analysis does not explicitly consider a broad range of **forced outage combinations** for generation assets. Unlike adequacy assessments, which typically evaluate multiple outage draws and availability scenarios, the FNA focuses primarily on system flexibility requirements. Consequently, the impact of generator outages on flexibility needs is only partially reflected in the assessment.
- Some differences in **climate-year assumptions** were used across the assessments. The system needs assessment considers multiple climate years, whereas the TSO network needs assessment is based on a single climate year. In addition, the temporal alignment between the assessments is not fully consistent, as the TSO network needs assessment and the system needs assessment rely on future weather-year representations, while the DSO network needs assessment is based on a historical weather year. This consistency could be improved in the future.
- The integration between the system needs assessment and the network needs assessment is based on a sequential approach. Results from the system needs assessment are used as input to the TSO network needs assessment, but no iterative feedback between the two assessments is applied. As a result, interactions between system operation and network constraints may not be fully reflected in the results. A more **integrated assessment** approach would involve the simultaneous representation of electricity market dispatch, flexibility resources and network constraints within a single modelling framework, allowing interactions between system operation and network constraints to be captured endogenously.

- Although all assessments are based on nationally aligned scenario narratives, some **differences** remain in the detailed **input data**. For example, demand assumptions in the VVT scenario used in the network needs assessment are not fully identical to those applied in the used in the system needs assessment. While these differences may affect individual quantitative results, they are not expected to materially alter the overall conclusions of the assessment.
- Analysis is performed using an **hourly modelling resolution**. While this resolution is considered appropriate for the purposes of the FNA, future flexibility challenges may increasingly arise on shorter timescales and may therefore not be fully captured in the current assessment framework.
- The impact of **grid tariff regime changes** is not reflected in this assessment. Although tariff reforms may affect the consumption and production patterns of market participants, the final design and implementation of these changes remain uncertain. Consequently, their potential impact could not be assessed robustly and has therefore been excluded from the current FNA. This limitation is expected to be addressed in future FNA iterations as greater clarity on the tariff regime becomes available.
- Finally, the assessment does not explicitly quantify the impact of **flexible connection agreements** and similar contractual arrangements (such as CSCs) on network loading and congestion. Although these mechanisms may influence network utilisation, there is currently limited insight into how they will be applied and operated in practice. Consequently, their impact is not explicitly represented in the present assessment.

While the limitations described above are not expected to materially affect the overall conclusions of this assessment, they should be considered when interpreting the results. Future editions of the FNA may provide opportunities to further improve the consistency between assessment components, the representation of uncertainty, and the modelling of flexibility resources and operational constraints, subject to methodological developments and data availability.

6.3. Next steps

The Flexibility Needs Assessment is intended not only as an assessment of future flexibility needs, but also as an input to decision-making by policymakers, regulators, system operators and market participants. As this is the first Dutch FNA conducted under the revised Electricity Regulation, it should be regarded as the starting point of an iterative process that will be further developed and refined in future editions.

6.3.1. Next steps for policymakers and the FNA process

Under Articles 19f and 19g of the amended Electricity Regulation, the publication of the FNA is followed by several subsequent policy and regulatory steps. Based on the findings of this assessment, the main next steps are expected to include:

- **Establishment of an indicative national objective for non-fossil flexibility by the Dutch government,** within six months of submission of this report**.** This target should include the respective specific contributions of both demand side response and energy storage to that objective, which should also be reflected in future updates to integrated National Energy and Climate Plan.[30]

[30] *Provisional national objectives may also be adopted, until the FNA report is formally adopted.*

- **Consideration of measures to facilitate the deployment of flexibility**, including the removal of identified market barriers and, where appropriate, improvements to market design and regulatory frameworks.
- Where market-based investment is not expected to deliver sufficient non-fossil flexibility to achieve the indicative national objective, the introduction of **non-fossil flexibility support schemes** may be considered In addition, the design of the planned Dutch capacity remuneration mechanism could take into account how participation by non-fossil flexibility resources, such as demand-side response and energy storage, can be facilitated.
- **Submission of the Dutch FNA report to** ACER and the European Commission. After analysing the national FNA reports ACER shall issue its own report providing recommendations on issues of cross-border relevance.

Together, these steps will help determine the extent to which additional actions may be required to ensure that sufficient flexibility is available to support a reliable, affordable and decarbonised electricity system.

6.3.2. Next steps for grid operators

For TenneT and the Dutch DSOs, the results of this assessment provide additional insight into the type, location and timing of future flexibility needs. These insights may be used to further develop flexibility products, improve procurement strategies, support network planning processes and facilitate more efficient use of existing grid infrastructure. Based on the findings of this first FNA, the following areas are expected to receive (continued) attention:

- **Delivering network reinforcements in a timely manner, and accelerating grid expansion projects where feasible**, given that many identified transmission and distribution network flexibility needs are expected to reduce significantly once planned reinforcements are commissioned;
- **Making more effective use of existing grid capacity**, including the continued deployment and further development of congestion management mechanisms, flexible connection arrangements and other solutions that increase utilisation of existing infrastructure;
- **Further developing flexible connection products and market-based flexibility solutions**, building on recent initiatives such as time-dependent transport rights (TDTR);
- **Identifying and implementing additional measures to unlock unused network capacity,** in cooperation with regulators, policymakers and market participants, while ensuring system security and efficient network operation;
- **Addressing the identified barriers and hurdles to flexibility participation in the balancing, congestion management and wholesale electricity markets**, including market access requirements, digitalisation challenges and information exchange processes;
- **Supporting market transparency** by providing visibility on potential future flexibility needs, e.g. in future editions of the FNA;
- **Performing detailed analyses in IP2028 on congestion and transport constraints, expected to materialise up to 2040**, providing a more updated view on future bottlenecks and the role of flexibility in addressing them;
- **Considering how to promote the participation of non-fossil flexibility in the design of the planned Dutch capacity mechanism,** together with EZK and ACM; and
- **Further developing analytical methods for identifying and categorising flexibility needs** to address the limitations of this FNA (see section 6.2), which could be considered for future editions of the FNA.

Together, these activities can help ensure that flexibility is effectively integrated into future system operation and network development, while supporting the transition to a reliable, affordable and sustainable power system.

6.3.3. Next steps for market participants

The results of this FNA provide market participants with additional transparency regarding the expected evolution of flexibility needs in the Dutch electricity system. In particular, the assessment highlights the growing role of storage, demand response, interconnection and other flexibility resources in supporting system operation and facilitating renewable energy integration. At the same time, the analysis demonstrates that future flexibility needs, as well as the extent to which these needs are covered, remain dependent on the successful deployment of both renewable generation and flexibility resources. The findings can therefore be used by market participants and investors as one input into future investment and business development decisions.

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Glossary

The table below explains several technical terms mentioned in the report. Key terms related to flexibility and flexibility needs are also explained in detail in Table 2 at the start of the report.

Term (Abbreviation)	Definition
Balancing timeframe	The (very short) period after closure of the intraday market up until real time delivery during which system operators must activate reserves to maintain system balance and frequency.
Bidding Zone	A geographic area within which electricity can be traded without network constraints being explicitly represented in the market. Currently the Netherlands constitutes a single bidding zone.
Congestion	A situation in which the expected electric current flow through a physical power system asset would exceed operational limits.
Curtailment	Reduction of renewable generation due to system or network constraints.
Day-ahead timeframe	The period up until closure of the day-ahead market at 12:00 the day before delivery (D-1), during which electricity generation and consumption are scheduled based on day-ahead forecasts.
Demand-side response (DSR)	Adjustment of electricity consumption by end-users in response to price signals or system needs.
Delivery	The actual physical supply and consumption of electricity at the time it is produced and used, for a specific contractual time period.
Derating factor	Reduction applied to available flexibility capacity to reflect operational or grid limitations.
Dispatchable resources	Resources whose electricity output can be controlled and adjusted when needed (e.g. a thermal power plant or a battery).
Economic dispatch	A mathematical optimisation model (as described in Article 7 of the ERAA methodology) used to schedule the operation of generation, storage, and demand resources to meet electricity demand under technical and operational constraints at the lowest possible cost.
Economic Viability Assessment (EVA)	A modelling step applied with the ERAA (or NRAA) aiming to assess the economic viability of capacity resources and to inform potential decisions on retirement, mothballing, re-entry, renewal or prolongation, and new-build capacity.
Energy Not Served (ENS)	The (modelled) amount of electricity demand that cannot be met due to insufficient supply and/or flexibility.
Energy Not Transported (ENT)	The (modelled) amount of electricity that cannot be transported through the network due to congestion.
European Resource Adequacy Assessment (ERAA)	The pan-European resource adequacy assessment performed by ENTSO-E on an annual basis.
Flexibility	Flexibility provided by low-carbon technologies such as storage, demand response, and interconnection is referred to as non-fossil flexibility.
Forecast error	The difference between the forecasted and the actual value of electricity demand or generation for a given time period.

GOPACS	The coordination platform used by TenneT and the Dutch DSOs to alleviate grid congestion by activating bids from market parties
Interconnector	A transmission asset that connects electricity systems between different bidding zones (often countries), enabling cross-border electricity trade.
Intraday timeframe	The period between the closure of the day-ahead market (i.e. 12:00 the day before delivery) and the closure of the intraday market (5 min before delivery), during which market participants can revise their positions to account for updated forecasts and unplanned deviations in consumption and/or generation.
Load flow analysis	A calculation used to determine power flows, voltages, and loadings in an electricity network under given conditions. Load flow calculations are used to determine TSO and DSO flexibility needs.
Monitor Voorzien-ingszekerheid	The National Resource Adequacy Assessment for the Netherlands, performed annually by TenneT.
N-1	Refers to the security criterion that the power system must remain within operational limits after the unexpected loss of any single relevant network element, such as a line, transformer, generator, or interconnector.
National Energy and Climate Plan	A country's official plan submitted under EU regulation, outlining national targets, policies, and measures for energy and climate, including renewable energy deployment and emission reductions over a 10-year period. Used in the FNA as the reference for RES integration targets.
Non-dispatchable	Refers to resources whose output cannot be fully controlled or scheduled, as it depends on external conditions such as weather (e.g. solar and wind)
Overload	A condition where power flow on a network component (e.g. transformer, cable, line) exceeds its safe operating limit.
PLEXOS	The commercial market modelling software used by TenneT to perform economic dispatch simulations for the identification of system needs.
Power-to-X (P2X)	Technologies that convert electricity into other energy carriers (e.g. heat, gas/hydrogen). As these technologies consume electricity they typically provide downward flexibility.
Renewable Energy Sources (RES)	Renewable energy sources include wind, solar photovoltaic (PV), and hydro. Electricity generated from RES has no (direct) carbon emissions, unlike generation from fossil-based power plants.
Residual load	The total demand for electricity minus non-dispatchable generation, such as from wind and solar generation. Any unmet (positive) residual load must be covered by dispatchable flexible resources in the system.
RES target	The national policy target for the share of renewable energy sources (RES) in the electricity sector. This is typically defined by a country in its National Energy and Climate Plan (NECP).
Temporal resolution	The time granularity used when modelling the power system (e.g. hourly, 15-minute).

Abbreviation list

ACER	Agency for the Cooperation of Energy Regulators
ACM	Authority for Consumers and Markets (Autoriteit Consument & Markt)
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CSC	Capacity Steering Contract
CSP	Congestion Service Provider
DNDP	Distribution Network Development Plan
DSO	Distribution System Operator
EMDR	Electricity Market Design Reform
ENS	Energy Not Served
ENT	Energy Not Transported
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
EU	European Union
EVA	Economic Viability Assessment
FNA	Flexibility Needs Assessment
IP	Investment Plan
KGG	Ministry of Climate Policy and Green Growth (Klimaat en Groene Groei)
MVZ	Monitor Voorzieningszekerheid (Dutch NRAA)
MW	Megawatt
MWh	Megawatt-hour
NECP	National Energy and Climate Plan
NEMO	Nominated Electricity Market Operator
NRAA	National Resource Adequacy Assessment (i.e. the MVZ for the Netherlands)
P2X	Power-to-X, meaning power-to-heat or power-to-gas
PLEXOS	Electricity market simulation software developed by Energy Exemplar
PV	Photovoltaic (solar power generation)
RES	Renewable Energy Sources
RNB	Regionale Netbeheerder (Distribution System Operator)
TSO	Transmission System Operator
TWh	Terawatt-hour
TYNDP	Ten-Year Network Development Plan
VVT	Verkenning Vertraagde Transitie (Delayed Transition) scenario
WOZ	Wind op Zee (Offshore Wind)

ANNEX 1 – Detailed methodological approaches for the Economic Dispatch modelling

Methodology for synthesising day-ahead forecast errors for load and RES generation

As described in Section 2.3.1 (Model C), synthetic day-ahead forecast errors are used to assess short-term flexibility needs.

The starting point for the synthesis is historical day-ahead forecast error data for native load, solar PV, onshore wind and offshore wind. Forecast errors are defined as the difference between day-ahead forecasts and realised values. Historical forecast errors observed in 2024 and 2025 were obtained from the Market Data Platform of Montel EnAppSys (Montel, 2026). As these forecast errors are only available in absolute terms (MW), they must be scaled before they can be applied to future target years.

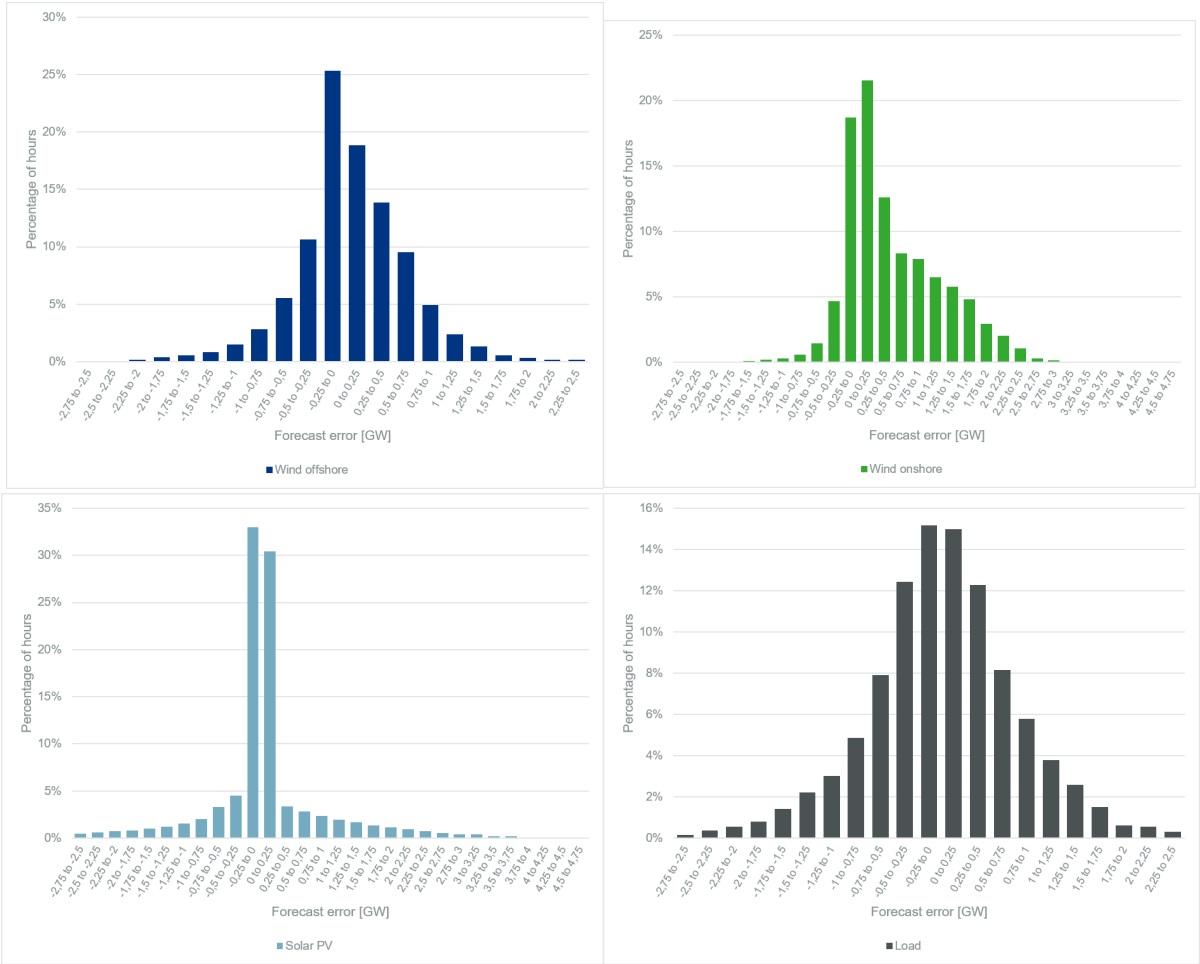
To realistically capture the temporal characteristics of forecast errors, these are statistically modelled using a Seasonal Auto Regressive Integrated Moving Average (SARIMA) approach. This method preserves key properties observed in historical forecast errors, including autocorrelation and recurring seasonal patterns (e.g. daily cycles), ensuring that simulated errors are time-correlated rather than independent random deviations.

Based on this modelling, synthetic forecast error time series are generated. These are expressed in relative terms, allowing them to be consistently scaled and applied to scenario-based time series for the target years. Forecast errors for wind and solar generation are scaled according to the installed capacities in the respective target years, while forecast errors for load are scaled based on total electricity demand. This implies that, while the relative magnitude of forecast errors is assumed to remain unchanged, absolute forecast errors increase in line with the growth in demand and installed generation capacities. No explicit assumptions are made regarding improvements in forecasting accuracy; historical forecast error characteristics are assumed to remain representative for the target years.

To ensure physical realism, the resulting time series are constrained within plausible ranges derived from the underlying scenario data, preventing implausible values such as negative generation or solar production in night-time hours.

The distribution of forecast errors, including extreme values, is captured through the statistical modelling approach. While explicit percentile metrics (e.g. 0.1 and 99.9 percentiles as mentioned in the Methodology, Article 10(1)) are not separately derived, the simulated time series reflect the full distribution of historically observed forecast errors.

Figure 50 | Historical day-ahead forecast error distributions for load, solar PV, onshore wind and offshore wind based on observations from 2024 and 2025. These distributions are used to calibrate the SARIMA models applied to generate synthetic forecast error time series.



ANNEX 2 - Differences with Congestion management reports

The network flexibility needs as reported in the Flexibility Needs Assessment reports differ from the needs as reported in the congestion management reports as published by the electricity system operators. This difference is caused by the different goals and assumptions of these studies. The main goal of a congestion management study is to determine how many customers can be connected in a specific region using measures such remedial actions and flexibility. The goal of the FNA is to determine a general figure of the national flexibility needs, where the network needs are also considered. The method for the FNA calculation has been prescribed by ACER and therefore differs from other studies like the IP2026 and congestion studies. These differences in methodology are the main reason why these results should not be compared to the congestion management studies.

- **Used scenarios:** The VVT-scenario has been developed to take into account the slower growth of renewables and demand as compared to the scenarios as used in the investment plan calculations. This VVT-scenario does not meet the climate goals. The VVT-scenario is also to be used as the basis for future congestion studies. Many of the earlier published congestion studies use the assumptions of the Koersvaste Middenweg (KM) scenario, which has a significantly higher growth.
- **Scenarios and customers:** The FNA uses the assumptions of the scenarios to determine the growth. These scenarios and the regionalization of these scenarios are based on customer requests and other studies. The congestion studies use more detailed analyses of the customer requests, do consider the effect of congestion (e.g. the connection queue) and can use different profiles for specific customers as compared to the scenarios.
- **Measurement years:** The profiles in the FNA as used by the DSOs are based on measurements from the previous year which are supplemented by the expected growth according to the scenarios. The measurements for the FNA have been taken from 2025, whereas most of the published congestion studies use measurements from 2024 or 2023.
- **Scenario and profiles:** For the TSO needs, the used profiles also differ compared to the congestion studies. In the congestion studies the profiles from the DSOs and measurements from TSO customers are used. Congestion studies are performed on a regional basis (e.g. one 150 kV region) and therefore do not have to take into account (inter)national balance. For the FNA this method cannot be used, because the profiles as used in the congestion studies will not result in a (inter)nationally balanced energy system and thus cannot be calculated.
- **Remedial actions:** In the congestion studies remedial actions are considered to increase the available capacity. This includes optimization of the grid using non-costly remedial actions such as changing the tap settings of phase shifting transformers or (temporarily) changing the grid configuration. Implementation of these measures take detailed studies, which are done in the congestion studies to enable connecting more customers. For the FNA these steps have not been performed.
- **Grid models:** For the FNA the most recent grid models have been used which take into account the planning of projects as described in the most recent IP. In the most recent IP a lot of projects have been delayed. Earlier published congestion studies will not have taken into account these project delays and will therefore use different grid situations.

ANNEX 3 – Results DSO network needs

Friesland

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Oosterwolde 110	110/20/10kV	Downward	2030	4.946	22	645	100	100% redispatch	PV hours, weekend and week
Rauwerd 110	110/10kV	Downward	2030	1.015	6	510	100	100% redispatch	PV hours, weekend and week
Wolvega 110	110/10kV	Downward	2035	1.987	17	328	100	100% redispatch	PV hours, weekend and week
Wolvega 110	110/10kV	Downward	2030	65	5	40	100	100% redispatch	PV hours, weekend and week

Groningen

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Groningen Heemskerkstraat	110/10kV	Upward	2030	18.895	31	1854		Redispatch & CSC	Winter, divers
Meeden	220/20kV	Downward	2030	5.583	39	383	100	100% redispatch	PV hours, week
Meeden	220/20kV	Upward	2030	13.859	71	1243		Redispatch & CSC	Divers

Vierverlaten 10	110/10kV	Upward	2030	10.012	30	889		Redispatch & CSC	Winter, morning and afternoon
Weiwerd	220/20kV	Downward	2030	43	12	11	100	100% redispatch	PV hours, weekend and week
Winschoten	110/10kV	Downward	2030	57	5	40	100	100% redispatch	PV hours, weekend and week

Drenthe

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Emmen Weerdinge	110/10kV	Downward	2030	9	4	6	100	100% redispatch	PV hours, weekend and week
Marsdijk	110/10kV	Upward	2030	1.689	13	807		Redispatch & CSC	Winter, afternoon and evening
Veenoord	110/10kV	Downward	2030	31.990	29	2028	100	100% redispatch	PV hours, weekend and week

Overijssel

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Zwolle Hessenweg	110/10kV	Upward	2030	6.657	38	534		Redispatch & CSC	Winter, morning and afternoon
Zwolle Weteringkade	110/10kV	Upward	2030	5	2	7		Redispatch & CSC	Winter, morning and evening

Flevoland

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Almere de Vaart 010	150/10kV	Downward	2030	6	3	7	100	100% redispatch	PV hours, weekend

Gelderland

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Arnhem 150	150/10kV	Upward	2035	98	6	41		Redispatch & CSC	Winter evening
Borculo 150	150/20kV	Downward	2035	9.293	49	692	100	100% redispatch	PV hours, weekend and week
Borculo 150	150/20kV	Downward	2030	3.428	37	347	100	100% redispatch	PV hours, weekend and week
Dale 010	150/10kV	Downward	2030	4.176	24	533	100	100% redispatch	PV hours, weekend and week
Dodewaard 150	150/50/10kV	Downward	2035	166	15	34	100	100% redispatch	PV hours, weekend
Dodewaard 150	150/50/10kV	Downward	2030	15	3	6	100	100% redispatch	PV hours, weekend

Nijmegen 150	150/50kV	Upward	2030	166	7	65		Redispatch & CSC	Winter, afternoon and evening
Nijmegen 150	150/50kV	Upward	2035	371	10	116		Redispatch & CSC	Winter, divers
Tiel 150	150/50/20/10 kV	Downward	2030	2.101	25	317	100	100% redispatch	PV hours, weekend
Zaltbommel 150	150/20/10kV	Upward	2035	2.940	22	379		Redispatch & CSC	Winter morning
Zaltbommel 150	150/20/10kV	Upward	2030	125	9	62		Redispatch & CSC	Winter morning

Utrecht

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Breukelen	150/10kV	Upward	2030	5	2	10		Redispatch & CSC	Winter evening and night
Bunschoten	150/10kV	Upward	2030	7	1	19		Redispatch & CSC	Winter evening
Bunschoten	150/10kV	Upward	2035	5.182	16	922		Redispatch & CSC	Winter evening and night
Nieuwegein	150/21/10kV	Downward	2030	38	8	12	100	100% redispatch	PV hours, week
Nieuwegein	150/21/10kV	Downward	2035	67	10	18	100	100% redispatch	PV hours, week
Nieuwegein	150/21/10kV	Upward	2030	50	5	28		Redispatch & CSC	Winter evening
Nieuwegein	150/21/10kV	Upward	2035	2.794	15	573		Redispatch & CSC	Winter evening and night

Soest 2	150/10kV	Upward	2030	5	2	9		Redispatch & CSC	Winter evening
Utrecht Merwedeknl.	150/10kV	Upward	2030	132	4	99		Redispatch & CSC	Winter evening

Noord-Brabant

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Aarle Rixtel	150/10kV	Downward	2030	644	21	84	100	100% redispatch	PV hours, weekend and week
Aarle Rixtel	150/10kV	Upward	2030	870	17	307		Redispatch & CSC	Winter, afternoon and evening
Bergen op Zoom	150/10kV	Upward	2030	3.167	19	543		Redispatch & CSC	Winter, divers
Biesbosch	150/10kV	Upward	2030	7	1	16		Redispatch & CSC	Winter, morning and evening
Boxtel	150/10kV	Upward	2030	23.976	38	2036		Redispatch & CSC	Winter, divers
Cuijk	150/10kV	Upward	2030	53	5	38		Redispatch & CSC	Winter, morning and afternoon
Eindhoven Oost	150/10kV	Upward	2030	777	18	255		Redispatch & CSC	Winter, afternoon and evening
Eindhoven West	150/10kV	Upward	2030	26.912	43	1788		Redispatch & CSC	Winter, divers
Geertruidenberg	150/10kV	Upward	2030	775	21	249		Redispatch & CSC	Winter, morning and afternoon
Groningen Heemskerkstraat	110/10kV	Upward	2030	18.895	31	1854		Redispatch & CSC	Winter, divers

Helmond Oost	150/10kV	Downward	2030	1	2	1	100	100% redispatch	PV hours, weekend and week
Helmond Oost	150/10kV	Upward	2030	1	2	1		Redispatch & CSC	Winter, divers
Oosteind	150/10kV	Upward	2030	1.538	13	349		Redispatch & CSC	Winter, morning and afternoon
Oss	150/10kV	Upward	2030	2.396	22	499		Redispatch & CSC	Winter, afternoon and evening
Princenhage	150/10kV	Upward	2030	291	8	117		Redispatch & CSC	Winter, afternoon and evening
s Hertogenbosch West	150/10kV	Upward	2030	876	14	198		Redispatch & CSC	Winter, afternoon and evening
Uden	150/10kV	Downward	2030	947	30	169	100	100% redispatch	PV hours, weekend and week
Uden	150/10kV	Upward	2030	4.482	30	781		Redispatch & CSC	Winter, divers
Waalwijk	150/10kV	Downward	2030	107	15	29	100	100% redispatch	PV hours, weekend and week
Waalwijk	150/10kV	Upward	2030	4.075	32	762		Redispatch & CSC	Winter, divers

Limburg

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Belfeld	150/10kV	Upward	2030	1.381	12	366		Redispatch & CSC	Winter, divers
Horst	150/10kV	Upward	2030	162	10	64		Redispatch & CSC	Winter, afternoon

Kelpen	150/10kV	Downward	2030	19	3	19	100	100% redispatch	PV hours, weekend and week
Maasbracht	150/10kV	Upward	2030	2.670	20	527		Redispatch & CSC	Winter, afternoon and evening
Venray	150/10kV	Downward	2035	2.160	56	144	100	100% redispatch	PV hours, weekend and week
Weertheide	150/10kV	Upward	2030	875	10	316		Redispatch & CSC	Winter, morning and afternoon

Noord-Holland

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Amsterdam Hemweg 150	150/50kV	Upward	2030	1.563	10	476		Redispatch & CSC	Winter evening
Haarlemmermeer 150	150/50/20/10 kV	Upward	2030	284	19	42		Redispatch & CSC	Winter morning
Middenmeer 150	150/20kV	Downward	2035	2.472	29	221	100	100% redispatch	PV hours, weekend and week
Middenmeer 150	150/20kV	Downward	2030	1.686	25	193	100	100% redispatch	PV hours, weekend and week
Oterleek 150	150/50/10kV	Downward	2030	9.514	49	666	100	100% redispatch	PV hours, weekend
Velsen 150	150/50kV	Upward	2030	331	10	149		Redispatch & CSC	Winter evening
Vijfhuizen 150	150/50/20kV	Upward	2030	4	1	5		Redispatch & CSC	Winter morning

Vijfhuizen 150	150/50/20kV	Upward	2035	102	17	350		Redispatch & CSC	Winter evening

Zuid-Holland

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Delft 1	150/10kV	Upward	2030	1.234	7	686		Redispatch & CSC	Winter evening and night
Delft 1	150/10kV	Upward	2035	5.508	25	1655		Redispatch & CSC	Winter evening and night
Europoort	150/10kV	Upward	2035	80	5	48		Redispatch & CSC	Winter night
Franklinstraat	150/25/10kV	Upward	2030	0	0	1		Redispatch & CSC	Winter evening
Franklinstraat	150/25/10kV	Upward	2035	721	8	367		Redispatch & CSC	Winter evening and night
Geervliet 1	150/10kV	Upward	2030	3.066	18	544		Redispatch & CSC	Winter evening
Gouda Ijsseldijk	150kV	Upward	2030	8	3	7		Redispatch & CSC	Winter evening
HVS Ypenburg	150/10kV	Downward	2030	4	2	3	100	100% redispatch	PV hours, weekend and week
HVS Ypenburg	150/10kV	Upward	2030	202	7	120		Redispatch & CSC	Winter evening and night
HVS Ypenburg	150/10kV	Upward	2035	10	1	36		Redispatch & CSC	Winter evening and night
HVS Zuid	150/23/10kV	Upward	2030	43	4	39		Redispatch & CSC	Winter evening

HVS Zuid	150/23/10kV	Upward	2035	166	4	166		Redispatch & CSC	Winter evening
Langeland Noord	150/13kV	Upward	2035	19	2	30		Redispatch & CSC	Winter evening
Merwedehaven	150/50kV	Upward	2030	308	8	118		Redispatch & CSC	Winter evening
Middelharnis	150/13kV	Upward	2035	1	1	1		Redispatch & CSC	Winter night
Ommoord	150/25/10kV	Upward	2035	15	2	27		Redispatch & CSC	Winter evening
Ommoord	150/25/10kV	Upward	2030	2.304	15	537		Redispatch & CSC	Winter evening and night
Oudeland	150/10kV	Upward	2035	3	1	7		Redispatch & CSC	Winter evening
Rotterdam Centrum	150/23kV	Upward	2035	0	0	1		Redispatch & CSC	Winter evening
Sterrenburg	150/50/13kV	Downward	2030	93	10	28	100	100% redispatch	PV hours, weekend
Sterrenburg	150/50/13kV	Downward	2035	81	10	22	100	100% redispatch	PV hours, weekend
Sterrenburg	150/50/13kV	Upward	2030	461	17	90		Redispatch & CSC	Winter evening
Sterrenburg	150/50/13kV	Upward	2035	1.916	16	429		Redispatch & CSC	Winter evening and night
Waalhaven	150/23/10kV	Upward	2035	2	0	6		Redispatch & CSC	Winter evening and night
Zoetermeer 9	150/10kV	Upward	2035	1	1	2		Redispatch & CSC	Winter night
Westerlee	150/25kV	Upward	2035	19.465	99	698		Redispatch & CRC	Winter night

Zeeland

Station	Voltage	Direction	Year	Flex need (MWh)	Congestion peak (MW)	Hours per year	% Downward flex need due to RES curtailment	Contract	Typical timeframe
Goes de Poel	150/50/10kV	Downward	2030	9.220	31	1009	100	100% redispatch	PV hours, weekend and week
Goes de Poel	150/50/10kV	Upward	2030	8.308	27	1573		Redispatch & CSC	Winter, divers
Rilland	150/21/10kV	Downward	2035	0	0	1	100	100% redispatch	Conpanies end wind, weekend
Rilland	150/21/10kV	Downward	2030	6.208	72	426	100	100% redispatch	PV hours, weekend and week
Westdorpe	150/10kV	Upward	2030	1.701	10	417		Redispatch & CSC	Winter evening and night