TYNDP // 2026

Version // June 2026

Scenarios Methodology Report

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TYNDP // 2026

Scenarios Methodology Report

CONTENTS //

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1 INTRODUCTION //

1.1 How to read this document

The TYNDP 2026 Scenarios Methodology Report sets out the key principles and processes underlying scenario development and describes the methodologies applied in scenario development. The document is structured as a step by step description of the scenario building process. It starts by outlining the guiding principles, definitions and governance agreements that frame the methodological choices. It then explains how scenario inputs are collected and processed through an integrated modelling toolchain, before detailing the methodologies applied for demand, supply, grids and weather representation. Finally, it presents the specific approaches used for gap filling, economic variants and sensitivity analyses.

The purpose of this report is to provide transparency on how those results are derived, and not to interpret scenario findings. It enables the reader to understand the modelling scope and assumptions, assess the internal consistency of the approach, and interpret scenario outputs presented in the TYNDP Scenario Report and associated visualisation tools.

1.2 Key definitions used throughout the report

To support clarity and consistency, the following key terms are used throughout this report:

National Trends (NT)

The term NT reflects the aggregation of national inputs submitted by electricity and gas Transmission System Operators (TSOs), based primarily on National Energy and Climate Plans (NECPs) and other official national strategies available at the time of data collection (cut-off date: December 2024).

National Trends+ (NT+) – Central Scenario

The term NT+ or Central Scenario constitutes the Central TYNDP 2026 Scenario. It is derived from the NT dataset through the application of a dedicated gap filling methodology to ensure consistency with selected EU level targets, while preserving national differentiation . NT+ is the baseline for all target year analyses (i.e. 2030/2035/2040/2050). In the reports the terms NT+ scenario and Central scenario are used as synonyms.

Economic Variants: High and Low Economic Variants (HEV/LEV)

In addition to the Central Scenario, the TYNDP 2026 framework includes two economic variants (High Economic Variant/HEV and Low Economic Variant/LEV) for target years 2035 and 2040. These variants are explicitly anchored to the NT data collection and are designed as stress tests, reflecting alternative macro economic growth assumptions. They do not represent alternative policy pathways.

Scenario Toolchain

The Scenario Toolchain refers to the sequence of modelling tools and data exchanges used to translate annual scenario inputs into hourly demand profiles, market simulation results, and aggregated supply indicators. The toolchain includes, among others, the Energy Transition Model (ETM), hourly demand profiling tools, the market simulation model and the Supply Tool.

Scenario Grid

The Scenario Grid is the network representation used exclusively for scenario modelling in TYNDP 2026. It defines the electricity and hydrogen transmission topology applied consistently across scenario and target years for market simulations (cf. Sec. 7, p. 39).

Weather Year

A Weather Year is a climate year selected to capture the impact of weather variability on demand and renewable generation. For each target year, a limited set of representative Weather Years (cf. Sec. 6, p. 38) is used instead of simulating the full range of possible climate outcomes.

Endogenous/Exogenous

Concepts endogenous and exogenous refer to origin of variables in modelling framework. Exogenous variables are given as inputs to the model and originating from external sources such as national climate and energy plans. Endogenous variables are determined within the model through optimisation or system interactions.

1.3 Core principles and assumptions guiding the methodological development

The methodology for developing the TYNDP 2026 central scenario and variants is grounded in alignment with the latest national and EU energy and climate policies, including the TEN-E Regulation, the ACER Framework Guidelines for the TYNDP scenarios and NECPs. It relies on data collected from electricity and gas TSOs.

The Ten-Year Network Development Plan has hence developed into a future-proofing lookout to a carbon-neutral Europe by 2050. The TYNDP Scenario Report therefore encompasses the short-term (2030) to the very long-term (2050).

Scenario development follows a structured and sequential process. TSOs initially submit data reflecting their national policies as set out in NECPs and mostly validated at national level, forming the National Trends (NT) dataset. These inputs are subsequently assessed against aggregated European objectives. Where gaps are identified, a dedicated gap-filling methodology is applied to derive the National Trends+ (NT+) scenario.

To support transparency and accountability, scenario inputs, methodological choices and key assumptions are subject to stakeholder engagement, including bilateral exchanges, public consultation and the Stakeholder Reference Group (SRG).

In addition to the Central Scenario (NT+), the TYNDP 2026 framework includes two Economic Variants reflecting higher and lower economic growth assumptions (HEV and LEV). These variants are modelled symmetrically, are explicitly anchored to the Central Scenario and therefore act as stress tests of the Central Scenario.

A detailed description of the TYNDP 2026 Scenario Framework and the associated stakeholder engagement process can be found in Chapters four, five and six of the TYNDP 2026 Scenario Report.

1.4 Governance and decision-making process for designing the methodology

This methodology report documents the outcome of a decision-making process within the Working Group Scenario Building (WGSB). This working group is a joint ENTSO-E and ENTSOG platform involving experts from both gas and electricity TSOs, The work carried out within the WGSB is informed by stakeholder input, including feedback obtained through public consultations, the SRG and bilateral exchanges. The work is validated by TSOs and, where possible, stakeholders.

The WGSB is structured into thematic sub-teams responsible for specific topics and modelling aspects. Methodological choices underpinning the TYNDP 2026 Scenarios were assessed and discussed within the relevant sub-teams before consolidation at the WGSB level. These choices were guided by the objective of ensuring model accuracy, while also accounting for practical constraints related to timelines, data availability, and computational requirements. The structure of the joint scenario building team is outlined below (Figure 1).

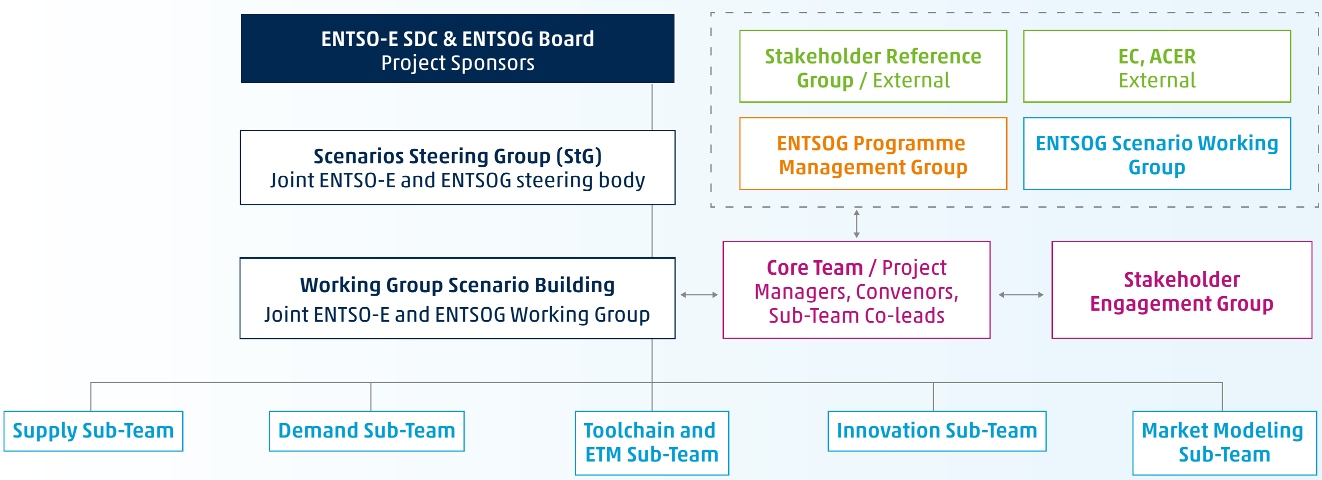


Figure 1: Decision making groups for the TYNDP 2026 scenario building and methodology definition

2 DATA COLLECTION //

The preparation of the TYNDP 2026 Scenario is supported by a coordinated joint data collection between ENTSO-E and ENTSOG, reflecting the increasing integration of Europe's energy system. This 2026 edition has also been organised as a single, joint effort between the Scenarios team and the ENTSO-E European Resource Adequacy Assessment (ERRA) team, recognising that both scenario building and adequacy assessment rely on the same national policy foundations.

The objective is to ensure the scenario datasets reflect the latest updated NECPs, complemented where needed by national planning and strategies, including those of non EU countries. A cut-off date of December 2024 applies, meaning only policies, plans and assumptions available before that date are used in the dataset.

As the modelling framework covers an increasingly wide set of interlinked energy sectors and carriers, the data collection brings together inputs spanning all components of the integrated system. These datasets are provided by electricity and gas TSOs, through coordinated submissions where sector interactions require alignment.

For this edition, the National Trends demand is quantified for the first time directly in the Energy Transition Model (ETM – for a description of the model, see section 3.2). Using ETM to construct a fully bottom-up scenario requires a substantially more detailed set of national inputs than most NECPs provide. Hence, the bottom-up design of scenarios is aligned to NECPs and national plans, while the bottom-up reconstruction of sector and application specific energy demand has been performed by the involved TSOs. This enhanced granularity strengthens transparency around the NT demand and supports a more robust assessment of the European Union's 2030 targets for energy and climate. The methodology for eliminating the gap between the targets and TSOs' input can be found in chapter 9, and the results can be found in section 9.1.2 of the main report.

In addition, the structured and comprehensive approach established for NT, in other words, the collection of national trends through the ETM, as a software deployed for this task, facilitates the development of the HEV and LEV variants, providing a coherent and traceable reference point from which the economic (stress-test) variants are built.

To support this integrated modelling framework, the data collection itself is structured in a way that reflects the multi-dimensional nature of the energy system. While the NT quantification relies on detailed national inputs across all energy carriers, the information required to populate the modelling tools is provided through a coordinated contribution from electricity and gas TSOs. Depending on the nature of each dataset and the level of interaction between sectors, some elements are submitted jointly and others individually. The following subsections describe the different categories of data collected for TYNDP 2026.

Joint TSO Data Collection/Synchronisation

Some items directly influence both the electricity and gas-hydrogen modelling layers and therefore require a single, aligned submission per country. These elements ensure a consistent representation of sector coupling, power-to-gas interactions and multi-vector demand (Table 1).

JOINT DATA ITEMS (ELECTRICITY + GAS TSOs)
Methane and hydrogen-fired power generation capacity
Electrolyser capacity and associated renewable generation (grid-connected, Shared RES, Dedicated RES)
TYNDP demand data (ETM)

Table 1: Joint data items

Electricity TSO Data Collection – Pan-European Market Modelling Data Base (PEMMDB)

Electricity TSOs provide the datasets required to characterise electricity supply and flexibility (Table 2):

ELECTRICITY TSO DATA
Renewable energy sources
Thermal unit capacity & must runs
Nuclear unit capacity & must runs
Battery capacities (prosumer & utility scale)
Demand-side response (capacity & activation price bands)
Electricity grid information
Grid losses

Table 2: Electricity TSO data collection

Gas TSO Data Collection

Gas TSOs provide all supply and infrastructure-related information for methane and hydrogen (Table 3):

GAS TSO DATA
Hydrogen grid information
Biomethane production potential
Hydrogen production capacity (Steam Methane Reforming (SMR), pyrolysis)
Share of SMR equipped with Carbon Capture and Storage (CCS)
CCS and Carbon Capture, Utilisation and Storage (CCUS) capacity
Domestic oil and natural gas production
Hydrogen infrastructure candidates for 2050 (storages & cross border capacity)
Import potentials for hydrogen and ammonia

Table 3: Gas TSO data collection

ADDITIONAL DATA ITEMS
District heating systems (municipal, industrial steam, agricultural heating)
Synthetic and biofuels (demand, supply, feedstock requirements)
Domestic ammonia production for shipping
Electricity demand of CCS facilities not connected to power plants (CCSnpp)

Table 4: Additional data items

TSO Survey on Electric Vehicle Charging and Flexibility

Additionally, passenger electric vehicle (EV) assumptions are based on a dedicated survey conducted among electricity TSOs (see section 4.2). The survey was designed to capture country-specific inputs where harmonised sources are not available, in particular regarding the share of passenger EVs with flexible charging behaviour and the uptake of vehicle-to-grid (V2G). TSOs provided selections for predefined flexibility and V2G participation options, differentiated by charging location (home/prosumer and public/street charging). These survey-based inputs are applied at national level and are used to parameterise the representation of EV charging flexibility in the electricity market model, while non-passenger electric vehicles are included exogenously in electricity demand profiles.

Conceptual Capacity Increases for the 2050 Grid

In parallel with the core data collection, ENTSO-E and ENTSOG launched a targeted request in April 2025 to TSOs and project promoters for the submission of conceptual capacity increases to be considered in defining the 2050 grid for the TYNDP 2026 Scenarios. This initiative was conducted alongside the first window of the ENTSO-E TYNDP 2026 project collection and responds to the need to ensure that the long-term grid representation adequately reflects plausible infrastructure developments required to achieve climate neutrality by 2050. These conceptual capacity increases are used exclusively for the purpose of scenario modelling and are only applied to the 2050 time horizon within the TYNDP 2026 Scenarios. For the avoidance of doubt, they do not form part of the reference grid used in the TYNDP project assessments.

Conceptual Capacity Increases are defined relative to the baseline grid resulting from the consolidated ENTSO-E TYNDP 2026 and ENTSOG TYNDP 2024 project collections and are implemented as additional Net Transfer Capacity (NTC) increments on top of the baseline cross-border NTC values when defining the 2050 scenario grid.

These expansions correspond to potential new interconnection capacities that have already undergone at least preliminary technical investigations but were not submitted as formal projects in the first project collection window. While these capacity increases may still be subject to a degree of uncertainty, preliminary assessments indicate a high likelihood of future development, technical feasibility, and relevance for the achievement of the EU's long-term decarbonisation objectives. Submissions were requested on a per-border basis and required agreement between the relevant countries to ensure a coherent cross-border representation. Eligible conceptual capacity increases include reinforcements on existing borders and new connections between neighbouring countries (including offshore hubs, provided they are consistent with geographical and maritime constraints). All submitted conceptual capacity increases had to be accompanied by a clear justification explaining their relevance, for instance in terms of system integration needs, decarbonisation pathways, or supporting technical studies. Following a qualitative review by the WGSB, only those submissions meeting the defined eligibility and justification requirements were incorporated into the 2050 grid representation of the central scenario (NT+).

Further details on the formation of the electricity and hydrogen grids across all time horizons are provided in Chapter 7 TYNDP 2026 Scenario – Grid of this report.

3 TOOLCHAIN //

The Scenario Building process for TYNDP 2026 introduces several methodological improvements aimed at enhancing transparency, consistency across sectors, and interoperability between modelling tools. One of the main objectives of this cycle was to strengthen the integration between sectoral demand modelling and multi-energy system analysis, enabling a more coherent representation of the evolving multi-energy system. To achieve this, the development of the whole scenario framework is based on a sectoral demand data collection in ETM for all target years. This represents a fundamental difference compared to previous scenario building cycles, particularly for the NT+ scenario.

3.1 Toolchain in the TYNDP 2026 Scenario Building process

The scenario building workflow is structured as a multi-stage modelling process, supported by a set of complementary tools that exchange data throughout the modelling chain (Scenario Toolchain).

The objective of the toolchain is to ensure a consistent and traceable translation of annual scenario inputs into hourly demand profiles, market simulation outputs and aggregated supply indicators, while allowing different modelling components to be developed in a coherent framework.

Figure 2 illustrates the data flow in the Scenario Toolchain used in the TYNDP 2026 scenario building cycle. Starting with TSOs data collection in ETM and other tools, a first result is the annual Final Energy Demand, provided with a detailed sectoral breakdown. After hourly profiling and market modelling electricity and hydrogen in PLEXOS®, model outputs are presented in the form of country-specific dashboards (yearly and hourly) also allowing a sub-nodal view. The Supply Tool finally complements the model output with non-modelled energy carriers in PLEXOS® and derives the Total Energy Consumption and CO_2 emissions.

Additional tools and input data from PECD and PEMMDB are explained in the respective chapters below.

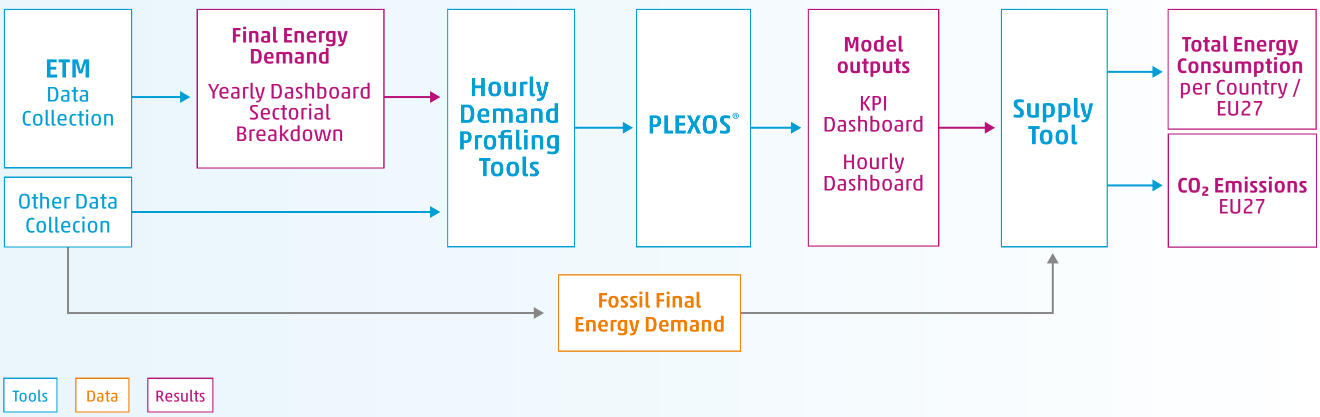


Figure 2: Data flow in TYNDP 2026 scenario toolchain

The Scenario Toolchain focuses on electricity, hydrogen, synthetic fuels, heat and transport demand. Fossil fuel demand collected through the data collection is neither transferred to nor explicitly modelled in PLEXOS®, as the corresponding fuel markets are not represented within the scope of the modelling framework. It is bypassed directly to the Supply Tool, where it is combined with the primary energy demand resulting from the PLEXOS® simulations to compute Total Energy Consumption.

This approach allows sectoral demand assumptions, with electricity, hydrogen, heat and synthetic fuels demand profiles, and market modelling to be developed in a consistent and iterative manner. In practice, this means that some input values initially defined in ETM are refined downstream through explicit modelling in PLEXOS®. One example is the dispatch of boilers and heat pumps in hybrid heat pump systems which is a result of the hourly PLEXOS® modelling and might lead to slightly different results compared to the original TSO data collection.

A detailed sectoral breakdown is available at ETM output level only, while the PLEXOS® model for Scenario Building 2026 represents demand with a more aggregated sectoral structure. Further details on the market model representation are provided in Chapter 8.

Following the collection of sectoral energy volumes in ETM, the scenario building process proceeds with the integration of these outputs into the other modelling tools. For TYNDP 2026, dedicated interfaces were developed to enable a structured exchange of data between the ETM and other tools within the modelling chain.

These interfaces connect the ETM to the three main downstream components of the Scenario Toolchain:

- **Hourly Demand Profiling Tools**, which generate hourly demand time series from annual demand inputs, including:
  - Demand Forecasting Tool (DFT), applied for electricity demand profiling, including parts of Electric Vehicles and Heat Pump electricity demand profiles;
  - Hydrogen Demand Profiling;
  - Thermal Demand Profiling for Hybrid Heat Pumps;
  - Synthetic Fuel Demand Profiling
- **PLEXOS® market simulation model**, to model the European electricity and hydrogen markets, including their interaction and coupling with other energy carriers.
- **Supply Tool**, applied to quantify energy supply sources for all energy carriers and to calculate CO_2 emissions.

This integrated workflow ensures that sectoral demand assumptions are consistently translated into carrier-specific demand profiles for electricity, hydrogen, heat (for hybrid heat pumps) and synthetic fuels, which are subsequently used as inputs for market simulations.

3.2 Sectoral demand data collection in the ETM

The starting point of the scenario building process is the collection of sectoral annual energy demand data in the ETM.

Within the ETM environment, electricity and gas TSOs provide projections of final energy demand across a detailed sectoral breakdown and across multiple energy carriers (including electricity, hydrogen, methane, heat, biofuels, coal, oil, ammonia and others).

All data provided by TSOs correspond to NT. The NT+ scenario is derived only after the application of the gap-filling methodology, as described in Chapter 9 of this report.

The ETM data collection covers the four scenario target years: 2030, 2035, 2040 and 2050.

All projections are anchored to the ETM reference year 2019, which currently serves as the baseline energy system dataset within the ETM. The baseline values are mostly derived from Eurostat energy statistics, ensuring a harmonised and transparent starting point for all countries included in the Scenario Building process.

The results of this data collection are aggregated and can be explored through an interactive Visualisation Platform, allowing stakeholders and scenario developers to explore the evolution of energy demand across sectors, countries, and energy vectors.

3.3 Electricity Demand Time Series Generation

Annual electricity demand values collected in ETM and complemented with additional data (additional electricity demand for CCS, grid losses, etc.) are converted into hourly electricity demand profiles using the Demand Forecasting Tool (DFT).

The DFT generates electricity demand time series using sectoral annual electricity demand, historical load patterns, normalised load patterns and weather-dependent relationships derived from the selected Weather Years. As such, the resulting profiles represent final electricity demand only and do not include components that are modelled endogenously in the power system optimisation. In particular, electricity consumption from electrolysers, as well as electricity used for storage technologies, is not included in the DFT-generated demand profiles, as these are determined as part of the market simulation.

The DFT-derived demand profiles therefore capture native electricity demand, including base load, electricity demand from heat pumps, and electric vehicle charging profiles based on predefined assumptions. These time series serve as inputs to the power system modelling performed in PLEXOS®.

Within the power system model, selected demand components are represented explicitly and optimised endogenously, notably passenger electric vehicles and hybrid heat pumps. For these technologies, electricity consumption is not taken directly from the DFT profiles but instead results from the optimisation process, allowing for price-responsive behaviour and technology-specific operational constraints enabled by the sector-coupled modelling of electricity, heat, and gas.

Consequently, while the DFT provides the underlying structure of final electricity demand (including base load, heat pumps, and electric vehicles), part of this demand – specifically for passenger EVs and hybrid heat pumps – is re-optimised within the model, whereas other demand components such as electrolysers and storage-related consumption are fully determined as model outputs.

3.4 Hydrogen Demand Time Series Generation and Thermal Demand for Hybrid Heat Pumps Time Series Generation

Hydrogen demand time series are constructed using a dedicated tool which translates annual hydrogen demand volumes from ETM and an additional data collection (see Chapter 4) into hourly profiles. Using the sectoral breakdown of demand provided by ETM, the tool constructs sector-specific demand time series. The sectoral profiles are subsequently aggregated to form hourly hydrogen demand per node. The resulting time series are used as inputs to energy system modelling in PLEXOS®. Certain hydrogen uses, such as for power generation, hydrogen boilers as part of hybrid heat pumps, and the production of synthetic fuels are modelled endogenously.

Hybrid heat pump thermal energy demand profiles are generated using a similar tool. The tool translates annual thermal demand into hourly profiles based on temperature-dependent relationships. The time series are used as inputs to the model, which determines endogenously whether the demand is satisfied using a boiler or a heat pump (see Chapter 5.3 for explanation).

3.5 Synthetic Fuels Demand Time Series Generation

Synthetic fuel demand profiles are derived by distributing the aggregated EU27 annual demand uniformly across all hours of the year. The resulting flat demand profiles for synthetic natural gas (SNG) and e-liquids are used as inputs to energy system modelling in PLEXOS®. For further details please see Section 5.4 on synthetic fuels.

3.6 Installed Capacities

The installed capacities considered in the analysis, together with all other data required to model electricity generation, transmission, and electrolyser demand, are collected through the Pan-European Market Modelling Database (PEMMDB) application. PEMMDB enables electricity TSOs to report this information on a unit-by-unit basis, thereby centralising the parameters required to construct the market model. The reported data primarily include the allocation of units to the bidding zones represented in the model, commissioning and decommissioning dates, installed generation capacities, and relevant operational constraints.

Data submission within PEMMDB remains under the responsibility of the reporting TSOs and follows the ENTSO-E data governance process, including dedicated validation rounds and consistency checks to ensure alignment with the applicable TYNDP scenario assumptions. Following validation and data freeze, unit level data are aggregated through dedicated scripts to safeguard sensitive information and comply with data confidentiality requirements. The resulting aggregated and scenario consistent dataset is subsequently used as input to the modelling framework.

3.7 Economic Dispatch modelling in PLEXOS®

All energy carrier-specific demand profiles generated along the scenario building toolchain are provided as inputs to PLEXOS®, which performs hourly market simulations for the integrated European electricity and hydrogen systems. The market simulations determine, among others, generation dispatch, energy flows, and system operation across the modelling horizon by minimising system cost over the considered target year and under given boundary conditions. This step provides insights into cost-sensitive elements such as electricity and hydrogen generation, fuel consumption, energy flows and hydrogen imports, and supports the assessment of the implications of the demand projections for the integrated energy system.

3.8 Supply Tool

The Supply Tool aggregates model outputs together with exogenous data collections to construct a consistent energy balance across all energy carriers, illustrating how they are used and where they come from – whether from domestic production, imports or conversion from one carrier into another (for example, heat supplied from hydrogen that is produced by domestic electrolysers powered by electricity). In doing so, it balances demand and supply for all energy carriers and ensures a consistent representation of energy flows across sectors within the scenario framework.

The resulting supply side information for the EU27 also serves as the basis for calculating the EU wide carbon budget. Further details on the EU-wide carbon budget methodology are provided in Section 5.6.

3.9 Summary of the Modelling Workflow

The TYNDP 2026 Scenario modelling workflow establishes a structured interaction between sectoral demand modelling, demand profiling, and integrated electricity and hydrogen market simulation. By connecting the ETM, various hourly demand forecasting tools for different carriers, PLEXOS®, and the Supply Tool through dedicated interfaces, the methodology ensures a coherent translation of sectoral demand assumptions into multi-energy system outcomes.

This integrated approach represents an important methodological improvement compared to previous scenario cycles, strengthening the consistency between demand projections and market modelling, while maintaining a system-wide energy perspective.

4 DEMAND //

4.1 Overview

This chapter describes the methodology applied to develop the demand inputs used in the TYNDP 2026 scenarios, including the Central Scenario (NT+) and LEV/HEV. As the market model simulations are performed on an hourly basis, the demand inputs must also be expressed as hourly time series.

Developing demand scenarios is a key part of the TYNDP 2026 Scenario Building process and follows the integrated toolchain described in Chapter 3. The approach is based on a bottom-up logic, starting from the collection of annual sectoral energy demand data coordinated between electricity and gas TSOs and subsequently translating these annual values into hourly demand profiles suitable for market simulations. The information relevant for the simulation model covers demand for hydrogen, electricity, electric vehicles, hybrid heat pump (HHP) heat and synthetic fuels.

Figure 3 shows the overall demand-related part of the toolchain, from annual demand values established through TSO data collection to the hourly demand timeseries used as inputs in the market model. For illustration purposes, a single hourly profile per energy carrier is shown. However, the demand profiling tools generate differentiated hourly profiles by sector and use, which are subsequently aggregated to a single nodal demand profile per carrier in PLEXOS®. Further details on the modelling approach are provided in Chapter 8.

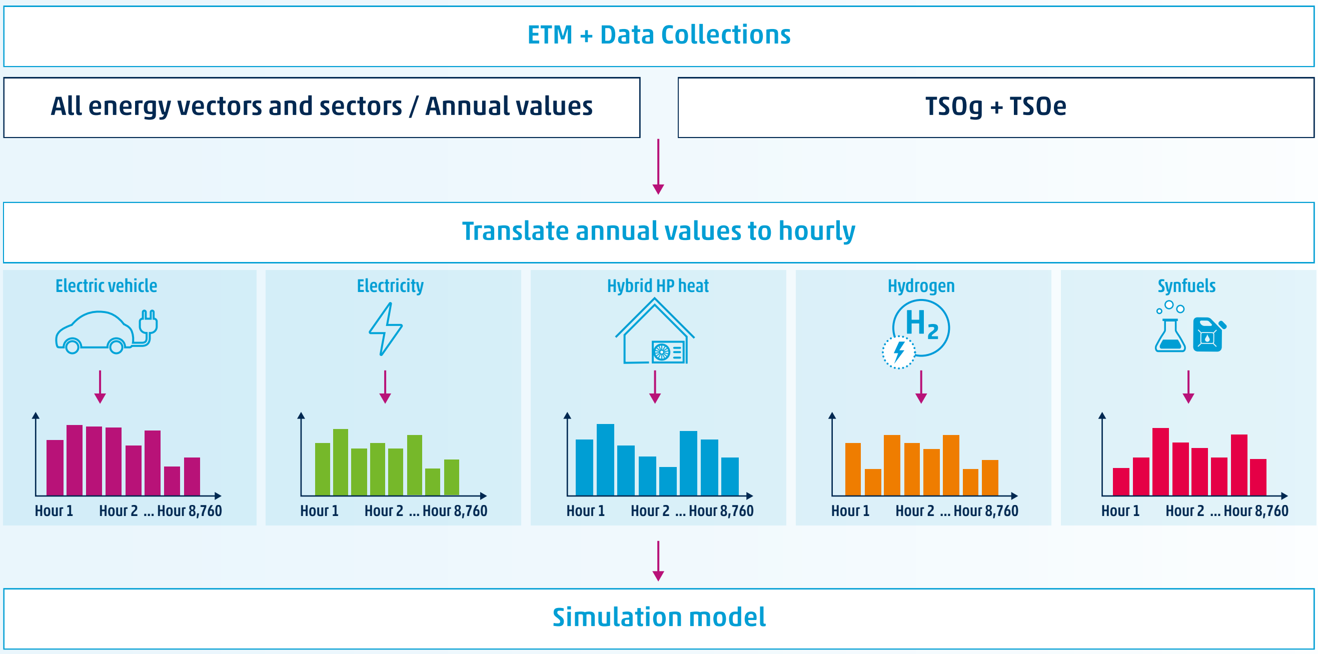


Figure 3: Demand data flow from annual values to hourly values

According to the Joint Data Collection Guidelines, demand inputs are to be provided by national TSOs and must be in line with the most recent NECPs. Where relevant, these inputs are complemented by the latest national policy measures and planning assumptions. This ensures consistency between the demand data used in the TYNDP 2026 Scenarios and the official national policy frameworks, while maintaining coherence with parallel European assessments, such as the European Resource Adequacy Assessment (ERAA).

In most cases, annual demand information is obtained from the ETM as described in Section 3.2. Where ETM data are not available or do not require completion, alternative data sources or dedicated data collection exercises are applied. Through this coordinated process, annual demand by energy carrier and sector is determined for each country. Section 4.2 provides further details on the annual demand data, while Annex VI summarises country-specific data sources and modelling approaches.

Once annual demand values are defined, they are translated into hourly demand profiles following the procedures outlined in Sections 3.3, 3.4 and 3.5 and detailed further in Section 4.3.

Chapter 10 presents the methodology applied to derive the annual demand values for the economic variant scenarios, ensuring alignment and consistency with the Central Scenario.

4.2 Annual Demand Data

ETM countries and scope

The demand input data are jointly collected by gas and electricity TSOs through the ETM.

The ETM[1] is a comprehensive, open-access energy system model to interactively build and explore energy system scenarios on country-base, covering all relevant sectors and energy carriers.

ETM covers all EU countries along with the United Kingdom, Norway, Switzerland, and Serbia. In this cycle most but not all these countries make use of the ETM as a demand data collection tool. For some countries a fallback solution is applied in the ETM. For a few other countries ETM was not used at all. They were treated like the countries not included in the ETM which submitted their demand input data via the PEMMDB demand file for 2030, 2035, 2040 and 2050 time horizons. For details, please consult Annex VI.

Starting point of any scenario created in the ETM is today's energy balance per country and a database which reflects the technical and economic characteristics of the technologies applied in the energy system (e.g. a heat pump). In combination with a user-defined set of scenario assumptions for a specific target year (e.g. 2040), the ETM then projects the future use of energy. Within the TYNDP 2026 scenario building process, only the demand side modelling features of the ETM have been used and integrated into the overall scenario toolchain. The supply part and other sections of the ETM were not used in this scenario-building cycle. The ETM demand section contains the relevant end user (sub)sectors, wherein the user can define various scenario parameters. As an example: For the subsector space heating in the demand sector-built environment, the user can define which share of the heat will be provided by which technology (heat pumps, gas boiler etc.) which in turn determines how much energy of which carrier is being consumed.

On the output side, the model provides a set of data tables and charts to visualise and explore the outcomes of a scenario. All results can be exported for further use in other applications. The ETM can be accessed both online via a Graphical User Interface (GUI) or via an Automated Programming Interface (API), allowing more advanced users to interact with the ETM by scripts to upload data to or export data from the model. The model itself and a comprehensive documentation are available online via this webpage. The underlying energy balances for the reference year can be fully explored via the dataset manager.

For all the countries in scope of the TYNDP 2026 Scenarios and included in the ETM, the demand scenarios were defined by aligning on a set of parameters per each of the following sectors:

- Households
- Buildings
- Industry (energetic)
- Industry (non-energetic)
- Datacentres & Information and Communication Technologies (ICT)
- Transport (national)
- Transport (international)
- Agriculture
- Other

1 ETM model is developed by Quintel Intelligence

The defined parameters range from general assumptions (e.g. population growth) to more detailed aspects such as technology mix and specific technical characteristics.

The energy demand outputs were retrieved and subsequently processed to support validation, scenario comparison, target achievement assessments and data conversion required for integration with other scenario tools.

The main result of the data collection in ETM is the Final Energy Demand per country. ETM allows a detailed sectoral breakdown enabling the downstream Time Series Generation tools to make use of sector specific temporal characteristics of different subsectors.

ETM Fallback Solution

Some of the EU27 countries did not submit ETM demand data themselves but made use of the ETM fallback solution that was offered. The list of countries is given in Annex VI. For those 6 countries, the 2026 ETM values are set to the mean of the 2024 DE and GA scenarios for all four NT+ scenario target years. Note that in 2024 cycle, the central NT/NT+ scenario is not available in ETM. Since the ETM model and especially its demand input parameters have evolved from the 2024 scenarios to the 2026 scenarios, a value mapping and interpolation process was required to ensure data compatibility and consistency.

Non-ETM Countries

For a third group, which consists of 2 EU countries and 11 non-EU countries (i.e. 13 countries in total), the ETM is not used to define demand data, either because ETM is not available for them or other constraints are faced. Instead, the ERAA 2025 electricity demand dataset is used as input for the e-demand. Hydrogen demand was assumed to be zero. Thus, these countries are modelled with a reduced functionality and nodal topology. For the United Kingdom, Bulgaria and Cyprus hydrogen modelling is implemented even though a complete ETM data set is not available. For details, again refer to Annex VI.

Additional Data Collections

Following a comprehensive analysis of the scenario development process within the new regulatory framework, several data gaps were identified. To collect the remaining datasets necessary for scenario construction, multiple surveys were distributed to electricity and gas TSOs.

The additional data collections (DC2) covered the following topics:

- **District heating, including industrial steam network and agricultural heating:**

  While ETM tool explicitly captures district heating demand and reports it under the "heat demand" category, additional information was required on the shares of primary energy sources supplying district heating. These shares, combined with efficiency factors, were necessary to calculate primary energy demand for district heating across all energy carriers.

- **Demand and supply for synthetic and biofuels:**

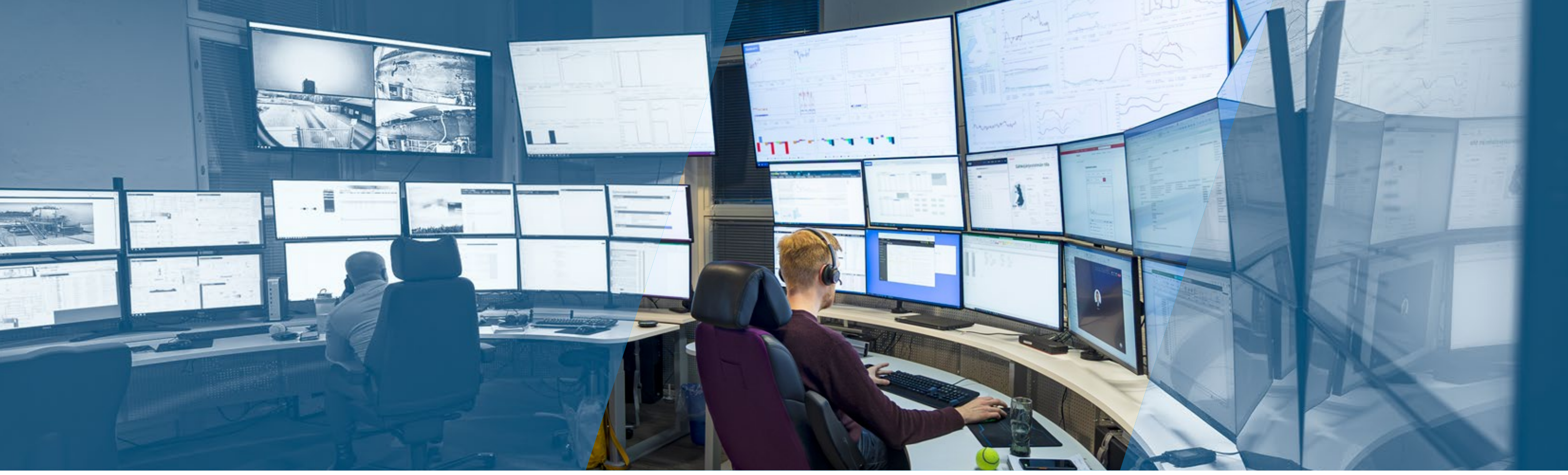
  One further piece of information required to complete the data collection dataset was the total demand for synthetic and biofuels, together with its allocation between domestic production and other supply channels, such as exchanges or imports. The synthetic fuel production values identified for each country determined the corresponding additional hydrogen as well as the need for CO_2 as a feedstock.

- **Domestic ammonia production for shipping:**

  The ETM tool includes ammonia demand for both fertiliser production and shipping fuel. While the ETM model specifies whether ammonia for fertilisers is produced domestically, this information is not available for ammonia used as shipping fuel. Therefore, additional data were collected to determine the share of shipping-related ammonia produced domestically. The total ammonia demand was then converted into hydrogen demand, which serves as an input to the modelling tool, together with the additional electricity required for the conversion process.

- **Electricity demand for CCS facilities that are not connected to a power plant (CCSnpp):**

  While CCS attached to power plants is inherently reflected in the plant efficiencies within PEMMDB data collection, an additional survey was required to collect national assumptions for CCSnpp and use them as an input to the scenario model. Furthermore, the assumed conversion efficiency of CCSnpp facilities was collected to determine the captured CO_2 volumes relative to electricity consumption.



- **Total CCS:**

  In addition to the CCS not connected to power plants, the data collection also covered the total CCS capacities on a country level as well as the share of CCS that stems from biogenic sources (BECCS).

- **EVs survey:**

  This additional survey was carried out to collect parameters required for modelling the flexibility potential of passenger electric vehicles (EVs).

  EVs can contribute to system flexibility by responding to market signals, primarily through smart or flexible charging strategies that optimise charging times. In this survey, TSOs were asked to indicate the share of EVs with fixed versus flexible charging profiles by selecting one of four predefined options for each target year.

	FIXED CHARGING (%)	OPTIMISED CHARGING (%)
	(DFT)	(PLEXOS®)
Market Driven	30	70
Balanced	50	50
Users Oriented	70	30
Business As Usual	85	15

	V2G (%)	2030	2035	2040	2050
HOME	Low flexibility	0	5	10	50
	Medium flexibility	15	20	25	35
	High flexibility	30	35	40	50
STREET	Low flexibility	0	1.5	3	5
	Medium flexibility	0	3.5	7	15
	High flexibility	0	5	10	20

Table 5: Predefined charging behaviour assumptions and V2G trajectories used in the ev flexibility survey

If no values were provided, the default assumption applied was the "Balanced" option for all target years.

Additionally, TSOs were requested to define the capability of EVs with flexible charging profiles to provide Vehicle-to-Grid (V2G) services. For this purpose, the EV fleet was categorised into two groups:

- **Home chargers:** EVs primarily charged at home and acting as prosumers, connected to the prosumer node in the market model
- **Street chargers:** EVs primarily charged at public charging points, connected to the electricity market node

The predefined options also included trajectories for V2G participation across target years, differentiated between home and street charging configurations (see Table 5).

If no values were provided, the medium trajectory was applied for both home and street charging EVs.

- **Survey on Grid Losses**

  TSOs were asked to submit grid losses for any target year. The fallback solution was to use 3% grid losses for all target years. For details see Annex VIII.

- **Electricity Market Area Split**

  For countries with multiple market areas (nodes), the national-level demand figures were disaggregated across the respective nodes to ensure accurate representation within the market model. This distribution was based on detailed input provided by TSOs through dedicated questionnaires, which specified the relative allocation of the various demand components among nodes for each target year. As a fallback solution for e-demand, the split reported in the 2024 scenarios was used.

4.3 Hourly Demand Data

Overview

The following sections describe how annual demand values are transformed into hourly demand time series for hydrogen, electricity, thermal energy for hybrid heating and synthetic fuels. As the methane system is not modelled explicitly, methane demand time series are not generated. Instead, ETM provides annual demand values for non-energy uses, while methane consumption in the energy system emerges endogenously from the model (on an hourly and yearly scale).

Hydrogen demand profiles

Hydrogen demand time series are computed for each hydrogen node and target year. The resulting hourly profiles represent exogenous hydrogen demand and reflect differences between countries, weather years (see Chapter 6) and target years. The differences arise from country-specific temperature assumptions and the composition of hydrogen demand across use cases, in particular the share of temperature-dependent demand such as demand for space and water heating.

The profiled hydrogen demand combined hydrogen demand from ETM and the Additional Data Collections: (1) Hydrogen demand (including sectoral breakdown) collected in ETM, with hydrogen demand for thermal energy removed, (2) hydrogen demand for use in hydrogen boilers in district heating networks from DC2 and (3) hydrogen demand for the production of ammonia for shipping from DC2. Hydrogen demand is not profiled for hydrogen-fired CCGT or OCGT plants, hydrogen use for thermal energy production in residential and tertiary hybrid heat pumps (see below), or hydrogen demand for synthetic fuel production (also see below), as these demands are determined endogenously within PLEXOS®.

Hydrogen demand profiles are constructed by sector and subsequently aggregated to form the total hydrogen demand time series for each node and year.

Residential and tertiary hydrogen demand is dominated by space heating and water heating, and therefore temperature dependent. The profile shape is derived by relating hydrogen demand to Heating Degree Days (HDDs) in a linear regression. This is done separately for space and water heating as the relationship to HDD is different. In general, this is determined for a reference year and then varied according to the temperature differences between the reference year and the modelled weather year. Hydrogen demand for hydrogen boilers in district heating follows the same temperature-dependent profile assumptions.

Transport-related hydrogen demand consists mainly of hydrogen demand for heavy goods vehicles (HGVs) and for aviation. Hydrogen demand for HGVs is assumed to follow a flat hourly profile. This is because even though some countries impose driving restrictions on HGVs (such as Sunday bans), these effects are not modelled. Hydrogen demand for aviation is derived from historical aviation kerosene consumption profiles which are used to capture seasonal variation in flight activity. No assumptions are made regarding changes in demand patterns in future years.

Industrial demand is assumed to follow a flat hourly profile without seasonal variation. This assumption is consistent with standard gas system modelling practices, where industrial demand is typically represented at daily resolution, as short-term variability can be balanced through the use of line pack as short-term storage medium. This industrial hydrogen demand, as set out in ETM data collection, includes energetic uses, such as process heat, and non-energetic uses, such as direct reduction in steel production or feedstock use in the chemical sector. Hydrogen demand for the domestic production of ammonia for shipping is also assumed to be flat.

Electricity demand profiles

1) Grid Losses

Electricity grid losses are calculated based on the yearly electricity demand ETM yields and the shares of the losses the TSOs submitted (see Annex VIII). (ETM loss estimation is not used). The total yearly grid losses are then considered as part of the inputs to DFT for creating the electricity market nodes hourly demand profile.

Note that the efficiencies of power plants are modelled in PLEXOS® endogenously accounting for the self-consumption and the CCS if in place at the site.

2) Electricity Market demand time series are generated using DFT (Demand Forecasting Tool) for most of the countries.

DFT uses, for each market node, a data-driven modelling approach based on historical load timeseries combined with new technologies load profiles. Load timeseries are weather dependent, the weather conditions have been identified in Chapter 6 and Annex III and do not only affect electricity load but also renewable productions as well as other energy carriers. The weather years used are future climate projections and have hourly resolutions in order to be used. The timeseries automatically consider all the characteristics related to the consumption sectors (industry, services, residential and transport) of each specific country based on historical data. The technological evolution is as well considered through assumptions on expected penetration of Datacenters, District Heating and Transports (Part of Passenger EVs, Trucks, Vans, Buses, Trains).

Regarding Passenger Electric Vehicles, a share of the fleet is assumed to charge in public or street locations. This segment is split into:

- a user-oriented (non-flexible) charging component, represented by fixed daily demand profiles derived from Energy Transition Model (ETM) assumptions and profiles directly in the DFT. In the model it is considered as additional electricity demand time series for the e-market node.
- a market-driven (flexible) charging component, corresponding to EVs, that are able to optimise charging in response to electricity prices and charging infrastructure availability. This flexible charging demand is not included in the DFT profiles and is instead endogenously determined by the market model optimisation. See next chapter and Annex I.

The electricity demand associated with Heavy Duty Transport EVs (trucks, buses and vans) is fully embedded in the DFT electricity demand profiles and treated as exogenous load.

3) Prosumer node

Prosumer demand time series comprises only the consumption of fully electric heat pumps. Profiling is conducted according to climatic conditions and includes three distinct categories: heating, cooling, and domestic hot water usage. The profiling is carried out according to DFT. The prosumer node also models the consumption of hybrid heat pumps. These technologies, in addition to adapting to weather conditions, must meet heating demand by utilising either gas (hydrogen or methane) or electricity, depending on which option is economically preferable.

For Passenger EV home charging, two components are considered:

- a user-oriented (non-flexible) charging component, represented by fixed daily demand profiles derived from ETM assumptions and profiled directly in the DFT as additional electricity demand time series for the prosumer node.
- a flexible charging component, whose charging behaviour is optimised endogenously in the market model, following the same modelling approach adopted for other flexible EV charging segments.

Consistently with the overall EV modelling framework, only the flexible share of Passenger EV charging is represented explicitly in the market model, while fixed charging demand is treated as exogenous electricity load.

4) Behind-the-meter

Few market nodes have chosen to simulate behind-the-meter production separately. Residential rooftop PV systems combined with batteries are optimised independently over a 24-hour horizon. Batteries may only be charged from associated Photovoltaic (PV) generation, and each of these prosumer nodes only considers its own demand, without accounting for the rest of the system when optimising the battery behaviour. The sum of the PV generation and battery charging and discharging time series is attached to the corresponding prosumer node as a fixed load. It is a negative demand time series corresponding to a supply. For Germany only the battery time series is used as the PV capacities are modelled endogenously. The capacities used for this behind-the-meter approach are given in Annex VII.

Electric Vehicles Transport Demand

In the TYNDP 2026 scenarios, EVs are modelled differently depending on whether they belong to Passenger Cars or Heavy Transport categories (i.e. buses, trucks, vans).

In principle, both categories could be represented explicitly in the market model to capture the interaction between charging behaviour and electricity market prices. However, for the sake of modelling consistency and tractability, only EV Passenger Cars are modelled explicitly within the market model framework. The electricity demand associated with Heavy Transport EVs is therefore embedded in the exogenous electricity demand profiles and modelled in the DFT as additional electricity load.

To represent EV Passenger Cars charging in the market model, the annual transport demand (in kilometres) provided by the ETM must be converted into an hourly time series, as the market model operates at hourly temporal resolution. This conversion is performed by applying driving profiles taken from the REM 2030 Driving Profiles Database[2].

As shown in Figure 4, the driving profiles represent the share of weekly transport demand occurring at each hour of the day. To ensure consistency over a full week, the profiles are constructed such that total demand corresponds to five weekday profiles and two weekend day profiles, summing to 100% of weekly transport demand.

For example, if a given hour (e.g. 08:00) represents 1.4% of daily driving in the weekday profile, this value is counted five times (once for each weekday). Similarly, weekend hourly values are counted twice. Summing all hourly contributions across these five weekday profiles and two weekend profiles results in 100% of weekly demand.

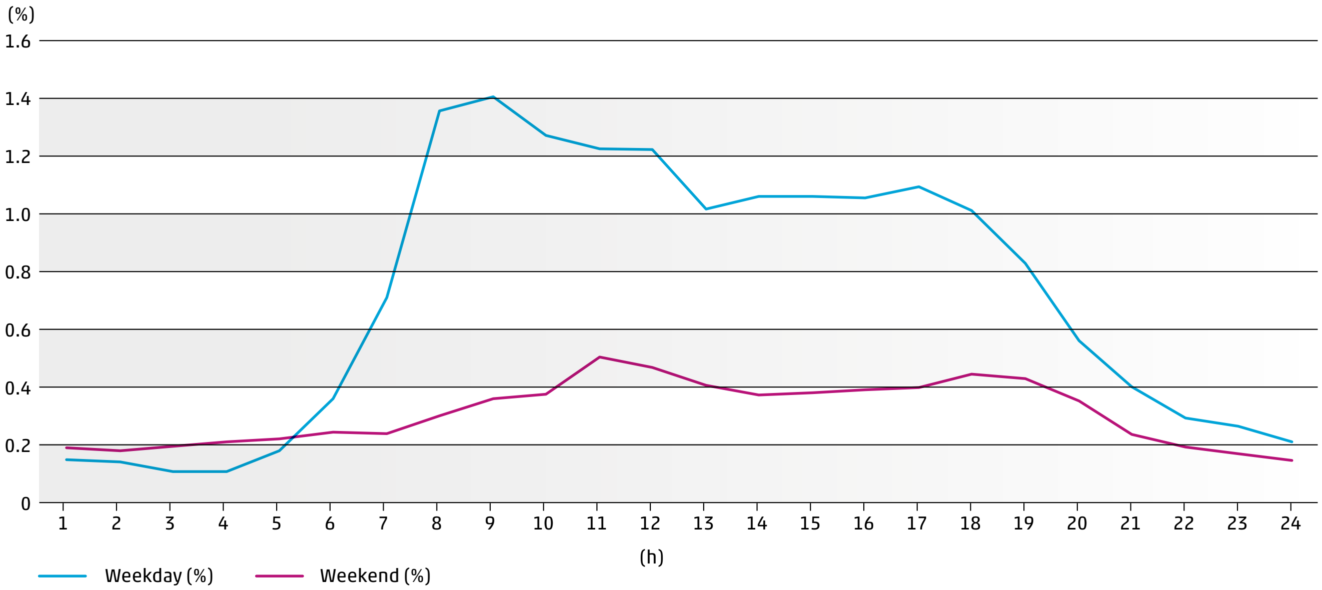


Figure 4: EV driving profiles – Share of weekly driving demand per hour [%]

For TYNDP 2026, the same driving profiles are applied:

- across all scenario horizons (2030–2050),
- across all countries,
- with a single distinction between weekdays and weekend days.

The annual EV Passenger Cars demand (in km) from the ETM is multiplied by these driving profiles to obtain hourly driving demand time series consistent with market model requirements.

As written above in the TYNDP 2026 scenario, EV Passenger Cars are divided into two main charging categories:

- EVs with imposed (non-flexible) charging profiles, following predefined charging patterns;
- Flexible charging EVs, whose charging behaviour can respond endogenously to electricity market prices.

Only flexible EV Passenger Cars are modelled explicitly in the market model. Consequently, the annual transport demand converted into hourly profiles using the driving profiles refers exclusively to this flexible EV segment. The electricity demand associated with EVs under imposed charging profiles is treated exogenously and is either calculated within the DFT or directly provided by TSOs.

Further details on the definition and modelling of flexible versus imposed charging are provided in Section 8.3.

2 Fraunhofer ISI (2015). REM2030 Driving Profiles Database V2015. Fraunhofer Institute of Systems and Innovation Research ISI, Karlsruhe, Germany.

Thermal energy profiles for hybrid heating

Thermal energy demand profiles define the hourly distribution of thermal demand to be met by HHPs in each target and weather scenario. Thermal energy may be provided by an electric heat pump or a gas boiler. Two sets of profiles were constructed: one for methane HHPs, one for hydrogen HHPs. It is a model outcome whether this thermal demand is satisfied using electricity or the respective gas.

Similar to the approach previously described for hydrogen demand, the profile shape is derived by relating thermal energy demand temperature in a linear regression. This relationship is determined for a reference year and then varied according to the temperature differences between the reference year and the modelled weather scenario.

Synthetic fuels

As described in Section 8.4, demand profiles for the EU27-aggregated e-liquids and SNG nodes are assumed to be flat over the year. This simplification is justified by the relatively small share of synthetic fuels in the overall fuel system, which does not warrant a more granular temporal representation, and by the typical operating pattern of synthetic fuel production plants. Synthetic fuel synthesis is a continuous chemical process, for which an economically optimal operation is generally based on near constant production (and corresponding consumption) 24 hours a day, 7 days a week.

In practical terms, the annual synthetic fuel demand figures from the additional data collection are divided by 8,760 hours to obtain a constant hourly demand. This yields static demand profiles that are independent of weather variability for all synthetic fuel types.

5 SUPPLY //

This chapter outlines how the supply capacities and datasets are obtained. It covers:

- *District Heating supply*
- *Commodity and CO_2 prices*
- *Technology costs*
- *Synthetic fuel*
- *Supply Tool*
- *Carbon Budget*
- *Extra EU hydrogen and ammonia imports*

5.1 District Heating

The Heat demand for district heating is taken from the ETM and covers the residential and tertiary, industrial, and agricultural sectors. In the supply tool (chapter 5.5), the heat demand from the ETM is converted into the required primary energy inputs by applying the technology and energy carrier information collected in an additional data collection together with target year specific efficiencies.

The additional data collection provides the shares of district heat supplied by the main sources (electricity, methane, liquids, biomass and biofuels, solids, renewables and waste heat, and hydrogen boilers) as well as the corresponding conversion efficiencies, for each country, sector, and year. It also covers Combined Heat and Power (CHP), including fuel splits (i.e. which carriers fuel CHPs) and CHP performance parameters for useful heat and electricity. Electricity used for district heating is reflected via a combined efficiency that captures the mix of heat pumps and electric boilers.

The calculation of the primary energy carriers needed to supply the thermal energy follows the same logic as before, but with added granularity. For each country, sector, and year, the useful heat from the ETM is allocated to the reported supply sources using the shares from the district heating supply dataset. These volumes are then converted into energy inputs by applying the reported efficiencies (or the coefficient of performance for electricity).

The only exception to this ex-ante calculation of fuel offtake is CHP fuel use. CHP units are modelled explicitly in the dispatch model, and their fuel consumption is determined endogenously as part of the optimisation process rather than being pre calculated. The allocation of CHP fuel offtake between power and heat is based on the country level information on CHP fuel splits and efficiencies, as provided in the additional data collection.

5.2 Commodity costs and CO_2 Prices

Fuel costs are a key assumption as they determine the merit order of the electricity generation units, and, consequently, the electricity dispatch and resulting marginal electricity costs. Projections of fuel costs and CO_2 prices depend not only on global energy demand and supply, but also on European and global policies.

Commodity costs cover the costs of different categories of fuels (nuclear, different kinds of coal, natural gas and other relevant gases, and different kinds of oil) and CO_2, which are used in the various processes of the TYNDP 2026 Scenario Building. These costs are stated for the relevant target years of this study (2030, 2035, 2040 and 2050) and are converted to 2024 euro values using the Harmonised Index of Consumer Prices (HICP), as shown in Table 5. Some commodities' costs (biomethane, heavy and light oil and blended gas (the gas blend of biomethane, synthetic gasses and natural gas in the system) are calculated as a weighted average of the costs of the methane carriers present in the system: fossil natural gas, biomethane, and SNG. These weights reflect the share of each carrier in the total European methane supply for each target year.

The CO_2 prices used in the model are those recommended by the European Commission for use in the NECPs by the different EU countries.

FUEL	UNIT	2030	2035	2040	2050	SOURCE
Nuclear	€/GJ	0.6	0.6	0.6	0.6	EIA (2023)
Lignite G1 (BG – MK – CZ)	€/GJ	1.9	1.9	1.9	1.9	Booze & Co same as 2022
Lignite G2 (SK – DE – RS – PL – ME – UKNI – BA – IE)	€/GJ	2.4	2.4	2.4	2.4	
Lignite G3 (SL – RO – HU)	€/GJ	3.1	3.2	3.1	3.1	
Lignite G4 (GR – TR)	€/GJ	4.1	4.1	4.1	4.1	
Hard coal	€/GJ	4.1	4.0	3.9	4.1	EC. Recommended parameters for reporting on GHG projections in 2025[3]
Natural Gas	€/GJ	9.2	9.8	10.4	9.8	
Crude oil	€/GJ	14.3	15.2	16.2	20.2	
CO_2 price	€/ton	97.5	197.5	297.5	502.7	
Biomethane	€/Gj	13.9	14.0	14.1	13.9	Calculation based on Danish Technology cataloque.
Synthetic Methane	€/Gj	32.8	31.3	29.8	28.0	IEA 2022 (APS). Renewable electricity, 70%, 55% and 50% of biogenic CO_2.
Light oil	€/GJ	18.3	19.5	20.7	25.9	Modelled from crude oil price (+28%)
Heavy oil	€/GJ	15.0	16.0	17.0	21.2	Modelled from crude oil price (+5%)
Oil shale	€/GJ	2.3	2.8	3.3	4.8	Value from 2024 TYNDP scenario cycle. No updates from TSOs.
Blended gas price	€/Gj	9.65	9.42	11.79	14.19	Blend of forecasted mix of methane, biomethane and synthetic methane

Table 6: Commodity costs and CO_2 prices used for this cycle. All Prices values are adjusted to 2024 Euros using HICP[4].
All GJ values are referred to thermal GJ in Lower heating value. .

3 This source can be consulted here.

4 Source.

Methodology for blended gas price cost

The cost of the gas blend used in the scenarios is calculated as a weighted average of the costs of the methane carriers present in the system, which are fossil natural gas, biomethane, and SNG. These weights reflect the share of each carrier in the total European methane supply in each target year.

Total methane demand is compiled from three sources:

- sectoral methane demand from the ETM,
- methane required to supply district heating as derived from the primary energy conversion described in the heating section,
- methane used in SMR and power generation, which is taken from the previous cycle as a proxy.

In parallel, TSOs provided their assumptions on national biomethane production, Synthetic Natural Gas (SNG) production (and SNG imports), and domestic methane production as it was described in the data collection chapter. It should be noted here that the synthetic fuel sector is modelled explicitly; therefore the domestic production figures from the data collection also act as a proxy and, representing a theoretical upper limit of what the model could determine as optimal domestic production. From these inputs, the annual shares of biomethane, SNG, and fossil methane in the overall methane system are calculated. These shares serve as the weights for the blended cost. Where intermediate years or missing entries occur, values are linearly interpolated. All costs are expressed in 2024 euros.

The resulting gas blend cost is computed by multiplying each carrier's cost by its supply share and summing across carriers. This blended commodity cost is used system-wide; CO_2 costs are added separately according to the CO_2 price trajectory and carrier-specific emission factors. In the economic variants, both the commodity costs (including the gas blend) and the CO_2 price are consistently adjusted to assess sensitivity to cost assumptions, an. The blended gas cost is recomputed using the same weighting approach.

5.3 Technology Costs

The assumptions on power generation Capital Expenditures (CAPEX) and Operating Expenditures (OPEX) are primarily based on the Danish Energy Agency's Technology Catalogue for the Generation of Electricity and District Heating, excluding offshore wind, electrolysers, pipelines and battery technologies. Cost assumptions for offshore wind, electrolysers, pipelines and battery technologies were derived from other sources, such as the North Sea Wind Power Hub's "Pathway 2.0 Study", Elia's "Blueprint for the Belgian electricity system" and National Renewable Energy Laboratory's "Annual Technology Baseline". CAPEX and OPEX assumptions are available on the download site of the Scenarios 2026 website.

Similarly to the commodity costs, these costs are shown for the relevant target years and are converted to 2024 euro values using the Harmonised Index of Consumer Prices (HICP) .

Due to the new regulatory requirements, an investment model was not required as in the TYNDP 2024 Scenario Building process. This means that the entire modelling process was carried out using a pure dispatch model. Therefore, technology costs assumptions were developed in this exercise to offer support to the downstream processes of the TYNDP.

5.4 Synthetic fuels

During the data collection process, TSOs were asked to provide information on the demand for and production capacities of synthetic fuels. The questionnaire covered the following fuel types:

- e-methane
- e-diesel
- e-kerosene
- e-ethanol
- e-methanol
- e-others

The category "e-others" captures any additional synthetic fuels not explicitly listed above.

For the purpose of the scenarios, these e fuels have been aggregated into two groups for simplicity, due to their similar hydrogen and CO_2 content (see Section 8.4): a gas group and a liquid group. The gas group consists of e methane only, while all the other listed fuels (e-diesel, e-kerosene, e-ethanol, e-methanol and e-others) are categorised as e liquids.

Based on the reported production capacities, the dispatch model determines how much of each country's synthetic fuel demand is met by domestic production and how much is imported. Domestic production of synthetic fuels creates a corresponding demand for hydrogen and for CO_2 from BECCS, in line with the stoichiometric requirements of the respective fuels. Import costs for synthetic fuels are derived from the EWI Global PtX (Power-to-X) Cost Tool, which provides production costs, production potential, and transport costs to specified destination countries. The tool covers hydrogen and tits derivatives ammonia, methane, methanol, and Fischer–Tropsch (FT) fuels. For e-liquids, import costs are obtained from the tool for FT-fuels (representing e-diesel, e-kerosene, and e-ethanol) and for e-methanol. For both fuel types, the cost figures include the cost of hydrogen production, direct air capture, fuel synthesis, storage, and transport. These costs are calculated for four export regions (Chile, Egypt, Morocco and Saudi Arabia), with Italy used as the destination country. For each fuel, both a baseline scenario and an optimistic investment cost scenario are considered. The values presented in Table 7 are the averages across the four countries and the two investment scenarios.

AVERAGE IMPORT COSTS FOR SYNTHETIC FUELS €/MWH				
	2030	2035	2040	2050
FT-fuels	289	256	232	212
Methanol	279	248	224	202

Table 7: Average import costs for synfuels €/MWh

The cost of the e-liquids blend is given by Table 9 and was calculated as the weighted average of these synthetic-fuel costs and the import shares collected in the data collections (Table 8).

SHARE OF IMPORT MIX OF SYNTHETIC FUELS				
	2030	2035	2040	2050
e-others	94 %	86 %	86 %	83 %
e-methanol	6 %	14 %	14 %	17 %

Table 8: Share of Import mix of synthetic fuels

MARGINAL IMPORT COST FOR E-LIQUID BLEND €/MWH				
	2030	2035	2040	2050
e-liquids	288.4	255.2	231.1	210.6

Table 9: Marginal import cost for e-liquid blend

5.5 Supply tool

The Supply Tool is an Excel-based dashboard that consolidates all relevant inputs and model outputs, providing a consistent view of energy balances and the carbon budget (as referenced in section 5.6). Its main purpose is to connect fixed final energy demand (derived from the scenario input data) with the primary energy required to supply that demand. This taking into account all conversion processes, domestic production, and imports.

As many energy carriers are converted into others (e.g. electricity into hydrogen, hydrogen into ammonia or other synthetic fuels, and hydrogen back into electricity, etc.), it is often difficult to distinguish between final and primary energy when considering o individual model component in isolation.

The Supply Tool therefore acts as a bookkeeping layer, keeping track of how fixed final energy demands are met by upstream energy carriers, and of the origin of those carriers (domestic production versus imports).

5.5.1 Demand Side (Inputs to the System)

On the demand side, the Supply Tool uses fixed exogenous data as inputs for the modelling chain. These are not optimised by the dispatch model; they represent scenario assumptions on final or useful energy consumption. The main demand-side inputs include:

- Final energy demand by carrier from the ETM.
- Useful heat demand for district heating (derived from ETM and the additional data collection).
- Exogenous demands for specific conversion chains, such as:
  - Hydrogen feedstock demand for Power-to-Methane (P2M).
  - Hydrogen feedstock demand for Power-to-Liquids (P2L).
  - Hydrogen feedstock demand for ammonia synthesis (NH_3).
- Biomass demand for the production of bioliquids and biomethane.

These demands provide the "fixed side" of the equation, specifying how much energy must ultimately be delivered in each target year, by carrier and by use.

The role of the dispatch model is then to determine the least-cost way of supplying these fixed demands under given availabilities, marginal costs, and technical constraints. In doing so, the market model generates endogenous fuel and carrier flows (e.g. how much gas is burned for power generation, how much electricity is used for electrolysis and how much hydrogen is converted into synthetic fuels, etc.). These flows are then imported into the Supply Tool as part of the supply-side picture.

5.5.2 Supply Side (How Final Demand Is Met)

On the supply side, the Supply Tool combines:

- Model-derived supply and conversion outputs from the dispatch model, such as:
  - Fuel use for electricity generation.
  - Electricity or hydrogen used for Power-to-gas (P2G), Power-to-liquid (P2L), ammonia, and other synthetic fuel pathways.
  - Hydrogen consumption in hybrid heating and other modelled sectors.
- Exogenous production potentials and capacities from data collections (mainly from TSOs), including:
  - Biomethane production potentials.
  - Power-to-Methane and Power-to-Liquids domestic production capacities.
  - Domestic production of oil, natural gas (methane), and other fossil fuels.
- Exogenous hydrogen production and import assumptions are included where relevant.

For each carrier, the Supply Tool aggregates all uses from the modelling chain. Taking natural gas as an example:

- Final gas demand from ETM (ex-ante).
- Additional gas demand from the dispatch model:
  - Gas-fired power generation,
  - Natural gas-based hydrogen production pathways (e.g. pyrolysis and SMR),
  - Gas use in hybrid heating systems.

These components are added together to obtain the total gas demand. This total is then compared with the collected domestic gas production data. The difference between the total demand and the domestic production is interpreted as the required import volume. The same logic is applied analogously to other carriers (e.g. hydrogen, liquids and ammonia).

5.5.3 Energy Balance and Conversions

The Supply Tool constructs a full energy balance at both country and EU level by combining fixed final demands with modelled conversion flows and exogenous production constraints, . For each carrier, it provides:

- How much final/useful demand is specified exogenously;
- How much primary energy (by carrier) is required to supply that demand;
- How much of that primary energy comes from domestic production versus imports and
- How much is converted into other carriers (e.g. electricity → hydrogen → synthetic fuels).

In this way, the Supply Tool makes the following explicit:

- The distinction between final energy demand (fixed inputs from ETM and data collections) and primary energy supply;
- The internal conversion chains between carriers;
- The net import/export position for each carrier.

All balances and indicators are produced for the scenario years 2030, 2035, 2040, and 2050.

5.6 Carbon budget

The carbon budget in the TYNDP scenarios focuses on the period from 2030 to 2050. The cumulative emissions of greenhouse gases (GHG) during this period are compared with the suggested budget and the reduction targets set out in the EU Climate Law. This aligns with the carbon budget in the Impact Assessment (IA) for the EC's agreed 2040 climate target.

The carbon budget ensures that the EU contributes to the global reductions in carbon emissions. This indicative 2030–2050 GHG budget is fully compatible with the long-term temperature goals of the Paris Agreement, which aim to keep the global temperature rise well below 2°C. However, according to Eurostat data, the EU only contributes around 8% to global emissions, meaning that contributions from the rest of the world regarding carbon reductions are crucial to achieving the Paris Agreement goal.

5.6.1 Budget and targets

The carbon budget for the scenarios is set at 16 GtCO_2-equivalent in the period from 2030 to 2050. According to the IA this value is consistent with the European Climate Law and fully compatible with the Paris Agreement. The carbon budget includes domestic EU emissions, international intra-EU aviation and maritime transport, and 50% of international extra-EU maritime transport, all of which are subject to the monitoring, reporting and verification (MRV) process.

EU Climate Law sets out targets to comply with, namely reducing net GHG emissions by at least 55% in 2030 compared to 1990 levels, and achieving climate neutrality by 2050.

In March 2026, the EU adopted a political agreement on a binding target of reducing net GHG emissions by 90% by 2040 with a domestic target of reducing emissions by 85%, and allowing up to 5% to be offset by international carbon credits.

An adequate contribution of up to 5% is expected. Therefore, a check on an 85% reduction in 2040 will be relevant in the TYNDP scenarios.

5.6.2 Methodology

The cumulative net emissions of GHG are calculated for the period from 2030 to 2050. Net emissions are calculated for each year during this period. As most of the data are calculated only for the years 2030, 2035, 2040 and 2050, the values for the intermediate years are determined by interpolation.

The calculations for emissions and removals can primarily be divided into the elements shown in Table 10 below, which illustrates the structure of the emissions and removals accounting framework.

EMISSIONS				**REMOVALS**
ENERGY		**NON-ENERGY (FROM NECPs + IA)**		**LULUCF** (from NECPs + IA) **CCU** (from PLEXOS®)
CO_2 (from ETM + PLEXOS®)	**Non-CO_2** (from IA)	**CO_2**	**Non-CO_2**	
Energy Industries **Manufacturing Industries and Construction** **Transport** **Other Sectors** **Other** (Not specified elsewhere) **Fugitive Emissions from Fuels**		**Industrial Processes and Product Use** **Agriculture** **Waste** **Other**		**CCS** (from other data collections and sources)

Table 10: Structure of emissions and removals accounting framework

Emissions are divided into **energy-related** and **non-energy sources**.

Energy emissions

These include CO_2 and non-CO_2 gases from sectors such as energy industries, manufacturing, and transport, as well as fugitive emissions.

- **CO_2 emissions from the energy sector:** These stipulate the emissions from the fossil fuels used in the TYNDP 2026 scenarios. The consumption of all fossil fuels for energetic purposes is calculated using ETM and dispatch model, and the emissions are obtained using IPCC emission factors given by IPCC (Intergovernmental Panel on Climate Change)[5]. International transport is accounted in this section, and its carbon budget methodology is explained in the next section (5.6.3).
- **Non-CO_2 emissions from the energy sector:** The non-CO_2 GHG emissions are Methane (CH_4), nitrous oxide (N_2O) and fluorinated gases (F-gases). These emissions can originate from transport, fugitive emissions, upstream emissions from oil and gas production sites and other sectors such as residential and commercial. The figures are taken from EC's Impact Assessment (IA) report (2024) using the figures provided for the S3 scenario.

Non-energy emissions

These include CO_2 and non-CO_2 gases from sectors such as industrial processes and product use, agriculture and waste. These emissions are sourced from the NECPs and from EC's IA report (2024) using the figures provided for the S3 scenario.

- CO_2 emissions from the non-energy sector: These emissions come from industrial processes (e.g. cement and chemical production) and product use.
- Non-CO_2 emissions from the non-energy sector: These emissions originate from agriculture, industry and waste.

As non-energy emissions from materials and industrial processes fall outside the scope of the scenarios, they are not directly estimated. Accordingly, non-energy consumption is excluded from the ETM emissions calculation, and data from the IA and NECP reports are used instead to ensure that these emissions are not double counted.

Removals

Removals are incorporated as negative terms in the carbon budget and are combined with emissions derived from primary energy consumption. The removals include carbon captured and stored underground (CCS), as well as those from Land Use, Land-Use Change and Forestry (LULUCF). Carbon captured and used (CCU) in synthetic fuel production is counted as neutral since the carbon is released again when the synthetic fuel is burned. However, the capacity to capture the carbon is included in the total CCS capacity.

The European Scientific Advisory Board on Climate Change (ESABCC) sets an upper limit on the total amount of CO_2 that can be captured in the EU, regardless of what happens to it. In other words, all CO_2 capture flows are included in this cap, regardless of whether the CO_2 is stored underground permanently (CCS/BECCS) or used in synthetic fuel production (CCU). In the Supply Tool, the sum of (i) CO_2 captured for synthetic fuel pathways, (ii) CCS volumes collected in the data, and (iii) an additional indicative "slack" term for CCS (representing uncertainty and missing national details) must be less than or equal to the ESABCC capture limit (425 Mt/year).

Synthetic fuels themselves are modelled under a conservative but simplifying assumption that they are net-zero (or low-carbon) fuels at the point of use. This means that for every unit of CO_2 emitted when synthetic fuels are burned biogenic carbon capture and storage (BECCS) balances this elsewhere in the system. In other words, the combustion emissions of synthetic fuels are offset in advance by biogenic CCS. For accounting purposes, the carbon source used for producing synthetic fuel (whether fossil, biogenic, or from direct air capture) is treated equivalently, provided that the net effect is balanced through BECCS at system level.

This balance is enforced by linking the synthetic fuel production to the availability of BECCS across the EU. The CO_2 required for synthetic fuel production is compared to the EU27 BECCS potential reported in the second data collection. Synthetic fuel production is limited so that the total CO_2 required for synthetic fuels does not exceed this BECCS potential. Only in years where the BECCS potential remains after covering the CO_2 related to synthetic fuels is the remaining BECCS counted as a net negative emission in the carbon budget. In years where the BECCS potential is exhausted by the synthetic fuel production, synthetic fuels are still treated as net zero, but no additional negative emissions from BECCS are booked.

5 These emission factors can be consulted in the Supply Tool.

In addition to CO_2 capture related to synthetic fuels, the carbon budget includes other CCS volumes and an indicative slack term. Explicitly reported CCS and BECCS figures from data collections and other scenario sources are included as removals where they correspond to permanent carbon storage. An additional non-country-specific slack term is introduced to reflect the uncertainty around future CCS deployment, and to allow aggregate capture up to the ESABCC technical limit, even where detailed national data is missing. Together, these CCS/BECCS contributions, subject to the ESABCC cap and after accounting for CO_2 capture related to synthetic fuels, form the non-synthetic fuel part of capture-related removals.

LULUCF is treated separately. Net removals from the LULUCF sector, representing CO_2 fluxes between soils, biomass and the atmosphere, are taken from the IA and NECPs and entered directly as negative emissions in the Supply Tool.

5.6.3 Note on the international transport methodology

The methodology reflects the EU Climate Law, which only covers part of the international transport. This means that it covers only 50% of extra EU international shipping, as well as intra-EU flights and flights departing from the EU to European Economic Area (EEA) non-EU countries, the United Kingdom, and Switzerland.

The carbon budget methodology starts with ETM fuel consumption, applies fuel-specific CO_2 emission factors, and takes into account shares of biofuel and synthetic fuel using TSO data. These emissions are then adjusted using discount factors to reflect the intra-EEA share of international transport. The factors are 45% for aviation[6] and 35% for maritime navigation. These factors are derived from Joint Research Centre's Integrated Database of the European Energy System (JRC IDEES) 2023[7], and an additional 50% discount is applied to the remaining share of navigation emissions. It is assumed that both international shipping and international aviation will follow EU regulation in the future, and that they will therefore use low emissions fuel.

For 2030, emissions from international aviation and maritime transport are benchmarked against the EU-wide estimated range of 106–154.1 $MtCO_2eq$, corresponding to emissions covered under the EU ETS, as reported in the EU-wide assessment of the final updated National Energy and Climate Plans. This range reflects the estimated emissions from international transport within the scope of EU climate policy, including intra-EU aviation and the relevant share of maritime transport emissions regulated under EU law. For subsequent years, projections from the IA are used as a reference.

6 International Intra-EEAwUK passenger aviation.

7 JRC-IDEES-2023: the Integrated Database of the European Energy System.

5.7 Extra EU Hydrogen Imports (excluding Switzerland and the United Kingdom)

In the scenarios the import potential of hydrogen is divided into two categories: imports of pure gaseous hydrogen, and hydrogen arriving by ship in the form of ammonia. Here, "ammonia" represents all relevant hydrogen carriers, including liquid hydrogen (LH_2), liquid organic hydrogen carriers (LOHC), and ammonia. All hydrogen import sources are considered to be renewable. All import potentials identified for the TYNDP scenarios arriving in EU member states are assumed to be converted back into gaseous hydrogen and injected into the European hydrogen network. Figure 5 below displays the import corridors and their commissioning dates.

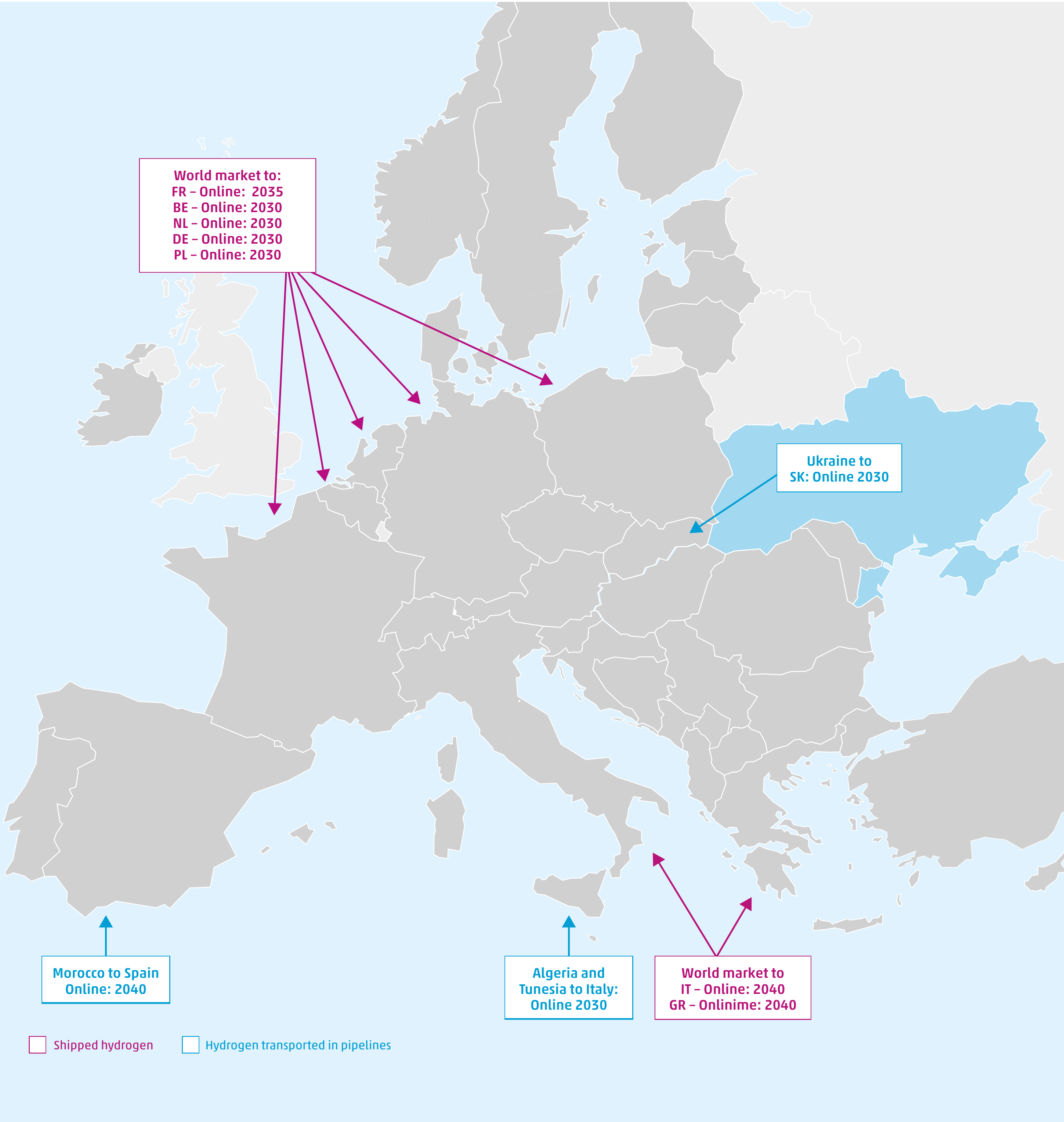


Figure 5: Hydrogen import corridors

For non-EU imports by pipeline and ship the reported capacities (technical view) are based on commissioning data and the capacities of projects submitted to the TYNDP 2024. National long-term strategies and policies are also taken into consideration as mentioned below. Unfortunately, the hydrogen project collection for the TYNDP 2026 was not ready in due time to be included in the 2026 scenarios, which, creates a discrepancy between the grids used and those that would have been established with these projects.

The methodology and data collection described below does not apply to non-EU hydrogen imports from Switzerland and the United Kingdom. Although they are not EU members, both countries have been modelled using the same hydrogen system modelling methodology as EU member states.

5.7.1 Pipelines

The basis for the pipeline capacities is the TYNDP 2024 projects, excluding cancelled projects such as the initially planned hydrogen pipeline between Norway and Germany, as summarised in Table 11 below. The original list of projects submitted to the TYNDP 2024 can be found in Annex A on the ENTSOG homepage.

GWh/DAY (NCV)	2030	2035	2040	2050
Italy	379	379	379	379
Spain	0	0	90	90
Slovakia	122	122	122	122

Table 11: Hydrogen imports capacities from projects delivered to TYNDP 2024 (starting point)

These capacities must be considered alongside the more recent information on the import potential to EU member states as provided by TSOs in the form of national long-term strategies and the political views of both importing and exporting countries. the import flow potential is shown in Table 12 below, and was reported by the TSOs of the relevant member states during the TYNDP 2026 data collection phase.

GWh/DAY (NCV)	2030	2035	2040	2050
Italy	180	280	379	694
Spain	0	0	89	223
Hungary	0	0	0	107
Slovakia	121	121	121	121
Netherlands	0	0	49	110
Germany	0	0	365	365

Table 12: Hydrogen import potentials: adjusted starting point

There are some differences between the two data sets. National long-term strategies and political views have resulted in some projects being brought online later than originally envisaged, such as imports to Hungary. In Italy's case, the full projected pipeline capacity is only expected to be matched by the corresponding import potential after an initial ramp-up phase. For countries such as the Netherlands, Germany and Spain, the long-term import potential reported in the strategies of EU member states and/or potential export countries exceeds the projected pipeline capacities (as reflected in the TYNDP 2024).

In the TYNDP 2026 scenario design, the maximum theoretical flows potential for each pipeline import corridor is calculated by using a two-step approach.

First, the import potential is adjusted using the "lesser of" rule. This conservative approach limits imports to the reported potential, if import potentials are lower than the 2024-reported pipeline capacities, and also caps import potentials based on the reported pipeline capacities, if import potentials exceed them (see Table 13 below).

GWh/DAY (NCV)	2030	2035	2040	2050
Italy	180	280	379	379
Spain	0	0	89	90
Hungary	0	0	0	0
Slovakia	121	121	121	121
Netherlands	0	0	0	0
Germany	0	0	0	0

Table 13: Hydrogen imports potentials: lesser of rule applied

Secondly, import potentials are reduced to maximum theoretical flows potentials to reflect the volatile nature of renewable hydrogen production in exporting countries. Renewable hydrogen imported from non-EU member states will be subject to varying production volumes from intraday to seasonal dynamics. The following approach was used to obtain these theoretical flow potentials:

- Creating hourly synthetic renewable hydrogen production profiles using the planned project locations, as listed in the Fraunhofer PtX Atlas , the corresponding renewable generation technology mix stated for these projects, and location-specific hourly weather profiles. Using the PtX Atlas as a basis, means that the underlying renewable production profiles do not correspond to the synthetic weather scenarios used for the different scenario runs (see Section 6), but to historic weather profiles from 2019.
- Sizing the hydrogen production in the exporting countries using these synthetic renewable hydrogen production profiles provides a maximum daily flow through the pipelines, ensuring that hydrogen production does not exceed the daily import potential (the "lesser of"-rule is applied).

This approach was chosen to reflect the expected volatility of hydrogen production in producer countries, while also recognising that these countries will have some degree of flexibility to mitigate intra-daily volatilities due to domestic hydrogen storage and linepack, at least on an intra-day basis. For Ukraine, the capability to mitigate renewable hydrogen production volatilities on a monthly basis is assumed from 2040 onwards. This assumption is based on the strong role of hydrogen storage capabilities are expected to play in the country's long-term prospectives[8]. For the Italian corridor, the role of Tunisia and Algeria as two separate entry points for the planned interconnector infrastructure has been taken into account when calculating flows.

The Table 14 below lists the maximum theoretical flow potentials for each pipeline import corridor. Please note that the daily flows presented are average values with the resulting flow potential patterns showing clear seasonal variations across all corridors.

MAXIMUM THEORETICAL FLOW POTENTIALS					
GWh/DAY (NCV)		**2030**	**2035**	**2040**	**2050**
Italy	average	143	230	316	316
	min	73	145	212	212
	max	180	277	373	373
Spain	average	0	0	73	73
	min	0	0	44	44
	max	0	0	89	89
Slovakia	average	58	58	89	89
	min	1	1	46	46
	max	121	121	121	121

Table 14: Maximum theoretical flow potentials for each hydrogen pipeline import corridor

8 https://www.iea.org/reports/unlocking-ukraines-hydrogen-opportunity-a-roadmap/the-hydrogen-opportunity

5.7.2 Imports by ship

The basis for the shipped hydrogen import capacities is the TYNDP 2024 projects, excluding cancelled projects, as summarised in Table 15 below. The original list of projects submitted to the TYNDP 2024 can be found in Annex A on the ENTSOG homepage.

Imports capacities from projects delivered to TYNDP 2024 (starting point)

SHIPPED H_2 IMPORTS GWh/DAY	2030	2035	2040	2050
Germany	37	57	274	274
Netherlands	116	116	189	189
Italy	0	0	28	28
Belgium	50	91	177	177
France	0	41	41	43
Greece	0	0	42	42
Poland	15	15	15	15

Table 15: Hydrogen (H_2) import capacities from projects delivered to TYNDP 2024

As with pipelines, these figures are updated using data collected from TSOs during the TYNDP 2026 data collection phase. This incorporates national long-term strategies, political views, and the expected increase in conversion capacity, which is elaborated further in Table 16.

Imports potentials (Starting point adjusted with political views and long-term strategies)

SHIPPED H_2 IMPORTS (FOR ENERGY) GWh/DAY	2030	2035	2040	2050
Germany	52	75	75	75
Netherlands	74	197	649	729
Italy	41	41	82	82
Belgium	66	181	211	238
France	20	61	76	106
Greece	0	42	42	42
Poland	15	15	15	15

Table 16: Hydrogen (H_2) import potentials

Adjustment to the national long-term strategies and political views indicate that some projects will be completed later than anticipated in the TYNDP 2024. At the same time import potential to the Netherlands, Belgium and other countries has been increased for later years (2040 and 2050). In contrast, Germany shows the opposite trend, with a more conservative political outlook than the project-based values.

For shipped hydrogen imports, the import potential is based on the lower value of the two values, meaning a conservative 'lesser of' methodology has been applied. The final numbers based on this approach are presented in Table 17 below.

Imports potentials (lesser of rule applied)

SHIPPED H_2 IMPORTS GWh/DAY	2030	2035	2040	2050
Germany	37	57	75	75
Netherlands	74	116	189	189
Italy	0	0	28	28
Belgium	50	91	177	177
France	0	41	76	106
Greece	0	0	42	42
Poland	15	15	15	15

Table 17: Hydrogen (H_2) import potentials: lesser rule applied

5.7.3 Hydrogen Import Costs

In the model, hydrogen imports are represented by two cost bands. Together, these import cost bands represent the main market dynamics that are expected to dominate the future trade of non-EU hydrogen imports.

Long-term contracts (LTC) with take-or-pay obligations are expected to be essential for the economic viability of infrastructure and investments in non-EU hydrogen import. Exporting countries, particularly those with a comparably low internal demand for renewable hydrogen, will require long-term off-take commitments. In an economic dispatch model such as that used for the TYNDP 2026 Scenarios, LTCs are represented as inelastic hydrogen supply, reflecting the contractual obligation to deliver predefined volumes irrespective of short-term market conditions. As a simplification, these flows are assumed to be non-price-responsive and are therefore modelled as an inelastic import component with a cost of 0 €/MWh. Due to the sector-coupled set-up, this representation can propagate into the electricity market by lowering the implied cost of hydrogen as a fuel and thereby affecting the merit-order position and dispatch of hydrogen-based generation.

In contrast, spot market-driven hydrogen imports that occur depending on their competitiveness with domestic EU hydrogen production. This allows them to flexibly react to economic signals of domestic hydrogen supply scarcity and fluctuating hydrogen demand. Since an economic dispatch model is used, the supply cost of market-driven hydrogen imports is modelled using the corresponding marginal production and transport costs.

Marginal production and transport costs are estimated using the EWI Global PtX Cost Tool in its version released in June 2025.

The cost calculation in the EWI tool, uses baseline investment cost assumptions are used (which can be baseline or optimistic), affecting all production units investment costs in the origin countries. For hydrogen pipeline costs and shipping charter rates, the medium-cost options are selected from the available ranges (high-cost new, low-cost new, repurposing for pipelines; medium-cost, high-cost, low-cost for shipping). Greenfield infrastructure is assumed instead of retrofitting, because consistent information on the proportion of retrofitting for individual projects is unavailable. In any case, pipeline costs represent only a relatively small proportion of the total costs in the tool. The tool's option that prioritises power generation over Power-to-X is not activated, because it would allocate the best renewable energy potential in each country to domestic electricity demand first and only use second-best sites for hydrogen production. As the analysis relies on proxy data for renewable potential, this option is not considered appropriate here.

Several adjustments have been made to the default methodology of the EWI tool in relation to the weighted average cost of capital (WACC), as the original WACC values are uneven and reflect current conditions rather than future developments. The new values use today's country-specific country default spreads and risk premiums.[9] For Tunisia, Algeria's WACC (15.6%) is used as a proxy for the higher Tunisian value (21.1%). For Ukraine, Romania's WACC (12.8%) is used for the period 2040–2050 instead of Ukraine's (24.8%), and an average of the Romanian and Ukrainian WACC values is used for 2035.

The hydrogen import costs for the flexible import band are then derived by selecting specific cost components from the EWI tool. For hydrogen imported via pipeline, the calculation includes the levelised cost of electricity used to operate the electrolyser (i.e. electricity as feedstock) and the pipeline transport costs. Fixed operation and maintenance costs (FOM) and electrolyser CAPEX are not included. For hydrogen imported in the form of ammonia, the calculation includes the levelised cost of hydrogen used as feedstock to produce ammonia, the electricity costs for ammonia synthesis, transport costs for ammonia, the electricity and fuel costs for ammonia cracking, storage costs, and the costs associated with losses along the chain. FOM and CAPEX for ammonia production and cracking are disregarded.

Additionally, a water cost of 0.27 €/MWh is added, consistent with the value used in the previous cycle. All values originally expressed in US dollars are converted to euros using the average 2023 exchange rate (1 EUR = 1.0831 USD). Together, these elements form the basis for the marginal hydrogen import costs applied to the higher-cost import band in the model.

9 https://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/ctryprem.html

The hydrogen costs used in the model, computed with the EWI tool, are displayed in the Table 18 below.

H_2 IMPORT COSTS				
IMPORT ROUTE (€/MWh)	**2030**	**2035**	**2040**	**2050**
H_2 imported as ammonia	225.3	210.0	196.4	180.9
Tunisia-Italy	106.9	102.7	99.7	95.5
Algeria-Italy	Not online	102.7	99.7	95.5
Ukraine-Slovakia	246.0	185.8	164.4	142.9
Morocco-Spain	Not online	Not online	73.7	70.1

Table 18: Hydrogen Import Costs

5.7.4 Methodology

The NT+ scenario and Economic Variants use the import capacities from projects submitted to the TYNDP 2024 (excluding cancelled projects), considering maximum theoretical flow potentials for pipeline imports and import potentials applying the "lesser of" rule for shipped hydrogen and ammonia imports.

Additional potential reflecting national long-term strategies and political views beyond the reported projects (see Table) is only made available to the model in the SOS loop.

LTC and spot market-driven imports are reflected using two different cost bands. This division represents a split between an inelastic part (LTC) and a flexible part. For both the NT+ scenario and the Economic Variants, the LTC represents 50% of the maximum theoretical import pipeline flow potential, calculated based on the hourly supply profile. This is shown conceptually for a seven-day period, below. The remaining flow potential is considered fully flexible and available at marginal costs. For ammonia imports, the LTC represents 50% of the import potential when the "lesser of" rule is applied.

Hydrogen supply sensitivity

In addition to the 50% LTC band selected for the NT+ scenario and the Economic Variants stress tests, further sensitivity analysis is conducted on the hydrogen supply mix structure. In this case, the LTC band for non-EU imports is varied as an exploratory exercise in the NT+ scenario's results when alternative assumptions are applied to all modelled target years. This sensitivity analysis is intended as an exploratory exercise on the hydrogen supply structure. For reference, it considers the indicative direction outlined in the REPowerEU Plan, which refers to a 50/50 split between non-EU imports and EU production by 2030, with the aim of moving away from importing Russian fossil fuels into EU.

The narrative and results of this supply sensitivity analysis, which increases the LTC share for all non-EU import corridors to 80%, are discussed further in the Scenario Report.

This illustrative sensitivity analysis (see Figure 6) does not affect the definition or interpretation of the central NT+ scenario. The assumptions, narrative and results of this sensitivity analysis are discussed separately in the Scenario Report.

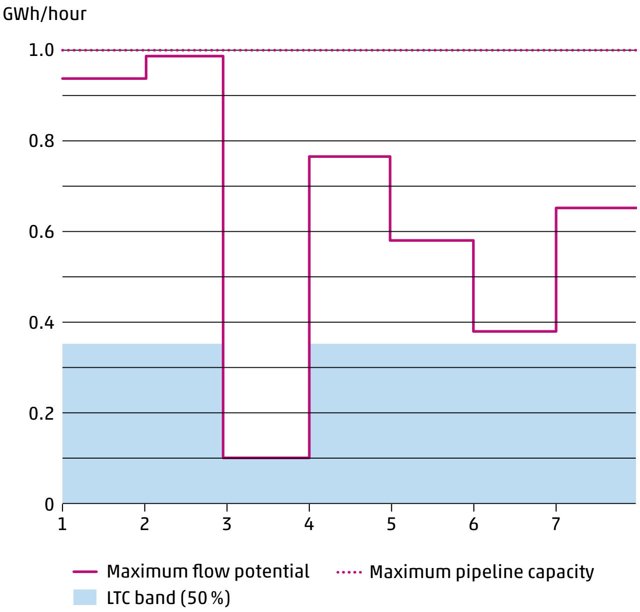


Figure 6: Conceptual LTC band for a 7 day period and pipeline capacity of 1 GWh/h assuming Daily fluctuating hydrogen production

6 WEATHER YEAR SELECTION //

Energy system outcomes are strongly influenced by weather conditions, which affect electricity demand, hydrogen demand, and other temperature-dependent energy uses, as well as electricity supply through wind, solar and hydro generation. For TYNDP 2026, the weather representation is enhanced by explicitly integrating future climate projections, ensuring that the analysis reflects expected climate change impacts over long-term horizons.

Climate and energy related variables considering the impact of climate on wind, solar and hydro energy generation are sourced from the Pan-European Climate Database (PECDv4.2), combining historical consistency with climate projections from the CMIP6 framework under the SSP2-4.5 emission scenario. For each TYNDP target year (2030, 2035, 2040 and 2050), weather conditions are represented by a pool of 30 candidate climate years derived from three climate models and a 10-year moving window around each horizon.

Simulating the full set of 30 climate years would lead to disproportionate computational effort with limited additional insight. Therefore, a statistical selection methodology is applied to identify three representative weather years per target year, preserving the diversity of renewable generation conditions and temperature-driven demand while keeping the modelling tractable.

The selection is based on key climate and energy related variables relevant for the European power system: wind, solar and hydro generation, as well as temperature indicators (heating and cooling degree days), derived by linking PECDv4.2 data with PEMMDB data. These variables are aggregated at macro-regional level, normalised, and analysed using dimensionality reduction and clustering techniques (k-means) to identify distinct weather regimes. For each regime (cluster), a representative climate year is selected by identifying the climate year closest to the centroid of each cluster.

The three selected weather years are assigned probability weights reflecting the share of candidate years belonging to each weather regime in relation to all the 30 climate years. These weighted weather scenarios are used to combine simulation results from different climatic conditions into a single set of representative outcomes for each target year, constituting the climatic basis for demand profiling, renewable and hydro timeseries generation, and power market simulations, while also ensuring consistency for other climate-sensitive energy demands modelled in TYNDP 2026.

The full methodological description of the weather year selection, including data processing, statistical indicators, clustering techniques and probability weighting, is provided in Annex III.

7 GRID //

To achieve the robustness of the scenario development, the construction of the Scenario Grid for TYNDP 2026 follows the overarching methodological logic applied in previous cycles and reflects the broader requirement that all components of the scenario framework must remain fully aligned with the suite of national and European planning documents and policy commitments.

It is important to note that the electricity and hydrogen grids used in the scenarios draw upon project data originating from different TYNDP cycles. This is a consequence of the fact that ENTSO-E and ENTSOG conduct their project collection according to the timelines established for their respective TYNDP processes, which, although broadly coordinated, do not follow an identical calendar. As a result, the project information available for the electricity system reflects the TYNDP2026 collection conducted in the first half of 2025, whereas the hydrogen system relies on the project list assembled for TYNDP2024 conducted in Q4 of 2023, complemented by a review to ensure the continued relevance of the data.

In addition to the formal TYNDP project collections, ENTSO-E and ENTSOG carried out a joint request in Q2 2025 for the submission of long term "conceptual capacity increases", corresponding to potential new interconnections for which preliminary investigations had already been conducted. These conceptual submissions—required to be technically sound, aligned with EU 2050 climate objectives and jointly agreed between the relevant countries – underwent a dedicated screening process and are used exclusively in the Scenario Grid for the 2050 horizon in both vectors. They are not considered in the TYNDP processes outside the scenario framework (including Identification of System Needs, Cost-Benefit Analysis, or the project lists associated with those processes).

Under this approach, the Scenario Grid forms the infrastructural backbone for the modelling of the 2030, 2035, 2040 and 2050 horizons. Its role is not to anticipate system needs nor to prejudge the outcomes of ongoing network development processes, but rather to provide a technically credible, policy consistent and maturity constrained representation of the European transmission system, ensuring that cross vector interactions and long term dynamics are assessed within a coherent and operationally meaningful network environment.

7.1 Electricity grid (incl. offshore)

The electricity transmission grid represented in the TYNDP 2026 Scenarios constitutes a critical input to the market modelling framework. Its configuration directly influences simulated cross-border exchange capacities and generation dispatch patterns across all target years. The Scenario Grid is therefore constructed with the objective of reflecting the most plausible evolution of European transmission infrastructure over the planning horizons considered.

The grid representation is derived from the ENTSO-E TYNDP 2026 project collection, which constitutes the most comprehensive and up-to-date dataset of planned transmission infrastructure available at the time of modelling. This dataset is compiled through a structured data-collection process involving all ENTSO-E member TSOs and, where applicable, third-party project promoters. It captures both internal reinforcement projects and cross-border interconnection investments across the ENTSO-E perimeter and its neighbouring systems.

To ensure that the scenarios reflect credible infrastructure trajectories, a maturity-based filtering approach is applied. Not all projects in the collection are included in all horizons; rather, infrastructure is incorporated into a given target year only when its commissioning can be considered plausible based on the project's maturity status at the time of data collection. This methodology is grounded in the principle that scenario credibility requires alignment between assumed infrastructure and the realistic pace of project development, permitting, and construction.

The maturity classification applied to the TYNDP 2026 project set follows the categories defined in the ENTSO-E CBA Guidelines (4^{th} edition), which establish a standardised taxonomy for assessing transmission project readiness. These categories reflect the progressive stages of infrastructure development, from initial conceptual planning through to active construction. The framework ensures a consistent, transparent, and reproducible basis for determining which projects are sufficiently advanced to be included in each modelling horizon.

The maturity categories, in order of increasing advancement, are summarised below in Table 19:

MATURITY	DESCRIPTION	KEY CHARACTERISTICS
Under Consideration	Project at an early stage of development, with preliminary studies underway or conceptual design initiated.	No formal permitting process commenced; feasibility or pre-feasibility studies may be ongoing.
Planned – Not Yet in Permitting	Project included in formal planning frameworks but not yet submitted for permitting.	Typically included in a National Development Plan or equivalent; system need identified; preliminary technical design available.
In Permitting	Permitting process formally initiated; project under active review by relevant authorities.	Application submitted to permitting authority; Environmental Impact Assessment (EIA) may be in progress; public consultation may have been initiated.
EIA Completed	Environmental Impact Assessment process concluded; project approved from an environmental perspective.	Permitting substantially advanced; remaining steps typically relate to final construction approvals or land acquisition.
Under Construction	Physical construction or procurement activities have commenced.	Final Investment Decision (FID) taken; contracts awarded; site works initiated or equipment manufacturing underway.

Table 19: Electricity transmission grid: maturity and key characteristics

This taxonomy provides the analytical basis for the horizon-dependent inclusion logic. By linking infrastructure assumptions to observable, documented milestones in the project development cycle, the methodology minimises the risk of over- or under-estimating future grid capacity in any given scenario.

The application of the maturity framework yields a structured, horizon-dependent selection logic that governs which projects are incorporated into the scenario grid for each target year. This tiered approach reflects the increasing uncertainty associated with longer planning horizons: near-term horizons require a higher level of project maturity, while more distant horizons accommodate projects at earlier stages of development.

The selection criteria for each horizon are as follows in Table 20:

HORIZON	MINIMUM MATURITY THRESHOLD	RATIONALE
2030	Under Construction or EIA Completed	Only projects with the highest maturity are included, reflecting the limited time remaining for commissioning. These projects have either commenced construction or completed the most critical permitting milestone, making their timely delivery highly probable.
2035	In Permitting or Planned (not yet in permitting)	The inclusion set expands to incorporate projects in active permitting or at an advanced planning stage. The longer lead time to this horizon provides a reasonable window for these projects to progress through remaining development stages.
2040	In Permitting or Planned (not yet in permitting)	As for 2035, projects in permitting or at an advanced planning stage are included. The additional time buffer further supports the expectation that these projects will reach commissioning.
2050	Selected Under Consideration + long-term conceptual projects	The set extends to selected Under Consideration projects and long-term conceptual projects submitted by project promoters during the Q2-2025 data-collection window. This reflects the exploratory nature of 2050 modelling and the need to capture strategic infrastructure trajectories.

Table 20: Electricity grid: Selection criteria for each time horizon: 2030, 2035, 2040 and 2050

For projects in the Planned – Not Yet in Permitting category, additional supporting evidence is assessed to determine the plausibility of inclusion. Relevant indications that may support a project's progression include, but are not limited to:

- Inclusion in a National Development Plan (NDP) or equivalent national infrastructure planning instrument;
- Existence of a national legal or regulatory obligation mandating the development of the project;
- Documented progress toward or achievement of a Final Investment Decision (FID);
- Evidence of formal interaction with permitting authorities, including pre-application consultations or scoping opinions;
- A clearly defined and documented system need, supported by national or pan-European studies;
- An indicative commissioning year consistent with the target horizon, as reported by the project promoter.

These indicators are evaluated collectively; no single criterion is deterministic, and the assessment is intended to capture a rounded view of each project's development trajectory.

Following the maturity screening, the resulting project set for each target year is translated into NTC values for use in market scenario modelling. NTC values represent the maximum commercial exchange capacity available at each cross-border boundary under normal system conditions and constitute the primary interface between the infrastructure assumptions and the market simulation toolchain. In the context of the TYNDP 2026 Scenario market modelling framework, NTC values define the upper limit of energy that can be traded between bidding zones in each direction at any given time step. These values are applied exogenously to the market model and directly constrain the optimisation of dispatch and trade flows. It is important to clarify that NTC values do not represent the physical or thermal capacity of the transmission assets. Instead, they reflect a commercial transfer limit derived from system security considerations and coordinated capacity calculation methodologies (including N 1 security criteria and related operational margins). As such, they are a reduced representation of grid capabilities, already internalising operational constraints such as security margins, contingencies, and stability requirements. Within the market simulation, NTC constraints are fully available to the optimisation algorithm at all time steps, without additional endogenous operational limitations. The model can therefore utilise up to 100% of the NTC value in any given direction whenever economically efficient, based on relative prices, generation dispatch patterns, and demand conditions across bidding zones. No explicit modelling of real-time operational constraints – such as dynamic security limits, redispatch actions, phase-shifting transformers, or flow-based allocation mechanisms – is implemented in the market simulations. Consequently, the use of NTC in the model should be understood as a simplified, zonal representation of cross-border exchange capabilities, consistent with long-term scenario analysis rather than detailed operational modelling.

2030 Scenario Electricity Grid

As shown in Figure 7, the 2030 Scenario Grid includes only projects classified as Under Construction or with a completed Environmental Impact Assessment. This yields a network closely aligned with the current transmission system, augmented by near-term reinforcements whose commissioning is highly probable within the horizon. Key features include established interconnection corridors in the North Sea and Baltic regions, as well as reinforcements across Central and South-Eastern Europe.

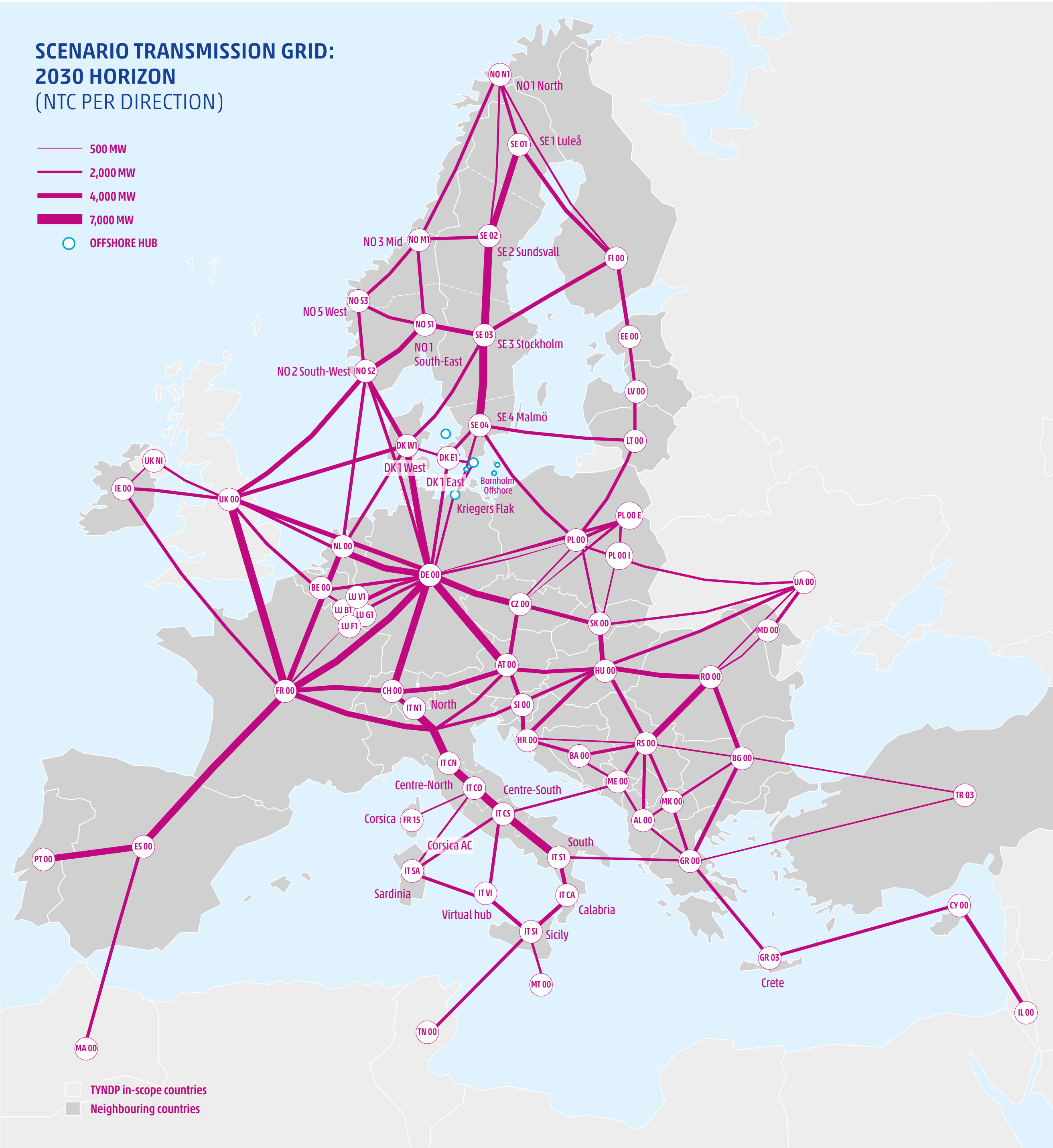


Figure 7: Scenario Electricity Transmission Grid: 2030 horizon (ntc per direction)

2035 Scenario Electricity Grid

The 2035 grid expands the project set to include those in permitting or at an advanced planning stage. Notable additions relative to 2030 include the emergence of additional offshore hub connections in the North Sea (NL Offshore North, NL Offshore South), the Sørlige Nordsjø hub, the LT Offshore hub in the Baltic, and new capacity on several onshore corridors, displayed in Figure 8. Several cross-border boundaries show increased NTC values, reflecting the maturation of projects currently in permitting.

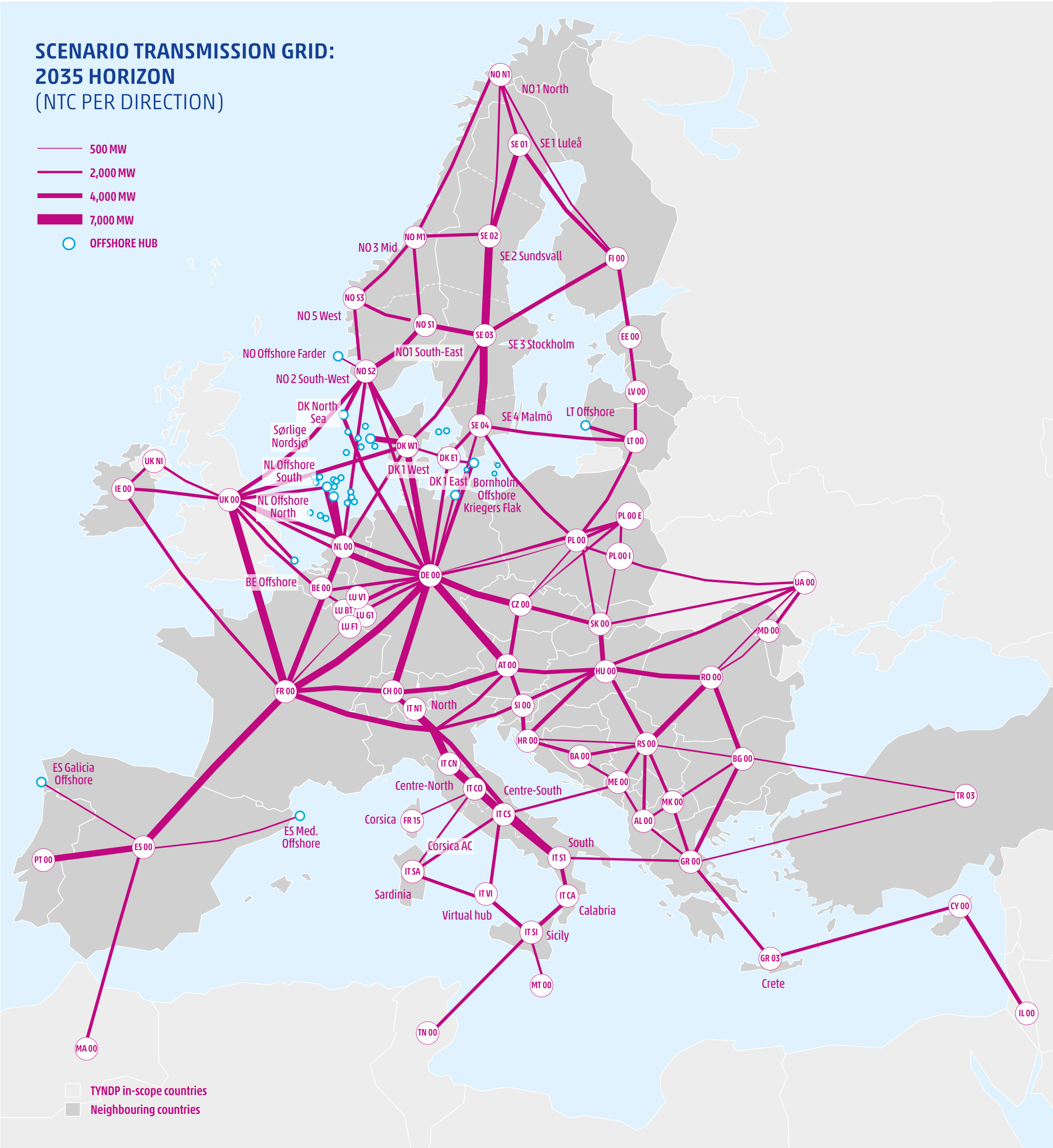


Figure 8: Scenario Electricity Transmission Grid: 2035 horizon (NTC per direction)

2040 Scenario Electricity Grid

The 2040 Scenario Grid applies the same maturity threshold as 2035 but captures projects whose indicative commissioning dates fall within the 2036–2040 window. Incremental changes relative to 2035 are visible, including the appearance of the NO Offshore West hub and further capacity reinforcements on several corridors in the Nordic, Central European, and Iberian regions (Figure 9). The overall topology remains broadly consistent with the 2035 grid, reflecting the relatively small number of additional projects entering the maturity window during this period.

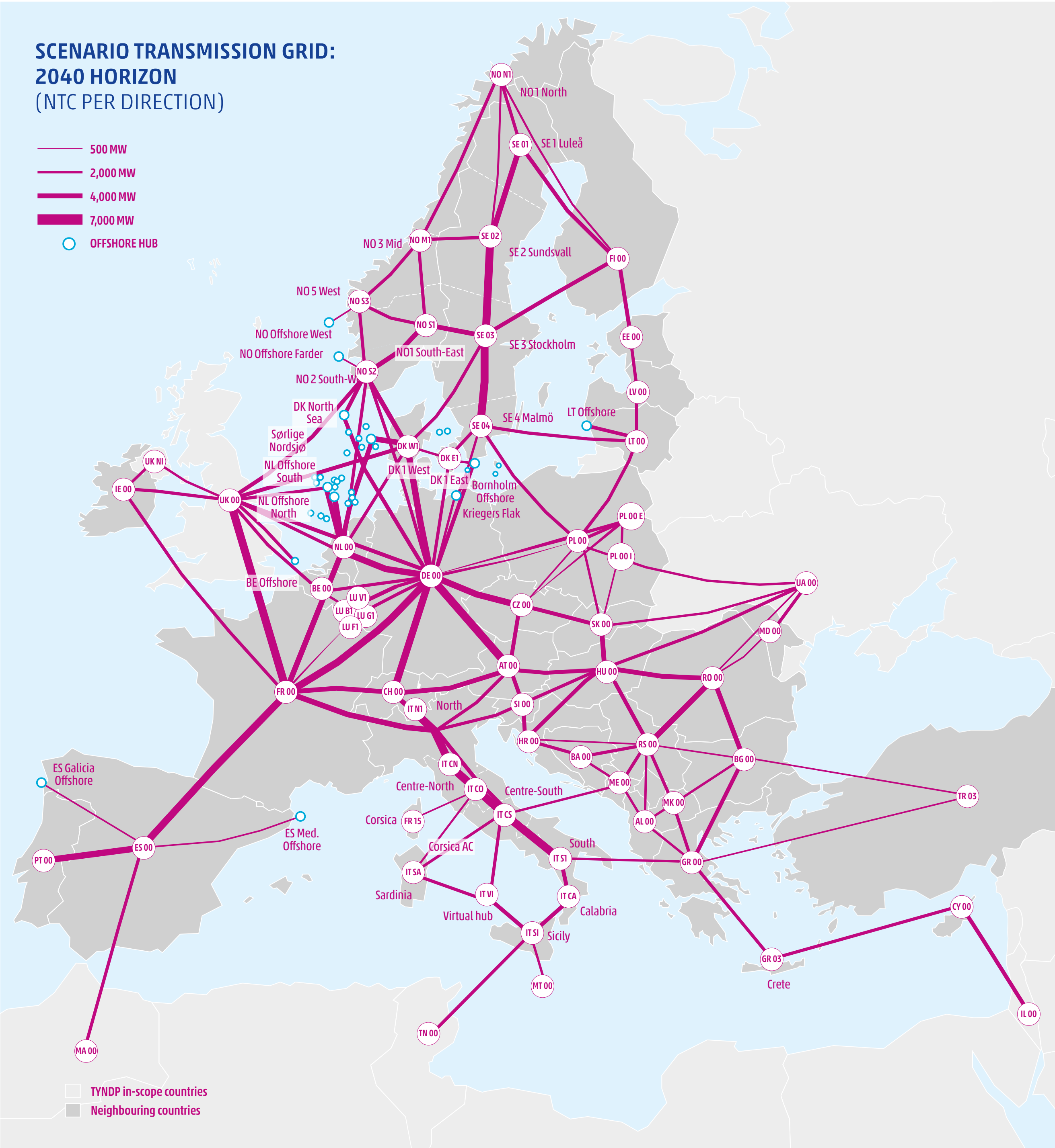


Figure 9: Scenario Electricity Transmission Grid: 2040 horizon (NTC per direction)

2050 Scenario Electricity Grid

The 2050 grid represents the most expansive topology across all horizons, incorporating selected Under Consideration projects and long-term conceptual submissions from the project data collection process (see Chapter 2). The most visible additions include the Nordland Offshore hub in northern Norway, the ES Offshore hub on the Iberian Atlantic coast, and further capacity increases across multiple corridors (Figure 10). The reinforcement of connections in South-Eastern Europe, the Eastern Mediterranean, and the Balkans is also evident. This grid reflects the strategic infrastructure vision needed to support the long-term decarbonisation trajectories embedded in the TYNDP 2026 scenario narratives.

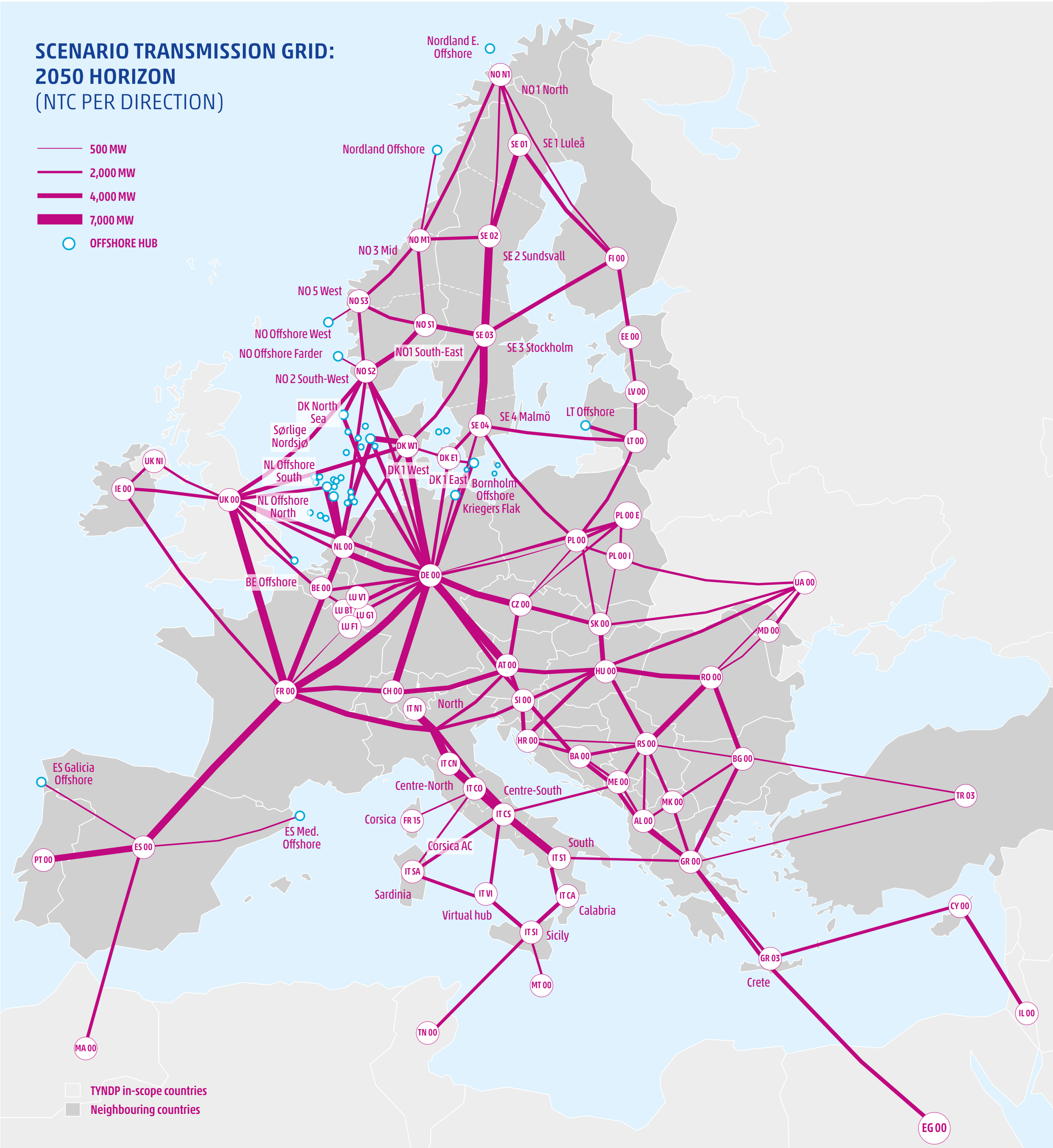


Figure 10: Scenario Electricity Transmission Grid: 2050 horizon (NTC per direction)

The 2050 target year warrants specific methodological consideration due to its position at the outer boundary of the planning timeframe. At this distance, infrastructure planning is inherently more speculative, and the project collection alone may not fully capture the grid evolution required to support long-term decarbonisation pathways, energy security objectives, or the integration of emerging energy vectors such as offshore renewable energy and cross-sectoral coupling.

To address this, the 2050 scenarios grid incorporates two additional categories of infrastructure beyond the standard maturity-filtered project set:

Selected "Under Consideration" projects: projects at an early stage of development that, while not yet in permitting, have been identified as strategically relevant for long-term grid development. Their inclusion is conditional on alignment with the scenario narratives and the system needs identified in the TYNDP 2026 Scenario modelling framework.

Long-term conceptual projects: submitted by project promoters during the concept project collection window, these represent forward-looking infrastructure concepts that extend beyond the current project pipeline. They may include novel interconnection corridors, offshore grid topologies, or reinforcements linked to emerging generation centres.

The inclusion of these categories in the 2050 horizon reflects the need for scenario-driven, rather than purely project-driven, grid assumptions at longer time scales. It also acknowledges that the realisation of ambitious climate and energy policy targets, as embedded in the scenario narratives, may require infrastructure investments that are not yet reflected in formal project pipelines.

7.2 Hydrogen grid (incl. offshore)

The hydrogen transmission grid configuration determines the spatial distribution of hydrogen production, consumption and trade across the European system, and through its coupling with the electricity sector via electrolysers, fuel-cell capacity and dispatchable hydrogen-fuelled units directly shapes the operational behaviour of the wider energy system in every target year.

The hydrogen grid is derived from the ENTSOG TYNDP 2024 project collection, complemented by an updated screening exercise to retain only those projects that remain relevant at the time of TYNDP 2026 scenario development. The scenario grid does not pre-empt or determine the project-based grid that will be assembled following the TYNDP 2026 hydrogen project collection. Its purpose is to provide a technically credible representation of the hydrogen transmission backbone, ensuring that cross-carrier interactions and long-term dynamics are assessed within a coherent environment.

Two-zone country topology

To balance modelling tractability with the level of granularity required to capture cross-vector interactions, each country in the TYNDP 2026 hydrogen perimeter is represented through a two-zone topology. This structure separates hydrogen volumes that interact with the high-pressure transmission backbone from those that are produced and consumed locally without recourse to the national grid, thereby preventing localised production from being implicitly pooled with the wider European market.

Zone 1 – Off-grid hydrogen system. Zone 1 represents localised hydrogen activity that does not require access to the national transmission grid. It encompasses dedicated production assets such as Steam Methane Reformers and specific industrial demand that is satisfied by co-located supply. Volumes in Zone 1 cannot flow to other countries.

Zone 2 – National transmission backbone. Zone 2 represents the high-pressure national hydrogen transmission system and acts as the central hydrogen market within each country. It captures cross-border pipeline flows, large-scale geological storage (e.g., salt caverns), import terminals (pipeline imports from non-EU sources and ammonia/hydrogen carrier terminals), and demand or production capacities connected to the transmission grid. Cross-border exchanges between countries occur exclusively through Zone 2.

The split between Zone 1 and Zone 2 is determined country by country, based on TSO inputs regarding the connection point of each production, storage and demand asset.

Reference grid and infrastructure inclusion logic

The TYNDP 2026 approach constructs a Reference Grid based on real project data submitted by TSOs and project promoters in the TYNDP 2024 process. The Reference Grid for a given horizon is the union of all hydrogen transmission projects whose status meets the maturity threshold associated with that horizon, complemented at the longer horizons by selected conceptual projects intended to capture the strategic infrastructure visions.

To prevent the Reference Grid from being inflated by outdated project plans that are no longer aligned with current ambitions, TSOs were given the possibility, during scenario building, to downscale or cancel project capacities that they considered unrealistic at the relevant horizon. TSOs were not, however, allowed to invent and add entirely new projects during scenario building: any such projects must enter the Scenario Grid through the formal project collection process.

Maturity classification

As with electricity, infrastructure is incorporated in a given horizon only when its commissioning can be considered plausible based on its maturity status at the time of data collection. Following the categories defined in the ENTSOG CBA Guidelines, the hydrogen project set is structured into three maturity levels, shown in Table 21:

MATURITY CATEGORY	DESCRIPTION	KEY CHARACTERISTICS
PCI/PMI infrastructure level	Projects with recognised strategic relevance at European level.	Includes existing hydrogen infrastructure, projects with FID, PCI/PMI-labelled assets and EC-requested import corridor adjustments.
Advanced infrastructure level	Projects with demonstrated development progress.	Includes projects with commissioning date ≤2030, inclusion in national plans or validated market tests.
Less Advanced infrastructure level	Early-stage projects.	Includes assets in conceptual, design or planning phases.

Table 21: Hydrogen (H_2) transmission grid: maturity and key characteristics

This classification provides the analytical basis for the horizon-dependent inclusion logic, reflecting different levels of project certainty across time horizons.

Horizon-dependent inclusion criteria

The progressive inclusion of projects across horizons reflects increasing uncertainty and longer development timelines. For 2030 and 2035, the grid is restricted to PCI/PMI-level and Advanced projects. For 2040 and 2050, the grid is allowed to incorporate Less Advanced and conceptual projects, in order to support the long-term supply and demand visions expressed in the scenario narratives (see Table 22).

HORIZON	MINIMUM MATURITY THRESHOLD	RATIONALE
2030	PCI/PMI + Advanced	Focus on mature infrastructure with high likelihood of commissioning in the short term.
2035	PCI/PMI + Advanced	Addition of projects in advanced development stages with commissioning date ≤2035.
2040	PCI/PMI + Advanced + Less Advanced	Inclusion of earlier-stage projects whose development trajectory may credibly support commissioning by 2040.
2050	All maturity levels + conceptual capacity increases	The grid incorporates all maturity levels–PCI/PMI, Advanced and Less-Advanced–together with a limited set of ex-ante conceptual capacity increases submitted in response to the joint ENTSO-E/ENTSOG request launched in Q2 2025.

Table 22: Hydrogen (H_2) grid: Selection criteria for each time horizon: 2030, 2035, 2040 and 2050

Through this maturity-driven approach, the hydrogen transmission system evolves in a stepwise manner across the four horizons, reflecting a combination of repurposed natural gas assets and newly built hydrogen corridors.

Operational constraints for hydrogen infrastructure: ramp rates and line pack

In order to achieve more realistic flows, in line with the physical constraints of the hydrogen transport network, H_2 infrastructure (pipelines, NH_3 terminals, SMR) is subject to operational constraints. Ramp-rate constraints have been introduced in the model to reflect limitations related to hydrogen transport velocity in pipelines, and the modulation capacity (i.e. hourly flow variation) of NH_3 terminals or SMR production. These constraints are used as a proxy for physical limitations.

Ramp-rate formulation: Ramp rates are specified in MW/min (implemented as a percentage of net capacity per minute) and applied to each pipeline's net capacity as well as to terminal infrastructure. The applicable rate depends on the asset class:

- Cross-border pipelines: ramp rates are derived from the maximum capacity of the pipeline, the physical properties of hydrogen, and the distance between the connected nodes, using an indicative travel speed of the gas of approximately 25 to 50 km/h. As an order of magnitude, a 600 km pipeline would therefore take roughly 24 hours to ramp from 0% to 100% of its capacity. This prevents unrealistic hourly fuel-switching spikes between distant European nodes.
- Import and storage terminals (e.g., NH_3 import terminals): ramp rates are set at 2%/h of maximum capacity, reflecting realistic send-out modulation.
- Steam Methane Reformers (SMR): ramp rates are set at 1.6%/h of maximum capacity, consistent with the thermodynamic and operational limits of large reforming units.

Note: Import pipelines (from non-EU countries: UA, TN, DZ, NO, MA to EU country) are not subject to operational speed constraints, as import capacities are unidirectional and already reflect variations in green hydrogen production profiles.

2030 Scenario Hydrogen Grid

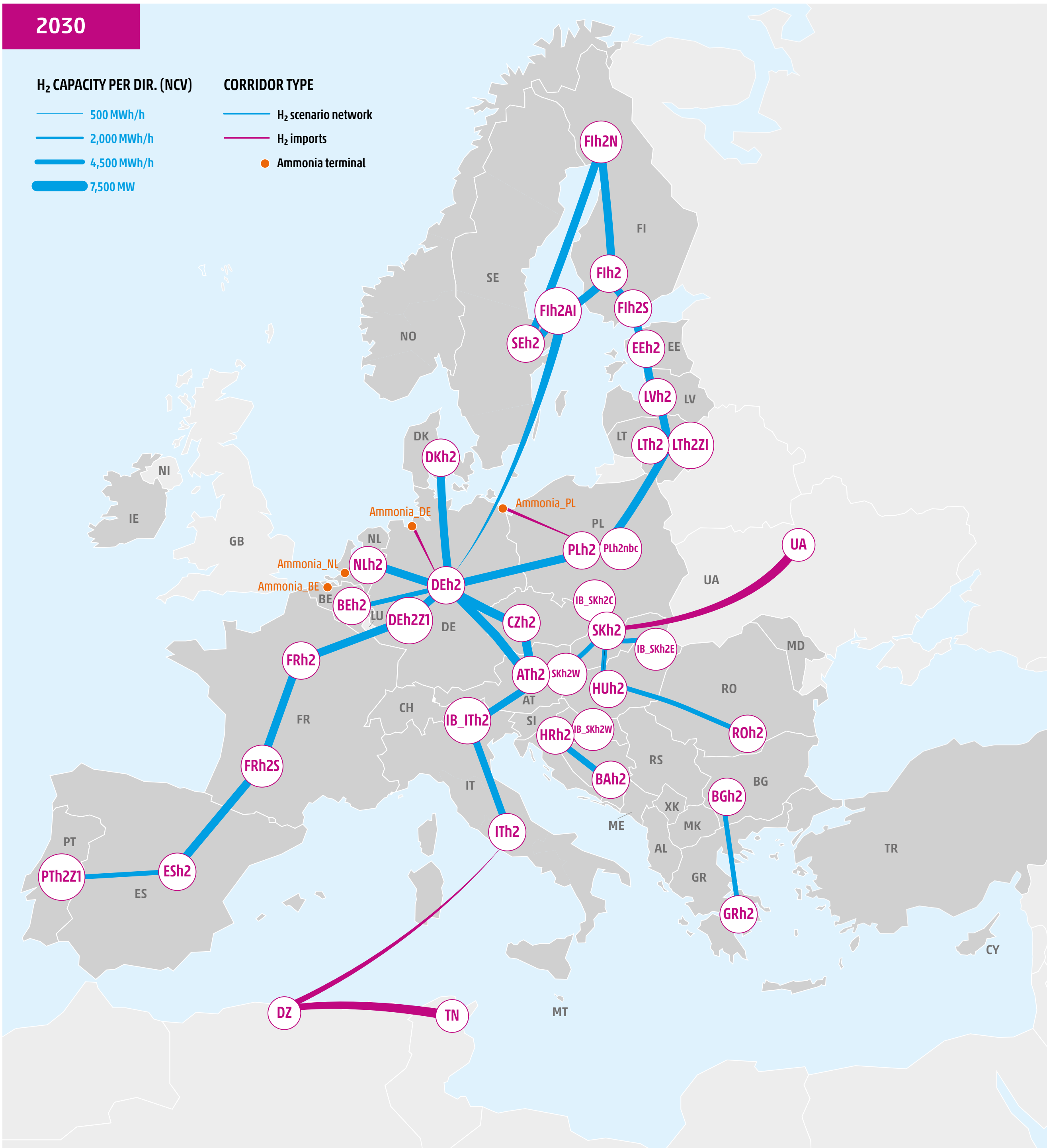


Figure 11: Scenario Hydrogen Transmission Grid: 2030 horizon

The 2030 hydrogen grid is primarily composed of PCI/PMI and Advanced infrastructure, resulting in a network characterised by:

- Limited cross-border connectivity
- Strong reliance on nationally or regionally developed assets
- Early-stage hydrogen corridors

This configuration reflects the initial phase of hydrogen system development, where infrastructure expansion is still constrained by project maturity and deployment timelines (compare Figure 11).

2035 Scenario Hydrogen Grid

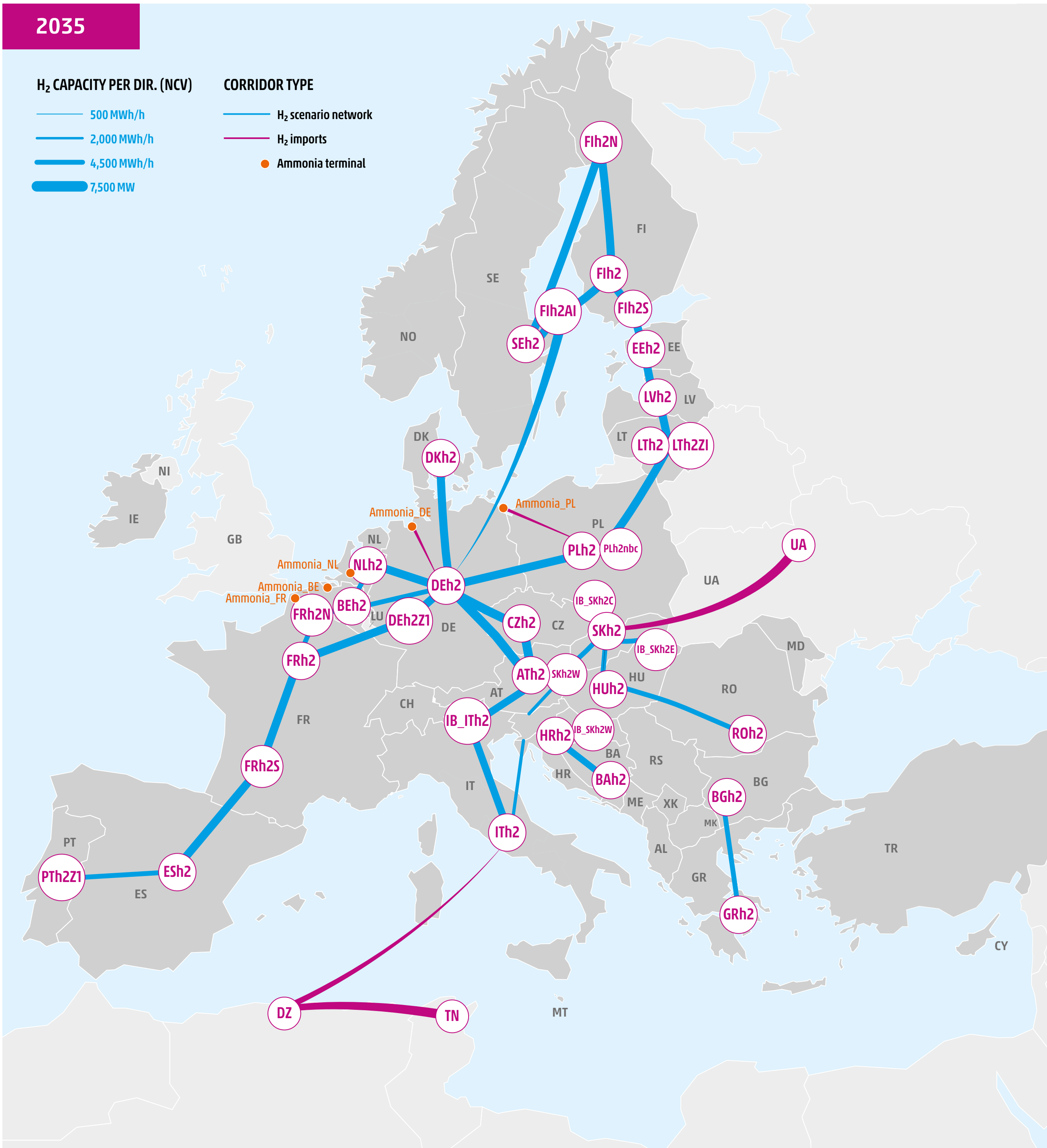


Figure 12: Scenario Hydrogen Transmission Grid: 2035 horizon

By 2035, the hydrogen grid expands through the inclusion of additional Advanced projects, leading to:

- increased cross-border connectivity
- the emergence of regional corridors
- stronger links between production and consumption zones

This horizon marks a transition towards a more coordinated European hydrogen system, although connectivity remains uneven across regions (see Figure 12).

2040 Scenario Hydrogen Grid

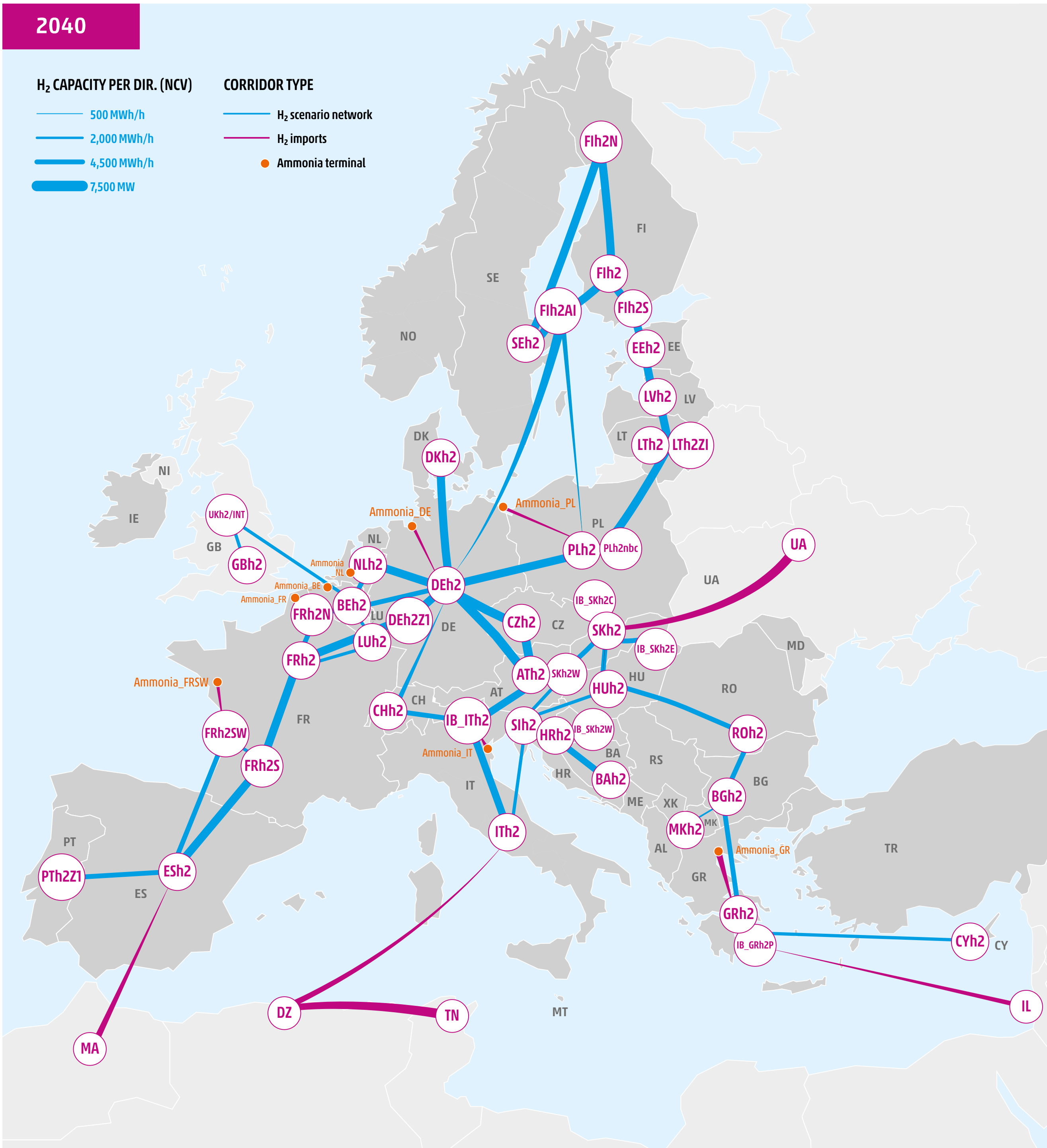


Figure 13: Scenario Hydrogen Transmission Grid: 2040 horizon

The 2040 horizon introduces selected Less Advanced infrastructure, enabling:

- further expansion of cross-border connections
- reinforcement of emerging hydrogen corridors
- improved system integration across regions

The network becomes increasingly interconnected, supporting more flexible hydrogen flows and enhanced system coordination (see Figure 13).

2050 Scenario Hydrogen Grid

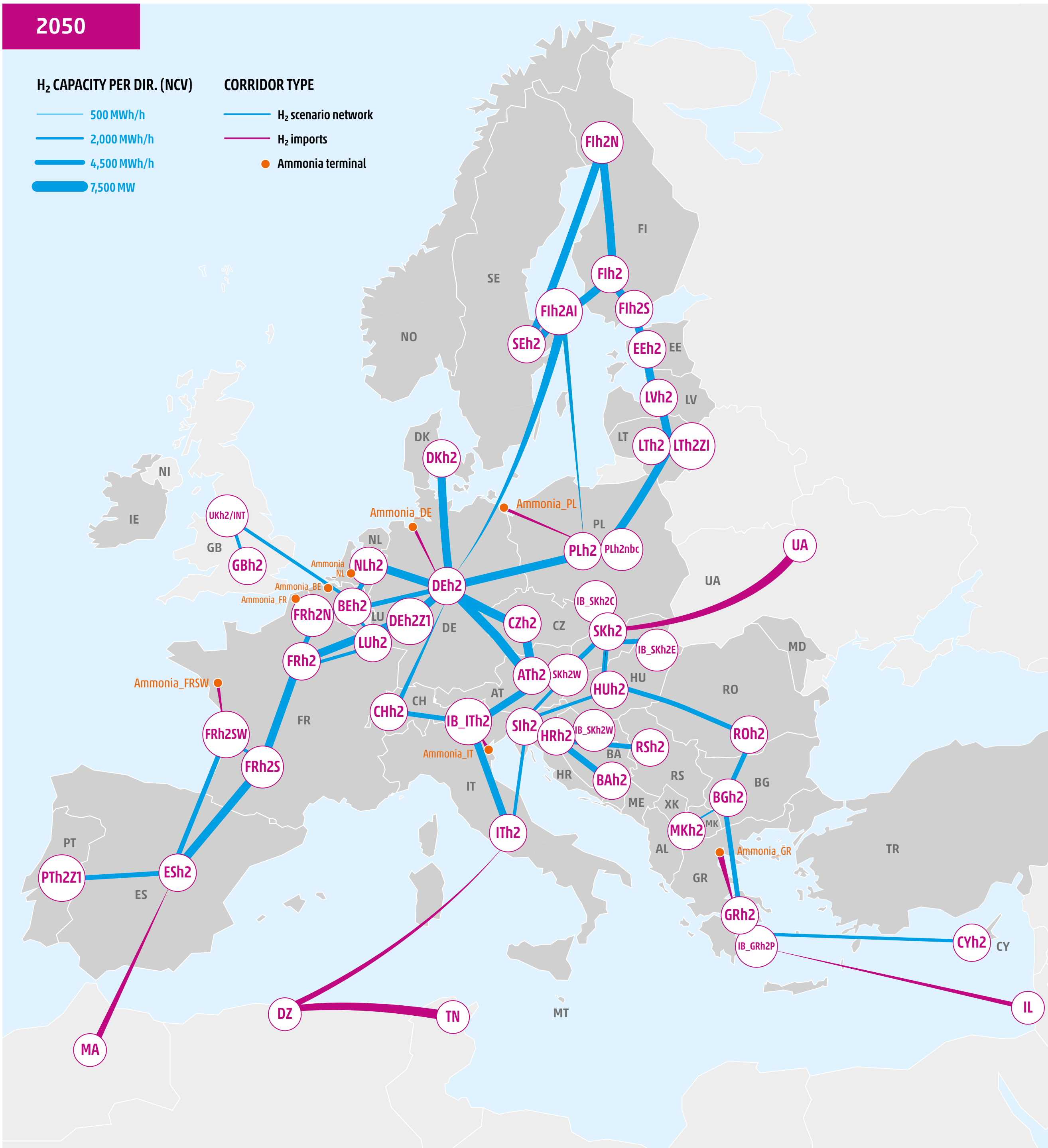


Figure 14: Scenario Hydrogen Transmission Grid: 2050 horizon

The 2050 hydrogen grid represents the most extensive and interconnected configuration, incorporating all maturity levels together with long-term conceptual capacity increases identified through the joint ENTSO-E/ENTSOG data collection process (see Figure 14).

Key characteristics include:

- fully developed cross-border hydrogen corridors
- integration of import infrastructure from neighbouring regions
- strong coupling between major production hubs and demand centres

This configuration reflects the strategic role of hydrogen in long-term decarbonisation pathways and the need for a sufficiently developed transmission system to enable large-scale deployment across Europe.

Methodological considerations for the 2050 horizon

As with the electricity grid, the 2050 horizon warrants specific methodological consideration due to its position at the outer boundary of the planning timeframe. At this distance, infrastructure planning is inherently more speculative, and the ENTSOG project collection alone may not fully capture the grid evolution required to support long-term decarbonisation pathways, energy security objectives, or the integration of emerging hydrogen vectors such as offshore production hubs and large-scale ammonia imports.

To address this, the 2050 hydrogen Scenario Grid incorporates two additional categories of infrastructure beyond the standard maturity-filtered project set:

- Selected Less Advanced and "conceptual" projects: hydrogen transmission projects at an early stage of development that, while not yet sufficiently mature for inclusion at earlier horizons, have been identified as strategically relevant for the long-term hydrogen system. Their inclusion is conditional on alignment with the scenario narratives and the system needs implied by the sectoral demand and supply trajectories.
- Long-term conceptual capacity increases: submitted by ENTSO-E and ENTSOG members during the joint Q2-2025 request, these represent forward-looking infrastructure concepts that extend beyond the current TYNDP project pipeline. Submissions had to be technically sound, aligned with EU 2050 climate objectives and jointly agreed between the relevant countries, and they underwent a dedicated screening process before being incorporated into the 2050 Scenario Grid.

The inclusion of these categories at the 2050 horizon reflects the need for scenario-driven, rather than purely project-driven, grid assumptions at longer time scales, and acknowledges that the realisation of ambitious climate and energy policy targets such as those embedded in the TYNDP 2026 scenario narratives may require hydrogen transmission investments that are not yet reflected in formal project pipelines.

8 MODELLING METHODOLOGIES //

8.1 Modelling principles

The TYNDP 2026 scenario modelling is based directly on the methodological framework developed for the TYNDP 2024 top-down scenarios, ensuring continuity, transparency and comparability across scenario cycles. At the same time, selected refinements have been introduced, reflecting stakeholder feedback, evolving data collection methods, modelling limitations identified by the scenario team, and technical issues identified during the 2024 scenario cycle.

The core objective of the modelling framework is to represent the operational behaviour of the European energy system under different scenario assumptions, with a particular focus on supply–demand balances, hydrogen import, cross border exchanges and interactions between the electricity and hydrogen sectors. The scenarios are designed to illustrate how the European energy system may operate under the assumptions defined in the National Energy and Climate Plans (NECPs) and under a selected set of weather conditions. They are not intended to assess network performance or to identify infrastructure investment needs, as these aspects are addressed through dedicated TYNDP network analyses and planning processes.

The modelling setup is fully aligned with the scenario grid assumptions and the input data provided by TSOs. The analysis does not rely on Monte Carlo simulations; instead, all runs are carried out using a single, fixed outage pattern for the power plants.

8.2 Modelling topology

The modelling framework represents the European energy system as an integrated set of electricity and hydrogen markets, with explicit interactions between both sectors.

The EU electricity sector is modelled with an hourly resolution, aiming to replicate day ahead market operation under a perfect foresight assumption, and is explicitly coupled with a detailed EU hydrogen market representation. In addition to electricity and hydrogen, part of the residential heat demand is modelled using Hybrid Heat Pumps. Synthetic fuel demand is introduced exogenously, while the model determines endogenously whether this demand is met through domestic production or through imports from outside the EU, depending on relative prices and availability.

General modelling topology

Figure 15 on page 55 illustrates the generic modelling topology applied to represent the electricity and hydrogen systems, and their interactions with other carriers.

The topology is applied consistently across all countries where detailed input data were available, primarily EU27 countries and Switzerland, for which ETM-based datasets were used. In these cases, the full modelling structure is implemented.

For countries where input data were less granular, a simplified modelling representation is applied, with reduced nodal detail and functionality. These simplifications are introduced to ensure consistency in scenario coverage while maintaining alignment with available data.

A detailed overview of country-specific modelling configurations, including the level of simplification applied where relevant, is provided in Annex VI.

Electricity system structure

The electricity sector is represented by three distinct nodes per Bidding Zone, each capturing different components of demand flexibility:

- **Electricity market (e-market):** All generators connected to the transmission grid (e.g. thermal power plants, utility-scale solar PV, onshore and offshore wind, and nuclear power plants) are modelled within the e-market node. Large-scale flexibility assets, such as electrochemical batteries and hydropower plants with reservoirs, are also represented. Electricity demand in this node includes non-residential consumption, such as that of industry and data centres. The e-market is coupled with the hydrogen sector via electrolysers and hydrogen-fired power plants.
- **Residential & tertiary sector (prosumer):** Small-scale resources, including rooftop solar PV and residential batteries, are modelled separately in dedicated prosumer nodes. The electricity demand in this node reflects only the electricity used for heating. A wheeling charge is applied between the e-market and the prosumer nodes to represent distribution grid costs (this fee is applied to flows from the e-market to the residential sector).

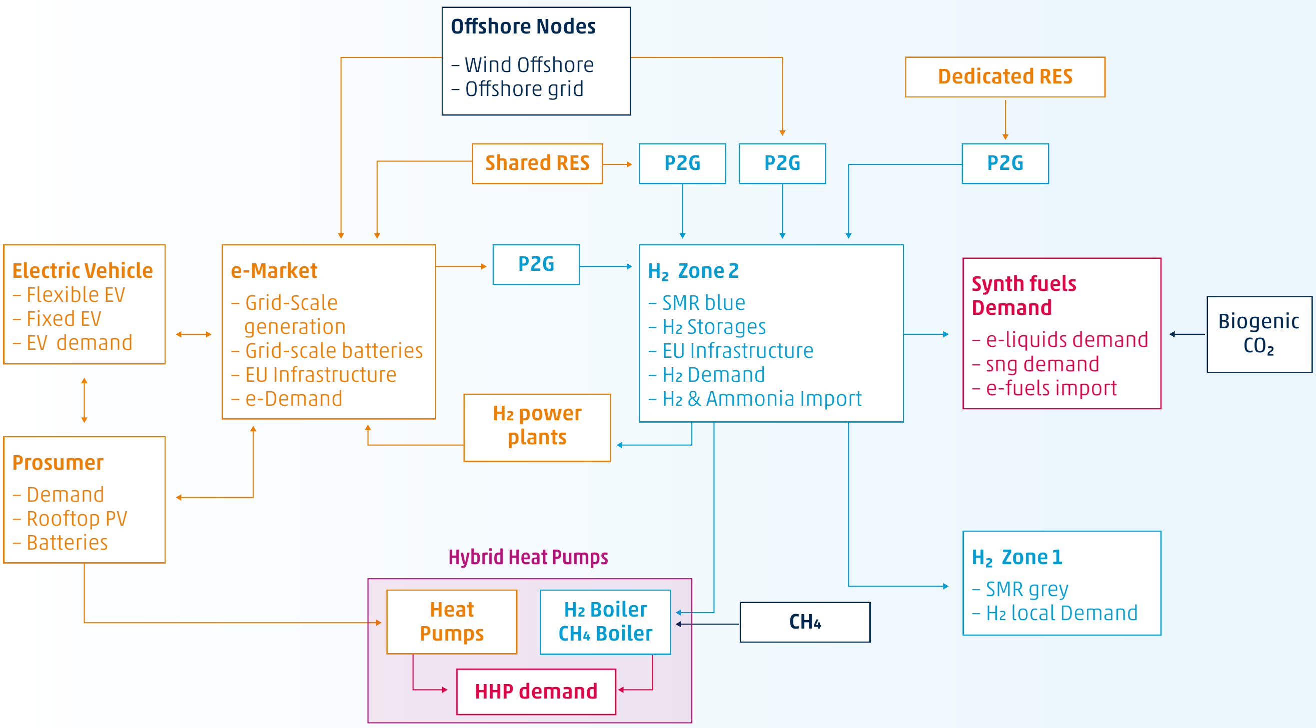


Figure 15: General model topology

- **Electric vehicles (EVs):** The passenger EV charging behaviour is modelled explicitly within the market tool, with charging decisions optimised to meet the mobility demand. The optimisation depends on the fleet characteristics (fixed vs. flexible), electricity prices, the availability of charging infrastructure over time, minimum battery state-of-charge requirements, and additional constraints representing the physical and operational limits of EVs. EVs are split into two distinct fleets based on their point of connection: when charging in public or on-street locations, they are linked to the e-market node, whereas when charging at home or at the workplace, they are linked to the prosumer node. Further details on EV modelling are given in the next section (8.3).

Interconnections between Bidding Zones are represented in line with the electricity infrastructure assumptions for each target year (see Chapter 7). Electricity grid losses are incorporated into the demand timeseries of the corresponding e-market and prosumer nodes. Details are given in section 4.3 and Annex VIII.

Power plant efficiencies include own-consumption and, where applicable, CCS effects.

Hydrogen system structure

The hydrogen sector is represented using two main hydrogen zones, in continuity with the deviation scenarios' topology adopted in the TYNDP 2024:

- A main integrated hydrogen market (**Zone 2**), representing future hydrogen system interactions.
- A dedicated zone for grey SMR hydrogen production without CCS (**Zone 1**) in selected countries (Germany, Lithuania, Portugal), ensuring that grey hydrogen does not contribute to the integrated market supply.

Additional bottleneck nodes may be introduced to capture technical constraints limiting hydrogen flows within a country.

The modelling includes multiple hydrogen import routes, allowing differentiation between supply sources and enabling the model to determine the share of imports versus domestic production. The hydrogen network representation is aligned with the approved scenario grid and perimeter, and follows the same principles adopted for the electricity sector. (see Chapter 7).

Sector coupling and additional elements

Sector coupling between electricity and hydrogen is explicitly represented through:

- Electrolysers (power-to-hydrogen)
- Hydrogen-fired power plants
- Dedicated and shared renewable generation linked to hydrogen production

Additional boundaries are included as exogenous inputs, including:

- Synthetic fuel demand
- Hybrid heat pump thermal demand
- Fuel availability for thermal power plants
- Biogenic CO_2 availability for synthetic fuel production

Heat representation

A share of residential heat demand is modelled through hybrid heat pumps (HHPs), represented via dedicated demand nodes connected to:

- The electricity system (prosumer node)
- The hydrogen network (for H_2 HHP) or a methane fuel object (for CH_4 HHPs)

Conversion efficiencies depend on the technology used (heat pumps vs boilers).

Offshore representation

Offshore wind generation, both for electricity and hydrogen production, can be connected either radially to onshore zones or to dedicated offshore nodes. Offshore grid assumptions fully follow TSO inputs, and no additional expansion is modelled within scenarios.

8.3 EV modelling approach

Passenger EVs are explicitly represented in the market model in order to capture the interaction between charging behaviour, flexibility provision, and electricity market. In contrast, electric trucks, buses, and vans are not modelled as individual flexible assets because of their driving schedules and driver's work hours; their electricity consumption is included exogenously within the demand profiles.

Passenger EVs are modelled in continuity with the approach adopted in the deviation scenarios of TYNDP24. However, the 2026 update introduces significant improvements to address two key shortcomings of the previous formulation.

In TYNDP 2024, passenger EVs were represented using only two aggregated fleets, differentiated solely by charging location (home or street). As a result, all EV charging was optimised purely based on electricity prices, leading to an overestimation of EV charging flexibility. In addition, a modelling inconsistency in the previous cycle resulted in a significant portion of EV transport demand being supplied directly by the electricity grid, effectively bypassing the vehicle battery charging-discharging cycle. Both effects contributed to unrealistically peaky charging patterns and an excessive representation of EV flexibility.

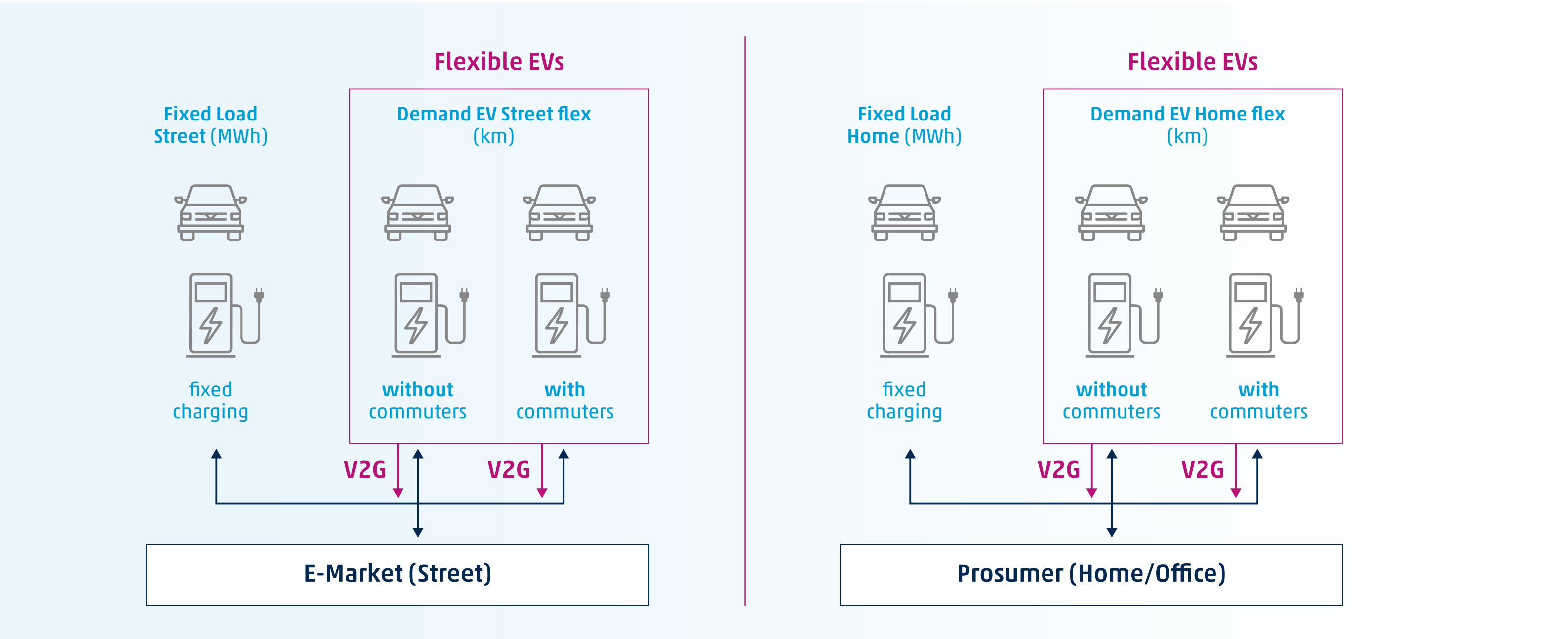


Figure 16: Electric vehicle (EV) modelling approach: E-market and prosumers (home)

The updated modelling framework corrects the accounting of EV energy flows and introduces a more granular fleet structure. This enables a more realistic representation of charging behaviour and flexibility provision by passenger EVs within the electricity system (Figure 16).

Passenger EVs are represented as separate prosumer and street-connected fleets. Flexible fleets can shift charging over time in response to hourly price signals and, where enabled, can also provide vehicle-to-grid (V2G) services. In addition, the new formulation introduces fixed charging profiles and a further split between commuter and non-commuter fleets to reduce the overestimation of flexibility that can arise when large EV fleets are pooled into a single optimised asset. In particular, commuter EVs are assumed to be unavailable for charging during midday (09–16 h) on weekdays, which constrains charging optimisation and shifts charging activity to other time windows within the day or week. The revised formulation yields materially less system flexibility than the TYNDP 2024 setup, which had been considered too optimistic.

Flexibility in the model is driven primarily by smart charging, while V2G is treated as an additional but smaller source of flexibility because participation rates and technical uptake remain more uncertain. For the 2026 cycle, the share of flexible passenger EVs is parameterised through TSO survey-based trajectories, while the remaining vehicles follow fixed charging profiles (usually originating from DFT, for details see Section 4.3). In addition, the share of flexible EVs enabled to provide V2G services is defined based on the same TSO survey inputs. This allows the model to reflect different national assumptions while keeping the overall framework consistent across countries. The model parameters and survey results are described in the technical annex.

8.4 Hydrogen and synthetic fuel modelling

Hydrogen

Hydrogen modelling in TYNDP 2026 is designed to determine how hydrogen demand is met across Europe within a sector-coupled system, where domestic production, imports, infrastructure constraints and system balancing requirements are assessed simultaneously.

Hydrogen supply is represented through a structured merit order that combines domestic production and imports, while reflecting different economic and contractual conditions. Hydrogen storage complements this supply stack as a flexibility option, allowing temporal decoupling between production and demand and contributing to system balancing and price formation.

Hydrogen supply can be conceptually structured into three main components.

Domestic production:

- Electricity-based production via electrolysers, including both grid-connected and dedicated-renewables configurations;
- Natural-gas-based production via Steam Methane Reformers (with or without CCS), representing both blue and grey hydrogen pathways depending on the scenario.

Non-European imports under long-term contractual arrangements: representing lower-cost supply with limited short-term flexibility. For modelling purposes, the low-cost band is assigned a cost of 0 €/MWhH_2 to ensure dispatch as a priority within the optimisation. This assumption should not be interpreted as a zero economic cost, but rather as a modelling construct used to reflect the inelastic nature of committed import volumes under long-term obligations.

Additional non-European imports at market-based prices (marginal-cost band): the residual share of import potential beyond the long-term contracted volumes, dispatched as flexible supply that responds to system conditions. Pipeline and shipping routes both add to this band.

However, as the model operates with a limited nodal topology, where each country is represented as a single node, cross-border flows supplying hydrogen from one region to another within the same country, but passing through another country, are not reflected in the model, even though these flows generate significant transport volumes in the transit country – such hydrogen flows are hidden in the respective country node.

In addition, hydrogen storage is represented as a flexibility option, allowing temporal decoupling between production and demand, and contributing to system balancing and price optimisation. Different storage types from steel tanks to salt caverns enter the merit order at different cost levels, depending on their flexibility characteristics.

Hydrogen imports: multi-band pricing and availability

Imported hydrogen is modelled using a marginal cost approach with differentiated import cost bands rather than as a single uniform import block. Different import routes and supply types, including renewable-linked pipeline imports, other pipeline imports, and ship-based imports such as ammonia, are represented with different marginal costs and, where relevant, specific availability profiles, elaborated in Table 23. A detailed explanation of import potentials, infrastructure assumptions and cost methodology is provided in Section 5.7.

PRICING BAND	PROFILE	MODELLING TREATMENT
Long-Term Contract (LTC) band	Flat, must-run profile	Represents firm "take-or-pay" infrastructure investments. Modelled with a zero marginal cost so that the contracted capacity is dispatched as a priority within the optimisation, irrespective of hourly system conditions.
Flexible / marginal band	Hourly availability, route-specific	Captures the residual import potential beyond LTC volumes. Subject to higher market prices and to availability constraints; for green hydrogen corridors (North Africa and Ukraine) the profile is derived from daily averages of the renewable generation profile in the exporting country.
Shipped ammonia / hydrogen carriers	Slower modulation, security-of-supply role	Modelled as providing flexibility and security of supply. The ammonia pathway is parameterised to include regasification. The LTC band approach is also considered for Ammonia.

Table 23: Modelling of Imported hydrogen (H_2)

Domestic production and coupling with the electricity system

Domestic electrolytic hydrogen production is fully coupled to the electricity system. Electrolysers and related conversion assets operate subject to electricity availability, variable costs, network constraints and the wider cross-sector merit order. Hydrogen production is therefore determined by the coupled dispatch rather than by an exogenous flat output assumption.

Electrolysers can be powered through three distinct configurations, which are treated differently in the dispatch:

- **E-market.** Electrolysers are directly connected to the electricity grid and procure power from the wholesale electricity market. Their dispatch is fully driven by marginal electricity prices, grid constraints and the cross-sector merit order, allowing them to operate flexibly in response to system conditions.
- **Dedicated RES (DRES).** The renewable asset is physically islanded and supplies hydrogen production exclusively. Power generated by DRES units does not enter the public electricity market and is converted into hydrogen up to the rated capacity of the connected electrolyser; any excess generation that cannot be absorbed is curtailed at source.
- **Shared RES (SRES).** The renewable asset operates in effect as a virtual Power Purchase Agreement (PPA): its hourly profile strictly prioritises the associated electrolyser, and only the energy left over after electrolyser uptake is allowed to spill into the electricity market. This preserves the contractual logic of dedicated supply while keeping the renewable surplus available to the wider system.

Water cost on electrolyser generation

To accurately reflect operating expenses, an explicit real-world water-usage cost is applied to electrolyser generation, calibrated at 0.33 €/MWh of hydrogen produced. While modest in absolute terms, this term ensures that the operating cost stack of electrolysers reflects all incremental variable costs and is internally consistent with the broader cost framework.

Hydrogen storage modelling

Hydrogen storage modelling moves away from generic representations to reflect actual geological and operational realities. Storage assets are characterised by varying flexibility levels typically described as daily, weekly or seasonal derived from TSO-submitted data covering injection capacities, withdrawal capacities and working-gas volumes. This explicitly differentiates fast-acting facilities from slower seasonal reserves.

Storage parameters are set on an asset-by-asset basis where data are available. Round-trip efficiency, ramp rates and minimum stock levels are reflected so that storage cycles compete realistically with imports and domestic production within the merit order.

Synthetic fuel Modelling

Synthetic fuels (or synfuels) are modelled as an integrated component of the system under the assumption of carbon neutrality at system level. This is achieved by enforcing that all CO_2 emissions from synthetic fuel combustion are offset by biogenic carbon capture and storage (BECCS) elsewhere in the system; therefore, synthetic fuels do not add net CO_2 to the atmosphere within the scenario framework.

From a modelling perspective, the origin of CO_2 used in synthetic fuel production (fossil, biogenic or from direct air capture) is not differentiated, provided that the overall system-wide CO_2 balance is satisfied via BECCS.

An EU-level carbon constraint is implemented whereby total CO_2 removed via BECCS must equal or exceed total CO_2 consumed in synthetic fuel production. National BECCS capacities are derived from a dedicated data collection and aggregated at EU level for modelling purposes. As a result, synthetic production is not geographically constrained by the location of CO_2 capture facilities.

To operationalise this constraint, annual synthetic fuel production capacities (provided in TWh) are converted into corresponding CO_2 feedstock requirements using molecular stoichiometry. This step bridges raw capacity data and the CO_2 budget constraint embedded in the model.

Representation of synthetic fuel production and aggregation

In the model, the EU synthetic fuel sector is represented through two aggregate nodes:

- Synthetic natural gas (SNG)
- Liquid synthetic fuels (e liquids)

Because different synthetic fuels have different chemical compositions, their energy volumes cannot be directly aggregated. Therefore, all synthetic fuel flows are converted into hydrogen-equivalent terms based on their synthesis requirements.

This hydrogen-equivalent representation allows:

- Aggregation of different synthetic fuel types
- Consistent coupling with the hydrogen system
- Integration into the overall system optimisation

The conversion to hydrogen-equivalent values is applied dynamically for each target year, reflecting changes in the composition of liquid synthetic fuels over time.

Stoichiometry and efficiency assumptions

The hydrogen and CO_2 inputs required for synthetic fuel production are determined through a two-step approach:

1// Calculation of theoretical minimum reactant quantities based on stoichiometry of industry standard synthesis reactions (e.g. Sabatier reaction for SNG).

2// Inclusion of industrial plant inefficiencies.

The first step defines the absolute physical limits of each synthesis route, assuming perfect (100%) conversion efficiency, with no mechanical losses and no unrecovered heat. For complex liquid fuels such as e-kerosene and e-diesel, simplified proxy molecules were selected to reproduce the average carbon-to-hydrogen ratio and energy density of the real fuel blends.

These reactions are inherently exothermic, implying that the hydrogen energy input exceeds the final fuel energy output (e.g., approximately 1.23 TWh of hydrogen is chemically required to produce 1 TWh of e-kerosene).

The second step incorporates plant-level inefficiencies, which capture additional energy requirements associated with:

- Compression
- Recycling loops
- Product separation
- Heat integration

Efficiency losses vary depending on process complexity:

- Simple gaseous fuels (e.g. methane, ammonia): lowest losses (~5%)
- Intermediate fuels (e.g. methanol): moderate losses (~10%)
- Multi-step liquid fuels (e.g. diesel, kerosene): higher losses (~15%)
- Complex pathways (e.g. ethanol): highest losses (~30%)

These values are treated as representative modelling assumptions rather than plant-specific parameters. A full carbon recovery rate is assumed, meaning that CO_2 losses within the process are negligible at model level.

The resulting conversion efficiencies are summarised in Table 24.

E-FUEL	OUR MODEL	LITERATURE RANGE*
e-methane	79%	70%-83%
e-diesel	70%	59%-78%**
e-kerosene	71%	
e-ethanol	65%	n.a.
e-methanol	80%	69%-89%

* Review of electrofuel feasibility—cost and environmental impact. Maria Grahn et al. (2022) Progress in Energy 4: 3.

** Hydrogen to Fischer–Tropsch

Table 24: Conversion efficiencies of different e-fuels used in our model and literature data

Demand and supply representation

Synthetic fuel demand is modelled as an exogenous input and expressed in hydrogen-equivalent terms. Demand is assumed to be constant over time, with annual demand distributed uniformly across all hours of the year. This reflects the high storability of synthetic fuels and is consistent with the approach adopted in previous TYNDP Scenario cycles.

On the supply side, synthetic fuel production is linked to national hydrogen systems. Each country can supply synthetic fuels up to its reported production capacity, converted into maximum hourly flows.

When domestic production is insufficient to meet EU-level total demand, imports are used to cover the remaining demand. Imports are modelled as unconstrained supply at higher marginal cost than domestic production.

Synthetic fuel import costs are converted into hydrogen-equivalent terms based on the hydrogen content of each synthetic fuel (LHV).

CO_2 accounting and BECCS constraint

To enforce carbon-neutrality, annual BECCS-availability is represented through annual constraint objects that track the total volume of biogenic CO_2 sequestered each year.

During synthetic fuel production, these objects are "consumed" based on the CO_2-to-H_2 ratio of the fuel being produced. For SNG, that ratio remains constant over time, as the product is a fixed molecule. For aggregated liquid synthetic fuels, the ratio varies annually with the evolving mix of individual liquids, weighted by their respective capacities and CO_2/H_2 stoichiometry.

Security-of-supply adequacy loop

To ensure that hydrogen demand is met in every hour of the simulation and to avoid failures resulting in Energy Not Served (ENS), an adequacy loop is deployed on top of the base dispatch and proceeds in clearly ordered steps:

1// If the base configuration leads to hydrogen curtailment in one or more hours, the model first releases unconnected ammonia import potentials at the highest market-band price. These volumes act as an additional security-of-supply layer, dispatched only when no cheaper option is available.

2// If a shortfall remains after these unconnected potentials have been exhausted, the model dispatches technology-neutral virtual units at the Value of Lost Load (VoLL). These virtual units carry no physical realism but ensure that demand can always be balanced and that the resulting cost signal correctly reflects the scarcity revealed by the simulation.

In this cycle, no additional supply of NH3 was needed to address adequacy issues.

ELEC MERIT ORDER	ELEC MERIT ORDER – PRIORITY	TECHNOLOGY	H_2 MERIT ORDER	H_2 MERIT ORDER – PRIORITY
			LTC – LOW band (nonEU Pipelines; NH3 imports)	1
RES	1	P2G	RES through P2G	2
Hydro	2		Hydro through P2G	3
Nuclear	3		Nuclear through P2G	4
Biofuels	4		Biofuels through P2G	5
			SMR	6
			nonEU imports	7
			NH_3 imports	8
Other nonRES	5	P2G to avoid H_2 curtailment	Other nonRES through P2G	9
Gas plants	6		Gas through P2G	10
Lignites	7		Lignite through P2G	11
Coal	8		Coal through P2G	12
Heavy oil	9		Oil through P2G	13
DSR	10			14
VOLL Elec, VOLL Heat			VOLL H_2, VOLL synfuels, VOLL Heat	

Table 25: Electricity and hydrogen merit order

8.5 Hybrid Heat Pump (HHP) modelling

HHPs are modelled as the only endogenous component of the heat system within the TYNDP 2026 Scenario modelling framework.

Each hybrid unit can generate heat through two alternative pathways:

- An electric heat pump, linked to the prosumer electricity node
- A boiler, supplied either by hydrogen or methane depending on the technology type

The efficiency of the electric heat pump component varies with weather conditions through time-dependent coefficient of performance (COP) profiles, reflecting the impact of ambient temperature on heat pump performance.

In the network representation, dedicated heat nodes are introduced at national level for each hybrid technology (one for hydrogen HHPs and one for methane HHPs). The load at each heat node is defined by the corresponding heat demand profile. The heat pump component links the prosumer electricity node and the heat node, with the conversion efficiency given by the time-varying COP profile.

For H_2 HHPs, the boiler component links the relevant hydrogen market node and the heat node, with a fixed boiler efficiency. For CH_4 HHPs, the boilers are not linked to a zonal gas market (since natural gas is not modelled as a market) but instead draws fuel from a single EU-wide natural gas fuel object dedicated to the hybrid heating system.

Installed capacities of both boilers and heat pumps are not constrained in the model. It is assumed that sufficient capacity is always available to fully meet the thermal energy demand, ensuring that capacity does not become a limiting factor. This formulation allows the optimisation to determine, at each point in time, whether heat is provided by the electric heat pump or by the boiler. The decision depends on the availability and marginal cost of electricity and hydrogen at their respective market nodes, the COP profile of the heat pumps, and, for CH_4 HHPs, the assumed natural gas cost and boiler efficiency.

In contrast, fully electric heat pumps are not modelled as separate assets in the system. Instead, their electricity consumption is implicitly included within the prosumer demand profiles, as described in Section 4.3, and therefore does not appear as a distinct technology or decision variable in the optimisation.

8.6 Dedicated RES and Shared RES modelling

Dedicated RES (DRES) and Shared RES (SRES) are explicitly represented in the modelling framework to capture the interaction between renewable generation and hydrogen production under different contractual agreements.

DRES refers to renewable generation that is physically co-located with electrolysers under Physical Power Purchase Agreements (PPAs). This collocation may result either from contractual arrangements between renewable asset owners and electrolyser operators or from common ownership of both assets. While the latter configuration does not formally constitute a PPA, it is treated equivalently within the modelling framework and included under the DRES category.

As for other technologies, installed capacities for DRES and their associated electrolysers are derived from TSO data. Production profiles follow the same RES datasets used elsewhere in the model and are used exclusively to meet hydrogen demand.

SRES are intended to represent renewable generation (solar PV, onshore wind, and offshore wind) contractually linked to electrolysers through virtual PPAs, without direct physical co-location. Electrolysers are required to prioritise the absorption of renewable generation when available, while any residual electricity can be sold to the electricity market.

Compared to the representation used in the TYNDP 2024 deviation scenarios, the current modelling of SRES introduces two key methodological changes. First, SRES capacities and the associated electrolyser capacities are defined ex-ante, based on NECP targets and national policy data, whereas in previous studies they were derived endogenously through expansion model optimisation. Second, hydrogen production is prioritised by construction: renewable generation is first allocated to electrolysers, and only surplus electricity is made available to the power market.

In the model implementation, SRES are treated similarly to DRES in order to decouple hydrogen production decisions from electricity market price signals. Renewable generation profiles are consistent with the PECD datasets used for the other renewable sources. Hydrogen production profiles are derived by combining RES generation with electrolyser capacity: when renewable production is lower than electrolyser capacity, the entire output is used for hydrogen production and no electricity is exported; conversely, when renewable generation exceeds electrolyser capacity, the surplus is supplied to the electricity market at the e-market node. Separate input profiles are therefore provided for hydrogen production and residual electricity generation.

8.7 Offshore modelling

Offshore modelling in TYNDP 2026 covers both electricity and hydrogen and is based on a conservative representation of offshore assets. The methodology approach follows TSO submissions, Scenario Grid inputs and validated project information, with datasets cross-checked against modelling inputs and project collections to ensure consistency.

For the electricity system, offshore generation is primarily modelled as being radially connected to the onshore e-market node of the corresponding bidding zone. However, in cases where TSOs have reported more detailed offshore configurations through the data collection, dedicated nodes and corresponding links are introduced. This allows the model to represent specific offshore structures – such as non-radial connections or internal offshore constraints – where these are considered material for system behaviour.

For the hydrogen system, the methodology distinguishes between electricity-led offshore configurations, hydrogen-led offshore production, and hybrid concepts. Fully off-grid hydrogen production and shared renewable pathways links are not collapsed into one generic offshore node when doing so would hide materially different infrastructure interactions.

Dedicated offshore nodes are introduced where required to preserve internal offshore bottlenecks, including cases where offshore wind capacity, electrical capacity and offshore electrolysis capacity are not interchangeable within a single aggregate node. This is particularly important where offshore hydrogen production or export depends on infrastructure constraints that differ from those governing electricity flows to shore.

9 GAP FILLING METHODOLOGY //

9.1 Objective and role of gap filling methodology

Demand scenarios are developed based on the latest NECPs submitted by Member States. This bottom-up data collection forms the foundation of the NT.

As the aggregated EU27 Final Energy Consumption (FEC) in the 2030 NT dataset exceeds the EU target of 763 Mtoe set under the Energy Efficiency Directive (Directive (EU) 2023/1791), an adjustment is required. This adjustment is implemented through the gap-filling methodology.

The gap-filling methodology ensures alignment with EU policy targets while preserving the integrity of Member State contributions. It represents a controlled transformation of the NT dataset into a policy-compliant scenario (NT+), in line with the ACER Scenario Framework Guidelines.

For TYNDP 2026 Scenarios, a dedicated task force was established to assess alternative approaches to the methodology in the 2024 cycle. This taskforce presented the enhanced methodology outlined below to key stakeholders including SRG, EC and ACER, shown in Figure 17.

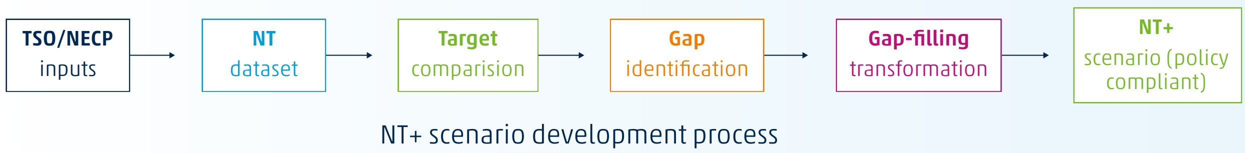


Figure 17: NT+ Scenario Development Process

9.2 Scope and application of the methodology

In the TYNDP 2026 Scenario, as in the 2024 cycle, the gap filling methodology was applied selectively:

- Only to member states exceeding their 2030 national FEC targets based on ETM outputs;
- Using targets defined by the EC in the Table 4 from "Results of formula Annex I EED recast."

This represents an evolution from previous cycles, where adjustments were applied more broadly. The methodology includes all energy carriers eligible for FEC reduction, with important exclusions.

1// Excluded carriers (high decarbonisation potential):

- Electricity
- Hydrogen
- Biofuels
- Derived heat

These exclusions reflect recommendations from the Stakeholder Reference Group (SRG).

9.3 Gap identification and target compliance

Gap identification is performed by comparing FEC from the NT data collection to EU and national FEC targets (see reference in previous subchapter). Where the NT exceeds the target, the difference defines the gap, which is quantified at member state level.

The methodology follows a structured logic:

1// Assess compliance at EU level
2// Identify member states exceeding targets
3// Quantify national gaps
4// Apply targeted adjustments

9.4 Core approach of gap filling methodology

The methodology aims to reduce final energy consumption by targeting the most emission-intensive energy carriers.

Sequential reduction approach

Fossil fuels are reduced in order of their greenhouse gas emission intensity:

1// Coal (solid fossil fuels)

2// Oil (liquid petroleum products)

3// Methane (if necessary)

Reduction is applied sequentially until the EC's national FEC targets are met.

In practice methane remains available as a reduction option. However, for TYNDP 2026, reductions in coal and oil were sufficient to meet targets, and methane reductions were not required.

Proportional and sectoral allocation

Within each member state, reductions are distributed proportionally across sectors, maintaining the relative structure of energy consumption.

9.5 Constraints and dynamic adjustments assumptions

To avoid unrealistic results, the methodology incorporates constraints:

- A minimum floor of 10% is applied to each energy carrier;
- Ensuring that no carrier is reduced by more than 90%.

This constraint approximates the real world behaviour observed in energy transitions, where phase-out processes occur progressively rather than instantaneously.

9.6 Time Horizon and Interpretation

The gap filling methodology is anchored to 2030 targets but applied consistently across all time horizons (2035, 2040, 2050).

The 2030 national FEC targets act as a ceiling constraint, ensuring that Final energy Consumption does not increase beyond 2030 levels and decarbonisation trajectories remain consistent over time.

9.7 Implementation principles

The application of gap filling is guided by the following principles:

- Target alignment: ensures compliance with EU policy objectives.
- Consistency across member states: based on national targets and proportional allocation.
- Preservation of system structure: avoids arbitrary distortions in sectoral shares.

Pragmatism and feasibility: uses a simplified approach to ensure timely delivery of the TYNDP cycle.

10 ECONOMIC VARIANTS METHODOLOGY //

10.1 Role of the economic variants in the TYNDP Scenario framework

The economic variants – the High Economic Variant (HEV) and the Low Economic Variant (LEV) – are built from the NT dataset, prior to gap-filling. This sequencing is a deliberate methodological constraint: the variants are constructed at the ETM stage, using the same modelling environment in which TSOs developed the NT dataset, before the policy-compliance transformation that produces NT+ is applied. Therefore, the economic variants are not required to comply with EU climate and energy targets, as their role is to explore sensitivities to macroeconomic conditions rather than policy-consistent pathways. Their purpose is different: in line with ACER Framework Guidelines Article 37, HEV and LEV are designed as plausible stress tests of the NT energy system, exploring how different macroeconomic and socioeconomic conditions may influence energy demand, technology uptake, sectoral activity and marginal-cost signals relative to the NT baseline.

This distinction carries two important implications that the reader should keep in mind throughout this chapter. First, all scaling factors, baseline shares and annual reference values used in the variant construction methodology are computed relative to NT values – not NT+ values. Second, the economic variants do not represent standalone policy scenarios, nor are they intended to sit within the policy-compliance envelope defined by the NT+. They complement the Central Scenario by providing a bounded sensitivity analysis around the NT baseline, supporting a more robust assessment of infrastructure needs under different economic conditions.

For TYNDP 2026, HEV and LEV are applied to the 2035 and 2040 target horizons. It is also important to acknowledge the scope of what these variants do and do not capture. Their trajectories remain relatively close to NT and are therefore less divergent than alternative scenarios used in past TYNDP cycles such as Distributed Energy and Global Ambition. They should not be interpreted as an exhaustive exploration of the full range of possible future developments.

Table 26 below summarises all parameters, their treatment in each variant, and whether they are exogenously set, model-determined, or fixed. It is placed here deliberately to give readers an immediate, concrete picture of what changes before the methodological narrative unfolds.

PARAMETER	DESCRIPTION	HIGH ECONOMY	LOW ECONOMY	STATUS
DEMAND – TECHNOLOGY MIX				
Adoption rate	Uptake of EVs, heat pumps, H_2, electricity-driven technologies	Faster	Slower	VARIES
Phase-out rate	Retirement of coal, oil and gas boilers, ICEs	Faster	Slower	VARIES
DEMAND – ACTIVITY				
Absolute demand shifts	Sectoral volumes: industrial output, transport demand	Higher	Lower	VARIES
DEMAND – EFFICIENCY				
Energy efficiency	Implicit via technology choice only	NA	NA	NO LEVER
Insulation level	Insulation level in Household & Building sector	NA	NA	NO LEVER
SUPPLY – PRICES				
CO_2 (ETS) price	±10% vs neutral trajectory	+10%	-10%	VARIES
Fossil commodity prices	±10% vs neutral trajectory	+10%	-10%	VARIES
Blue H_2 price (NO imports)	Scales with commodity ±10%	+10%	-10%	VARIES
E-fuels and biofuels share	Harmonised with economic variant	Increases	Decreases	VARIES

PARAMETER	DESCRIPTION	HIGH ECONOMY	LOW ECONOMY	STATUS
SUPPLY – ENDOGENOUS (MODEL-DETERMINED)				
CCU/S levels	Optimised by model	Model decides	Model decides	ENDOGENOUS
Renewable extra EU imports	Optimised by model	Model decides	Model decides	ENDOGENOUS
SUPPLY – FIXED (STRESS-TEST DESIGN)				
Installed supply capacities	Generation, storage, flexibility	Unchanged	Unchanged	FIXED
Grid capacities	Transmissions and distribution	Unchanged	Unchanged	FIXED
WACC	Cost of capital for new investment	Unchanged	Unchanged	FIXED
Technology costs	CAPEX/OPEX for all technologies	Unchanged	Unchanged	FIXED
Green H_2 and NH3 imports	Import prices held constant	Unchanged	Unchanged	FIXED

VARIES // Exogenous – set differently per variant   ENDOGENOUS// Value determined by model optimisation   FIXED// Held constant – stress-test design choice

Table 26: Overview of economic variant parameters, treatment per variant, and modelling status

10.2 Application across TYNDP 2026 time horizons

The economic variants are applied to the 2035 and 2040 horizons, which correspond to the mid-term and long-term planning horizons required for the TYNDP framework.

These time horizons are sufficiently distant for economic divergence to materially affect energy demand, technology deployment, and infrastructure requirements, while still being relevant for network planning decisions.

By contrast, the 2030 horizon is treated as a short-term milestone and remains closer to the implementation logic of current policies and near-term planning assumptions. The 2050 horizon remains part of the overall scenario timeline, but for the economic variants exercise it is considered very long-term, with significant uncertainty. For this reason, the economic variant framework is primarily centred on 2035 and 2040, where the value of testing different economic conditions becomes more meaningful.

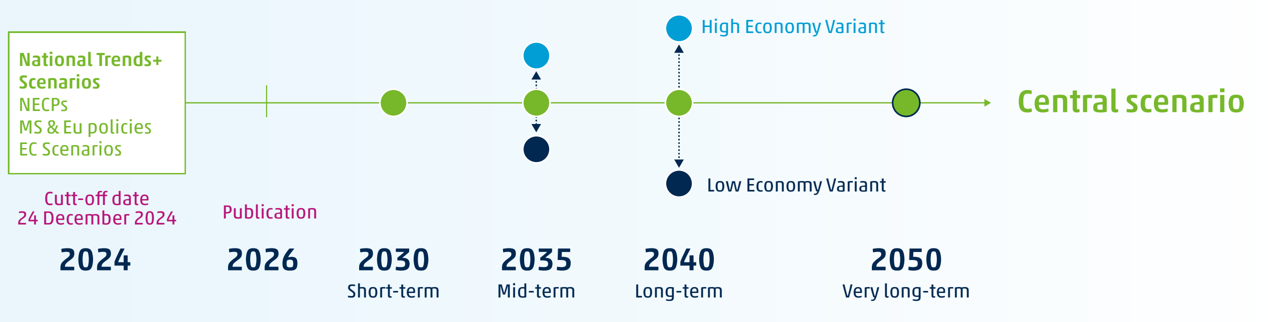


Figure 18: Time horizons considered for the economic variants

10.3 Economic logic behind the high and low variants

The high economic growth variant reflects a context in which economic performance exceeds the assumptions embedded in the central scenario (Chapter 9 of the Scenario Report). In practical terms, this variant is associated with higher GDP, stronger sectoral activity, greater purchasing capacity, and a higher willingness to spend and invest. It also assumes a stronger orientation towards innovation, including riskier or earlier-stage investments, and a greater capacity to take long-term decisions in support of sustainability-related investments.

By contrast, the low economic growth variant reflects a more constrained economic environment. In this case, GDP growth is weaker than in the central scenario. Sectoral activity is more moderate, spending capacity is reduced, and consumers and firms are more likely to prioritise affordability and short-term cost control. Under these conditions, investment appetite may weaken, innovation may proceed more slowly, and decision-making may favour business-as-usual or lower-risk pathways.

These contrasting assumptions are not introduced to build optimistic or pessimistic narratives for their own sake. Rather, they are intended to capture the main economic mechanisms that may alter the pace and scale of energy transition drivers. A stronger economy can accelerate demand growth, industrial output, technology deployment, and investment in new assets. A weaker economy can delay replacement cycles, reduce activity levels, and shift choices towards lower-cost solutions. The variants therefore test not only volume effects, but also behavioural and structural responses that are relevant for infrastructure planning.

10.4 Methodological principles for constructing the variants

Building demand variants

(i) Variants are anchored to the central scenario

The starting point for both economic variants is always the Central Scenario. This ensures methodological consistency across all scenario outcomes and preserves the role of National Trends as the main reference case for TYNDP 2026.

Anchoring the variants to the central scenario has two methodological benefits. First, it avoids the creation of disconnected scenario worlds based on entirely separate assumptions. Second, it makes the effect of economic deviations easier to interpret, since changes observed in the variants can be read an outcome of adjusted economic conditions rather than as the combined result of multiple unrelated methodological changes.

In this sense, the variants should be understood as stress tests of the central scenario, not as standalone products.

(ii) Variations remain limited and plausible

The purpose of the economic variants is to explore plausible economic deviations, not extreme macroeconomic futures. The deviations from the central scenario therefore remain within ranges that are considered credible and relevant for infrastructure planning.

This design choice ensures that the variants remain both informative and credible. Variants that are too close to the central scenario would add limited analytical value, while variants based on extreme assumptions could undermine the relevance of the results for planning decisions.

The methodology therefore balances analytical differentiation with realistic economic conditions. This approach also supports comparability and transparency across countries and sectors.

(iii) Targeted variation of key parameters

The economic variants are implemented through targeted changes in selected key parameters that transmit economic conditions into the energy system.

The objective is not to construct a completely new storyline, but to adjust parameters that have a clear relationship with economic activity and energy demand. These parameters may include, for example, activity-related drivers, technology uptake rates, investment-related assumptions, demand volumes in selected sectors, and behavioural parameters associated with affordability or spending willingness.

Focusing on a limited number of influential parameters ensures that the variants remain transparent and manageable while still capturing meaningful sensitivities in the modelling results. The full list of parameters selected for variation, together with those held fixed and the rationale, is documented in Annex IX.

(iv) Balanced contrasts across variants

Where appropriate, parameter changes should be applied in a balanced way across the two variants. In other words, when a relevant parameter is adjusted upward in the high variant, the methodology should assess whether a corresponding downward adjustment is justified in the low variant, and vice versa.

This principle supports transparent comparison between variants and facilitates interpretation of the modelling results.

However, balanced contrasts do not imply strict symmetry in all cases. In some sectors, economic responses may be non-linear or constrained by technological or policy factors. The changes in the parameters are subject to the Saturation curve (S-curve) methodology, which allows flexibility where needed to preserve realistic system behaviour.

(v) Saturation methodology for adjusting technology mixes in economic variants

As previously described, the economic variants are derived from the NT dataset by changing two elements: the level of sectoral activity and the technology mix. Sectoral activity describes the volume of activity in a sector (for example, total passenger kilometres driven by personal vehicles) and can be scaled directly. The technology mix is the disaggregation of that sectoral activity across technologies and/or energy carriers (for example, the shares of battery electric, hydrogen, and fossil fuels in road transport). Because each technology has its own efficiency, changing the mix implicitly alters aggregate system efficiency.

To keep adjustments realistic, the methodology embeds observed adoption and phaseout dynamics. Adoption typically resembles an S-curve: low and slow uptake in the early phase, rapid growth during diffusion, then slowing growth as saturation is approached. Phaseout shows resistance: as a technology declines, a residual "core" use remains that is hard to substitute, so further decreases become progressively limited.

Rather than assigning discrete stages by judgment, the stage and the feasible adjustment are determined directly from the current market share s (in percent) using two uniform functions that are applied consistently across all sectors and target years:

- **Potential increase (adoption capacity) is given by:**
  $f_{up}(s) = 100 \times e^{-(s-50)^6/3 \times 10^9)}$
  This bell-shaped function behaves like the derivative of an S -curve. It is low for very small shares (early stage), peaks around the mid range near 50% (diffusion), and declines again at high shares (saturation). The value of f_{up} (s) represents the maximum feasible increase (in percent) for the technology mix scaler in the adjustment step.
- **Potential decrease (phase out capacity) is given by:**
  $f_{down}(s) = \frac{100}{1+e^{-(s-7)}}$
  This logistic function is near zero when the share is very small, reflecting limited scope for further reduction in residual uses; it rises rapidly around a threshold near 10% and approaches 100 for large shares. The value of $f_{down}(s)$ represents the maximum feasible decrease (in percent) for the technology mix scaler in the adjustment step.

These functions eliminate the need for technology or sector specific parameterisation, ensuring transparency and avoiding unnecessary complexity. They also implicitly classify technologies by stage: low $f_{up}(s)$ indicates early or saturated conditions, high $f_{up}(s)$ indicates active diffusion; low of $f_{down}(s)$ indicates a residual core that should not be pushed down further, a high $f_{down}(s)$ indicates ample scope to reduce.

The adjustment procedure proceeds as follows. First, the economic variant narrative indicates which technologies should increase (for example, electric and hydrogen) and which must decrease to compensate (for example, diesel and gasoline), preserving the constraint that the sum of shares remains 100%. Using the NT baseline shares, each technology's feasible change is computed by multiplying the technology mix scaler with $f_{up}(s)$ for each technology slated to increase and $f_{down}(s)$ for those slated to decrease. The total feasible increase and the total feasible decrease are then reconciled. If one side's potential exceeds the other's, the larger side is proportionally scaled to the smaller side (the bottleneck), preserving balance. Adjustments are distributed proportionally to each technology's computed capacity, applied to the shares, and the mix is normalised to ensure it sums to 100% without exceeding practical bounds implied by the functions. A numerical illustration of this procedure applied to a specific sector and country is provided in Annex IX, alongside the complete parameter adjustment outputs for the 2035 and 2040 horizons.

This approach yields smooth, plausible trajectories: early-stage technologies can grow, but not unrealistically fast; mid-stage technologies grow most strongly; saturated technologies slow down; and declining technologies reduce progressively without being forced below practical minima. By using the same functional forms across sectors and years, the methodology remains consistent and reproducible while capturing the essential saturation and phaseout behaviours observed in real markets.

(vi) Scaling electricity and hydrogen hourly demand

As previously mentioned, the NT dataset's hourly electricity demand profiles were built using DFT starting from annual demand values collected from ETM and from the second data collection. Hourly electricity demand input values were divided in three main categories in PLEXOS®:

- Prosumers: heat pumps and AC units in households, tertiary and industry
- Passenger electric vehicles
- "Baseline" demand: any electricity demand component that was not included in the previous two categories. E.g., electricity consumption for steel making, freight transport

The NT dataset's hourly load profiles (divided in the three main categories listed above) were then rescaled using "scaling factors" to derive the new PLEXOS® inputs for the high and low economic variants.

The scaling factors for each demand category were defined as the ratio of economic variants' annual demand values over its corresponding annual value from the NT dataset.

For example, electricity demand for passenger electric vehicles in Germany in 2040 on ETM was estimated at 110.58 TWh, 125.07 TWh and 96.26 TWh in the NT dataset, High variant and Low variant respectively. Therefore, the 2040 factors that were used to rescale EVs hourly demand values in Germany were equal to 1.1311 (or +13.11%) for the high variant and 0.8705 (or −12.95%) for the low variant.

An alternative methodology was implemented for the members that chose to use ERAA demand values rather than ETM outputs (e.g., Bulgaria and Cyprus). Total electricity load in PLEXOS® was not split into different demand categories in PLEXOS® for those countries. The scaling factors for those states were defined as the average scaling factors of their neighbouring countries weighted by their total load.

The methodology described in this chapter was also used to rescale hydrogen hourly demand profiles, except that a single scaling factor per scenario was used. (In PLEXOS®, hydrogen demand input values are not split into multiple categories).

The same hydrogen demand scaling factors for Romania were also used to define the new hourly inputs for Bulgaria.

Hydrogen demand in the United Kingdom was increased/decreased based on the average scaling factors of France and Germany.

Building supply variants

In the design of the economic variants, the primary objective is to stress test the central scenario's supply capacities under different levels of demand driven by varying macro and socio economic conditions (i.e. different levels of economic activity and growth). The supply side infrastructure (installed assets and capacities) is therefore held fixed across variants, and the variants explore how this fixed system performs when demand and marginal costs conditions deviate from the central case.

From the supply perspective, several items could in principle be affected by economic variants: commodity costs for fossil fuels, the CO_2 price, energy supply capacities, flexibility providing capacities, cost of capital (WACC), technology costs, CCU/S volumes, and energy imports. In practice, for this cycle, only cost parameters are varied. Installed capacities (generation, conversion, flexibility, import infrastructure) are not expanded or reduced in any of the economic variants, and their dispatch remains fully determined endogenously by the model in all cases.

WACC and technology costs are not adjusted either, as no endogenous capacity expansion is modelled in this cycle and changes in investment costs would therefore not affect the asset base. Likewise, CCU/S volumes are not set ex-ante but continue to be purely model outputs, driven by the interplay of the fixed infrastructure, demand levels and marginal cost signals. For energy imports, the physical import infrastructure and its technical limits remain unchanged but import flows respond endogenously to the different demand levels and marginal cost assumptions in each variant.

The main levers used to reflect different economic conditions are commodity and CO_2 prices. Their values are modified in line with the high level narrative of each variant: in a higher growth environment, stronger overall energy demand and emission allowances translates into higher prices; in a lower growth environment, weaker demand leads to lower prices. Concretely, a constant proportional adjustment is applied to both commodity and CO_2 prices: +10% in the High Economic variant and −10% in the Lower Economic variant relative to the central scenario.

Under this setup, the economic variants do not alter the structure or capacity of the supply system. Instead, they test how the fixed central scenario supply capacities and infrastructure respond to different levels of demand and to systematically higher or lower commodity and CO_2 prices (see section 10.1 and Table 26).

ANNEX I: EV PROPERTIES //

Passenger EVs are represented explicitly in the market model, while electric trucks, buses and vans are not modelled as separate flexible assets and are instead included exogenously in electricity demand profiles. Passenger EVs are connected through separate prosumer and street charging representations. Flexible EV fleets can optimise charging in response to model conditions and, where enabled, can provide vehicle-to-grid (V2G), while non-flexible fleets follow fixed charging profiles. Compared with the previous formulation, the updated implementation introduces a more granular fleet structure and corrects the battery-bypass issue in the earlier setup.

The implementation is parameterised through four main profile types as in TYNDP 2024 (minimum state of charge, charger availability, fixed charging profiles and driving profiles) and through a set of scalar parameters including fleet shares, battery size, charger ratios, charger capacities, vehicle efficiency and V2G participation. The purpose of the fleet split is to reduce the overestimation of flexibility that can arise when large EV fleets are pooled into a single optimised asset. In the detailed implementation, flexible fleets are further divided into commuter (who cannot charge during the day on weekdays) and non-commuter segments.

For replication, the assumptions are reported below, separated for model scope and fleet structure, annual vehicle assumptions, charging infrastructure assumptions, and survey-based flexibility and V2G settings.

PARAMETER	VALUE
Prosumer charging share	70%
Street charging share	30%
Fixed charging share of total passenger EV fleet	Based on TSO survey
Flexible commuter share of total passenger EV fleet	Based on TSO survey
Flexible non-commuter share of total passenger EV fleet	Based on TSO survey
Split within flexible share	50% commuter/50% non-commuter

Table 27: Structural shares of the fleet composition

Table 28 and Table 29 show the EV and charging station parameters:

ELECTRIC VEHICLES PROPERTIES	2030	2035	2040	2050
Battery Capacity (kWh/EV)	79	81	83	100
Efficiency (Wh/km)	ETM	ETM	ETM	ETM
Transport Demand (km/EV)	ETM	ETM	ETM	ETM
Number of EVs (#)	ETM	ETM	ETM	ETM
Max Charge/Discharge Rate (kW/EV)	7.4	7.4	7.4	7.4
Street/Home split (%)	30/70	30/70	30/70	30/70

Table 28: Electric vehicles properties

CHARGING STATIONS PROPERTIES	HOME	STREET
Max Charge/Discharge Rate (kW/station)	7.4	16
Use of Station Charge (EUR/MWh)	30	35
Charge/Discharge Efficiency (%)	94	94
Station per EV (#)	1	0.5

Table 29: Charging stations properties

These are the survey-based options for the share of passenger EVs that are optimised flexibly in the market model. The results of the survey are taken into account by country/TSO response (Table 30).

FLEXIBILITY OPTION	FLEXIBLE CHARGING SHARE	FIXED CHARGING SHARE
Business-as-usual	15%	85%
Users Oriented	30%	70%
Balanced	50%	50%
Market Driven	70%	30%
Default if no selection is made	50%	50%

Table 30: Results of the passenger EV survey

V2G is applied **only to the flexible subset** of EVs, not to the total EV fleet. Separate trajectories are defined for prosumer/home and street charging. The results of the survey are taken into account by country/TSO response (see Table 31 and Table 32).

V2G OPTION	2030	2035	2040	2050
Low	0%	5%	10%	20%
Medium	15%	20%	25%	35%
High	30%	35%	40%	50%

Table 31: Prosumer/home charging V2G participation rate (% of flexible EVs)

V2G OPTION	2030	2035	2040	2050
Low	0%	1.5%	3%	5%
Medium	0%	3.5%	7%	15%
High	0%	5%	10%	20%

Table 32: Street charging V2G participation rate (% of flexible EVs)

These values are explicitly given in the survey results and are applied only to EVs that are already assigned to the flexible fleet.

Example for 2040 (illustrative values)

This example illustrates how the survey inputs provided by TSOs are used to derive the size of each EV fleet and the subset enabling V2G. Numbers are purely illustrative.

Assumptions

- Total number of passenger EVs in country X: **1,000,000**
- Home (prosumer)/street charging split (centralised): **70%/30%**
- Flexibility option selected by the TSO: **User Oriented → 30% flexible, 70% fixed**
- Split within the flexible fleet (centralised): **50% commuter/50% non commuter**
- V2G option selected by the TSO:
  - Home charging: **Medium**
  - Street charging: **Low**

Step 1 – Home/Street split

- EVs with home (prosumer) charging: 0.7 × 1,000,000 = 700,000
- EVs with street charging: 0.3 × 1,000,000 = 300,000

Step 2 – Fixed vs. flexible fleets (survey-based)

- **Home (prosumer)**
  - Fixed: 0.7×700,000=490,000
  - Flexible: 0.3×700,000=210,000
- **Street**
  - Fixed: 0.7×300,000=210,000
  - Flexible: 0.3×300,000=90,000

Step 3 – Split of the flexible fleet (centralised assumption)

The flexible fleet is split equally into commuter and non commuter EVs.

- **Home (prosumer)**
  - Flexible with commuter profile: 0.5 × 210,000 = 105,000
  - Flexible without commuter profile: 0.5 × 210,000 = 105,000
- **Street**
  - Flexible with commuter profile: 0.5 × 90,000 = 45,000
  - Flexible without commuter profile: 0.5 × 90,000 = 45,000

At this stage, **six fleets** are defined (fixed and flexible, home and street, with and without commuter constraints). Transport demand and charging infrastructure assumptions follow the same split. For street charging, one charging station is assumed per two EVs.

Step 4 – V2G enabled EVs (survey-based)

V2G is applied **only to the flexible fleets**.

- For **home charging**, the TSO selected **Medium** V2G participation for 2040 → **25% of flexible EVs**
- For **street charging**, the TSO selected **Low** V2G participation for 2040 → **3% of flexible EVs**

Resulting V2G-capable EVs:

- Home, flexible with commuter: 0.25 × 105,000 = 26,250
- Home, flexible without commuter: 0.25 × 105,000 = 26,250
- Street, flexible with commuter: 0.03 × 45,000 = 1,350
- Street, flexible without commuter: 0.03 × 45,000 = 1,350

Fixed fleets do not provide V2G.

ANNEX II: CLIMATE DATABASE //

The climate-dependent inputs used in the TYNDP 2026 scenario assessment are derived from the **Pan European Climate Database version 4.2 (PECDv4.2)**. PECDv4.2 has been developed by the Copernicus Climate Change Service (C3S) in collaboration with European Network of Transmission System Operators for Electricity (ENTSO-E). It provides climate variables and energy-related indicators across large temporal and spatial scales and is specifically designed to support pan European power system and energy studies aiming to increase the resilience of future energy systems under consideration of climate change.

PECDv4.2 builds upon previous Pan-European Climate Database (PECD) releases by extending the temporal coverage of the dataset and by introducing updated climate simulations and improved energy conversion methodologies. In particular, it combines long historical time series based on climate reanalysis with forward looking climate projections, enabling the representation of both observed climate variability and future climate conditions over long term horizons.

Structure of the database

PECDv4.2 is organised around two main data streams:

- a **historical stream**, based on the European Centre for Medium-Range Weather Forecasts Reanalysis Version 5 (ERA5) reanalysis by the European Centre for Medium-Range Weather Forecasts, providing climate variables and derived energy indicators from 1950 to near present; and
- a **projection stream**, covering the period 2015–2100, based on temporally and spatially downscaled and bias adjusted climate simulations from an Equilibrium Climate Sensitivity-guided subset of Coupled Model Intercomparison Project Phase 6 (CMIP6) global climate models under multiple greenhouse gas emission scenarios (Shared Socioeconomic Pathways (SSP); SSP1 2.6, SSP2 4.5, SSP3 7.0 and SSP5 8.5).

For both streams, climate variables are first produced at gridded level over the PECD domain (18°N–75°N, 31°W–45°E) at 0.25° × 0.25° horizontal resolution and hourly (or daily/weekly where applicable) temporal resolution. Energy indicators are then derived using dedicated conversion models and provided primarily as spatially aggregated time series for predefined regions.

Climate variables

The core climate variables available in PECDv4.2 include:

- near surface air temperature at 2 m above ground;
- population weighted temperature;
- wind speed at 10 m and 100 m above ground;
- total precipitation; and
- surface solar radiation downwards (global horizontal irradiance).

Population weighted temperature is computed at onshore bidding zone level using a gridded population mask, enabling a temperature indicator that better reflects population exposure and is suitable for demand related analyses.

For wind speed, PECDv4.2 applies an explicit treatment of vertical wind profiles through a power law formulation, using spatially and temporally resolved coefficients derived from ERA5. Compared to approaches relying on constant shear assumptions, this methodology enables a more realistic extrapolation to near surface wind to turbine relevant heights.

The Global Wind Atlas is further used for additional bias adjustment of wind speeds.

Energy indicators and conversion models

Based on the climate variables, PECDv4.2 provides energy indicators for four main technologies: wind power, solar photovoltaic (PV), concentrated solar power (CSP), and hydropower.

- **Wind power** indicators are derived using physical wind to power conversion models. Profiles are provided separately for existing wind installations and for a range of future wind technologies, characterised by combinations of hub height and specific power. The bias adjustment of wind speeds based on the Global Wind Atlas is applied within PECDv4.2 and affects both climate variables and indirectly the derived wind power indicators, improving the representation of wind resource intensity and spatial heterogeneity compared to earlier PECD versions. Wind power capacity factors are provided on an hourly basis.
- **Solar photovoltaic** indicators are computed using a physically based modelling framework that converts irradiance and temperature into PV generation, accounting for optical losses, temperature effects and inverter losses. PECDv4.2 introduces multiple PV technology types—residential rooftop, industrial rooftop, utility scale fixed and utility scale tracking—allowing different installation configurations to be represented at an aggregated level, while solar PV indicators are also provided at gridded level over the 0.25° × 0.25° PECD domain. Solar photovoltaic generation capacity factors are provided on an hourly basis.
- **Concentrated solar power** is modelled using a technology specific physical representation of the solar field, power block and thermal storage, producing both pre dispatch and dispatched generation profiles for different storage configurations. Concentrated solar generation capacity factors are provided on an hourly basis.
- **Hydropower** indicators are produced using statistical models that relate temperature and precipitation to generation and inflows for different hydropower technologies, including reservoirs, run of river, pondage and pumped storage. For the historical stream, these models are trained and validated against observed generation and storage data where available and used to reconstruct long time series consistent with the ERA5 climate record. Hydropower indicators are provided on a weekly basis.

Spatial aggregation

PECDv4.2 supports multiple spatial aggregation levels relevant for European energy system analysis, including countries, sub national regions, bidding zones and pan European onshore and offshore zones. Aggregation is performed using floating point spatial masks derived from harmonised geographical shapefiles, allowing area weighted averaging of gridded climate and energy data.

Climate variables are generally available both at gridded and aggregated levels, while most energy indicators are delivered as aggregated time series. Solar PV indicators constitute an exception, as both gridded and aggregated products are provided.

Role in the TYNDP 2026 scenarios

Within the TYNDP 2026 framework, PECDv4.2 provides the underlying climate and weather dependent inputs used to derive renewable generation profiles, hydropower availability and temperature related effects on electricity demand. For the projection stream applied in the TYNDP 2026 scenarios, climate data are taken from the Shared Socioeconomic Pathway (SSP2 4.5) emission scenario available in PECDv4.2.

ANNEX III: WEATHER YEAR SELECTION METHODOLOGY //

TYNDP 2026 introduces a climate-adaptive weather year selection methodology that integrates future climate projections (CMIP6 runs with SSP2-4.5) alongside historical reanalysis weather information. This enables energy system modelling that better captures expected changes in renewable generation conditions and temperature-driven electricity demand.

Input Data

The methodology is based on weather and energy variables from the **PECDv4.2** dataset (Annex II), featuring the following models:

- CMCC-CM2-SR5 (CMR5) by the Centro Euro-Mediterraneo sui Cambiamenti Climatici, Italy,
- EC-Earth3 (ECE3) by the European community Earth System Model, and
- MPI-ESM1-2-HR (MEHR) by the Max Planck Institute for Meteorology, Germany

The methodology uses:

- Hourly **PV, onshore wind, offshore wind** power capacity factors
- Weekly **hydro reservoir** and **run-of-river** generation profiles
- Daily **temperatures**, converted into **Heating Degree Days (HDD)** and **Cooling Degree Days (CDD)**, using regional thresholds (e.g., Austria: 12.3°C heating, 25.5°C cooling)
- Installed RES capacities (PEMMDB) and load projections (ETM) for each target year

Candidate Climate Years

For each study horizon (2030, 2035, 2040, 2050), a window of **10 years per climate model** is used (e.g., TY2030: 2025–2034). Together with the three climate models (CMR5, ECE3, MEHR) , this yields **30 candidate climate-year series per target year**, from which **three representative years** are selected.

High level step-by-step selection method

1// Computation of annual averages and cumulative anomalies

- For each climate year
- For each variable (PV, wind offshore, wind onshore, hydro power run of river generation, hydro power reservoir generation, HDD+CDD)

2// Calculation of overall statistics (mean, standard deviation) and deltas

- Deltas quantify the deviation from the full candidate range

3// Application of regional weighting

- Based on installed RES capacities and load relevance
- Only ENTSO-E regions included (exclusions: Turkey, Ukraine, Moldova)

4// Normalisation of all parameters

- Subtraction of the global mean and division by standard deviation to ensure comparability across variables with different units and magnitudes.

5// Dimensionality reduction via Principal Component Analysis (PCA)

- Climate variables are reduced to key principal components, capturing the dominant patterns in RES availability and temperature-driven load.

6// Clustering using k-means methodology (k = 3)

- Climate years are grouped in PCA space based on the similarity of normalised, weighted characteristics.
- For each cluster, the medoid (year closest to the centroid) is selected.

See below for further details on the methodology overview.

Outcome

The method provides three representative weather years per TYNDP target year, each reflecting a distinct climate pattern (see Table 33).

Although the CMR5 model appears over-represented in final selections, **this has no climatic significance** and does not bias the methodology.

CODE NAME	SSP SCENARIO	CLIMATE MODEL	CLIMATE YEAR	STUDY TARGET YEAR
WS003	SSP245	CMR5	2027	2030
WS021	SSP245	MEHR	2025	2030
WS029	SSP245	MEHR	2033	2030
WS032	SSP245	CMR5	2031	2035
WS037	SSP245	CMR5	2036	2035
WS059	SSP245	MEHR	2038	2035
WS065	SSP245	CMR5	2039	2040
WS071	SSP245	ECE3	2035	2040
WS077	SSP245	ECE3	2041	2040
WS091	SSP245	CMR5	2045	2050
WS092	SSP245	CMR5	2046	2050
WS106	SSP245	ECE3	2050	2050

Table 33: Climate year codes

Motivation and Role in Scenario Building

Energy system planning studies must account for weather-driven variability in both demand (temperature-dependent heating and cooling) and supply (wind, solar, and hydro generation). Simulating the 30 scenarios from the three climate models for each target year is computationally heavy and time consuming. The Weather Scenario Selection methodology reduces this set to k = 3 representative weather years per target year, each carrying a probability weight that reflects the frequency of its weather characteristics. This reduction aims make the computational problem tractable while keeping an appropriate level of quality on the final outcomes.

The selected scenarios and their weights allow downstream market modelling processes to approximate expected values over weather uncertainty. This reduces the simulation burden from 30 to 3 runs per target year.

The Weather Scenario Selection is performed early in the scenario building process. Its outputs are the three representative weather scenarios and their associated weights are used as inputs to:

- Demand profiling: hourly electricity, hydrogen and thermal demand time series for hybrid heating are constructed for each selected weather scenario, reflecting temperature-driven heating and cooling loads;
- RES generation profiles: wind, solar, and hydro generation time series are extracted by linking PECDv4.2 with PEMMDB for the selected weather scenarios;
- Market modelling: adequacy and market simulations are run for each of the three representative weather scenarios, and results are combined using the probability weights.

Scope of Analysis

The scope of analysis for the weather year methodology is further elaborated in Table 34 below.

PARAMETER	VALUE
Target years	2030, 2035, 2040, 2050
Climate year windows	2030 (2025–2034), 2035 (2030–2039), 2040 (2035–2044), 2050 (2045–2054)
Climate models	CMCC-CM2-SR5 (CMR5), EC-Earth3 (ECE3), MPI-ESM1-2-HR (MEHR)
Candidates per target year	3 models × 10 years = 30 weather scenarios
Number of representative years (k)	3
Bidding zones	53 European zones
Technologies / Parameters analysed	6: HDD / CDD, Run-of-River, Reservoir, Wind Offshore, Solar PV, Wind Onshore
Macro regions	9 (Baltic, CE, CW1, CW2, Nordic, SC, SE, SW, UK)

Table 34: Scope of analysis for weather year methodology

Methodology Overview

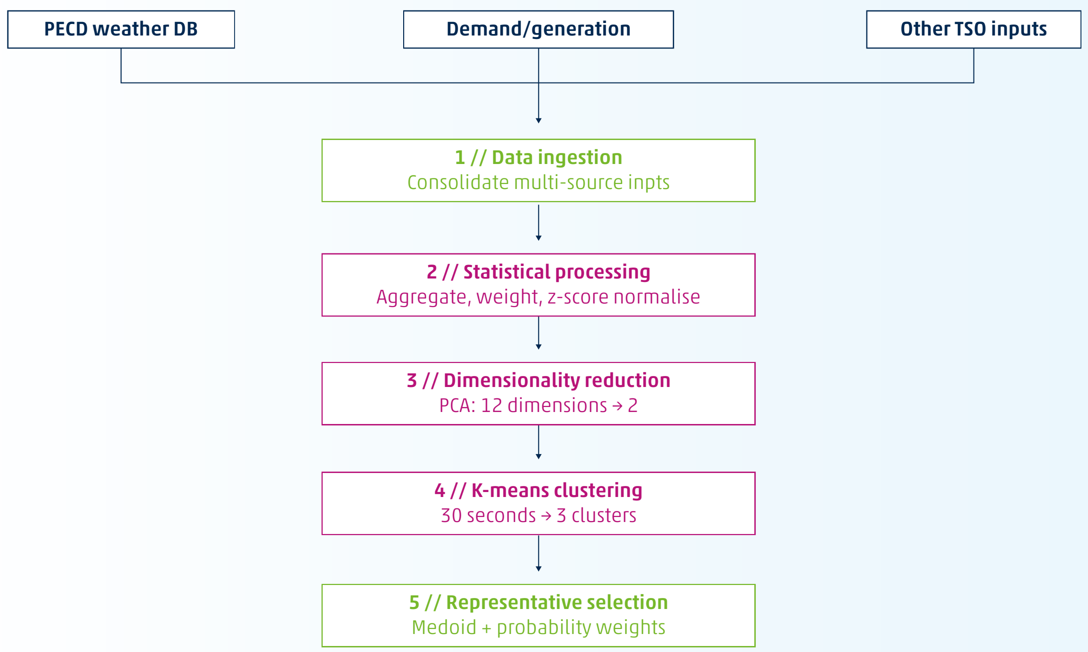


Figure 19: Overview of the weather year selection methodology

The selection follows a five-stage pipeline: (1) Data Ingestion consolidating inputs from the PECD, demand and generation time series, and other TSO-provided data; (2) Statistical Processing including regional aggregation, weighting, and z-score normalisation; (3) Dimensionality Reduction via PCA; (4) k-means Clustering of the 30 weather scenarios into 3 groups; and (5) Representative Selection of the medoid from each cluster together with probability weights, shown in Figure 19 above.

Stage 1: Data Ingestion

Three categories of weather-dependent data are loaded for each of the 30 candidate weather scenarios and 53 bidding zones:

Heating and Cooling Degree Days (HDD/CDD)

Hourly temperature data from the three climate models is converted to daily averages. A threshold transformation is then applied using zone-specific heating and cooling thresholds derived from econometric calibration (per-country GDP, building thermal transmittance, and regression coefficients). Temperatures above the cooling threshold produce cooling degrees for the definition of CDD; temperatures below the heating threshold produce heating degrees for the definition of HDD; temperatures within the comfort band produce zero contribution to both HDD and CDD.

Renewable Generation (Solar PV, Wind Onshore, Wind Offshore)

PECD capacity factor profiles are multiplied by installed generation capacity (MW) from the TYNDP generation capacity dataset for the target year. Sub-types are aggregated to technology level (e.g., Solar PV utility tracking, non-tracking, industrial rooftop, and residential rooftop are summed into a single "Solar" category; fixed and floating offshore wind are summed into the "Offshore" category).

Hydro Inflows (Run-of-River, Reservoir)

Inflow time series are loaded directly from PECD files for each zone, validated against installed hydro capacity in the generation dataset.

Stage 2: Statistical Processing

For each of the six technologies, two indicators are computed per weather scenario to characterise its mean level and its intra-annual variability relative to the climatological baseline.

Macroregional Aggregation

The 53 bidding zones are grouped into nine macroregions to reduce dimensionality while preserving geographic diversity (Table 35):

MACROREGION	COUNTRIES
Baltic	Latvia, Estonia, Lithuania
CE	Czech Republic, Slovakia, Hungary, Poland, Romania
CW1	Belgium, France, Netherlands
CW2	Germany, Austria, Switzerland, Luxembourg
Nordic	Denmark, Finland, Norway, Sweden
SC	Italy
SE	Greece, Cyprus, Bulgaria, N. Macedonia, Croatia, Slovenia, Albania, Bosnia-Herzegovina
SW	Spain, Portugal
UK	United Kingdom, Ireland

Table 35: Macroregional aggregation

For each macroregion, the regional time series is the sum across all constituent bidding zones.

Mean-Anomaly Delta

For each region "r" and weather scenario "s", the annual mean is computed and compared to the "grandmean" across all scenarios. The mean-anomaly delta is the difference between a scenario's annual mean and the average across all 30 scenarios. This captures whether a given weather year produces above- or below-average generation (or demand) for a given technology in a given region.

Variability-Anomaly Delta

The variability indicator captures how much the intra-annual variability of a scenario deviates from the expected level. It is computed as the cumulative anomaly (the running sum of deviations from the "grand-mean" over all timesteps) minus the standard deviation of per-scenario standard deviations across all scenarios. This distinguishes between years with stable output and years with highly volatile output.

Capacity Weighting

Regional deltas are weighted to reflect the relative importance of each macroregion. The weighting approach differs by technology type:

- **For renewable and hydro technologies:** the weight of a region equals its share of total installed capacity for that technology. Regions with more installed capacity exert a proportionally greater influence on the clustering.
- **For HDD/CDD:** the weight of a region equals its share of total electricity demand (from the Bidding Zone Overview dataset), reflecting the fact that temperature sensitivity scales with consumption volume.

The weighted deltas collapse the regional dimension into a single value per scenario for each technology.

Z-Score Normalisation

Each weighted delta series is standardised to zero mean and unit variance. This ensures that all six technologies contribute equally to the subsequent dimensionality reduction, regardless of their original physical units and scales.

Stage 3: Dimensionality Reduction (PCA)

After the previous Stage 2, each of the 30 weather scenarios is described by a 12-dimensional feature vector comprising six normalised mean-anomaly values and six normalised variability-anomaly values, one per technology.

These 12 dimensions are organised into two independent subspaces: (i) the mean-anomaly matrix A (30 scenarios × 6 technologies), whose columns are the z-scored mean deltas for each technology; and (ii) the variability-anomaly matrix S (30 scenarios × 6 technologies), whose columns are the z-scored variability deltas.

A Principal Component Analysis (PCA) is applied independently to each subspace, retaining only the first principal component (PC1). Each weather scenario is then represented as a point in a two-dimensional space: the first axis (PC1 of the mean-anomaly matrix) captures the dominant mode of co-variation in mean generation/demand levels across technologies; the second axis (PC1 of the variability-anomaly matrix) captures the dominant mode of co-variation in intra-annual variability.

Stage 4: K-Means Clustering

The 30 points in the reduced 2D space are partitioned into k = 3 clusters by k-means clustering, minimising the within-cluster sum of squares. The algorithm is run with 10 random initialisations to mitigate sensitivity to initial centroid placement, and the partition with the lowest total within-cluster variance is retained. A fixed random seed ensures full reproducibility.

The representative year for each cluster is the scenario closest to the cluster mean in the two-dimensional PCA space. By selecting an actual weather scenario rather than the centroid itself (which is a synthetic point with no corresponding time series), the representative weather scenario chosen always corresponds to an existing model year with a complete, physically consistent set of profiles across all technologies and zones.

Stage 5: Probability Weight Computation

The probability weight of each representative scenario equals the proportion of historical weather years assigned to its cluster: $w_k = |C_k| / N$, where $|C_k|$ is the number of years in cluster k and N = 30 is the total number of candidate scenarios.

This is a non-parametric density estimator under the ergodicity assumption: the temporal frequency of weather patterns in a sufficiently long temporal record approximates their probability of occurrence. The weights are non-negative, sum to unity by construction, and represent the empirical likelihood of each weather regime – not a measure of weather severity or extremity.

Results

The following Table 36 summarises the selected representative weather years and their probability weights for each target year:

TARGET YEAR	CLUSTER	REPRESENTATIVE YEAR	WEIGHT	CLUSTER SIZE
2030	0	WS029	0.30	9
2030	1	WS003	0.63	19
2030	2	WS021	0.07	2
2035	0	WS037	0.43	13
2035	1	WS059	0.33	10
2035	2	WS032	0.24	7
2040	0	WS077	0.40	12
2040	1	WS071	0.40	12
2040	2	WS065	0.20	6
2050	0	WS106	0.20	6
2050	1	WS091	0.23	7
2050	2	WS092	0.57	17

Table 36: Representative Weather Scenarios for TYNDP 2026

For each target year, the k-means algorithm identifies three distinct weather regimes. One cluster typically contains roughly half of the 30 candidates, representing the most common weather pattern, while the other two clusters capture less frequent but distinct regimes.

Integration with the Scenario Building Process

The three representative weather years and their weights are integrated into the broader scenario building workflow as follows:

1// **PECD data extraction:** For each target year, the full hourly PECD time series (renewable capacity factors, hydro inflows, temperature profiles) are extracted for only the three selected weather years, rather than all 30 candidates.

2// **Demand profile construction:** The temperature time series of the selected weather years feed into the demand profiling process, where they drive the construction of weather-dependent electricity demand components – in particular heating (heat pumps, electric boilers, hybrid heat pumps) and cooling (air conditioning) loads. Each selected weather year produces a distinct annual demand profile reflecting its temperature characteristics.

3// **RES and hydro profiling:** Wind, solar, and hydro generation profiles are built from the PECD capacity factors of the three selected years, scaled by the installed capacities defined in the scenario.

4// **Market simulations:** Adequacy and market studies are run three times per target year, once for each representative weather scenario. The simulation results (e.g., generation dispatch, flows, marginal costs, adequacy margins) are then combined using the probability weights to produce expected values. This weighted-average approach allows planners to derive robust expected indicators while preserving the ability to examine individual weather regimes.

Key Assumptions and Design Choices

- **k = 3 clusters:** The number of representative years is set to three, balancing computational cost against weather variability. This is consistent with previous TYNDP cycles and provides a manageable set for downstream modelling while still distinguishing between fundamentally different weather regimes.
- **Equal technology weighting via z-score normalisation:** All six technologies receive equal influence in the PCA through standardisation.
- **Two independent PCA reductions:** Separating the mean-anomaly and variability-anomaly subspaces into two independent PCA reductions preserves the interpretability of the resulting axes: one captures level effects (wet vs. dry, windy vs. calm years) and the other captures variability effects (stable vs. volatile years).
- **Ergodicity assumption:** The 30 weather scenario series are assumed to constitute a representative sample of the climate distribution for each target year window. Under this assumption, cluster sizes directly estimate the probability of each weather regime.
- **Macroregional aggregation:** Reducing 53 bidding zones to 9 macroregions prevents the analysis from being dominated by node-level noise while preserving the major geographic contrasts in European weather patterns (e.g., Nordic vs. Mediterranean, Atlantic vs. Continental).

Meteorology of the Selected Weather Years

The following graphs show the selected weather years, its weighted average according to Table 36 and the whole 30 candidate weather years for any target year. Any weather year is characterised by 6 parameters grouped in 3 figures: offshore and onshore wind, HDD/CDD and solar irradiance, hydropower run-of river and reservoir generation.

Offshore Wind vs. Onshore Wind

Figure 20 shows the deviation of the 30 candidate weather years from their ensemble mean for each target year for offshore and onshore wind speed. PECD data has been aggregated separately for P2OF and P2ON zones to derive the combined deviations for all 27 EU countries. The result of the selection is highlighted with blue, orange, and green circles, while the weighted selection is indicated by the black square. The weighted selection is striking for target year 2040, with a deviation of -0.16 m s-1 in offshore wind and –0.19 m s-1 in onshore wind.

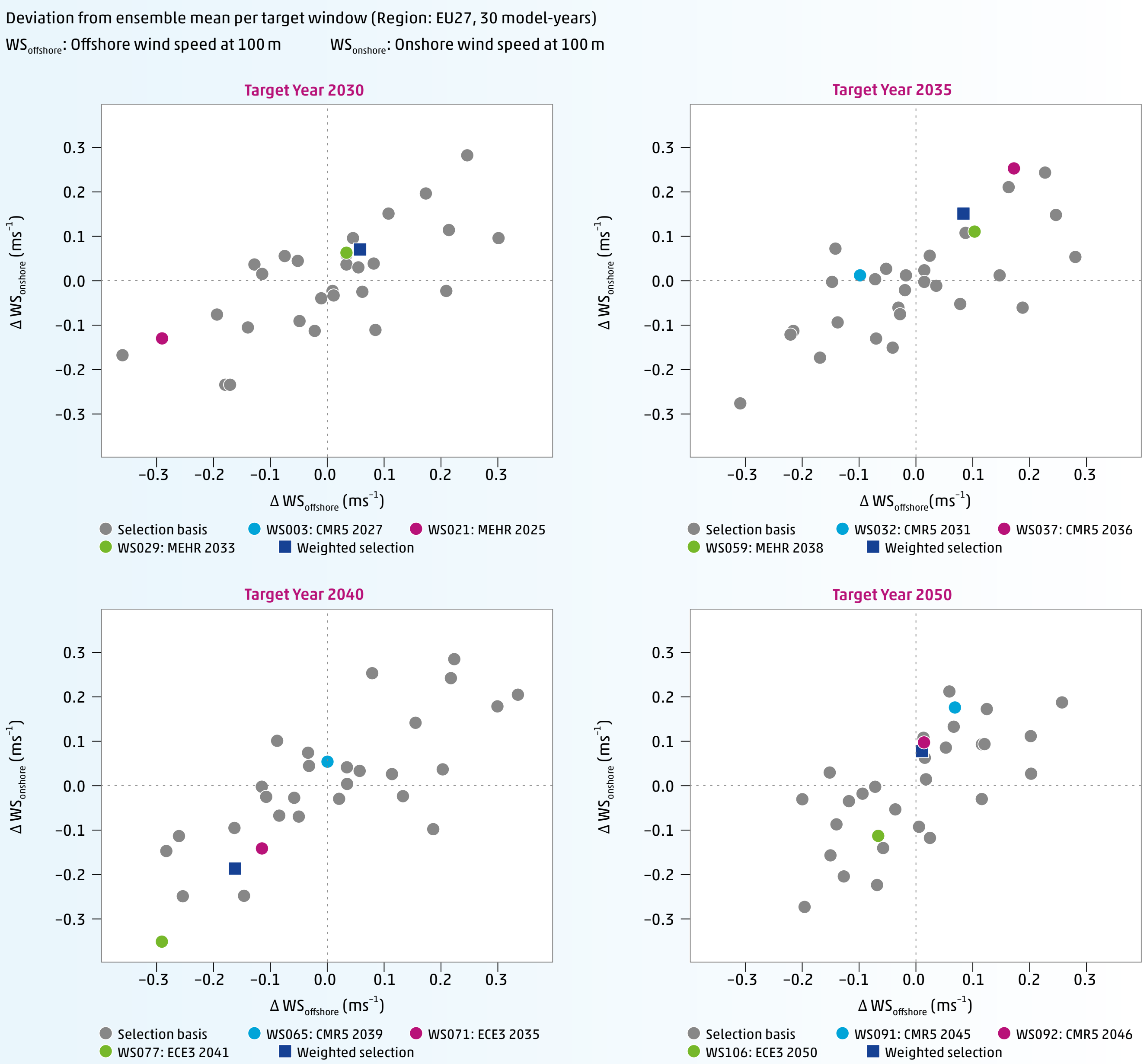


Figure 20: Offshore and onshore wind in 2030, 2035, 2040 and 2050

HDD/CDD vs. Solar irradiance

Figure 21 shows the deviation of the 30 candidate weather years from their ensemble mean for each target year for global horizontal irradiance and HDD/CDD. For calculating the deviations for the global horizontal irradiance, P2ON regions have been aggregated for all EU-27 countries. For calculating the deviations for HDD/CDD, hourly air temperatures from PECD have been averaged to daily temperatures before deriving HDD and CDD. HDD and CDD have been aggregated by calculating the double sum over the specific climate year and all 27 EU countries. The result of the selection is highlighted with blue, orange, and green circles, while the weighted selection is indicated by the black square. The weighted selection for target year 2030 indicates 1.78 W m-2 less solar irradiance than the ensemble mean, while the weighted selection for target year 2040 indicates 3626°C x days less than the ensemble mean for heating and cooling across the 27 EU countries.

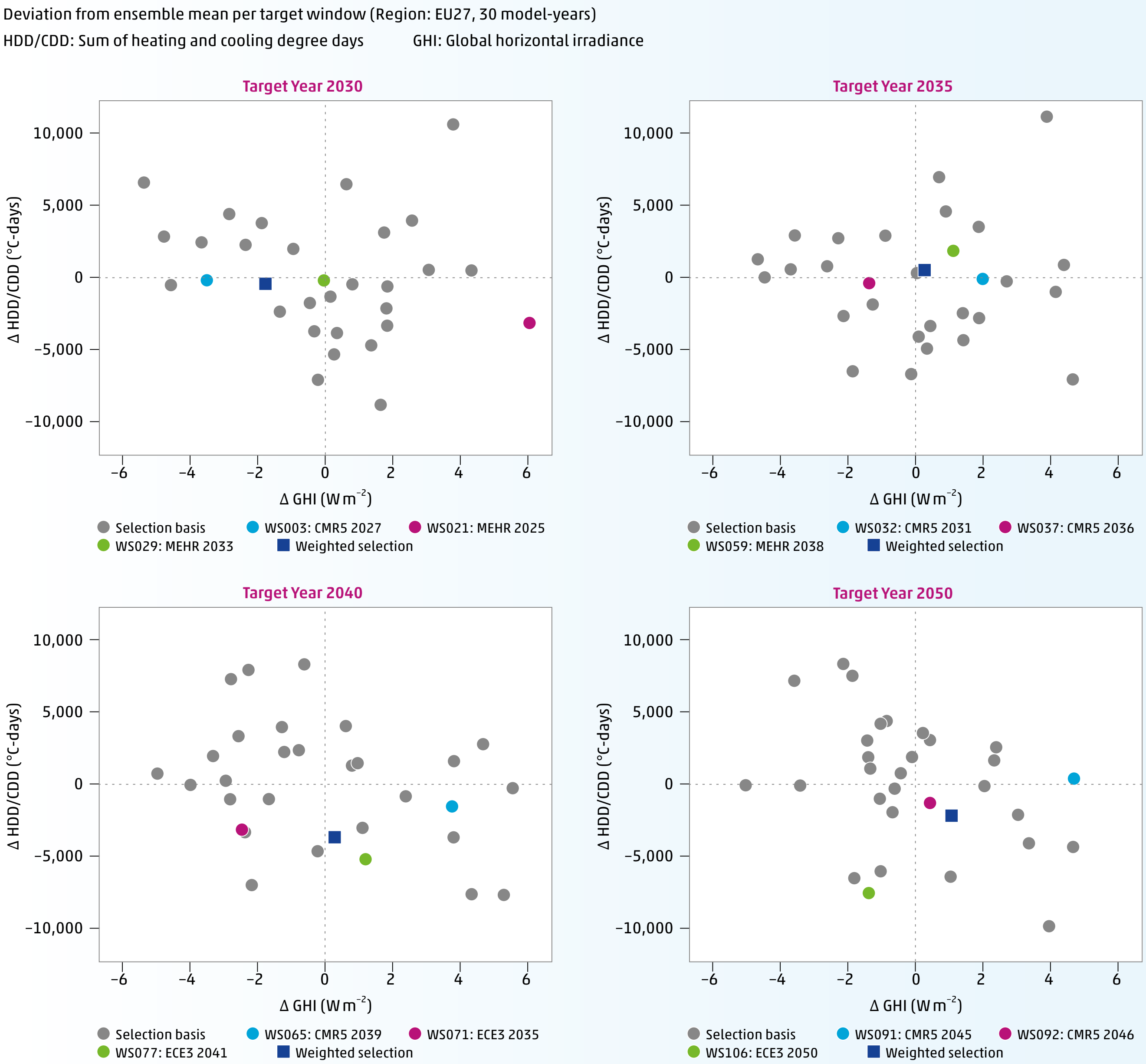


Figure 21: HDD/CDD vs solar irradiance in 2030, 2035, 2040 and 2050

Hydropower run-of river vs. reservoir

Figure 22 shows the deviation of the 30 candidate weather years from their ensemble mean for each target year for hydropower reservoir generation energy and hydropower run-of-river generation energy. Weekly PECD data of the produced amount of energy has been aggregated for SZON bidding zones to derive the combined deviations for all 27 EU countries. The result of the selection is highlighted with blue, orange, and green circles, while the weighted selection is indicated by the black square. The weighted selection indicates a hydropower reservoir energy generation slightly above average for target years 2030, 2040 and 2050 and slightly below average for target year 2035. The hydropower run-of-river energy generation of the weighted selection is very close to the average for all target years with a maximum of 3.56 GWh deviation in 2035.

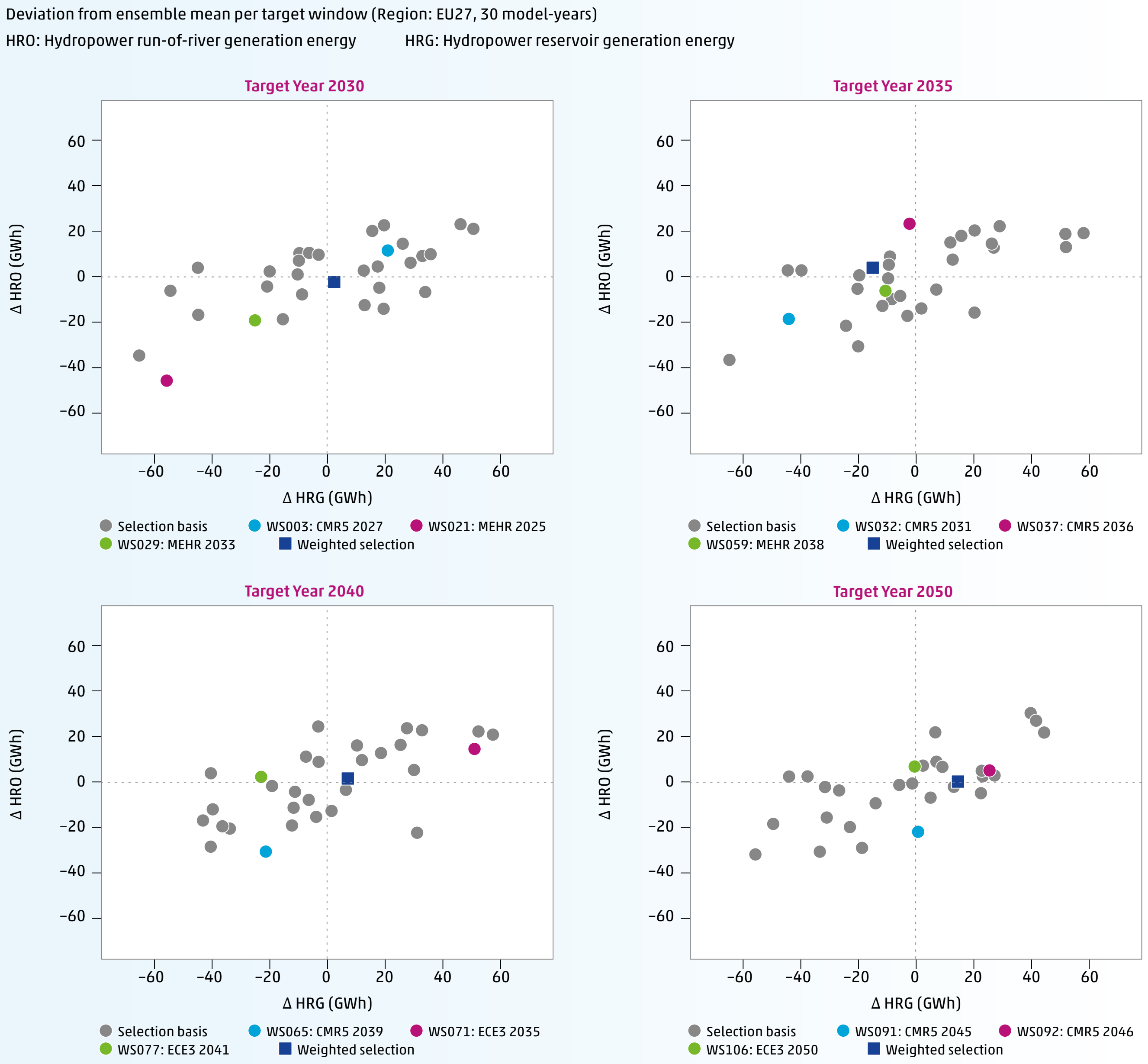


Figure 22: Hydropower run-of-river vs reservoir in 2030, 2035, 2040 and 2050

ANNEX IV: MARKET MODELLING INPUTS //

The market modelling inputs, with respective parameters, concerned sectors, and related data sources are elaborated in Table 37.

PARAMETER	SECTOR	SOURCE
DEMAND PROFILES		
PROSUMER	Electricity	ETM/DFT
MARKET	Electricity	ETM/DFT
LOSSES	Electricity	ENTSO-E
EV	Electricity	ETM/DFT
HYBRID HEAT PUMPS	Heat	ETM
H_2 ZONE 1	Hydrogen	ETM/ENTSOG tool
H_2 ZONE 2	Hydrogen	ETM/ENTSOG tool
SYNTHETIC FUELS	Synthetic Fuels	ETM & Data Collection
INFRASTRUCTURE		
HYDROGEN PIPELINES	Hydrogen	ENTSOG
ELECTRICITY GRID	Electricity	ENTSO-E
ELECTRICITY PRODUCTION		
HYDRO	Electricity	ENTSO-E
NUCLEAR	Electricity	ENTSO-E
GAS TURBINES (CH_4)	Electricity	ENTSO-E & ENTSOG
GAS TURBINES (H_2)	Electricity	ENTSO-E & ENTSOG
COAL	Electricity	ENTSO-E
LIGNITE	Electricity	ENTSO-E
OIL	Electricity	ENTSO-E
OTHER NON-RES	Electricity	ENTSO-E & ENTSOG
OTHER RES	Electricity	ENTSO-E
CONCENTRATED SOLAR POWER	Electricity	ENTSO-E
ONSHORE WIND	Electricity	ENTSO-E
OFFSHORE WIND	Electricity	ENTSO-E
SOLAR PV	Electricity	ENTSO-E
PECD	Weather	ENTSO-E

PARAMETER	SECTOR	SOURCE
HYDROGEN SUPPLY SOURCES		
ELECTROLYSIS	Hydrogen	ENTSO-E & ENTSOG
HYDROGEN IMPORTS	Hydrogen	ENTSOG
STEAM METHANE REFORMING	Hydrogen	ENTSOG
PYROLYSIS	Hydrogen	ENTSOG
FLEXIBILITIES		
DSR	Electricity	ENTSO-E
BATTERY STORAGE	Electricity	ENTSO-E
HYDROGEN STORAGE	Hydrogen	ENTSOG
ELECTRIC VEHICLE	Electricity	ETM
ELECTRIC VEHICLES		
FLEET TYPE: FIXED OR FLEXIBLE	EV	TSO Survey
BATTERY CAPACITY	EV	Innovation Team
EFFICIENCY	EV	ETM
TRANSPORT DEMAND	EV	ETM
FIXED CHARGING PROFILES	EV	ETM/DFT
NUMBER OF EVs	EV	ETM
START SOC	EV	Innovation Team (TYNDP2024)
MIN SOC	EV	Innovation Team (TYNDP2024)
AVAILABILITY PROFILES	EV	Innovation Team (TYNDP2024)
DRIVING PROFILES	EV	REM2030 study
STREET/HOME SPLIT	EV	Innovation Team (TYNDP2024)
COMMUTER/NON-COMMUTER SPLIT	EV	Innovation Team
CHARGING STATION CHARGE RATE	EV	Innovation Team (TYNDP2024)

PARAMETER	SECTOR	SOURCE
USE OF STATION CHARGE	EV	Innovation Team (TYNDP2024)
CHARGING STATION EFFICIENCY	EV	Innovation Team (TYNDP2024)
NUMBER OF STATIONS PER EV	EV	Innovation Team
VEHICLE-TO-GRID RATIO	EV	TSO Survey
SPACE AND WATER HEATING		
HEAT DEMAND FOR HHP	Heat	ETM
NUMBER OF HEAT PUMPS IN HHP	Heat	ETM
INSTALLED CAPACITY PER HEAT PUMP IN HHP	Heat	ETM
HEAT PUMP COP	Heat	Innovation Team (TYNDP2024)
BOILER EFFICIENCY IN HHP (HEAT RATE)	Heat	Innovation Team (TYNDP2024)
SYNTHETIC FUELS		
CO_2/SYNTHETIC FUEL RATIOS	Synthetic Fuels	Innovation Team
PRODUCTION CAPACITY	Synthetic Fuels	Data Collection
BIOGENIC CO_2 SUPPLY	Synthetic Fuels	ENTSOG
OTHER		
COMMODITY PRICES		Supply Team
GAS PRICE & CO_2 EMISSIONS FACTOR		Supply Team

Table 37: Market modelling inputs

ANNEX V: DEMAND FORECASTING TOOL (DFT) //

For the creation of hourly load profiles for most European countries, ENTSO-E uses a load forecasting toolbox that incorporates uncertainty analysis under various climate conditions. The toolbox comes in a software application developed by an external provider.

The demand forecasting toolbox (DFT) combines **historical load data, weather variables** (such as temperature and irradiance), **calendar effects** (weekdays, weekends, holidays, and special days), and **scenario-based structural adjustments** to model future electricity consumption patterns.

In addition, DFT is able to integrate electrification drivers and demand-side flexibility assumptions, including the impact of:

- electric vehicles (EVs),
- heat pumps (HPs),
- air-conditioning growth,
- sanitary water heating,
- temperature-dependent demand growth

DFT contains three different algorithms for modelling the hourly electric load time series. These are popular machine learning algorithms that can provide precise estimates of future load curves. At the same time these methods can give interpretable results so the main drivers of load evolution can also be inferred. Currently available algorithms in DFT: Generalised Additive Models (GAM), Random Forest, Linear regression.

ANNEX VI: COUNTRY SPECIFIC DATA COLLECTION AND MODELLING //

The level of detail provided by ETM demand data enables an explicit representation of sector coupling within the modelling framework. Where complete and consistent ETM data was available, modelling of hydrogen, pEVs and HHPs was implemented. This applies to most EU27 countries and Switzerland.

For the majority of these countries, ETM data was submitted directly by TSOs. In cases where such data was not available, a predefined fallback solution was applied, as described in Section 4.2. For the remaining countries, the ERAA dataset was used as input for the electricity demand, while hydrogen demand was assumed to be zero. As a results, these countries were modelled with a reduced level of functionality and simplified nodal representation.

For the United Kingdom, Bulgaria and Cyprus, a hydrogen representation was implemented despite the absence of a complete ETM dataset.

It should be noted that the modelling columns in the Table 38 on page 88 indicate the availability of model representation. The presence of "HHPs modelling" does not imply that HHPs were included in all national datasets.

	COUNTRY ID	COUNTRY NAME	ETMU SED	H_2 MODELLING	FLEX pEV MODELLING	HHP MODELLING	BTM
1	AT	Austria	yes	yes	yes	yes	yes
2	BE	Belgium	yes	yes	yes	yes	no
3	BG	Bulgaria	no	yes	no	no	no
4	CY	Cyprus	no	yes	no	no	no
5	CZ	Czech Republic	fallback	yes	yes	yes	no
6	DE	Germany	yes	yes	yes	yes	only batteries
7	DK	Denmark	yes	yes	yes	yes	no
8	EE	Estonia	fallback	yes	yes	yes	no
9	ES	Spain	yes	yes	yes	yes	no
10	FI	Finland	yes	yes	yes	yes	no
11	FR	France	yes	yes	yes	yes	no
12	GR	Greece	yes	yes	yes	yes	no
13	HR	Croatia	fallback	yes	yes	yes	no
14	HU	Hungary	yes	yes	yes	yes	yes
15	IE	Ireland	fallback	yes	yes	yes	no
16	IT	Italy	yes	yes	yes	yes	no
17	LT	Lithuania	yes	yes	yes	yes	no
18	LU	Luxembourg	yes	yes	yes	yes	no
19	LV	Latvia	yes	yes	yes	yes	no
20	NL	Netherlands	yes	yes	yes	yes	no
21	PL	Poland	yes	yes	yes	yes	no
22	PT	Portugal	yes	yes	yes	yes	no
23	RO	Romania	fallback	yes	yes	yes	no
24	SE	Sweden	yes	yes	yes	yes	no
25	SI	Slovenia	yes	yes	yes	yes	no
26	SK	Slovakia	fallback	yes	yes	yes	no
27	MT	Malta	yes	yes	yes	yes	no
28	CH	Switzerland	yes	yes	yes	yes	yes
29	RS	Serbia	no	no	no	no	no
30	NO	Norway	no	no	no	no	no
31	UA	Ukraine	no	no	no	no	no
32	TR	Turkey	no	no	no	no	no
33	MD	Moldova	no	no	no	no	no
34	BA	Bosnia and Herzegovina	no	no	no	no	no
35	AL	Albania	no	no	no	no	no
36	ME	Montenegro	no	no	no	no	no
37	MK	North Macedonia	no	no	no	no	no
38	UK	United Kingdom	no	yes	no	no	no
39	UKNI	Northern Ireland	no	no	no	no	no

Table 38: Country specific data collection and modelling

ANNEX VII:
BEHIND THE METER CAPACITIES //

This Annex provides the installed capacities of behind-the-meter photovoltaic (PV) systems and associated battery storage considered in the modelling approach described in Section 4.3. These assets are not represented within the market optimisation and are therefore optimised externally. Their resulting net load profiles (including PV generation and battery operation) are integrated into the model as fixed demand time series at the corresponding market nodes, which may take both positive (net demand) and negative (net generation) values.

RENEWABLES	2030	2035	2040	2050
	Gen/GW	Gen/GW	Gen/GW	Gen/GW
AT	8	10.5	13	13
CH	16.8	24.1	30.09	37.51
DE	45.3	60.57	63.15	58.33
HU	0.12	0.22	0.27	0.37

BATTERIES	2030		2035		2040		2050	
	Gen/GW	Sto/GWh	Gen/GW	Sto/GWh	Gen/GW	Sto/GWh	Gen/GW	Sto/GWh
AT	3.7	7.4	4.85	9.7	6	12	6	12
CH	2.3	1.15	2.99	1.49	6.94	3.47	10.1	5.05
DE	27.18	58.44	36.34	87.22	37.89	94.73	35	87.5
HU	0.12	0.33	0.22	0.62	0.27	0.76	0.37	1.04

Table 39: Behind the meter capabilities

ANNEX VIII: GRID LOSSES //

As described in Section 4.3, the share of electricity transmission and distribution losses per year and market node are listed in the following Table:

ELECTRICITY LOSS FACTORS				
UNIT	FRACTION OF NET DEMAND	FRACTION OF NET DEMAND	FRACTION OF NET DEMAND	FRACTION OF NET DEMAND
YEAR	2030	2035	2040	2050
AT00	0.06	0.06	0.06	0.06
BE00	0.04	0.05	0.05	0.05
CH00	0.08	0.08	0.08	0.08
CZ00	0.06	0.06	0.06	0.06
DE00	0.07	0.07	0.08	0.08
DKE1	0.05	0.05	0.05	0.05
DKW1	0.06	0.06	0.06	0.06
EE00	0.08	0.08	0.08	0.08
ES00	0.04	0.04	0.04	0.04
FI00	0.05	0.05	0.06	0.06
FR00	0.05	0.05	0.04	0.04
GR00	0.06	0.06	0.05	0.05
GR03	0.08	0.08	0.08	0.07
HR00	0.04	0.03	0.03	0.03
HU00	0.03	0.03	0.03	0.03
IE00	0.07	0.07	0.07	0.07
ITCA	0.06	0.06	0.06	0.06
ITCN	0.06	0.06	0.06	0.06
ITCS	0.06	0.06	0.06	0.06
ITN1	0.06	0.06	0.06	0.06

ELECTRICITY LOSS FACTORS				
UNIT	FRACTION OF NET DEMAND	FRACTION OF NET DEMAND	FRACTION OF NET DEMAND	FRACTION OF NET DEMAND
YEAR	2030	2035	2040	2050
ITS1	0.06	0.06	0.06	0.06
ITSA	0.06	0.06	0.06	0.06
ITSI	0.06	0.06	0.06	0.06
LT00	0.08	0.08	0.08	0.08
LUG1	0.05	0.04	0.04	0.04
LV00	0.05	0.05	0.05	0.05
MT00	0.05	0.05	0.05	0.05
NL00	0.04	0.04	0.04	0.04
PL00	0.06	0.05	0.04	0.04
PT00	0.09	0.09	0.09	0.09
RO00	0.11	0.11	0.11	0.11
SE01	0.13	0.16	0.03	0.03
SE02	0.10	0.11	0.03	0.03
SE03	0.08	0.08	0.03	0.03
SE04	0.08	0.08	0.03	0.03
SI00	0.06	0.06	0.05	0.05
SK00	0.06	0.06	0.06	0.06

Table 40: Electricity transmission and distribution loss shares per target year and electricity market node

LIST OF ACRONYMS //

ACER	Agency for the Cooperation of Energy Regulators
BECCS	Bioenergy with Carbon Capture and Storage
C3S	Copernicus Climate Change Service
CAPEX	Capital Expenditures
CBA	Cost Benefit Analysis
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CDD	Cooling Degree Days
CH_4	Methane
CHP	Combined Heat and Power
CMIP6	Coupled Model Intercomparison Project Phase 6
CMR5	CMCC-CM2-SR5, one of the PECD Climate Models
COP	Coefficient of performance
CO_2	Carbon Dioxide
CSP	Concentrated Solar Power
DC2	Additional Data Collections
DE	Distributed Energy
DFT	Demand Forecasting Tool
DRES	Dedicated Renewable Energy Sources
EC	European Commission
ECE3	EC-Earth3, one of the PECD Climate Models
EEA	European Economic Area
EIA	Environmental Impact Assessment
ENS	Energy not served
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ERA5	European Centre for Medium-Range Weather Forecasts Reanalysis Version 5
ERAA	European Resource Adequacy Assessment
ESABCC	European Scientific Advisory Board on Climate Change
ETM	Energy Transition Model
EU	European Union
EUR	Euro
EV	Electric Vehicles
F-gas	Fluorinated gas
FID	Final Investment Decision
FEC	Final Energy Consumption
FT	Fischer-Tropsch
GA	Global Ambition
GAM	Generalised Additive Models
GDP	Gross Domestic Product
Gen/GW	Battery generation capacity in GW
GHG	Greenhouse gas
GHI	Global Horizontal Irradiation
GJ	Gigajoules
GT	Gigatonne
GWh	Gigawatt hours
GWh/h	Gigawatt hours per hour
H_2	Hydrogen
HDD	Heating Degree Days
HEV	High Economic Variant
HGVs	Heavy Goods Vehicles
HHP	Hybrid Heat Pumps
HICP	Harmonised Index of Consumer Prices
HP	Heat Pumps
HRG	Hydro Reservoir Generation for EU27
HRO	Hydro Run of River Generation for EU27
IA	Impact Assessment
IPPC	International Plant Protection Convention
JRC	Joint Research Centre

JRC-IDEES	Joint Research Centre's Integrated Database of the European Energy System
LEV	Low Economic Variant
kWh	Kilowatt hours
LH_2	Liquid hydrogen
LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carriers
LTC	Long Term Contract
LULUCF	Land Use, Land-Use Change and Forestry
MEHR	MPI-ESM1-2-HR, one of the PECD Climate Models
MT	Megatonne
MWh	Megawatt hours
N_2O	Nitrous oxide
NDP	National Development Plan
NECPs	National Energy and Climate Plans
NH_3	Ammonia
NT	National Trends i.e. the data collection from TSOs
NT+	National Trends+ i.e. the Central Scenario for TYNDP 2026
NTC	Net Transfer Capacity
OPEX	Operating Expenditures
P2G	Power-to-Gas
P2L	Power-to-Liquids
P2M	Power-to-Methane
P2OF	PECD Offshore Zones
P2ON	PECD Onshore Zones
P2X	Power to X
PCA	Principal Component Analysis
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PPA	Power Purchase Agreement
PV	Photovoltaic
RES	Renewable Energy Sources
SMR	Steam Methane Reforming
SNG	Synthetic Natural Gas
SRG	Stakeholder Reference Group
SRES	Shared Renewable Energy Sources
SSP	Shared Socioeconomic Pathway
Sto/GWh	Battery storage capacity in GWh
SZON	Zones in PECD, typically related to entire countries
TEN-E	Trans-European Networks for Energy
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
V2G	Vehicle to Grid
VOLL	Value Of Lost Load
WACC	Weighted Average Cost of Capital
WGSB	Working Group Scenario Building
WS onshore/offshore	Onshore/Offshore Windspeed weighted by installed capacity
WS (XXX)	Weather Scenario (followed by number of weather scenario)

LIST OF FIGURES //

LIST OF TABLES //

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Joint-Publishers

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European Network of
Transmission System Operators
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Avenue de Cortenbergh 100
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for Electricity

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Design

DreiDreizehn GmbH, Berlin | www.313.de
Cover artwork: ZN Consulting, Brussels |
www.znconsulting.com

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Publishing date

June 2026

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