TYNDP // 2026

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Draft Scenarios Report

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FOREWORD //

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We are pleased to jointly present the TYNDP 2026 Scenarios underpinning ENTSO-E's and ENTSOG's 2026 Ten-Year Network Development Plans (TYNDP). The joint electricity, gas, and hydrogen scenario and, for the first time ever, the economic variants provide a consistent and forward-looking foundation for planning Europe's future energy infrastructure in support of the energy transition.

Scenarios are a prerequisite for outlook assessment of the European energy system. Under the TEN-E Regulation (EU) 2022/869 and the ACER TYNDP Scenarios Framework Guidelines, they play a central role in ensuring that infrastructure planning across electricity, methane and hydrogen is aligned, coherent, and based on shared assumptions. The TYNDP 2026 cycle marks the first full implementation of these Guidelines from the outset, strengthening the transparency, comparability, and reliability of the scenario-building process.

Within the legal boundaries outlined above, modelling is performed by the technical operators (ENTSO-E and ENTSOG). This ensures robust system analysis and projections based on operational expertise. It ensures a direct link to national planning realities, operational needs and infrastructure delivery, which is essential for credible and implementable grid deployment. ENTSO-E and ENTSOG contribute as trusted advisors and bring well established expertise, hands-on experience, and in-depth knowledge to the process. This insight is essential to create realistic scenarios based on industries and citizens' needs while enabling political ambitions to meet the energy and climate goals.

The TYNDP 2026 Scenarios Framework introduces a streamlined structure centred on one Central Scenario (National Trends +), complemented by two Economic Variants reflecting high and low economic growth. The Central Scenario reflects the latest national strategies, updated National Energy and Climate Plans (NECPs), and EU policy objectives, while the Economic Variants act as stress tests in assessing the resilience of the energy system under different macroeconomic conditions. Together, they provide a credible and policy-aligned basis in determining infrastructure requirements for a secure, interconnected and sustainable future.

The Central Scenario illustrates a profound transformation of Europe's energy system towards climate neutrality by 2050. It highlights a structural transformation of Europe's energy landscape with a continued decline in overall energy demand driven by efficiency gains and electrification, alongside strong growth in electricity demand. Methane demand progressively decreases and becomes a fully decarbonised energy vector over time, while hydrogen emerges as a key energy carrier, particularly in the industry sector and as the major source of flexibility. These trends underline the growing importance of an integrated energy system in which electricity and hydrogen play central roles, supported by decarbonised and renewable gases.

In line with EU requirements, the Central Scenario's design is consistent with the Union's 2030 energy and climate targets and the 2050 climate neutrality objective. Where gaps between aggregated national trajectories and EU-level targets were identified, a transparent and harmonised methodology was applied to ensure alignment while preserving national contributions. The results are benchmarked against external European studies, reinforcing their credibility.

The development of the scenario followed a structured and inclusive process, with extensive stakeholder engagement and public consultations. In particular, we express our appreciation to everyone involved in the Stakeholder Reference Group (SRG) who guide us in a structured review on methodologies and datasets, ensuring transparency, broad participation, and effective scrutiny. This collaborative approach contributes directly to the quality and buy-in of the results.

The resulting scenario and its variants form the analytical backbone for the ENTSO-E and ENTSOG TYNDPs, enabling the assessments of infrastructure gaps, identification of investment gaps and the evaluation of project benefits. They provide policymakers, Member States, and stakeholders with a shared and dependable reference to support informed decisions on Europe's future energy infrastructure. In addition to TYNDP Scenarios, the ENTSO-E European Resource Adequacy Assessment (ERAA) reflects the importance to more deeply analyse risks within a 10-year period. ENTSOG proposes further work to undertake a more thorough investigation of adequacy between supply and demand in the context of the gas grid infrastructure and the ongoing status of the energy transition via the Mid-Term European Gas Adequacy Assessment.

The EU Grids Package includes a proposal to revise of the TEN-E Regulation which is a cornerstone for the TYNDPs used by ENTSO-E, ENTSOG, ENNOH and national TSOs. It is more important than ever to have robust system planning based on TYNDP Scenarios that reflect targets, technical context and are rooted in the reality to deliver infrastructure. ENTSO-E and ENTSOG stand ready to continue their work in next TYNDPs together with stakeholders. Geopolitical context and national policies change rapidly, and correct investment decisions should be made for infrastructure that will have long lasting impact to create resilience and reduce costs.

Our scenario teams remain available for any further information at scenarios@entsos-tyndp-scenarios.eu. We look forward to continuing our cooperation with all stakeholders as we move forward in the TYNDP process.

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1 EXECUTIVE SUMMARY //

The Ten-Year Network Development Plan (TYNDP) 2026 Scenario Package provides a transparent and cross-sectoral outlook for the future European energy system. It is jointly developed by the European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Network of Transmission System Operators for Gas (ENTSOG) to underpin the Union-wide TYNDPs. The scenarios establish a consistent quantitative basis for electricity, gas, and hydrogen infrastructure assessment. The Scenarios ensure that network planning decisions are grounded in policy-aligned and stakeholder-informed assumptions.

Scenarios are not meant to forecast the future. They are exploratory tools rather than predictive exercises, illustrating how developments may unfold under different assumptions regarding policy, technology, markets, and societal trends.

Given the uncertainty about those developments and the complexity of the exercise, the TYNDP Scenarios – ranging from the modelling of demand of multiple energy carriers to highly detailed pan-European electricity and hydrogen system representations – necessarily rely on simplifications and assumptions. To support the use and interpretation of the scenarios by industry, academia and the wider stakeholder community, the reports and their appendices give more context on how to interpret the results. Nevertheless, these scenarios constitute one of the most comprehensive and detailed representations of possible developments in European energy demand and supply. Being anchored in National and European policy objectives as well as climate ambitions, they provide the basis for pan European infrastructure planning within the respective Ten-Year Network Development Plans (TYNDP) 2026, and further analytical work. The TYNDP 2026 Scenario Framework comprises one Central Scenario (also called National Trends+ (NT+)), reflecting the latest national strategies, updated National Energy and Climate Plans (NECPs), and EU policies. It is complemented by two Economic Variants which differ in high and low economic growth. These variants function as stress tests of the Central Scenario. They provide insights into the robustness of infrastructure needs under differing macro-economic conditions. These are in line with the Agency for the Cooperation of Energy Regulators (ACER) "TYNDP Scenarios Guidelines". Scenario inputs were subject to a policy cut-off date with extensive validation at national level by TSOs and national authorities.

This cycle marks the first full implementation of ACER's TYNDP Scenarios Framework Guidelines from the start of the process. The scenario development followed a structured, transparent, and inclusive methodology, covering preparation, objective-driven design, and comprehensive stakeholder engagement. A fully operational Stakeholder Reference Group (SRG), public consultations and the publication of methodologies and datasets ensured effective scrutiny and accountability throughout the process. The scenario results are benchmarked with relevant external studies, including European Commission (EC) and Joint Research Centre (JRC) scenarios, to enhance comparability and credibility.

Compliance with the EU's 2030 energy and climate targets and the 2050 climate neutrality objective is a core design feature of the scenario set. Where gaps between aggregated national trajectories and EU-wide objectives remained, a transparent gap-filling methodology was applied. This approach ensured consistency with Union targets while preserving national input where possible. This highlights the structural gap between current policy trajectories and agreed EU targets, which requires additional adjustments at EU level to ensure consistency with the climate objectives. Achieving such consistency would require further improvements in energy efficiency, accelerated deployment of renewable energy sources, and enhanced integration across electricity, gas and hydrogen systems. The achievement of these outcomes therefore depends on the timely implementation of these developments within the assumed time horizons.

The TYNDP 2026 scenarios highlight a structural transformation of Europe's energy system towards climate neutrality by 2050. Over the long term, final energy demand declines, driven by efficiency gains and the progressive electrification of end-use sectors.

At the same time, electricity demand increases significantly. This growth is driven by electrification in transport, widespread deployment of heat pumps, the transformation of industrial processes, and the expansion of hydrogen production via electrolysis, among other factors. As a form of indirect electrification, electrolysis increasingly relies on renewable electricity and is aligned with periods of high renewable generation, thereby also contributing to system flexibility.

Methane demand steadily decreases and reaches full decarbonisation by 2050 through the use of biomethane and synthetic gases. This decline is more gradual in final consumption sectors, while a faster phase-out is observed in the power generation sector.

Hydrogen emerges as a key energy carrier for hard-to-abate sectors such as parts of industry and transport. Beyond its role in direct applications, hydrogen contributes to system flexibility and serves as a critical input for the production of e-fuels. Over time, hydrogen demand for e-fuel production increases significantly, becoming comparable in scale to direct hydrogen use.

Overall, the scenarios depict a progressive decarbonisation pathway towards an integrated energy system in which electricity and hydrogen play a central role.

2 CONTENT OF THE SCENARIOS PACKAGE //

The TYNDP 2026 Scenarios Package provides a transparent, cross-sectoral and policy-aligned foundation for assessing Europe's future energy system and related infrastructure needs. It consists of the following components:

TYNDP 2026 Scenarios Report

The main report of the scenarios package. It presents the purpose, policy context, and key outcomes of the TYNDP 2026 Scenario, detailing how stakeholder engagement shaped scenario development and how the scenario complies with ACER's Scenarios Framework Guidelines. The report also presents the main scenario results, assesses consistency with EU energy and climate targets, and benchmarks the outcomes against other relevant European scenario studies.

TYNDP 2026 Scenarios Methodology Report

A dedicated report describing the methodology used to develop the 2026 scenario. It explains the assumptions and approaches applied across demand, supply, grids, and market modelling, including data collection, modelling tools, and validation processes. It also explains the gap-filling and Economic Variants methodologies.

TYNDP 2026 Scenarios Report Data Figures

A technical dataset providing the numerical values underlying the figures presented in the TYNDP 2026 Scenarios Report. This dataset includes the data used to generate charts, tables and visual outputs in the report.

TYNDP 2026 Scenario Inputs

A technical dataset providing the input data used in the TYNDP 2026 scenario simulations. This dataset includes the processed input templates structured for direct use in the market modelling tool, containing all relevant parameters and datasets required to run the simulations. It reflects the transformation of collected data into model-ready inputs, ensuring consistency and reproducibility of scenario results.

TYNDP Scenarios Innovation Roadmap

This is a forward-looking living document outlining methodological improvements, model enhancements, and innovation priorities for successive scenario cycles. It was published in February 2025 as part of the TYNDP 2026 Scenario Package. It is outlined in both the Scenario Report and the Methodology Report.

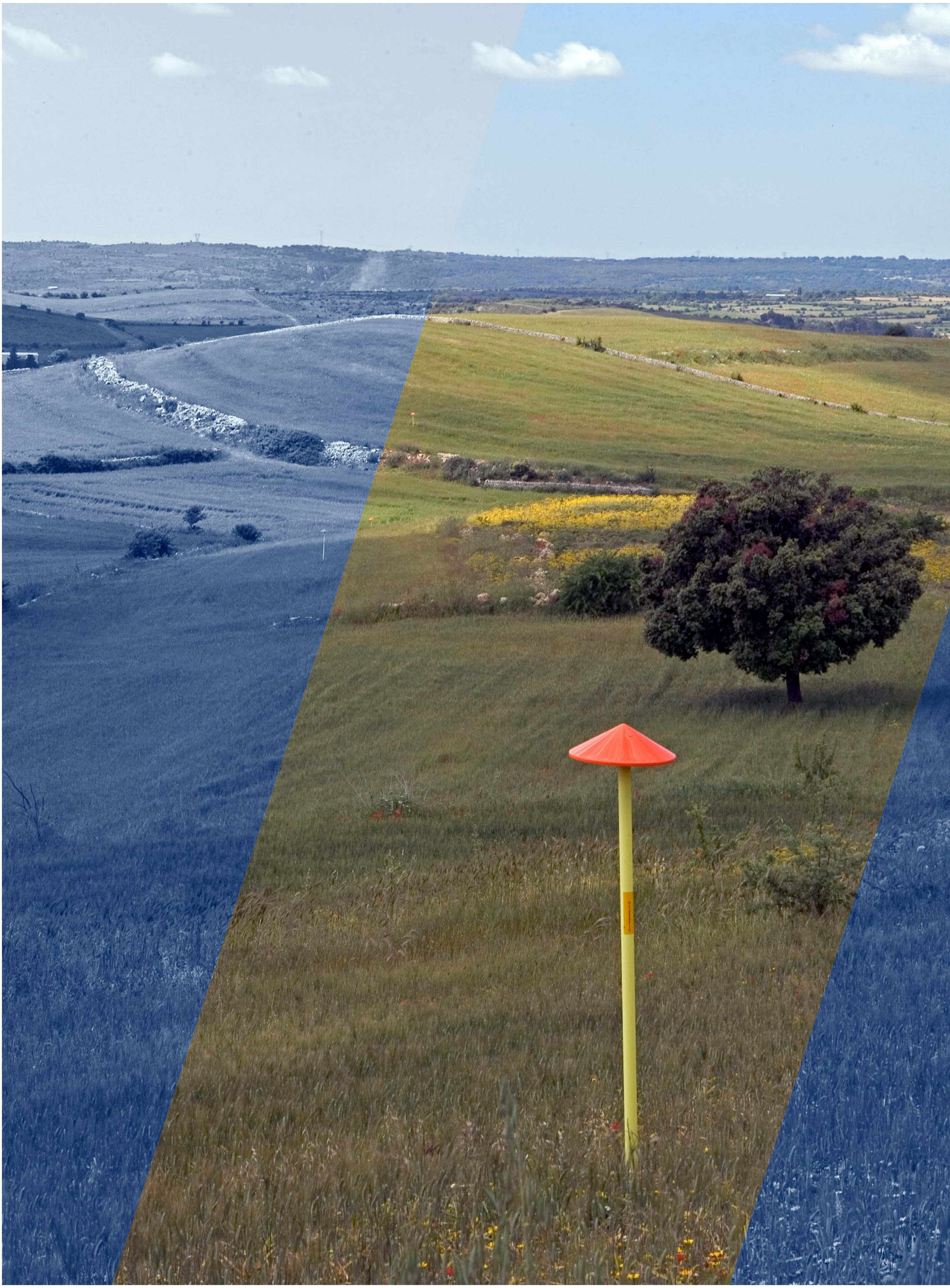
TYNDP 2026 Stakeholder Engagement Plan

This report is a supporting documentation describing the stakeholder engagement process, including consultations, workshops, and responses to feedback, demonstrating how stakeholder input informed assumptions, methodologies, and scenario design.

TYNDP 2026 Scenario visualisation tool

This is an interactive platform providing access to scenario results across countries, sectors, and energy carriers, enabling users to explore outputs transparently and to support further analysis. This cycle's interactive dashboard provides users with a comprehensive view of the results. It brings together both model optimisation and final energy demand results in a single dashboard, in order to simplify data access for users. In this cycle, an emphasis was also placed on ensuring more transparency in the tool, with information regarding the European carbon budget now included in the platform. The visualisations include insights into the electricity and hydrogen mix by fuel type and country, as well as final energy demand by carrier, sector, or subsector.

Together, these elements form an integrated scenarios package that supports comprehensive, transparent, and EU target-compliant infrastructure planning, while providing clarity on methodologies, assumptions, uncertainties, and stakeholder input.



3 PURPOSE OF THE TYNDP SCENARIOS //

3.1 Scenarios provide an analytical framework for European energy infrastructure development

The TYNDP Scenarios represent the cornerstone for the development of Union-wide electricity and gas/hydrogen TYNDPs, serving as the primary input for the identification of the gaps in electricity and gas/hydrogen infrastructure at European level. Scenarios also provide the framework for the Cost-Benefit Analysis (CBA) of cross-border electricity and hydrogen infrastructure projects, supporting the optimisation of EU energy grid development while minimising overall system costs and ensuring a safe and affordable energy supply for European consumers.

The TYNDP Scenarios are designed to capture the impact of EU policies and their implementation at national level at the given point in time. In doing so, they provide a structured framework for analysing possible pathways towards achieving the EU objective of climate neutrality by 2050.

Scenarios are developed jointly through close collaboration between ENTSOG and ENTSO-E and provide a coherent and consistent outlook across gas, hydrogen and electricity systems. This joint approach enables the identification of synergies and interdependencies between different energy carriers and supports the assessment of infrastructure needs on a cross-sectoral basis.

More specifically, the joint scenarios:

- Capture interactions and dependencies between electricity, gas and hydrogen systems,
- Provide a reference framework for assessing future infrastructure needs, and
- Support a common understanding of scenario outcomes among EU policy makers, Member States, the European Scientific Advisory Board on Climate and Change (ESABCC), EU- and energy sector stakeholders.

3.2 Legal framework

Regulation (EU) 2022/869 (‘Trans-European Networks for Energy (TEN-E) Regulation’)[1] requires ENTSO-E and ENTSOG to jointly develop scenarios for the future European energy system in support of their respective TYNDPs, in accordance with the Framework Guidelines issued by ACER, and applied consistently across the Union-wide TYNDP process.

In January 2023, ACER published the *Framework Guidelines for the joint TYNDP scenarios to be developed by ENTSO for Electricity and ENTSO for Gas “TYNDP Scenarios Guidelines”*, defining the requirements for both the scenario development process – including stakeholder involvement- and the characteristics of robust, objective-driven scenarios to be assessed by ACER, Member States, the European Commission and the ESABCC.

TYNDP 2026 is the first scenario cycle developed fully in line with these Framework Guidelines from the outset, allowing their requirements to be consistently integrated throughout the scenario-building process. Further information on compliance with the Framework Guidelines is provided in Chapter 5.

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[1] Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013

4 TYNDP 2026 SCENARIO FRAMEWORK //

4.1 Evolution of the scenario framework

In previous cycles, the TYNDP Scenario framework consisted of a fully bottom-up NT+ Scenario alongside with two deviation Scenarios – Distributed Energy (DE) and Global Ambition (GA) – which illustrated alternative decarbonisation pathways toward 2050.

Under the new ACER's TYNDP Scenario Framework Guidelines, this structure has been streamlined: the NT+ Scenario serves as a Central Scenario with the core reference aligned with national and EU policy targets.

The previously defined additional deviation scenarios are no longer maintained in their original form; instead, the framework introduces two Economic Variants: a High Economic Variant (HEV) and a Low Economic Variant (LEV). These variants are designed as stress tests applied to the Central Scenario and should not be interpreted as directly comparable stand-alone scenarios. The following section details the framework upon which the TYNDP 2026 Scenarios are based.

4.2 Aligning with national and EU climate and energy targets

The TYNDP 2026 Scenarios are built on a two-step approach, distinguishing between the National Trends (NT) data collection and the Central Scenario National Trends + (NT+).

The National Trends (NT) data collection reflects energy demand and supply data submitted by electricity and gas TSOs based on national policies, including National Energy and Climate Plans (NECPs) complemented by relevant national strategies and EU policies. As such, NT represents a bottom-up view of the energy system derived from nationally reported inputs, without further adjustments.

According to the European Commission's latest communication on the EU-wide assessment of the final updated NECPs (28 May 2025), the latest available NECPs demonstrate improved alignment with EU's 2030 targets compared to the draft updated NECPs. However, some gaps with respect to EU-wide targets remain at aggregated level.

To ensure consistency with EU targets, a gap-filling methodology is applied to the NT dataset. This methodology introduces additional adjustments at EU level, while applying proportional corrections at country level.

The outcome of this process is the Central Scenario (NT+), which represents the target-compliant scenario used as the main reference for the TYNDP 2026 analysis.

The methodology follows a transparent and harmonised framework, ensuring neutrality and equal treatment across all countries. It formed an integral part of the consultation process, offering stakeholders the opportunity to give feedback on the approach. While efforts have been made to improve the methodology, there is still room for further improvement; however, this would require a more significant revision of the bottom-up data, which is based on the NECP complemented by relevant national strategies and EU policies.

Further information on the gap-filling methodology is provided in the "TYNDP 2026 Scenarios Methodology Report", Chapter 9. Impacts of the gap-filling methodology application are presented in chapter 9.2.2 Final Energy Demand in the NT+ Scenario after the gap-filling methodology and chapter 10.4 Assessment of carbon budget and targets. More information on alignment of the NT data collection provided by TSOs and national climate and energy policies is available in Annex I.

While supply and demand inputs are based on NECPs, the electricity and hydrogen grids are based on TYNDP projects (ENTSO-E TYNDP 2026 and ENTSOG TYNDP 2024 Project Collections). For further information, see Chapter 8 in the TYNDP 2026 Scenarios Methodology Report.

4.3 TYNDP 2026 Scenario framework

The 2026 scenario framework includes one Central Scenario (NT+) reflecting the latest updated national strategies, following the application of the gap-filling methodology described in Chapter 9 of the TYNDP 2026 Scenarios Methodology Report, and two Economic Variants, representing higher and lower economic growth trajectories respectively. For the current 2026 cycle, the economic variants exercise is applied to the 2035 and 2040 target horizons. It thus complies with Regulation (EU) 2022/869 ("TEN-E Regulation") and the ACER TYNDP Scenarios Framework Guidelines. Figure 1 illustrates the scenario time horizon framework used in the TYNDP 2026 cycle.

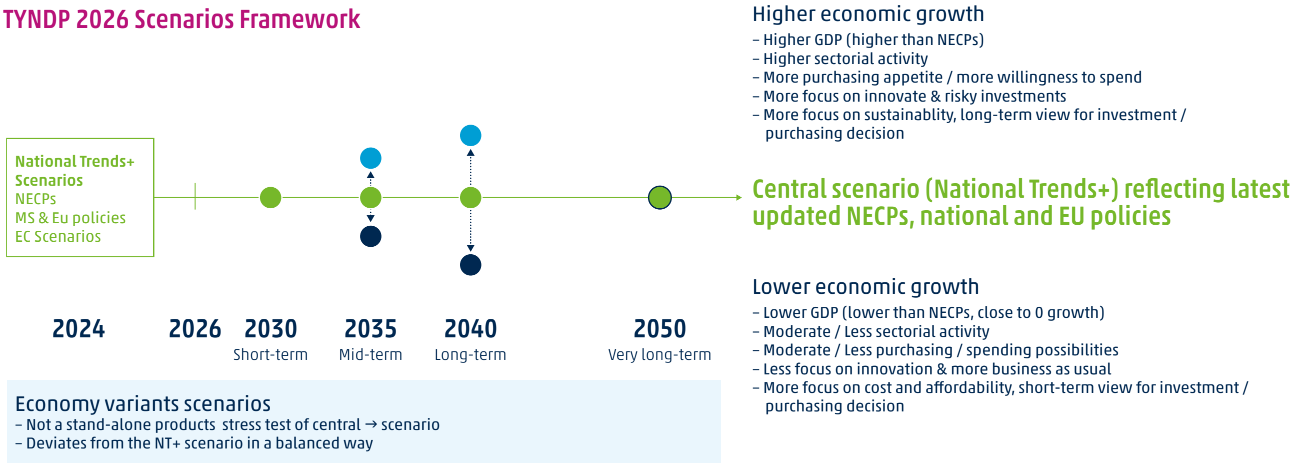

Figure 1: TYNDP 2026 Scenario Framework.

4.4 Main principles of the Central Scenario (NT+)

The Central Scenario (or NT+) represents the core reference for the TYNDP 2026 scenarios and is derived from the National Trends (NT) data collection following the application of the gap-filling methodology described above. As such, it reflects a target-compliant scenario that combines nationally reported inputs with adjustments to achieve alignment with EU climate and energy objectives.

The NT dataset is based on data collected from electricity and gas TSOs, reflecting the latest available national and European energy and climate policies and strategies. By the cut-off date (24 December 2024), 24 NECPs out of 27 had been updated.

Some differences between the updated NECPs and the submitted datasets were identified. These mainly relate to differences in data granularity, the need to provide information beyond the NECP time horizon, and the application of fallback solutions where requested data were not available. Further details on data alignment and fallback approaches are provided in Chapter 11.

In order to ensure consistency with national policy developments, 80 % of EU27 electricity and gas TSOs validated the submitted datasets with NRA/Ministry in their respective Member States (see TSO Survey Outcomes, Annex I). Where datasets were incomplete for certain energy carriers and additional sources or assumptions were required, the applied methodologies and resulting data were subject to stakeholder feedback through public consultation and the SRG.

4.5 Main principles of the Economic Variants

In addition to the Central Scenario (NT+), two Economic Variants (HEV and LEV) are developed to assess the sensitivity of the energy system to alternative economic conditions.

These variants represent higher and lower economic growth pathways and are not intended as standalone scenarios with separate storylines, but as targeted stress tests of the scenario framework.

The Economic Variants are derived from the underlying National Trends dataset (NT), prior to the application of the gap-filling methodology. This ensures that the variants reflect alternative macroeconomic conditions based on national inputs.

The variants deviate from the reference assumptions through a limited set of selected parameters, chosen for their relevance and impact on system outcomes. Parameter changes are applied symmetrically across both variants to ensure balanced comparison and interpretability of results (e.g. +x % in one variant, –x % in the other).

The HEV represents a higher Gross Domestic Product (GDP) growth than NECPs indicate, including higher sectoral activity, purchasing power or willingness to pay, stronger focus on innovation and risky investments, and a stronger focus on sustainability as well as long-term views on investment decisions.

The LEV represents a lower GDP than NECPs indicate. It includes a more moderate or lower levels of sectoral activity, purchasing power or spending opportunities, less focus on innovation and a more business-as-usual approach. It involves stronger focus on cost and affordability, and a short-term view on investment decisions.

The Economic Variants are developed for the 2035- and 2040-time horizons , and the methodologies used for their construction were subject to stakeholder consultation.

5 MEETING ACER'S SCENARIOS FRAMEWORK GUIDELINES, ADDRESSING OPINION 05-2024 AND CRITICAL EUROPEAN COMMISSION FEEDBACK //

5.1 Background

With the document "Framework Guidelines for the joint TYNDP scenarios to be developed by ENTSO for Electricity and ENTSO for Gas "TYNDP Scenarios Guidelines", issued on 23 January 2023, ACER established criteria for a transparent, non-discriminatory and robust development of scenarios in the context of the European energy networks development. As the publication of ACER's TYNDP Scenarios Guidelines interfered with the TYNDP 2024 Scenarios cycle, the guidelines could not be completely accounted for. Thus, the TYNDP 2026 Scenarios are the first cycle in which the TYNDP Scenarios Guidelines were followed from the beginning of the development process.

The ACER "TYNDP Scenarios Guidelines" are grouped into criteria for timely scenario preparation process, criteria for robust objective-driven scenarios, and criteria for a transparent, inclusive and streamlined development process. The document further contains guidelines on how to ensure stakeholder scrutiny, timely updates, and reporting requirements on how the guidelines were implemented.

5.2 Alignment with ACER Guidelines and Regulatory Feedback

ENTSO-E and ENTSOG have ensured that the TYNDP 2026 Scenario is fully aligned with ACER's TYNDP Framework Guidelines, demonstrating a robust and transparent methodology that meets all applicable regulatory expectations. Throughout the process, both organisations have proactively and systematically addressed critical regulatory and legislative feedback to the widest extent possible, integrating stakeholder input and regulatory recommendations wherever feasible while clearly justifying any remaining constraints. As a result, the TYNDP 2026 Scenario reflects a high level of compliance with the European regulatory framework, supports informed decision-making at EU and national level, and fully adheres to all regulatory requirements.

To capture the ENTSOs' compliance with the requirements of ACER's Scenarios Framework Guidelines, ENTSOG and ENTSO-E implemented a structured scenario development process that addressed each of ACER's guideline specifications. A table summarising the defined criteria and how the ENTSOs implemented those in the TYNDP 2026 scenario cycle can be found in the Annex III. Additionally, a summary of critical feedback points provided by ACER's Opinion 05-2024 on the TYNDP Scenarios 2024 is addressed in the Annex III. In the TYNDP 2026 scenario cycle, the ENTSOs further paid due attention to incorporating key comments from the European Commission, addressing the European Commission's justification on the approval of the joint Scenarios Report for the 2024 TYNDP; this has been addressed to the greatest extent possible and is summarised in Annex IV.

6 HOW STAKEHOLDER ENGAGEMENT SHAPED THE SCENARIOS //

6.1 Core principles of stakeholder engagement

Engaging stakeholders in developing TYNDP scenarios is based on three core principles: transparency, inclusiveness and efficiency. Transparency ensures that the complex process of developing long-term energy demand and supply scenarios is clearly communicated. ENTSO-E and ENTSOG aim to provide transparency on all assumptions and make underlying data openly accessible, so that scenarios can be plausibly replicated by third parties. Inclusiveness reflects the importance of ensuring that TYNDP Scenarios represent the general opinions of EU citizens. Any organisation or individual can contribute through multiple fully public stakeholder events and written consultations. Continuous interaction with stakeholders ensures that the most up-to-date data, technologies, and real-world experiences are integrated into the Scenarios by timely implementing stakeholder input.

6.2 Overview of main stakeholder engagement activities

Stakeholder engagement played a central role in shaping the TYNDP 2026 Scenarios by informing about every major step of the scenario-building process (Figure 2). At the beginning of the TYNDP 2026 Scenarios cycle, stakeholders were asked to provide information and preferences on interactions between the ENTSOs and public, thus co-designing the Stakeholder Engagement Plan[2]. During the framework (storyline) development, the SRG and wider stakeholders influenced the framing of uncertainties, key parameters, and Economic Variants. Inputs from workshops in 2024, 2025 and public consultations in June to July 2025 guided which elements were prioritised in HEV/LEV and how methodologies followed ACER's Scenarios Framework Guidelines. For the Innovation Roadmap, stakeholders, especially the SRG, proposed innovations and provided feedback that shaped which items were included, refined, or postponed. This iterative feedback loop directly informed both the initial roadmap and planned updates in 2026. In the development of data, methodologies, parameters and assumptions, stakeholder engagement influenced modelling choices (e.g., electric vehicles (EVs), hybrid heat pumps (HHPs), H_2/synfuel systems), cost assumptions, commodity prices, and country-level datasets. SRG reviews helped identify outliers, refine gap-filling approaches, and improve the carbon-budget methodology. Finally, through the public consultations and SRG reviews, stakeholders shaped the draft scenarios by providing inputs on assumptions, methodologies, and scenario design. Their feedback informed revisions ahead of the final Central Scenario and Economic Variants.

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[2] ENTSO-E/ENTSOG TYNDP 2026 Scenarios Stakeholder Engagement Plan, final version to be published in June 2026, https://2026-data.entsos-tyndp-scenarios.eu/stakeholder/TYNDP_2026_Scenarios_Engagement_Plan_version_January_2026_final.pdf

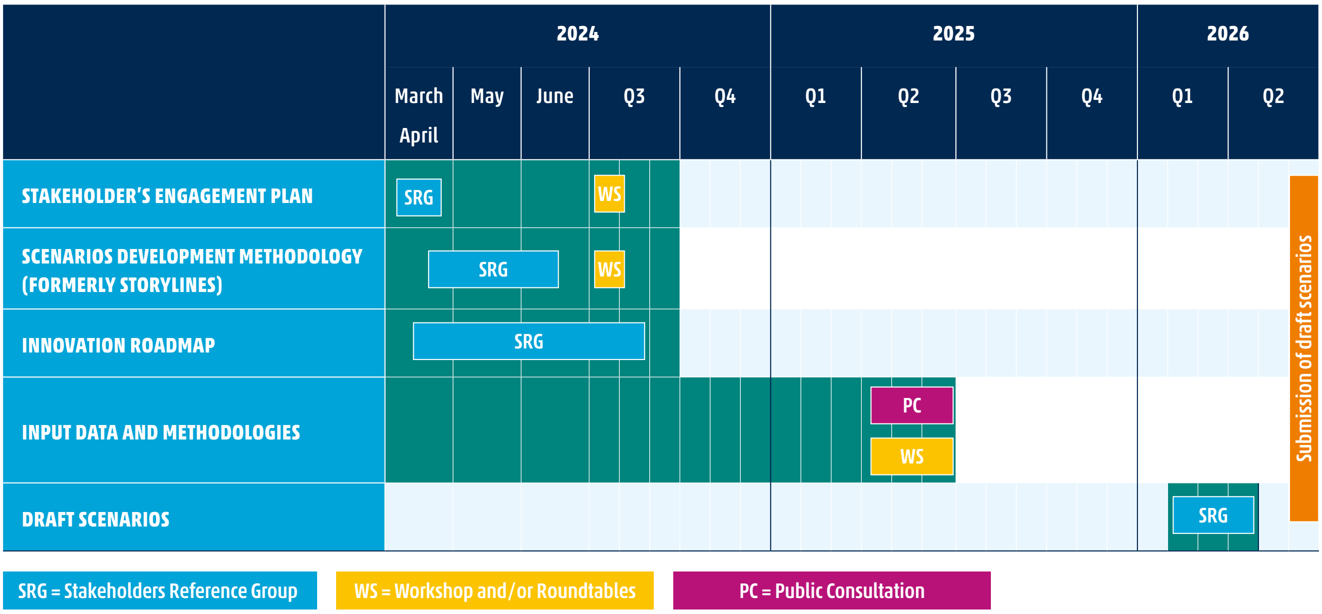

Figure 2: TYNDP 2026 Scenarios Stakeholder Engagement Timeline

Further information on the involvement of stakeholders throughout the TYNDP 2026 scenario-building process can be found available on the TYNDP 2026 Scenarios' introduction and download websites, in the TYNDP 2026 Scenarios Stakeholder Engagement Plan[3], the Stakeholder Engagement Timeline, consultations material and accompanying workshop recordings, as well as the Consultations Summary Report.

ENTSO-E & ENTSOG TYNDP 2026 Scenarios – Consultations Summary Report


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All answers received to the public consultations

Download All Answers Received (Excel)

Figure 3: TYNDP 2026 Scenarios Consultations Summary Report

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[3] ENTSO-E/ENTSOG TYNDP 2026 Scenarios Stakeholder Engagement Plan, final version to be published in June 2026, https://2026-data.entsos-tyndp-scenarios.eu/stakeholder/TYNDP_2026_Scenarios_Engagement_Plan_version_January_2026_final.pdf

6.3 Main outcomes and learnings from the 2026 Scenarios cycle

During the 2026 development cycle, the ENTSOs took feedback and learnings from the public consultations and SRG onboard when developing the next version of the Central Scenario and Economic Variants. A distinct listing of considerations on the public consultations can be found in Chapter 5 "Summary of responses by question and ENTSOs" comments' of the TYNDP 2026 Scenarios Public Consultations Summary Report. The main learnings and considerations in the 2026 cycle have been summarised below.

6.3.1 First issuing of the Innovation Roadmap and feedback

Stakeholders rated the Innovation Roadmap a moderate level of satisfaction. Some respondents acknowledged the value of the current Innovation Roadmap, especially its future orientation and flexibility. However, they also identified several opportunities for improving how innovations are prioritised within the TYNDP 2026 planning cycle.

The feedback confirms that the Innovation Roadmap largely meets stakeholder expectations, particularly regarding the emphasis on future climate variability, system integration and transparency, although there is room for improvement.

There is a need to address the following points in the future:

- More structured prioritisation criteria, including climate and societal impacts,
- Clearer communication on the selection process and associated trade-off,
- Improved transparency regarding implementation and future development of innovation items,
- Adoption of a balanced, technology-neutral approach that reflects the diversity of national energy strategies,
- To enhance clarity and usability for both expert and non-expert audiences, and
- To expand the modelling scope to better represent flexibility, demand-side measures, and infrastructure resilience.

As a result, the Innovation Roadmap is updated to generate a more transparent, answerable and enforceable document. The second edition will be particularly relevant for the 2028 cycle and will be readily published at the start of the next development cycle. Chapter 8 details how the Innovation Roadmap was implemented in this cycle.

6.3.2 Draft supply assumptions

Stakeholders raised several points regarding the transparency and robustness of key supply assumptions, including:

- Hydrogen import potentials, infrastructure reliance and import price outlooks.
- Commodity and technology cost trajectories.
- Synthetic fuel import prices.
- CO_2 price pathway and its alignment with EU ETS revisions.
- Consistency with external datasets.

As a response, the ENTSOs voiced commitment to increase transparency, improving documentation of assumptions and increasing alignment with external data sources where relevant, while maintaining consistency with the methodological framework.

6.3.3 Methodologies and modelling assumptions

Stakeholders' feedback on modelling approaches focused on:

- Improving representation of demand-side flexibility,
- Strengthening the robustness of weather year selection,
- Enhancing transparency of the gap-filling methodology, and
- Clarifying cross-sector modelling interactions and constraints.

ENTSOs acknowledged these points and implemented or initiated improvements in modelling approaches, data structures and methodological documentation, including stronger integration of flexibility and enhanced explanation of modelling choices.

6.3.4 Economic Variants methodology

Stakeholders generally welcomed the introduction of Economic Variants in line with ACER framework, while requesting:

- Clearer explanation of their purpose as stress tests,
- Broader parameter variation, and
- improved transparency on how economic deviations propagate through sectors.

As a result, the ENTSOs clarified the role of the variants and committed to providing more explicit documentation of parameter changes and their effects on scenario outcomes.

6.3.5 Stakeholder inclusion and data equity

Feedback also addressed the composition and functioning of the stakeholder engagement process itself. In particular, stakeholders highlighted the importance of maintaining a balanced mix of perspectives across all relevant sectors, including strengthening the involvement of demand-side actors and exploring greater participation of Member States in the Stakeholder Reference Group (SRG), including as observers where appropriate.

Stakeholders also emphasised the need to further enhance transparency and accessibility of data, tools and processes, especially for organisations that are not directly represented in the SRG. ENTSO-E and ENTSOG have strengthened their approach to data and process transparency by providing consolidated access to scenario material through dedicated platforms, including all draft methodologies and input data, workshop recordings, stakeholder engagement content, Innovation Roadmap and visualisation platform of all final data. Approaching public consultation phases continue to be publicly communicated via ENTSO-E's and ENTSOG's media platforms, including their websites, newsletters or LinkedIn.

Additional efforts have been made to improve the accessibility and usability of data, including the development of a centralised results platform with enhanced visualisation and data-tailoring functionalities. This allows stakeholders with different levels of expertise to better understand scenario inputs and results, and facilitates a more transparent interpretation of key elements such as the carbon budget and system-wide outcomes.

6.4 Conclusions on the 2026 cycle's stakeholder engagement

Overall, engagement was continuous, multi-channel and iterative. We would like to thank all stakeholders who participated in this cycle's online public consultations, workshops or roundtables, in the SRG or bilateral discussions.

One important contributor throughout the TYNDP 2026 Scenarios building process was the SRG that gave valuable input on the TYNDP Scenarios Innovation Roadmap, draft gap-filling methodology, draft commodity prices, and actively shaped the Central Scenario and Economic Variants to be more robust and accountable. In general, the SRG aims at providing expert input to the development of scenarios and operates independently from ENTSO-E and ENTSOG. The SRG's Terms of Reference approved by the SRG, written advice, list of members, possibility to apply and minutes of meetings are available on the Stakeholder Reference Group website[4]. Details on how the SRG delivered to provide feedback on the various topics covered throughout the Scenarios development process can be found in the SRG's dedicated opinion in Annex V.

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[4] https://www.entsos-tyndp-scenarios.eu/stakeholder-reference-group/

7 IMPROVEMENTS OF THE TYNDP 2026 SCENARIOS //

Both ENTSO-E and ENTSOG continuously strive to enhance data quality, modelling tools and methodologies across TYNDP scenario cycles. The TYNDP 2026 Scenarios built on lessons learned from previous editions, with improvements identified and prioritised based on external stakeholder feedback, SRG input and evolving regulatory requirements.

7.1 Innovation Roadmap and methodological framework

For the TYNDP 2026 cycle, improvements are structured through the TYNDP 2026 Scenarios Innovation Roadmap.

Work on the Innovation Roadmap started in April 2024 within the Working Group Scenario Building (WGSB), involving experts from ENTSO-E and ENTSOG. The roadmap was subsequently reviewed by member TSOs and further refined through engagement with the SRG. It was also subject to public consultation as part of the Draft 2026 TYNDP Scenarios Input Data and Methodologies in June – July 2025.

The Innovation Roadmap serves as a key reference document guiding methodological developments in the TYNDP 2026 cycle.

It brings together three complementary dimensions of improvement:

- A review of innovations not implemented during the TYNDP 2024 cycle,
- A set of essential model fixes introduced to improve the 2024 models,
- Newly proposed innovations to address emerging needs in the 2026 Scenario cycle.

Innovations are proposed by ENTSOs, stakeholders and SRG, and are influenced by regulatory developments. They are prioritised based on their expected impact on scenario robustness and their feasibility within the given timeline.

To support prioritisation, innovations are grouped into three main categories:

- Group 1 – development of methodologies, toolchain innovations and critical model fixes
- Group 2 – mandatory innovations and data analysis tools
- Group 3 – new innovations

7.2 From innovation to modelling methodology

Following prioritisation, selected innovations are translated into methodological developments within the WGSB. These developments are tested and validated before being integrated into the modelling framework. Innovations that successfully passed the testing phase within the project timeline were incorporated into the TYNDP 2026 Scenarios.

As a result, the TYNDP 2026 Scenarios Methodology Report reflects not only technical improvements but also a direct response to stakeholder feedback and SRG recommendations, ensuring that the TYNDP 2026 Scenarios are built on a transparent and forward-looking foundation.

7.3 Key areas of improvement

The main areas of improvement in the TYNDP 2026 Scenarios cycle include:

- Model robustness and quality control, through refinement of methodologies and validation processes,
- Improved data management and transparency, including enhanced use of common data platforms and tools,
- Enhanced system representation, particularly in emerging sectors such as hydrogen, synthetic fuels and flexibility solutions, and
- Simplification and harmonisation of modelling approaches, supporting efficiency and consistency across energy carriers and countries.

The implementation of these improvements and their impact on the TYNDP 2026 Scenarios are described in the following chapter.

8 INNOVATION ROADMAP IMPLEMENTATION //

8.1 Role of the Innovation Roadmap in the 2026 cycle

The TYNDP Scenarios Innovation Roadmap is "a living roadmap document detailing planned changes and larger innovation to be implemented for future scenarios cycles" (ACER, TYNDP Scenarios Framework Guidelines 2023).

For its first issuing, the ENTSOs invited feedback from the SRG on potential innovations to be included, notably in February 2025 and subsequently during the public consultation phase in June – July 2025.

The main takeaways from the first edition of the Innovation Roadmap and from stakeholder feedback are summarised in chapter 6 on stakeholder engagement.

A second edition of the Scenarios Innovation Roadmap, anticipated to be published at the beginning of the 2028 Scenario development cycle, will incorporate the feedback received and provide an overview of the innovations planned for future implementation.

8.2 Scope and approach to implementation

This chapter, together with Annex II, outlines which innovations from the current Innovation Roadmap were implemented in the 2026 cycle.

Not all innovations could be carried out within the 2026 scenario cycle, reflecting both significant changes in the scenario development architecture and a compressed timeline. As a result, a prioritisation of the toolchain enhancements and critical methodological developments was required.

Experts addressed key model issues identified during consultations to ensure a robust and high-quality baseline mode. Requirements from the SRG, TSOs, and other stakeholders were taken into account to prioritise and refine the implementation of innovations.

Further elaboration on the application of innovations in this cycle can be explored in the TYNDP 2026 Scenarios Methodology Report.

8.3 Stakeholder-driven implementation and public consultation

Stakeholder engagement played a key role not only in shaping the Innovation Roadmap, but also in guiding its implementation.

The public consultations conducted between June and July 2025 covered the Innovation Roadmap alongside key elements of the scenario framework, including energy demand and supply data, infrastructure and capacity, market and commodity assumptions, modelling methodologies and compliance aspects related to both the Central Scenario and the Economic Variants.

These consultations enabled stakeholders to gain deeper insight into the scenario development process and to actively influence both methodological choices and modelling outcomes.

In addition to the formal question-and-answer process, the Public Consultation Summary Report includes written responses from the ENTSOs to stakeholder comments, including those raised during the complementary public workshop held in July 2025.

Early stakeholder involvement proved particularly valuable, allowing engagement to focus on the definition of inputs and methodologies rather than on final outputs. The use of written responses and structured feedback loops through consultations and workshops further increased transparency and accountability in the implementation process.

8.4 Main implemented innovations

The implementation of the Innovation Roadmap focused on a set of priority areas, where innovations were either fully implemented or significantly advanced.

Advancements in hydrogen modelling

- Differentiation of short-term and seasonal storage, to improve representation of system flexibility needs,
- Improved representation of flow speeds in hydrogen pipelines and cross border flows,
- Alignment of hydrogen import assumptions with updated data, and
- Development of hybrid electrolyser production approaches to better reflect hydrogen pricing dynamics
- Simplified Hydrogen grid topology, taking into account technical constraints (bottlenecks, SMR grey dedicated to local production, offshore connections etc.).

Enhancing EV modelling

- Improved optimisation of EV charging patterns
- Refined fleet segmentation
- Strengthened modelling of Vehicle-To-Grid (V2G)

Sector coupling and emerging fuels

- Exploratory modelling of synthetic fuels, including methanol for maritime applications

Geographic and climate data integration

- Improved modelling assumptions through enhanced use of geographic and climate datasets

Modelling tools and data infrastructure

- Inclusion of Switzerland in ETM within the 2026 cycle,
- Dispatch model validation using a custom-built Key Performance Indicator dashboard, and
- Development of web-based interfaces to improve transparency and accessibility of scenario data and results.
- Introduction of a new aggregated market model output format with KPIs for consistency checks

8.5 Implementation outcomes

In summary, innovations from the Innovation Roadmap show a broadly positive implementation outcome during the TYNDP 2026 scenarios cycle.

Most of the listed innovations were implemented either fully or in a materially enhanced form, in particular across:

- the modelling toolchain,
- the quality control framework,
- system modelling (including hydrogen, EVs, storage and grid behaviour), and
- climate-aware assumptions.

Notable advancements include the upgraded visualisation platform and dashboard, the transition to an improved database enabling a better representation of future climatic variability, the establishment of a transversal Quality Control Task Force, improvements to hydrogen system representation (including imports, storage, pricing and topology), and a significantly refined EV and prosumer modelling approach.

In total, around two-thirds of the innovations identified in the roadmap were delivered within the cycle, with several others partially implemented or addressed through alternative methodologies.

8.6 Limitations and deferred innovations

The main obstacles to full implementation were not related to technical feasibility, but rather to scope and timing constraints, data availability and maturity, and the prioritisation of core deliverables.

As a result:

- some innovations were only partially implemented,
- some were addressed through simplified or alternative methodologies, and
- others were deferred or treated ex post.

These include, for example, further developments in electricity grid granularity, economic assessment integration, electric heat pump flexibility modelling, emerging technologies, and certain sector-specific or out-of-scope items such as innovative grid technologies.

8.7 Link to future cycles and traceability

The Innovation Roadmap is designed as a living document ensuring continuity across scenario cycles.

Innovations not fully implemented in the 2026 cycle, as well as additional developments identified through stakeholder engagement, will be incorporated into future iterations of the roadmap.

For a detailed overview of which innovations were implemented and how, Annex II provides a complete tracking table covering all innovations included in the roadmap. This includes the innovation number, description, implementation status, underlying rationale and links to supporting documentation where applicable.

9 TYNDP 2026 SCENARIO RESULTS //

The TYNDP 2026 scenario results chapter provides a system-wide view of how energy demand and supply evolve in NT+, its Economic Variants and the underlying NT data collection. The demand section first describes the NT input data and then the NT+ scenario after application of the gap-filling methodology, analysing demand by energy carrier and sector. The supply section explains how this demand is met through domestic production, imports and conversion chains, and the chapter concludes with known limitations and modelling constraints.

9.1 Demand

Demand results are structured around a clear distinction between final energy demand and total energy consumption, and between the National Trends (NT) data collection and the target-compliant NT+ scenario.

Final energy demand refers to energy consumed by end-use sectors such as households, buildings, industry, transport and agriculture, based on data collected primarily through the Energy Transition Model (ETM) (see TYNDP 2026 Scenarios Methodology Report Chapter 4). These values reflect nationally reported trends and policies. Final energy demand in the NT data collection is presented by sector and energy carrier, highlighting the main structural developments over time. The chapter then turns to the results of the gap-filling exercise in section 9.1.1, which adjusts final energy demand to ensure consistency with EU climate and energy targets. This step marks the transition from NT data collection to NT+ scenario and highlights the resulting reductions in fossil fuel use and changes in the energy mix.

The final part focuses on total energy consumption by carrier. Total consumption combines final demands for electricity, hydrogen with additional demand generated endogenously by the market model optimisation, including demands for power generation, hydrogen production, hybrid heat pumps and synthetic fuel production. These total consumption levels form the basis for the supply result presentation in the following subchapter. Comparisons between the Economic Variants, the NT data collection and subsequent NT+ central scenario are made throughout to illustrate the effect of different economic assumptions.

9.1.1 Final Energy Demand in the NT data collection and Economic Variants

Final energy demand overview

In this section, final energy demand refers to energy values collected from electricity and gas TSOs in the NT data collection, mainly through the ETM. These values are presented before the application of the gap-filling methodology. Within the TYNDP 2026 Scenario Building process, the NT data collection shows a decreasing trend in the final energy demand when compared to Eurostat's final energy consumption for 2019 and 2023. This reduction reflects the impact of national policy and market developments, in particular the latest NECPs of each Member State.

At EU27 level, between 2023 and 2050 overall final energy demand across all sectors excluding the energy sector decreases by 18%, falling from 12,160 TWh in 2023 to 9,990 TWh in 2050. The downward trend is evident already in 2030 (11,960 TWh, ~2% below 2023), confirming the long-term EU policy trajectory.

Figure 4[5] presents the final energy demand by energy carrier for the NT data collection and for 2019, 2023, 2030, 2035, 2040 and 2050.

When applying the calculation principles of the EU Energy Efficiency Directive (EED), the long-term trend intensifies. In line with the EED methodology, several ETM sectors are excluded from the calculation of final energy consumption. These sectors are industry non-energetic uses, refineries (energetic and non-energetic), international shipping, and other non-energetic sectors. They are hereafter referred to as "Others (not included in Final Energy Consumption (FEC) target)". More information regarding the sectors excluded from FEC is available in the visualisation platform[6]. Under the EED framework, final energy demand reaches 10,080 TWh in 2030 and declines further to 8,240 TWh in 2050 from 10,470 TWh registered in 2023.

Figure 5 presents the final energy demand and its sectoral distribution[7] for all target years for the NT data collection.

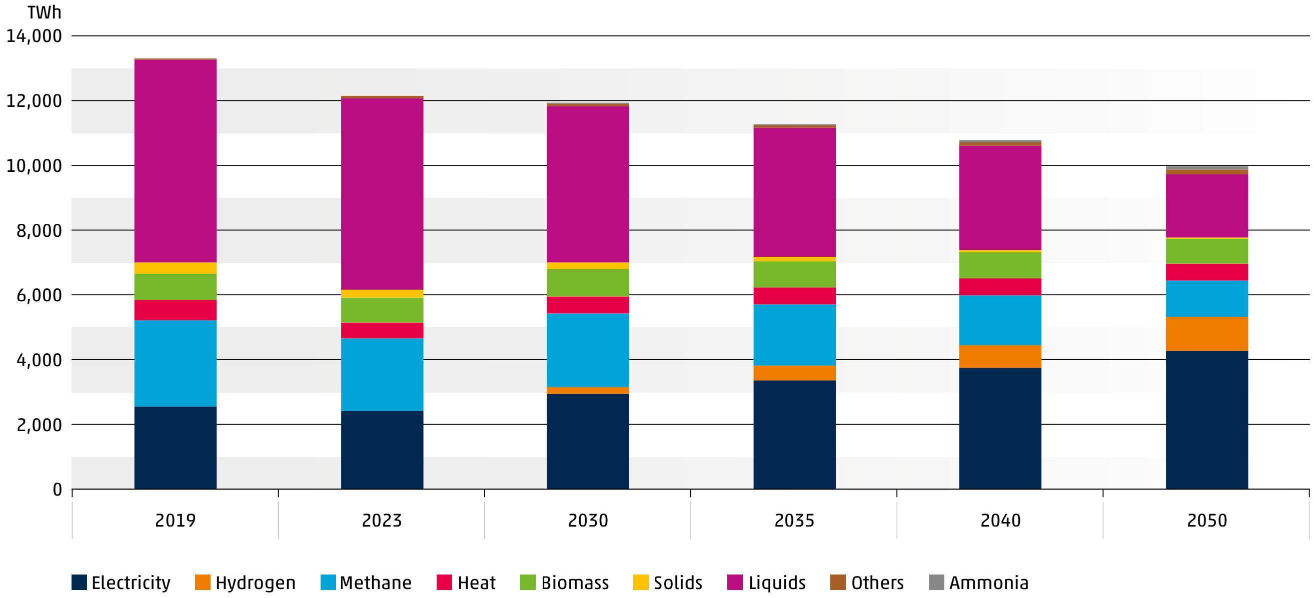

Figure 4: Final energy demand per energy carrier (EU27, TWh)

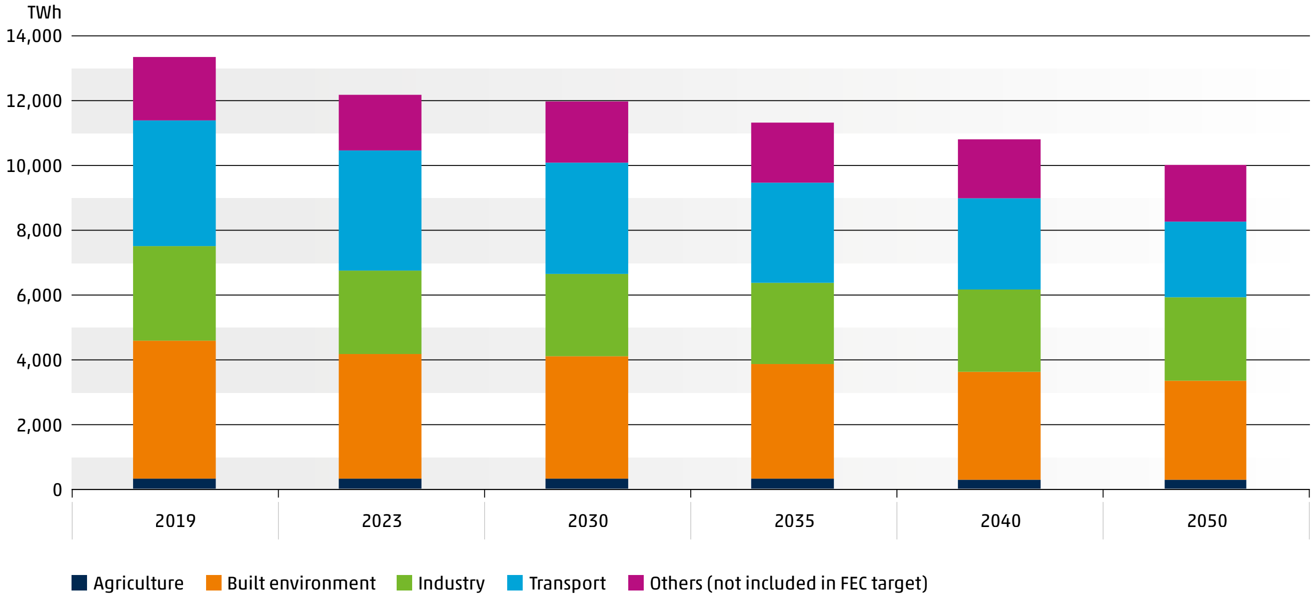

Figure 5: Final energy demand per sector (EU27, TWh). Agriculture, Built Environment, Industry and Transport add up to the FEC target of the EED. "Others" represents sectors not considered in the EED calculation principles for the FEC target

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[5] Energy carrier "Others" represents technologies like solar thermal and geothermal

[6] Visualisation Platform | TYNDP 2026 Scenarios by ENTSO-E & ENTSOG

[7] Transport sector includes energy demand for international aviation

In the TYNDP 2026 process, two economic variants are considered: the High Economic Variant (HEV) and the Low Economic Variant (LEV) (for details on the implemented approach, refer to Scenario Methodology Report, Chapter 10). Their FED deviates from the NT data collection by −1% and +1.2% in the mid-term (2035) and −0.9% and +1% in the long-term (2040). Table 1a) provides a detailed breakdown of the FED per carrier. Table 1b) shows that even though the sum of FED is only varying by about 1% across the variants, the variation of individual carriers is up to 10 times higher. In the HEV, electricity, hydrogen, heat, biomass and ammonia demand is increased compared to NT. Methane, solids and liquids demand is decreased.

In the LEV the situation is vice versa. This is consistent with the premise that electrification and the transition to more sustainable technologies are accelerated in the HEV, while this transformation is slower in the HEV. There is an interplay between the level of economic activity and the changes in the technology mix. In each variant scenario, those changes are pulling the total FED in opposite directions. For example, in the HEV, the higher economic activity will be offset by an increased market share of more efficient technologies. This explains why, in sum, we see small changes of the total FED.

A)

SCENARIO	TARGET YEAR	ELECTRICITY	HYDROGEN	METHANE	HEAT	BIOMASS	SOLIDS	LIQUIDS	OTHERS	AMMONIA	TOTAL
LEV	2035	3,083	416	1,989	529	775	164	4,115	82	41	11,194
NT	2035	3,361	456	1,891	535	796	145	3,996	82	45	11,306
HEV	2035	3,626	488	1,808	560	817	134	3,877	82	49	11,442
LEV	2040	3,432	629	1,690	519	756	93	3,415	114	57	10,704
NT	2040	3,741	700	1,560	533	784	77	3,226	116	63	10,799
HEV	2040	4,051	765	1,428	557	815	68	3,038	117	68	10,907

B)

SCENARIO	TARGET YEAR	ELECTRICITY	HYDROGEN	METHANE	HEAT	BIOMASS	SOLIDS	LIQUIDS	OTHERS	AMMONIA	TOTAL
LEV over NT	2035	-8%	-9%	5%	-1%	-3%	13%	3%	0%	-9%	-1%
HEV over NT	2035	8%	7%	-4%	5%	3%	-7%	-3%	0%	9%	1%
LEV over NT	2040	-8%	-10%	8%	-3%	-4%	21%	6%	-2%	-9%	-1%
HEV over NT	2040	8%	9%	-8%	4%	4%	-12%	-6%	1%	9%	1%

Table 1: a) Absolute values of Final Energy Demand [TWh] for EU27,
b) Final Energy Demands Relative Share of the Variants over NT data collection (EU27)

Figure 6 shows a graphical representation of both variants FED against the NT data collection for all carriers and target years.

Additionally, Figure 7 details the sectoral breakdown[8] for the economic variants as well as the final energy demand calculated following EED criteria.

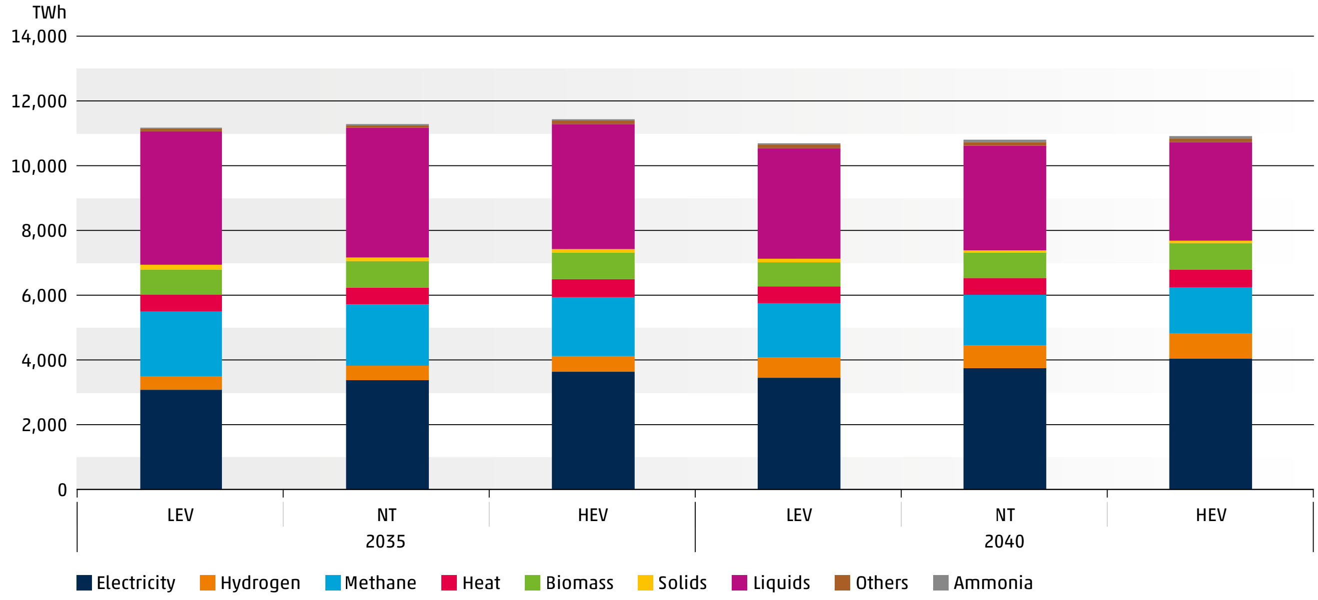

Figure 6: Final energy demand per carrier, Low/High economic variant (EU27, TWh)

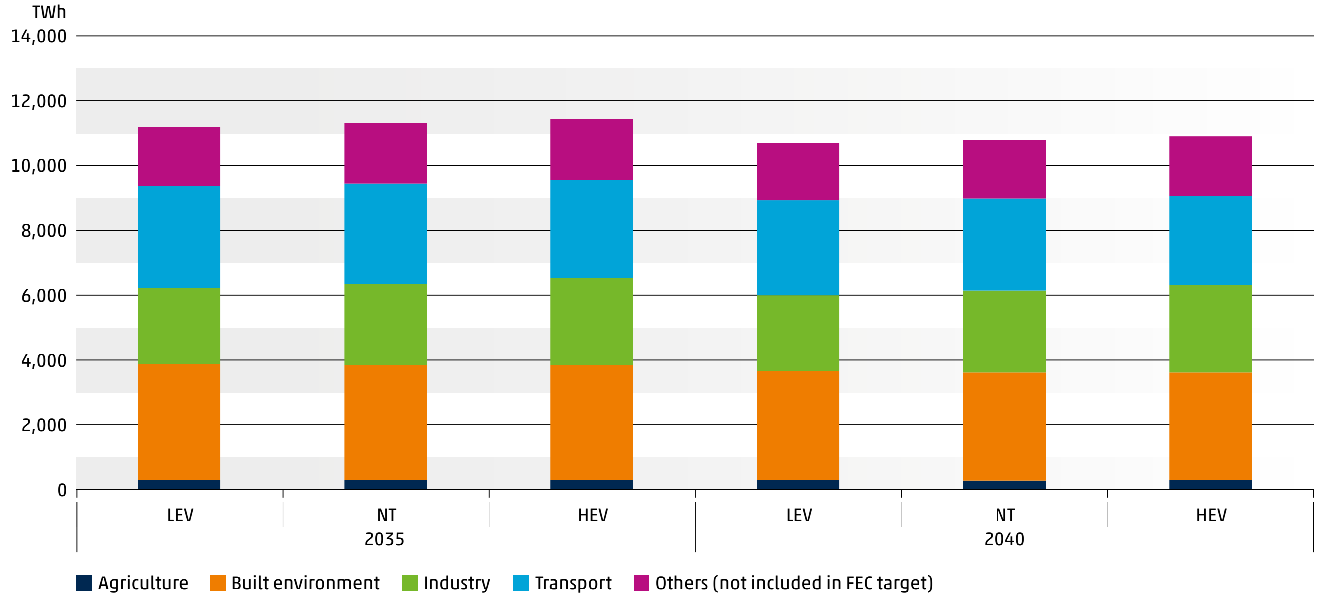

Figure 7: Final energy demand per sector, Low/High economic variant (EU27, TWh)

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[8] Transport sector includes energy demand for International aviation

Final Demand per sector

Built environment

Households and buildings require energy for lighting, power, cooking, heating and cooling[9]. Today, most of the energy consumption comes from fossil fuels. To meet the climate ambitions for 2030 and beyond, a vast transition of the building sector is needed. This will not only decrease energy demand but also improve living standards.

Most of the energy demand in the built environment is associated with heating. Figure 8 and Figure 9 illustrate how the market share of different space heating technologies in households develops over time in the National Trends scenario and the economic variants[10] based on ETM inputs (i.e., the technology mix for space heating in percentage terms and the number of households in future scenario). The market share of each technology is a proxy of the number of installed units in EU27. Today the use of conventional boilers is dominant. This dominance reduces over time, when heat pumps (HPs) and district heating become more prominent.

The share of homes that use a traditional gas boiler drops from 41% in the reference year to approximately 10% in 2050. Gas boilers in 2050 make use of renewable gas like biomethane and hydrogen.

HPs offer increased efficiency by making use of ambient heat. Furthermore, hybrid heat pumps (HHPs) can provide also flexibility to the electricity system, by switching to gas (methane or hydrogen) in cold winter days, during grid congestion or when there is insufficient renewable electricity available. By 2040 the households' market share of HPs (electric and hybrid) has grown to around 45% (41–49% in the economic variants). In the following years, this market share is assumed to increase further, to up to 57% by 2050.

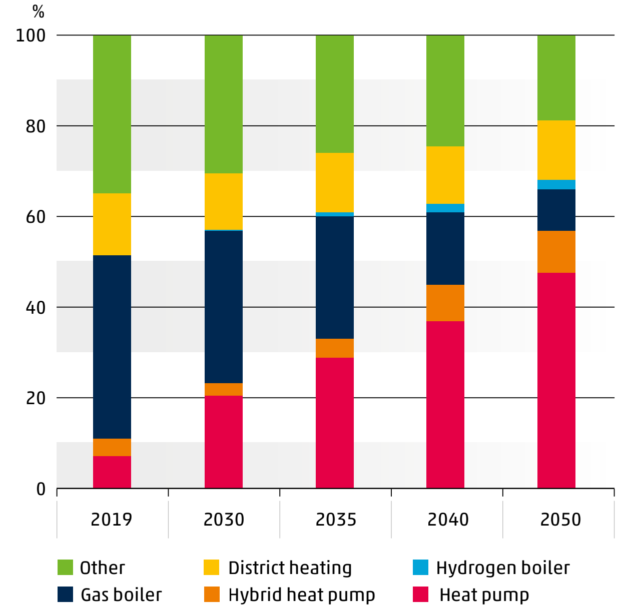

Figure 8: Market share of space heating technologies in households (EU27), central scenario (EU27)

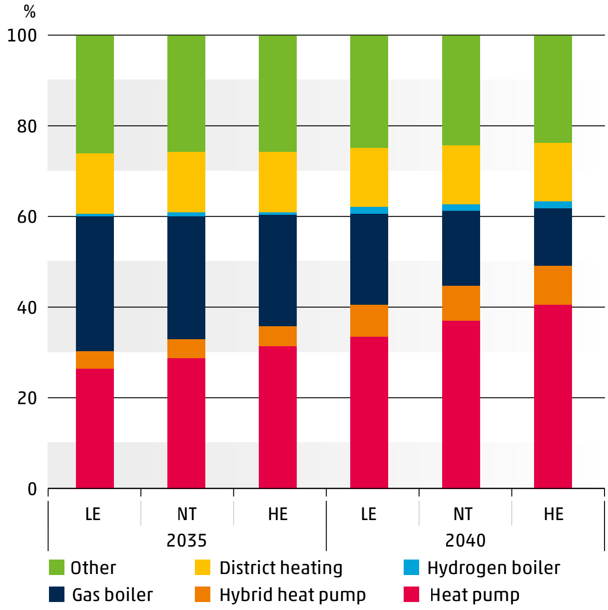

Figure 9: Market share of space heating technologies in households (EU27), central scenario and economic variants (EU27)

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[9] Following the definitions used by the European Commission, the built environment also includes energy demand for datacentres. In the ETM model, this demand is included under industry.

[10] The technology shares for the buildings sector are very similar to those for households.

Through changes in heating technology and increased efficiency, the NT data collection shows a sharp decrease in overall energy demand for households and buildings. This is illustrated by Figure 10. By 2050, final energy demand declines by roughly 20% compared to 2023, despite an increase in the number of dwellings and increased energy demand for Datacentres. This increased energy efficiency is the result of both an ambitious renovation rate and the use of more efficient appliances like heat pumps. The use of oil and coal will almost completely disappear. Gas demand also shows a sharp decline. Part of the methane demand is replaced with hydrogen. For the methane demand that remains, the share of renewable gas (i.e. biomethane) will increase over time.

The share of electricity in total energy demand increases from 37% in 2023 up to 59% in 2050. This is mainly driven by the increased use of HPs for space heating and hot water.[11] The role of district heating (heat) also increases, from 9% in 2023 up to 12% in 2050.

The economy variants show slight variations in the energy mix for the built environment. This is illustrated in Figure 11. The HEV shows a lower market share for fossil fuels (i.e. natural gas). The role of renewables like electricity, district heating and hydrogen is more important. The LEV shows the opposite.

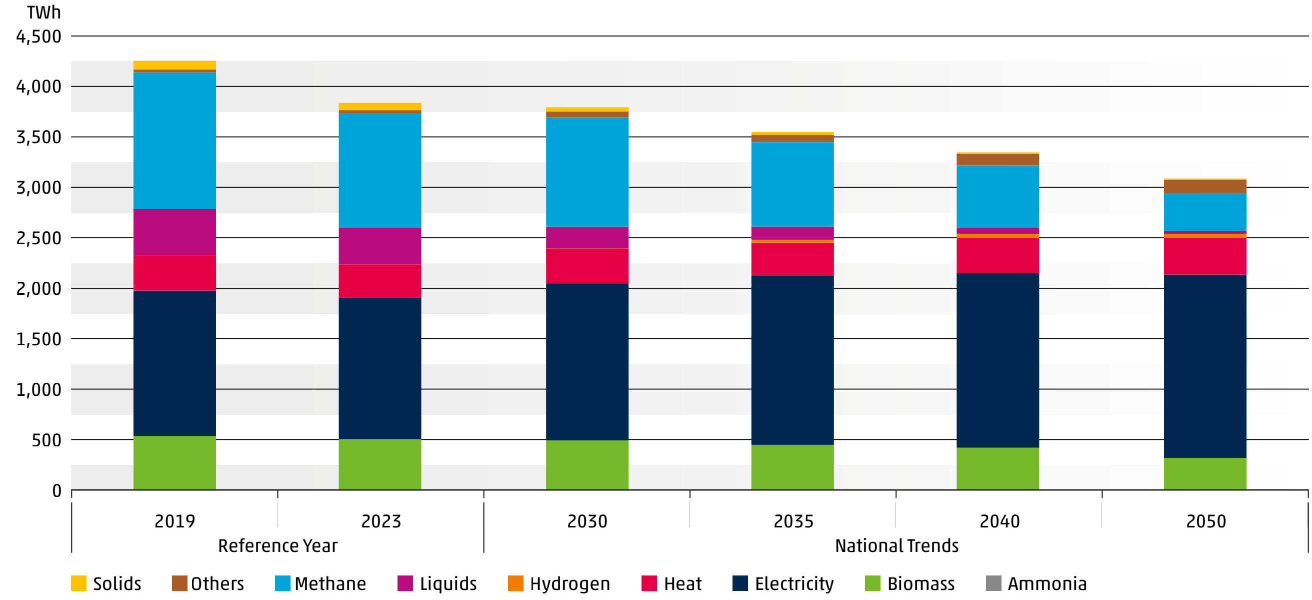

Figure 10: Energy demand in the built environment (EU27)

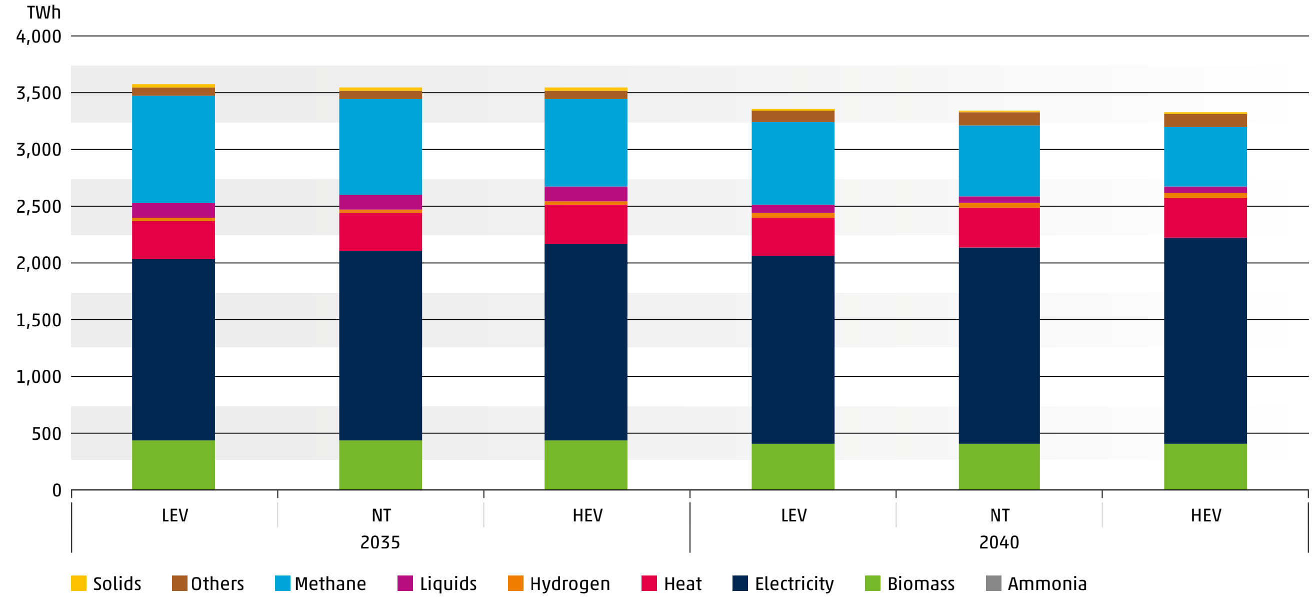

Figure 11: Energy demand in the built environment for the economic variants (EU27)

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[11] The energy use for HHPs (electricity, hydrogen and/or methane) reflects the data collection inputs submitted by TSOs via ETM. The energy quantities might differ from the dispatch in PLEXOS® market modelling, which used different assumptions for weather conditions.

Industry

European industry has a high demand for energy and raw materials. It is also characterised by strong heterogeneity, with significant differences in demand across subsectors. The basic industries for steel, chemicals, and refining account for the largest share of the industry's energy and raw material consumption. Smaller industry sectors might also face specific challenges to reduce emissions, for instance regarding high temperature processes (i.e. glass, ceramics, brick production).

Any shift within the industry – who decarbonises when and how – will have a major impact on future energy demand. The evolution of the energy demand for the different industrial subsectors is illustrated in Figure 12[12].

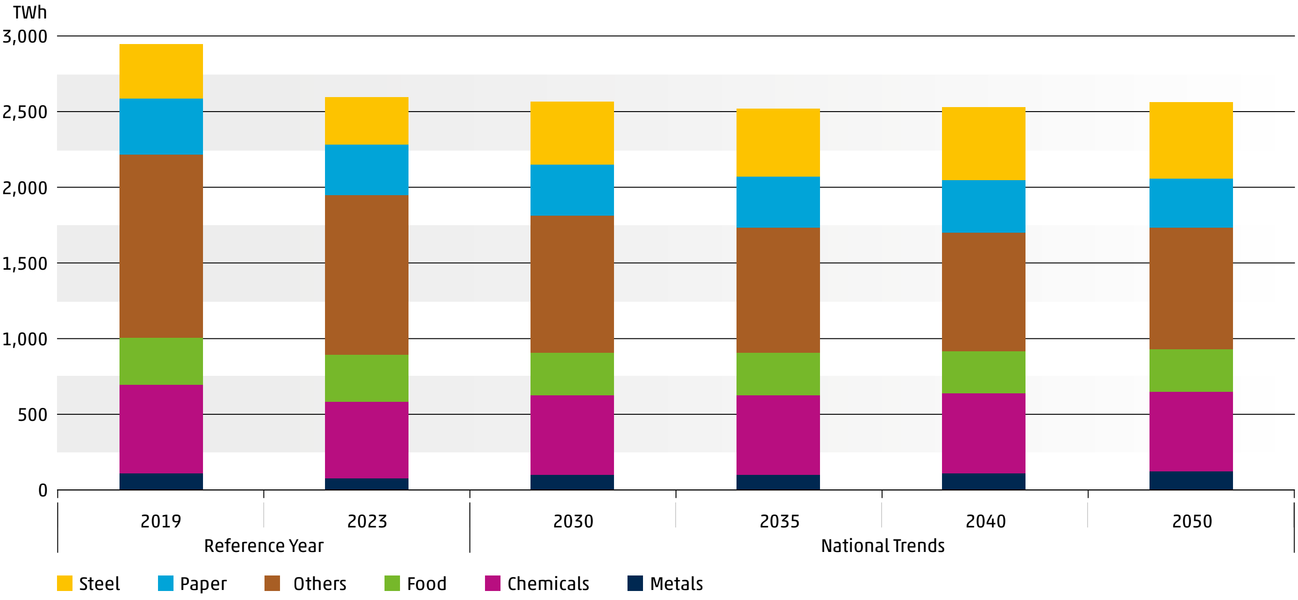

Figure 12: Industrial energy demand by sector (EU27)

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[12] Industrial demand excludes refineries and non-energetic use.

The NT data collection shows a rather stable industrial energy consumption, as shown in Figure 13.[13] Fossil fuels like oil, coal and gas decline over time. The electrification rate increases from one-third in the reference year 2023 to more than half in 2050. Hydrogen's importance grows,[14] especially in sectors that are challenging to decarbonise, such as those requiring temperatures above 200 degrees Celsius, making electrification difficult. Industries such as steel, cement, aluminium, and petrochemical production are examples where hydrogen plays a crucial role.

Figure 14 provides a comparison of industrial demand between National Trends and the economic variants. The HEV assumes higher industrial activity, which results in an increase in energy demand of approximately 7%. This increase is primarily accounted for by renewables like electricity and hydrogen. The LEV shows opposite dynamics.

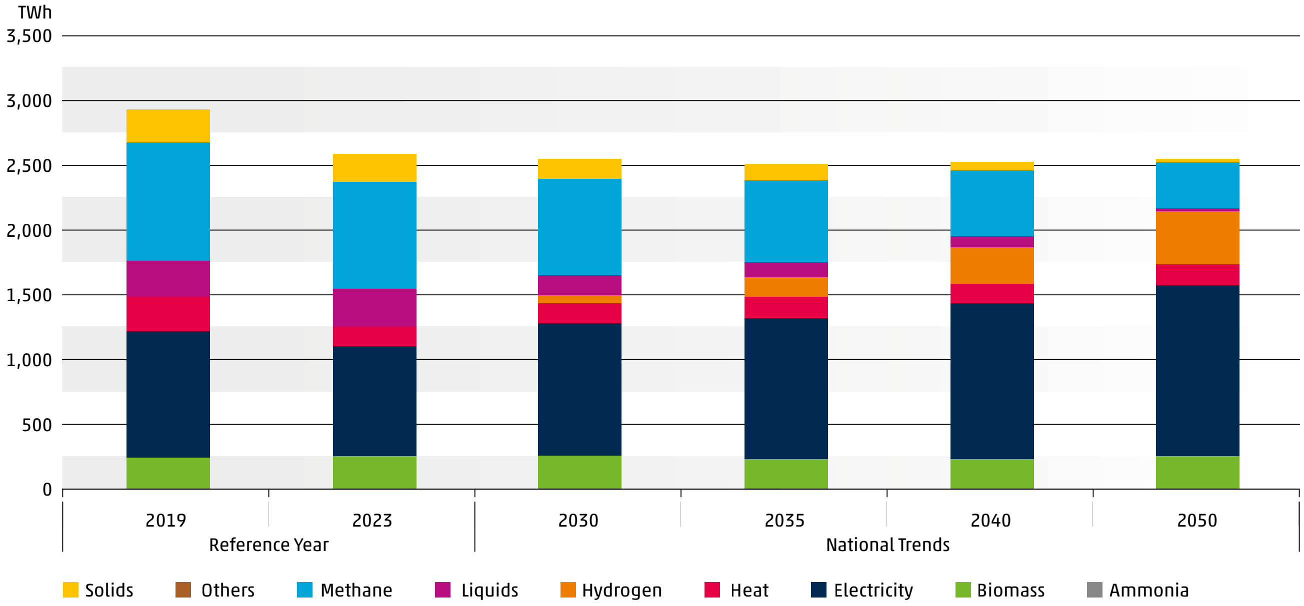

Figure 13: Industrial energy demand by carrier (EU27)

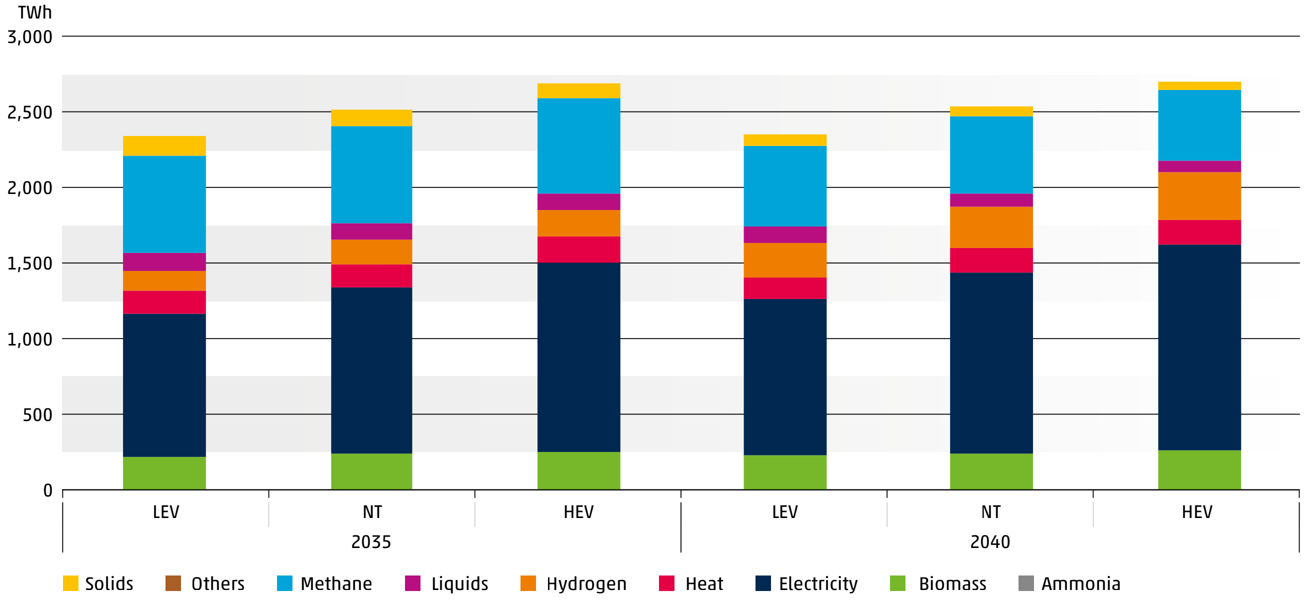

Figure 14: Industrial demand by carrier for the economic variants (EU27)

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[13] Industrial demand excludes refineries and non-energetic use.

[14] The graphs only display hydrogen quantities that need to be transported. All hydrogen that is produced on the same location as where it is consumed (which is most of the existing usage) is not visible as hydrogen demand in the figures. For on-site hydrogen production, the energy balance shows the associated feedstocks (oil, methane, etc.) instead.

As the EU production of fossil transport fuels reduces over time, the energetic use in refineries also declines. Furthermore, up to 2050 the energy consumption in refineries becomes more renewable. This is illustrated in Figure 15. Today refinery gasses[15] are the most prominent energy source, complemented by natural gas. Towards 2050 the role of hydrogen becomes more prominent.

Which is in part produced out of the refinery gasses (post-combustion CCS) that are currently used directly as a fuel. The HEV shows a reduction in energy consumption by refineries compared to NT, as presented in Figure 16. This is primarily driven by a lower production of transport fuels, which is linked to an increased electrification rate in road transport in this variant. The LEV shows an opposite trend.

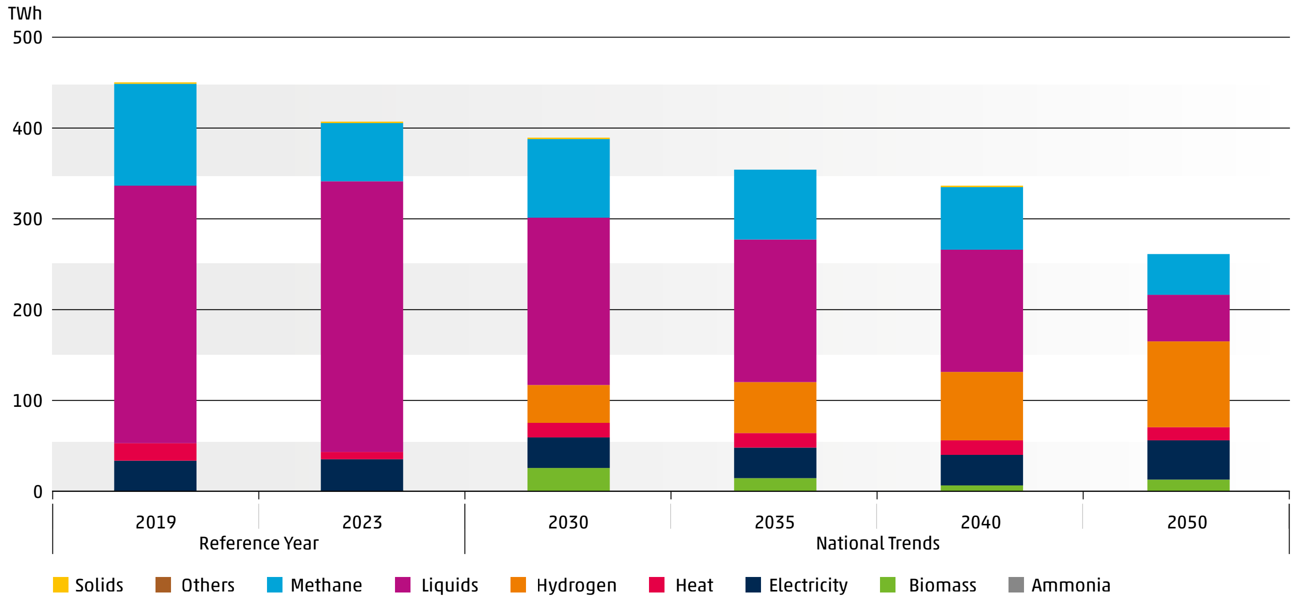

Figure 15: Energy demand in refineries (EU27)

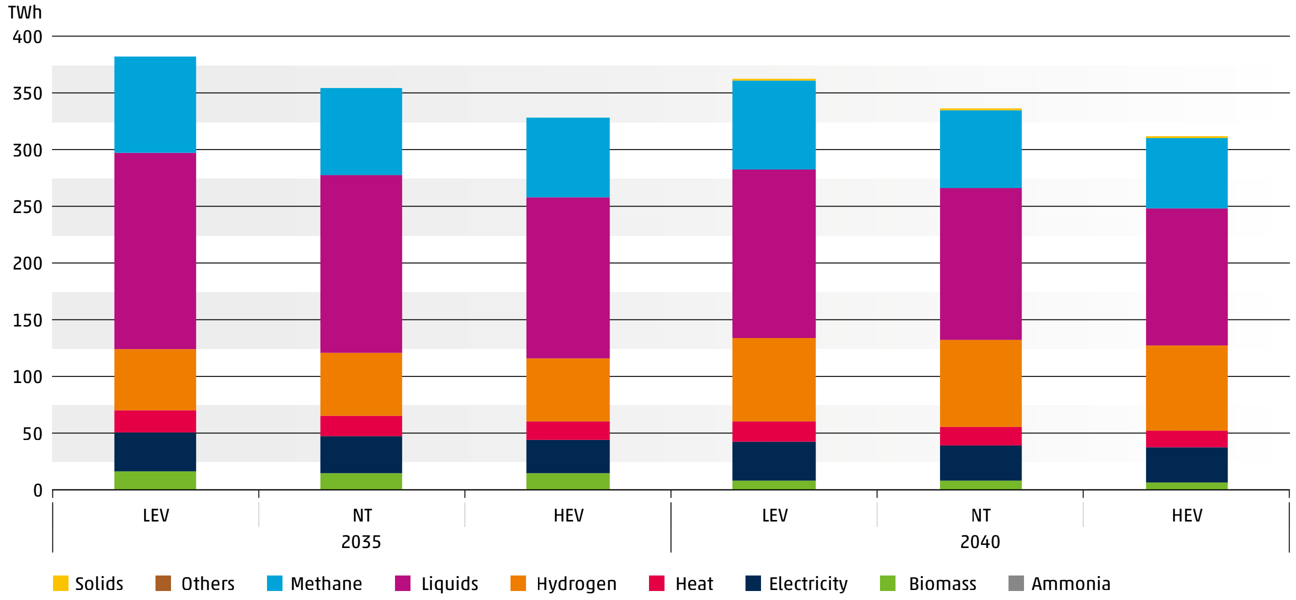

Figure 16: Energy demand in refineries in the economic variants (EU27)

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[15] Refinery gasses are a by-product of the oil refining process, which is subsequently used to fuel the furnaces. In case refineries use biogenic feedstock, the refinery gasses become (partly) renewable as well.

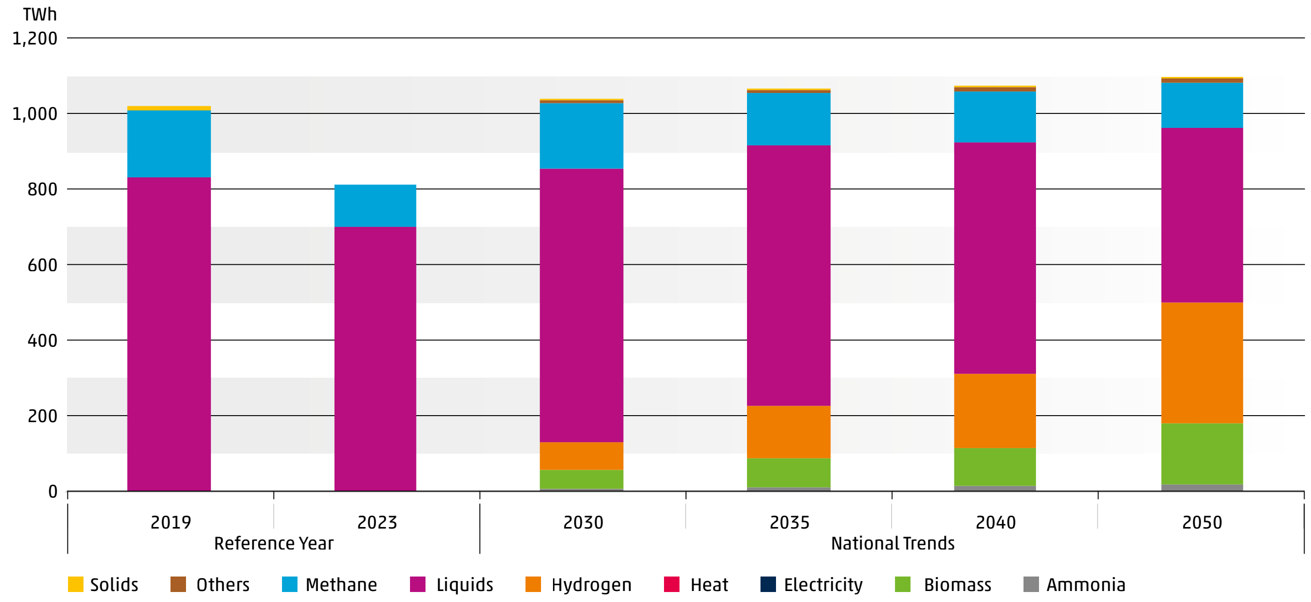

Figure 17: Non-energetic demand by carrier (EU27)

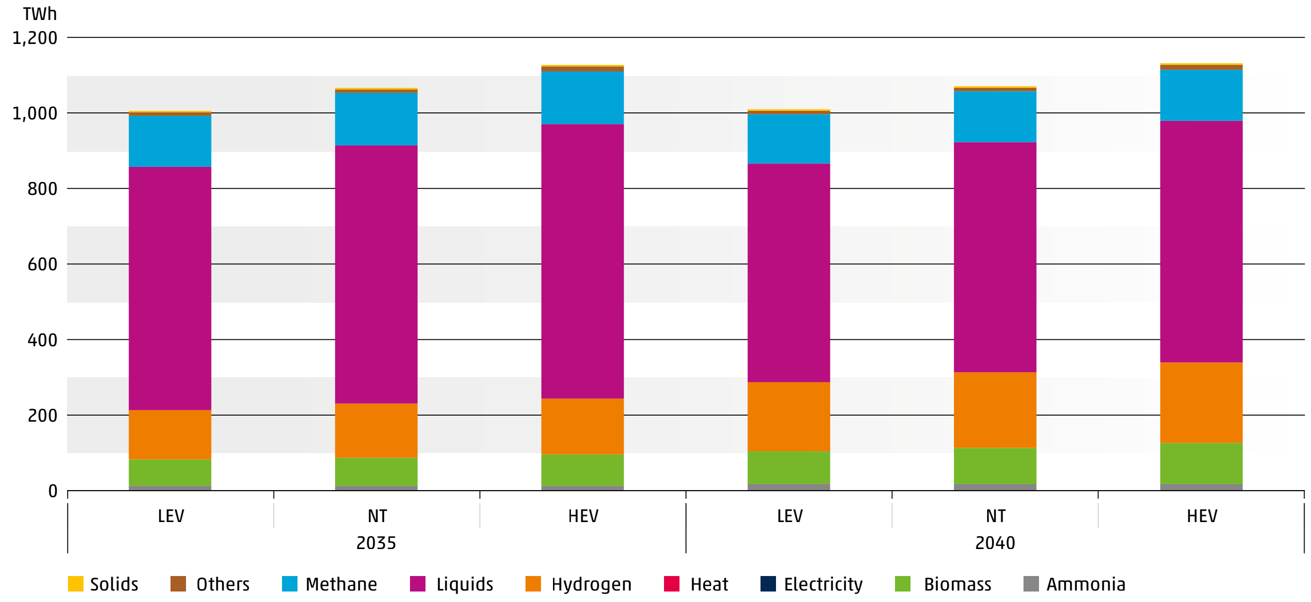

Figure 18: Non-energetic demand by carrier in the economic variants (EU27)

Regarding non-energy consumption within industry, current usage predominantly involves liquids and methane, serving mainly two purposes: the production of chemicals, particularly liquid-based petrochemicals for plastics, and manufacturing of fertilisers, with ammonia being a key component produced through Steam Methane Reforming (SMR). The non-energetic use of liquids (oil products) drops significantly, but remains the primary energy carrier until 2040, after which renewables (ammonia, hydrogen, biomass) take the lead, driving the transition in the feedstock sector. Different assumptions regarding economic growth lead to increased or decreased industrial production, which translates to differences in non-energetic use. This is illustrated in Figure 17 and Figure 18.

Mobility (Transport)

The transport sector is undergoing a sustained and structural energy transition driven by environmental imperatives, energy security concerns, and the strategic objective of reducing dependence on fossil fuels. This transformation is characterised by a broad set of measures aimed at enabling sustainable mobility, improving energy efficiency, and progressively decarbonising transport systems across all modes. While the transformation unfolds at different speeds and with varying technological pathways across transport segments, the overall direction is consistent: electricity emerges as the primary energy carrier wherever direct electrification is technically and economically feasible, with hydrogen assuming a complementary role in applications with higher energy requirements or operational constraints (See Figure 19).

At the centre of the scenario lies the systematic decarbonisation of transport, supported by technological innovation, policy intervention, and evolving consumer preferences. While certain transport sectors such as maritime shipping and aviation will remain heavy to decarbonise also in the long term, the rapid deployment of EVs represents a key pillar of this shift, enabled by continued improvements in battery performance, declining costs, supportive regulatory frameworks, and increased awareness of air quality and climate impacts. In recent years, EVs have experienced strong sales growth, observed across European markets. From a demand-side perspective, uptake is primarily driven by the need to reduce local air pollution, enhance energy efficiency, and lower CO_2 emissions.

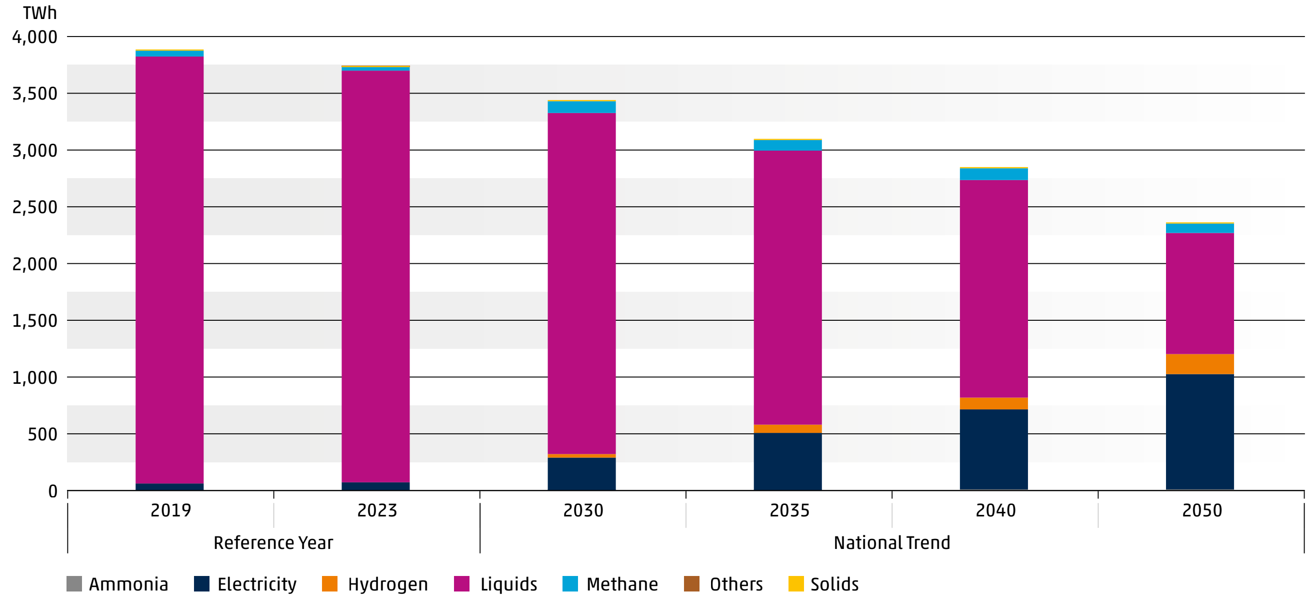

Figure 19: Final energy demand in the transport sector (EU27)

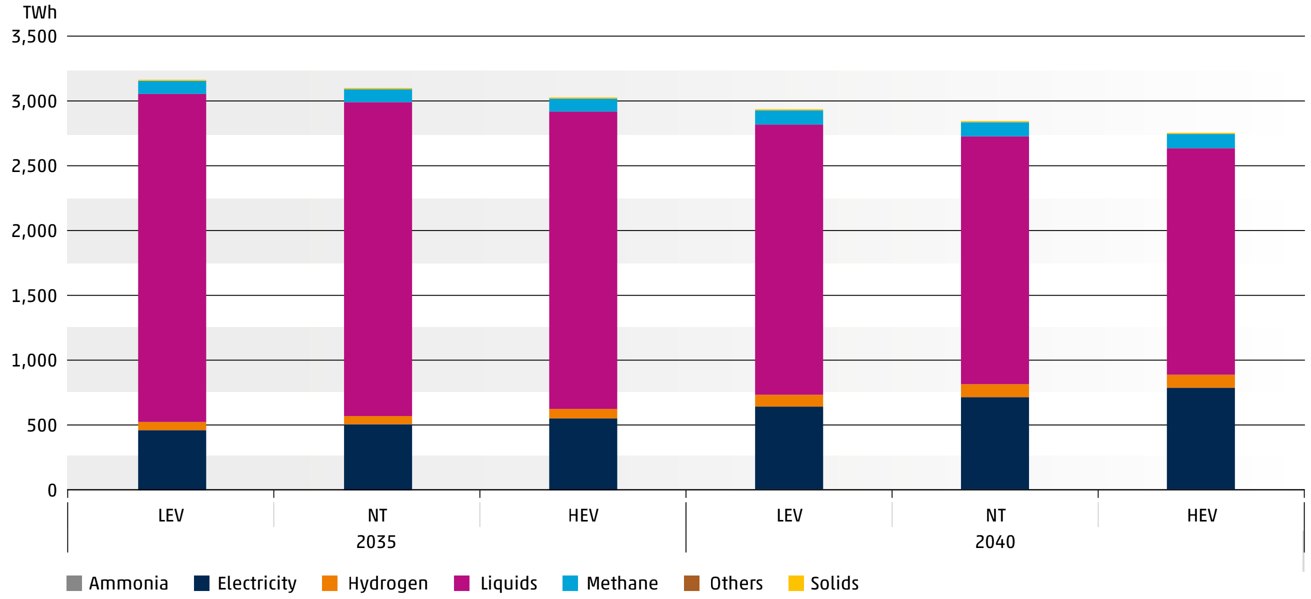

Figure 20: Final energy demand in the transport sector (EU27; economic variants)

Across NT data collection and economic variants, overall transport energy demand declines over time as a result of efficiency gains, improved vehicle technologies, and structural changes in mobility. Differences between the HEV and LEV are primarily reflected in the pace of change (See Figure 20). Higher investment levels and faster technology diffusion in the HEV scenario accelerate fleet renewal and fossil fuel displacement, while the LEV scenario follows a similar trajectory with delayed uptake and a more gradual reduction in energy demand.

Passenger cars lead the transition in all scenarios. Oil use declines sharply, while electricity and hydrogen play an important role. The HEV scenario shows faster electrification and lower residual fossil fuel use, whereas the LEV scenario retains conventional vehicles for longer.

Buses follow a similar pathway but with a more balanced role for hydrogen. Hydrogen gains relevance for longer routes and higher utilisation needs. The HEV scenario enables faster deployment of both electric and hydrogen buses, while the LEV scenario shows a more gradual transition with continued reliance on conventional fuels in the medium term.

Trucks transition more slowly due to operational challenges. Electricity grows mainly in short- and medium-haul applications, while hydrogen becomes increasingly important for long-distance freight transport. The HEV scenario places greater emphasis on hydrogen, reflecting earlier infrastructure availability and stronger investment capacity. In the LEV scenario, the shift away from oil is slower, and alternative technologies penetrate the fleet more gradually.

Vans show strong electrification potential, especially in urban logistics and last-mile delivery. Electricity increasingly replaces conventional fuels, supported by predictable driving patterns. Hydrogen plays only a limited role. Differences between scenarios are mainly related to timing, with the HEV scenario achieving faster electrification and the LEV scenario lagging slightly behind.

Rail transport is already largely electrified and continues to strengthen this position. Electricity remains the dominant energy carrier in all scenarios, while hydrogen appears as a niche solution for non-electrified lines. The HEV scenario supports a faster reduction of residual oil use, while the LEV scenario maintains limited fossil fuel use for longer.

Maritime shipping and aviation remain the most challenging sectors to decarbonise. In shipping, electricity is largely confined to short-distance and port-related activities, while hydrogen gains relevance over time, especially under favourable economic conditions. Aviation shows limited penetration of electricity and hydrogen with decarbonisation driven primarily by Sustainable Aviation Fuels (SAF). Differences between scenarios are comparatively small, reflecting persistent technological and operational constraints.

Agriculture

Agriculture, while accounting for a relatively limited share of energy demand, relies significantly on fossil fuels for machinery, irrigation, and heating. Historically, oil has dominated energy use on farms (more than 50% share in 2019), powering tractors, harvesters, and grain dryers. In addition, the energy demand of greenhouse (horticulture) operation amounts to a significant share in this sector in certain countries.

However, as global decarbonisation targets tighten and energy costs fluctuate, the sector is undergoing a profound transformation toward cleaner, more sustainable sources, as shown in as shown in Figure 21.

In the NT data collection, the overall energy demand for agriculture is expected to gradually decrease from around 300 TWh in 2030 to around 260 TWh in 2050. The share of oil is also steadily decreasing throughout the years (although it remains the most important energy carrier throughout the analysed time horizon) and is partially replaced by electricity – driven by the electrification of farm equipment and the adoption of precision agriculture technologies. The demand for biofuels increases slightly, while heat demand decreases throughout the years. Methane demand remains stable, while other carriers (coal, hydrogen, ammonia and others) are insignificant for energetic use in agriculture.

Overall, the difference between the NT data collection and the Economic Variants is rather limited regarding energy demand in agriculture as shown in Figure 22.

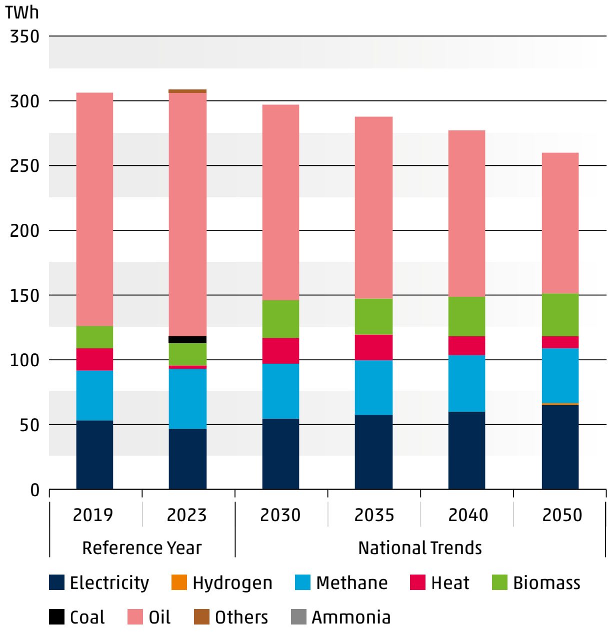

Figure 21: Energy demand in the agricultural sector

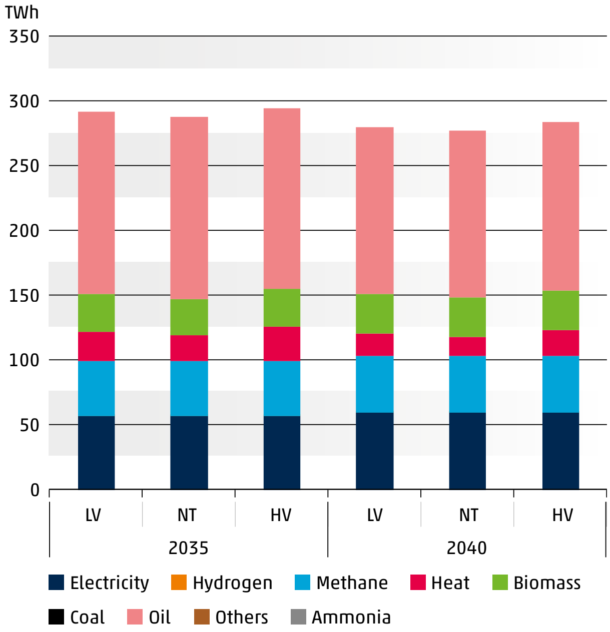

Figure 22: Energy demand in the agricultural sector for the economic variants (EU27)

Final Demand per carrier

Electricity

Final electricity consumption shows a substantial increase throughout all target years. This growth is primarily driven by Europe's progressive shift away from fossil fuels, reflecting the region's commitment to improving energy efficiency and advancing decarbonisation.

Looking at final electricity demand, a strong and continuous increase is observed across all target years when assessed under the EED. Starting from 2,380 TWh in 2023, demand rises to around 2,920 TWh in the short term (2030), reaches 3,710 TWh in the long term (2040) and further increases to 4,220 TWh by 2050, corresponding to increases of 23%, 56% and 77%, respectively.

This increasing trend is observed in the variants too, although its magnitude varies depending on economic assumptions. In the HEV, electrification is even more pronounced, with final electricity demand increasing by 8% in the medium term (2035) and 8.4% in the long term (2040) relative to the NT data collection. This additional growth is mainly driven by further electrification within the industrial sector. However, the widespread implementation of efficiency measures helps moderate the scale of this increase. In contrast, the LEV projects a decline in final electricity demand of 8.4% by 2035 and 8.4% by 2040 compared to the NT data collection.

Within this overall increase, growth is not evenly distributed across sectors. The transport sector shows the strongest growth in final electricity demand over time. Between 2023 and 2030, the expansion of this demand in the transport sector is particularly notable. Currently dominated by oil as its main energy source, the sector is undergoing a major transition towards electric mobility. This trend continues through 2050. From 2030 to 2050 the electricity demand in the transport sector increases by a factor of 3.5. This shift not only eliminates local emissions but also improves energy efficiency, given that electric motors are significantly more efficient than internal combustion engines.

Despite the strong growth of final electricity demand in the transport sector, the ranking of sectors by electricity consumption remains largely unchanged across scenarios and target years. The built environment sector represents the largest share of electricity consumption, followed by industry and transport. This is mainly driven by the widespread deployment of HP, which efficiently provide heating and cooling using electricity, as well as by improvements in appliance efficiency and building insulation. In addition, the built environment also includes the growing electricity consumption associated with ICT related activities. The continued digitalisation of the economy (including datacentre expansion and cloud-based services) further increases the electricity demand within this sector, consolidating its dominant contribution across all scenarios.

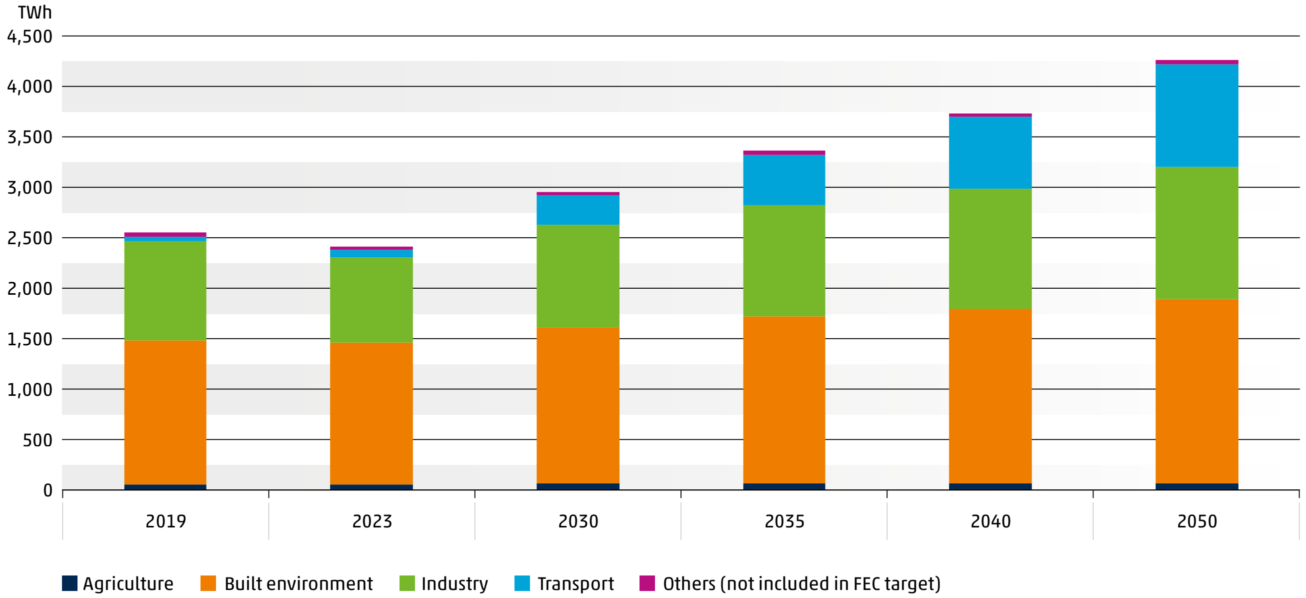

Figure 23: Final electricity demand per sector (EU27, TWh)

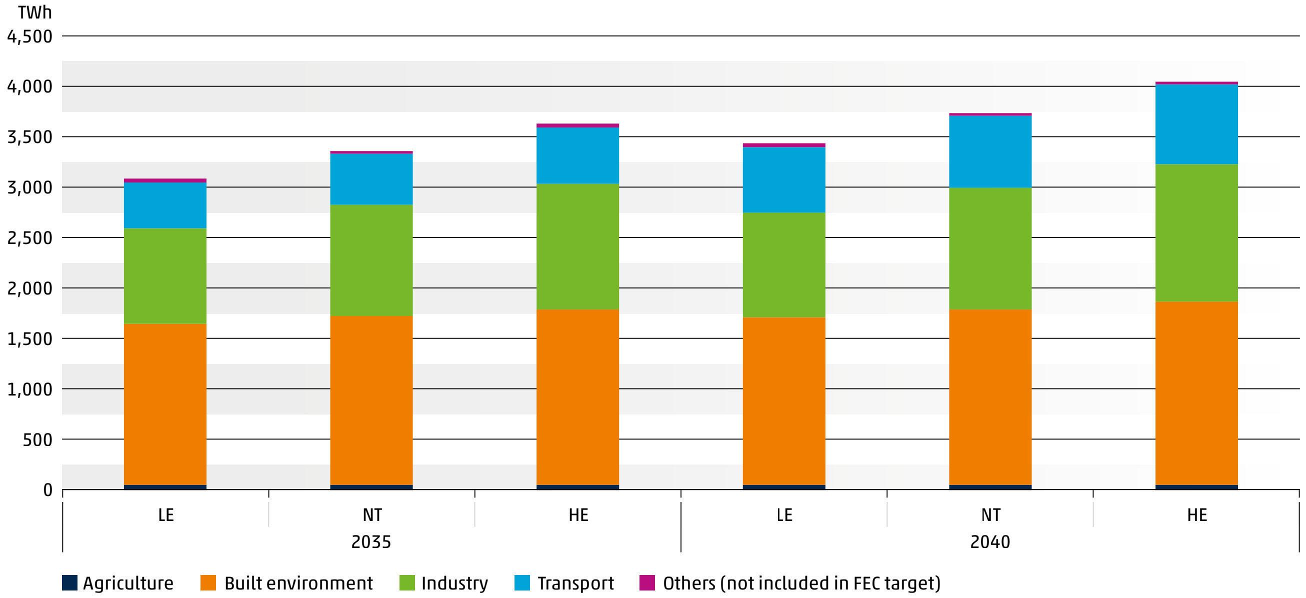

Figure 24: Final electricity demand per sector, Low/High economic variant (EU27, TWh)

Figure 23 and Figure 24 illustrate the final electricity demand following the sectoral breakdown[16] considered in the EED for the NT data collection and economic variants, respectively.

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[16] Transport sector includes energy demand for International aviation

Methane

Methane final demand shows a near-term stabilisation followed by a long-term decline (Figure 25). In the NT data collection, methane demand in 2030 remains close to the level observed in 2023, at 2,255 TWh compared to 2,238 TWh in 2023. This is substantially below the 2019 reference level of 2,657 TWh. In 2030, demand remains concentrated in the built environment and industry, which together account for around 80% of total methane demand.

Beyond 2030, methane demand declines substantially, mainly due to reduced demand in the built environment sector and in energetic use in industry. In the NT data collection, total methane demand falls to around 1,097 TWh in 2050. The built environment shows the largest absolute reduction, decreasing from around 1,072 TWh in 2030 to around 376 TWh in 2050. This reflects the increasing electrification of heating, fuel switching and improvements in energy efficiency. Industrial methane demand also declines steadily, from around 743 TWh in 2030 to around 346 TWh in 2050, although it remains significant throughout the period due to continued process-related uses and limited alternatives in certain industrial applications.

Other sectors show more mixed developments. Agriculture remains broadly stable over time, while demand in the "Others" category changes only moderately. While methane demand decreases across most sectors, transport shows a clear increase compared to the historical reference years, rising from 38 TWh in 2023 to around 108 TWh in 2030 and remaining above historical levels until 2050. This increase is mainly driven by international maritime transport, reflecting the limited availability of alternative decarbonisation options in this sector and a growing reliance on methane-based fuels. However, transport remains relatively small compared to the built environment and industry.

In the economic variants, differences are most visible in the built environment and industry sectors, where methane demand is most sensitive to assumptions on electrification, fuel switching and efficiency improvements (Figure 26). In 2040, methane demand in the built environment ranges from around 527 TWh in the HEV to around 728 TWh in the LEV, compared to around 622 TWh in the NT. Industrial methane demand ranges from around 470 TWh in the HEV to around 537 TWh in the LEV, compared to around 509 TWh in the NT. This reflects the economic variant assumptions: the HEV shows stronger reductions in methane demand, while the LEV shows a slower decline and higher residual methane use. Agricultural methane demand remains relatively stable across scenarios and over time.

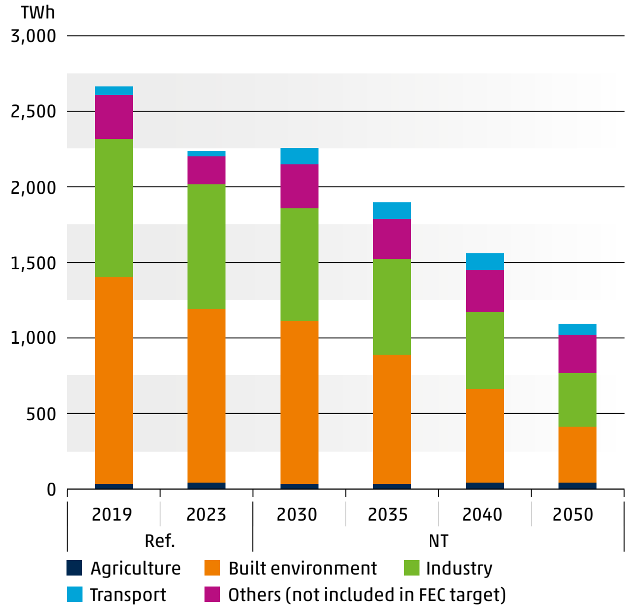

Figure 25: Final Methane demand per sector (EU27)

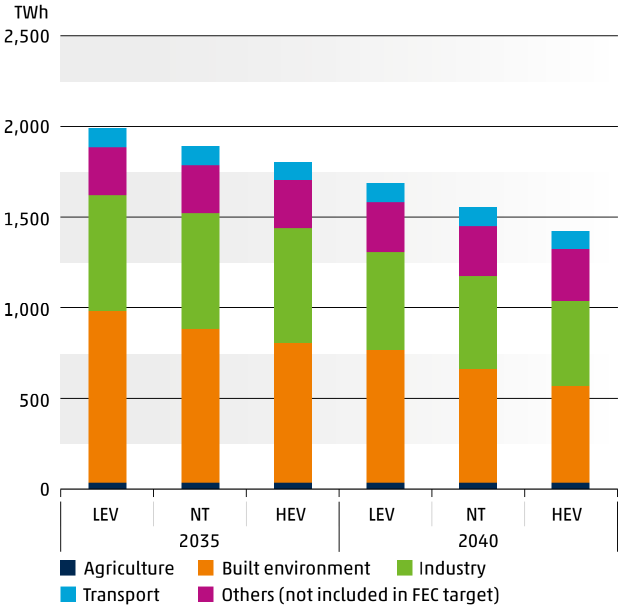

Figure 26: Methane demand per sector in the economic variants (EU27)

Hydrogen

Hydrogen final demand increases strongly over time, rising from 212 TWh in 2030 to 1,071 TWh in 2050 in the NT data collection (Figure 27). This growth is mainly driven by industrial and non-energetic uses of hydrogen. In the sectoral breakdown, this is reflected both in the industry category and in the "Others" category, which mainly includes non-energetic industrial uses and refinery-related demand. Together, these two categories account for around 80% of hydrogen demand in 2030 and remain the dominant components throughout the period.

After 2030, hydrogen demand expands substantially. Demand in the Others category increases from 113 TWh in 2030 to 438 TWh in 2050, while industrial hydrogen demand rises from 58 TWh to 407 TWh over the same period. This reflects the growing role of hydrogen in industrial decarbonisation, both as an energy carrier and as a feedstock replacing fossil-based inputs in hard-to-abate sectors and refinery-related applications.

Hydrogen demand also increases in transport, from 32 TWh in 2030 to 170 TWh in 2050. While this growth is significant, transport remains smaller than the industrial and non-energetic demand categories. Demand in the built environment rises, too, from 9 TWh in 2030 to 55 TWh in 2050, while agricultural demand remains negligible. Hydrogen therefore does not become a mass energy carrier across all final demand sectors but is concentrated in hard-to-abate industrial, non-energetic and select transport applications.

In the economic variants, differences are most visible in industry and Others (Figure 28). In 2040, industrial hydrogen demand ranges from around 229 TWh in the LEV to around 317 TWh in the HEV, compared to around 275 TWh in the NT. Demand in the Others category ranges from around 270 TWh in the LEV to around 302 TWh in the HEV, compared to around 287 TWh in the NT. This reflects the economic variant assumptions, with the HEV showing higher hydrogen uptake and the LEV showing slower deployment. The overall sectoral structure remains similar across variants, with demand concentrated mainly in industrial energy use, non-energetic uses, refinery-related demand and, to a lesser extent, transport.

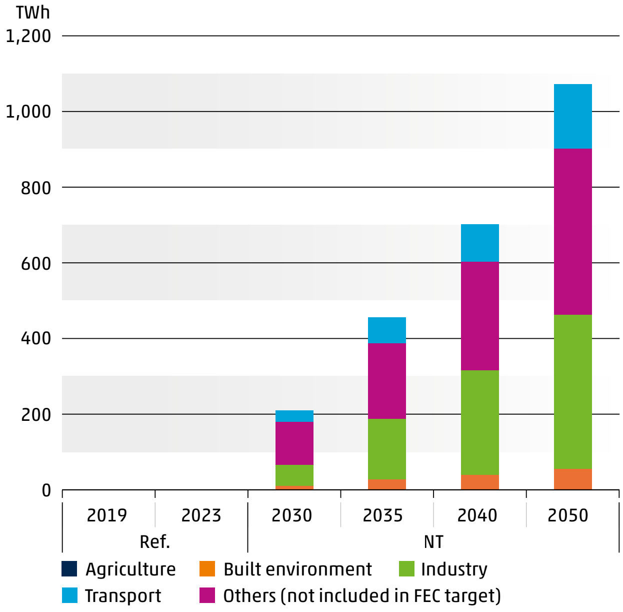

Figure 27: Final Hydrogen demand per sector (EU27)

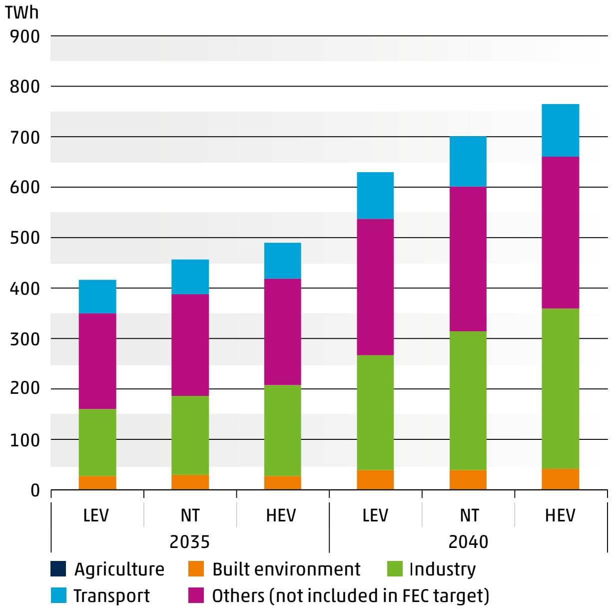

Figure 28: Final hydrogen demand per sector in the economic variants (EU27)

Biomass

Biomass in this context covers solid bioenergy used as a final energy carrier, primarily in the built environment and industry, with additional use in agriculture and for non-energy applications. As biomass in the ETM is represented only as solids, there is no explicit biomass entry for the transport sector in this breakdown. The "Other (non-FEC)" category is mainly driven by non-energetic uses of biomass in the chemical industry and related process applications.

As shown in Figure 29, total biomass demand in the NT dataset decreases progressively from 2030 to 2050, although the reduction is moderate. Final biomass use in the built environment remains the largest component over the period but declines from 491 TWh in 2030 to 304 TWh in 2050, reflecting the gradual replacement of solid biomass heating and efficiency improvements.

Industrial biomass demand stays relatively stable in aggregate terms, at about 261 TWh in 2030 and 258 TWh in 2050, with only a temporary dip in 2035–2040. Agricultural biomass use increases slightly over time, from 28 TWh in 2030 to 33 TWh in 2050 but remains small in absolute terms. In parallel, biomass in "Other (non-FEC)" grows steadily from 76 TWh in 2030 to 172 TWh in 2050, indicating an increasing role of biomass as a non-energetic feedstock, mainly in the chemical industry. Overall, the sectoral composition gradually shifts from a dominance of built-environment use towards a more balanced distribution between buildings, industry and non-FEC uses.

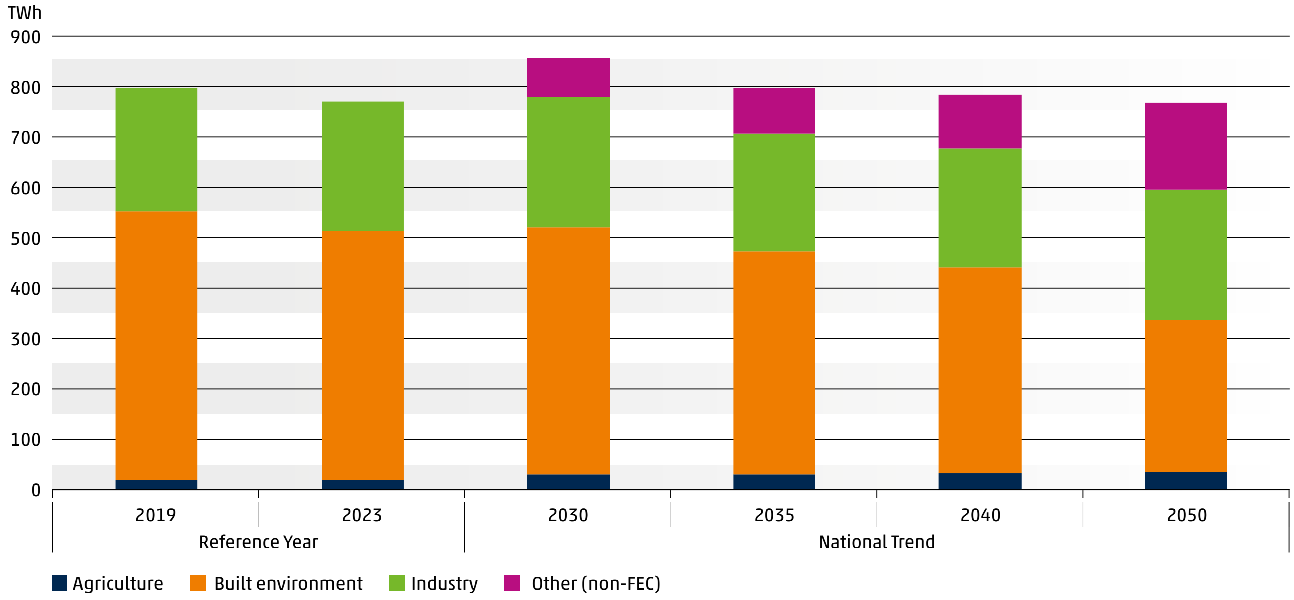

Figure 29: Final Biomass demand per sector (EU27)

The Economic Variants introduce a moderate spread around the NT values for 2035 and 2040, as illustrated in Figure 30. For agriculture, biomass demand is identical across LEV, NT and HEV (around 29 TWh in 2035 and 30 TWh in 2040). In the built environment, differences are limited: biomass demand ranges from 442–444 TWh in 2035 and 408–413 TWh in 2040, with NT lying between LEV and HEV in both years. The largest variations appear in industrial biomass use and other non-FEC biomass. In 2035, industrial demand spans from 216 TWh (LEV) to 251 TWh (HEV), compared to 233 TWh in NT; by 2040, it ranges from 221 TWh (LEV) to 255 TWh (HEV), with NT at 237 TWh. Non-FEC biomass follows a similar pattern, with 86–96 TWh (LEV–HEV) in 2035 and 97–117 TWh in 2040, compared to 90 TWh and 107 TWh in NT. Despite these differences in absolute levels, all three datasets (NT, LEV and HEV) preserve the overall trend of gradually declining biomass use in the built environment, relatively stable industrial use, and increasing biomass deployment and the use cases excluded from the final energy demand as per the EED.

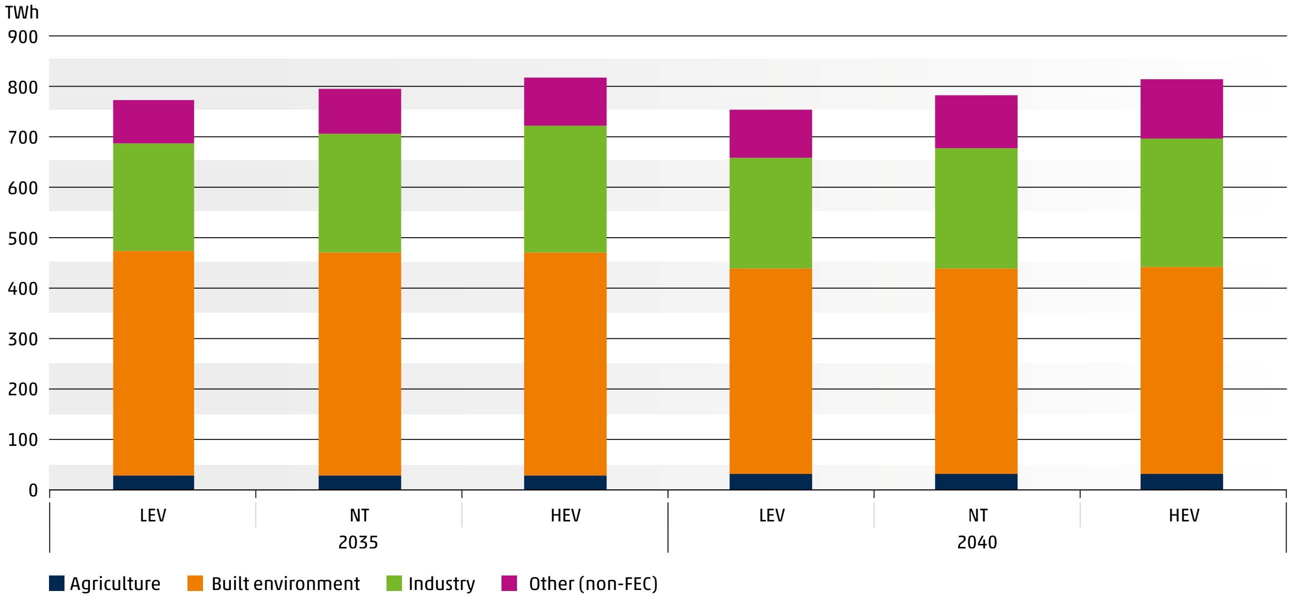

Figure 30: Final Biomass Demand per sector, comparison of NT with variants (EU27)

Heat

Heat as an energy carrier represents centralised heat delivered to final consumers via district heating networks. It is mainly used in the residential and tertiary sectors (combined here as "Built Environment"), in Industry and in Agriculture. Other forms of heat demand – such as space heating supplied by individual heat pumps or boilers – are not reported under the "heat" energy carrier but are captured indirectly via the final energy delivered in the form of electricity, hydrogen, methane or other fuels. Heat is also not used in the transport sector in this framework, which is why transport does not appear in the sectoral breakdown.

As shown in Figure 31, total final energy demand for heat in the NT dataset remains relatively stable over time, at around 540–550 TWh per year between 2030 and 2050. The Built Environment is the largest user of district-heating-based heat, with demand increasing from 343 TWh in 2030 to 358 TWh in 2050. Industrial heat demand via district heating remains broadly stable, fluctuating between 160 TWh in 2030 and 169 TWh in 2050, while Agriculture accounts for a comparatively small and declining share, from 20 TWh in 2030 to 9 TWh in 2050. Overall, the sectoral composition changes only marginally, indicating that the role of district heating within the different end-use sectors does not fundamentally shift over the period.

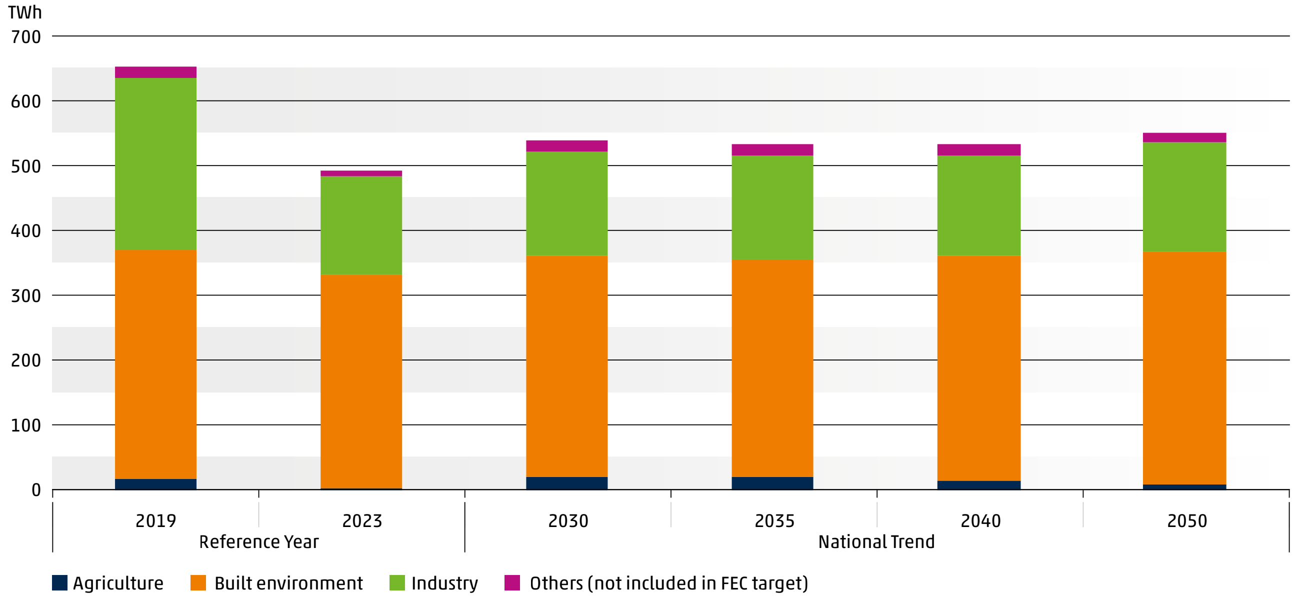

Figure 31: Final heat demand per sector (EU27, TWh)

The Economic Variants introduce a similarly moderate spread around the NT values for 2035 and 2040, as depicted in Figure 32. In the high economic variant (HEV), total heat demand is higher than in NT, with additional consumption mainly visible in the Built Environment and Industry: for 2035, built-environment heat demand rises from 338 TWh (NT) to 349 TWh (HEV) and industrial demand from 160 TWh to 169 TWh; in 2040, the corresponding values are 348 TWh vs. 357 TWh (Built Environment) and 154 TWh vs. 163 TWh (Industry).

In the low economic variant (LEV), total heat demand is slightly lower, particularly in Industry and, to a lesser extent, in the Built Environment: in 2035, industrial demand falls to 152 TWh and built-environment demand to 335 TWh, and in 2040 to 145 TWh and 339 TWh respectively. Agricultural heat demand is higher in LEV and HEV than in NT but remains small in absolute terms. Despite these level differences, all three datasets (NT, LEV, HEV) show a broadly stable trajectory for district-heating-based heat demand and maintain a very similar sectoral structure over time.

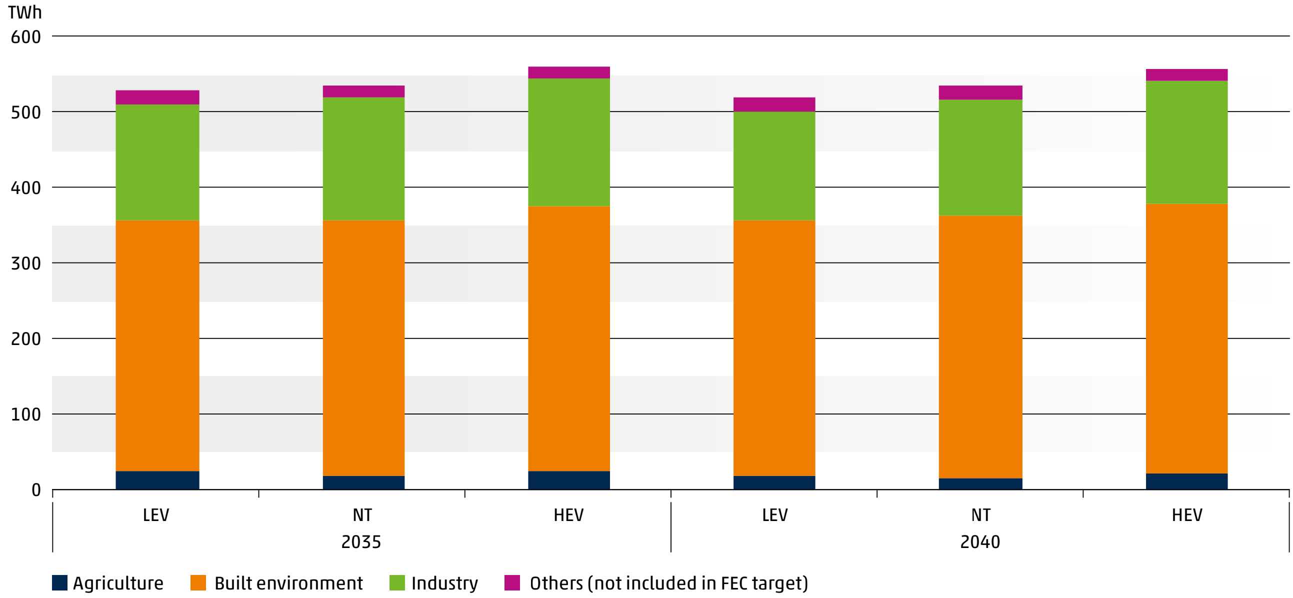

Figure 32: Final heat demand per sector (TWh), Low/High economic variant (EU27)

9.1.2 Final Energy Demand in the NT+ Scenario after Gap-filling Methodology

Gap-filling refers to the methodology applied to shift from the NECP- and policy-aligned NT data collection to the EED target-compliant NT+ scenario. In line with this methodology, solids and subsequently liquids demand were reduced at country level, while demand for other carriers and conversion demand remained unchanged. Further information on the methodology can be found in Chapter 10 of the Methodology Report, while Chapter 10.2 of the Scenario Report provides additional context on the EED target. The dashboard provides country-level results. The TSO Survey in Annex I of the Scenario Report provides further information on the alignment of the NT data collection with national policies.

Gap-filling affects (1) overall FEC levels, (2) final demand for solids and liquids, and (3) the composition of carriers within overall final energy consumption. The applied reductions are largest in 2030 and decline over time, as the methodology carries the 2030 limits for solids and liquids forward to later horizons.

The results are shown in Figure 33 and Figure 34. Regarding overall FEC levels, EU27 final energy consumption decreases from 10,081 TWh (867.0 Mtoe) in the 2030 NT data collection to 8,866 TWh (762.5 Mtoe) in the NT+ scenario, corresponding to a reduction of 1,215 TWh (104.5 Mtoe, –12.1%). The impact of gap-filling becomes smaller over time as fossil fuel demand already declines in the underlying NT data collection. By 2050, EU27 final energy consumption declines by only 178 TWh (15.3 Mtoe, –2.2%), from 8,244 TWh (708.9 Mtoe) in the NT data collection to 8,066 TWh (693.5 Mtoe) in the NT+ scenario.

In 2030, liquids decrease by 1,034 TWh (–88.9 Mtoe, –29.3% of liquids demand), while solids decrease by 181 TWh (–15.6 Mtoe, –86.6%). By 2050, the reduction reaches 148 TWh (–12.850 Mtoe, –12.0%) for liquids and 30 TWh (–2.6 Mtoe, –74.2%) for solids. Methane demand remains unchanged across all horizons, as reductions in solids and liquids were sufficient to meet the targets.

The reduction in solids and liquids affects the composition of final energy consumption. In 2030, the share of liquids in EU27 final energy consumption decreases from around 35% in the NT data collection to 28% in the NT+ scenario, while the combined share of electricity and hydrogen correspondingly increases from around 30% to 34%. By 2050, the impact on the overall carrier composition becomes smaller, as fossil fuel demand is already substantially reduced in the underlying NT data collection.

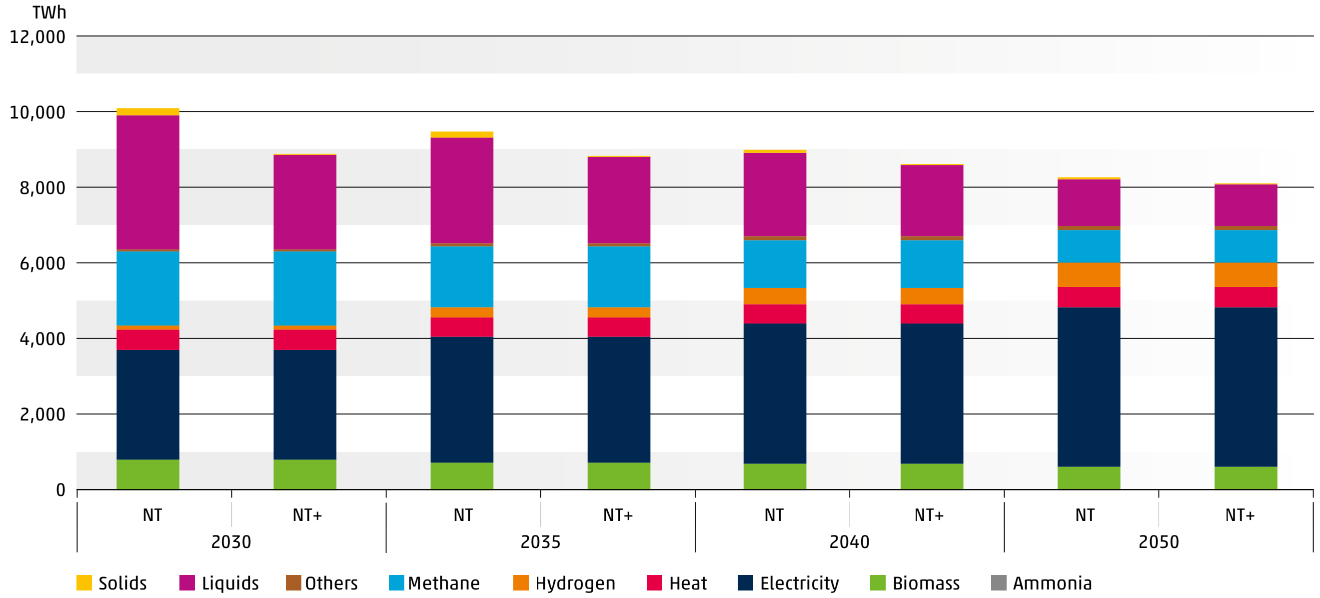

Figure 33: Final energy consumption (TWh) before gap-filling (NT) and after (NT+)

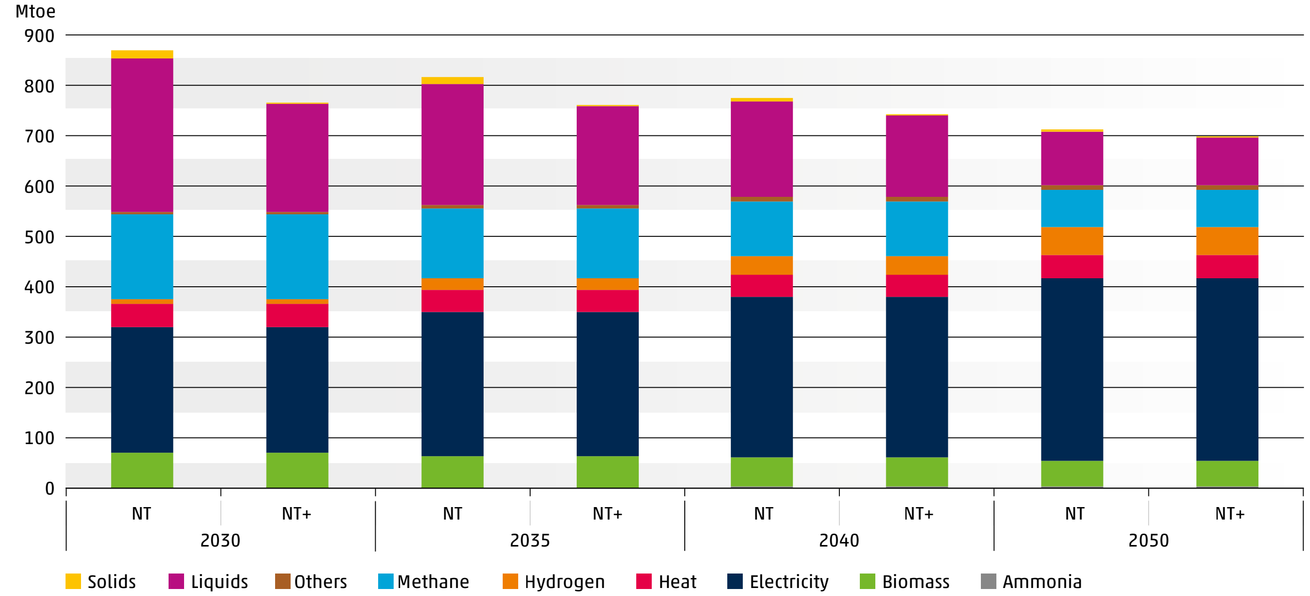

Figure 34: Final energy consumption (Mtoe) before gap-filling (NT) and after (NT+)

9.1.3 Total Energy Consumption and Consumption Peaks

In contrast to final energy consumption, which captures only the energy delivered to end-users, the total demand presented in the following sections covers energy use across all modelled conversion steps. It combines final energy demands collected in the ETM with additional consumption of energy carriers in power and CHP generation and in sector coupling conversion processes (such as electrolysis, hydrogen-to-power and heat production). Taken together, these elements provide a system-wide view of how much of each carrier is used within the modelled energy system, as reported in the Supply Tool.

Storage operation (including charging and discharging of batteries and other storage technologies) is not counted as additional yearly net demand in these totals, since storages are modelled cyclically with no net consumption or injection over the year.

In addition to the yearly total energy consumption, this section also reports the peak values of electricity, hydrogen and methane demands and loads based on the model results for NT+ and the variants to reflect the peak infrastructure utilisation. Where relevant, the impact of storage operation on peak load is also captured in this analysis.

Electricity

Peak demand comprises components derived from final energy consumption: native electricity demand, hybrid heat pumps (HHPs) and passenger EVs. For passenger electric vehicles (pEVs), part of the peak may be scheduled for flexibility purposes, reflecting the modelling of flexible charging rather than pure transport needs.

Peak load represents the full system load as seen by the electricity network. In addition to peak demand, it includes all modelled conversion and flexibility uses, such as market-coupled and shared RES electrolysers, charging of batteries and other storage technologies, and electricity consumption related to sector-coupling processes (e.g. heat production).

Hydrogen

While peak final demand for hydrogen consists of only native demand and hydrogen used in hybrid heat pumps, peak load of the hydrogen system also includes other demands and loads, such as injections into hydrogen storage, hydrogen use in power and CHP-heat generation and hydrogen demand for SNG and e-liquid production.

Methane

Methane in the model is used for hybrid heat pumps, power and CHP-heat generation and hydrogen production via SMR and pyrolysis. The "native" methane demand profile (final consumption) is not endogenously modelled but taken from an ENTSOG data collection.

Peak load for methane is constructed by superimposing the model-dependent time profiles of methane use (for power/CHP, HHPs and SMR/pyrolysis) on top of this native methane peak. This provides an overall methane peak load and for the selected weather year, average contributions of each component.

As a consequence, methane peak load may be somewhat overestimated, since the peak of native methane demand is not required to coincide in time with the peak of the model-driven methane uses. In addition, storage-related load is not considered.

For each carrier and target year, hourly profiles are available for three weather years. The reported peak loads are obtained by summing the relevant components to build a system load profile and then selecting the highest hourly value for electricity and the highest daily value for the gases across the three weather years. The average values shown for each component refer to the average contribution over the selected weather year in which the overall system peak occurs.

Electricity NT+ & variants

Total electricity demand in the NT+ scenario almost doubles, increasing from 3,420 TWh in 2030 to 6,320 TWh in 2050. This increase of around 2,900 TWh reflects the combined effect of end-use electrification, the expansion of electric mobility, and the growing role of electricity in hydrogen and synthetic fuel production, supporting the system's decarbonisation beyond direct electrification. Figure 35 shows total electricity demand in the NT+ scenario for the EU-27.

As shown in Figure 35, all main components of electricity consumption increase over time, with particularly strong growth in passenger electric vehicles and Power-to-Gas (P2G). While native[17] electricity demand increases from 3,040 TWh in 2030 to 4,070 TWh in 2050, electricity consumption for passenger electric vehicles grows to 570 TWh in 2050. Over the same period, electricity use in P2G expands by a factor of seven, from 225 TWh in 2030 to 1,630 TWh in 2050.

In the Economic Variants, electricity demand deviates from NT+ in line with the variant methodology. In 2035, native electricity demand ranges from 3,104 TWh in LEV to 3,618 TWh in HEV, compared to 3,370 TWh in NT+. By 2040, it increases to 3,378 TWh (LEV), 3,659 TWh (NT+) and 3,937 TWh (HEV).

The same pattern appears for passenger electric vehicles (pEVs): electricity use for pEVs is 236 TWh (LEV), 274 TWh (NT+) and 310 TWh (HEV) in 2035, rising to 339 TWh, 391 TWh and 441 TWh respectively in 2040. These differences reflect the scaling down (LEV) or scaling up (HEV) of electrified end-uses in the variant construction.

For modelled conversion sectors, the impact of variant assumptions is more nuanced. Electricity consumption in P2G is higher in LEV than in NT+ or HEV, at 698 TWh (LEV), 603 TWh (NT+) and 530 TWh (HEV) in 2035, and 1,064 TWh, 963 TWh and 860 TWh in 2040. This reflects the higher relative availability of electricity in LEV given the static supply capacities, which allows more electricity to be channelled into hydrogen production. In HEV, the general scarcity of both electricity and hydrogen reduces the utilisation of P2G despite higher overall activity levels. Electricity demand for hybrid heat pumps (HHPs) remains comparatively small in all cases, but shows the same direction of change: in 2035, it is 25 TWh (LEV), 23 TWh (NT+) and 23 TWh (HEV), and in 2040 it reaches 36 TWh, 37 TWh and 32 TWh respectively, with lower availability of electricity in HEV slightly dampening HHP operation. Figure 36 shows total electricity consumption under the LEV and HEV for the EU27.

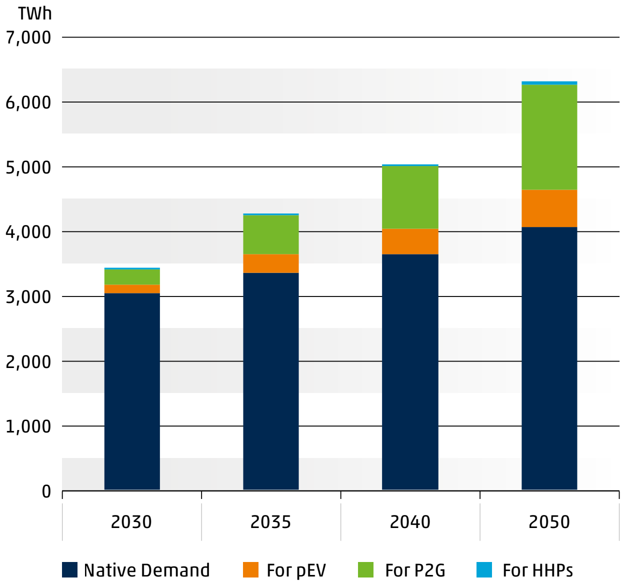

Figure 35: Total electricity consumption, NT+ (EU27)

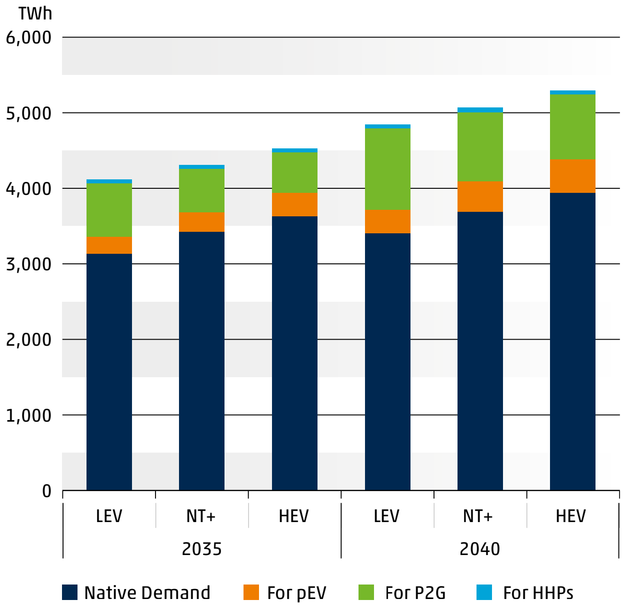

Figure 36: Total electricity consumption, Low/High economic variant (EU27)

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[17] Native demand includes all electricity demands from ETM and additional data collections except for the types of consumption that are explicitly modelled in PLEXOS® and thus usually provide the system with flexibility (i.e. flexible share of passenger EVs, P2G (including e-market, SRES and DRES) and the heat pump part of hybrid heat pumps)

Beyond total annual demand, peak electricity demand provides key insights for system operation. Two peak metrics are considered: peak electricity demand, which includes native demand and a limited set of flexible loads[18] (EVs and HHPs) that still represent final demand of electricity, and peak electricity load, which additionally incorporates further flexible uses through conversion of energy such as P2G, pumped storage and battery charging.

Figure 37 and Figure 38 present the maximum peak demand and peak load, respectively, for each target year across the three weather scenarios, together with the average contribution of each component in the peak scenario.

In the NT+ scenario, peak demand increases over time, reaching 538 GW in 2030, 632 GW in 2035, 725 GW in 2040 and 851 GW in 2050. When additional flexible and controllable components are included, peak load increases further, by a 15% in the short term (621 GW in 2030) and almost doubling in the long term (1,272 GW in 2050).

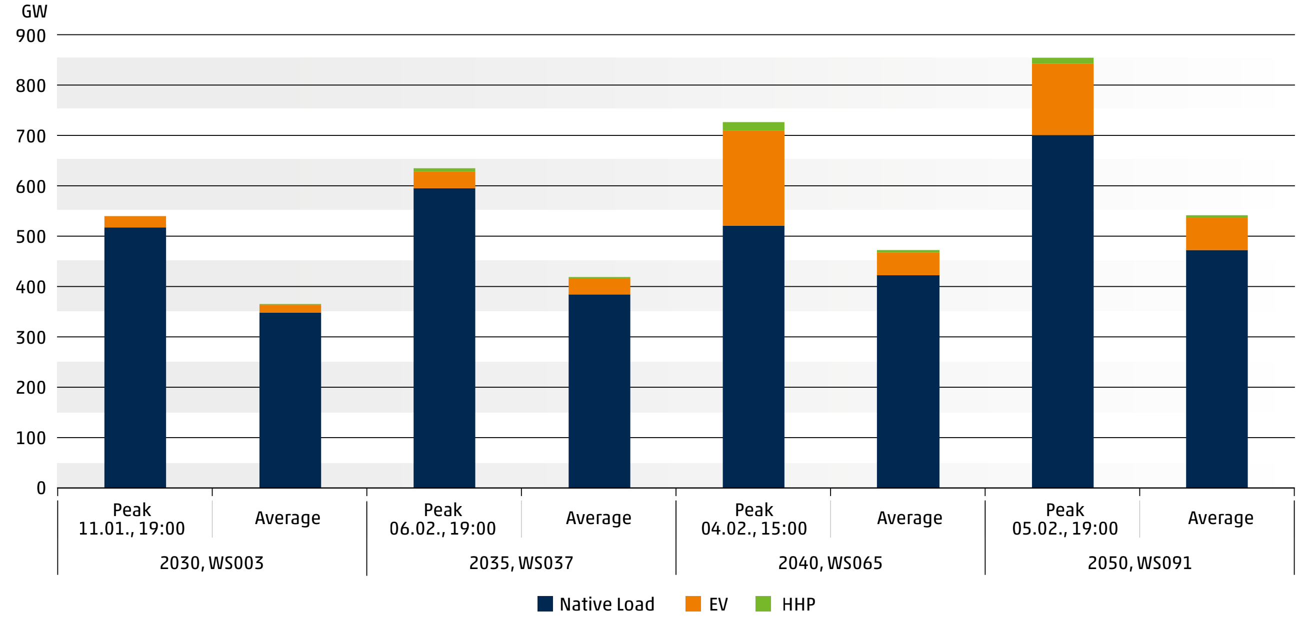

Figure 37: Electricity peak demand, NT+ (EU27)

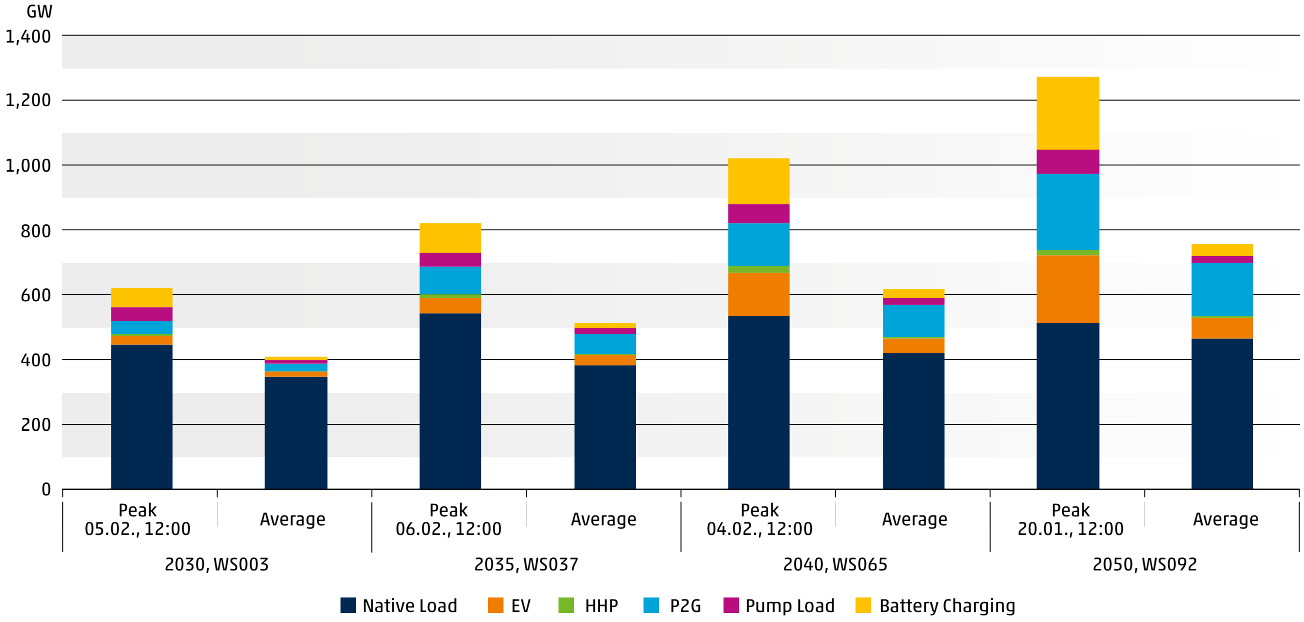

Figure 38: Electricity peak load, NT+ (EU27)

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[18] Flexible load values are the result of the PLEXOS® optimisation

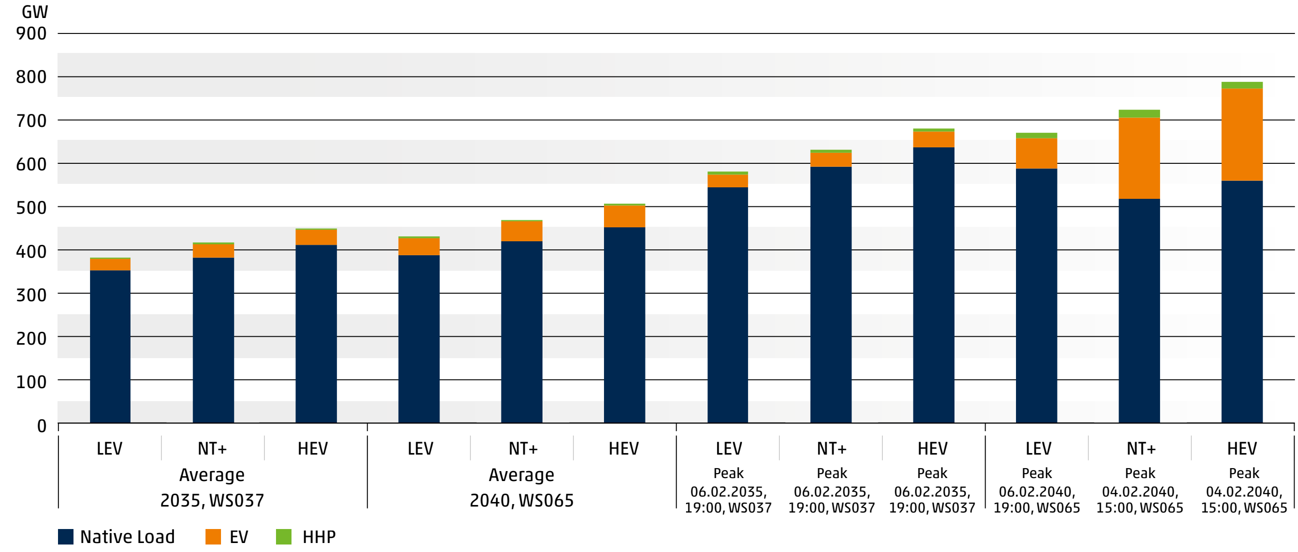

Figure 39: Electricity peak demand, Low/High economic variant (EU27)

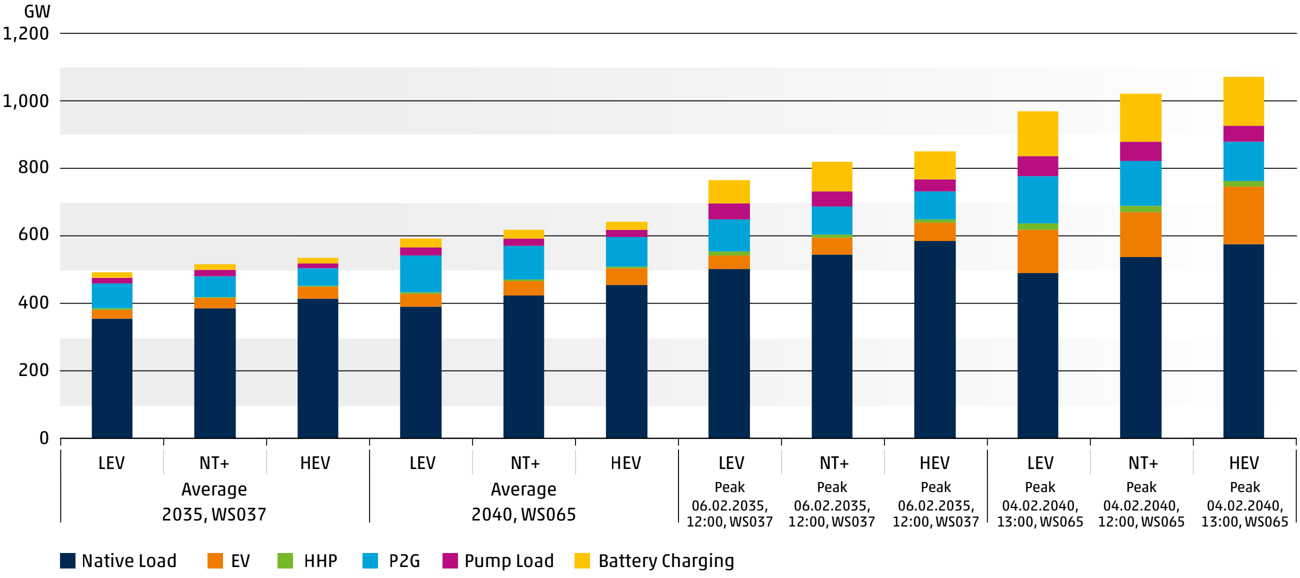

Figure 40: Electricity peak load, Low/High economic variant (EU27)

The comparison between peak and average values shows that the influence of flexible loads in the peak becomes increasingly significant over time. While native demand presents limited differences between average and peak values, flexible components show much stronger deviations, particularly in the long term. By 2050, the contribution of flexible technologies at peak hours becomes comparable to that of the native load, despite their more moderate average contribution. Historically, peak demand has been driven by temperature-dependent uses and typically occurs in winter, often in January. Despite the inclusion of flexible loads peak values remain in winter as native demand continues to play a dominant role.

While the peak demand and peak load remain in winter, its timing within the day changes. Peak demand (with limited flexibility) typically occurs during evening hours, whereas peak load (including a broader set of flexible components) shifts towards midday.

This reflects the interaction of flexible demand with renewable generation profiles and price signals. Figure 39 and Figure 40 show the maximum peak demand and peak load, respectively, for the weather scenarios identified to have the highest peaks, comparing the LEV and HEV variants with the NT+ scenario. Both figures also include the average contribution of each component in the peak scenario. As seen, peak demand vary with economic assumptions.

In 2035, peak demand ranges from 581 GW in LEV to 681 GW in HEV, compared to 632 GW in NT+. By 2040, it increases to 671 GW (LEV), 725 GW (NT+) and 789 GW (HEV). A similar pattern is observed for peak load, with higher absolute values due to the inclusion of additional flexible components. However, as the installed capacities remain fixed across variants, the difference in peak load across variants results primarily from the adjusted native demands. Peak load reaches 764 GW (LEV) and 849 GW (HEV) in 2035, rising to 970 GW (LEV) and 1,070 GW (HEV) in 2040.

Hydrogen NT+ & variants

Hydrogen applications are found in the end use sectors, but also in energy conversion like power generation or synthetic fuel production. Figure 41 illustrates the total use of hydrogen.[19] Most of the demand consists of final demand for energetic and non-energetic use (mainly as feedstock in industry). In part this contains existing demand where grey onsite hydrogen production is replaced with externally energy from electrolysis or imports. Additionally, the NT+ scenario sees an increased hydrogen volume needed for synthetic products such as ammonia and sustainable aviation fuels or as feedstock in chemical processes. Hydrogen use in power generation also increases. As hydrogen fired power plants are primarily used for balancing the electricity system, these run for relatively few hours per year. Consequently, the annual demand quantity is rather low.

Figure 42 provides a comparison of total hydrogen demand National Trends+ and the economic variants. Generally, the final demand for hydrogen is lower in LEV and higher in HEV, as defined in the economic variants methodology. Total demand in the variants, however, is rather similar to NT+. This is explained by the fact that energy supply capacities were not changed in economic variants. Consequently, a lower final demand in the LEV means that there is relatively more hydrogen available at lower costs enabling a higher utilisation of hydrogen in the modelled sector-coupling elements and for conversion like the production of synfuels, the provision of heat and for power generation. For the HEV the inverse of this behaviour can be observed. An exception is hydrogen demand for heat production, which also increases in the HEV compared to NT+. This is mainly driven by more frequent operation of hydrogen-fired CHPs as peaker plants under higher electricity demand and unchanged generation capacities. Higher electricity prices also increase the use of gases in hybrid heat pumps, further contributing to the rise in hydrogen demand for heating.

Final hydrogen demand shows limited variability within the year, as illustrated in Figure 43. This can be explained by the dominance of industry and mobility sectors, which are not weather dependent. As opposed to the methane system, where the residential and tertiary sectors have a rather large market share. For example, final hydrogen demand (native demand + hydrogen demand for HHPs) in the NT+ scenario increases from on average 1,296 GWh/d to a peak of around 1,476 GWh/d in 2035, and from around 3,220 GWh/d to a peak of around 3,772 GWh/d in 2050. Hydrogen use in hybrid heat pumps remains limited across all horizons and contributes only marginally to overall hydrogen final demand.

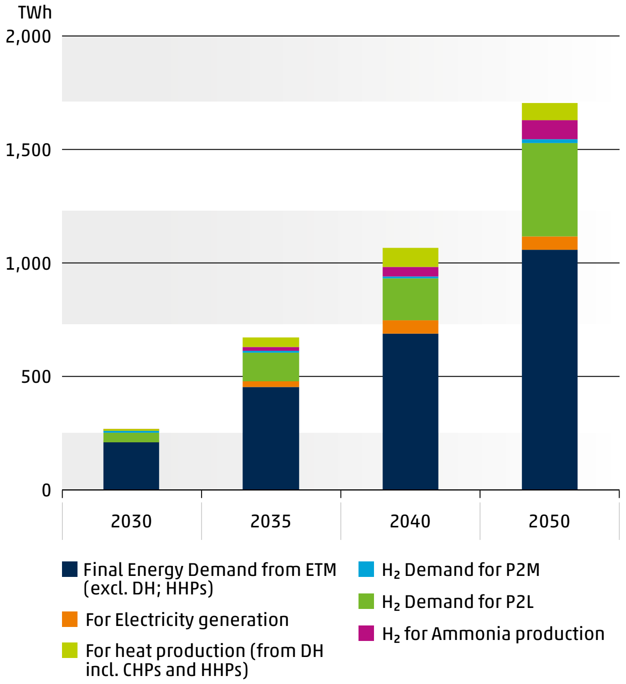

Figure 41: Total hydrogen consumption in TWh for NT+ (EU27)

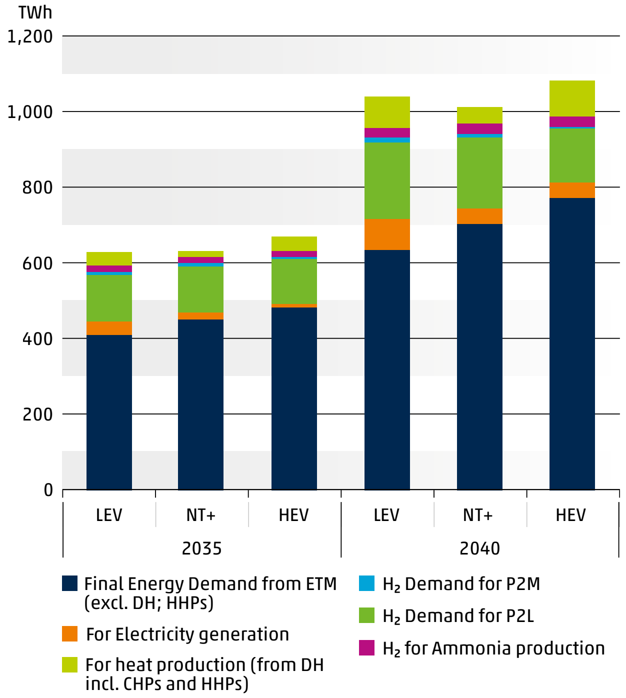

Figure 42: Total hydrogen consumption, Low/High Economic variant (EU27)

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[19] The graph only displays hydrogen quantities that need to be transported. All hydrogen that is produced on the same location as where it is consumed (which is most of the existing usage) is not visible as hydrogen demand in the figures. For on-site hydrogen production, the energy balance shows the associated feedstocks (oil, methane, etc.) instead.

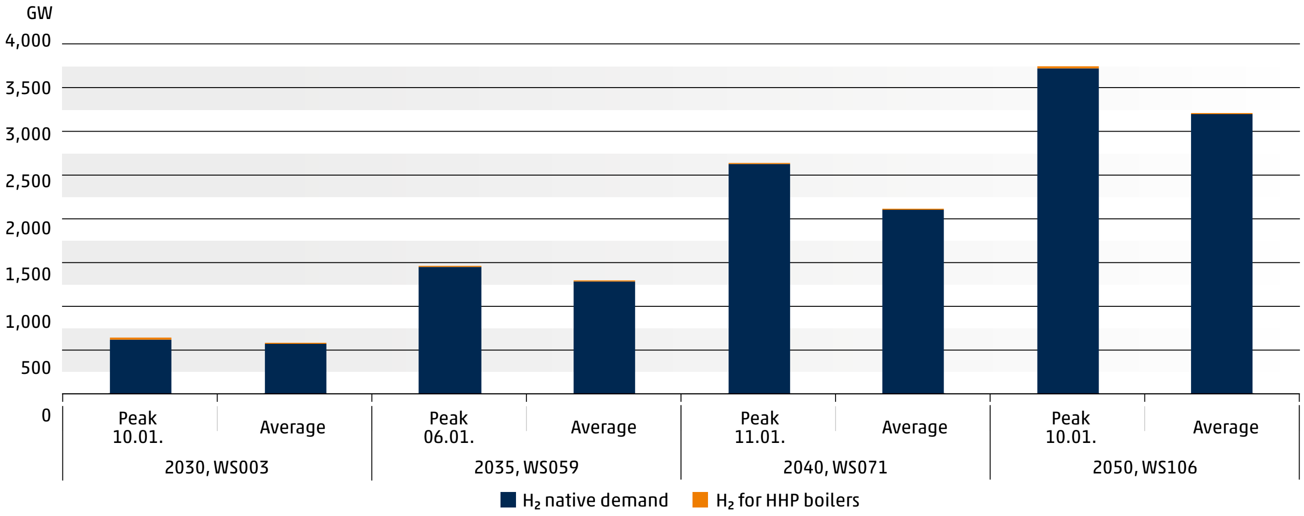

Figure 43: Hydrogen final demand on a peak and average day

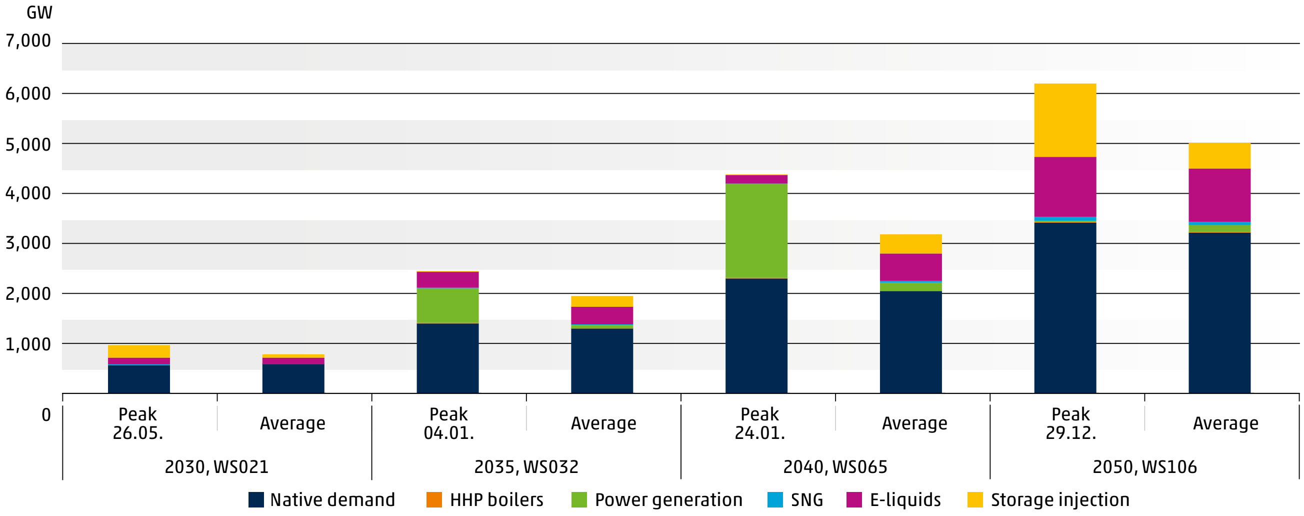

Figure 44: Hydrogen system load on a peak day compared to the yearly average

Figure 44 shows the load of the hydrogen system on a peak day, which considers final demand as well as demand for conversion and storage. While native hydrogen demand remains the largest component in most cases, conversion demand can become equally as important or even dominant during specific system situations. The utilisation of hydrogen fired power plants is particularly dependent on conditions in the electricity market, except for CHPs with must-run conditions. During periods of high renewable generation, most gas power plants are likely to operate only to a limited extent. The yearly average load of these facilities is rather small, due to relatively low full-load hours during the year. However, during dark periods with little wind, hydrogen power plants will operate intensively, which translates to a high load on peak days.

Consequently, hydrogen demand for power generation can become a major contributor to hydrogen system peaks. In the peak day of WS065 of 2040, 1,880 GWh are used for power generation, compared to a native demand of 2,301 GWh.

Hydrogen supply can also drive peak load of the hydrogen system. During periods with high renewable generation and high electrolysis output, excess hydrogen can be injected into storage, increasing total hydrogen system load, as shown in Figure 44. Sometimes the load from electrolysis supply leads to higher peaks than the peak demand situation, as shown for 2050. In contrast to the peak load days in 2035 and 2040, which are largely driven by hydrogen demand in power generation during tight market conditions and therefore show relatively limited storage injections, the 2030 and 2050 peaks are associated with surplus renewable generation, high electrolysis output, increased storage injections and greater conversion of hydrogen into synfuels.

For the economic variants in 2035 and 2040, peak load dynamics similar to NT+ can be observed, where peak situations are likewise primarily driven by hydrogen demand for power generation during tight market conditions. Figure 45 compares average load and peak load in the hydrogen system in the economic variants to the NT+ scenario. In the average-load cases, native hydrogen demand remains the dominant component of system load and increases from LEV to NT+ and further to HEV, in line with the economic variant assumptions.

In 2040, for example, average native hydrogen demand increases from around 1.9 TWh/d in the LEV to 2.3 TWh/d in the HEV. Part of this increase is then offset by changes in conversion demand, particularly for power generation and e-liquids production, resulting in smaller differences in total system load between the variants than differences in native demand alone would suggest. Figure 45 shows individual weather years (those with the highest peaks), whereas the previously discussed annual TEC figures are based on weighted averages across weather years.

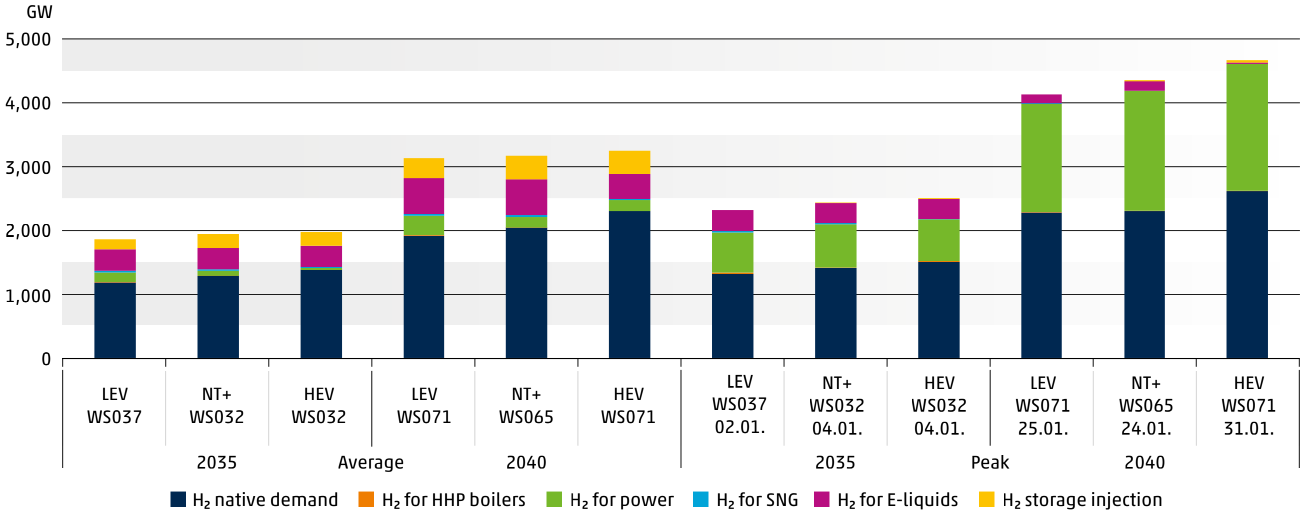

Figure 45: Hydrogen peak and average load in the economic variants (EU27)

Methane NT+ & Variants

Total methane demand in the NT+ case declines strongly over time, falling from around 3,200 TWh in 2030 to about 1,500 TWh in 2050. This reflects a structural shift away from methane in end-use sectors, only partially offset by continued use in power generation, district heating and low-carbon hydrogen production. Figure 46 shows total methane demand in the NT+ scenario for the EU27, broken down into final energy demand and the main conversion uses.

All main methane demand components decrease over the time horizon, but at different speeds. Final energy demand from the ETM (excluding district heating and hybrid heat pumps) falls from 2,224 TWh in 2030 to 1,032 TWh in 2050, illustrating the progressive substitution of methane in buildings, industry and other end-uses. Methane use in power generation drops from 604 TWh to 156 TWh between 2030 and 2050, and its use for heat production in district heating (including CHPs and HHPs) declines from 311 TWh to 138 TWh. In parallel, methane demand for low-carbon hydrogen production (blue SMR and pyrolysis) first increases, from 48 TWh in 2030 to 127–110 TWh in 2035–2040, and then reaches 206 TWh by 2050, while residual grey SMR use is phased out by 2050.

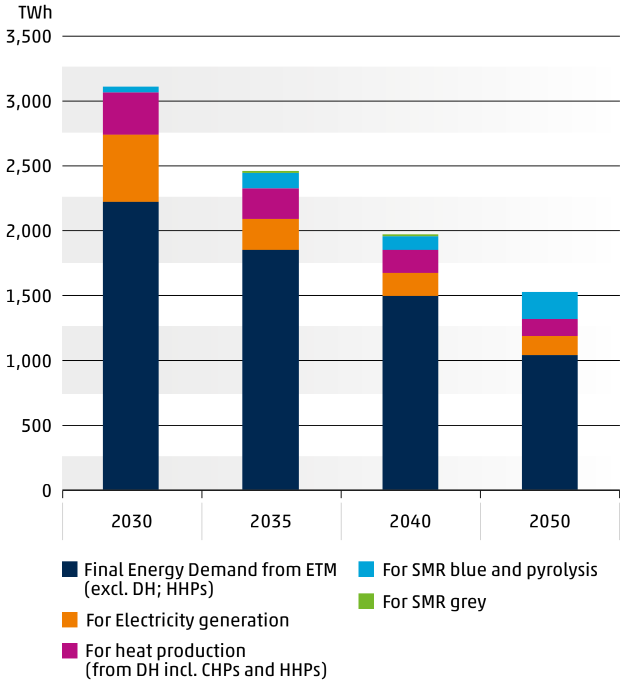

Figure 46: Total methane consumption in TWh for NT+ (EU27)

In the Economic Variants, methane demand diverges from NT+ in line with the methodology in Chapter 11 of the TYNDP 2026 Scenarios Methodology Report. In these variants, sustainable options such as electrification and hydrogen are scaled up or down, and methane-based technologies are the first to compensate for these changes in final demand. In the low-economic variant (LEV), final methane demand (excluding district heating and HHPs) is 1,949 TWh in 2035 and 1,635 TWh in 2040, slightly above NT+ (1,852 TWh and 1,499 TWh). In the high-economic variant (HEV), it is lower, at 1,767 TWh in 2035 and 1,367 TWh in 2040, reflecting faster phase-out of methane-based technologies in end-use sectors despite higher activity levels, as depicted in Figure 47.

Conversion uses of methane show a stronger spread across variants, driven by differences in native electricity and hydrogen demand. In 2035, methane use for power generation ranges from 146 TWh in LEV to 510 TWh in HEV, compared to 281 TWh in NT+. By 2040, the range is 69–375 TWh (LEV–HEV), with NT+ at 190 TWh. District-heating-related methane demand falls between 224 TWh (LEV) and 266 TWh (HEV) in 2035 and between 151 TWh and 199 TWh in 2040, versus 237 TWh and 177 TWh in NT+. Methane use for low-carbon hydrogen production via blue SMR and pyrolysis follows the same pattern: 26 TWh (LEV) to 141 TWh (HEV) in 2035, and 46 TWh to 159 TWh in 2040, compared to 127 TWh and 110 TWh in NT+. Residual grey SMR remains small in all cases but is lowest in LEV (1–2 TWh) and highest in HEV (28 TWh in 2035 and 17 TWh in 2040), with NT+ at 9 TWh in both years.

Overall, lower native electricity and hydrogen demand in LEV reduce the utilisation of gas-fired power plants, methane-based heat generation and SMR capacities, keeping total methane use below what would result from a like-for-like replacement of sustainable options. In HEV, higher native electricity and hydrogen demands lead to more frequent operation of gas-fired plants, higher methane use in district heating and increased SMR-related methane consumption, despite higher fuel and carbon prices. As a result, conversion-related methane use is significantly higher in HEV than in NT+, even though the long-term trend of declining methane use is preserved in all variants.

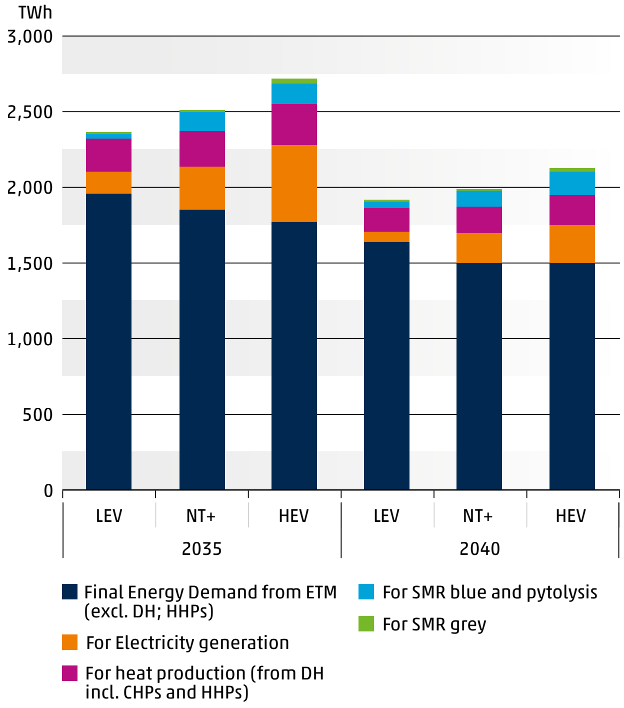

Figure 47: Total methane consumption, Low/High Economic variant (EU27)

Figure 48 provides a comparison on peak and average load on the methane system for National Trends +. Most sectors show a substantial difference between peak and average load, with steam methane reforming being the only exception. This illustrated the vast amount of flexibility that the gas system provides. Final demand has a strong seasonal profile with high load peaks in winter, due to the role of methane in residential and tertiary heating.

In the long term, the gas system remains important for seasonal flexibility, for instance with the use of hybrid heat pumps. Gas also provides flexibility to the electricity system via gas fired power plants, which are dispatched when supply from solar and wind is insufficient. Over time, the peak use for power plants reduces, in part due to a transition towards hydrogen in dispatchable generation.

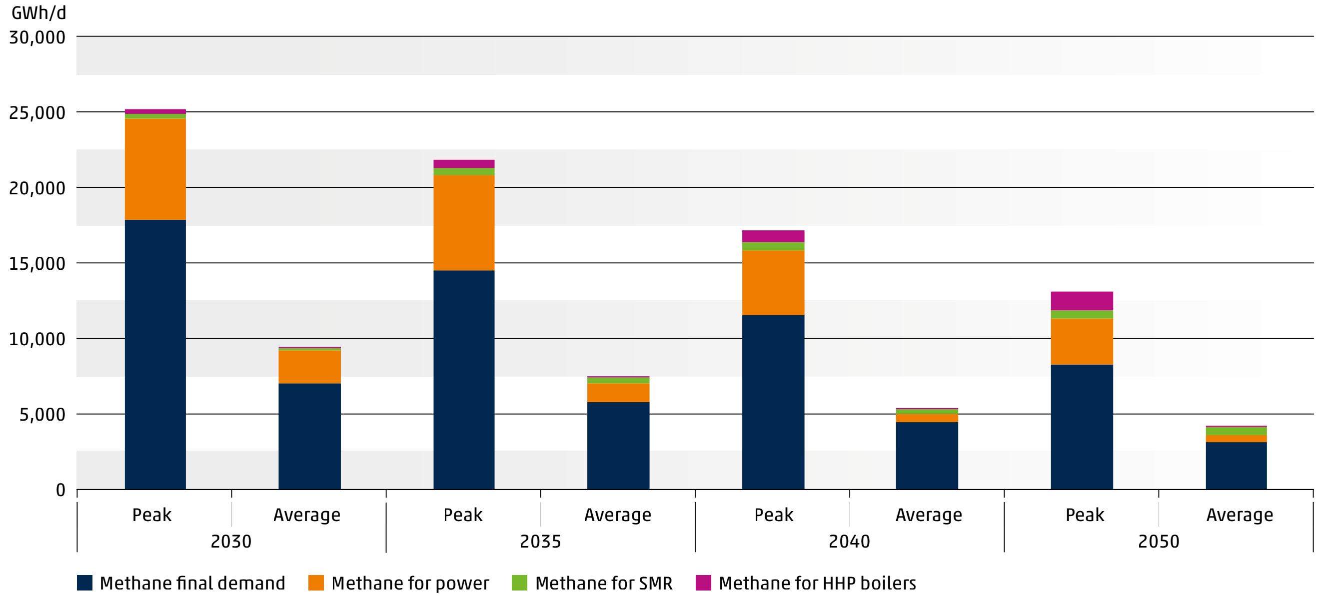

Figure 48: Methane demand on a peak day compared to the yearly average

9.2 Supply

This chapter provides an overview of the evolution of energy supply in the European Union within the TYNDP 2026 scenarios. It begins with total primary energy supply[20] in NT+ Scenario, setting out the overall decarbonisation trajectory characterised by declining fossil fuel use, increasing energy efficiency, and the expansion of renewable energy sources. Across this chapter, the study of the economic variants (LEV and HEV) highlights how different macroeconomic conditions primarily affect the scale of the energy system while leaving the structural transformation largely unchanged. The chapter then covers the evolution of the fossil fuel share, followed by a comprehensive analysis of electricity supply as a key vector of decarbonisation, including generation mix and flexibility needs.

The next dedicated sections subsequently address the transformation of gas and methane supply, the scale-up of hydrogen and the flexibility of operation in this vector, the role of e-fuels and biomass, and the evolution of energy imports, providing a consistent cross-carrier view of how different energy vectors contribute to the transition. Finally, the chapter includes a targeted sensitivity analysis focusing on hydrogen supply to complement the economic variants. This analysis assesses the robustness of the central scenario with respect to uncertainties in the balance between domestic production and imports.

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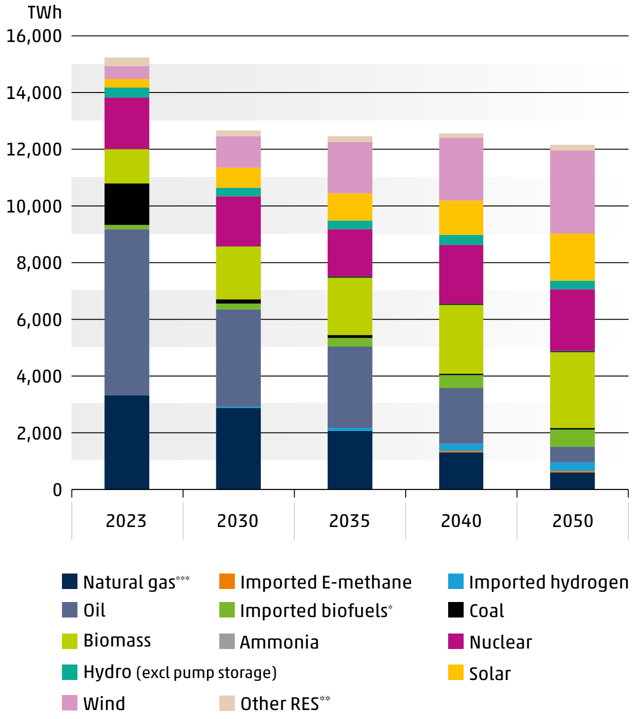
[20] In this TYNDP 2026 Scenario Building exercise, the definition of Primary Energy Supply is the gross inland consumption of all products. It includes the products used for electricity generation, transportation (including international maritime bunkers & international aviation), heat and non-energetic use.

Total primary energy supply in NT+ Scenario

The European energy supply decarbonises through the development of renewable capacities and implementation of energy efficiency measures. In the NT+ scenario, total primary energy supply is reduced by 16.87% by 2030 and 20.3% by 2050 compared to 2023 levels, despite increasing demand for electricity and synthetic fuels. This decline is driven primarily by the replacement of fossil fuels with more efficient low-carbon technologies and by structural efficiency gains across end-use sectors. Figure 49 illustrates the evolution of the EU27 primary energy supply mix in absolute terms. Fossil fuels decline rapidly over the period, with coal nearly phased out by 2035 and oil and natural gas volumes reduced by around 90% by 2050 compared to 2023. Natural gas progressively shifts from a dominant energy carrier to a residual and adequacy-oriented role, supporting system flexibility and security of supply rather than serving as a primary energy source.

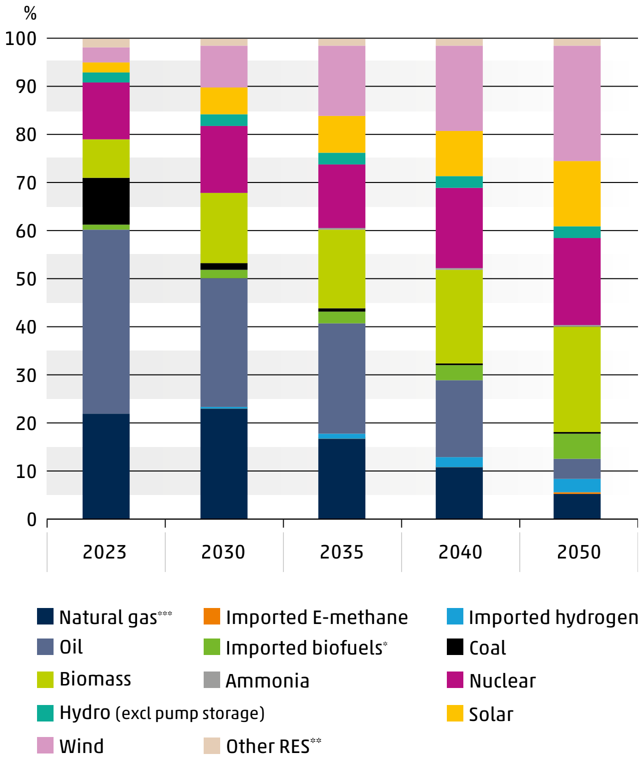
In parallel, Renewable Energy Sources (RES) expand substantially. Wind and solar increase more than twofold by 2030 and reach approximately seven- to eight-fold their 2023 levels by 2050, becoming the backbone of the EU energy system. Biomass and renewable gases (biomethane, biogas and synthetic methane) grow steadily, supporting decarbonisation in sectors that are more difficult to electrify.

While Figure 49 highlights the absolute decline in fossil energy volumes, Figure 50 shows the corresponding structural transformation of the energy mix. By 2050, RES account for roughly 70% of total primary energy supply, with wind and solar alone representing more than 35% of the total mix, compared to less than 5% in 2023. Nuclear energy remains relatively stable in absolute terms over the long term, but its share of total primary energy declines, reflecting the faster expansion of renewable generation. Hydropower remains broadly constant, continuing to provide a stable and dispatchable renewable contribution.



* Including Liquids (decarbonised), biomethane and biogas
** Other RES includes Tide, wave, ocean, geothermal & additionally ambient heat for historic datasets
*** Historic value includes non-renewable waste

Figure 49: Total Primary energy supply in TWh (including international maritime bunkers & international aviation & non-energy use)(EU27)



* Including Liquids (decarbonised), biomethane and biogas
** Other RES includes Tide, wave, ocean, geothermal & additionally ambient heat for historic datasets
*** Historic value includes non-renewable waste

Figure 50: Total Primary energy supply share (including international maritime bunkers & international aviation & non-energy use)(EU27)

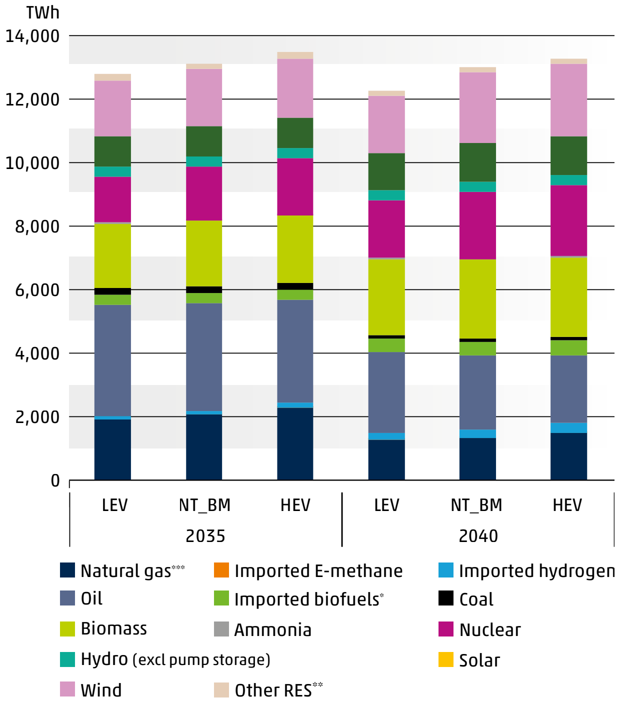
Total primary energy in the Economic Variants

The NT+ scenario serves as the main reference for this exercise, reflecting existing national policies and announced measures. Since the Economic Variants are derived from NT, they differ with NT+ Scenario when comparing total primary energy or carriers affected by the gap-filling methodology (explained in the associated chapter from the methodology report). To better assess the economic variants in those two sections, the NT Benchmark (NT BM)[21] was developed to be used as an ancillary reference. NT Benchmark positions itself between the HEV and the LEV, enabling a systematic exploration of sensitivities related to macro-economic developments.

As shown in Figure 51, higher economic growth in HEV results in a larger energy system, with higher absolute primary energy supply volumes across most energy carriers, particularly electricity-based renewables, hydrogen and biomethane. Fossil fuel demand declines more slowly in absolute terms, especially in hard-to-abate industrial and transport segments, leading to higher residual use of oil and natural gas in 2035 and 2040. Conversely, LEV results in a smaller energy system. Lower industrial activity and transport demand significantly reduce oil and natural gas consumption, while renewable deployment proceeds at lower absolute volumes. The overall energy mix remains structurally similar to NT.

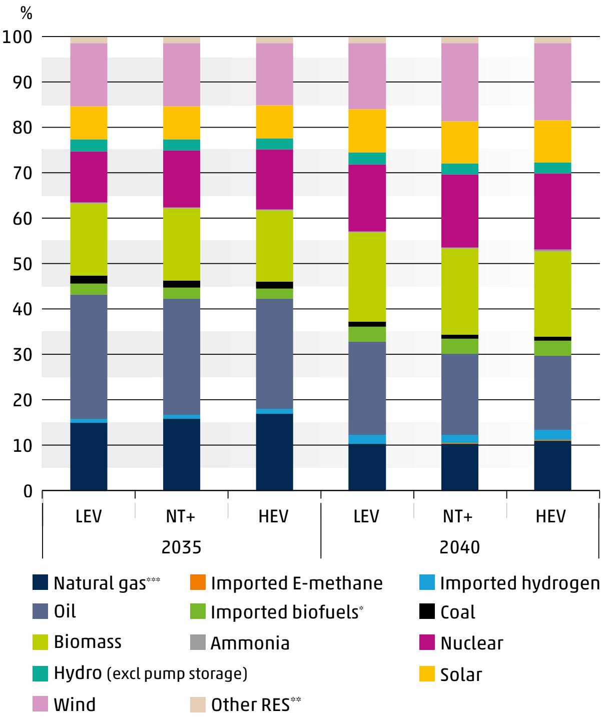
Figure 52 shows the percentage contribution of fossil fuels, nuclear, and RES (including biomass, wind, solar, hydro, and other RES) to total primary energy supply.

Figure 52 confirms that economic growth assumptions primarily affect absolute volumes rather than the relative composition of the energy mix. Across all variants, RES consistently dominate primary energy supply by 2040, indicating that the direction of the energy transition remains robust under different macro-economic conditions. Overall, the comparison shows that economic growth assumptions primarily affect total energy volumes, rather than the direction of the energy transition. HEV and LEV define upper and lower bounds for demand, investment and system sizing, supporting future robustness testing of scenario outcomes within the TYNDP framework.



* Including Liquids (decarbonised), biomethane and biogas
** Other RES includes Tide, wave, ocean, geothermal & additionally ambient heat for historic datasets
*** Historic value includes non-renewable waste

Figure 51: Primary energy supply mix in the EU27 under the NT Benchmark (NT BM), High Economy Variant (HEV) and Low Economy Variant (LEV) for 2035 and 2040 (TWh)



* Including Liquids (decarbonised), biomethane and biogas
** Other RES includes Tide, wave, ocean, geothermal & additionally ambient heat for historic datasets
*** Historic value includes non-renewable waste

Figure 52: Primary energy supply mix in the EU27 under NT Benchmark (NT BM), Low (LEV) and High (HEV) economic variants for 2035 and 2040.

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[21] To provide an intermediate comparison for the primary energy supply graph, an "NT Benchmark" reference is used. This benchmark is an intermediate reference constructed by using a combination of two different sources into the supply tool, using pre-gap-filling data (NT) and some NT+ Scenario results from model runs. It has to be noted that this reference is not a developed Scenario, and its sole purpose is to help understand the LEV and HEV for the supply part of this exercise in a more complete context.

Fossil fuel share in NT+ Scenario

TYNDP scenarios show a pronounced shift in the primary energy supply towards renewable sources (Figure 53). In the NT+ Scenario, the share of RES in the total primary energy supply reaches 72% by 2050. Renewable supply is dominated by wind and solar photovoltaic generation, complemented by biomass and energy recovered from waste. Low-carbon sources, notably nuclear energy and blue hydrogen, also contribute to the decarbonisation of the energy system. Together, these sources account for around 18% of the total primary energy supply in the NT+ Scenario. In parallel, the share of fossil fuels declines significantly over time. By 2050, coal represents only 0.2% of the total primary energy supply, while oil accounts for 4.4%. The remaining oil demand is largely concentrated in hard-to-abate segments, including international aviation and maritime bunkering, as well as non-energy uses.

The evolution of the primary energy supply mix reflects a structural transition from a system historically dominated by fossil fuels to one largely based on RES. Although fossil fuels currently account for around 70% of the primary energy supply, their role is steadily diminishing as the energy system is reshaped by electrification, efficiency improvements and the large-scale deployment of renewable generation. By 2040 and beyond, renewables will form the backbone of the primary energy supply, with fossil fuels being confined increasingly to residual demand in specific sectors where substitution remains challenging. This shift is fundamental to the long-term decarbonisation trajectory and has significant implications for infrastructure planning, system flexibility and security of supply.

Fossil fuel share in the Economic Variants

Under the LEV, fossil fuel use remains higher, primarily driven by a stronger persistence of oil consumption. In contrast, the HEV shows a comparatively higher reliance on fossil fuels linked to natural gas, associated with higher energy demand under stronger economic growth.

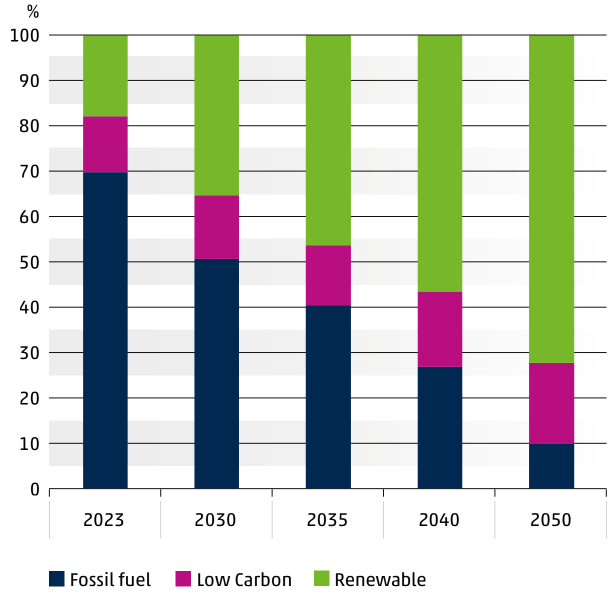

Figure 53: Share of fossil, low carbon and renewable energy in EU27 total primary energy supply (including international maritime bunkers & international aviation & non-energy use)

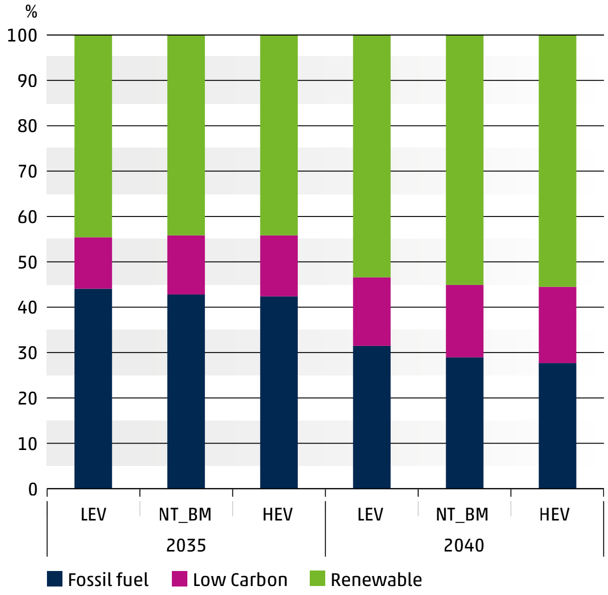

Figure 54: Economic Variants vs NT Benchmark. Share of fossil, low carbon and renewable energy in EU27 total primary energy supply (including international maritime bunkers & international aviation & non-energy use) Electricity supply

Electricity supply NT+ scenario

In the NT+ scenario, one of the main vectors for the decarbonisation of the energy system is electricity: final demand nearly doubles by 2050, variable renewables supply most energy, and a portfolio of firm low-carbon generation and flexibility options help ensure adequacy under increasingly climate-dependent operating conditions. As can be seen in Figure 23, total electricity demand is expected to increase, driven by direct higher shares of electrification and an expansion in the production of renewable fuels through electrolysis. By 2050, the electricity required for electrolysis is expected to represent around 20% of the total electricity demand in the NT+ scenario. The generation figures presented in this chapter therefore reflect total electricity requirements, encompassing both final consumption and electrolysis-related demand.

Figure 55 distinguishes final electricity consumption (including transmission and distribution losses) from electricity demand for hydrogen and synthetic fuel production via electrolysis. The NT+ scenario assumes a rapid decarbonisation of electricity generation over the assessment horizon, as illustrated in Figure 56. By 2035, around 96% of total electricity generation in the EU27, (including electricity used for electrolysis) is expected to be delivered by RES (i.e. wind, solar), nuclear and gas-fired power plants supplied with renewable and decarbonised gases. Toward 2050, variable RES become the backbone of the electricity system, accounting for around 75% of total electricity generation, compared with 53% in 2030 and 30.7% in 2025. Firm low-carbon technologies continue to complement variable generation, ensuring system adequacy and security of supply. As a result, electricity generation is nearly fully decarbonised by 2050, with only a very limited residual contribution from carbon-emitting sources.

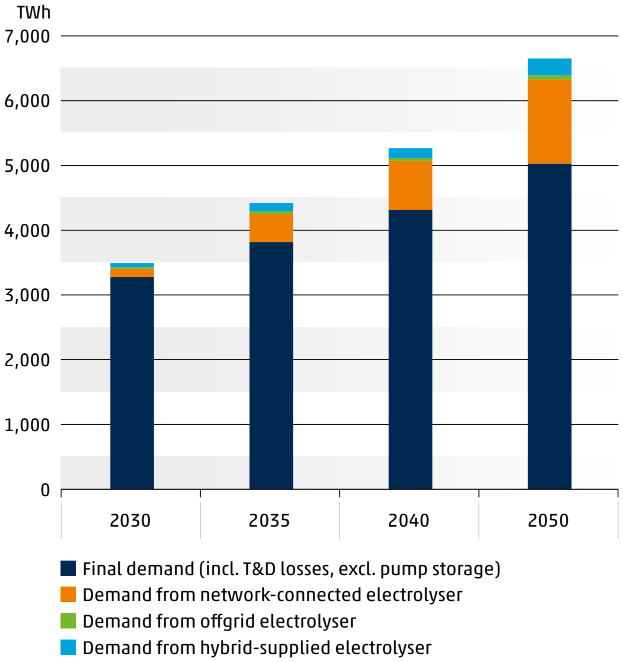

Figure 55: Evolution of total electricity demand in the EU27 under the National Trends+ (NT+) scenario

Hybrid electrolysers' electricity demand is supplied mainly by dedicated or on-site renewable generation; remaining demand is met by the electricity grid

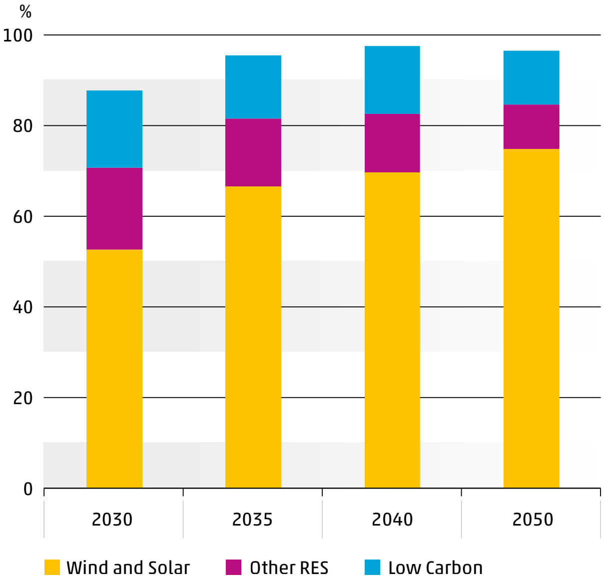

Figure 56: Share of total electricity generation covered by RES and low-carbon technologies in the EU27 NT+ scenario

Meeting the strong growth in electricity demand requires a substantial expansion of generation and storage capacity across all target years (Figure 57). Wind and solar capacities increase sharply, reaching around 1,086 GW in 2030 and 2,041 GW by 2040. This expansion is essential to meet decarbonisation, energy efficiency, and renewable energy targets, as well as to supply electricity for renewable fuel production to replace fossil fuels. While wind and solar represent the dominant capacity additions, they are complemented by other RES such as hydro and biomass, with hydro remaining the most significant among them. Firm low-carbon capacities, notably nuclear and hydrogen-fired power plants, remain an integral part of the system, ensuring adequacy and resilience in a system with high shares of variable renewables (Figure 57).

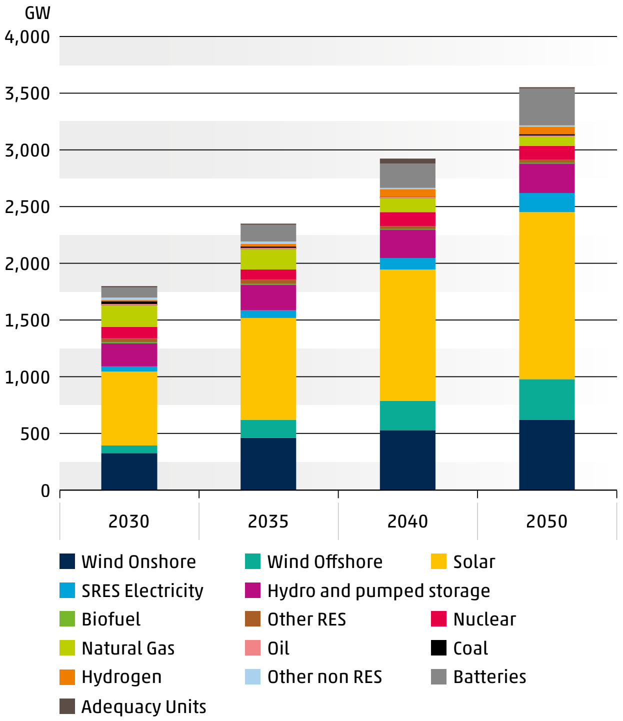

Figure 57: Installed electricity generation and storage capacity mix in the EU27 across the assessment years in the NT+ scenario

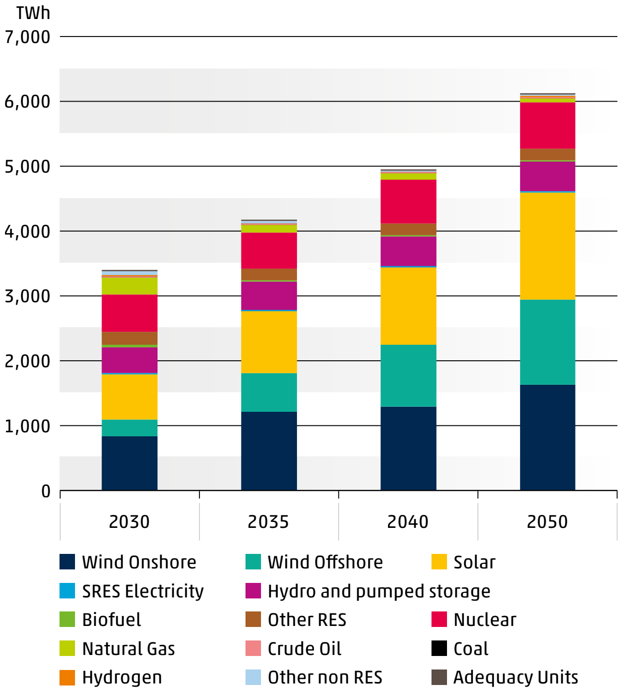

Figure 58: Electricity generation by technology in the EU27 NT+ scenario

For Denmark, a significant share of offshore wind capacity included in the scenarios corresponds to energy islands intended for export, for which no bilateral agreements or grid connection configurations are defined at this stage. In order to enable subsequent Offshore Network Development Plan (ONDP) assessments, these offshore installations are therefore represented without connection to any onshore system. As a consequence, these specific offshore nodes are included in the dataset with offshore wind and electrolysis capacity, but no offshore generation is assigned in the scenario modelling, resulting in zero modelled generation. The installed capacity of offshore wind and electrolysis associated with these nodes is reported in Annex VII.

Coal and lignite are progressively phased out under the combined effect of national phase-out policies and increasing CO_2 prices along the ETS trajectory, becoming almost negligible in electricity generation from 2030 onwards. Gas-fired power generation undergoes a structural change in its system role22. While total electricity generation from gas decreases significantly towards 2050 (Figure 58), gas-based technologies increasingly provide flexibility rather than baseload energy. Methane is progressively decarbonised through rising shares of biomethane and synthetic methane, while hydrogen-fired power plants expand substantially over time (Figure 59).

The declining average full-load hours of both methane- and hydrogen-fired power plants (Figure 60) reflect their evolving role as dispatchable and adequacy-providing resources, activated primarily during periods of low renewable generation. Despite lower utilisation levels, these units remain essential in covering prolonged periods of scarce renewable output, during which they can be fully dispatched.

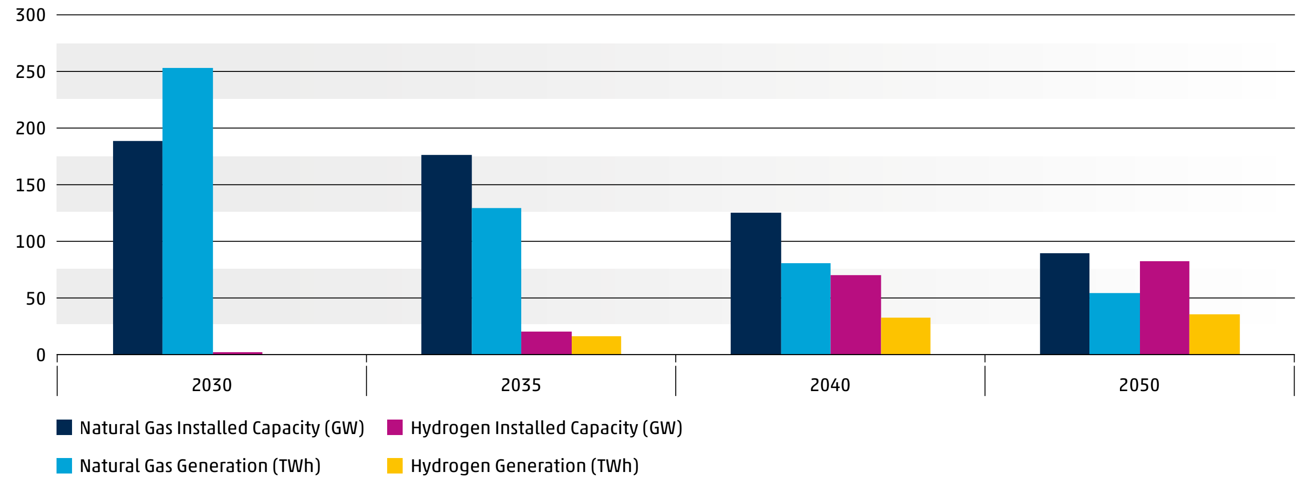

Figure 59: Evolution of installed capacity and annual electricity generation from methane- and hydrogen-fired power plants in the EU27 NT+ scenario

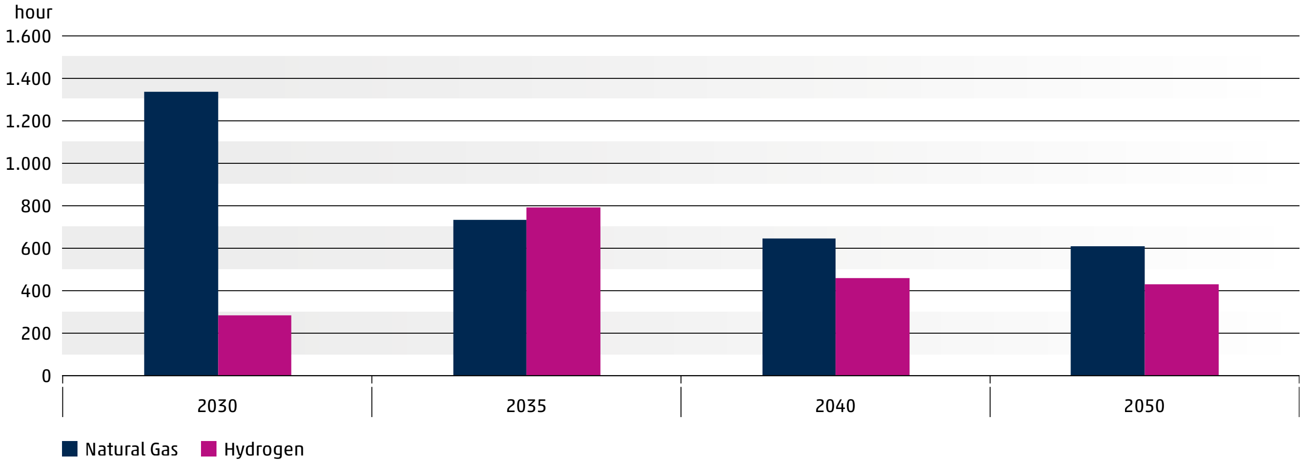

Figure 60: Average annual full-load hours of methane- and hydrogen-fired power plants in the EU27 NT+ scenario

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22 Excluding Small Thermal and CHP which operation can be driven by factors such as heat production.

High shares of variable renewable generation are supported by a diverse portfolio of flexibility solutions. Short-term flexibility is provided by batteries, pumped hydro storage, demand-side response, flexible operation of electrolysers, and electric vehicle charging, including vehicle-to-grid (V2G) services (Figure 61). These flexibility options substantially reduce the need for thermal generation to operate at high load factors, shifting its role towards system adequacy.

For longer periods of time where flexibility needs arise, such as weeks where Dunkelflaute conditions are given, the use of cross-border interconnections and dispatchable resources ensure system adequacy. In this context, interconnectors and gas and hydrogen-based technologies play a central role in providing flexibility and ensuring supply.

Potential limitations that may affect the feasibility of the identified flexibility options should be further and more thoroughly assessed in forthcoming TYNDP scenario cycles, as well as in complementary assessments such as the European Resource Adequacy Assessment (ERAA).

Flexibility requirements are expected to increase, together with the diversity of technologies contributing to their provision. The electrification of the heating sector and the continued deployment of wind and solar generation will increase the climate dependency of the electricity system. At the same time, the effects of global warming on weather variability are already observable. Consequently, the decarbonisation of the electricity mix must be accompanied by the parallel development of flexibility solutions in order to preserve security of supply. The extent of the flexibility needs and the development of technologies to meet depend on the scenario assumptions. The scenario shows a joint usage of upstream flexibility (generation side) and downstream flexibility (consumer side) to adequate for the evolving needs of the electricity system.

The development of prosumer behaviours will result in a high development of residential batteries and V2G services providing short term storage solutions. Finally, the need to produce synthetic fuels to help achieve decarbonisation targets may also offer the opportunity of seasonal flexibility by coupling the electricity and hydrogen systems. Electrolysis and hydrogen storage will then be beneficial to the security of the energy system.

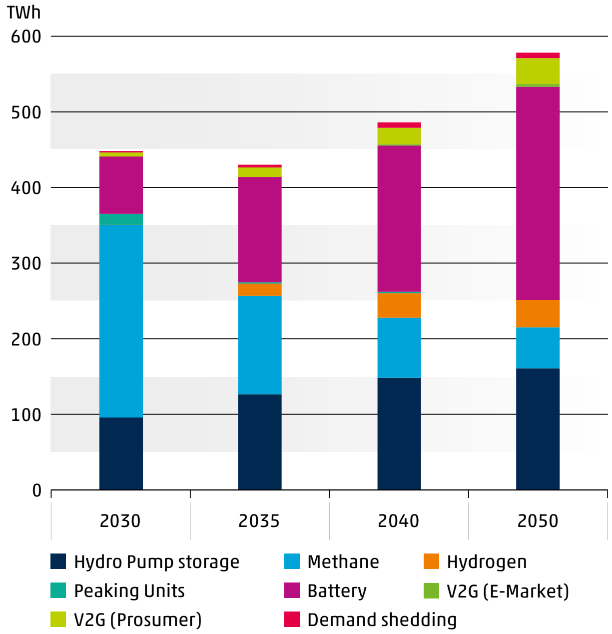


Figure 61: Contribution of key flexibility sources to electricity system balancing in the EU27 NT+ scenario. Peaking units encompass Coal, Crude Oil and Adequacy Units

The scenario shows a flexible consumer behaviour, with PV-connected household batteries and bidirectional usage of electric vehicles. In addition to that, utility-scale batteries are used in the same order of magnitude as hydro pump storages. As a takeaway, the results of this exercise show that system adequacy is ensured through a combination of storage, demand-side flexibility and firm generation.

The increasing relevance of climate conditions for system operation is illustrated through detailed simulations of representative weather situations. In Figures 62, 63 and 64 below, hourly dispatch results for 2040 show how the system maintains balance during periods of high winter demand as well as during prolonged episodes of low wind and solar generation (Dunkelflaute).

These examples highlight the critical contribution of firm low-carbon generation, storage, and demand-side flexibility in preserving security of supply under stressed operating conditions.

Overall, the NT+ scenario illustrates a credible pathway towards a highly electrified, nearly fully decarbonised, and climate-resilient European power system by 2050, in which large-scale deployment of renewable energy is complemented by firm low-carbon generation and an expanding portfolio of flexibility solutions to ensure long-term security of supply.

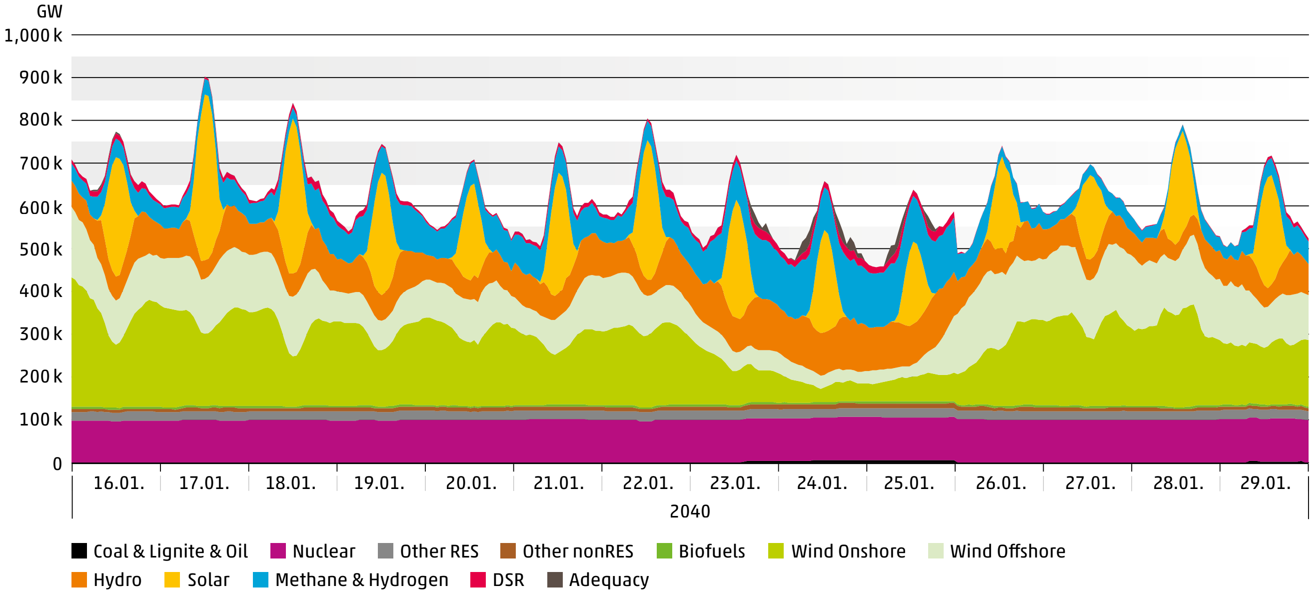


Figure 62: Hourly electricity system balance during a winter period with high electricity demand in the EU27, illustrating the combined contribution of renewable generation, firm low carbon sources, storage, and flexibility options under peak load conditions

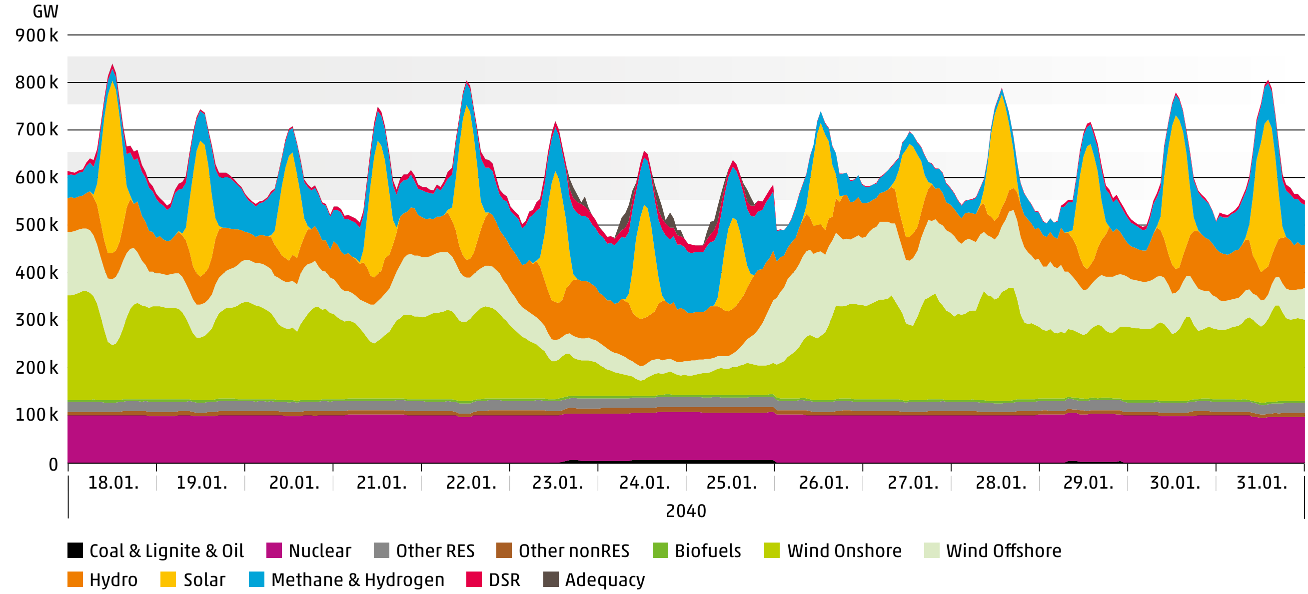


Figure 63: Hourly electricity system balance during a prolonged period of low wind and solar generation (Dunkelflaute) in the EU27. The figure highlights the critical role of the firm and flexible generation, storage, and demand side measures in preserving security of supply

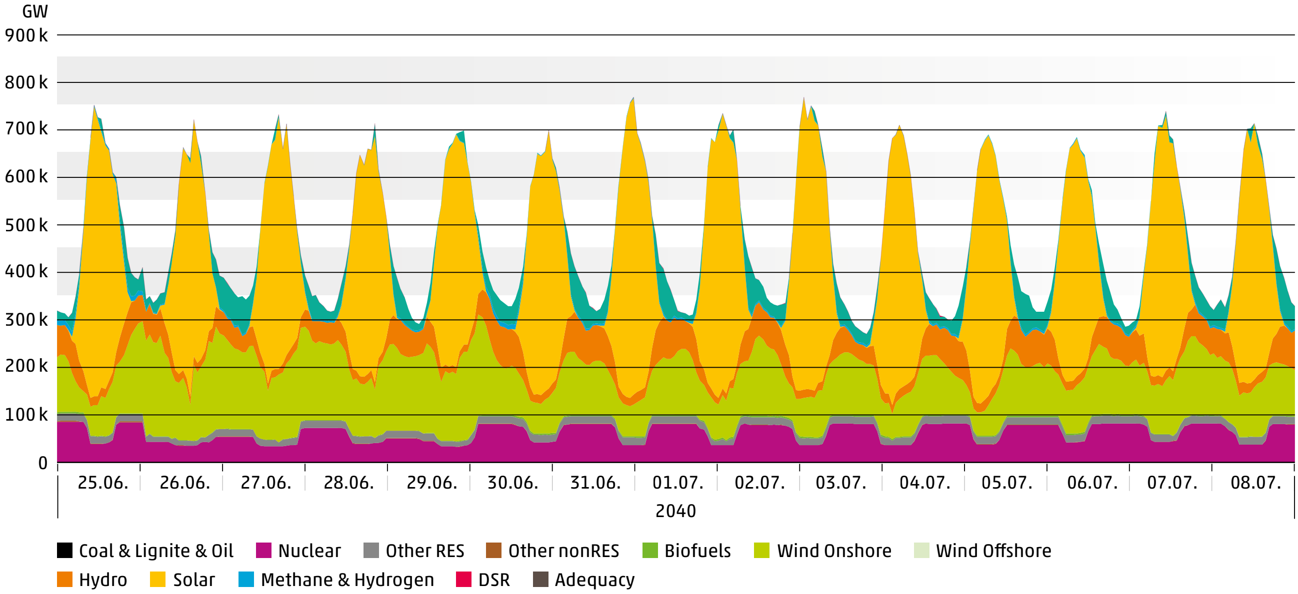


Figure 64: Hourly electricity system balance during a typical summer period in the EU27, characterised by high solar generation and increased use of storage and flexible demand to accommodate variable renewable production.

Electricity supply variants

Electricity supply variants are designed as economic stress-tests of the central scenario, providing a structured assessment of how alternative demand and cost trajectories affect the evolution of the electricity generation mix, the role of firm capacity, and the level of flexibility required to ensure system adequacy and security of supply. The variants explore the robustness of the electricity system under lower (LEV) and higher (HEV) electricity demand and electrification assumptions compared with the National Trends + (NT+) scenario (Figure 65).

Across all variants, electricity plays a central role in the decarbonisation of the European energy system, driven by direct electrification and the growing use of electricity for the production of renewable and synthetic fuels through electrolysis. Differences between variants primarily affect the scale and timing of capacity deployment, rather than the overall direction of system transformation.

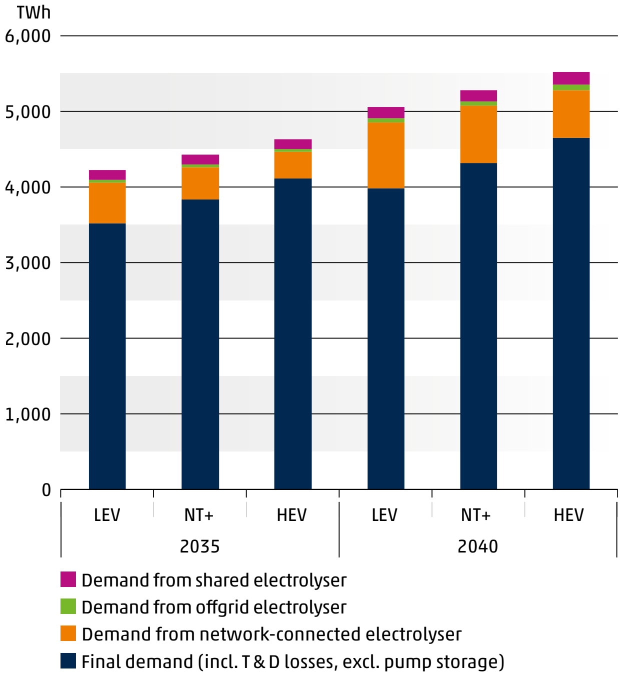


Figure 65: Evolution of total electricity demand in the EU27 under the National Trends+ (NT+) scenario and Economic Variants, distinguishing final electricity consumption (including transmission and distribution losses) from electricity demand for hydrogen and synthetic fuel production via electrolysis

The generation mix remains strongly aligned across variants (Figure 66). Variable RES (wind and solar) provide the dominant share of electricity generation in all cases. By 2035, wind and solar jointly account for approximately 65–70% of total generation, increasing further towards 2040. The HEV variant shows a slightly lower renewable share, reflecting higher levels of dispatchable generation required to meet peak demand and flexibility needs.

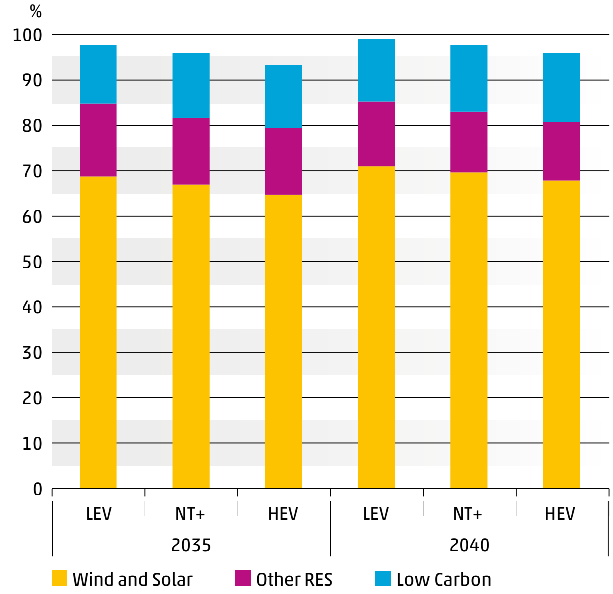


Figure 66: Share of total electricity generation covered by RES and low-carbon technologies in the EU27 NT+ scenario and Economic Variants

Electricity supply scope of the Economic Variants confirms a rapid phase-out of fossil fuel-based electricity generation (Figure 67):

- Natural gas-fired power plants undergo a structural change in their system role, shifting away from baseload generation towards flexibility and adequacy provision.
- Methane is progressively decarbonised through increasing shares of biomethane and synthetic methane.
- Hydrogen-fired power plants usage expands across Low Economy variants, partially offsetting the decline in methane-fired usage.
- Nuclear generation remains a key source of firm low-carbon electricity. While absolute nuclear output varies, its contribution provides stability and predictability to the system in all cases.
- Other RES, including hydro and biomass, continue to play an important complementary role, with hydro providing both renewable generation and system flexibility.

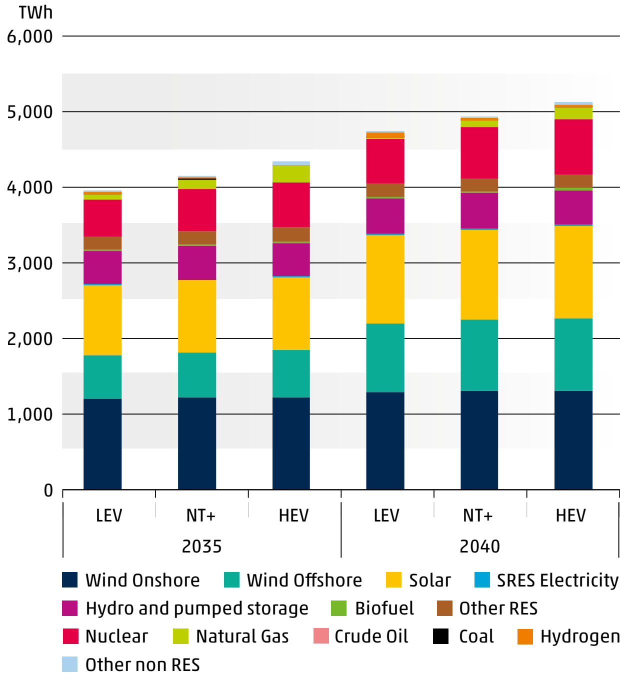


Figure 67: Electricity generation by technology in the EU27 NT+ scenario and Economic Variants

The HEV variant shows the highest reliance on dispatchable capacity and flexibility, reflecting higher electricity demand and peak load levels, while the LEV variant relies more strongly on variable renewables and downstream flexibility (Figure 68 and Figure 69).

Hourly dispatch simulations demonstrate that, across the variants and target years, the electricity system is able to maintain balance during periods of high demand and during extended periods of low wind and solar generation. Firm dispatchable low-carbon generation, storage technologies, and demand-side flexibility jointly ensure adequacy, highlighting the resilience of the system architecture assumed in the scenarios.

Overall, the electricity supply variants confirm that:

- The direction of decarbonisation is robust across the studied range of demand and electrification assumptions.
- Firm dispatchable low-carbon generation and flexibility solutions are indispensable, irrespective of the variant, to preserve security of supply in a highly renewable and climate-dependent electricity system.
- The combined deployment of renewable generation, storage, flexible demand, and dispatchable low-carbon capacity provides a credible and resilient pathway towards a mostly decarbonised European electricity system by 2050.

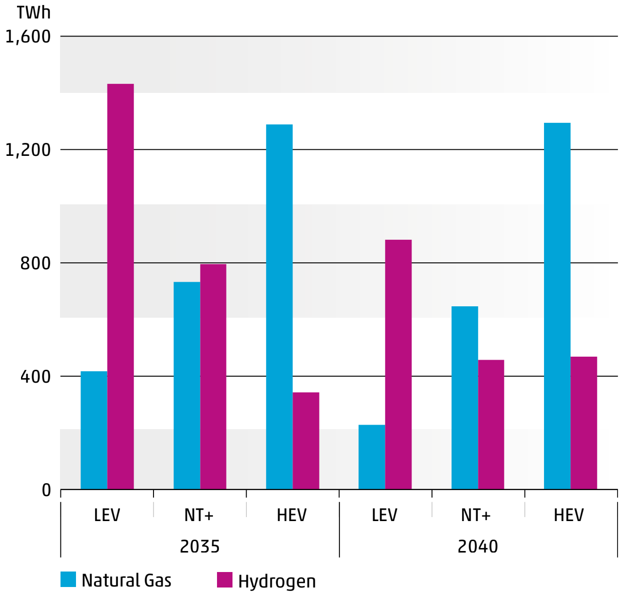


Figure 68: Average annual full-load hours of methane- and hydrogen-fired power plants in the EU27 NT+ scenario and Economic Variants

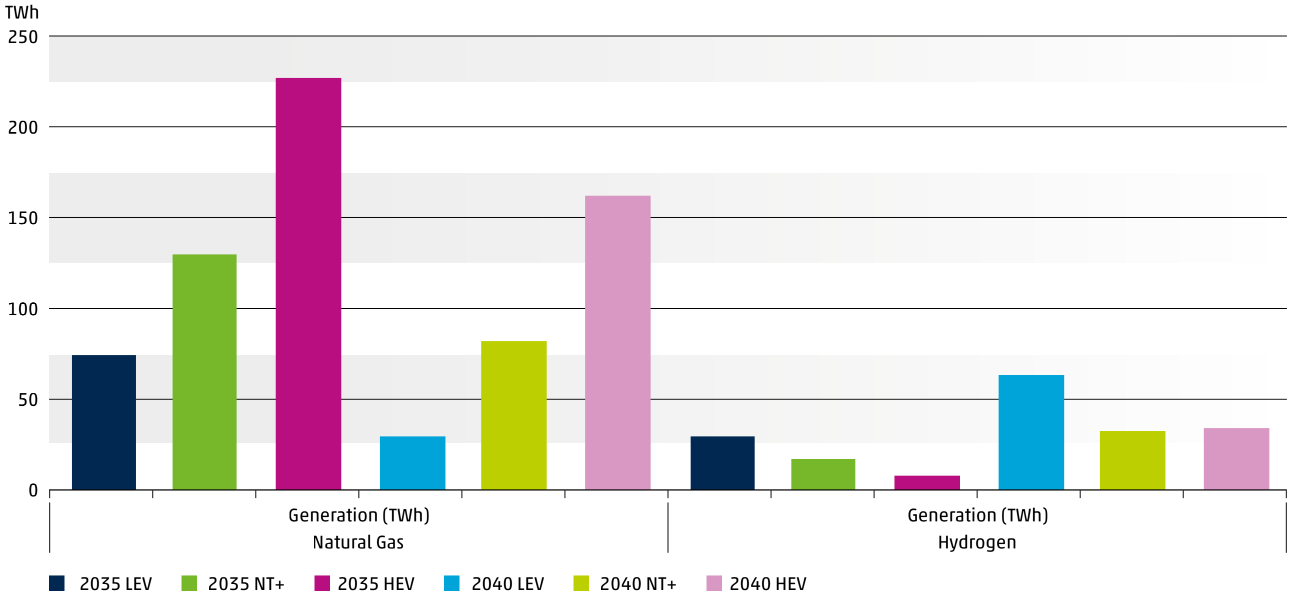


Figure 69: Evolution of annual electricity generation from methane and hydrogen-fired power plants in the EU27 NT+ scenario and Economic Variants

Gas and Methane supply in NT+ Scenario

Figure 70 provides an overview of the methane supply in the NT+ scenario together with the current figures. Total methane supply declines steadily towards 2050, reaching approximately half of the 2030 level. While domestic natural gas production decreases continuously and is almost phased out by 2050, domestic biomethane production increases substantially, reaching around 800 TWh/year and becoming the largest component of methane supply.

Over the same period, imports of natural gas decline significantly, falling from nearly 2,500 TWh/year in 2030 to approximately 600 TWh/year in 2050. Domestic e-methane production plays only a minor role throughout the period, whereas imports of e-methane increase steadily towards 2050.

As shown in Figure 71 and Figure 72. The increasing share of biomethane and e methane, primarily produced domestically, more than compensates for the decline in domestic natural gas production.

The reduction in methane imports highlights the importance of domestic renewable methane production for enhancing the energy independence of the EU. Furthermore, the growing share of renewable gases in the gas system underlines their crucial role in the decarbonisation of the EU energy system.

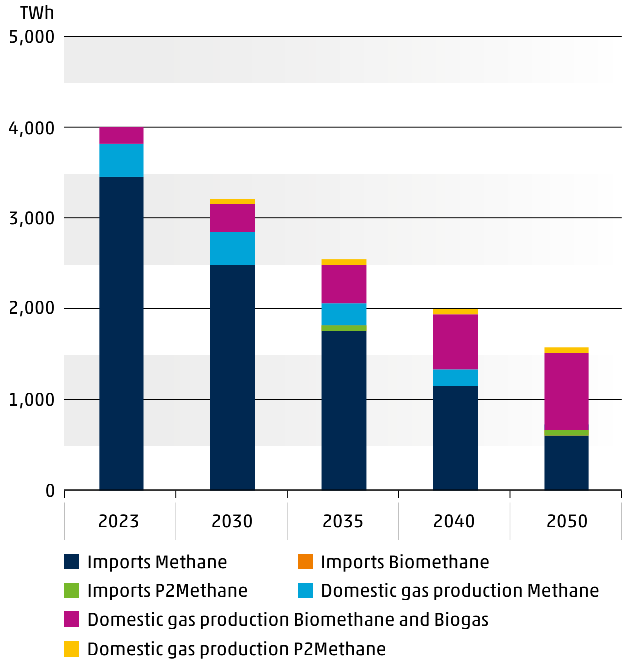


Figure 70: Overview of methane supply in the EU27 under the NT+ scenario, showing the evolution of domestic production and imports of natural gas, biomethane, and e-methane between 2030 and 2050.

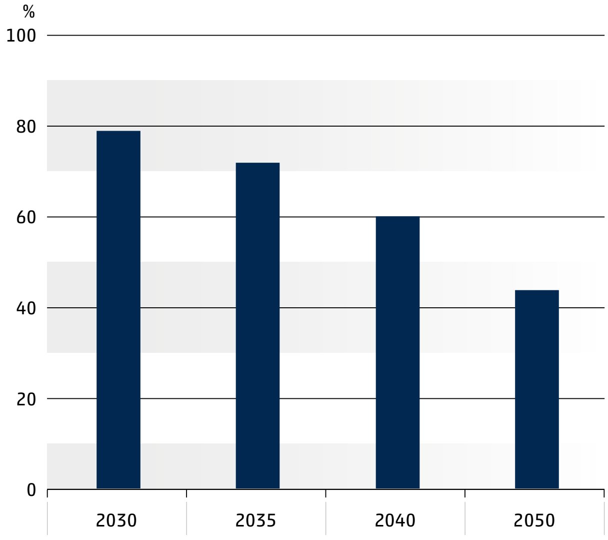


Figure 71: Share of imported methane in total methane supply in the EU27 under the NT+ scenario, highlighting the declining reliance on imports between 2030 and 2050.

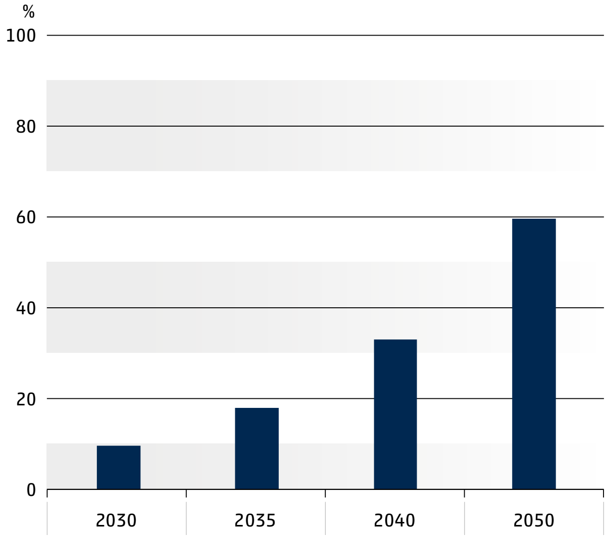


Figure 72: Share of renewable methane in the methane grid in the EU27 under the NT+ scenario, illustrating the increasing contribution of biomethane and e-methane towards 2050.

Gas and Methane supply in the Economic Variants

The main differences between the variants and the NT+ scenario are observed in the total methane supply. The high economic variant exhibits the highest demand, while the low economic variant shows the lowest. As domestic supplies of natural gas and biomethane are fixed based on the data assumptions, the only factor contributing to these differences is the level of imported natural gas.

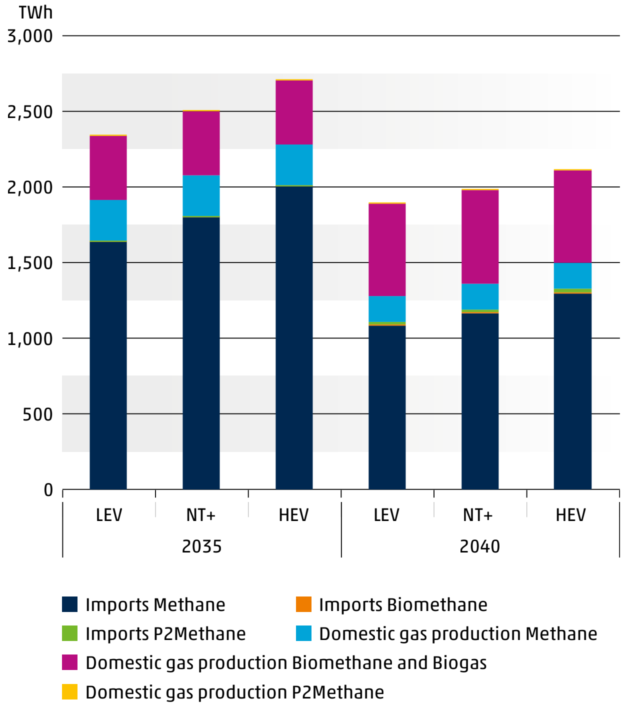


Figure 73: Methane supply, Low/high economic variants (EU27)

Hydrogen supply and generation in NT+ Scenario

Today hydrogen is mainly used as a feedstock in the chemical and fertiliser industry in the EU. The Hydrogen is mainly produced with SMR/Autothermal Reforming (ATR) (90%) while the remaining volumes are from by-products from other industrial processes (8%) and only a small fraction is produced with water electrolyses or reforming with CCS. In the NT+ scenario, the EU energy system increasingly integrates hydrogen as an energy carrier towards 2050. As described in detail in the demand section the hydrogen consumption growth is expected in energy conversion (power generation, synthetic fuels production), and its role as a feedstock in industrial processes will grow as well, but in a more limited way.

As shown in Figure 74, the supply of hydrogen is growing from around 250 TWh in 2030 to more than 1,600 TWh in 2050. The hydrogen in the NT+ scenario is mainly produced by electrolysers in EU, while imports via ships or pipelines as well as SMR with CCS will be less used sources. SMR without CCS and Pyrolysis were hardly used and only present in a few countries.

The share of imported hydrogen is highest in 2030 (27%) and lowest in 2035 (18%), but in absolute figures the volume of imports increases from 69 TWh in 2030 to 237 TWh in 2050 (see Figure 75).

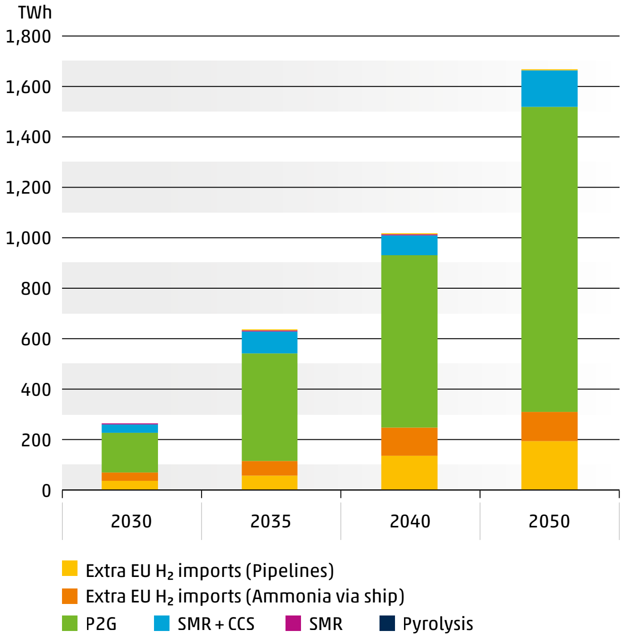


Figure 74: Hydrogen Supply grouped by Sources (Including UK balance)

The graph only displays hydrogen quantities that need to be transported. All hydrogen that is produced on the same location as where it is consumed (which is most of the existing usage) is not visible as hydrogen demand in the figures. For on-site hydrogen production, the energy balance shows the associated feedstocks (oil, methane, etc.) instead.

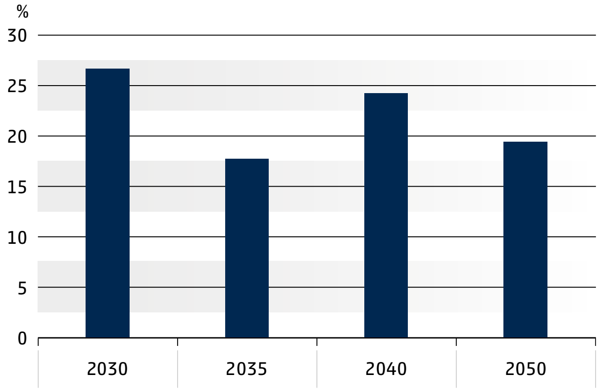


Figure 75: Imported Hydrogen Share

Hydrogen import corridors

Table 2 below the hydrogen corridors used are used is displayed to show the origins of the imported hydrogen.

In the initial target years (2030 and 2035), pipeline imports are limited to Italy and Ukraine, with Italy accounting for the largest share. By 2040, additional infrastructure will become operational, notably the Morocco–Spain connection, enabling hydrogen transport to Europe. Furthermore, a connection to the United Kingdom will support system balancing within the EU. In both 2040 and 2050, the UK is expected to function as an additional hydrogen supply source for the EU.

Table 3 presents import hydrogen volumes transported via ships, including their points of arrival. The data shows that the Netherlands, Belgium, and Germany act as early movers in the import of ammonia (liquefied hydrogen) and remain the dominant importers across all target years.

France is expected to scale up its ammonia imports at a later stage but will reach substantial import volumes by 2040 and 2050. Greece and Italy are projected to begin ammonia imports around 2040. In contrast, Poland remains the smallest importer throughout all considered target years.

TWh/YEAR	2030	2035	2040	2050
Morocco - Spain	0.0	0.0	17.4	19.9
Algeria and Tunisia - Italy	26.2	44.8	76.1	84.0
Ukraine - Slovakia	10.6	10.6	19.5	17.6
UK - Belgium*	0.0	0.0	22.2	73.0
Total	**36.8**	**55.4**	**135.2**	**194.5**

* since UK is part of the modelling perimeter this is the net exchange (model output)

Table 2: Green hydrogen imports (Extra EU)

TWh/YEAR	2030	2035	2040	2050
Belgium	9.2	16.6	32.5	32.3
Germany	6.8	10.5	14.0	13.8
France	0.0	7.4	13.9	19.3
Greece	0.0	0.0	7.9	7.8
Italy	0.0	0.0	5.1	5.0
Netherlands	13.5	21.1	34.4	34.5
Poland	2.7	2.7	2.8	2.7
Total	**32.2**	**58.3**	**110.6**	**115.5**

Table 3: Ammonia imports (extra EU, used as hydrogen)

Hydrogen supply and generation in the Economic Variants

Figure 76 shows the results for the high and low economic variants. Overall, the difference in total hydrogen (H_2) supply between the two variants is relatively small.

However, more pronounced differences appear when comparing the composition of H_2 supply. In the low economic variant, green hydrogen production via P2G increases, whereas it declines in the high economic variant. By contrast, both hydrogen imports and H_2 production via steam methane reforming (SMR) are higher in the high economic variant than in the low variant.

This indicates that higher electricity demand in the high economic variant shifts hydrogen production away from P2G, as electricity becomes a scarce/expensive resource. Instead, supply is increasingly met through imports and SMR-based production.

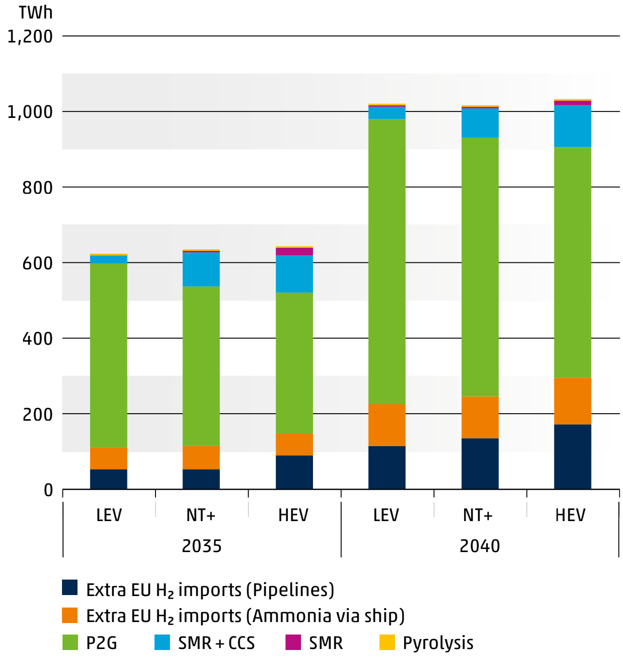


Figure 76: Variant Comparison of Hydrogen Supply

Flexibility from hydrogen storages in NT+ Scenario

To support the hydrogen network, that in the startup phase is characterised by a baseload demand and dispatchable supply, hydrogen storages plays a critical balancing role. In the future the hydrogen system is supposed to see a higher need for flexibility when hydrogen for heating will introduce temperature dependent demand. Renewable hydrogen supply through electrolysis will be weather dependent. Furthermore, hydrogen will enable increasing flexibility in the electricity system, through dispatchable power plants to run at peak times. There is still great uncertainty as to what the optimum portfolio of flexibility will be. The figure below illustrates EU hydrogen storage capacity in working gas volume alongside annual dispatchable volumes (represented by the withdrawal volumes), highlighting the importance of storage in meeting system needs.

Figure 77 shows that hydrogen storage assets are actively utilised across all target years. When considering storage cycles, 2030 stands out with the highest utilisation, exceeding four full cycles per year, while in later years this decreases to around three cycles annually. Even so, this represents significantly higher utilisation compared to traditional seasonal methane storage facilities, which typically operate at much lower cycling frequencies (seasonal balance).

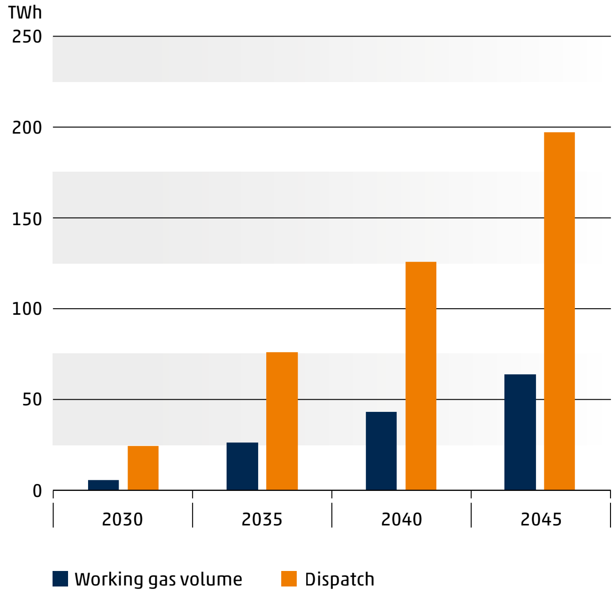


Figure 77: Hydrogen storage capacity and usage

Flexibility from hydrogen storages in the Economic Variants

In Figure 78 the hydrogen storage capacity and usage is displayed for the economic variants. For the variant we see a change where the storage usage is lower for the low economic variant while the High Economic variant is more or less in line with the NT+ scenario which indicate a higher demand for flexibility in a high economy.

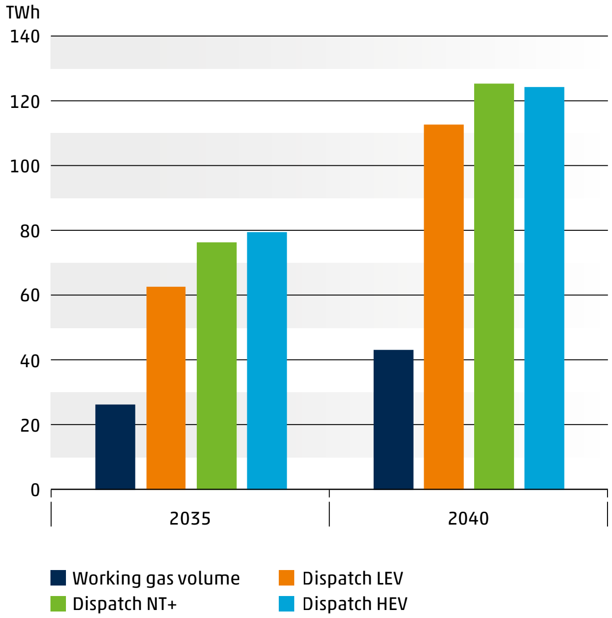


Figure 78: Hydrogen storage capacity and usage

E-fuel supply

The demand and supply of e-liquids and e-methane are modelled endogenously. Demand can be met either through direct imports of e-liquids or e-methane, or through domestic synthesis based on biogenic CO_2 and hydrogen (H_2). Consequently, total domestic production of e-methane and e-liquids is constrained by the availability of captured biogenic CO_2. Figure 79 illustrates the total supply of e-liquids and e-methane, differentiated between imports and domestic production. In the NT+ scenario, most of the e-fuel consumption consists of e-liquids, while the use of e-methane remains limited.

A slight majority of the e-liquids is produced within Europe, rather than imported. E-fuels – and particularly e-liquids – play an important role in meeting future energy demand. However, domestic production of e-liquids requires substantial quantities of hydrogen as a feedstock. In addition to hydrogen, a carbon source is necessary for fuel synthesis. The required amounts of captured biogenic CO_2 therefore represent a key limiting factor for domestic e-fuel production (see Figure 80). Data on biogenic CO_2 availability and capture were collected from the TSOs.

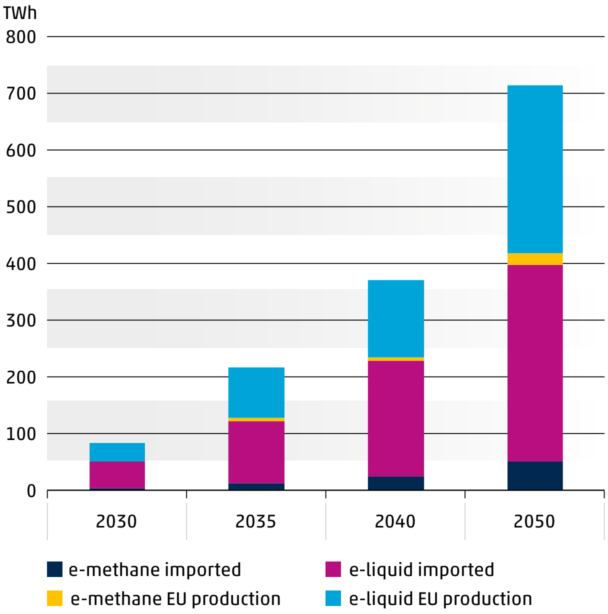


Figure 79: E-Fuel Supply Grouped by Kind and Source

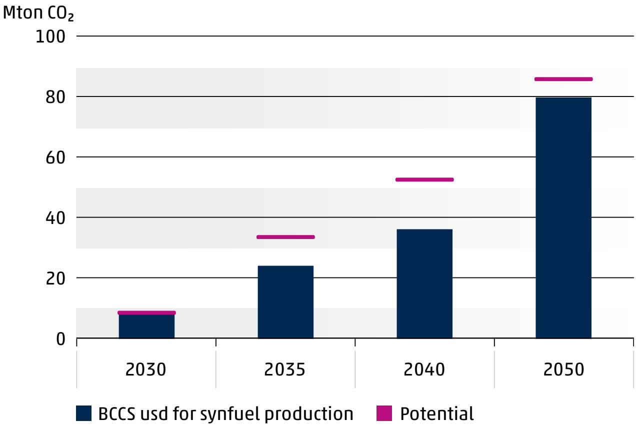


Figure 80: Biogenic CO_2 captured and used for synthetic fuel production

Biomass supply

Biomass is used for a range of applications and serves different purposes across the scenarios. It is consumed directly as final energy for heating and industrial processes, and it is also used as a feedstock for the production of biofuels, biomethane, and electricity. Through these conversion processes, biomass is transformed into secondary energy carriers that are subsequently used in end-use sectors such as transport, heating, and other applications.

Looking ahead, both the use and the role of biomass are expected to change. In particular, biomethane and biogases are projected to shift away from local electricity generation and heat production toward direct injection into the methane grid or use as a feedstock replacing natural gas. This development is illustrated in Figure 81. Over the period shown, the most significant changes occur in the allocation of biomass between final energy demand and its major consumption sectors. Notably, the share of biomass used for electricity and heat generation declines over time, accompanied by corresponding increases in the shares allocated to the production of biofuels and biomethane. By contrast, the direct use of biomass as final energy shows a slight decline. Overall, the figure indicates that the dominant trend is a growing use of biomass for the production of bioliquids and biomethane.

Figures for the production and imports of biofuels were collected from the TSOs based on their NECPs and best estimates. Figure 82 shows that the supply of biodiesel and biomethane is projected to approximately double between 2030 and 2050.

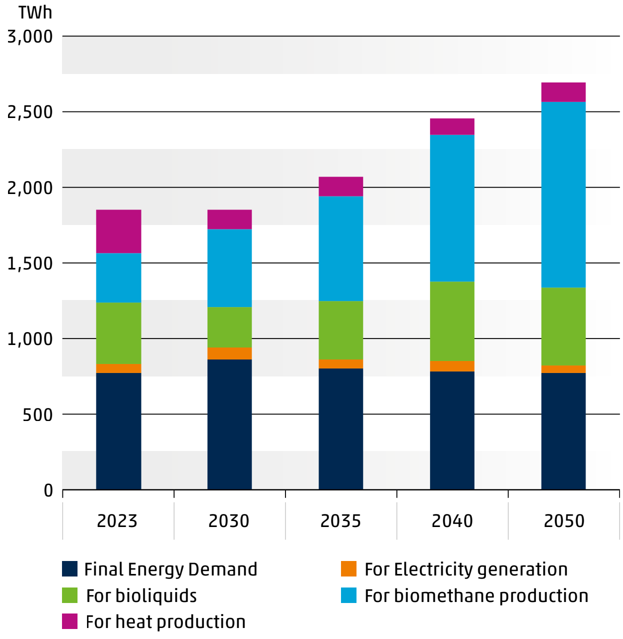


Figure 81: Use of Supply Biomass

In addition, their share of domestic production is expected to increase, while the share of imports will decline, even though the total imported volume continues to rise. In contrast, the supply of biogas is expected to remain largely unchanged over the same period. The same values for biofuels were used in the economic variants, which is why no additional graph for the variants is shown.

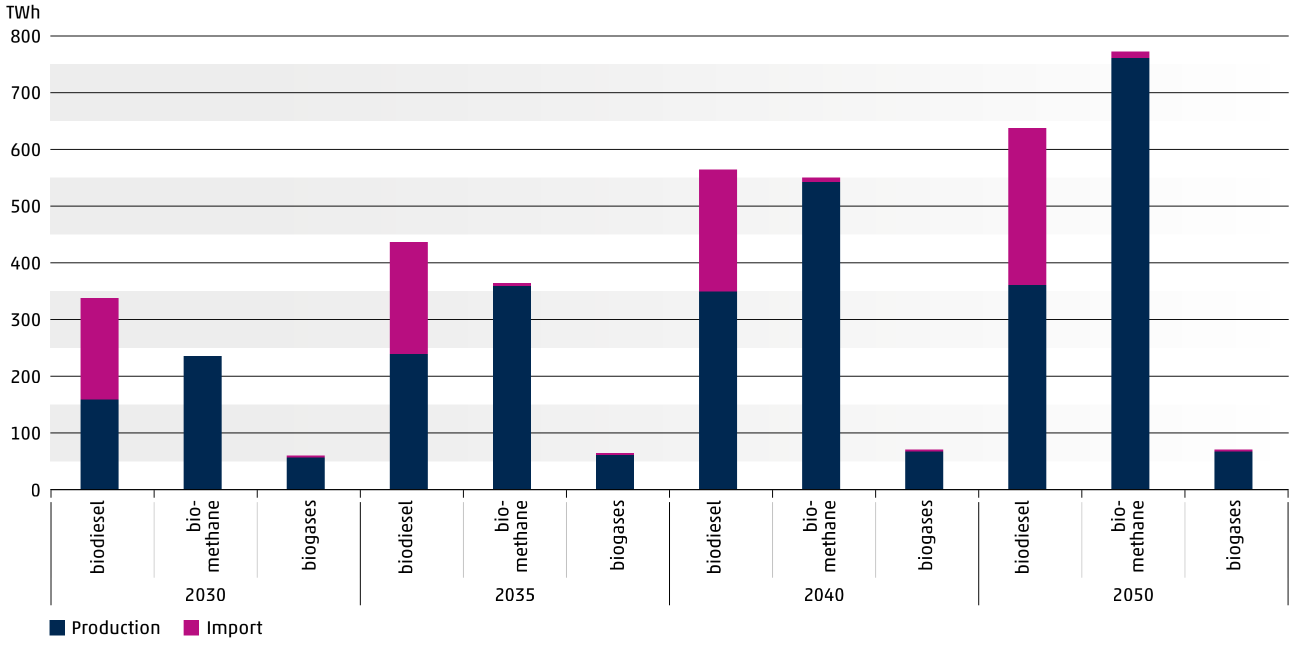


Figure 82: Supply biofuels

Imports

In the NT+ scenario, the combination of ambitious energy efficiency measures and deeper integration across energy systems substantially reduces import needs. Moreover, a strong expansion of indigenous renewable capacities further diminishes future reliance on energy imports (Figure 83).

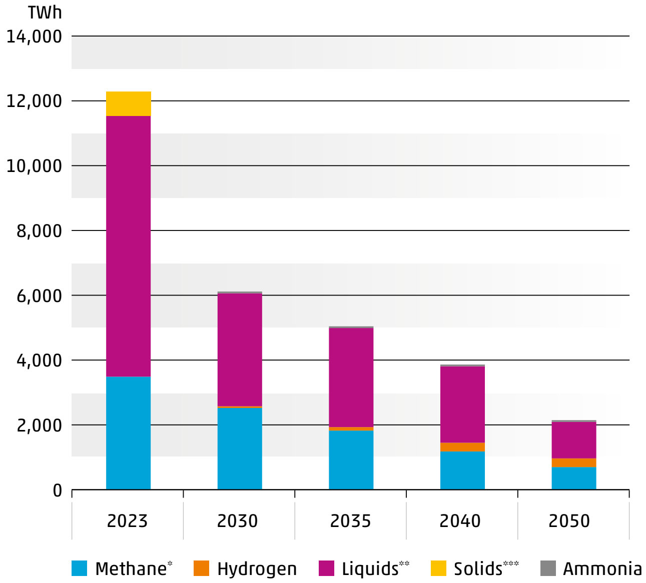
System integration plays a central role in fostering clean energy production and strengthening energy independence. As integration across energy systems increases, the EU energy system progressively relies on domestically produced renewable sources to meet its energy demand. This enables the large-scale development of indigenous production capacities, significantly reducing dependence on coal, oil, and gas.

Added to this is the ambitious implementation of energy efficiency measures. As a result, the need for carbon-intensive energy imports declines markedly over time. Overall, the scenarios show a substantial reduction in energy imports compared to current levels. In the NT+ scenario, this downward trend is already clearly visible by 2030.

In the variant, only slight changes are observed compared to the main scenario. The corresponding import levels are illustrated in the Figure 84 below.

A higher share of oil imports in the HEV scenario compared to the NT+ and LEV scenarios reflects higher overall energy demand. Similarly, higher hydrogen imports in the HEV scenario relative to NT+ and LEV are driven by both increased hydrogen demand and lower domestic hydrogen production, as less electricity is available in the EU for P2G processes. Due to the specific representation of the electricity sector within the modelling framework, electricity imports and exports cannot be treated consistently with other energy carriers. In particular, the electricity system modelling differs from that of other carriers as it explicitly includes the power systems of selected non-EU27 countries. In addition, fixed cross-border exchanges between the EU27 and certain third countries are embedded in the model setup.

As a consequence, electricity import and export flows are not reported in aggregate form but are instead provided at country level through the dedicated KPI dashboard file.



* Methane is covering biomethane, E-methane and Natural gas
** Liquids are covering Oil, bio liquids and e-liquids.
*** Imports of solids are not considered in the NT+ scenario

Figure 83: Energy imports EU27 by carrier (TWh/year)

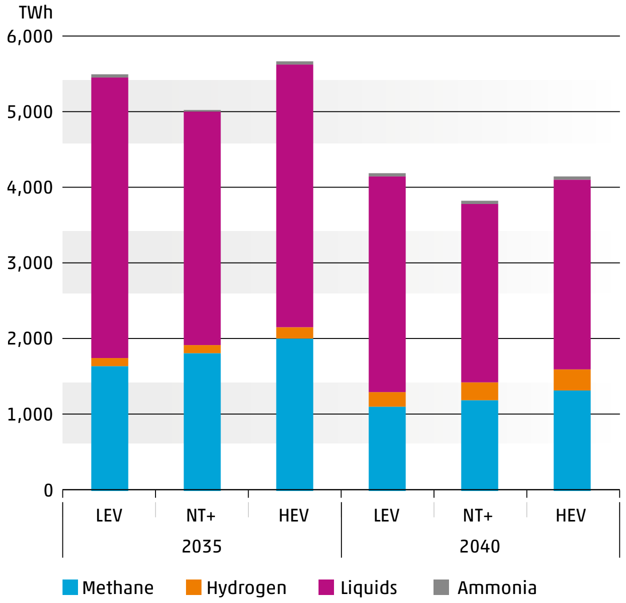


Figure 84: Energy imports in Low/High economic variants, (EU27, TWh/year).

Hydrogen supply variant analysis (LTC sensitivity analysis)

Introduction

According to ACER TYNDP Scenarios Framework Guidelines, ENTSOs shall provide, among others, a qualitative assessment of how the scenarios would be impacted by the uncertainty around the main selected assumptions and drivers.

On the demand side, the TYNDP 2026 scenarios introduce two Economic Variants, representing higher and lower economic growth assumptions for the 2035- and 2040-time horizons. These variants primarily assess the sensitivity of energy demand across sectors to different economic conditions.

On the supply side, an additional sensitivity analysis is performed specifically on hydrogen supply mix structure across all target years as the development of energy supply mix and the role of different supply sources is also characterised by uncertainty.

This analysis does not aim to explore the full range of supply-side uncertainties. Instead, it focuses on a specific aspect of the supply structure through a dedicated sensitivity applied to the base NT+ scenario.

To complement economic demand variants, and to support the robustness of the NT+ scenario, this chapter presents a sensitivity analysis focusing on the distribution of hydrogen supply between domestic production and import sources. This sensitivity builds on supply-side considerations explored in earlier TYNDP Scenario editions, where scenarios with a higher reliance on hydrogen imports were assessed, and applies them in a targeted manner to the Central Scenario.

National NT+ datasets describe a range of potential hydrogen supply options. The TYNDP modelling framework determines how these options are utilised to meet hydrogen demand, resulting in a base case with a stronger contribution from domestic production compared to imports.

Long-term import contracts, as described in Chapter 6 of the TYNDP 2026 Scenarios Methodology Report, represent one possible element of hydrogen supply arrangements. In the Central Scenario, long-term contracts are assumed for 50% of hydrogen import capacity. These contracted volumes are modelled with zero marginal import costs, reflecting their limited flexibility to adjust to short-term changes in domestic hydrogen demand. Import capacity above this threshold is modelled using corridor-specific marginal import costs. Further methodological details are provided in the TYNDP Scenario Methodology Report.

This chapter presents a sensitivity analysis in which the share of inelastic supply (LTC band) is increased to 80% of import capacity (LTC80). The objective is to assess how changes in the level of in-elastic import volumes affect the utilisation of domestic production and import routes, thereby testing the robustness of the base scenario outcomes. This sensitivity does not constitute an alternative supply-side scenario.

When setting the level for sensitivity analysis ENTSOs took into consideration indicative non-binding direction outlined in the EU strategy communication REPower Plan, which refers to 50/50 split between non-EU import and EU production share in 2030. In this context, the hydrogen system could very well develop in the direction of the current gas system. This would mean the hydrogen imports based on long-term contracts (LTC) with Take-or-Pay clauses and utilisation rates of the import capacity at least 70–90%. These LTCs are an important market-based tool as it splits the significant commodity and capacity risks between the infrastructure operator and infrastructure users. Hence LTCs ensure the use of import infrastructure and security of supply.

Assessment

This sensitivity shows a different supply mix, where more hydrogen is imported into the EU. Compared to the reference year, the imported volumes increase across all corridors, as shown in Figure 85.

In contrast, the market share of EU supply sources drops, both for electrolysis and SMR production. However, the market share of domestic hydrogen supply sources is dominant, particularly renewable production. Import share reaches in target year 2030 43 percent in the variant with the declining trend to 20 percent share in 2050 target year against 27 percent share in 2030 and 15 percent share in 2050 in the central scenario.

Import shares in this variant are comparable to the lower end of the range assumed in the previous TYNDP 2024 scenario edition (Figure 86, Figure 87).

Ship imports of hydrogen in the form of ammonia do not have the allocation to the specific country source as ammonia as commodity is part of the world market. Ammonia import capacities into EU27 (receiving terminals) are based on the TYNDP 2024 projects.

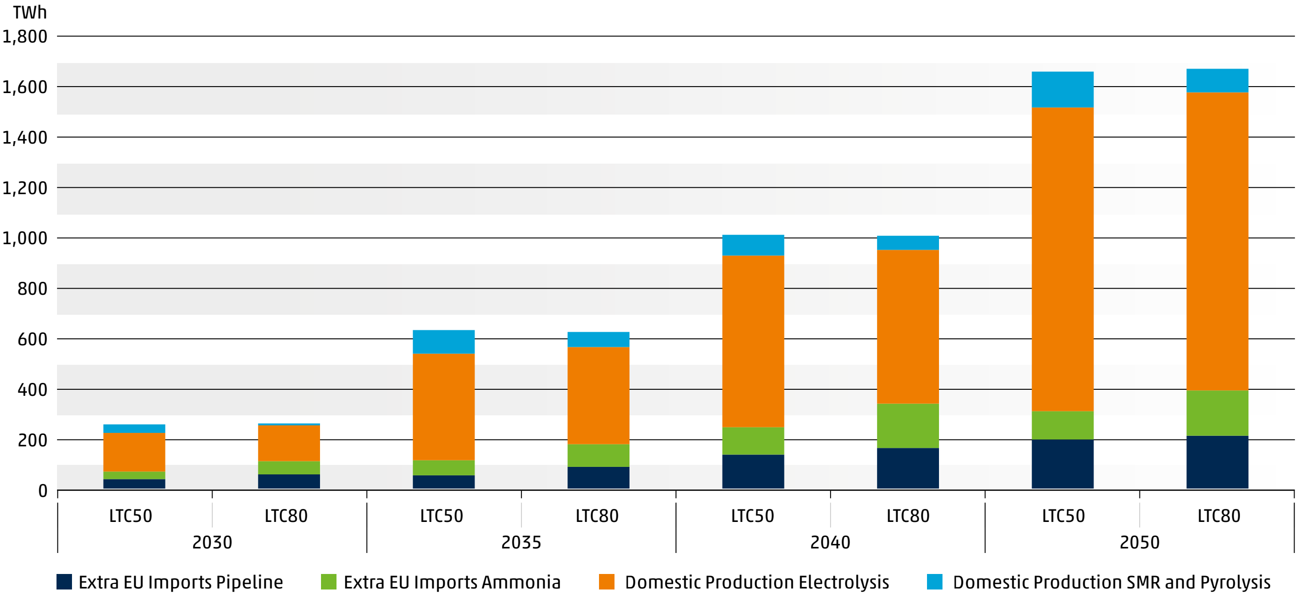


Figure 85: Sensitivity analysis – Change in the Hydrogen supply mix (EU27, TWh)

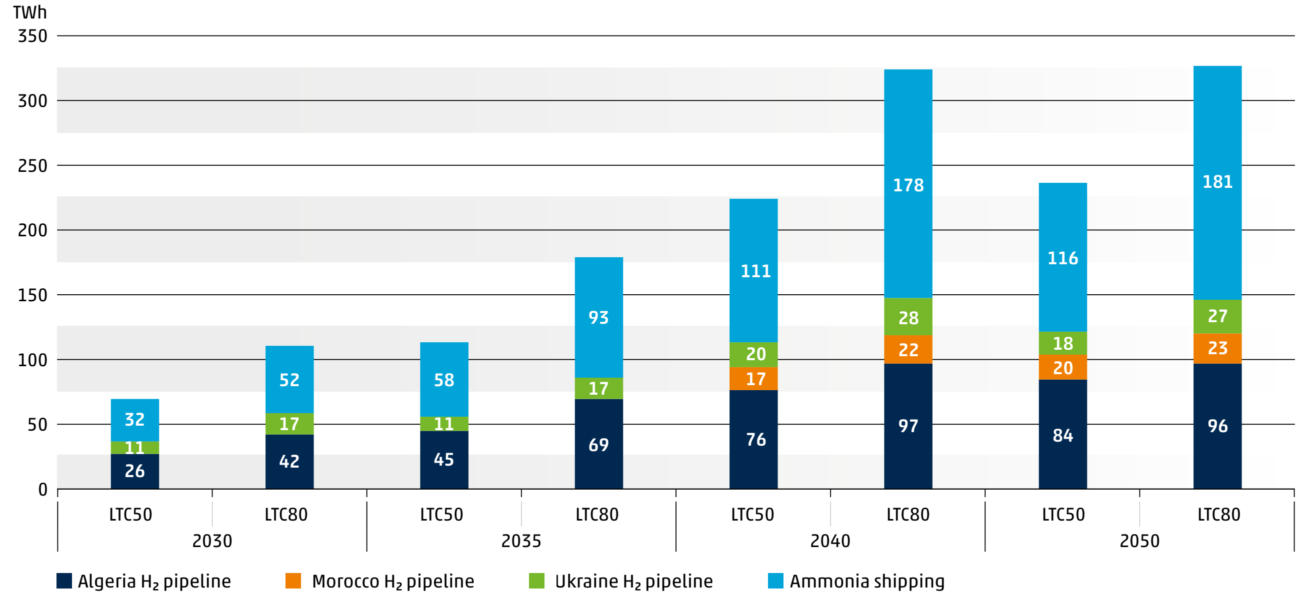


Figure 86: Sensitivity analysis – Change in the extra EU hydrogen imports (EU27, TWh)

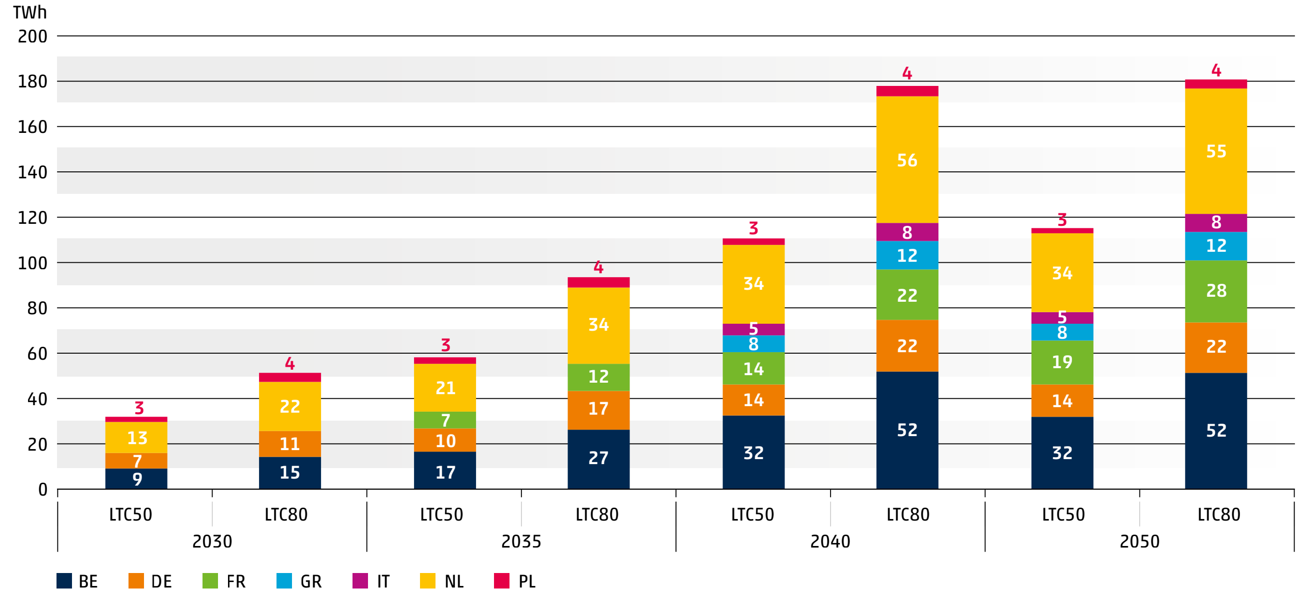


Figure 87: Sensitivity analysis – Change in the extra EU ammonia imports (EU27, TWh)

The difference in supply assumptions also has implications for the dispatch of hydrogen CCGTs and OCGTs. On average, the running hours of these facilities increase, but this is primarily driven by the model topology. In the Scenario 2026 Modelling exercise the assumption was implemented that long-term contracts for imports are modelled at zero marginal costs to allow the hydrogen pipeline imports.

As a consequence of this solution, these higher shares of hydrogen pipeline imports will reduce fuel cost for hydrogen CCGTs and subsequently increase power plant dispatch. Supply capacities were not changed for the LTC 80 sensitivity. Consequently, the higher import volumes translate into lower full load hours for the domestic supply sources like electrolysis and steam methane reforming (SMR). The dispatch of electrolysis capacity (P2G) slightly decreases compared to the reference scenario but remains within a range of 2,500–3,500 hours per year (Figure 88 and Figure 89).

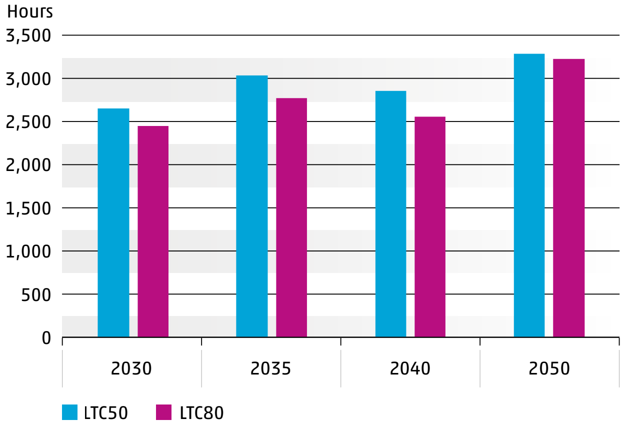


Figure 88: Sensitivity analysis – Change in the electrolysers running hours (EU27)

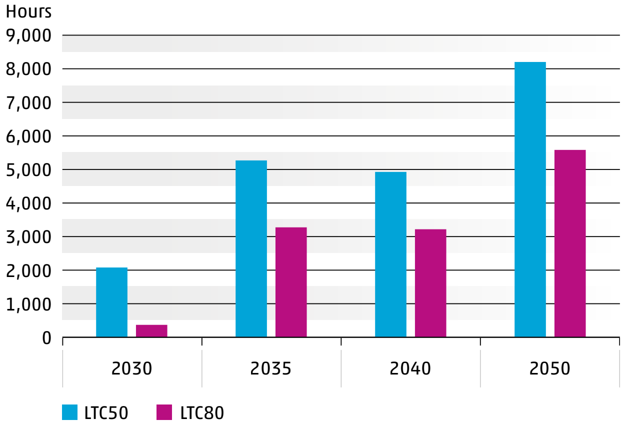


Figure 89: Sensitivity analysis – Change in the SMR running hours (EU27)

See in Figure 90 that the curtailment of renewable electricity generation (i.e. solar and wind) increases marginally.

Percentage changes of the analysed parameters – P2G full load hours and change of curtailment of EU27 PV and wind RES generation can be observed in Figure 90. There is higher change in the SMR full load hours parameter, but as the share of SMR on the overall hydrogen supply is less than 10 % in 2040 and 2050, this change is not significant in total terms. Share of the hydrogen imports EU27 does not exceed the 33% share to cover expected demand in 2035, 2040, 2050 thus the EU's goal of achieving energy independence from the need to import energy raw materials from third parties is not threatened. Still, most of the hydrogen demand can be covered via domestic production within EU through all target years.

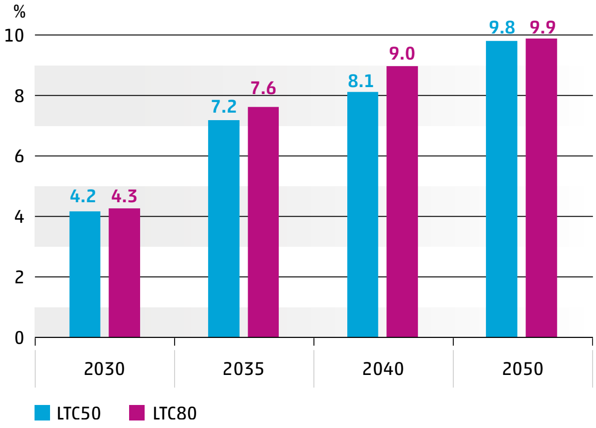


Figure 90: Sensitivity analysis – Change in the PV and Wind renewable electricity generation curtailment (EU27, %)

9.3 Context for Interpretation and Known limitations

A more detailed description of interpretation aspects, known limitations and modelling considerations is being provided in Annex VII. When analysing the Scenario results, readers are encouraged to take these elements into account, as they provide important context, particularly at regional or sectoral level.

10 COMPLIANCE WITH 2030 EUROPEAN ENERGY AND CLIMATE TARGETS AND CARBON NEUTRALITY IN 2050 //

The TEN-E regulation requires ACER to publish the "Framework Guidelines for the joint TYNDP scenarios to be developed by ENTSO for Electricity and ENTSO for Gas".

These guidelines establish criteria for development of the scenario and shall also aim to ensure that this is fully aligned with (1) the EE1st principle, (2) the EU's 2030 targets for energy and climate, (3) the EU's 2050 climate neutrality objective. The scenario shall take the latest available Commission scenarios, as well as, where relevant, the NECPs into account. The ACER guidelines require the Scenario report to analyse how the considered EU targets are achieved, including sufficient information about GHG emissions from the energy sector and carbon budgets (which go beyond the energy sector). This shall allow the evaluation of the TYNDP scenario with regards to climate targets and justify how the scenario is aligned with targets. For the 2026 scenario cycle, by the policy cut-off day set for 24 December 2024, 24 final updated NECPs were available; 3 countries were in the stage of preparation of the final updates (having obtained the EC feedback to the draft NECP). In the survey provided by the ENTSOs (for more details on survey see Chapter 11 and Annex I), TSOs representing 22 EU members confirmed data validation at national level prior to its submission to the scenario development process. Only 5 countries submitted data without such a national validation process. Table 4 shows the summary of TSO responses representing EU27 Member States. It shows how their data submission was aligned with the country level targets confirming if:

- energy demand data is compliant with indicative national contributions towards the EU's FEC targets sent to Member States
- submitted data is compliant with indicative national contributions towards the EU's RES target
- the delivered datasets are compliant with national references to comply with the EU's binding 2030 GHG reduction target
- provided datasets are compliant with national targets under the EU's binding 2050 net-zero emissions objective.

TARGET	ALIGNED	NOT ALIGNED	ALIGNMENT NOT ASSESSED	COMMENTS
FEC	9	9	9	For justification of the answers, see Annex I
RES	16	2	9	For justification of the answers, see Annex I
GHG reduction	12	3	11	1 country responded not applicable
2050 climate neutrality	13	1	12	1 country responded not applicable

Table 4: Summary of national TSO responses on how data submission aligns with country level targets.

This scenario report follows alignment with these relevant EU Policy targets:

a) Target year 2030:

- Energy efficiency target reduction of energy consumption by 11.7% to reach EU final energy consumption of 763 Mtoe
- Share of renewable energy of at least 42.5% (aiming at 45%) in the energy mix

b) Decrease in total net GHG emissions of 55% compared to 1990, GHG emissions from sectors covered by the Effort sharing regulation decrease by 40% compared to 2005, in the land sector according to the Land Use, Land Use Change and Forestry (LULUCF). Target year 2040 – testing the decrease in total net GHG emissions of 90% compared to 1990.

c) Target year 2050:

- EU Climate neutrality – 0 or lower net emissions of GHG

The EC, in its EU-wide assessment of the final updated NECPs from May 2025,[23] acknowledges that there are gaps for meeting the 2030 targets at EU level specifically in:

- the GHG emissions from the sectors covered by the effort sharing regulation (gap of 2 percentage points) and LULUCF in the land sector (gap of 42 MtCO_2eq. of net removals),
- in the EU's 2030 target for renewable energy share (gap of 1.5 percentage points) and
- EU's target for energy efficiency by 2030 (gap of 31.1 Mtoe/3.6 percentage points).

Although the actual status of national trajectories is behind to reach the 2030 targets, ENTSOs based on steering by the EC and ACER must comply with the requirements of the framework guidelines. For this purpose, the ENTSOs implemented the FEC gap-filling methodology described in detail in Chapter 9 of the Scenario Methodology Report.

10.1 Compliance with the 2030 targets

Energy Efficiency 1st Principle

The EE1st principle aims to ensure that energy efficiency solutions, demand-side resources and system flexibilities are considered in planning, policy and investment decisions in the energy and non-energy sectors alike. In the EE1st principle guidelines annexed to European Commission Recommendation (EU) 2021/1749[24] of 28 September 2021, the principle's application in the TYNDP is detailed as follows:

> "The TEN-E [Regulation] includes the EE1st principle in all the stages of the European Ten-Year Network Development Plans development, more specifically in the scenario development, infrastructure gaps identification and projects assessment. […] The practical implication of the EE1st principle in the planning means that the infrastructure development must include within the decisional process options to better utilise the existing infrastructure (by operational mechanisms), implement more energy-efficient technologies, and make better use of the market mechanisms such as, but not exclusive to, demand-side response. […] When implementing the EE1st principle, one must strive to reach the balance between secure and reliable energy supply, quality of energy supplied and overall associated costs […]."

In the NT+ scenario, the EE1st principle was thus considered in the following ways:

(1) Inclusion of options for better utilisation of existing infrastructure

The existing infrastructure considered in the scenario topology is updated for each scenario cycle with information provided by the infrastructure operators and/or publicly consulted. These underlying energy infrastructure capacities are the main parameter capturing the ability of better utilisation through operational improvements, including by digital solutions. Additionally, the utilisation of the existing infrastructure capacities in the model is improved through the consideration of multiple energy carriers, allowing flexibility provision across sectors.

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[23] COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS EU-wide assessment of the final updated national energy and climate plans Delivering the Union's 2030 energy and climate objectives, Brussels, 27 May 2025

[24] EUR-Lex – 32021H1749 – EN – EUR-Lex

(2) Inclusion of options to include more energy-efficient technologies

The NT+ scenario is developed on an NECP-based scenario storyline. Within the NT+ scenario development, energy-efficient technologies are set at ambitious levels based on the NECPs, EU energy and climate targets, or infrastructure operator inputs in combination with stakeholder consultations. The renovation of buildings is also included in the set of assumptions at a highly ambitious level.

(3) Inclusion of options to make better use of the mechanisms

By assuming perfect competition and allowing demand-side response within each zone without additional infrastructure or market constraints (aside from inter-zonal limits represented as nodes such as country hydrogen sub-zones or electricity bidding zones), the model likely overestimates the benefits of demand-side management.

Demand-side response technologies are modelled as either (i) optimised use of sector-coupling assets through conversion (e.g., electrolysers and hydrogen-fired power plants) or (ii) demand shedding (e.g., temporary reductions in industrial demand triggered by a market-clearing price threshold). The modelling aims to balance security of supply, quality of service, and cost efficiency. System-wide investment benefits – including energy-efficiency measures and infrastructure development – are reflected by monetising unserved demand (VoLL and CODH), incorporating adequacy loops, and penalising energy losses that reduce life-cycle efficiency (e.g., via marginal fuel costs, conversion losses in electrolysers and power plants, and storage efficiencies). Emissions are also penalised through consistency checks against the EU's legal energy and climate targets and, where applicable, reflected in marginal fuel costs.

Lastly, the TYNDP 2026 scenarios are based on policy documents and infrastructure lists which themselves have to comply with the EE1st principle. First, demand scenarios were built based on the latest NECPs. The integrated NECPs published by Member States must take into account the energy efficiency first principle as stated in Article 3 of Regulation (EU) 2018/1999. Second, electricity and hydrogen grids used for TYNDP26 take PCI/PMI projects into account. TEN-E regulation (REGULATION (EU) 2022/869) states that any project of common/mutual interest should comply with the EE1st principle.

FEC Targets

The 2020 EU Reference Scenario projection estimates EU final energy consumption at 864 Mtoe in 2030. The EU Energy Efficiency 2023/1791 Directive[25] establishes a binding EU-level target for FEC in 2030, set at 763 Mtoe. This target corresponds to an additional reduction of 11.7% compared to the 2020 EU Reference Scenario projection. The NT+ scenario is compliant with the EED's FEC target. While final energy consumption reported through the ETM in the NT data collection initially amounted to 867 Mtoe, the application of an advanced gap-filling methodology reduced final energy consumption to 762 Mtoe in the NT+ scenario.

The gap-filling methodology applied is described in detail in Section 9 of the TYNDP 2026 Scenarios Methodology Report, while the carrier-level impacts are presented in Section 9.3 of the demand chapter of this report. The gap-filling methodology bridges the gap between a policy-based bottom-up data collection and a target compliant NT+ scenario.

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[25] Directive (EU) 2023/1791 of the European Parliament and of the Council of 13 September 2023 on energy efficiency and amending Regulation (EU) 2023/955 (recast)

Renewable Energy Share target

The Renewable Energy Directive 2023/2413 establishes an overall target of at least 42.5% renewable energy in gross final energy consumption (GFCoE) by 2030 (with the aspirational goal to reach 45%). In Eurostat statistics, this share is defined as the ratio of renewable energy consumed by end-users to total FEC, excluding non-energy uses of fuels.

According to the modelling results of the NT+ scenario, the overall RES share reaches 42.55% and thus the target, if only green hydrogen and green ammonia are counted as renewable, and 43.22% if low carbon hydrogen and ammonia (including blue and imports) are included in the renewable definition (Table 5).

NT+ SCENARIO[26]	**2030**
OVERALL RES SHARE (GROSS FINAL CONSUMPTION OF ENERGY (GFCOE) ADJUSTED) [%]	**42.55%**
Numerator [GWh]	**3,957,113**
renewable part of: FEC – from ETM (excl. pEVs; int. shipping and HHPs; incl. international aviation)	3,445,837
renewable part of: FEC of pEVs from model results	98,102
– renewable part of: FEC of HHPs from model results	29,640
– renewable part of: Transmission and Distribution losses for electricity	118,916
– renewable part of: The consumption of electricity and heat by the energy branch for electricity and heat production – GWh	48,625
renewable part of: Transmission and distribution losses for derived heat*	1,527
Ambient Heat (normal HPs)	214,466
Denominator [GWh]	**9,299,923**
GFCoE	**9,356,059**
FEC – from ETM (excl. pEVs; int. shipping and HHPs; incl. international aviation)	8,688,582
FEC of pEVs from model results	142,988
FEC of HHPs from model results	62,839
Transmission and Distribution losses for electricity	173,325
The consumption of electricity and heat by the energy branch for electricity and heat production	70,874
Transmission and distribution losses for derived heat*	2,985
Ambient Heat (normal HPs)	214,466
GFCoE adjusted (Aviation Cap)**	**9,299,923**

* The transmission and distribution losses for derived heat is taken 0.57% of FEC (The share calculated acc to EC FF55)
** GFCoE adjusted/GFCoE share is taken from EC FF55 scenario (99.4%)

Table 5: NT+ EU wide RES by the year 2030, according to the Renewable Energy Directive (RED III) under the more conservative definition of renewable hydrogen and ammonia

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[26] Methodological note: RES share is a metric that is defined as the ratio of renewable final energy consumption (RES-FEC) to total FEC. Methodologically, to calculate this for the NT+ scenario, seven components contribute to both the so-called denominator (total FEC) and the numerator (renewable FEC).

In the NT+ scenario framework, it is outside the model scope to track the renewable content of every final energy flow after all conversion and blending steps. Instead, a supply-side proxy is applied: for each energy carrier, the renewable share of its supply mix is used as a proxy for the renewable share embedded in its final consumption. This avoids double-counting conversion losses and reflects the actual decarbonisation level of each carrier's supply.

The calculation of the RES-share is structured in two steps:

Denominator – GFCoE adjusted for the aviation cap

Final energy consumption is first derived from ETM for the NT+ scenario by aggregating all relevant sectors across the following carriers: ammonia, biomass/biogenic, electricity, heat (district heating), hydrogen, liquids, gas, solids and "other", while excluding the international shipping sector In line with the Energy Efficiency Directive and the RED accounting scope and the following other exceptions that are added separately:

- explicitly modelled final uses such as pEVs and HHPs are added separately according to their modelled consumption;
- electricity and heat transmission and distribution losses;
- electricity and heat consumption within the energy branch for producing electricity and heat;
- ambient heat used by regular heat pumps, which is not reflected in the initial ETM FEC.

The sum of these components yields GFCoE, adjusted for the cap on the aviation sector's contribution to a Member State's FEC according to the proxy from the Commissions FF55 scenario.

Numerator – renewable part of FEC

For each of the FEC components above, the renewable share is derived using the supply mix proxy, i.e. the share of renewables in the supply of the corresponding carrier. The following renewable shares (r) are applied for NT+.

ENERGY CARRIER	RES SHARE	BASIS / REMARKS
Ammonia	0%/100%	Share of renewable Ammonia under two definitions: completely green or low carbon (blue, green h2 and imports)
Biomass/ biogenic	100%	Treated as fully renewable
Electricity	69%	Derived from RES-e Share calculation (excluding nuclear)
Heat (district heating)	51%	Accounts for all renewable sources in the district heating supply mix (i.e. ren. gas and liquids blend share, biomass, h2, renewables and waste heat and ren. electricity share)
Hydrogen	37%/99,4%	Share of renewable Hydrogen under two definitions: completely green or low carbon (blue, green h2 and imports)
Liquids	11%	Reflects the renewable liquids blend share
Gas	10%	Reflects the renewable gas blend share
Other	0%	Conservative assumption – no renewable attribution
Solids	0%	Conservative assumption – no renewable attribution

Table 6: Renewable shares in the supply of the corresponding carrier

For each carrier, renewable FEC is obtained by multiplying final consumption by the corresponding RES share, and the total renewable FEC is the sum across all carriers and components.

Reduction of GHG emissions target

The 2030 GHG emissions target can be found together with the 2040 and 2050 targets in the chapter below. In this chapter the following topics are discussed:

- the overall emissions – CO_2 and non-CO_2 emissions from energy and non-energy sectors
- removals – CCUS, LULUCF
- deduction of emissions from internation transport- shipping and aviation
- assessment of carbon budget and targets
- focus on carbon foodprint of electricity and hydrogen

10.2 GHG emissions

To assess whether NT+ is compliant with the EU emissions reduction targets and the indicative carbon budget for 2030–2050 as described in Chapter 6.6 of the Scenario Methodology Report, greenhouse gas emissions and removals are calculated consistently with the approach used in the European Commission's Impact Assessment (IA) for the 2040 Climate Target. Annual net emissions for 2030–2050 are computed and then summed over the period; intermediate years are obtained by interpolation between 2030, 2035, 2040 and 2050.

The Figure 91 illustrates projected evolution of Total GHG emissions (energy emissions and non-energy emissions). There is a clear declining trend in emissions from the energy system, reflecting increased deployment of RES and an overall reduction in energy demand. Nevertheless, emissions do not reach zero by 2050, implying that negative emissions are required to comply with EU climate targets.

Furthermore, when considering total GHG emissions, it is evident that contributions from non-energy sectors, industrial processes and agriculture, will also be necessary as well in order to meet the targets.

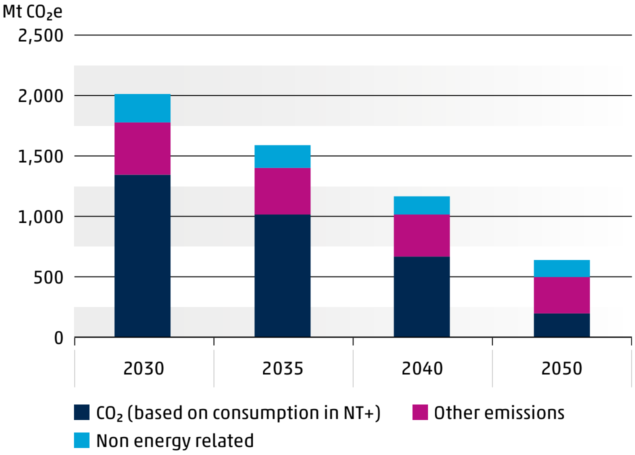

Figure 91: Total GHG emissions ($MtCO_2e$)

Removals

Figure 92 shows evolution of these key elements over time:

- the total amount of captured CO_2,
- the portion of this capture that is used as CCU for synfuel production, and
- the portion that is permanently stored as CCS/BECCS and therefore enters the carbon budget as a negative emission.

An additional volume of CCS ("Slack CCS") is introduced in the modelling framework to ensure consistency with the EU carbon budget constraint. This represents the residual level of carbon removals required in the model to achieve climate neutrality by 2050 under the given assumptions.

As shown in Figure 92, slack CCS deployment begins in 2048 and increases steadily towards 2050, reaching a required level of 170 $MtCO_2$ per year to secure carbon neutrality. The total volume of CO_2 captured including from CCS, BECCS, CCU and slack CCS, are subject to the upper capture limit 425 $MtCO_2$/year recommended by the ESABCC[27]. In line with the methodology, the sum of (i) CO_2 captured for synfuels, (ii) reported CCS/BECCS volumes and (iii) slack CCS is kept at or below this ESABCC cap. The CCU/CCS figure also indicates the amount of slack CCS used in NT+, i.e. the additional permanent storage that is needed, beyond reported national volumes, to be consistent with the EU wide capture potential and climate targets.

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[27] ESABCC: Towards Climate Neutral and resilient energy networks across Europe

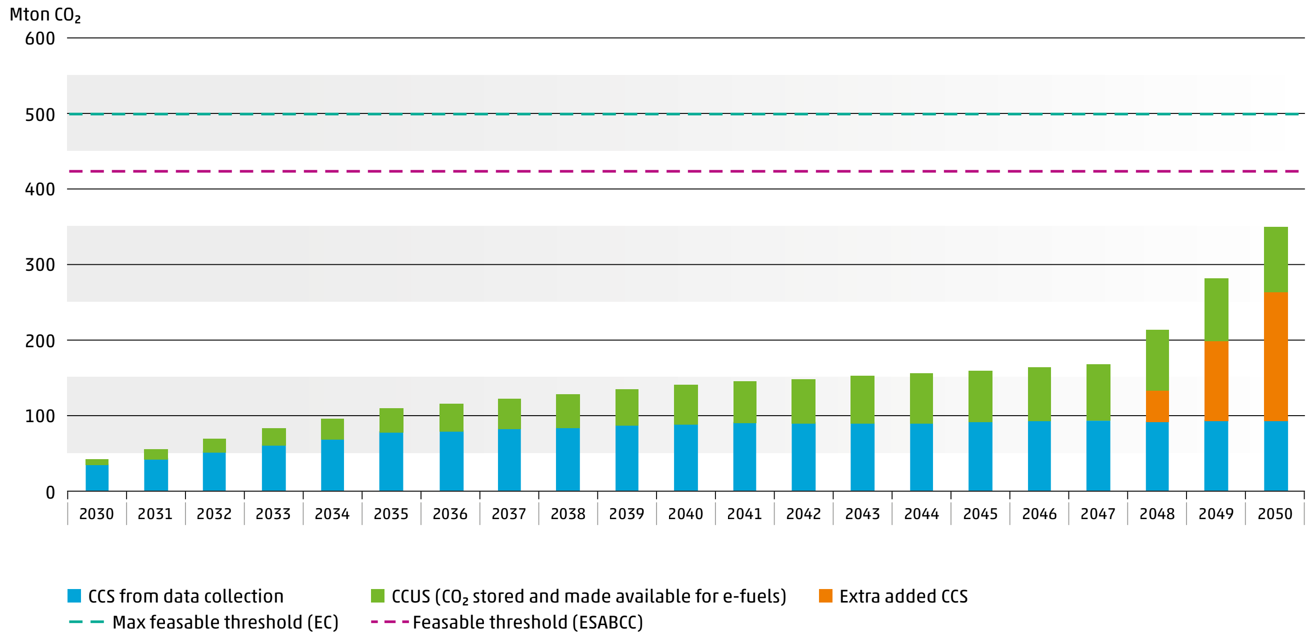

Figure 92: CCS/CCUS used in the NT+ scenario

LULUCF

Negative emissions from LULUCF increase from 271 $MtCO_2e$ in 2030 to 333 $MtCO_2e$ in 2050, as shown in Figure 93. The estimates for net LULUCF emissions in 2030 are based on the expected contributions reported in the NECPs. For 2040 and 2050, projections are taken from the EU Impact Assessment, specifically the S3 scenario. Linear interpolation is applied for the intermediate years between 2030 and 2040, and between 2040 and 2050.

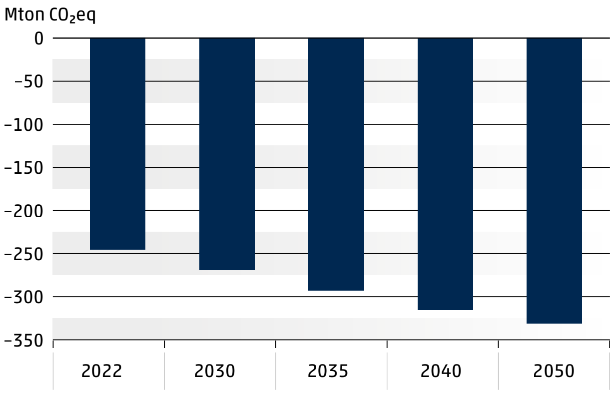

Figure 93: Negative emissions from LULUCF

Deduction of emissions from international shipping and aviation

As illustrated in Figure 94, the deducted CO_2 emissions from international shipping and aviation are relatively limited, particularly in the later years of the analysis. This is primarily driven by the assumption that the energy mix will see a high uptake of renewable and low carbon fuels in these sectors, in line with existing and forthcoming EU regulatory requirements.

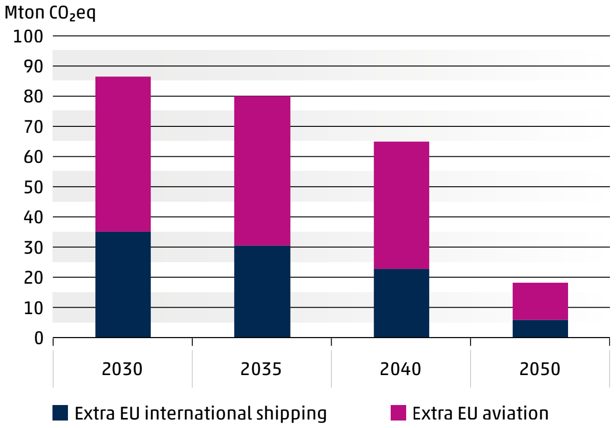

Figure 94: Deduction of emissions from international shipping and aviation

10.3 Assessment of carbon budget and targets

The assessment of the carbon budget and compliance with the emission targets is carried out exclusively for the NT+ scenario. The underlying methodology, assumptions, and calculation approach are described in detail in the accompanying TYNDP 2026 Scenarios Methodology Report.

Targets

Under the EU Climate Law, the EU is required to reduce GHG emissions by at least 55% by 2030 compared to the 1990 levels of total emissions, which were 4,726 MtCO_2e, and to achieve climate neutrality by 2050. In March 2026, the EU further reached a political agreement on a binding 2040 target of a 90% reduction in net GHG emissions. This target includes a domestic reduction of at least 85%, with the remaining up to 5% to be met through international carbon credits. In this context, assessing compliance with an 85% domestic emissions reduction by 2040 is particularly relevant for the TYNDP scenario.

Figure 95 compares emissions from the NT+ scenario against the EU climate targets. The results show that the NT+ scenario remains within the emissions limits for all assessed milestone years.

In particular, the scenario achieves the required reductions for 2030, 2040, and aligns with the long-term objective of climate neutrality by 2050 the latter achieved by using a small amount (170 Mt) of Slack CCS. Therefore, the NT+ scenario can be considered fully consistent with the EU Climate Law targets.

The NT Benchmark, where no gap-filling was added, is still compliant with the target for 2030 where a reduction on 60% is achieved without using any “slack CCS”. For 2040 the reduction ends up at 84%, one percent from the target if 5% is achieved through international credits and no “Slack” CCS is used. For the climate neutrality by 2050 the NT need 210 Mt of “Slack” CCS to be neutral, 40 Mt more than the NT+ scenario. This means that all targets can be reached within the technology cap on CCS.

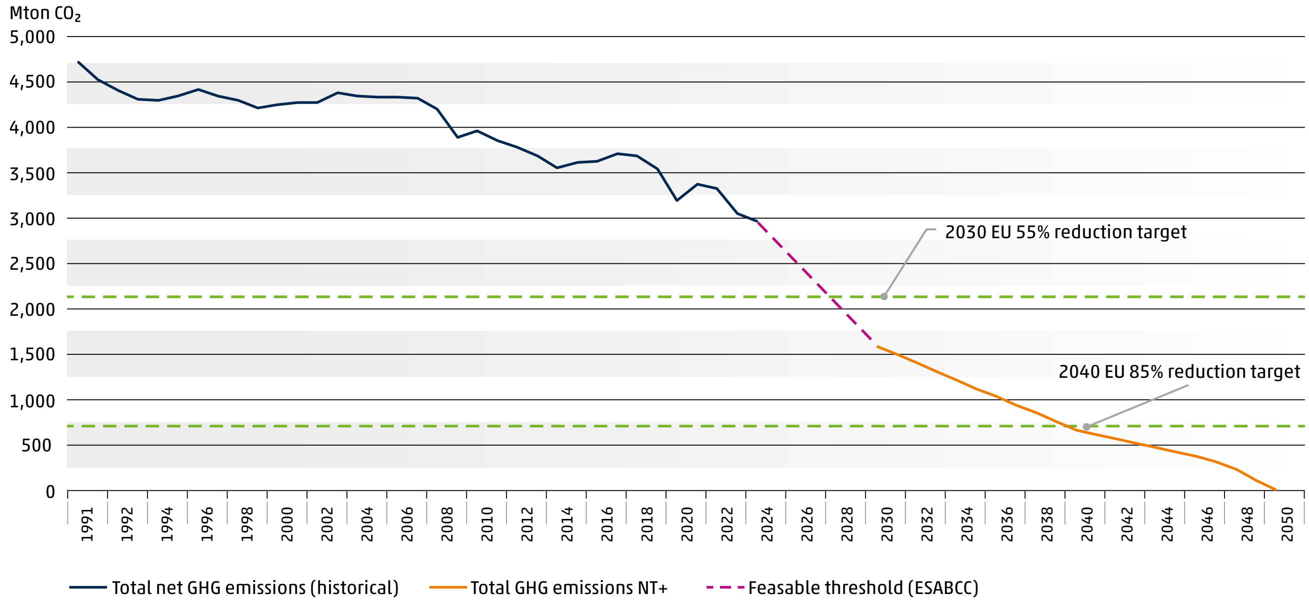

Figure 95: Net Greenhouse Gas Emissions

Carbon budget

The carbon budget for the scenario is set at 16 $GtCO_2eq$ for the period 2030–2050. This value is taken from the European Commission's Impact Assessment and is deemed consistent with the requirements of the EU Climate Law as well as fully compatible with the objectives of the Paris Agreement.

The figure below presents cumulative emissions and removals over the assessed period, together with cumulative net emissions.

The cumulative net emissions reach 16 $GtCO_2eq$ in 2050, thereby remaining within the recommended carbon budget. A key factor in meeting this budget is the timely and sustained reduction of gross emissions combined with the progressive scaling up of carbon removals towards 2050. This balance ensures that net emissions decline sufficiently over time, allowing the NT+ scenario to stay within the cumulative budget constraint while achieving climate neutrality by mid-century.

In contrast, the NT Benchmark (combination of NT dataset and PLEXOS® model results, as introduced in Chapter 9.2) is projected to overshoot the carbon budget, reaching approximately 2,600 $MtCO_2eq$ above the limit by 2050, assuming the same level of CCS deployment as in NT+. To comply with the budget, Member States would need to intensify efforts e.g. by significantly increasing carbon removals or/and by implementing deeper reductions in fossil fuel use. If CCS is used more widely the budget can still be reached within the technical constraint on CCS.

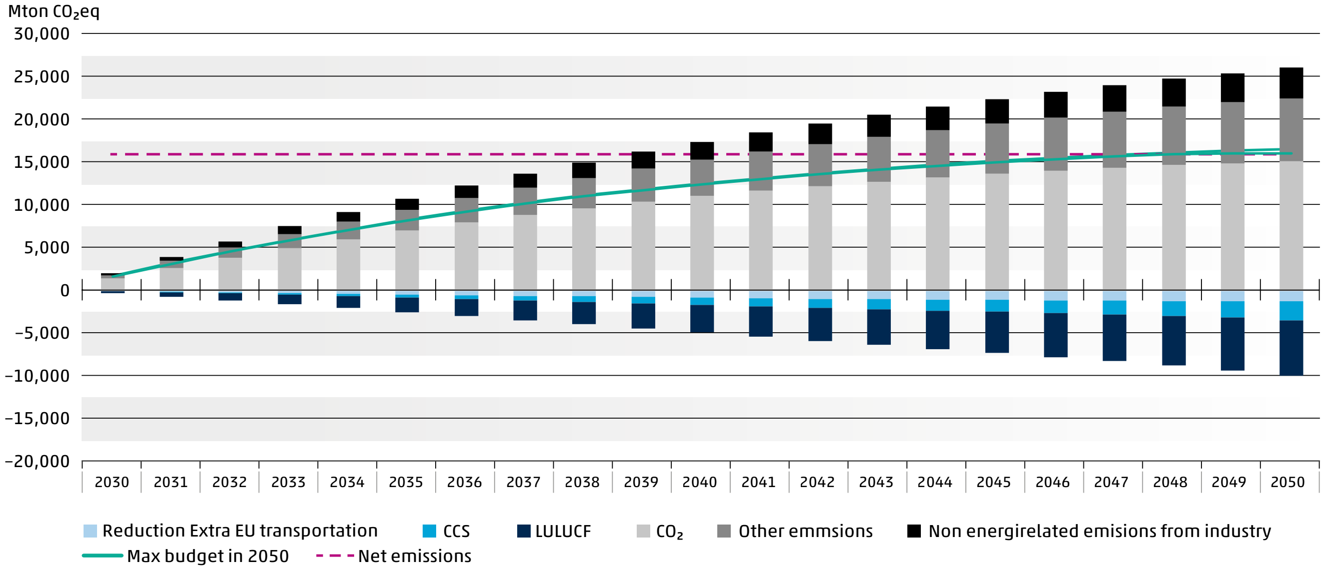

Figure 96: Cumulative GHG emissions NT+

10.4 Carbon footprint

10.4.1 Electricity

Emissions from the power sector decrease sharply in the NT+ scenario. By 2030, total emissions fall to 144 $MtCO_2$, representing only 9.4% of total electricity-sector emissions in 1990. Emissions decline further to just 9 $MtCO_2$ by 2050, indicating a power sector operating almost entirely on renewable energy.

Across the variants, total emissions from the electricity sector are higher in the High Economic variant than in the NT+ scenario, while emissions are lowest in the Low Economic variant. Higher electricity demand in the High Economic variant requires additional fossil fuel generation, leading to higher emissions. In contrast, under the Low Economic variant, RES are sufficient to supply almost the entire electricity demand, resulting in minimal emissions.

Along with the sharp decline in total emissions from electricity generation, the carbon intensity of power generation is also expected to decrease significantly. In the NT+ scenario, higher electricity generation is supported primarily by increased deployment of RES (wind and solar), combined with expanded use of hydrogen, biomethane, and synthetic fuels in power plants.

By 2030, the carbon intensity of electricity generation is projected to fall to 42 gCO_2/kWh, which is substantially below the EEA projection of 110 gCO_2/kWh and corresponds to only 8.4% of the 1990 level.

Under the NT+ scenario, the carbon intensity of electricity continues to decline towards 2050, reaching 1.48 gCO_2/kWh, effectively approaching full decarbonisation of the power sector.

The High Economic Variant exhibits a slightly higher carbon intensity than the NT+ scenario due to a greater reliance on fossil fuels in the energy mix. In contrast, the Low Economic Variant achieves an even lower carbon intensity than NT+, reflecting reduced overall energy demand and a higher relative share of low carbon generation.

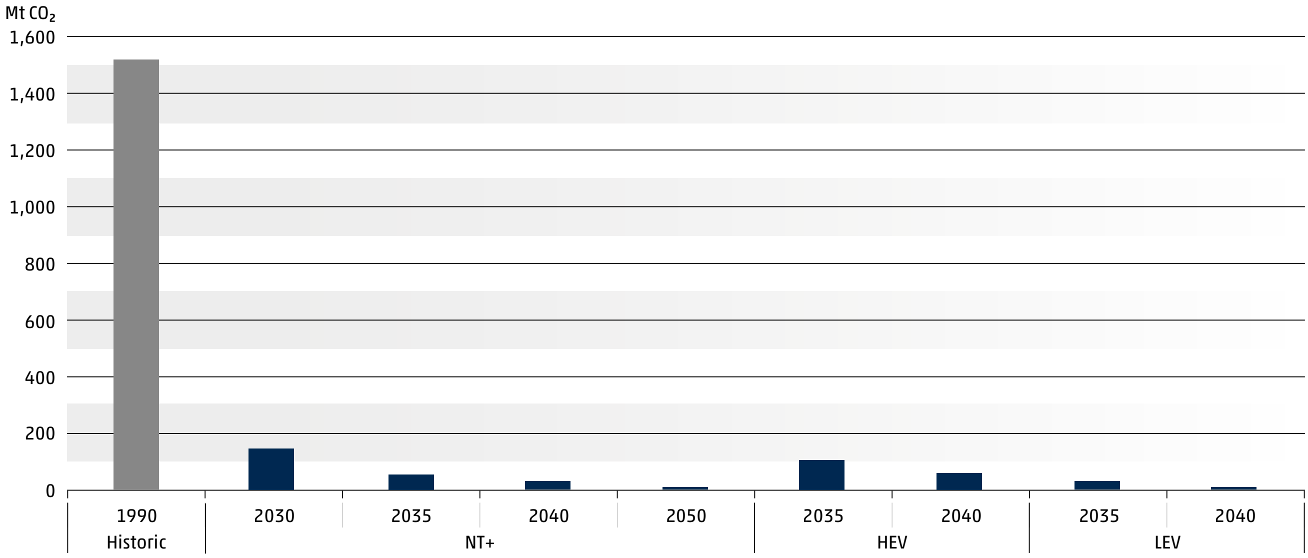

Figure 97: Emissions of the electricity generation

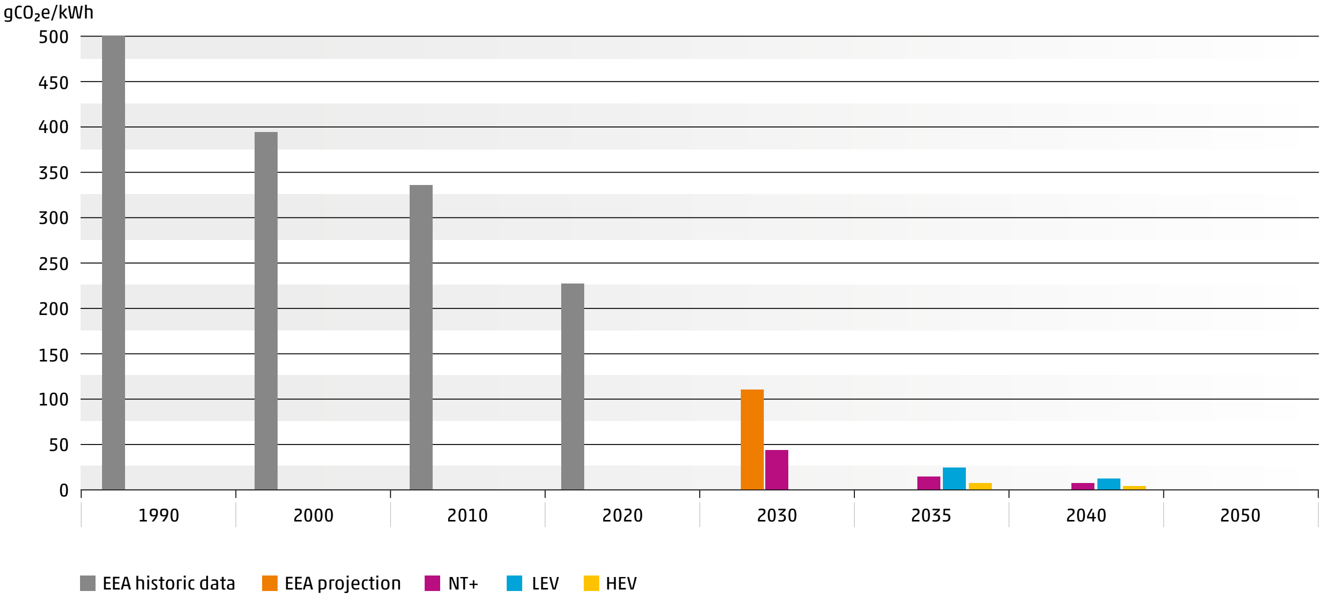

Figure 98: Carbon intensity of power generation

10.4.2 Hydrogen

Electrolysers are supplied by both dedicated RES and market electricity. Dedicated RES ensures carbon free hydrogen and synthetic fuel production, while electrolysis based on market electricity may still involve limited emissions. As the electricity and hydrogen systems are price driven, the model largely avoids operating electrolysers, when this would trigger additional fossil fuel generation.

Due to system constraints such as, must run operation up to 2030, minimum CHP output, and hydrogen supply demand requirements, electrolysers may operate for a limited number of hours using electricity with low, but nonzero, carbon intensity. This remains compatible with the pathway to carbon neutrality where the alternative system response would be more carbon intensive.

In this context, the hydrogen produced is expected to be increasingly transported through existing gas infrastructure, suitably adapted, thereby fostering the integration of energy systems and optimising the use of already available infrastructure assets. Furthermore, the system may be complemented by imported hydrogen flows, contributing to ensuring security of supply.

Overall, emissions from hydrogen production remain modest (Figure 99). In the NT+ scenario, they peak at 3.77 MtCO_2 in 2035. The High Economic Variant reaches a higher peak of 7.28 MtCO_2 in 2035, while the Low Economic Variant records the lowest emissions, peaking at 1.04 MtCO_2 in 2040.

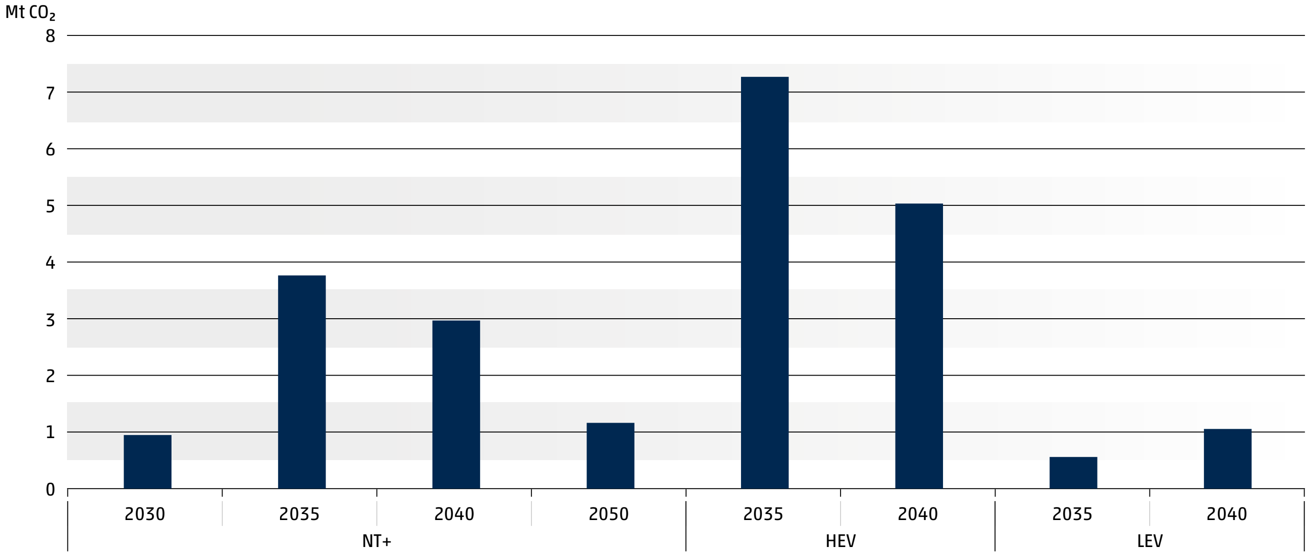

Figure 99: Emissions of the hydrogen generation (EU27)

11 TSO SURVEY INTRODUCTION //

As part of the Scenario Building process for TYNDP 2026, conducted jointly with ERAA 2025, a dedicated survey was conducted among national electricity and gas TSOs to validate input datasets. This was done to ensure alignment with European regulatory requirements and enhance transparency in scenario development. The survey builds on the data collection exercise for ERAA 2025 and TYNDP 2026 launched in November 2024 by ENTSO-E and ENTSOG, and guided by the "Joint ERAA 2025 and TYNDP 2026 Scenarios Data Collection Guidelines"[28].

The survey was open between 25 July and 29 August 2025, and responses were requested as joint submissions from electricity and gas TSOs at national level. A total of 35 responses were received out of 40 countries, representing a high participation rate and providing a robust basis for assessing the quality, consistency, and transparency of the datasets used in Scenario Building 2026. All EU27 member states TSOs responded to the survey.

The responses collected through this survey confirmed the following points:

- National datasets submitted by TSOs are mostly aligned with key European requirements, including the TEN-E Regulation and the ACER Framework Guidelines. If not aligned, a justification was provided by the country.
- National datasets provided were mostly validated on national level before submission by Ministries, DSOs, other national authorities, or other stakeholders.
- National datasets are mostly compliant with the country NECPs or national strategies, and if not a justification was provided by the country.

Responses are published in Annex I as part of the TYNDP 2026 Scenarios Package, supporting a transparent scenario development process.

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[28] Document is available here: https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/ERAA/ERAA_2025/ERAA2025%20_%20TYNDP2026%20Data%20Collection%20Guidelines.pdf

12 BENCHMARK //

ACER Framework Guidelines require ENTSOs to benchmark their scenario with the most relevant external scenarios by providing a comparison of key inputs and outputs for the whole scenario time frame. Deviations should be described in detail and to the extent possible explained as well as their expected implications on scenario outcomes. Given the large number of available scenario studies, ENTSOs had to identify comparable scenarios mainly from the methodological baseline and assumptions point of view.

When choosing suitable benchmark scenario respecting the principles of robustness and comparability as defined by the ACER Framework Guidelines, ENTSOs selected following criteria:

- Scenario developed by the European Commission (EC) or a body with close connection to the EC
- Scenario selected as a benchmark shall be EU target compliant for all target years, if not possible at least meeting ultimate 2050 target on Union climate neutrality
- Scenario published as close as possible to the ENTSOs scenario report and providing outputs for all scenario target years

Based on the literature review the most suitable scenarios were selected as follows:

A) European Commission 2040 Climate target plan Scenarios[29]

Impact assessment report was issued in February 2024. It is focusing on the goal to reach climate neutrality in 2050. Projections in the assessment report are targeted to years 2040 and 2050. The impact assessment (IA) works with four scenarios reaching the climate neutrality in 2050. The main difference is for the target year 2040 when the levels of the net GHG emissions vary in the range of 78% – 94% reduction compared to 1990.

For the purposes of benchmark study in this report, ENTSOs work with the 2030 IA common starting point and S3 scenario for target years 2040 and 2050.

B) Joint Research Centre – Global Energy and Climate Outlook (GECO) 2025[30]

The scenarios in the Global energy and climate outlook intend to reach goals of the Paris Agreement. Time horizon of the study covers the target years of the TYNDP 2026 scenario. The GECO report works with four scenarios:

- Reference – represents the energy emissions trajectory under policies legislated up until early December 2025
- Nationally Determined Contribution-Long-Term Strategies (NDC-LTS) considers the emissions targets of NDC in the medium term (2030 and 2035) and the LTSs in the longer term. This scenario employs country-specific carbon values to achieve economy-wide emission targets.
- 2° C scenario and 1.5° C scenario – both scenarios are designed to limit global temperature increase at the end of the century to 2° C and 1.5° C These scenarios are constructed based on the policy settings of the Reference scenario, to which the global carbon price is added as the sole additional policy driver. These scenarios are therefore stylising representations of an economically efficient pathway to the temperature target, as the uniform global carbon price ensures that emissions are reduced where abatement costs are lowest.

For the purposes of benchmark study in this report, ENTSOs work with the 1.5° C scenario.

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[29] Impact assessment report is available here: EUR-Lex – 52024SC0063 – EN – EUR-Lex

[30] Full report is available here: JRC Publications Repository – Global Energy and Climate Outlook 2025

In addition, ENTSOs recognise that energy scenarios from a range of other organisations can produce complementary insights about energy infrastructure and related future developments and directions. Below, selected scenarios across EU27 countries are described, pointing to potentially alternative future developments to be recognised further. Cross-cuttingly, these scenarios assume fossil fuel phase-outs. Most raise issues relevant to actors outside the energy sector. A qualitative analysis of some of their key arguments is provided in Table 7.

As a limitation, a full breakdown across all their variables is not possible due to a range of different assumptions. Some scenarios also rely on TYNDP 2024 (and one of them relies on TYNDP 2022) as a data source. This list may not be exhaustive. Scenarios in academic publications are not included in the literature review and could be investigated. Technical note: Some of the scenarios are produced by organisations that also have been a part of the SRG in the TYNDP 2026 cycle.

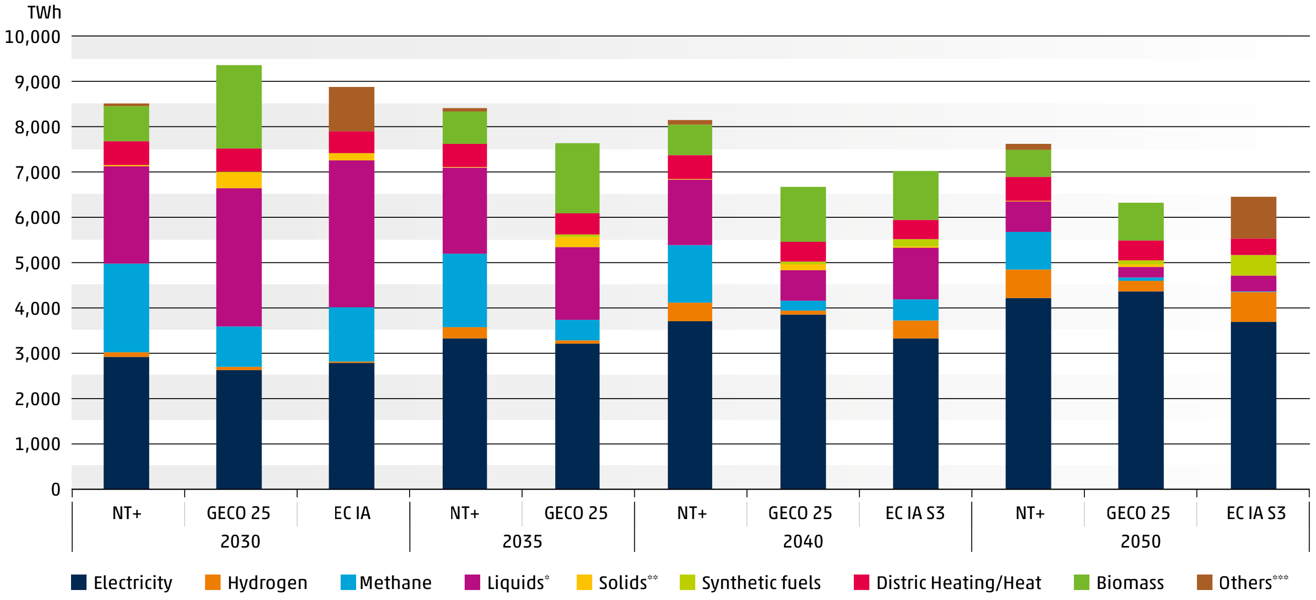
TITLE	KEY MESSAGES	ORGANISATION TYPE	AUTHORS
Designing energy infrastructure for a climate-neutral Europe	– Integrated, cross-sector, cross-vector energy scenarios to avoid misplaced investment – A cluster approach for clean molecules allows for a strategic use – Open-source modelling is helpful in investigating infrastructure choices	Think tank(s)	Agora Energiewende, Forum Energii, IDDRI, EPG and ECCO (2025)
Paris Agreement Compatible scenarios (PAC) 2.0 for energy infrastructure	– If buildings, transport and industry have lower demands, this can optimise supply – Very high flexibility in the energy system to optimise infrastructure – 100% renewable energy system by 2040 – An advanced circular economy EU-wide	Non-governmental organisations (NGOs)	CAN Europe, EEB, RGI and REN21 (2024)
Ensuring Resilience in the European Energy Transition	– Ramp up of renewable electricity, green hydrogen, biomethane, synthetic gases as well as carbon capture – Repurposing existing gas infrastructure into hydrogen infrastructure – Asks what happens, if energy demand is high, RES is low, or the grid is delayed	Industry	Eurogas (2024)
Collaborative Low Energy Vision for the European Region (CLEVER)	– Lower energy demand optimises supply – Building renovations, fossil free heating and mobility transformation, also supported by circularity – Sufficiency, efficiency and renewables assist in remaining within +1.5 C	NGOs, academia, research institutes	négaWatt (2023)
Choices for a more Strategic Europe	– Electrification is based on high shares of renewables, with EVs and heat pumps – Advanced EU-wide circular economy – Competitiveness, industrial modernisation and innovation require clear signals for long-term planning	Think tank	Strategic Perspectives (2023)
Decarbonisation Speedways	– Major growth in RES, electrification, energy efficiency, as well as system flexibility with demand response and storage options – More radical actions expedite the pathway – Investment is also required on DSO grids	Industry	Eurelectric (2023)

Table 7: Other European-wide energy and climate scenarios point to changes in energy supply as well as demands in key sectors, such as buildings, transport and industry

12.1 Final energy demand

Final energy demand is reduced in all scenarios. The benchmarked scenarios, GECO 25 and EC IA Scenario 3, after 2030 show a more aggressive decrease in the final energy demand compared to the NT+ as the central scenario. Demand reduction is particularly visible in the GECO 2025 scenario but also stands out in the EC IA S3 in the next decade (2030–2040).

Further reduction of final demand is expected in the 2050s in all three scenarios. All three scenarios foresee decreases in the demands for fossil fuels to contribute to a more efficient energy system. The future demands for each carrier are next presented, respectively.



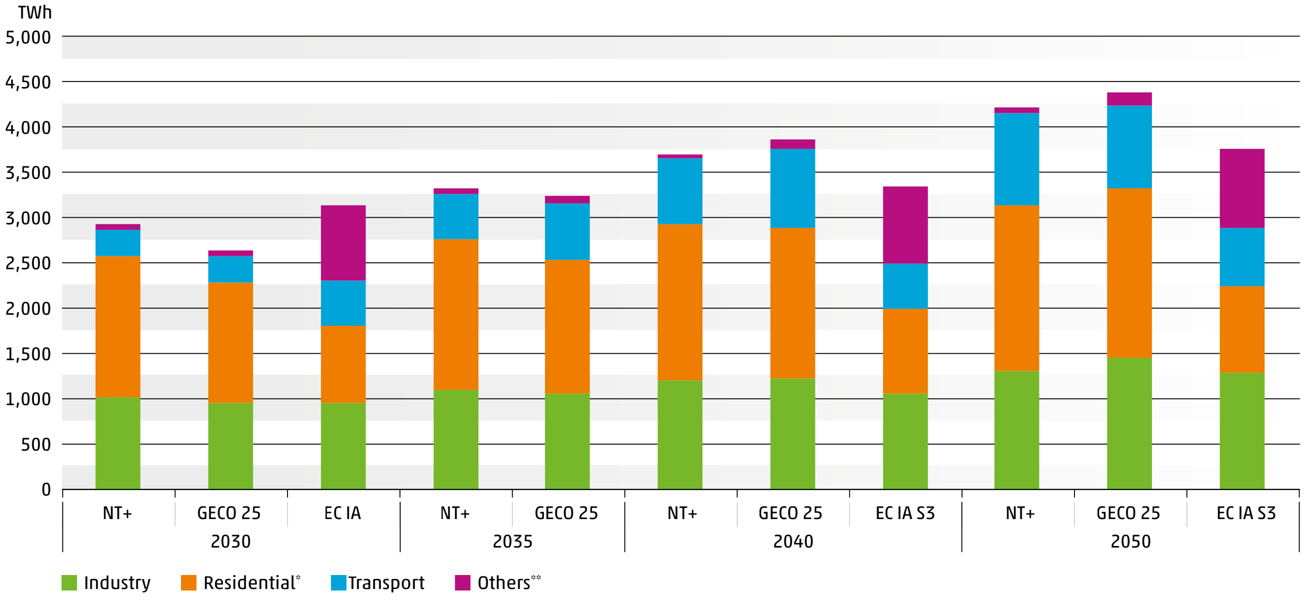
Final energy demand excludes non energy use, energy branch and international shipping. NT+ data after gap-filling methodology application.

* Liquids includes only oil for GECO 25 and EC IA S3.
** Solids include coal for GECO 25 and EC IA S3.
*** Others include Ammonia and geothermal, industrial excess heat, power to gas excess heat and solar for NT+, renewables for EC IA S3.

Figure 100: Benchmark – Final energy demand by fuel (EU27, TWh)

12.2 Electricity Demand

Overall, electricity demand grows in NT+ and the benchmarked scenarios alike. NT+ scenario is slightly below the GECO 25 trajectories for 2040 and 2050 target years. Both of the benchmarked scenarios, GECO 25 and EC IA show similar trends towards 2050 – a slight but steady increase of electricity demand in all sectors.

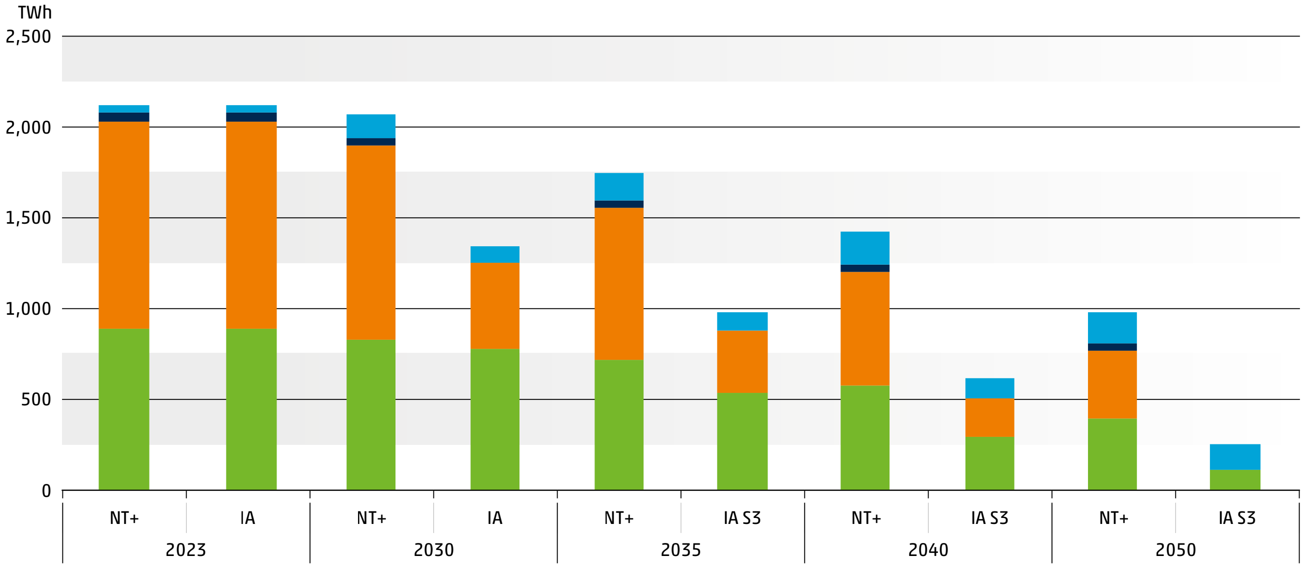


* Residential includes Built environment for TYNDP, for GECO includes Buildings
** Others for TYNDP includes agriculture and energy branch, for GECO includes Agriculture

Figure 101: Benchmark – Electricity demand per sector (EU27, TWh)

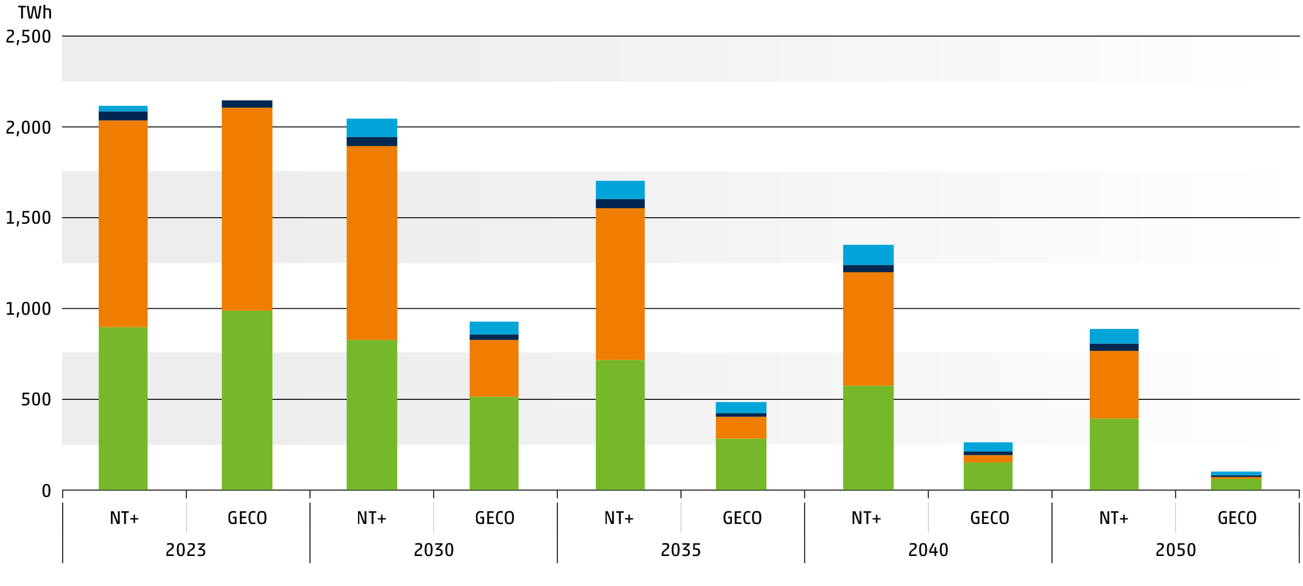
12.3 Methane demand

NT+ and IA scenario deviate in the built environment, while the overall trajectory is towards to a reduction of methane demand, as shown in Figure 102 below. For GECO, the deviation is even bigger: the industry and built environment sectors show lower values of methane starting from 2030, as shown in Figure 103.



* Industry comprehends refineries and does not comprehend the Non-energy uses.
** Built environment includes households and buildings.
*** Transport does not include international aviation and maritime bunkers.

Figure 102: Methane demand by sector: benchmarking of NT+ and IA S3



* Industry comprehends refineries and does not comprehend the Non-energy uses.
** Built environment includes households and buildings.
*** Transport does not include international aviation and maritime bunkers.

Figure 103: Methane demand by sector: benchmarking of NT+ and GECO

12.4 Hydrogen demand

In each source the hydrogen demand increases, with comparable values in NT+ and EC IA S3. The main deviation is visible in the transport sector, as shown in Figure 104 and Figure 105. While GECO shows a lower hydrogen consumption in general.

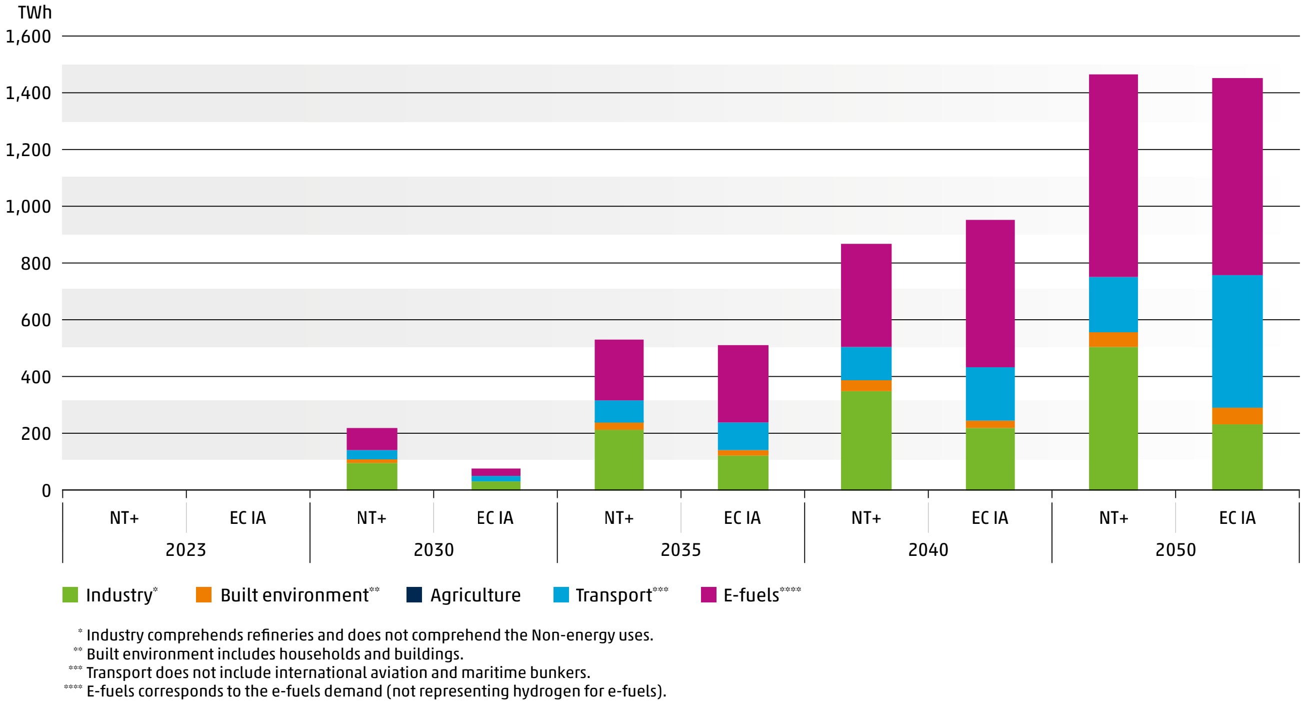


Figure 104: Hydrogen demand by sector: benchmarking of NT+ and IA S3

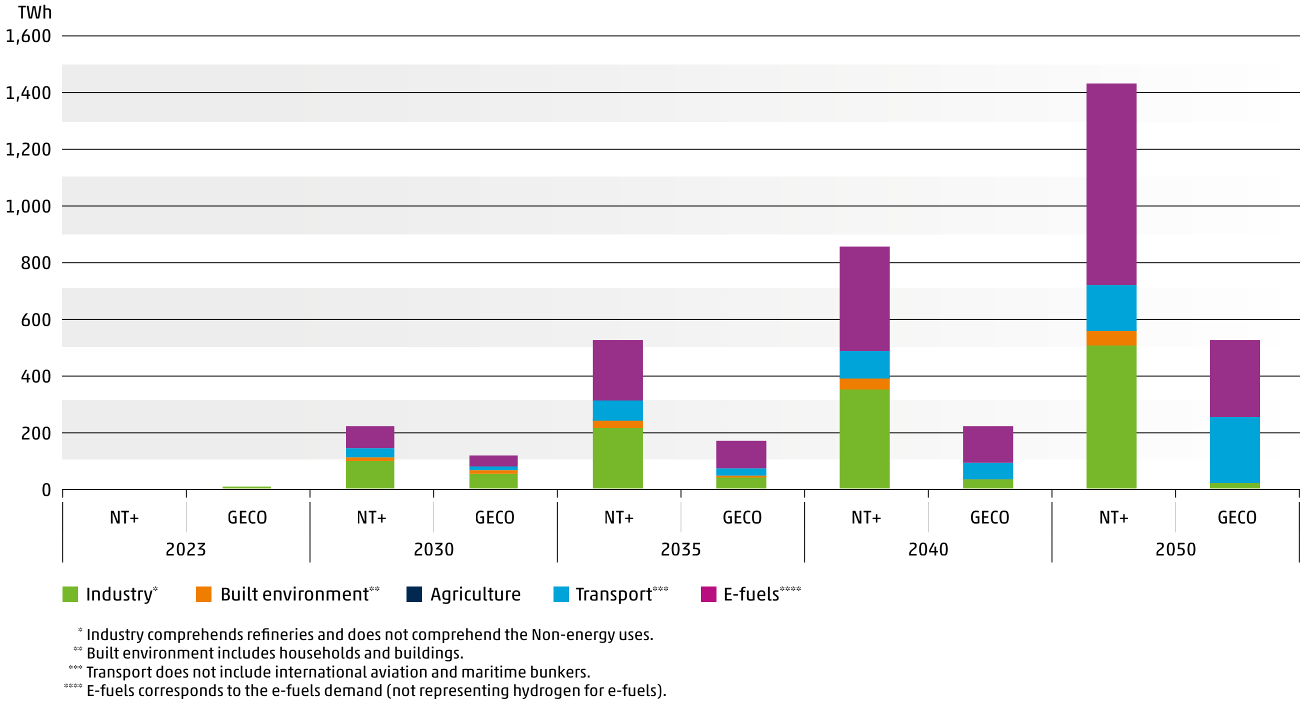


Figure 105: Hydrogen demand by sector: benchmarking of NT+ and GECO

12.5 Electricity generation

Installed capacities

GECO vs NT+

Fossil fuel capacity declines steadily over the period in NT+ scenario, opposite of what happens in the GECO study. While remaining relevant in the short to medium term to support adequacy and flexibility, fossil capacity is significantly reduced, for TYNDP NT+ scenario, towards 2050. The GECO scenario retains higher residual thermal generation capacity than NT+, indicating a continued need for dispatchable capacity to ensure system resilience under very high renewable penetration.

Nuclear capacity remains broadly stable over time, with differences between scenarios. For GECO, nuclear capacity decreases over time, while for NT+ follows the opposite path. This reflects lifetime extensions of existing units and selective new investments in some Member States.

Overall, the benchmark confirms a transition driven by large-scale renewable capacity additions. Figure 106 shows the differences in fossil fuels, nuclear and renewable electricity net installed capacity trajectories for electricity generation in the GECO and NT+.

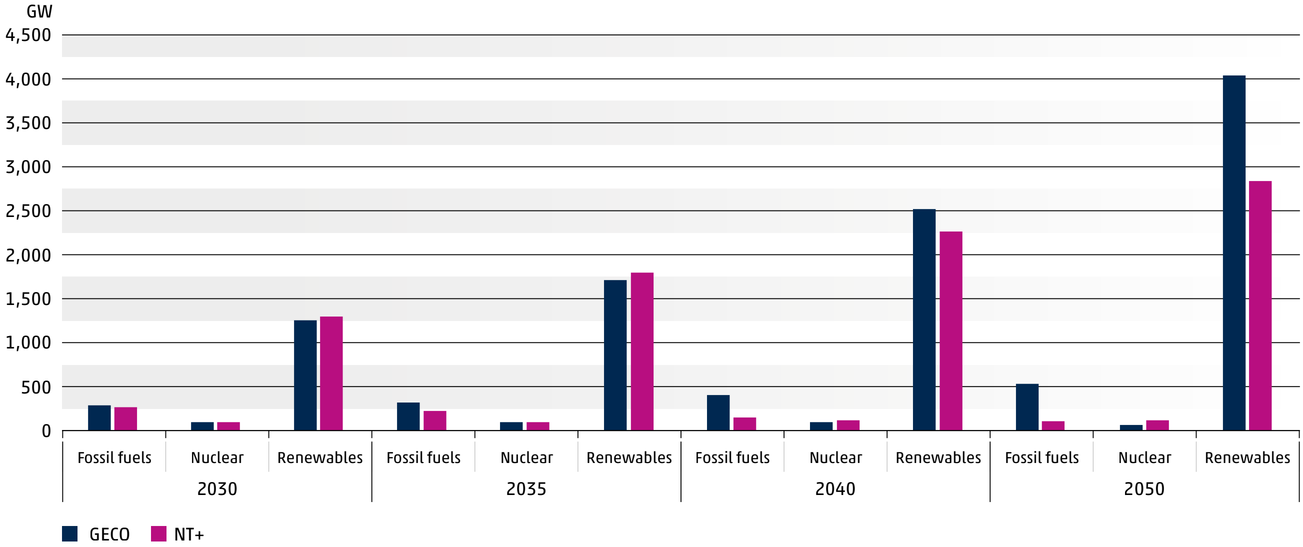


Figure 106: Benchmark of net installed capacity for electricity generation (EU27, GW)

Impact assessment vs NT+

In 2030, the IA scenario shows slightly lower total installed capacity compared with the NT+, with differences observed across all generation technologies. Fossil fuel capacity is reduced in IA relative to NT+, reflecting an earlier phase-out of conventional thermal assets. Nuclear capacity is marginally lower in IA, broadly consistent with similar lifetime assumptions in both frameworks, while renewable capacity remains almost identical, indicating a common view on near-term renewable deployment at EU27 level.

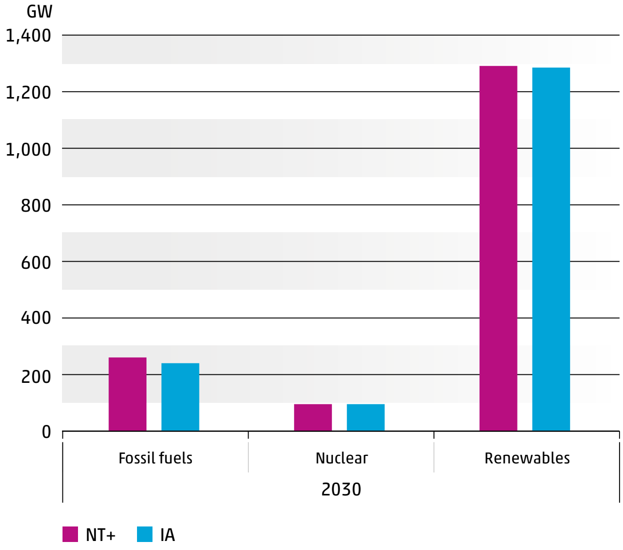


Figure 107: Benchmark for 2030 of net installed capacities for electricity generation, NT+ vs Impact Assessment (EU27, GW)

Overall, the comparison suggests that differences in the 2030 horizon are limited and largely driven by fossil capacity assumptions. Both IA and NT+ reflect a system already strongly oriented towards renewables, with only moderate divergence in the role of dispatchable thermal capacity to ensure adequacy and flexibility. Figure 107 shows the differences in fossil fuels, nuclear and renewable net installed capacity 2030 trajectory for electricity generation in the NT+ and IA.

By 2040 and 2050, more pronounced differences emerge between IA pathways and NT+. Across all IA variants, nuclear capacity is significantly lower than in NT+, reflecting stricter phase-out assumptions or limited lifetime extensions. This reduction is partly compensated by higher renewable capacity in most IA scenarios, particularly in S3, which shows the highest renewable build-out by 2040.

Thermal generation capacity in IA remains higher than in NT+ in both horizons, indicating a more persistent role for dispatchable thermal capacity under IA assumptions. This contrasts with NT+, where thermal generation capacity declines more sharply towards 2050, highlighting different perspectives on system flexibility needs and the pace of full decarbonisation. Figure 108 shows the differences for 2040 and 2050 net installed capacity pathways for electricity generation in the NT+ and IA.

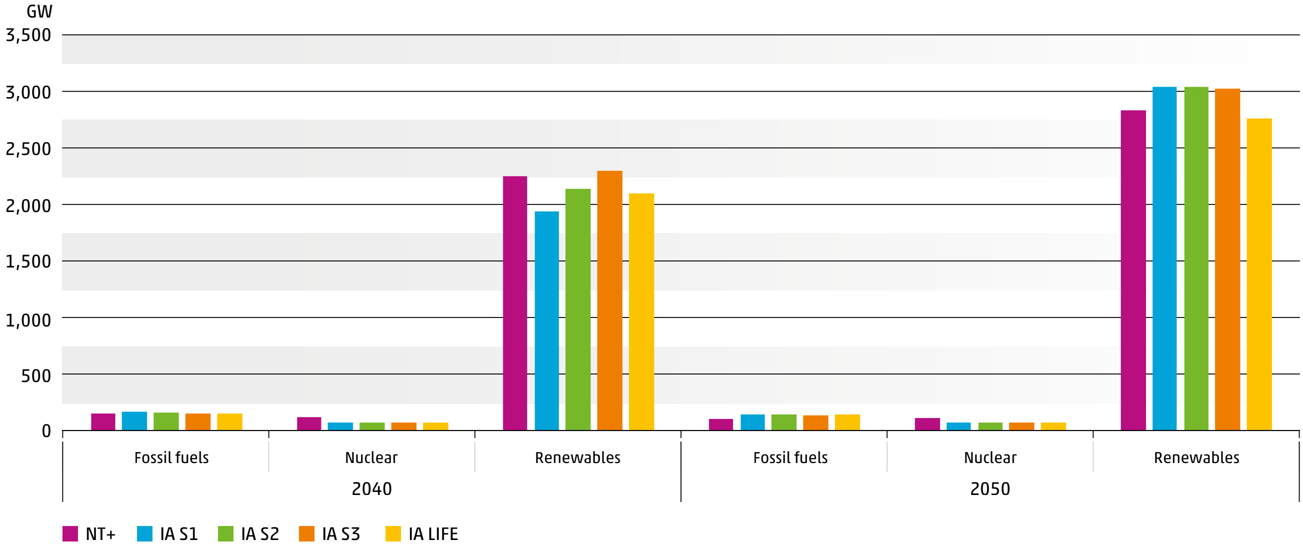


Figure 108: Benchmark for 2040 and 2050 of net installed capacity for electricity generation, NT+ vs Impact Assessment (EU27, GW)

Electricity generation

GECO vs NT+

Regarding fossil fuels, the GECO study assumes an increasing level of utilisation towards 2050. This contrasts with the NT+ scenario, where the reliance of the EU27 electricity system on fossil fuels decreases over time, reaching a marginal share of generation. In NT+, fossil-fuel-based generation mainly contributes to system flexibility and adequacy.

In terms of renewable energy, the GECO study assumes lower production yields than NT+. This is observed despite higher levels of installed renewable capacity in GECO in the 2040 and 2050 horizons compared with NT+.

Electricity generation from nuclear sources is higher in GECO but only in the short and medium term. This reflects in 2030 and 2035 higher assumed yields relative to NT+. By 2040 and 2050, nuclear generation is higher in the NT+ scenario than in GECO.

Overall, the benchmark indicates diverging supply-side or weather year assumptions between the two frameworks. In the GECO study, lower renewable generation yields compared with NT+ result in a higher contribution from fossil-fuel-based electricity generation. Figure 109 shows electricity generation per technology for GECO and NT+.

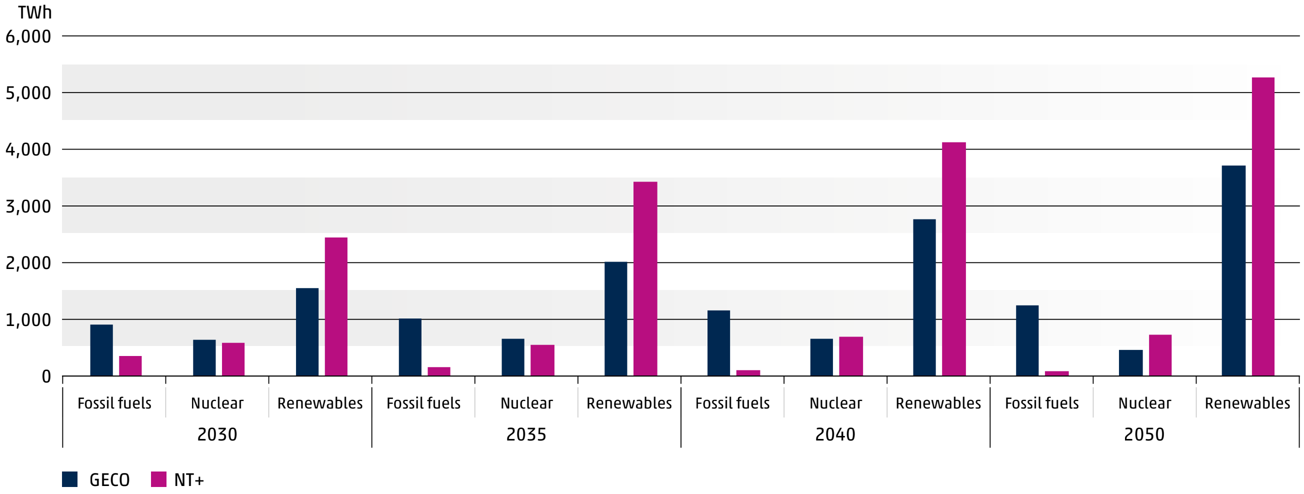


Figure 109: Benchmark of electricity generation (EU27, TWh)

Impact Assessment vs NT+

In 2030, electricity generation in the IA scenario shows higher fossil-fuel-based output compared with NT+, despite lower installed fossil capacity. This indicates higher utilisation of thermal assets in IA, potentially reflecting more conservative assumptions on renewable availability or flexibility. Nuclear generation is lower in IA than in NT+, while renewable generation remains broadly comparable. The benchmark suggests that, in the short term, IA relies more on conventional generation to balance the system, whereas NT+ assumes higher effective contribution from low-carbon sources.

These differences underline contrasting assumptions on operational patterns rather than structural disparities in installed capacity. Figure 110 shows the differences in fossil fuels, nuclear and renewable generation in 2030 for electricity generation in the NT+ and IA.

In the longer term, IA scenarios display substantially higher fossil-fuel-based generation than NT+, particularly in 2040. Although this contribution decreases by 2050, it remains significantly above NT+ levels, where fossil generation becomes marginal. Nuclear generation in IA is consistently lower than in NT+, in line with the lower installed nuclear capacity.

Renewable generation in IA increases strongly towards 2050 and exceeds NT+ levels in absolute terms, driven by higher installed renewable capacity. Nevertheless, the continued role of fossil generation in IA highlights a more gradual transition towards a fully decarbonised electricity mix, contrasting with the more accelerated decarbonisation pathway assumed in NT+.

Figure 111 shows the differences for 2040 and 2050 electrical generation per technology in the NT+ and IA.

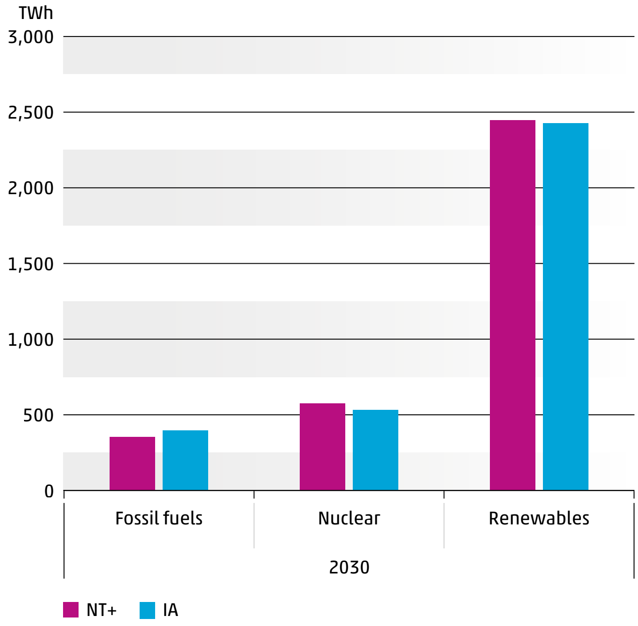


Figure 110: Benchmark for 2030 of electricity generation, EU27 for Impact Assessment and NT+ scenario

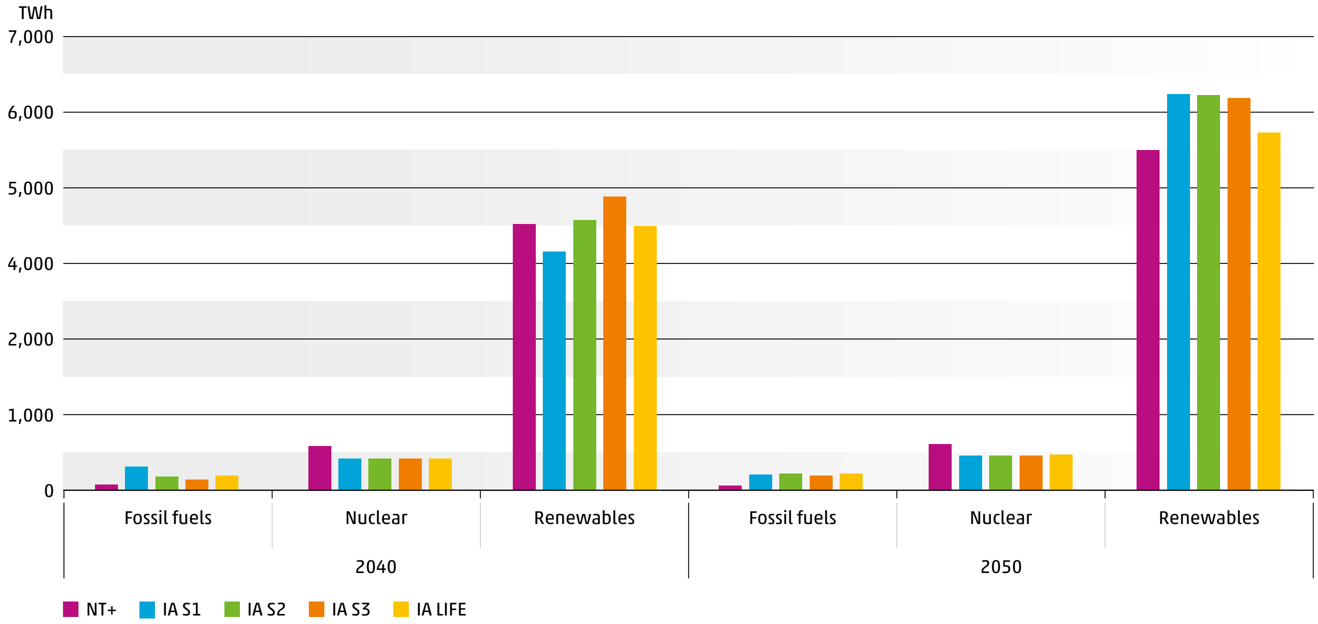


Figure 111: Benchmark for 2040 and 2050 of electricity generation, EU27 for Impact Assessment and NT+ scenario.

12.6 Methane supply

All three scenarios show a declining trajectory of methane supply over time. Compared with the GECO and IA scenarios, NT+ maintains a higher level of methane supply throughout the target years, starting from 2030, and ends in 2050 with a higher remaining methane supply than both benchmarking scenarios. See section on Gas and Methane Supply on methane composition in NT+.

Although the scenarios differ in supply volumes, methane supply is cut into less than half in 20 years in NT+ and GECO alike. For IA, only 2040 and 2050 figures are displayed (Figure 112). As the figures are not disaggregated by gas type, a detailed comparison of different methane sources is not possible. Nevertheless, most of the methane in the NT+ scenario consists of biomethane produced within the EU.

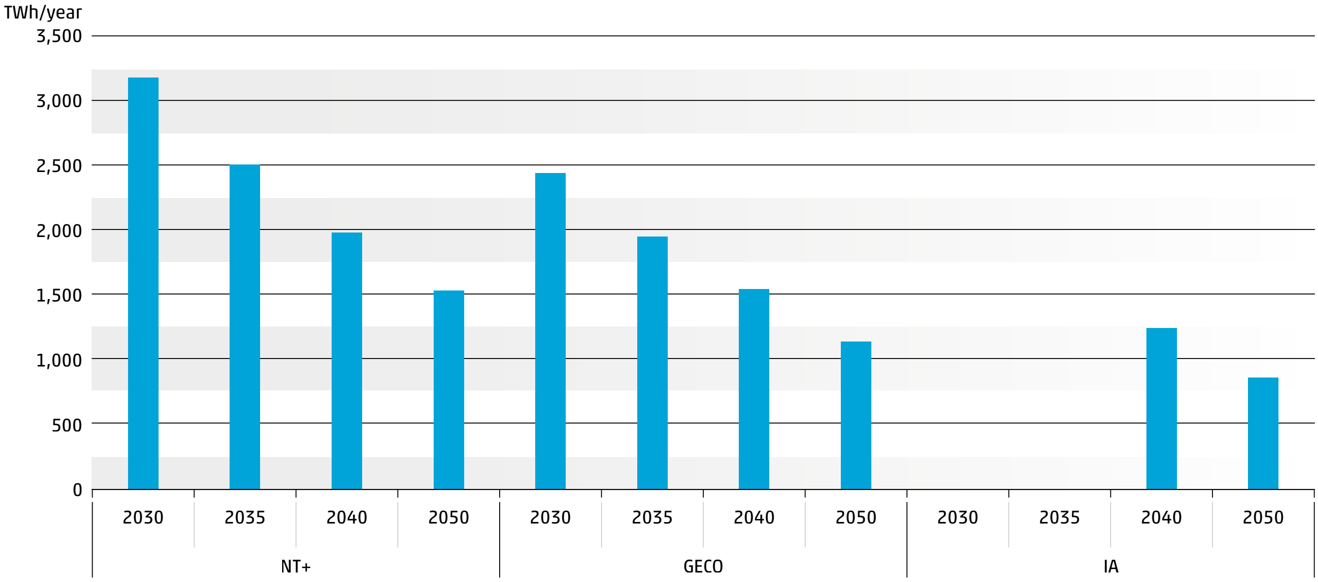


Figure 112: Benchmark of methane supply (EU27)

12.7 Hydrogen supply

The NT+ scenario shows a steadily increasing hydrogen supply, reaching around 1,600 TWh/year by 2050. For NT+, visit sections on Hydrogen supply and generation as well as Hydrogen supply variant analysis. Compared with the IA scenario, the two trajectories are broadly aligned around 2040, whereas by 2050 the IA scenario exceeds NT+ in terms of total hydrogen supply (Figure 113).

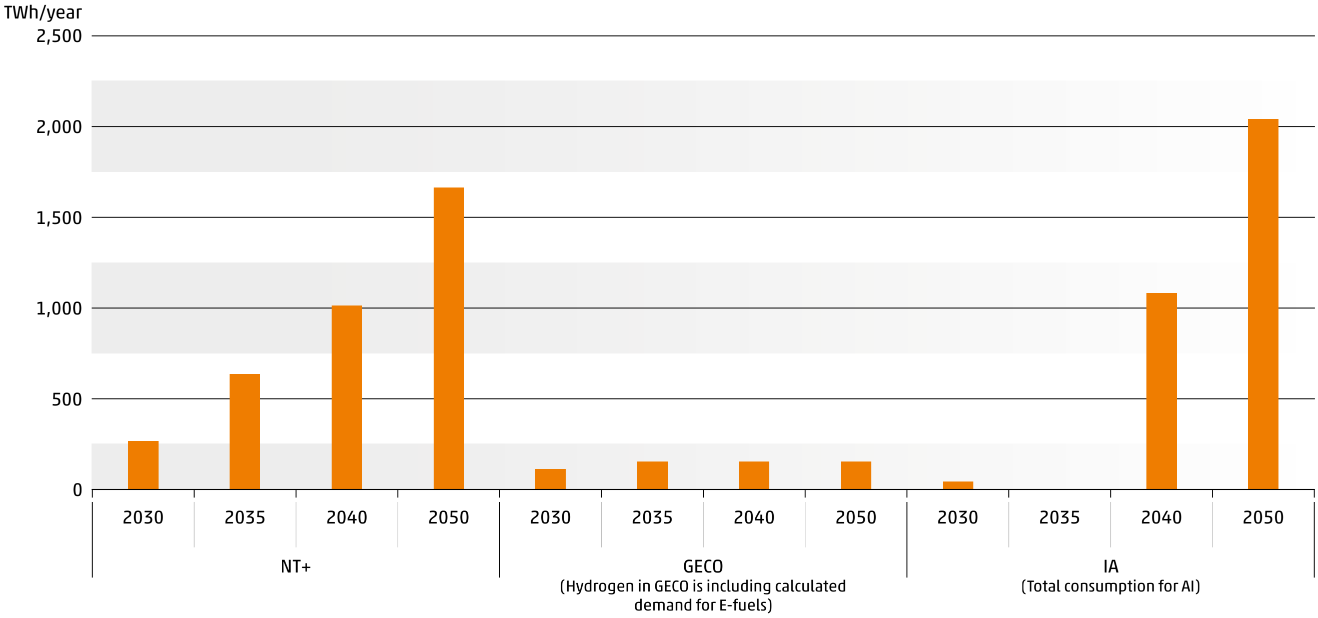


Figure 113: Benchmark of hydrogen supply (EU27)

12.8 Biomass supply

In the NT+ scenario, biomass supply remains consistently below the GECO reference level throughout the entire period, while generally exceeding the levels reported in the IA. After 2040, both the GECO and IA scenarios show declining biomass supply trajectories, whereas the NT+ scenario continues to increase biomass supply over the same period.

As discussed in the chapter on Biomass Supply, the TYNDP 2026 scenarios foresee the use of biomass across several applications, and in all scenarios, biomass plays an important role in the energy system. Figure 114 shows biomass supply assumptions for NT+, GECO and IA.

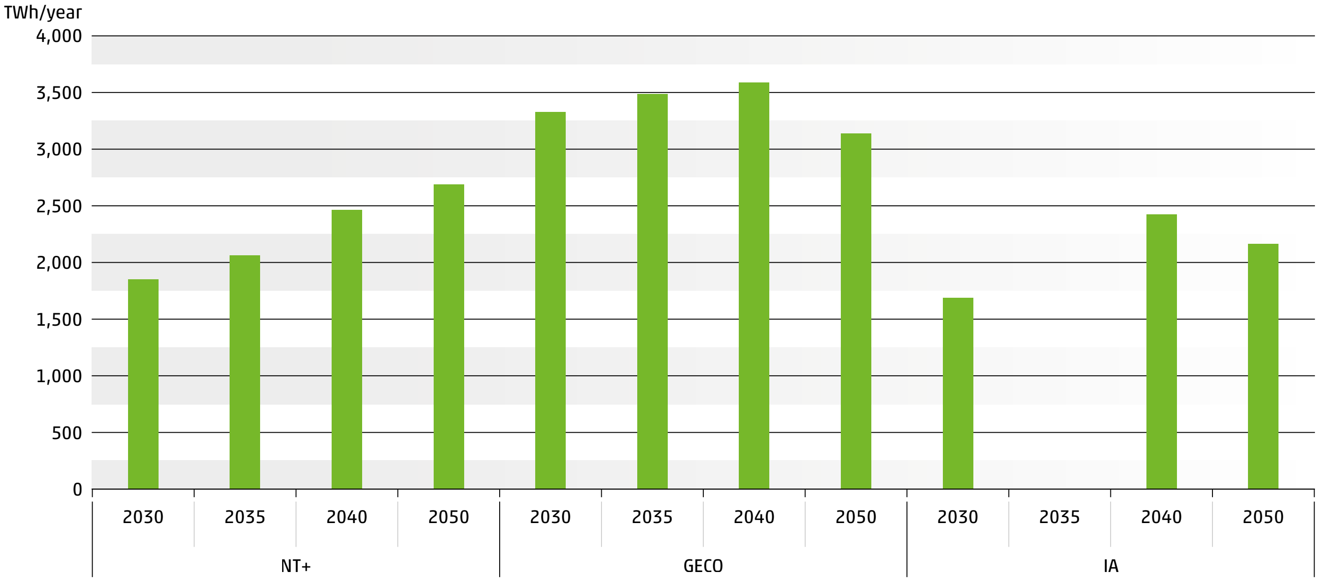
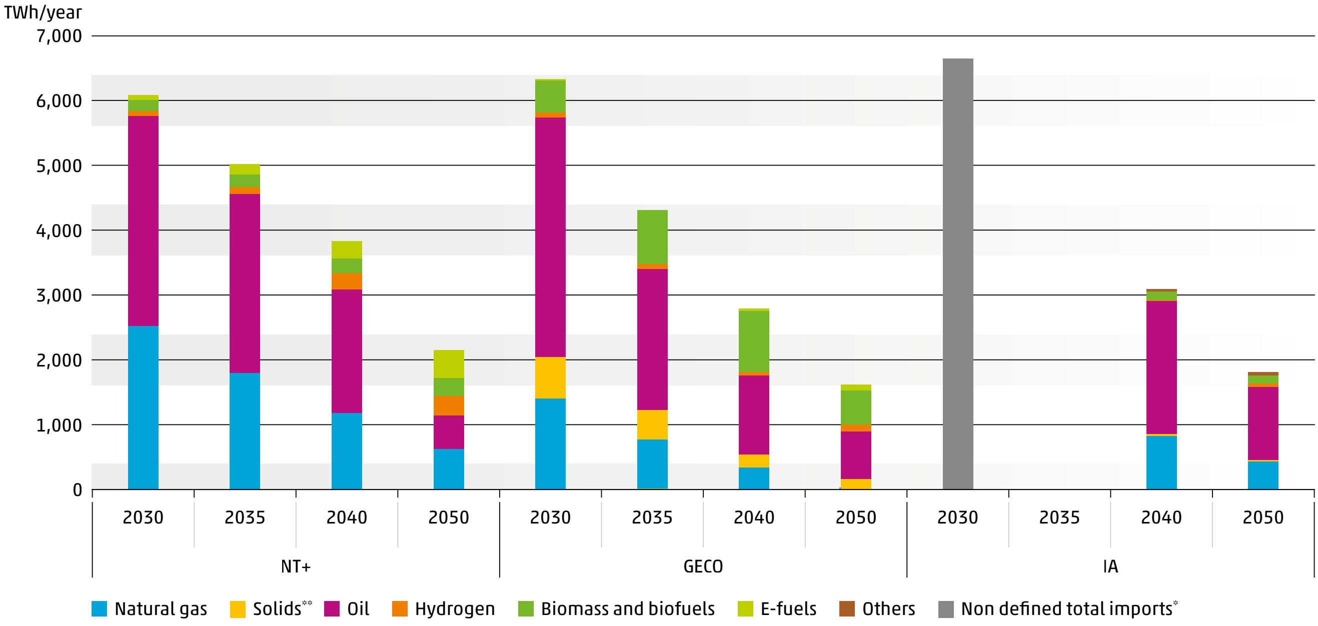


Figure 114: Benchmark of biomass supply (EU27)

12.9 Energy imports

Compared with the GECO and IA scenarios, NT+ shows lower total energy imports in 2030, but higher total energy imports across the remaining target years 2035, 2040 and 2050. This trajectory suggests that NT+ would be slightly less energy independent than the other two scenarios over the long term. Looking at individual energy carriers, the NT+ scenario relies more heavily on natural gas, hydrogen, and e-fuel imports than both GECO and IA across time horizons.

In contrast, the GECO scenario has the highest imports of biofuels and biomass. In 2050, GECO scenario has the highest levels of solids. However, unlike NT+ and IA, GECO has no natural gas imports left in 2050. The IA scenario, in particular, stands out for its significantly higher reliance on oil imports and is the least diversified in terms of its energy import mix in the long-term future.



*only total imports of is given for 2030 in EC IA ** Imports of solids was not considered in the NT+ scenario

Figure 115: Benchmark of energy imports (EU27)

13 APPROVAL PROCESS //

Following the finalisation of the TYNDP 2026 Scenario Report, the next steps are structured in line with the regulatory and governance framework set out under the TEN-E Regulation. The publication of the joint Scenario Report by ENTSO-E and ENTSOG marks the completion of the scenario-building phase, subject to approval. Once approved by the relevant governance bodies, the report is published and made available to stakeholders.

Within three months of receipt of the draft joint Scenario Report, ACER shall submit its opinion on compliance of the scenarios with the framework guidelines including possible recommendations for amendments.

Within three months of receipt of the opinion the Commission shall approve the draft joint Scenario Report or request the ENTSO for Electricity and the ENTSO for Gas to amend it.

Within two weeks of the approval of the joint Scenario Report the ENTSO's shall publish it on their websites.

LIST OF ACRONYMS //

ACER	Agency for the Cooperation of Energy Regulators
ATR	Autothermal Reforming
BECCS	Bioenergy with Carbon Capture and Storage
CBA	Cost Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CDD	Cooling Degree Days
DE	Distributed Energy
DFT	Demand Forecasting Tool
EC	European Commission
EE1st	Energy Efficiency First principle
EEA	European Economic Area
EED	EU Energy Efficiency Directive
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ERAA	European Resource Adequacy Assessment
ESABCC	European Scientific Advisory Board on Climate Change
ETM	Energy Transition Model
ETS	Emissions Trading System
EU	European Union
EU27	27 member states that constitute the European Union (EU)
EV	Electric Vehicle
FEC	Final Energy Consumption
FED	Final Energy Demand
GA	Global Ambition
GDP	Gross Domestic Product
GECO	Global Energy and Climate Outlook
GFCoE	Gross Final Consumption of Energy
GHG	Greenhouse Gas
HDD	Heating Degree Days
HEV	High Economic Variant
HHP	Hybrid Heat Pump
HP	Heat Pump
IA	Impact Assessment
ICT	Information and Communications Technology
IEA	International Energy Agency
JRC	Joint Research Centre
LEV	Low Economic Variant
LTC	Long-Term Contract
LULUCF	Land Use, Land Use Change and Forestry
NECPs	National Energy and Climate Plans
NT	National Trends
OCGT	Open Cycle Gas Turbine
P2G	Power to Gas (Electrolysis)
PECD	Pan European Climate Database
PEMMDB	Pan European Market Modelling Database
pEV	Passenger Electric Vehicle
RES	Renewable Energy Source
SAF	Sustainable Aviation Fuels
SMR	Steam Methane Reforming
SRG	Stakeholder Reference Group
SSP	Shared Socioeconomic Pathways
TEN-E	Trans-European Networks for Energy
TYNDP	Ten-Year Network Development Plan
TSO	Transmission System Operator
WGSB	Working Group Scenario Building

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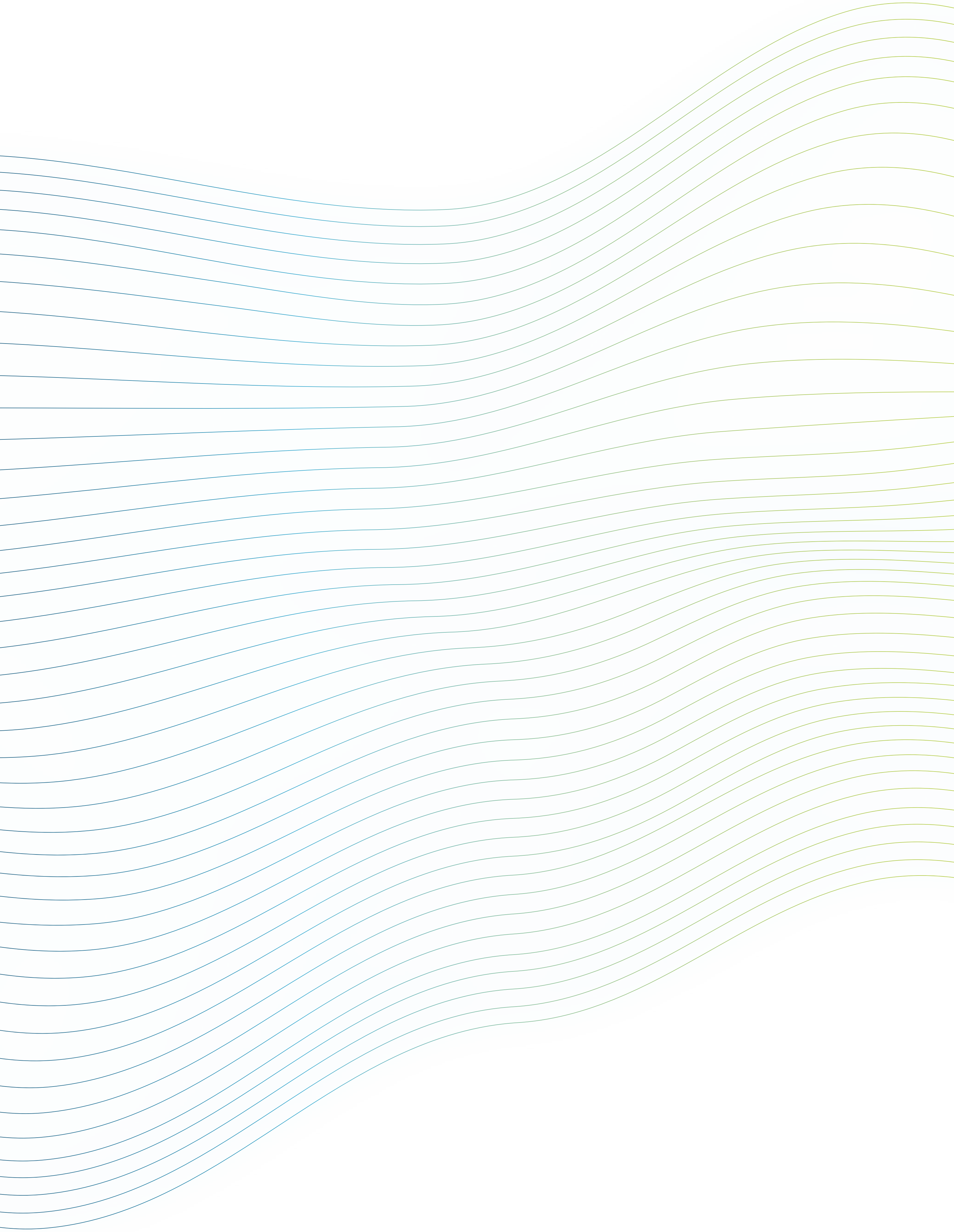

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