TYNDP 2024

The Hydrogen and Natural Gas TYNDP

HEAT
SUPPLY
INDUSTRY
NATURAL GAS
RETROFIT
BIOGAS
NETWORK
DECARBONISE

Natural Gas
System Assessment Report

Draft for public consultation

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1 INTRODUCTION

This document is established in accordance with Article 26 of Regulation (EU) 2024/1798, as part of the Hydrogen and Decarbonised Gas Market Package, and with Article 13 of Regulation (EU) 2022/869 regarding guidelines for trans-European energy infrastructure (the "TEN-E" Regulation). All information about the legal background, assumptions, modelling tools, and methodologies can be found in the TYNDP 2024 Hydrogen and Natural Gas System Assessment Methodology (Annex D3) as well as in the TYNDP 2024 scenarios.

For the first time, ENTSOG is publishing hydrogen and natural gas system-level assessments as separate, self-standing documents within its TYNDP. This report complements ENTSOG's draft TYNDP 2024 Hydrogen Infrastructure Gaps Identification Report. For an integrated sector perspective, the two reports can be seen in parallel to ENTSO-E's Identification of System Needs (IoSN) Report.

This document is a draft version, prepared for feedback during a public consultation, expected in June or July 2025. After integrating stakeholder feedback, it will be submitted to ACER for its Opinion, as part of the draft TYNDP 2024 package, under Article 27 of Reg. (EU) 2024/1789 on the internal markets for renewable gas, natural gas and hydrogen. The underlying methodology, detailed in Annex D3, mentioned above, underwent extensive consultation between 19 June and 9 July, 2024.

Since its previous edition, ENTSOG's TYNDP provides an overview of both the European hydrogen and natural gas infrastructure and its future developments. In TYNDP 2024, the main goal of the natural gas system-wide assessment is to measure the network's resilience and security of supply under a series of stress cases. In practice, this is quantified by demand curtailment. The report additionally contains a yearly supply adequacy outlook, including a biomethane progress report.

The integrated gas network is mapped in line with a scenario that follows National Energy and Climate Plans and is considered central to TYNDP 2024 (National Trends or NT+). Demand and supply for this scenario are based on figures collected from the TSOs, translating the latest policy and market-driven developments as discussed at national level.

Continued effort is necessary to further support sustainability, affordability and security of supply, in the current legal and geopolitical context. New regulatory provisions, like the updated legislation on internal markets for renewable gas, natural gas and hydrogen[1] are complemented by initiatives for alignment with industrial competitiveness goals. At the same time, diversification and ultimately independence from Russian volumes continue to be a high priority.

The results of this natural gas system assessment are also presented though an interactive visualisation platform, available here. ENTSOG is constantly working on improving the presentation of TYNDP simulations, to make results as accessible and user-friendly as possible.

1 Directive (EU) 2024/1788 on common rules for the internal markets for renewable gas, natural gas and hydrogen and Regulation (EU) 2024/1789 on the internal markets for renewable gas, natural gas and hydrogen.

2 RESILIENT, FLEXIBLE AND FUTURE-READY ENERGY SYSTEM

The TYNDP 2024 System Assessment confirms the EU's steady progress toward decarbonisation, supported by renewable energy integration and declining fossil fuel use. While market integration brings efficiency gains, delays in infrastructure development may lead to congestion, affecting sustainability, competition and diversification. Coordinated action among TSOs, regulators and policymakers remains essential to build a resilient, flexible, and future-ready energy system.

ROLE OF NATURAL GAS INFRASTRUCTURE IN THE EU'S ENERGY SYSTEM

Natural gas infrastructure remains essential in the EU's evolving energy system, particularly as the EU pursues its climate goals under the European Green Deal. The recent Clean Industrial Deal comes to complement these ambitions, with specific focus on decarbonising energy-intensive industries, as production of chemicals, steel and other metals. At the same time, security of supply is essential in reaching these goals, tested in three time frames: the whole year, a 2-week Cold Dunkelflaute, and a Peak Demand situation. A coordinated approach, integrating electricity and gases – including natural gas, biomethane, synthetic methane and hydrogen – is critical to ensuring cost-effective and efficient infrastructure development in a technology-neutral way.

In this context, the role played by gas infrastructure in providing the capacities needed for the electricity sector to back up variable renewable energy sources (RES) is pivotal. It helps mitigate electricity price hikes, leading to lower costs for industries and society as a whole. The upcoming "Grids Package", expected in 2026, may further contribute to such cross-sector integration, through further optimised network planning mechanisms and support for improved technical solutions.

In addition, repurposing existing natural gas infrastructure to transport hydrogen is expected to significantly contribute to the future European hydrogen network. This process must be planned transparently and in coordination between operators, while safeguarding natural gas security of supply and fulfilling regulatory requirements. An EU-wide security of supply assessment should complement analyses to evaluate the impact of repurposing on system resilience.

SUPPLY ADEQUACY AND SUSTAINABILITY

Conventional natural gas production in Europe is expected to decline steadily. However, it will be compensated by increasing volumes of biomethane contributing to the energy mix, in line with decarbonisation objectives. As renewable gas production scales up, natural gas infrastructure will continue to play a key role in supporting system flexibility and ensuring supply security throughout the transition. Underground gas storage remains a crucial asset for balancing supply and demand, especially during periods of peak use. While a decline in methane demand reduces the overall reliance on storage, its strategic function remains essential, helping to manage seasonal fluctuations, strengthening resilience in the event of supply disruptions and providing flexibility and resilience of electricity grid at peak time or periods of low RES infeed.

INDEPENDENCE FROM RUSSIA

The invasion of Ukraine by Russia on 24 February 2022 led to a major overhaul of energy policy objectives in terms of energy security and diversification of supply. The future development of gas infrastructure must consider the ongoing decarbonisation trend and a need to phase out Russian gas by 2027. The EC Communication on a roadmap will be followed by legislative proposals in June 2025. Based on the roadmap[2], the EC will propose that the phasing out of gas, under existing long-term or spot contracts, ends at the latest by 2027.

Picture courtesy of terranets bw

2 Roadmap towards ending Russian energy imports

3 SECURITY OF SUPPLY

Security of supply needs are assessed by measuring the ability of European gas systems to ensure continuity of methane and hydrogen supply to all countries under various stress conditions.

The assessment of hydrogen infrastructure is conducted in the draft TYNDP 2024 Hydrogen Infrastructure Gaps Identification report, based on the hydrogen demand curtailment from the Dual Hydrogen/Electricity Model (DHEM) results, which is used to identify infrastructure gaps within the assessed infrastructure levels, for assessed years.

The results presented in this document are solely based on the Dual Gas Model (DGM) and assess the resilience of the European natural gas system to cope with various stressful events for the reference weather year (i.e., 1995) and the stressful weather year (i.e., 2009) for the analysed infrastructure levels (i.e., Low natural gas and Advanced natural gas infrastructure levels, in combination with PCI/PMI hydrogen and Advanced hydrogen infrastructure levels) for the simulated years 2030 and 2040.

The stress cases are assessed based on their duration: 1 day for Peak Demand (PD), 2 weeks for Cold Dunkelflaute[3] (CDF), and a full year for the reference and stressful weather years.

The resilience of the natural gas system is measured by the degree to which the respective demand can be satisfied under the stress cases mentioned. It is expressed as the share of demand that is curtailed (curtailment rate – %) or as the absolute value of unsatisfied demand (curtailed demand – CR). This indicator is calculated at country or balancing zone level over the full-time horizon of the TYNDP assessment. Thereby, a cooperative behaviour among all countries is assumed, i.e., the available infrastructure will be used to equalise to the extent possible the curtailment rates of the different countries or balancing zones.

The simulations in Dual Gas Model (DGM) are undertaken on the daily granularity. All values that refer to the energy content (e.g., GWh/d or TWh/y) are stated in terms of their Gross Calorific Value (GCV) in this System Assessment Report. For methane, the conversion factor from NCV to GCV is 1.11; for hydrogen, the conversion factor from NCV to GCV is 1.176.

3.1 DEMAND ELASTICITY

Historically, high demand events, especially when combined with low supply or infrastructure conditions, have led to price increases that result in demand reductions. However, demand elasticity is influenced by various assumptions that vary from country to country.

When assessing the impact of climatic stress on gas infrastructure, demand is considered static and does not respond to potential supply deficits or price signals. This assumption is essential for conducting a consistent assessment across different years and scenarios in the TYNDP. To ensure consistency and transparency, the level of exposure to curtailment is always expressed as a percentage of demand, assuming no reaction to the various stressful events. This can also be interpreted as the required demand reduction to prevent curtailment.

3 "Kalte Dunkelflaute" or just "Dunkelflaute" (German for "cold dark doldrums") expresses a climate case, where in addition to a 2-week cold spell, variable RES electricity generation is low due to the lack of wind and sunlight.

3.2 INFRASTRUCTURE LEVELS[4]

Infrastructure levels represent the potential level of development of the European hydrogen network, electricity network, or natural gas network. More specifically, and as in previous TYNDP editions, the project status is the basis for the definition of natural gas infrastructure levels:

Low natural gas infrastructure level

The Low natural gas infrastructure level consists of:

- **Existing natural gas infrastructure** which represents the minimum level of natural gas infrastructure development and refers to natural gas infrastructure that is operational at the time of the TYNDP 2024 Project Collection as well as natural projects with the final investment decision (FID) taken and expected commissioning before 31 December 2024.
- **FID natural gas projects** which refer to projects having taken the final investment decision ahead of the TYNDP 2024 Project Collection.
- **Individual projects identified by the European Commission.** Despite not having taken final investment decision ahead of TYNDP 2024 Project Collection, identified projects are likely to show higher certainty of implementation, as they have been fully or partially funded by the respective EU Member States through the Recovery and Resilience Facility (RRF).

Advanced natural gas infrastructure level

An Advanced natural gas infrastructure level consisting of:

- **Low natural gas infrastructure level** as defined above.
- **Advanced[5] natural gas projects.**

Infrastructure levels serve as the basis for identifying infrastructure gaps in the TYNDP 2024 System Assessment. The TYNDP 2024 natural gas system assessment takes into account both natural gas and hydrogen infrastructure levels in the Dual Hydrogen/Natural Gas Model (or "Dual Gas Model" – DGM). This is accomplished by combining each natural gas infrastructure level with both hydrogen infrastructure levels within the TYNDP 2024 System Assessment, and coupling them through hydrogen production using methane. The assessment of hydrogen infrastructure is conducted in the draft TYNDP 2024 Hydrogen Infrastructure Gaps Identification Report.

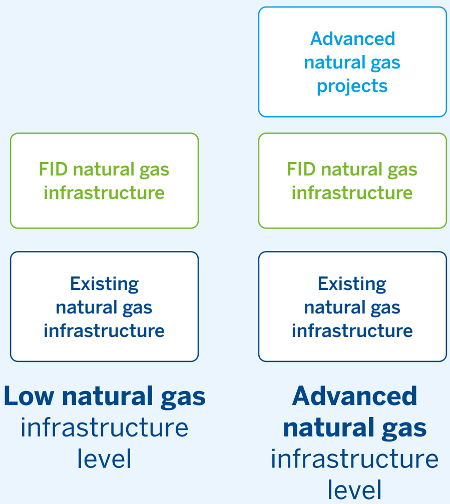

Figure 1: Natural gas infrastructure levels in TYNDP 2024

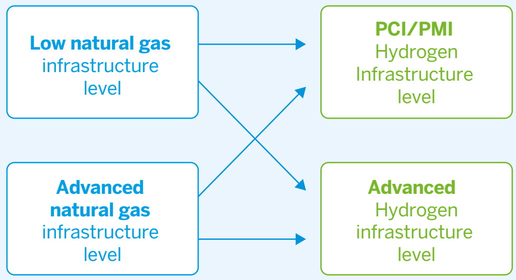

Figure 2: Natural gas and Hydrogen infrastructure levels in the System Assessment

4 Detailed information about the project collection and infrastructure levels is provided in the TYNDP 2024 Draft Infrastructure Report.

5 The "Advanced" status, as defined in the Methodology for Cost-Benefit Analysis of hydrogen projects, refers to projects with an expected commissioning date no later than 31 December of 2029 (six years after the 31 December of the year of the TYNDP project data collection, i.e., 2023 for TYNDP 2024) and that fulfil at least one of the following criteria: the permitting phase has started ahead of the TYNDP 2024 project collection, or the project has completed FEED (front-end engineering design) ahead of the TYNDP 2024 project collection.

Hydrogen infrastructure comprises both newly built infrastructure dedicated to hydrogen, and existing natural gas infrastructure that has been repurposed for hydrogen use. Consequently, it is essential to assess the implications of such repurposing within the natural gas infrastructure levels, particularly in the context of security of supply. The interaction between hydrogen and natural gas infrastructure introduces variability in infrastructure levels where repurposing is involved. Projects involving repurposed natural gas infrastructure can affect the availability and resilience of the natural gas network.

However, some hydrogen projects with Less-Advanced[6] status are excluded from the infrastructure levels considered in this analysis, as they are neither part of the Projects of Common or Mutual Interest (PCI/PMI) list nor sufficiently mature to be classified as having Advanced status[7].

Monitoring the evolution of these projects is essential, as hydrogen initiatives can progress rapidly between TYNDP cycles and may reach a more mature status in the near future. As previously noted, this dynamic development is one of the reasons that certain projects may not be included. Numerous initiatives are currently underway and continue to evolve. In this context, repurposing existing natural gas infrastructure to transport hydrogen is expected to play a key role in developing the future European hydrogen network. A clearer assessment of the impact of hydrogen repurposing on natural gas supply security requires more comprehensive and in-depth analysis.

More details on the various infrastructure levels and the related projects are available in the TYNDP Draft 2024 Infrastructure Report.

6 Projects which do not meet the criteria for FID or Advanced status are considered as having the Less-Advanced status.

7 The projects included in the infrastructure levels are listed in Annex I of the TYNDP 2024 Annex D1, Implementation Guidelines for Project-specific Cost-Benefit Analyses of Hydrogen Projects.

4 SUPPLY ADEQUACY OUTLOOK

The supply adequacy outlook is based on the comparison between the full range of natural gas supply potentials and the demand projections under the National Trends+ (NT+) scenario[8]. It covers the yearly demand of EU-27 countries and of other countries included in the assessment, supplied via the EU natural gas infrastructure.

Extra-EU supply needs are defined as the gap between EU demand and indigenous production, which includes biomethane production, conventional natural gas production, and synthetic methane. In this assessment, these supply needs can be met through a combination of LNG and pipeline gas imports.

As observed in **Figure 3**, a declining trend of extra-EU supply need is seen for the NT+ scenario. The combination of a lower demand and a higher biomethane production[9] in 2040 leads to decreasing extra-EU supply import needs over time in the NT+ scenario. The increased production of biomethane contributes towards a stable level of the indigenous production.

Under the NT+ scenario, extra-EU supply needs are estimated to range between 3,050 and 3,150 TWh/year (or 276 and 287 bcm/year) in 2030, and between 1,400 and 1,450 TWh/year (or 129 and 132 bcm/year) in 2040.

Any future deviations from the NT+ scenario assumptions regarding biomethane production, domestic natural gas output, or overall gas demand would directly affect these extra-EU supply needs.

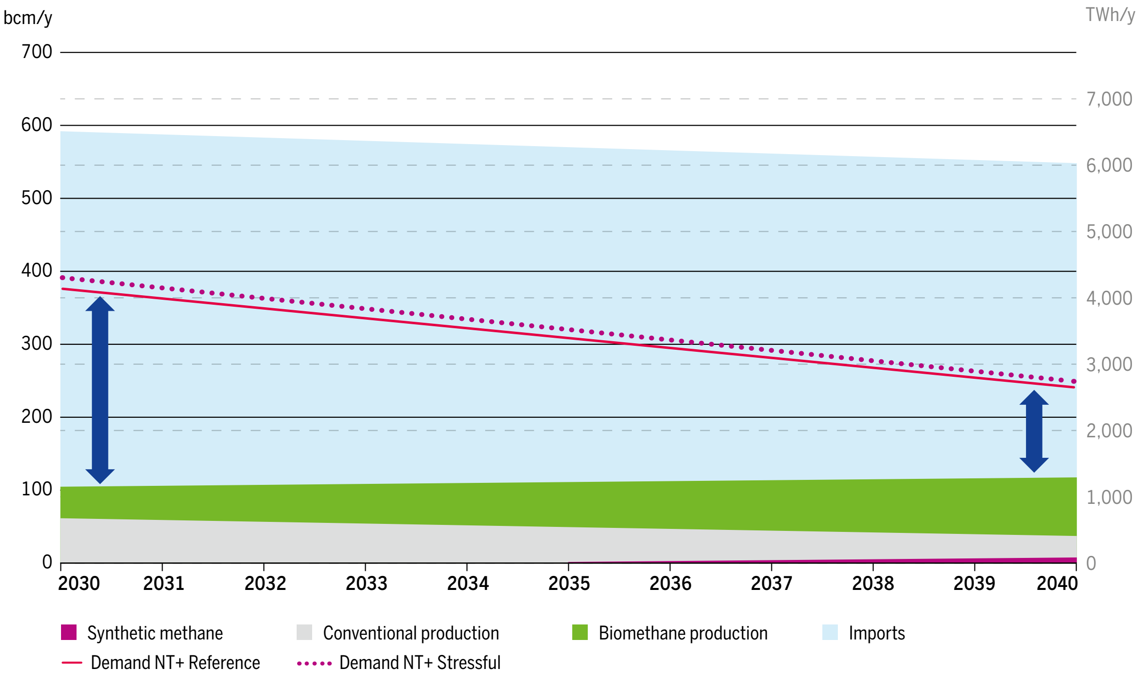

Figure 3: Supply Adequacy Outlook

8 The range is thereby defined by the variation of natural gas demand associated with the **reference weather year (i.e., 1995) and that of the stressful weather year (i.e., 2009)**.

9 The analysis of biomethane production can be found in Chapter 4.2, Biomethane production progress.

In addition, every four years, in accordance with the Security of Supply Regulation[10], ENTSOG conducts a Union-wide simulation of gas supply and infrastructure disruption scenarios. The Union-wide Security of Supply Simulation report assesses the role of the natural gas infrastructure under challenging conditions, such as cold winter demand and low gas storage levels disruption scenarios. Considering the evolution of the gas system anticipated over the next four years, such simulations reflect the configuration of emergency gas corridors applicable during the implementation of the next national preventive action and emergency plans.

4.1 SUPPLY MIXES

Underground natural gas storage is one of the most common and efficient methods of energy storage. These facilities are considered highly secure due to their subsurface location in porous geological formations, such as sedimentary rocks or aquifers, which are specifically designed to prevent gas leakage.

During the summer months, when energy demand is lower, natural gas is injected into underground storage to enhance security of supply. The gas is stored under high pressure and held until needed – typically during the colder months.

In winter, gas is withdrawn from storage and transported through pipelines to meet heating demand in residential and commercial sectors, as well as to supply electricity generation plants such as combined cycle gas turbines (CCGTs). Gas stocks must be carefully monitored to ensure that sufficient supply is available to meet demand at all times.

The supply configuration applied in the Dual Gas Model (DGM) is designed to minimise the use of Russian natural gas. In line with this assumption, the simulation results indicate that Russian pipeline supply does not contribute to the overall supply mix. This reflects a strategic shift towards diversification of supply sources and enhanced energy security.

10 Regulation (EU) 2017/1938 of the European Parliament and of the Council concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010 ("the Regulation") entered into force on 1 November 2017. It was subsequently amended by Regulation (EU) 2024/1789 of the European Parliament and of the Council of 13 June 2024 on the internal markets for renewable gas, natural gas and hydrogen.

SUPPLY MIXES UNDER PEAK DEMAND SITUATIONS

Under Peak Demand (PD) situations, the balance between supply and demand significantly depends on the utilisation of underground natural gas storage. However, due to the substantial decline in methane demand over the years, the level of sufficiency required from storage has decreased.

Nevertheless, natural gas infrastructure (including underground storages) remains essential for enhancing the security of gas supply in Europe, particularly to support the supply and demand balance not only in the Peak Demand (PD) situations or event of import disruptions but also amid a decrease in gas imports over time.

The following charts illustrate the evolution in the different infrastructure levels and scenarios.

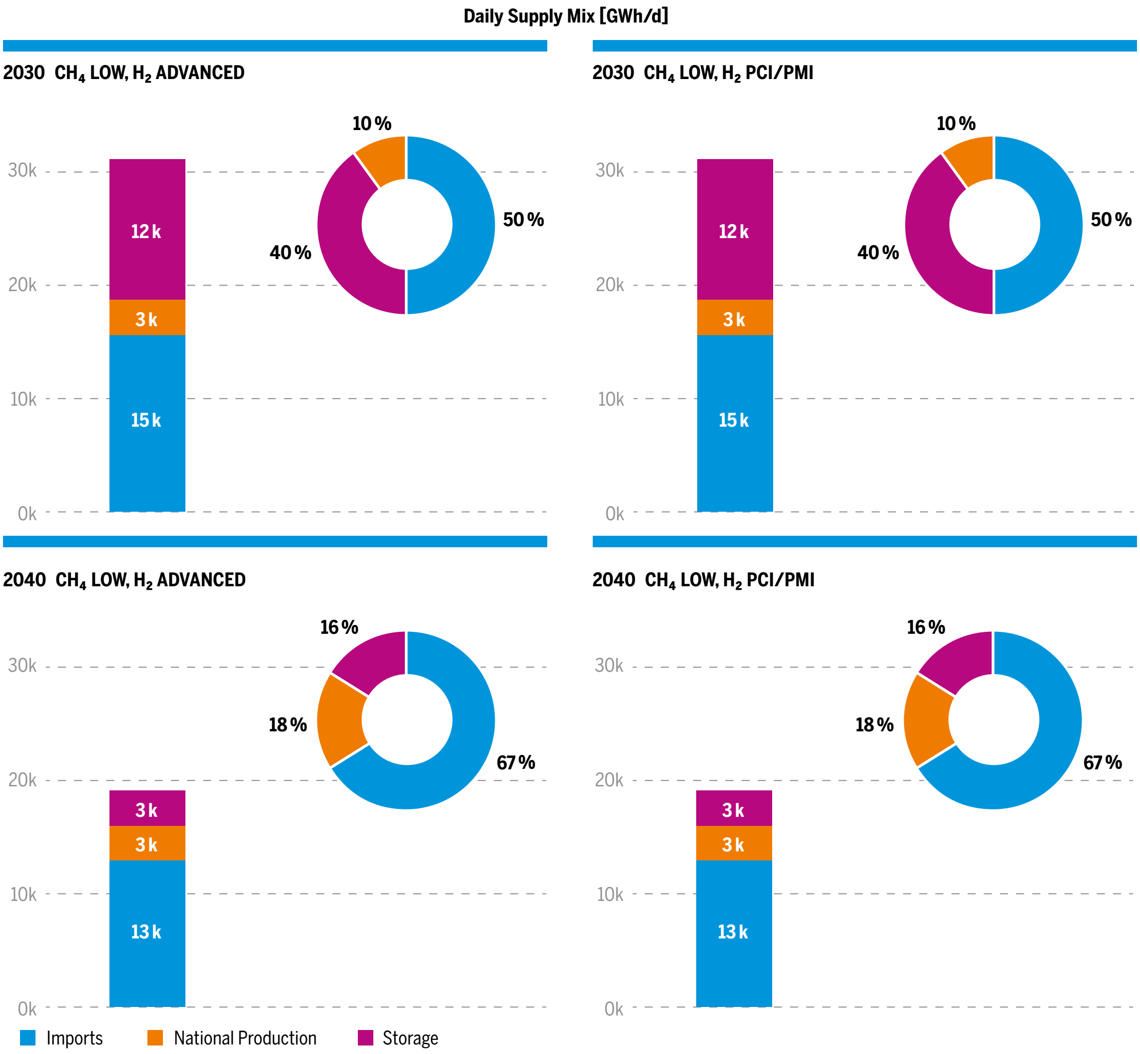

Figure 4: CH_4 Supply Results with Peak Demand in Low natural gas infrastructure level

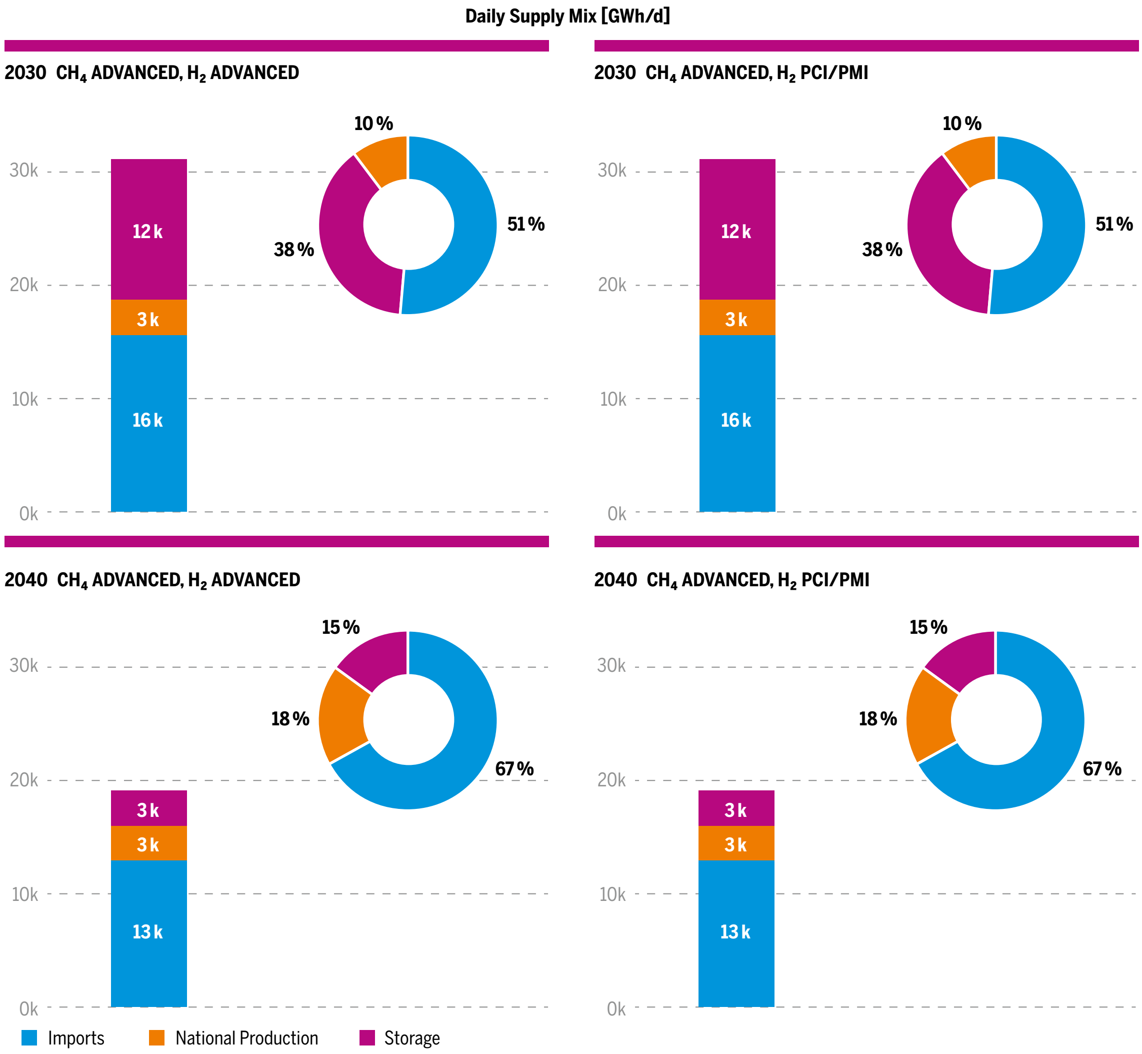

Figure 5: CH_4 Supply Results with Peak Demand in Advanced natural gas infrastructure level

SUPPLY MIXES UNDER YEARLY DEMAND

This analysis is based on the differences of the contrasted supply mixes in the European yearly supply and demand balance for the reference weather year (i.e., 1995) and the stressful weather year (i.e., 2009). Storage facilities are assumed to balance seasonal fluctuations, with injection starting and withdrawal ending at a 30 % storage level. Therefore, storage is not represented in the yearly supply mix graphs.

Conventional natural gas production declines over the years and is gradually replaced by the expected ramp-up in biomethane production.

At the same time, the import shares from Norway, LNG, North Africa, and the Caspian region are increasingly substituted by national production, alongside a substantial decrease in methane demand over time.

The evolution of the supply mix shares under both the Low and the Advanced natural gas infrastructure levels follows the same trend.

The overall yearly supply and demand balance under stressful weather conditions (i.e., 2009) represents an increase by approx. 5 percentage points when compared to the reference weather year (i.e., 1995).

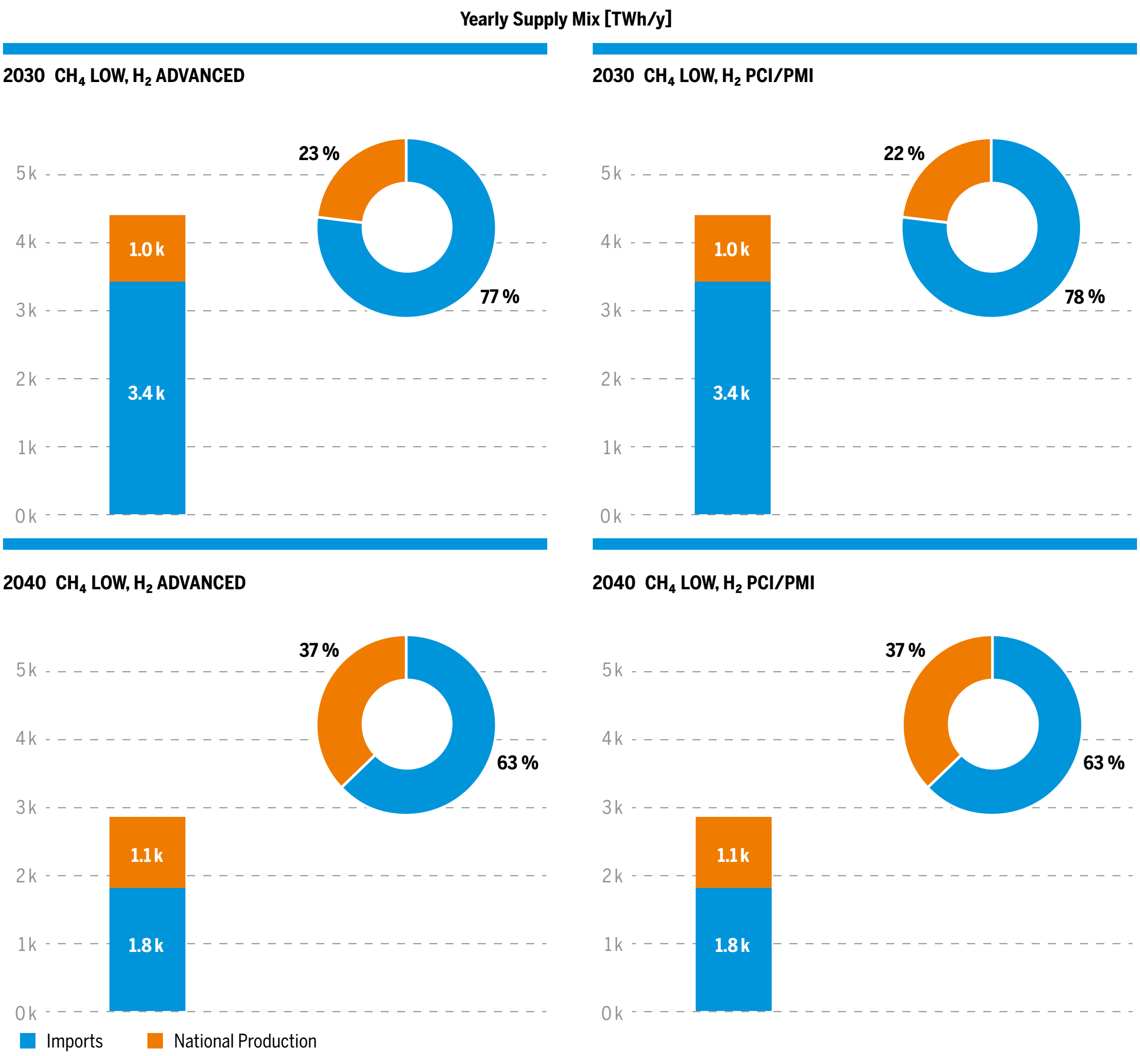

Figure 6: Reference weather year Supply Results in Low natural gas infrastructure level

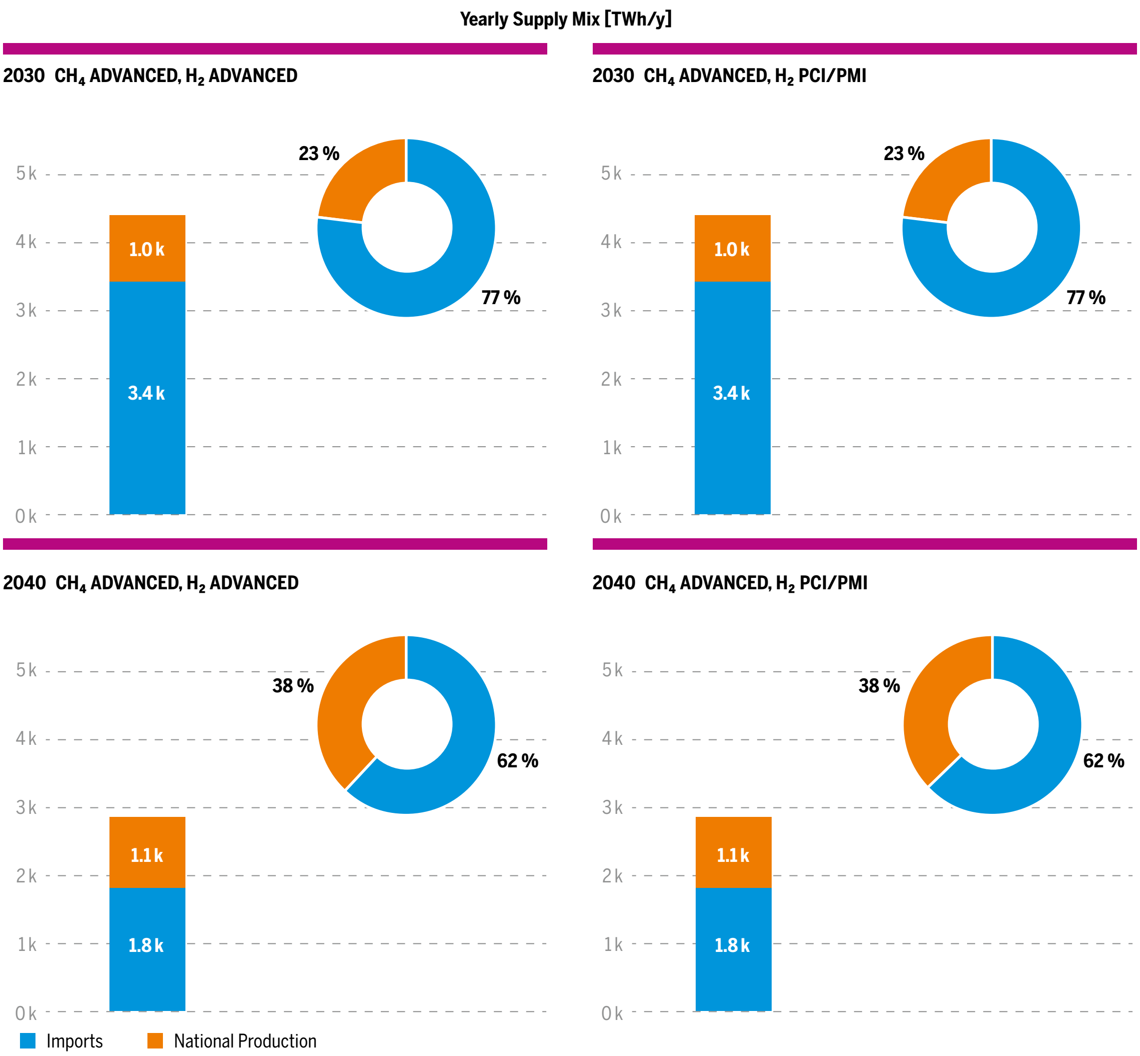

Figure 7: Reference weather year Supply Results in Advanced natural gas infrastructure level

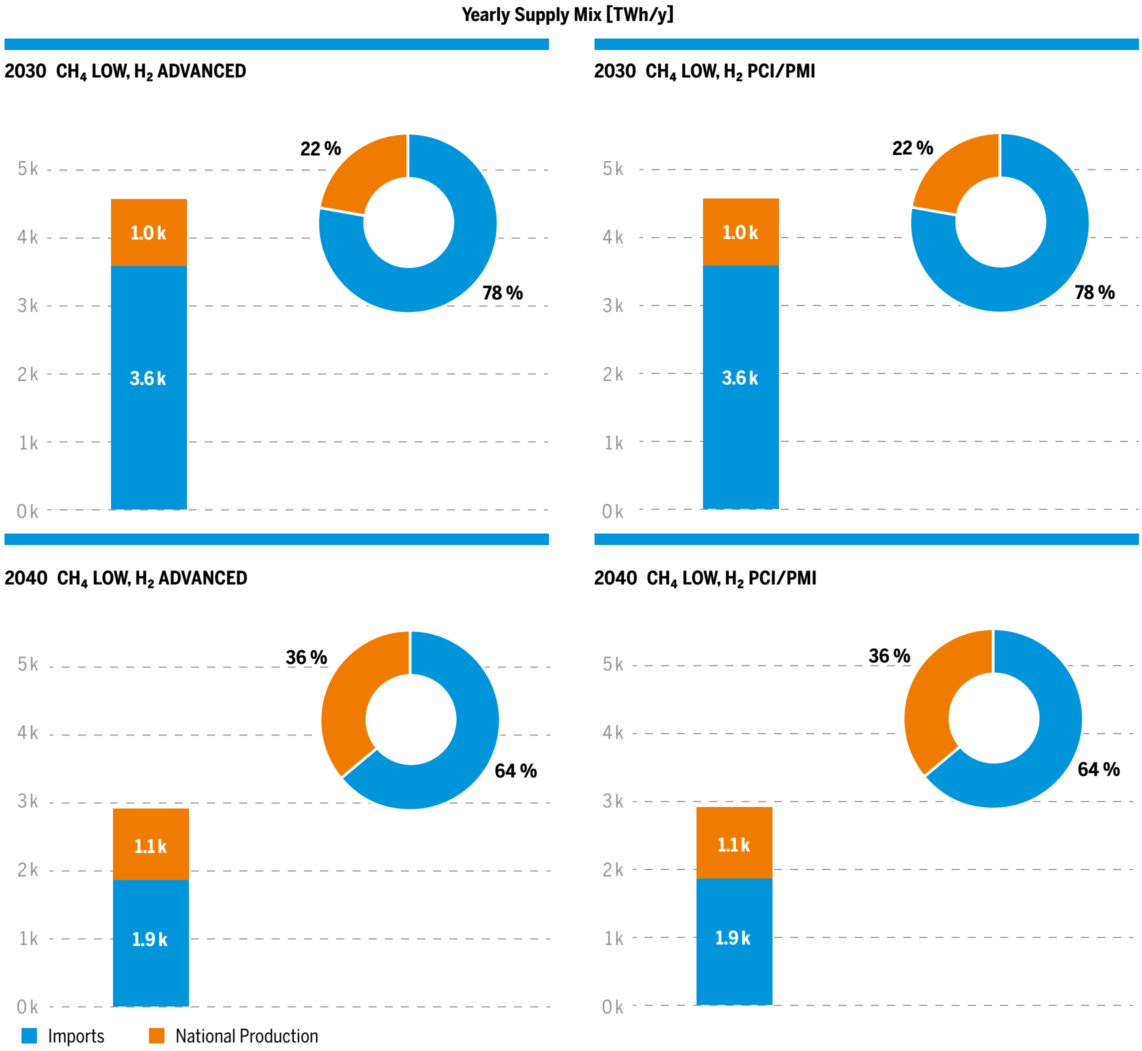

Figure 8: Stressful weather Supply Results in Low natural gas infrastructure level

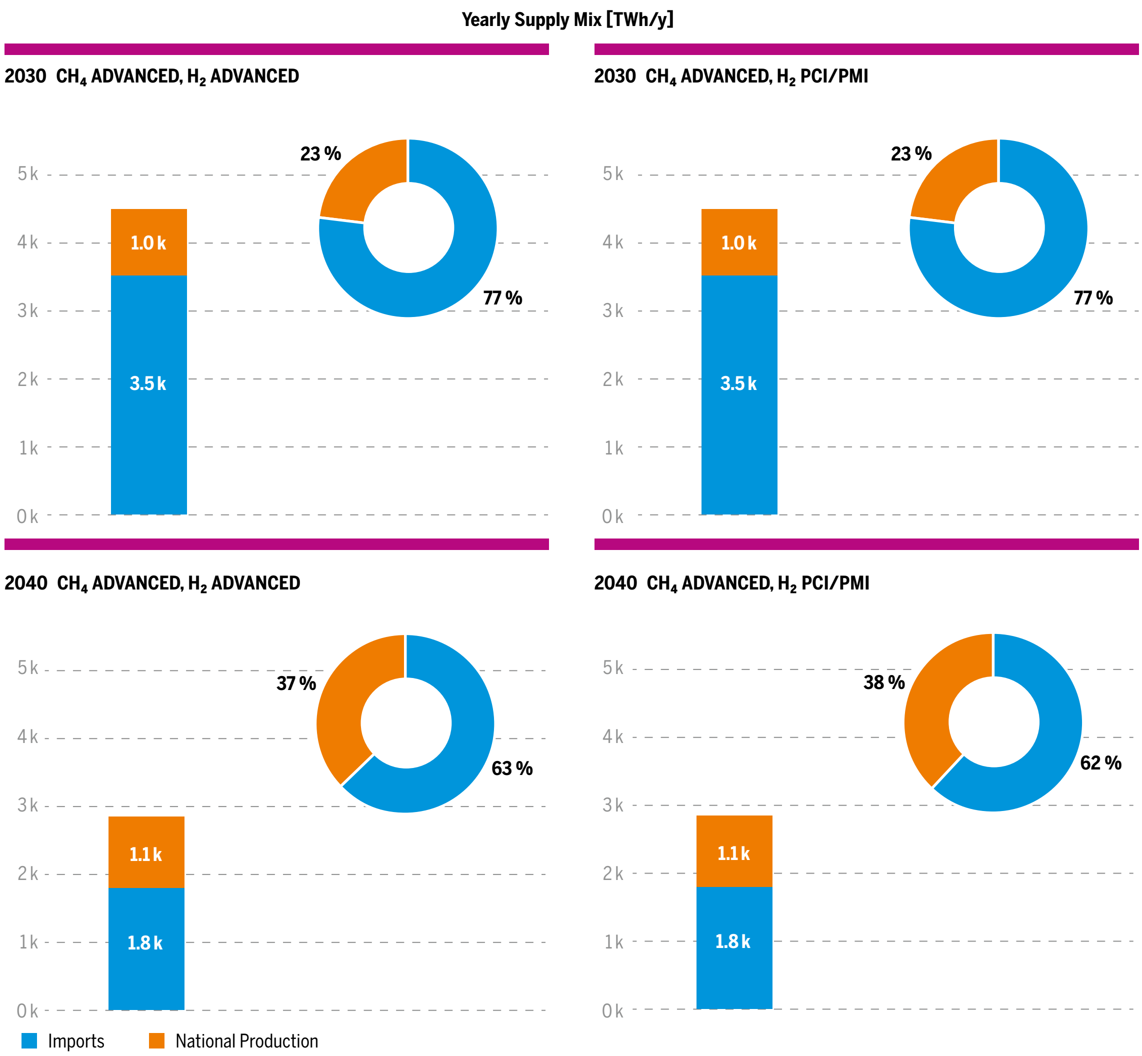

Figure 9: Stressful weather Supply Results in Advanced natural gas infrastructure level

4.2 BIOMETHANE PRODUCTION PROGRESS

Biomethane plays an increasingly important role in ensuring a stable and reliable energy supply, as it can be injected directly into both distribution and transmission gas networks, serving as a renewable and locally produced alternative to natural gas.

The European Biogas Association (EBA) has been actively tracking and reporting on investments in biomethane production across Europe in the coming years. According to the 2nd EBA Investment Outlook from 2024, biomethane production investments will yield a total added capacity of 6.3 bcm within Europe to reach approximately 11 bcm by 2030. This projection is based on a database of announced European biomethane projects, combined with an assumed sectoral growth rate.

As shown in **Figure 10**, EBA projections indicate that biomethane production is not currently on track to meet the REPowerEU target of 35 bcm by 2030. However, the same figure also presents data from the ENTSOG and ENTSO-E TYNDP 2024 Scenarios Report, which offers a more optimistic outlook. According to this assessment, Europe's biomethane production potential could exceed 40 bcm by 2030. Italy, France, and Spain are identified as key contributors, each with an estimated potential of around 6 bcm, followed by Germany with 4 bcm.

At the same time, conventional natural gas production is expected to continue its gradual decline, increasingly replaced by biomethane as projected in the scenarios. Although biomethane and biogas production have grown at a strong pace in recent years, the current trajectory still falls short of meeting the REPowerEU target.

Consequently, the natural gas infrastructure with methane supply is expected to play a critical role for a longer transition period than initially foreseen, ensuring system flexibility and supply security as renewable gas volumes continue to scale up.

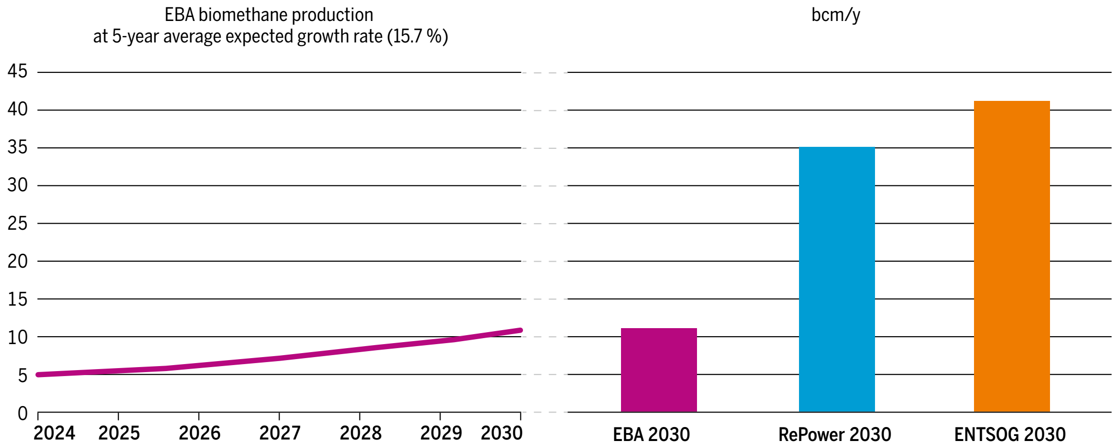

Figure 10: Biomethane production progress comparison


Picture courtesy of Snam

5 SIMULATION RESULTS

ENTSOG focuses its simulations on transmission network-related demand and supply, depending on data availability. For the Dual Gas Model (DGM), the country-specific inputs for final natural gas demand and supply are sourced from the ENTSO-E and ENTSOG TYNDP 2024 Scenarios Report. Values for natural gas demand for power generation are derived from the Dual Hydrogen/Electricity Model (DHEM) simulation results.

It should be noted that the simulations for yearly demand and climatic stress conditions – namely the 2-week Dunkelflaute (CDF) and Peak Demand (PD) – are conducted independently. In the simulations under climatic stress conditions, all underground gas storage facilities are assumed to be at 35 % of their working gas volume, and flexibility from LNG tanks is used as additional supply during the PD scenario and throughout both weeks of the CDF.

Supply stress conditions related to **import source dependency (S-1)**, specifically for natural gas from Russia, are considered in the Dual Gas Model (DGM). However, as the DGM is designed to minimise the use of Russian natural gas, the simulation results show no contribution from Russian pipeline supply in the overall supply mix. As a result, the S-1 scenario for Russian gas is omitted from the analysis.

Infrastructure stress conditions (N-1), referring to the Single Largest Infrastructure Disruption (SLID) for natural gas during Peak Day (PD) demand, are designed to assess the system's resilience in the event of a failure of the largest gas infrastructure asset entering each country. This assessment excludes underground storage facilities and domestic production. The objective is to evaluate the potential impact of such a disruption on the national level, as well as its broader implications for the European gas system during PD. By simulating SLID under peak conditions, the analysis provides insight into the robustness of cross-border interconnections and the ability of the infrastructure to ensure security of supply under extreme stress.

Furthermore, the results are shaped by the model's behaviour, which does not account for commercial supply agreements and relies on assumptions regarding infrastructure developments.

The raw simulation results of the TYNDP 2024 Natural Gas System Assessment are provided in TYNDP 2024 Annex E, Analysis tables. All results and maps will be available through the visualisation platform.

5.1 REFERENCE CASE

5.1.1 REFERENCE WEATHER YEARLY DEMAND

The analyses show that there is no risk of methane demand curtailment in any scenario except for Cyprus. The results indicate a lack of infrastructure under the Low natural gas infrastructure level in 2030 and 2040.

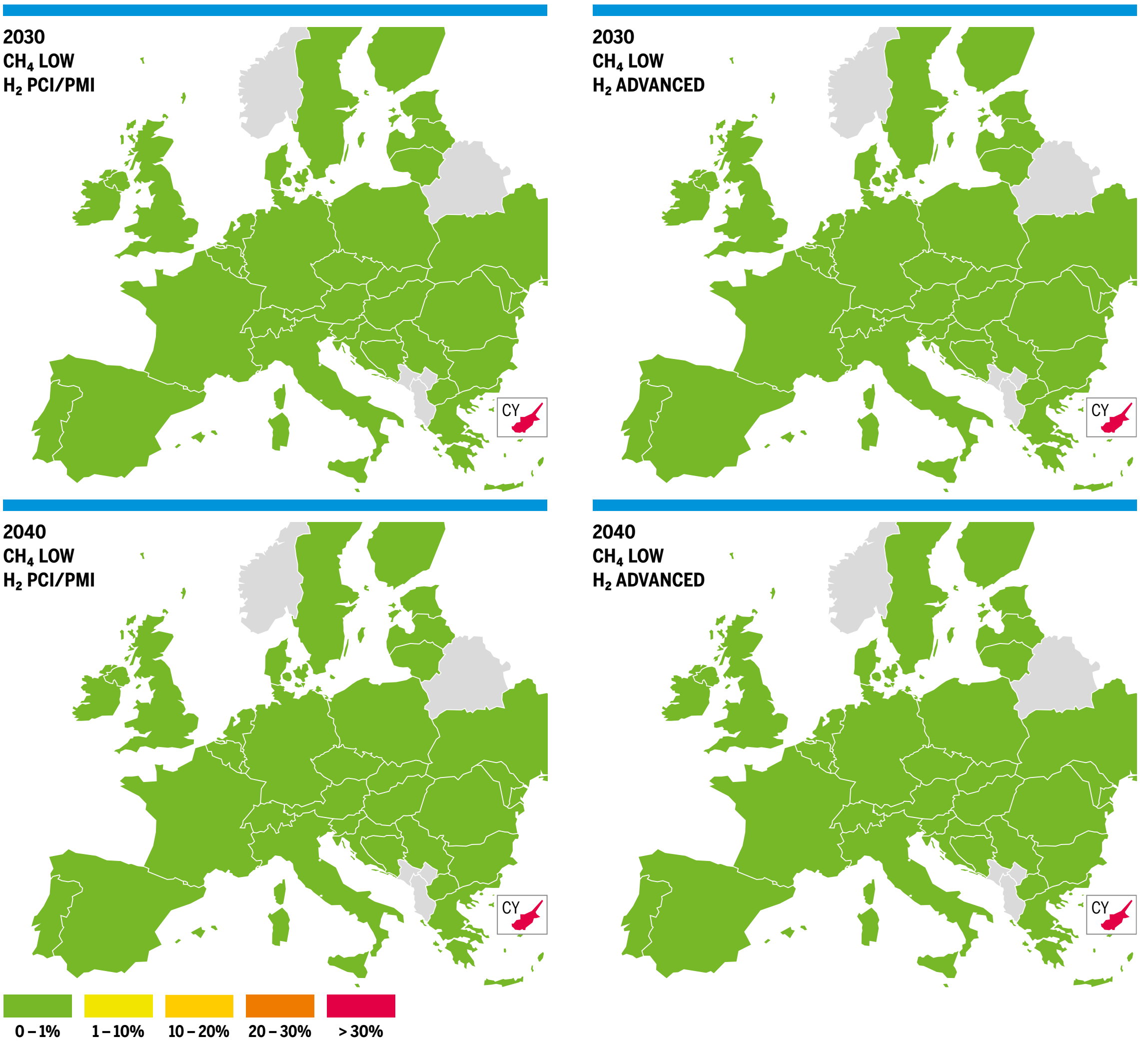

Figure 11: Reference weather year Results in Low natural gas infrastructure level

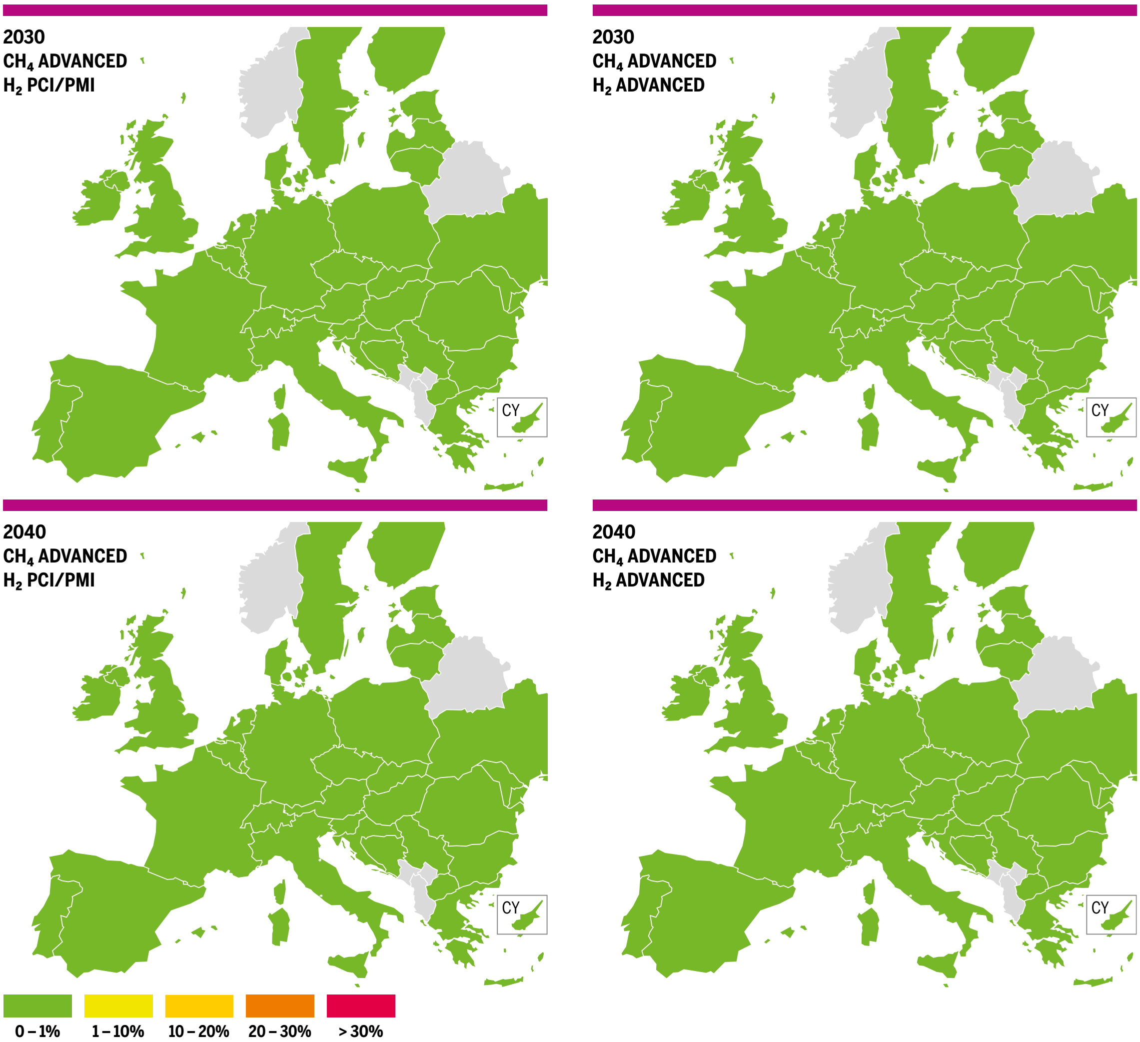

Figure 12: Reference weather year Results in Advanced natural gas infrastructure level

5.1.2 STRESSFUL WEATHER YEARLY DEMAND

The analyses show that there is no risk of methane demand curtailment in any scenario except for Cyprus. The results indicate a lack of infrastructure under the Low natural gas infrastructure level in 2030 and 2040.

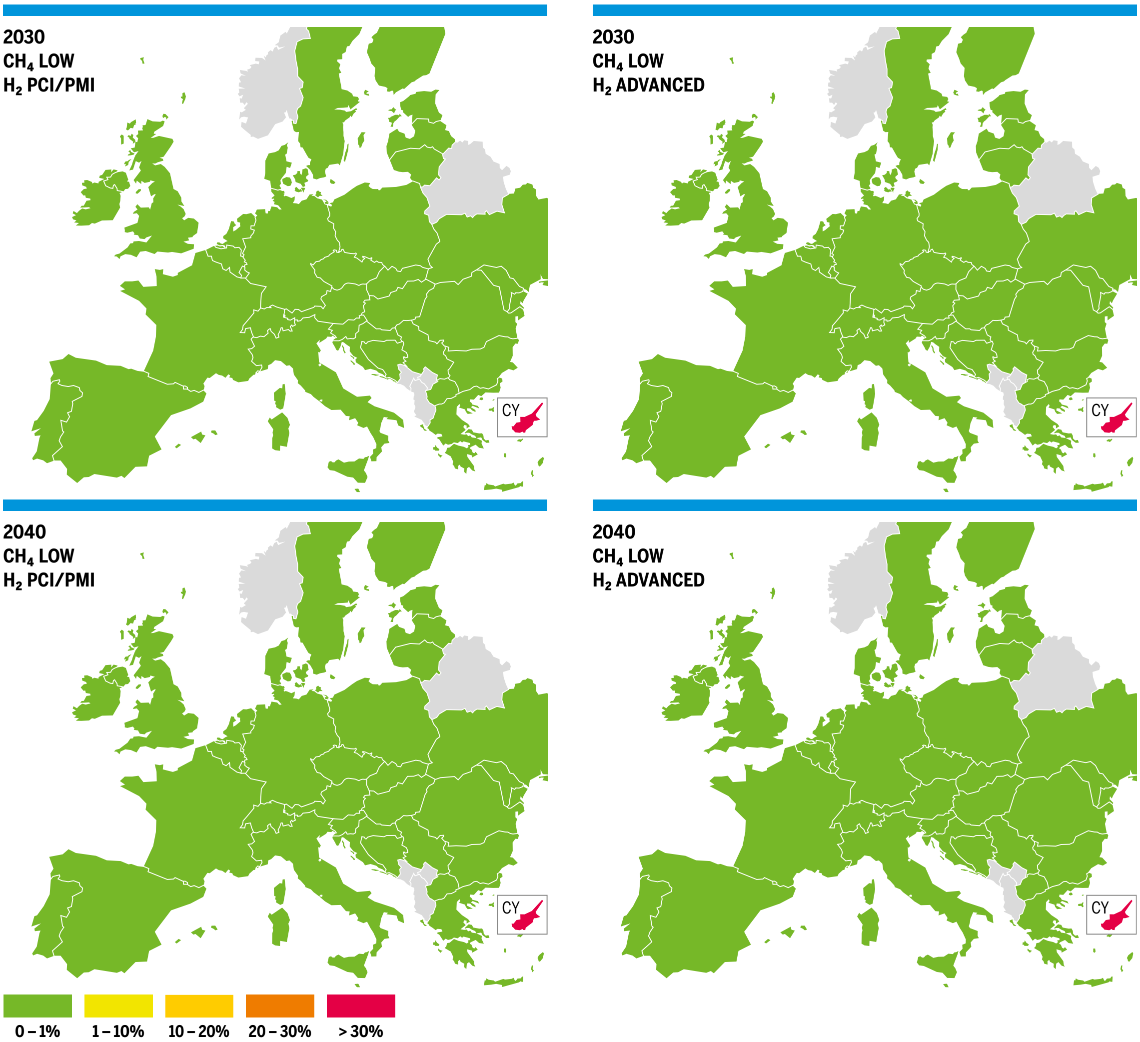

Figure 13: Stressful weather year Results in Low natural gas infrastructure level

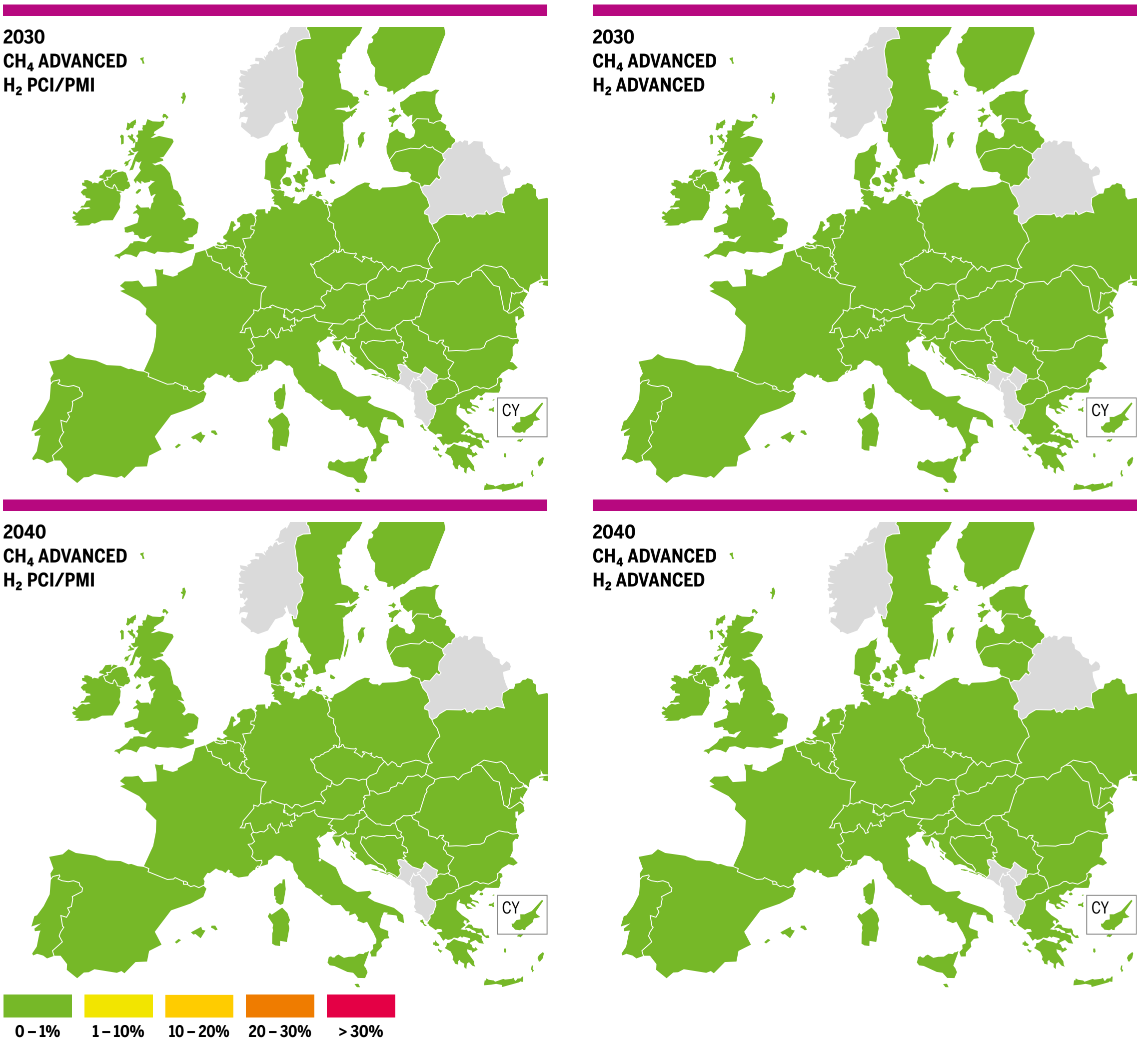

Figure 14: Stressful weather year Results in Advanced natural gas infrastructure level

5.1.3 2-WEEK DUNKELFLAUTE DEMAND

In National Trends+ (NT+) scenario, all EU Member States satisfy their methane demand due to the available supply and sufficient interconnection capacities.

However, one country cannot satisfy its methane demand due to an infrastructure limitation:

- **Cyprus**. The results indicate a lack of infrastructure under the Low natural gas infrastructure level.

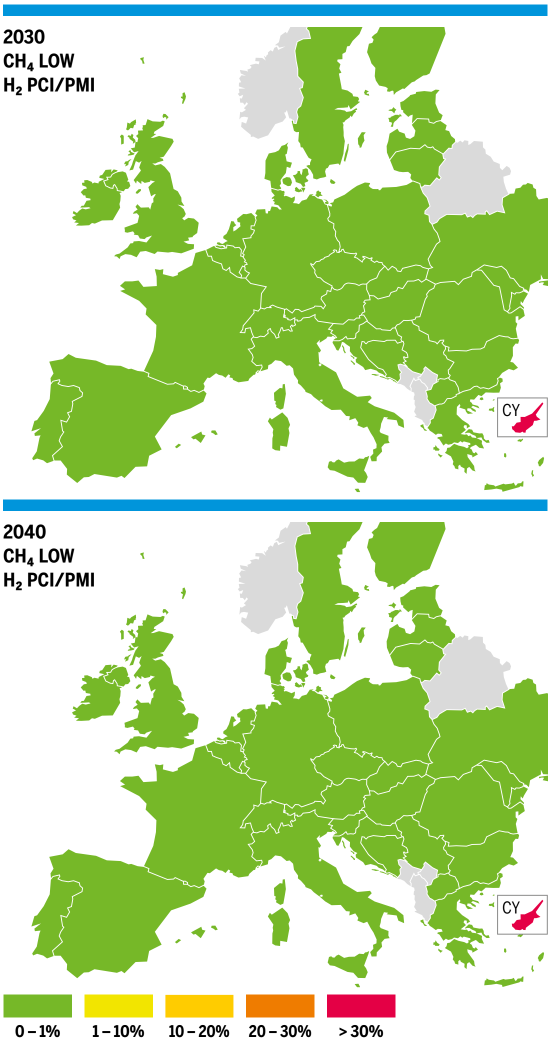

Figure 15: 2-week Dunkelflaute results in Low natural gas infrastructure level

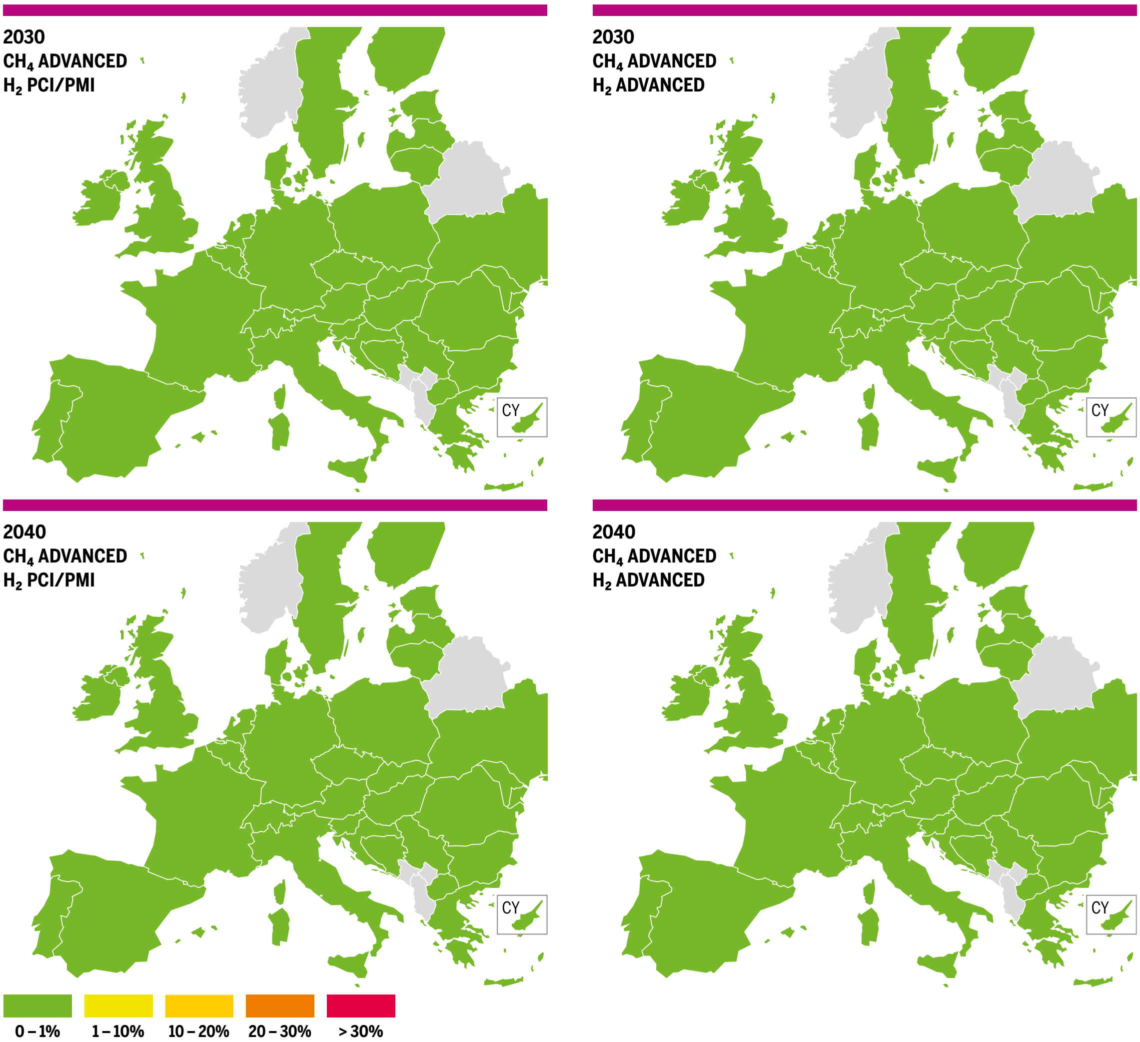

Figure 16: 2-week Dunkelflaute results in Advanced natural gas infrastructure level

5.1.4 PEAK DEMAND

In National Trends+ (NT+) scenario, all EU Member States satisfy their methane demand due to the available supply and sufficient interconnection capacities.

However, one country cannot satisfy its methane demand due to an infrastructure limitation:

- **Cyprus**. The results indicate a lack of infrastructure under the Low natural gas infrastructure level.

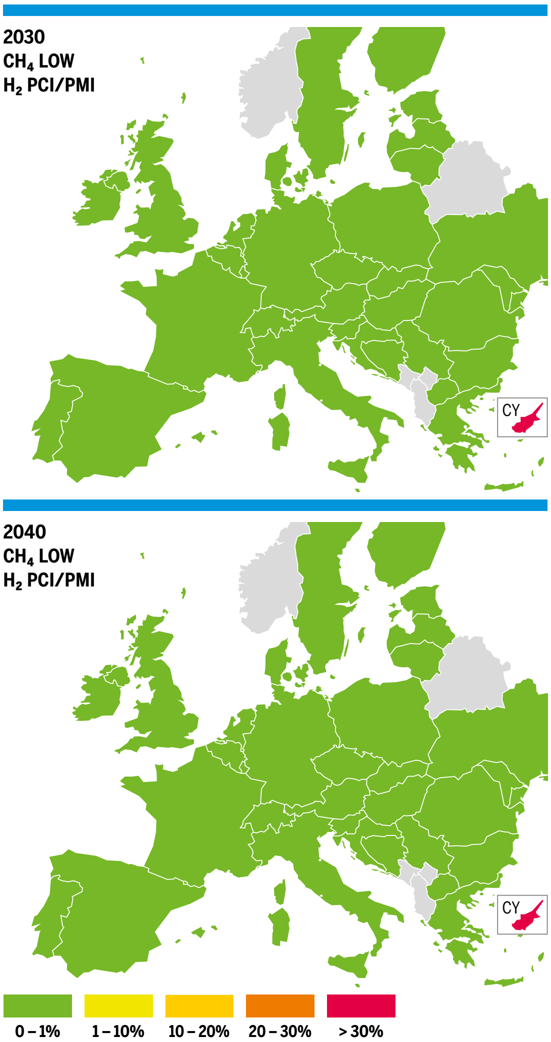

Figure 17: Peak Demand results in Low natural gas infrastructure level

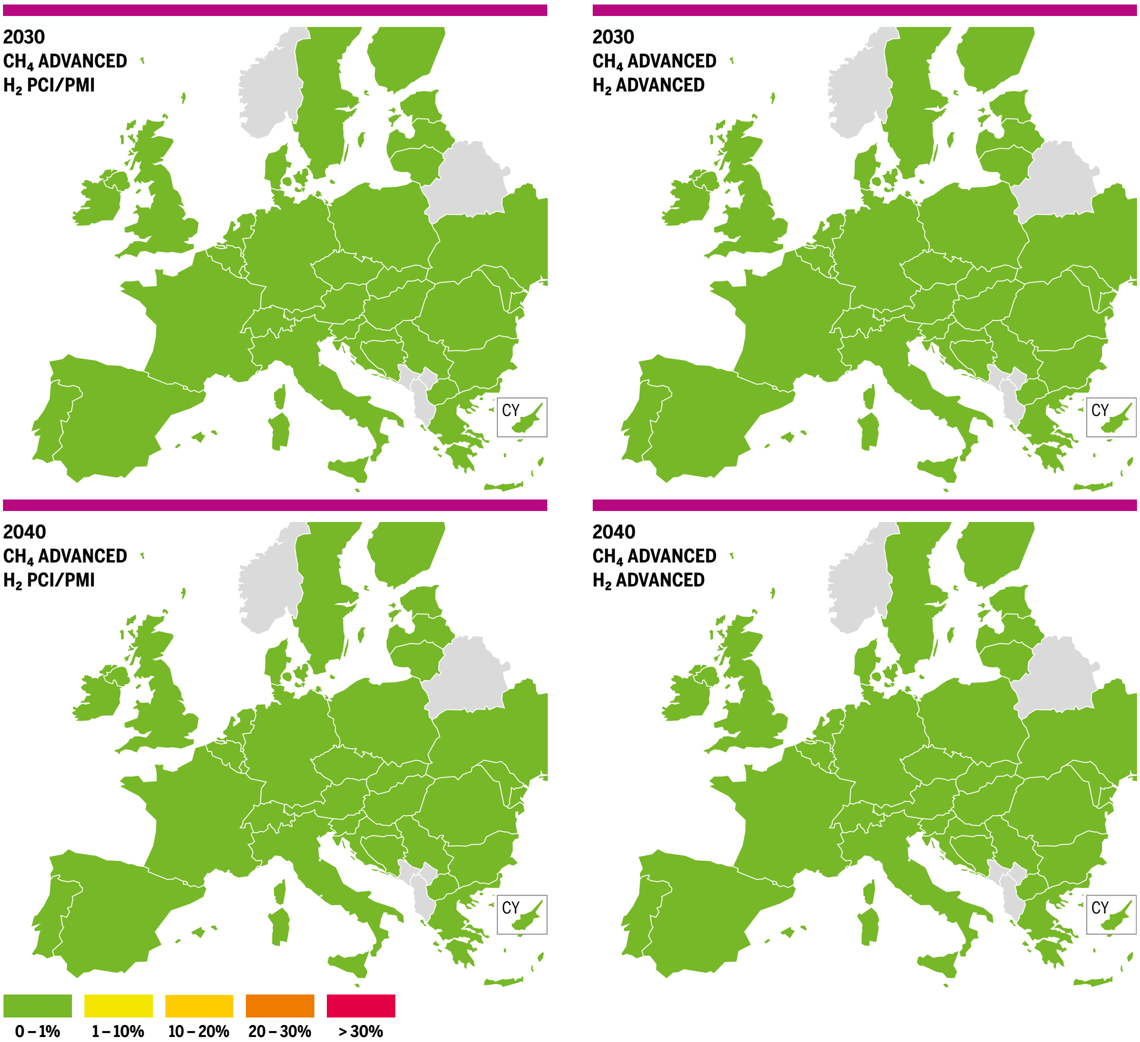

Figure 18: Peak Demand results in Advanced natural gas infrastructure level

5.2 SINGLE LARGEST INFRASTRUCTURE DISRUPTION (SLID)

This section investigates the impact of a disruption to the single largest infrastructure in each country during Peak Demand (PD). For PD, the country-specific values of final natural gas demand are sourced from the TYNDP 2024 Scenario Report. The natural gas demand for power generation is based on DHEM simulations during a stressful weather year, specifically the day when the EU recorded the highest total natural gas usage for power generation and hydrogen production[11]. The Single Largest Infrastructure Disruption (SLID) scenario evaluates the curtailed demand following the disruption of the single largest interconnection infrastructure for a given country, excluding domestic production and storage facilities. The single largest infrastructure depends on the simulation year and the infrastructure level considered.

A detailed table listing the single largest infrastructure and the corresponding risk group for each country included in the assessment is provided in TYNDP 2024 Annex E, Analysis tables. It should be noted that this chapter does not include descriptions of countries where no demand curtailment occurs under the SLID scenario during Peak Demand (PD) event.

5.2.1 PEAK DEMAND

In the National Trends+ (NT+) scenario, the Single Largest Infrastructure Disruption (SLID) impacts are most significant in countries located at the periphery of the EU, where interconnection diversification remains limited due to geographical and infrastructural constraints. These countries are more vulnerable to supply disruptions resulting from their reliance on a limited number of import routes.

Overall, the simulation results indicate a generally robust level of infrastructure cooperation across the EU countries. This resilience is further supported by the projected decline in natural gas demand and the anticipated increase in biomethane production, both of which are key assumptions in the NT+ scenario. These developments contribute to enhancing the system's flexibility and reducing dependence on single infrastructure elements over time.

- **Cyprus, Malta** and **Bosnia and Herzegovina** are exposed to 100 % demand curtailment, as they each have only one interconnection.
- **Sweden** is exposed to a 4 % demand curtailment in 2030 under the SLID scenario, due to the disruption of its only interconnection with Denmark. By 2040, increased biomethane production contributes to fully meeting the country's gas demand, eliminating curtailment under the SLID scenario.
- **Finland** shows a 23 % demand curtailment in 2030 under the SLID scenario, as the disruption corresponds to its main import capacity, with insufficient interconnection capacity available from Estonia to compensate. By 2040, a combination of reduced gas demand and increased biomethane production helps address this supply limitation.
- **Northern Ireland** faces up to 34 % demand curtailment (equivalent to 1 % of the United Kingdom's demand) in 2030 under the SLID IE scenario due to the disruption of Interconnector 2, which impacts interconnection between Ireland and Northern Ireland and results in no flow through the South-North CSEP. By 2040, a decrease in gas demand contributes to fully meeting supply needs without curtailment. The disruption of Interconnector 2 also prevents gas flow to the Isle of Man.
- **Luxemburg** is exposed to 32 % demand curtailment in 2030 and 16 % in 2040 under the SLID scenario. The disruption corresponds to one of two pipelines of the interconnection with Belgium, while the other pipeline of interconnection with Belgium and interconnection with Germany presents infrastructure limitations. The reduction in demand in 2040 compared to 2030 contributes to the lower curtailment level.

11 According to the methodology, the PD for power-to-gas demand at the EU level was identified as 9 January. However, due to the non-simultaneity approach used in the SLID analysis for individual Member States in this report, the peak demand for power generation may vary by country. The varying PD for power demand configurations could change the outcome of the individual Member State SLID impact assessments affecting the level of curtailment according to N-1 Standard. For example, in the case of Ireland, SLID results would show a significant level of demand curtailment in alternative, individual peak day configurations.

- **North Macedonia** is exposed to 29 % demand curtailment in 2030 and 2 % in 2040 under the SLID scenario. The disruption corresponds to the interconnection with Greece, while limited interconnection capacity from Bulgaria prevents full compensation. The lower demand in 2040 compared to 2030 contributes to the reduced curtailment.
- **Greece** shows a 2 % demand curtailment in 2030 under the SLID scenario at the Low natural gas infrastructure level, primarily due to internal bottlenecks that limit the ability to supply natural gas from LNG terminal. At the Advanced infrastructure level, planned capacity enhancement projects enable greater imports of Caspian Sea gas, improving the country's ability to meet demand. By 2040, a decrease in gas demand contributes to fully meeting supply needs without curtailment.

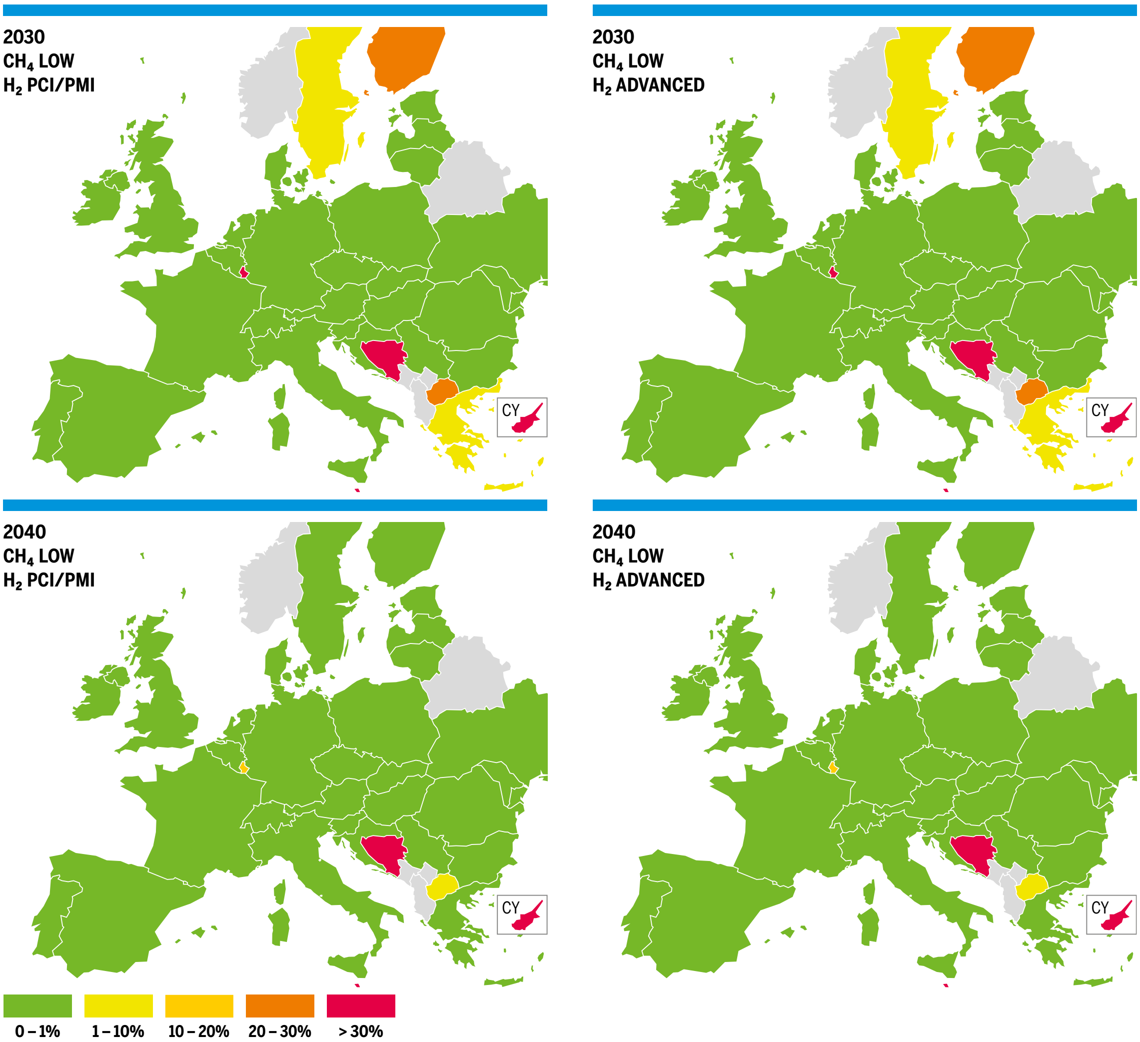

Figure 19: SLID Peak Demand results in Low natural gas infrastructure level

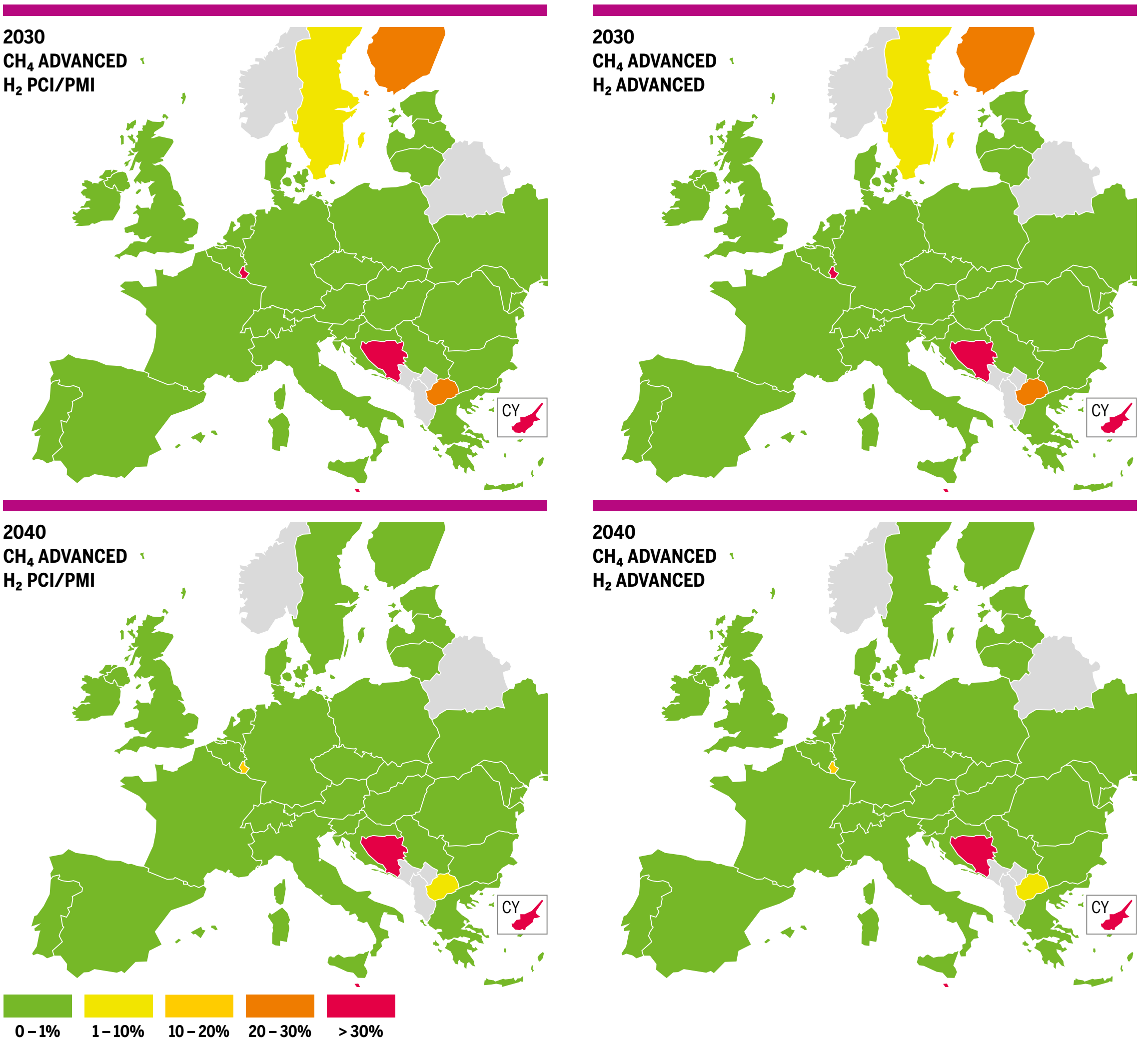

Figure 20: SLID Peak Demand results in Advanced natural gas infrastructure level


Picture courtesy of Gas Connect Austria
HOV 4245

LIST OF FIGURES

LIST OF **ABBREVIATIONS**

ACER	Agency for the Cooperation of Energy Regulators
bcm	Billion cubic meters/Billion cubic meters per annum
CCGT	Combined-cycle gas turbine
CDF	2-week Dunkelflaute
CH_4	Methane/Natural Gas
DGM	Dual Gas Model
DHEM	Dual Hydrogen/Electricity Model
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EU	European Union
FID	Final Investment Decision
FEED	Front-End Engineering Design
GCV	Gross Calorific Value
GIE	Gas Infrastructure Europe
GWh	Gigawatt hour
GQO	Gas Quality Outlook
H_2	Hydrogen
IP	Interconnection Point
LNG	Liquefied Natural Gas
mcm	Million cubic meters
MS	Member State
MWh	Megawatt hour
NCV	Net Calorific Value
NRA	National Regulatory Authority
NT+	National Trends+
PCI	Project of Common Interest
PD	Peak Demand
PMI	Project of Mutual Interest
RES	Renewable Energy Sources
SLID	Single Largest Infrastructure Disruption
SMR	Steam Methane Reforming
SoS	Security of Supply
TEN-E	Trans-European Networks for Energy
TSO	Transmission System Operator
TWh	Terawatt hour
TYNDP	Ten-Year Network Development Plan
UGS	Underground Gas Storage (facility)

COUNTRY CODES (ISO)

AL	Albania
AT	Austria
AZ	Azerbaijan
BA	Bosnia and Herzegovina
BE	Belgium
BG	Bulgaria
BY	Belarus
CH	Switzerland
CY	Cyprus
CZ	Czech Republic
DE	Germany
DK	Denmark
DZ	Algeria
EE	Estonia
ES	Spain
FI	Finland
FR	France
GR	Greece
HR	Croatia
HU	Hungary
IE	Ireland
IT	Italy
LT	Lithuania
LU	Luxembourg
LV	Latvia
LY	Libya
MA	Morocco
ME	Montenegro
MK	North Macedonia
MT	Malta
NL	Netherlands, the
NO	Norway
PL	Poland
PT	Portugal
RO	Romania
RS	Serbia
RU	Russia
SE	Sweden
SI	Slovenia
SK	Slovakia
TM	Turkmenistan
TN	Tunisia
TR	Turkey
UA	Ukraine
UK	United Kingdom

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