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TEN-YEAR NETWORK DEVELOPMENT PLAN 2017

TYNDP 2017

MAIN REPORT

ENTSOG – A FAIR PARTNER TO ALL!

Ten-Year Network Development Plan 2017

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Foreword

I am honoured to preface this fifth edition of the Union-wide Ten-Year Network Development Plan. I have been a privileged witness of its continuous improvement since the first edition. With each edition ENTSOG endeavours to deepen its analysis, fitting it in the evolving European energy and climate framework.
I truly believe that the Ten-Year Network Development Plans delivers real added-value to a wide range of stakeholder and decision-makers.

Important steps have been taken over the last months and weeks which will play a key role for the European energy sector. In terms of market functioning, the adoption in Comitology of the Tariffs Network Code and amendments to Capacity Allocation Management (CAM) Network Code completed the set of gas network codes, whose implementation will greatly support the completion of the Internal Energy Market. In terms of climate and energy policy, the COP21 Paris Agreement, aiming at strengthening the global response to the climate change challenges, entered into force on 4 November 2016. In follow up of this agreement, the European Commission has identified as a priority the implementation of the EU 2030 climate and energy policy framework, agreed by the European Council in October 2014. The European Commission has also published its proposal for "Clean Energy for all Europeans" on 30 November 2016, with new ambitious goals for the European energy development.

It is paramount that policy and decision-makers consider the European gas infrastructure in the perspective of the completion of the Internal Energy Market and the contributions it can bring to the achievement of the European climate and energy policy. The European gas infrastructure has seen decades of development and the existing infrastructure already ensures a high level of market integration across most of Europe. The gas transmission infrastructure, LNG terminals and gas storages provide safe, reliable and affordable low carbon energy to European citizens.


Image courtesy of Gascade

Yet, in specific areas, further development of the infrastructure is still required. These investments will connect isolated areas and achieve further integration. They will bring affordable, diversified and competitive supplies of gas, in turn providing a stimulus for further development of the gas market.

I am particularly proud of the way ENTSOG has taken up the challenges of this TYNDP edition. It ensures a highly robust and reliable assessment of the gas system and identification of the further infrastructure needs. It also confirms the existence of the projects - transmission infrastructure, interconnections, storages, LNG terminals as well as infrastructure supporting the development of new intra-EU or extra-EU gas supplies - which will ensure a secure, competitive and sustainable energy future for all Europeans.

The challenges taken up in this new TYNDP edition are multiple. Based on the previous edition's feedback, ENTSOG has further improved the assessment, beyond the requirement of the CBA Methodology in force. In particular the TYNDP assessment builds on contrasted gas demand scenarios. These scenarios represent differentiated paths towards achieving the EU decarbonisation targets and consider generation capacities for the power sector defined consistently between ENTSOG TYNDP 2017 and ENTSO-E TYNDP 2016. At all stages of the TYNDP development, ENTSOG has ensured a very high standard of stakeholder involvement and transparency.

ENTSOG TYNDP 2017 will deliver real added-value to stakeholders and decision-makers. Together with ENTSO-E TYNDP 2016 it has a key role to play in the 3rd PCI selection process led by the European Commission. The process, kicked-off in September 2016, aims at establishing the 3rd PCI list in autumn 2017. ENTSO-E developed the electricity TYNDP from 2015, published the draft version in June 2016 and intends to release the final version by end 2016. ENTSOG developed the gas TYNDP fully in 2016 based on information collected in the first half of the year. To best support the PCI process, ENTSOG shared preliminary TYNDP results with the parties involved from October 2016, ahead of the report publication, and endeavoured to release the present version by end 2016.

The present version incorporates stakeholder feedback received at different stages of the development process: during the stakeholder engagement process in the first part of 2016, as part of presenting the underlying data in July 2016 and as part of sharing preliminary results in autumn 2016.

On behalf of ENTSOG, I would like to thank all parties involved in the TYNDP process. I encourage you to provide your feedback through our upcoming consultation process. This feedback, together with ACER Opinion, will be considered by ENTSOG to release the TYNDP final version in April 2017.

Now it is time for me to let you discover the TYNDP stimulating findings!

Stephan Kamphues

ENTSOG President

1 Introduction

Image: GRTgaz Deutschland

The TYNDP is produced by ENTSOG in compliance with the European 3rd Energy Package requirement to produce "a non-binding Community-wide ten-year network development plan including a European supply adequacy outlook every two years" (Art. 8 (3)(b), REG-715) and in compliance with the requirement of Art. 11(1) of REG-347 that the Energy System Wide Cost-Benefit Analysis Methodology (CBA Methodology) "shall be applied for each subsequent 10-year network development plan developed by the [...] ENTSO for Gas". Finally, in accordance with REG-703, this edition incorporates for the first time a regional-level long-term gas quality monitoring outlook, based on TYNDP results.

The Ten-Year Network Development Plan 2017 (TYNDP 2017) represents the fifth edition of the report published by ENTSOG since its establishment in 2009. TYNDP aims at developing a **European supply adequacy outlook and assessment of the resilience of the gas system, including identification of the investment gaps** by identifying where missing infrastructure prevents achieving the pillars of the internal energy market: sustainability, security of supply, competition and market integration. Subsequently, the TYNDP **assesses at energy system-wide level, how the submitted projects jointly contribute to the improvement of the European gas system, mitigating the infrastructure needs**. In application of the CBA methodology in force, approved by the European Commission in February 2015, this assessment consists of a multi-criteria analysis to measure the level of completion of the pillars of the EU Energy Policy from an infrastructure perspective.

Since the first publication of its TYNDP, ENTSOG has endeavoured to continuously increase the quality of its reports in close cooperation with all stakeholders. Based on the feedback on TYNDP 2015 and its contribution to the 2nd PCI selection process, ENTSOG committed for this edition of TYNDP to:

- A high-level of transparency towards stakeholders
- Reliable inputs ensuring a reliable TYNDP
- An improved TYNDP assessment building on an improved assessment of the infrastructure needs, a better consideration of different level of advancement of projects, further monetisation of benefits and the development of a long-term gas quality monitoring outlook

The close working relationship of TSOs within ENTSOG has been decisive to improve and develop this TYNDP in line with different stakeholders' expectations. ENTSOG would also like to highlight the close cooperation with the European Commission and the Agency for the Cooperation of Energy Regulators (ACER) in developing this TYNDP, which has played a key role in finding solutions to address their expectations. Finally, ENTSOG would like to thank stakeholders for their commitment. Their input and feedback is fundamental to continuously improve the quality of TYNDP. They are warmly encouraged to provide their feedback on this edition as part of the TYNDP public consultation which will open shortly after the report release.

1.1 A strengthened cooperation with stakeholders

The TYNDP is developed for a wide range of stakeholders. For this reason, the dialog, transparent information and engagement with all kinds of stakeholders is a fundamental element of developing the TYNDP.

AN IN-DEPTH STAKEHOLDER ENGAGEMENT

For TYNDP 2017, from January 2016 to May 2016, ENTSOG organised in close cooperation with the Commission and the Agency:

- A kick-off workshop, where the Commission and Agency provided their feedback on TYNDP 2015 along with their recommendations for TYNDP 2017, and ENTSOG presented the foreseen directions for improvement in TYNDP 2017
- Five full-day Stakeholder Joint Working Sessions (SJWS) to inform and get feedback from stakeholders on all building blocks of TYNDP: projects collection process, consideration of projects in the assessment, scenario storylines, supply potentials, modelling and outputs
- A concluding workshop to present the TYNDP final concept as well as how the stakeholder feedback had been taken into account.

To enable a wide range of participation, ENTSOG invited all interested stakeholders to contribute (promoters, NRAs and Member States representatives, associations, NGOs…). To facilitate participation and engagement, the dates were announced well in advance (in December 2015 for all SJWS), the supporting material was published ahead of the SJWS, the minutes were made available afterwards and two of the events were organised in Vienna and Ljubljana respectively in order to increase geographical coverage and accessibility to these events.

The stakeholder engagement process has proved to be efficient and valuable as on average 40 people have participated to the SJWS and workshops, with a number of elements that have been improved based on stakeholder feedback. This has included collecting TSOs' assumptions for the demand data provided along the different scenarios, adopting a "tomorrow as today" approach for supply flexibility in 2017 and improving the modelling of LNG terminals.

COOPERATION WITH ENTSO-E IN CONSIDERING THE ELECTRICITY TYNDP 2016

ENTSOG has also worked in close dialog with ENTSO-E regarding the power sector, making use of the scenario material developed by ENTSO-E for the electricity TYNDP 2016 at each stage of the gas TYNDP scenario development process. For each scenario, ENTSOG has looked for the electricity TYNDP 2016 Vision that best matches in terms of storyline. ENTSOG used the electricity demand, generation capacities and generation mix from the ENTSO-E TYNDP scenario development process as a basis for the annual gas demand in the power sector. **This alignment allows the TYNDP 2017 scenarios to reflect an overall view of the power sector, not only on gas-fired but also on coal-fired and renewable generation.**

A THOROUGH INVOLVEMENT OF PROJECT PROMOTERS

To ensure a European-wide perspective, it is fundamental that all relevant projects, promoted both by TSOs and third-party promoters, are submitted as part of the TYNDP project collection. For those projects in particular intending to take part in the PCI selection process, submission to TYNDP is a pre-requisite under Regulation (EU) 347/2013.

To ensure the collection of proper and accurate information of all concerned promoters, ENTSOG covered the project collection topic on several occasions as part of the SJWS process. To facilitate the submission of projects by promoters ENTSOG further improved and developed its online Project Data Portal, provided promoters with a project submission Documentation Kit and organised a Webinar dedicated to promoters ahead of the project collection period. ENTSOG has been available throughout the whole collection period to answer questions from promoters at short-notice. In addition, ENTSOG published several Press Releases to announce and remind promoters about the project collection phase.


Image courtesy of Plinacro

1.2 A highly transparent TYNDP ensuring reliable inputs

ENTSOG has always considered transparency as a vital element for developing the TYNDP. For this edition, ENTSOG further increased its commitment to transparency by releasing additional information at an early stage of the development process.

ENTSOG has taken steps in terms of early and increased transparency, providing the ability to ACER, NRAs as well as other stakeholders to react at an early stage of the process if necessary.

In July 2016, **immediately after the collection and validation of the TYNDP input data was finalised, ENTSOG organised a workshop to present stakeholders with the overview on the related information:** scenarios, indigenous production and projects submitted to TYNDP. At the same point in time, ENTSOG made this data available on its website. This data is used for developing both this TYNDP edition and the next edition of the Gas Regional Investment Plans (GRIPs).

Additionally, at the end of October ENTSOG published on its website, for the first time, a TYNDP project map. This map displays the projects submitted to the TYNDP together with their advancement status and labels which of these projects belong to the 2nd PCI list.

Finally, **to support the 3rd PCI process in the most timely and efficient way, ENTSOG endeavoured to share the preliminary TYNDP results, consisting of the identification of the regional infrastructure needs, with promoters and the Regional Groups from October 2016**, well ahead of the TYNDP publication. ENTSOG also organised a webinar dedicated to promoters, which was attended by more than 45 participants to present those results and receive promoters' feedback. Further on, ENTSOG presented the regional infrastructure gaps in the Regional Group meetings that took place between end of October and early November 2016.

ENTSOG considers allowing early reaction of ACER and NRAs, as well as other stakeholders, as an effective complement to receiving stakeholders and ACER Opinion at the end of the process.

1.3 An improved analysis

A MORE COMPREHENSIVE APPROACH TO DEMAND SCENARIOS

TYNDP looks twenty years ahead. Performing the TYNDP assessment in a meaningful way requires the definition of scenarios that cover the reasonable scope of the gas and energy sector evolution. For this fifth edition of TYNDP, ENTSOG developed four demand scenarios:

- **Slow Progression**
- **Blue Transition**
- **Green Evolution**
- **EU Green Revolution**

Among these scenarios three achieve European climate and energy targets set for 2030, taking differentiated paths towards these targets.

In order to develop the scenarios, ENTSOG elaborated storylines based on a number of parameters ranging from general elements, including macro-economic considerations and EU climate targets, as well as covering specific energy factors (heating, power and transport sectors). The storylines were discussed with stakeholders at multiple SJWS. Regarding the power sector, and as mentioned above, ENTSOG has built on information stemming from ENTSO-E TYNDP 2016 scenario development process. This allows the TYNDP 2017 scenarios to reflect an overall view of both the gas and power sector. Data was collected from the TSOs, and the EU Green Revolution was derived by ENTSOG applying consistent elaborations to the collected data. Illustration on how these scenarios achieve the European 2030 energy and climate targets is part of the Demand chapter.

To ensure a meaningful TYNDP, it is fundamental that the assessment of infrastructure needs and of projects is handled for all three of the on-target scenarios. The demand level for the off-target scenario falls within the range of the other scenarios, therefore it has not been covered in the assessment.

Scenarios cover both the annual and peak demand perspectives, in line with national standards, in order to ensure a meaningful assessment of the gas infrastructure.

AN IMPROVED ASSESSMENT OF THE GAS SYSTEM RESILIENCE, INFRASTRUCTURE NEEDS AND PROJECTS

ENTSOG developed TYNDP 2017 based on the CBA methodology currently in force, approved by the European Commission in February 2015. Building on the experience of TYNDP 2015, as well as on stakeholder feedback, ACER Opinion and 2nd PCI selection process, ENTSOG has enlarged the scope of the assessment on a voluntary basis.

To provide a clear picture, **the analysis of the gas system resilience, including the investment gaps and infrastructure needs, is handled in a dedicated part of the Assessment chapter**. The different indicators are structured using the categories of security of supply, market integration, competition and sustainability criteria stemming from Regulation 347/2013. The European-wide assessment, together with the country-level granularity of the results, provides a clear view of the countries lagging behind these criteria and of the infrastructure limitations.

More information has been collected on projects, regarding their detailed scheduling, if they have experienced delays since the previous TYNDP edition and if they are part of the national development plan.

The energy system-wide assessment has been improved by using a better reflection of the level of advancement of projects. In close cooperation with ACER, ENTSOG has defined an additional advancement status for projects: the advanced non-FID status. Projects are now categorised as one of the following 3 statuses: FID (having taken their final investment decision), advanced non-FID or less advanced non-FID. The TYNDP subsequently assesses different levels of development of the gas infrastructure – Low, Advanced and High - corresponding to these 3 statuses, as well as an additional level as a feedback loop on the last PCI selection.

The Low infrastructure level, which considers only FID projects in addition to the existing infrastructure, is adopted as the basis for the assessment of the infrastructure needs.

The Advanced infrastructure level introduced in this edition, which considers the FID together with advanced projects in addition to the existing gas infrastructure, represents a realistic development of the infrastructure, therefore providing a meaningful basis for the energy system-wide assessment of the concerned projects. This will also provide useful information for the assessment of specific projects as part of the 3rd PCI selection process.

A specific infrastructure level includes all projects listed on the 2nd PCI list as a feedback loop.

The High infrastructure level, including all FID and non-FID projects in addition to the existing infrastructure, represents a very high number of projects, among which a number of competing initiatives as well as projects at a very early stage are included, for which further studies or the realisation of other initiatives may lead to the abandonment of the project. It should not be understood as a realistic gas infrastructure development objective and has demonstrated limited added-value in the TYNDP 2015 and 2nd PCI list processes. ENTSOG decided to maintain this infrastructure level in line with the CBA methodology in force, but will provide the results only in Annex E and not as part of the main TYNDP report.

ENTSOG has further improved the TYNDP energy system-wide CBA, by collecting project costs from promoters[1] and reflecting them per infrastructure level, and by proposing further monetisation of benefits in terms of competition and security of supply risk mitigation.

1) These costs are collected for use in TYNDP 2017

FURTHER IMPROVEMENTS AND ADDITIONS TO THE TYNDP

The modelling has been improved along the following lines:

- A separate assessment of the whole year situation and the high demand situations: national design case peak day (DC) and 1-in-20-year 2-week high demand case (2W). Separating the assessment is more realistic as it avoids the simulation anticipating the high demand situation. This allows use of the storage level calculated from the whole year simulation as starting point for the high demand situations. Additionally, it allows the impact of the different situations to be computed independently.
- An improved modelling of the LNG terminals, developed in cooperation with GLE, to better reflect the annual and peak capacities.
- A refined modelling of storages has been introduced by matching the summer and winter period for the whole year simulation with the injection (April to October) and withdrawal (November to March) periods. Additionally, the modelling uses withdrawal capacity curves (function of the storage level) recently updated in cooperation with GSE.

The following elements have also been added to the TYNDP:

- A section on the achievement of the EU 2030 energy and climate targets for the different scenarios, in the Demand chapter.
- A qualitative analysis of the embedded diversification of the LNG supply source, developed by GLE, in the Supply chapter.
- An Energy Transition sub-chapter providing an insight into how gas infrastructure can be an essential part of the future integrated energy system based on sector coupling, in the Infrastructure chapter.
- As required by Regulation (EU) 2015/703, a regional-level Long-term Gas Quality Monitoring Outlook, based on TYNDP results, in a dedicated chapter and respective annex.
- A TYNDP project Map displaying the projects submitted to the TYNDP together with their advancement status and labelling the projects part of the 2nd PCI list, available as an electronic Annex to the TYNDP, and for which a paper version will be provided together with the TYNDP printed version.

1.4 Structure of the Report

This section presents the chapters composing the TYNDP report. Each chapter is complemented by specific Annexes available in electronic format.

The two first chapters, the Demand chapter and Supply chapter, set the scene for the assessment.

The **Demand chapter** recalls historical development, provides an analysis per sector, describes in detail the demand scenarios and how they achieve the EU 2030 energy and climate targets, informs on the commodity prices retained and provides a detailed analysis of the data for the different scenarios. This data has been collected from the European TSOs, or derived by ENTSOG applying consistent elaborations to this data for the EU Green Revolution scenario. This chapter is supported by Annex C1 where TSOs have provided insight on the data they have submitted for the different scenarios, Annex C2 which contains all demand data, Annex C3 which provides the power generation assumption data and Annex C4 on demand methodology.

The **Supply chapter** shows the evolution of supplies and details the supply potentials retained. Supply potentials are built on the data publicly available from governmental sources and other recognised institutions or publications. The chapter includes an analysis by GLE of the embedded diversification of LNG. The chapter also provides the supply potentials for biomethane as collected from the TSOs in accordance with the storylines of the different scenarios. The supply potentials serve as basis for the Supply Adequacy Outlook and to define the possible range for each supply as part of the analysis and calculation of indicators composing the TYNDP multi-criteria assessment. This chapter is supported by Annex C5 which provides all supply data.


Image courtesy of Gascade

The following two chapters covers the projects submitted to TYNDP. The **Infrastructure chapter** provides a detailed overview of gas infrastructure projects as submitted by the promoters. It details the project collection process, informs on the project statuses and infrastructure levels, and provides an in-depth analysis of the projects, including in terms of progress since the previous TYNDP and regarding investment costs. The **Barriers to Investment chapter** analyses the obstacles to future investment in gas infrastructure, combining the views of all TSOs and other project promoters. These chapters are supported by Annex A which provides all non-confidential information on the projects submitted as well as project fiches, and by the **TYNDP project Map**.

The **Assessment chapter** represents the TYNDP-Step of the Energy System Wide Cost-Benefit Analysis Methodology. It consists of the **Supply Adequacy Outlook**, the **Assessment of the infrastructure needs** under the low infrastructure level and the **Energy System Wide assessment of the advanced projects**. The analysis covers the three assessed scenarios (Blue Transition, Green Evolution, EU Green Revolution), looking at the sustainability, security of supply, competition and market integration perspectives. A specific section is dedicated to analysing the overall impact of the 2nd PCI list projects as a feedback loop. This chapter is supported by Annex D which provides detailed information on the topology and capacities, existing and developed by projects for the different infrastructure levels. It is also supported by Annex E, which provides all modelling results, and Annex F, which describes the modelling tool and modelling methodology. Assessment Chapter is also complemented by the **Energy Transition chapter** providing an insight into how gas infrastructure can be an essential part of the future integrated energy system based on sector coupling.

The last chapter covers the **Long-term Gas Quality Monitoring Outlook**, based on the TYNDP results and developed in accordance with the Regulation (EU) No. 2015/703. It is supported by Annex G which provides additional quantitative results. In addition, the required L to H conversion of areas currently supplied by L-gas in parts of the North-West region is assessed in the related North-West Gas Regional Investment Plan, based on the TYNDP CBA methodology and using data consistent with the TYNDP.

And now, enjoy reading this new TYNDP edition!

2 Demand

Image courtesy of National Grid

2.1 Introduction

The demand chapter provides an outlook of the European gas demand for the period 2017 – 2037 from an ENTSOG perspective. This chapter has three specific aims. The first is to provide a context for European gas demand that currently exists and how it has developed in recent years. The second is to provide demand scenarios for the EU supply adequacy outlook as stipulated in REG 715/2009 and TYNDP assessment. The third is to provide the detailed demand data used for this assessment.

The demand scenarios show the evolution of the gas demand on a yearly basis. Whilst the yearly information facilitates the comparability between scenarios, the key parameters for network design and operation are based on hourly and daily (peak) demand. These high demand scenarios, on a single day or over a sustained period, indicate the capacity that a transmission system must be able to provide. This information is vital for the safe, secure and sustainable operation of a transmission system.

Storylines and parameters that define these scenarios were a key part of the stakeholder engagement process, along with their alignment with other publications in terms of electricity generation and commodity prices. The scenarios are a combination of bottom-up and top-down approaches. The top-down approach is based on macro-economic parameters for the final gas demand scenarios (residential & commercial, industrial and transport sectors) and cooperation with ENTSO-E to use TYNDP 2016 data within a power generation methodology (see Annex C4). The bottom-up approach is based on TSO submission of gas demand figures for their system for each scenario. This data is provided separately for final gas demand (including the split between residential & commercial, industrial and transport sectors where possible) and power generation sectors. The output of this process was shared with stakeholders as part of a workshop which took place in July 2016, designed to give early transparency on the input data that would be used for TYNDP assessment.

TYNDP covers a geographical perimeter consisting of the EU-28 countries as well as Switzerland, Bosnia and Herzegovina, Serbia and Former Yugoslav Republic of Macedonia (FYROM). For all the countries within the perimeter, gas demand was collected in existing demand areas along with gasification demand[1)]. More details are available in the country specifics document (Annex C1). In addition to this, the Kaliningrad area of Russia, Ukraine and Turkey are considered with their importation demand, which are exports from the EU and the TYNDP perimeter.

1) The gasification demand was provided for Bosnia and Herzegovina, Cyprus, Malta and Former Yugoslav Republic of Macedonia.

2.2 Current state

2.2.1 YEARLY DEMAND EVOLUTION

The level of gas demand in Europe has been influenced by the development of the gas market and the specific climatic conditions over the years. Energy and environmental policies have had a positive effect by improving energy efficiency. However, more negatively there have been events like the economic crisis, plus the evolution of commodity prices leading to coal displacing gas in the power generation mix. These factors, along with mild climatic conditions during 2014 and 2015 have reduced gas demand in recent years.

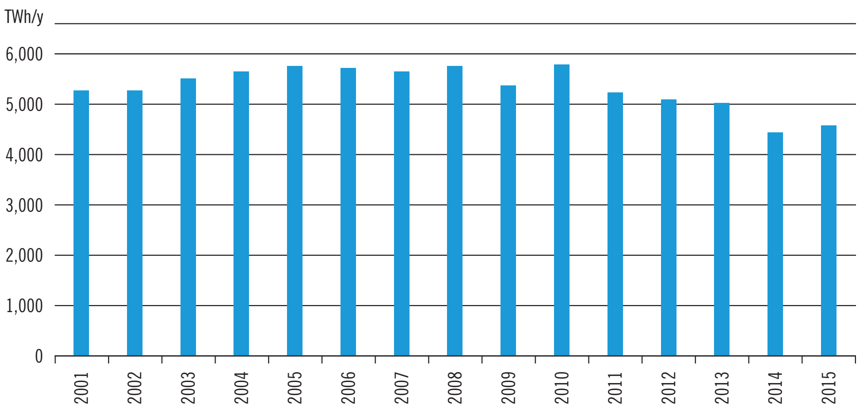


Figure 2.1: Evolution of European gas consumption
(Source converted from Eurostat figures)

2.2.1.1 Split between final and power generation demand (last 6 years)[1)]

Some elements of gas demand are more sensitive to climate factors than commodity prices or economic slowdown, as a result splitting total gas demand into different classifications allows greater analysis of how the demand is evolving.

Final demand (made up of residential & commercial, industrial and transport sectors) was relatively constant between 2010 and 2013 before seeing a decrease in 2014 and 2015. Part of this decrease can be attributed to these being the warmest years on record for the EU which would have a significant effect on the requirements for space heating. However, energy efficiency is also driving down the demand in some countries.

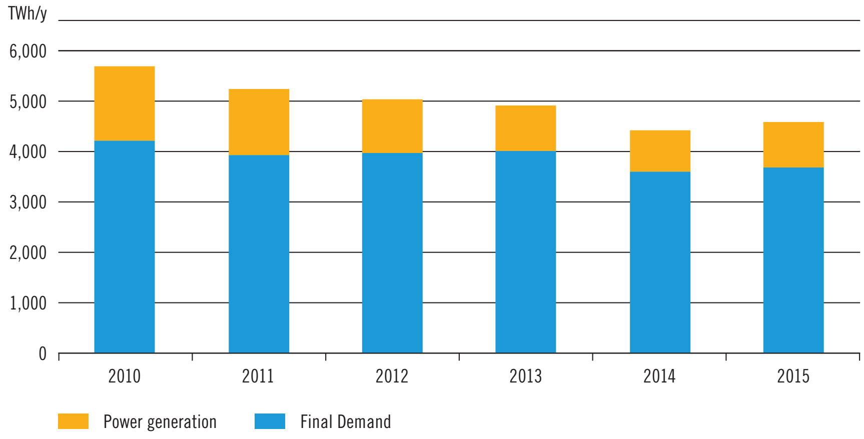


Figure 2.2: Evolution of European yearly gas consumption and its breakdown.

Gas demand for power generation had been in a continual decline since 2010, but reversed the trend in 2015. Some of the key factors behind these figures will be explored in this chapter, including looking at the evolution of sectoral demand collected for the first time in TYNDP 2017

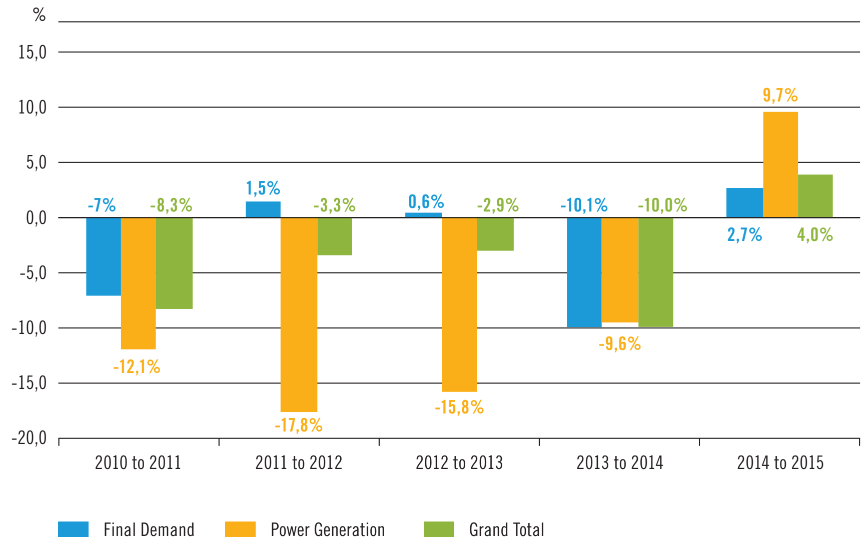


Figure 2.3: Breakdown of the European year to year gas consumption evolution.

1) For countries unable to provide the disaggregation between final and power, all demand appears as final.

2.2.1.2 Final sectoral

Final demand is made up of the following sectors: Residential & Commercial, Industrial and Transport. A breakdown of this split was requested during the data collection for both the demand scenarios and historical data.

Many TSOs could provide this breakdown for TYNDP 2017[1] and it is something that ENTSOG plans to continue collecting, presenting and analysing in order to provide greater detail on the current trends and help to build more comprehensive future demand scenarios on a sectoral level.

Figure 2.4 shows how residential & commercial dominates the share of final demand, but that it is more variable due to requirements for heating being driven by climatic conditions. The remaining share is taken up largely by industrial usage with gas demand for transport continuing to be under 1% across the period.

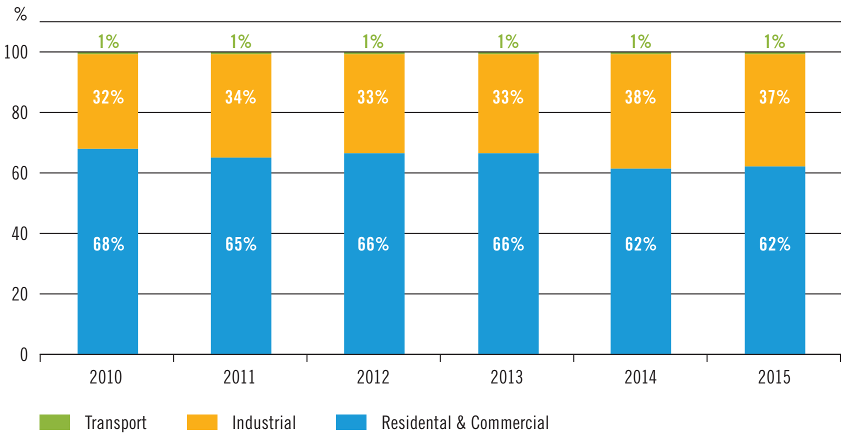


Figure 2.4: Evolution of sectoral split of final demand

2.2.1.3 Power generation in Europe

Despite a steady increase in renewable generation (excluding hydro) installed as the decarbonisation of the electricity mix continues, thermal generation remains as the main source for power generation in Europe. Hydro and Nuclear generation have remained stable in the generation mix, with very little growth in capacity either due to environmental concerns or national policies.

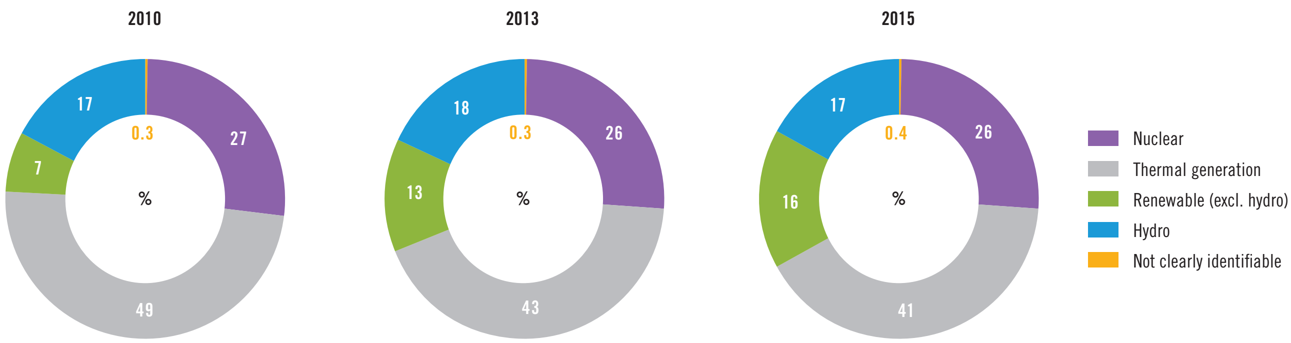


Figure 2.5: European generation mix for power generation 2010, 2013 and 2015 (Source: ENTSO-E data platform, ENTSOG depiction)

1) BA, BE, CZ, DE, EE, ES, FR, GR, HR, IT, LT, LU, MK, PT SK, UK. (Excluding FRt balancing zone in FR)

The individual fuel shares of thermal power generation have evolved over recent years, mainly due to fuel prices. A shift to coal and lignite can be seen between 2010 and 2013, causing the gas share to reduce from 33 % to 27 %. Although 2015 closely resembles 2013, gas recovered some of its share moving to 30 % reflecting the data submitted by TSOs. In aggregate, other fossil fuels have played only a minor role in power generation in recent years.

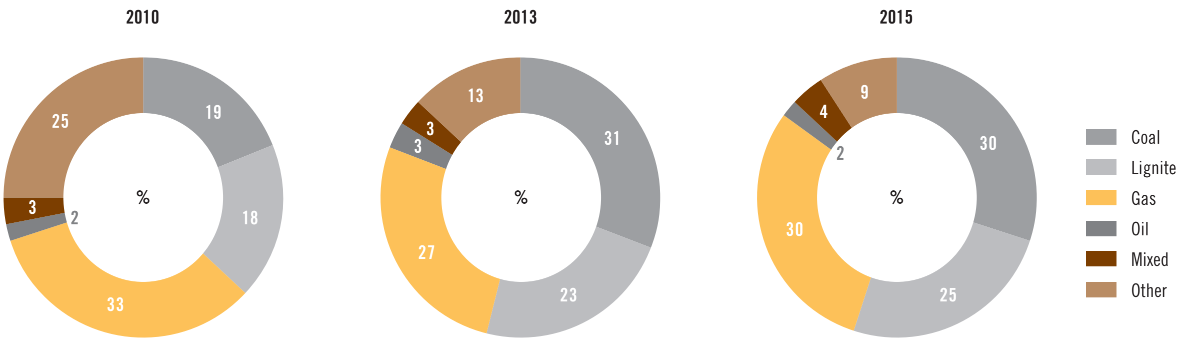


Figure 2.6: European thermal generation mix for power generation 2010, 2013 and 2015 (Source: ENTSO-E data platform, ENTSOG depiction)

2.2.1.4 Split by country (last 6 years)

The following graph contains information on actual gas consumption over the past six years across Europe. The data has not been adjusted for climatic conditions, as a result the cold year of 2010 and the warm years of 2014 and 2015 need to be taken into consideration for identifying the trends.

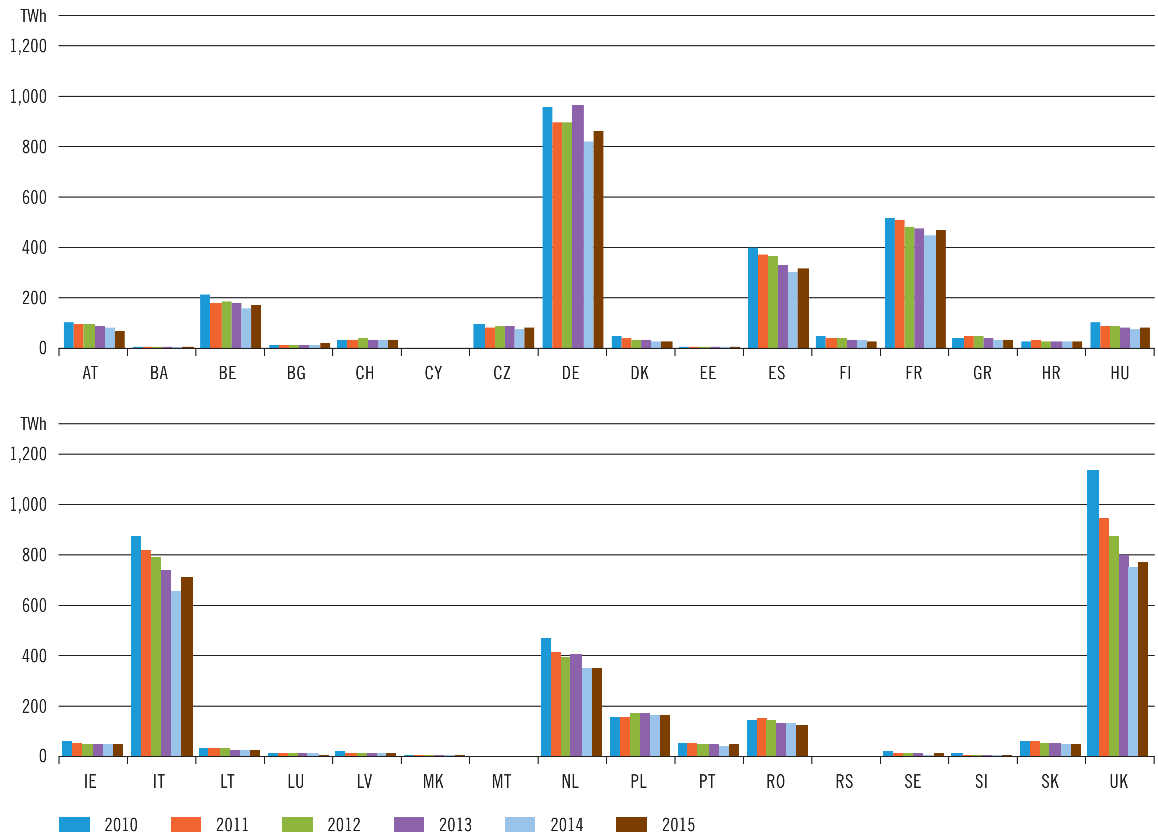


Figure 2.7: Evolution of European yearly gas consumption by country (TWh/y) (Source: ENTSOG)

2.2.2 SEASONAL AND PEAK CONSUMPTIONS

2.2.2.1 Seasonal

The gas transmission network experiences different seasonal demand levels driven largely by the climate and heating requirements, the variation seen is represented in figure 2.8.

Although October is seen as a winter month in the gas year, it is typically a storage injection month. In order to capture the seasonality of the gas market in the over-the-whole-year simulation, average demand levels for summer and winter days are based on the storage injection and withdrawal periods, more details on this methodology can be found in Annex C4.

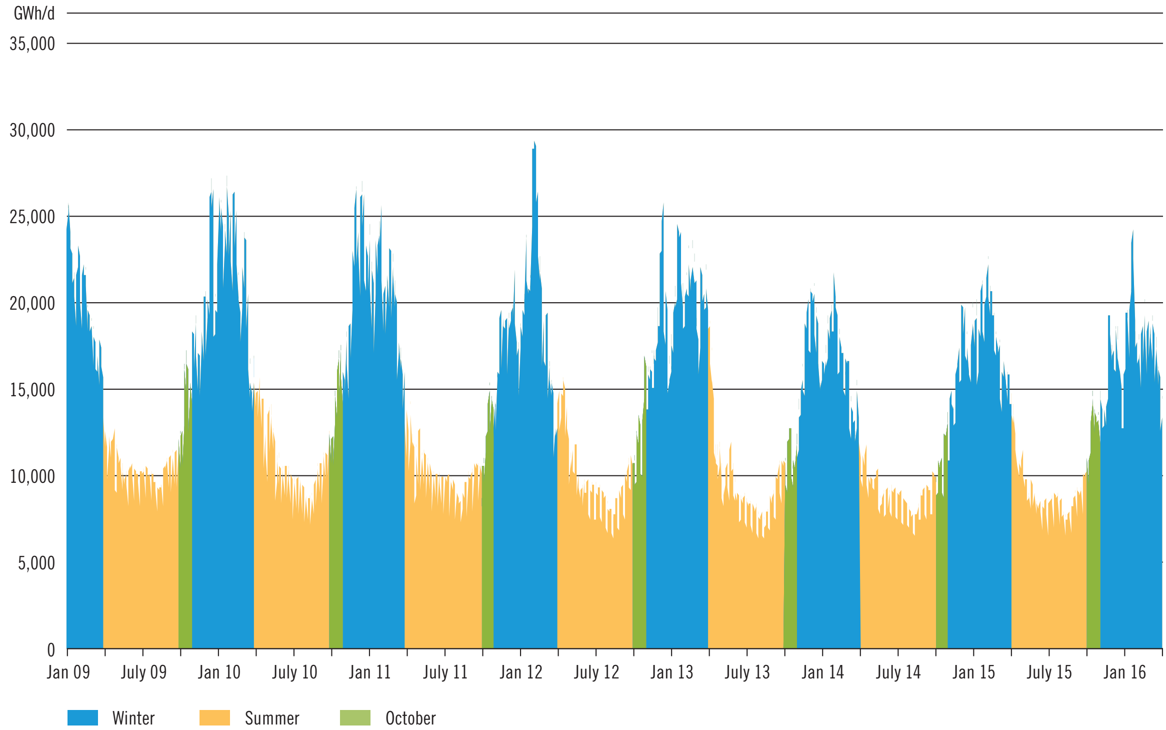


Figure 2.8: Yearly modulation

2.2.2.2 Peak day and highest 14-day period by year

The day of highest consumption in the year is a key input of the network design process and represents one of the most stressful situations to be covered by the gas transmission system. The design and operation of a system is also challenged by the availability of supply sources during periods of high consumption.

On this basis, ENTSOG has considered both the peak day and the highest 14-day demand period as significant for testing the resilience needs of the system[1]. However as table 2.1 shows from the last seven winters at EU aggregated level, the highest daily consumption can often occur outside of the highest 14-days average consumption

1) Please note that for the TYNDP assessment this corresponds to the National TSO Design Case and highest 14-day demand relates to a 1-in-20 year situation

HIGH DAILY AND HIGHEST 14-DAY GAS CONSUMPTION				
	Daily peak demand (GWh/d)	**Date**	**Highest 14-day period average demand (GWh/d)**	**Date**
Winter 2009/10	27,431	26/01/2010	24,645	03/01/2010 – 16/01/2010
Winter 2010/11	27,091	17/12/2010	24,633	09/12/2010 – 22/12/2010
Winter 2011/12	29,452	07/02/2012	27,842	31/01/2012 – 13/02/2012
Winter 2012/13	25,772	12/12/2012	23,280	13/01/2013 – 26/01/2013
Winter 2013/14	21,769	30/01/2014	19,800	02/12/2013 – 15/12/2013
Winter 2014/15	22,715	05/02/2015	20,708	30/01/2015 – 12/02/2015
Winter 2015/16	24,326	19/01/2016	20,876	11/01/2016 – 24/01/2016

Table 2.1: Highest daily and highest 14-day gas consumption

2.2.2.3 Split by country[1]

For most countries the highest daily consumption over the last five winters was reached during winter 2011/12.[2] See figure 2.9 to the right.

2.2.2.4 Simultaneity

Historical data shows a high level of simultaneity for peak demand across Europe, with a range between 93 % and 98 % from the ENTSOG calculated European Peak Simultaneity (EPS)[3] as displayed in table 2.2.

As a consequence, when carrying out peak assessment in the TYNDP, ENTSOG has retained a 100 % simultaneity assumption in order to avoid the risk of underplaying security of supply.

2009–2016 PEAK GAS CONSUMPTIONS AND THEIR SIMULTANEITY

	Day	Peak demand (GWh/d)	Simultaneity (EPS)
Winter 2009/10	26/01/2010	27,431	94 %
Winter 2010/11	17/12/2010	27,091	93 %
Winter 2011/12	07/02/2012	29,452	97 %
Winter 2012/13	12/12/2012	25,772	96 %
Winter 2013/14	30/01/2014	21,769	94 %
Winter 2014/15	05/02/2015	22,715	96 %
Winter 2015/16	19/01/2016	24,326	98 %

Table 2.2: 2009 – 2016 peak gas consumptions and their simultaneity

1) Data for BA only available from Winter 2013/14
2) The exceptions are: 2014/15 for Bosnia and Herzegovina. 2013/14 for FYROM. 2010/11 for Finland, Portugal and Sweden. 2009/10 for Ireland, Lithuania, Latvia, Slovenia, Spain and United Kingdom
3) All countries across Europe may not reach their expected highest level of demand on the same day. In order to measure the simultaneity between the peak days in different countries, ENTSOG calculates the European Peak Simultaneity (EPS). This is the ratio of the aggregated European Peak Daily Demand over the sum of all individual country peak daily demands having occurred non-simultaneously: EPS = European Peak Daily Demand / Non-simultaneous Peak Daily Demand (%)

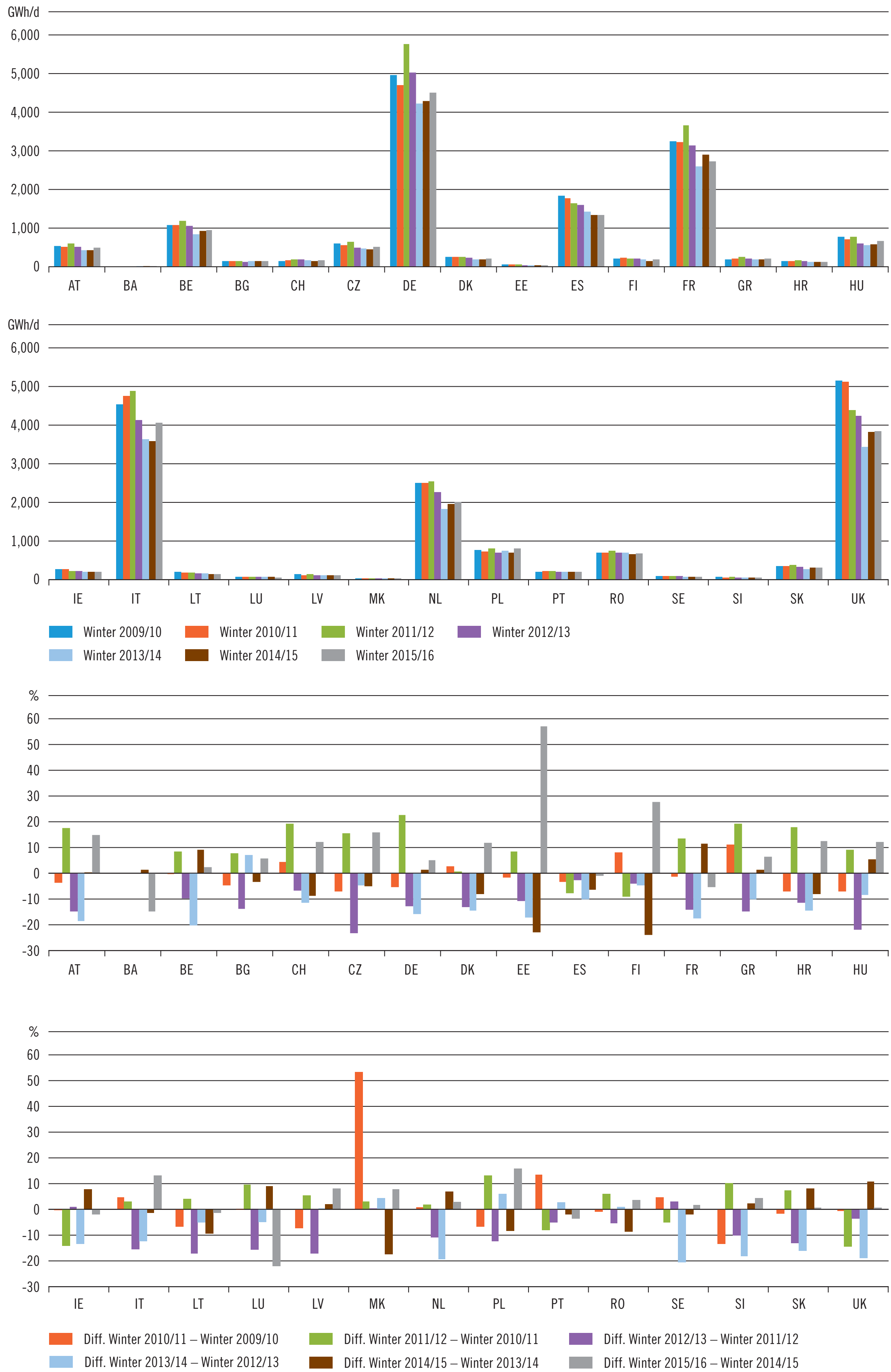


Figure 2.9: Day of the highest consumption by country and year (GWh/d) and year percentage difference

2.2.3 CURRENT CLIMATE AND ENERGY POLICIES

Since 2007, the commitment of Europe to become a highly energy-efficient, low carbon economy has been defined by the setting of climate and energy targets. The environmental targets have evolved and become more ambitious over time as indicated below:

The "20-20-20" target (set in March 2007, enacted in legislation in 2009 as the Climate and Energy package) is aiming to achieve the following by 2020:

- A 20 % reduction in greenhouse gas emissions from 1990 levels
- Raising the share of renewable energy sources to 20 %
- A 20 % improvement in energy efficiency

The 2030 framework (adopted in October 2014):

As an intermediate step towards 2050, the 2030 framework sets the following targets for 2030:

- A binding target for the reduction of GHG emissions by at least 40 % compared to 1990
- A binding target of at least 27 % of all energy from renewable energy by 2030, which would require a 45 % share for renewables in the total electricity production, according to EU Commission estimates.
- An indicative target for energy savings of at least 27 %.

To achieve these targets the EU introduced a revision to the Emissions Trading System (ETS) scheme aimed at increasing the pace of emissions cuts in the industrial and power sectors. The revisions aim to ensure GHG reductions of 43 % by 2030 compared to 2005 levels.

The 2050 EU Roadmap (agreed in March 2011):

- A 80 % reduction in greenhouse gas emissions from 1990 levels by 2050
- Milestones to reduce emissions by 40 % by 2030 and 60 % by 2040

The Roadmap sets out milestones which form a cost-effective pathway to these goals. The table below shows the main sectors responsible for Europe's greenhouse gas (GHG) emissions. The roadmap shows how these sectors can contribute to the transition to a low-carbon economy.

GHG REDUCTIONS ACCORDING TO 2050 EU ROADMAP

GHG reductions compared to 1990	2005	2030	2050
Total	**-7 %**	**-40 to -44 %**	**-79 to -82 %**
Sectors			
Power generation (CO_2)	-7 %	-54 to -68 %	-93 to -99 %
Industry (CO_2)	-20 %	-34 to -40 %	-83 to -87 %
Transport (incl. CO_2 aviation, excl. maritime)	+30 %	+20 to -9 %	-54 to -67 %
Residential and services (CO_2)	-12 %	-37 to -53 %	-88 to -91 %
Agriculture (non-CO_2)	-20 %	-36 to -37 %	-42 to -49 %
Other non-CO_2 emissions	-30 %	-72 to -73 %	-70 to -78 %

Table 2.3: GHG reductions according to 2050 EU Roadmap

The Paris Agreement[1] **(agreed in December 2015, entered into force November 2016)**:

At the Paris climate conference (COP21), 195 countries adopted the first-ever universal, legally binding global climate deal. The agreement sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to well below 2°C.

Governments agreed:

- a long-term goal of keeping the increase in global average temperature to well below 2°C above pre-industrial levels;
- to aim to limit the increase to 1.5°C, since this would significantly reduce risks and the impacts of climate change;
- on the need for global emissions to peak as soon as possible, recognising that this will take longer for developing countries;
- to undertake rapid reductions thereafter in accordance with the best available science.

Effort Sharing Decision Proposal

On 20 July 2016, the European Commission presented a legislative proposal, the "Effort Sharing Regulation"[2], setting out binding annual greenhouse gas emission targets for Member States for the period 2021–2030. These targets cover sectors of the economy that fall outside the scope of the EU Emissions Trading System (EU ETS). These sectors, including transport, buildings, agriculture and waste management, account for almost 60 % of total EU emissions. The proposal is the follow-up to the Effort Sharing Decision [3], which established national emissions targets for Member States in the non-ETS sectors between 2013 and 2020.

2.2.3.1 Current status

Overall the European Commission reports the EU has already exceeded the target set for CO_2 reduction and is on track to meet other targets for 2020. The graph below shows the evolution of the total EU greenhouse gas emissions since 1990. Total EU greenhouse gas emissions in 2014 fell by over 6% compared to 2013, to around 24 % below 1990 levels (scope of the 2009 Climate and Energy package).

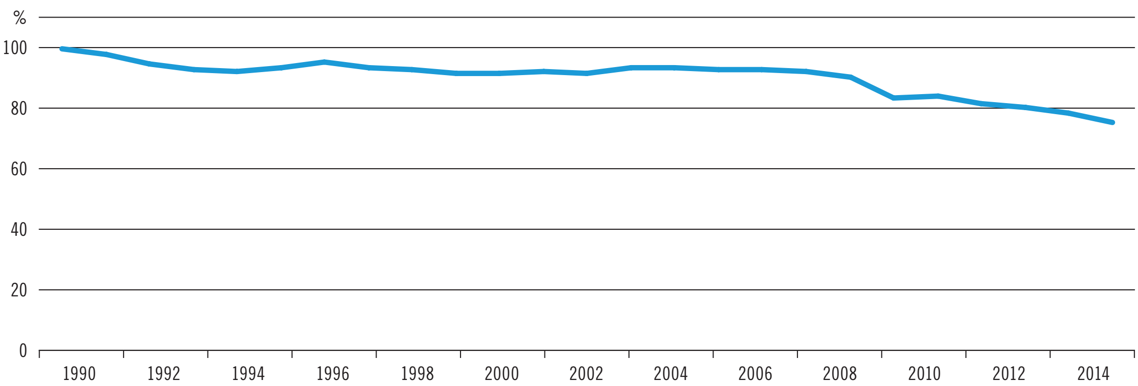


Figure 2.10: Total GHG emissions (in CO_2 equivalent) indexed to 1990. EU-28 (Source: Eurostat)

1) https://ec.europa.eu/clima/policies/international/negotiations/paris/index_en.htm

2) http://ec.europa.eu/clima/policies/effort/proposal/index_en.htm

3) http://ec.europa.eu/clima/policies/effort/index_en.htm

Figure 2.11 using Eurostat data, shows the share of renewable energy in the gross final energy consumption for the EU-28 is 16 % in 2014, slightly above the target set by the National Renewable Energy Action Plans (NREAPs). Sectors are performing at different levels and transport is believed to have challenging but feasible path from 5.9 % in 2014 to 10 % in 2020.

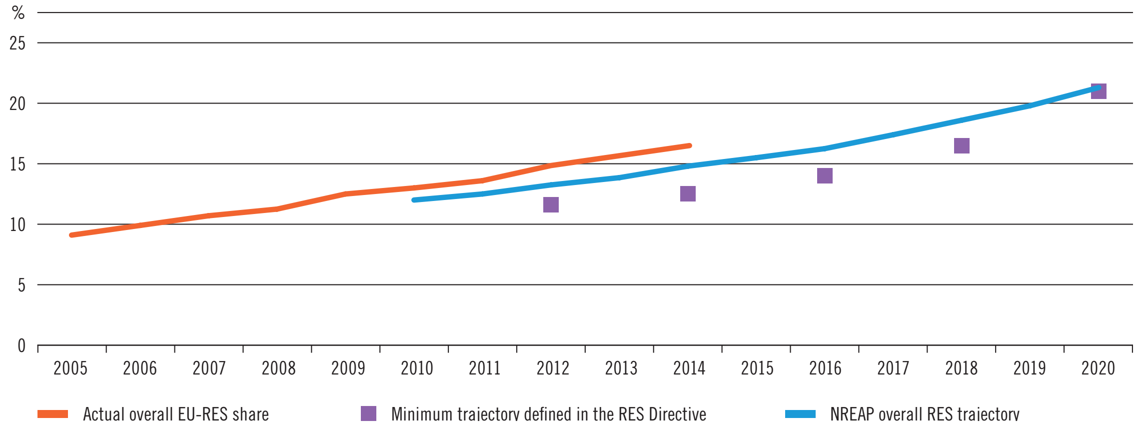


Figure 2.11: RES share in gross final energy consumption (Source: Eurostat and NREAP data)

In order to reach the 2030 targets for total energy consumption from renewables, the European Commission estimates that this will require approximately a 45 % share of renewables in the total electricity production. In 2014, Eurostat reports that the EU28 reached 27.5 %.

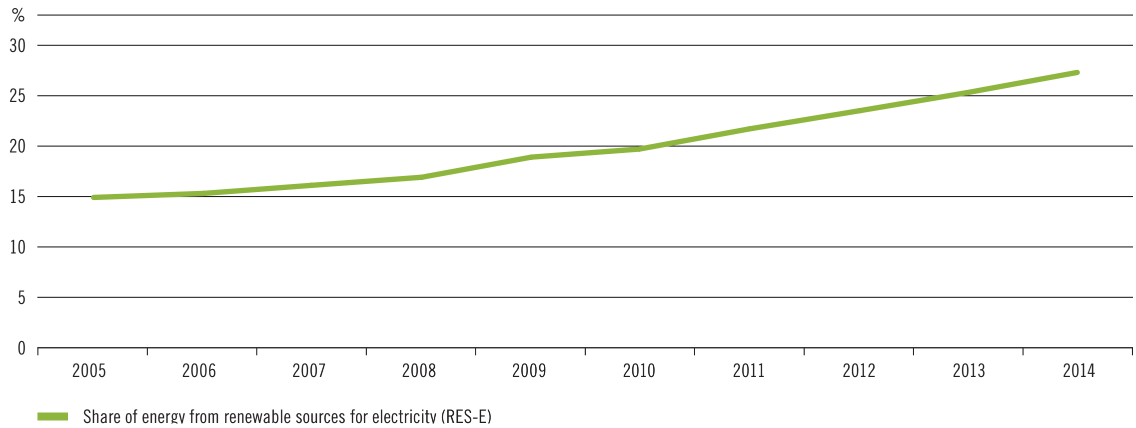


Figure 2.12: RES share in electricity (Source: Eurostat)

2.2.4 FUEL PRICES AND EMISSION TRADING SYSTEM

As described in the power generation section earlier in this demand chapter, one reason for the increased use of coal for power generation since 2010 but with a subsequent small recovery of gas in 2015 is the price difference between the two fuels.

Reviewing data from the European Commission (DG Energy), since 2012 the price of coal in Europe has been on a downward trend, largely driven by the shale transformation of the gas industry in the USA, reducing their domestic demand for coal. European gas prices remained above coal, with LNG (liquefied natural gas) supplies heading to Asia due to increased demand in the region and following the 2011 Fukushima accident and ensuing shutdown of nuclear reactors in Japan.

However, these prices drove the increase in global supplies of LNG and as demand in Asia began to weaken, Japan LNG prices declined during 2014 before becoming comparable to UK NBP Spot prices in early 2015. In addition to this, oil prices plummeted in late 2014 and in January 2016 hit the lowest price since 2003, which affects oil indexed gas contracts.

These factors have seen European gas hub prices steadily decreasing throughout 2015, increasing the competition between coal and gas in the power market.

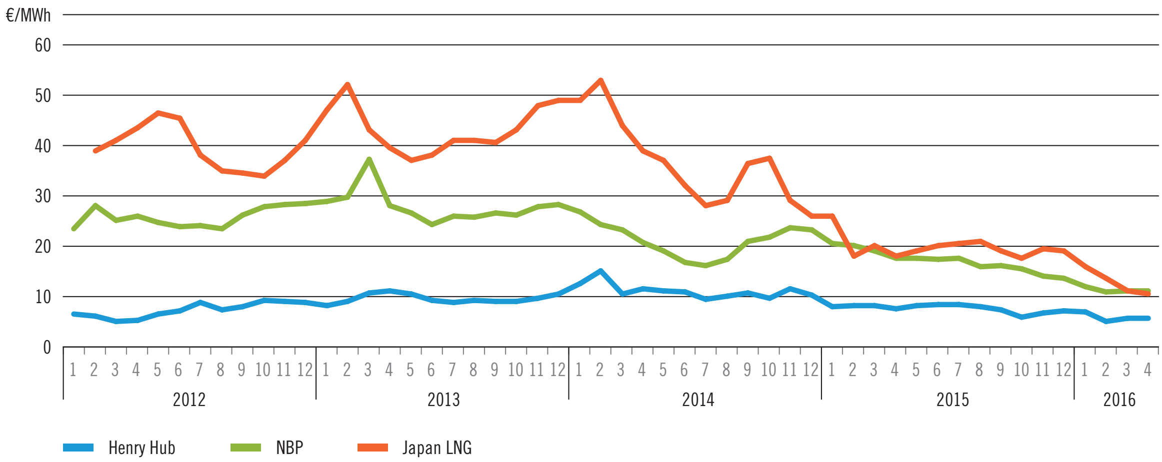


Figure 2.13: Evolution of US, EU and Japan LNG Prices.
(Source: Quarterly Report on European Gas Markets, DG Energy, ENTSOG depiction)

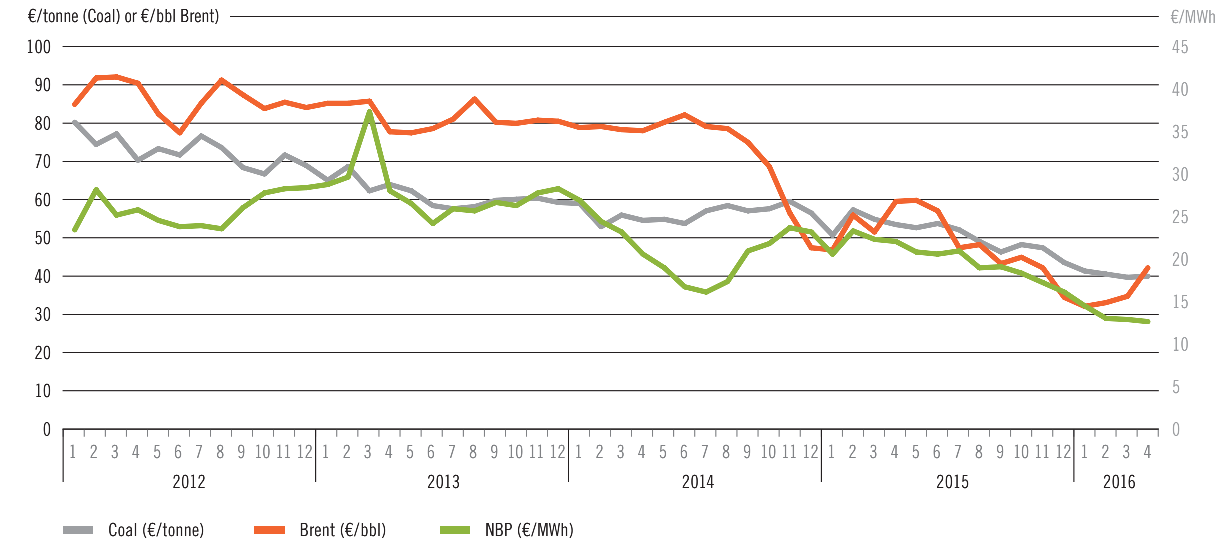


Figure 2.14: Evolution of European spot prices for gas and coal.
(Source: Quarterly Report on European Gas Markets, DG Energy, ENTSOG depiction)

The EU Emissions Trading System (ETS) has not generated a sufficiently high CO_2 price to favour gas against coal for power generation given the underlying fuel prices. This has seen some countries introducing or proposing national carbon taxes to encourage the use of less carbon intensive fuels.

ETS Phase 1 (2005–2007) was characterized by an oversupply of allowances as real emissions were lower than expected, hence prices fell to almost zero at the end of the first period.

ETS Phase 2 (2008–2012) saw the yearly amount of certificates decrease but prices still remained low.

ETS Phase 3 (2013–2020) sees yearly allocations decreasing until the end of the period in 2020. Monthly prices peaked at 8.49 €/EUA[1)] in November 2015, but have seen a significant decline in 2016 potentially caused by reductions in emissions outstripping the 1.74 % yearly cap reduction.

In July 2015 the European Commission presented a legislative proposal to revise **ETS Phase 4 (2021–2030)** in order to deliver the EU target for GHG reductions by 2030 and as part of its contribution to the Paris Agreement[2)]. The overall number of emission allowances will decline at an annual rate of 2.2 % from 2021 onwards, compared to the current rate of 1.74 %.

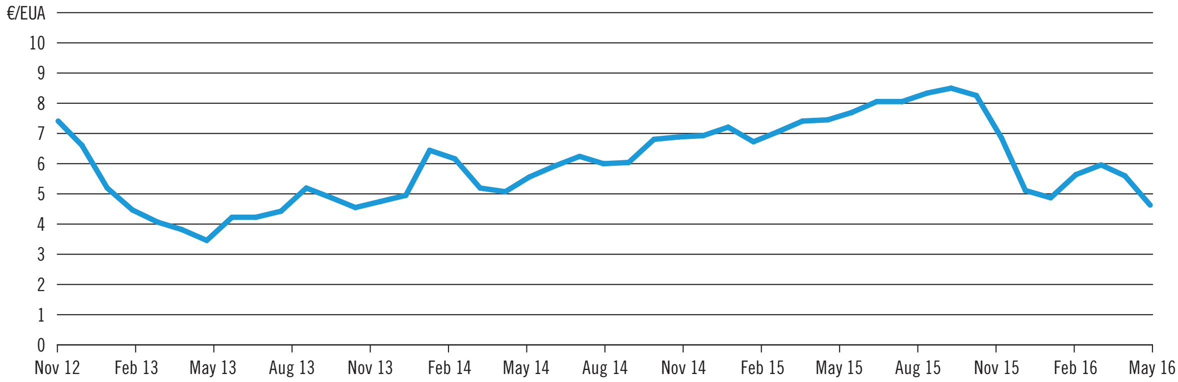


Figure 2.15: Evolution of European spot prices for emission rights for the period November 2012 – July 2016 (Data from EEX, ENTSOG depiction)

1) EUA stands for "EU Allowance". One EUA is the minimum trading unit and enables the owner to emit one ton of CO_2 equivalent (definition of EEX).

2) At the Paris climate conference (COP21) in December 2015, 195 countries adopted the first-ever universal, legally binding global climate deal. The agreement sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to well below 2°C. The agreement is due to enter into force in 2020. (EC Climate Action website)

2.3 Demand Sector Specifics

2.3.1 HEATING SECTOR

In large parts of Europe, the current residential heating market is dominated by gas. As a consequence, the gas demand in Europe shows a strong seasonal pattern, with demand being substantially higher in the winter than in the summer. This differs from the power demand profile, which is more constant throughout the year (however this might differ from country to country). This is illustrated in figure 2.16 below.

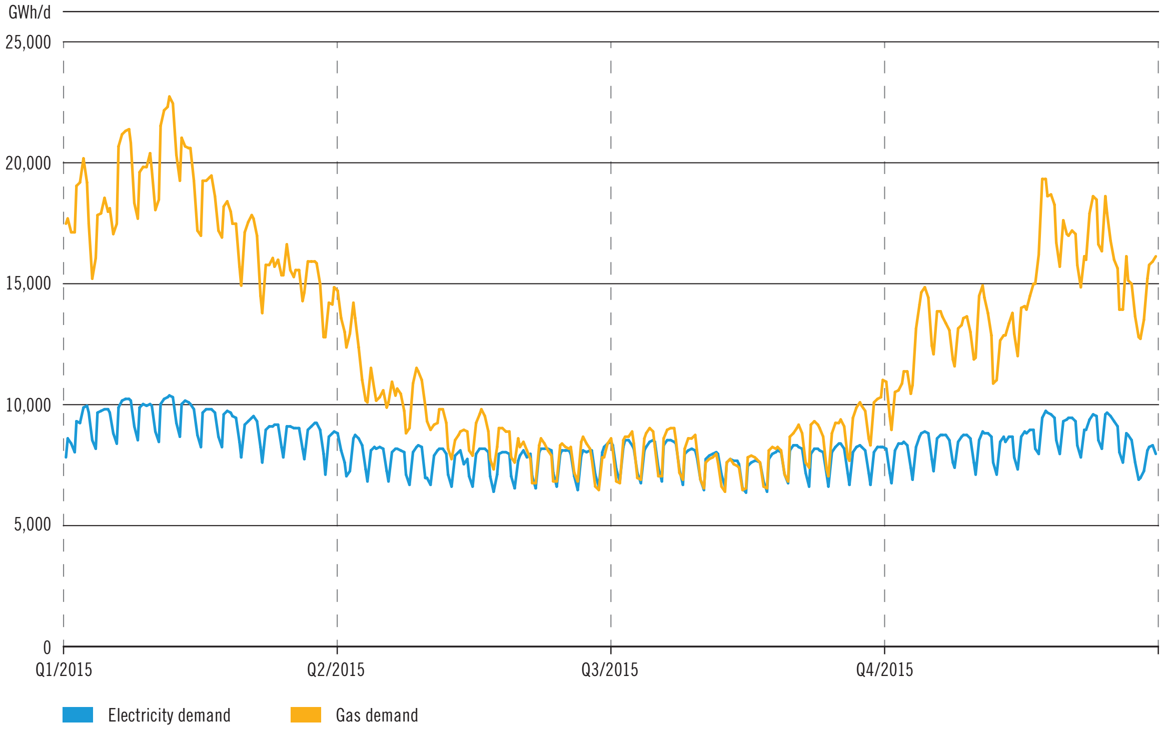


Figure 2.16: Daily EU total gas and electricity demand 2015 (data source: ENTSOG, ENTSO-E)

The high EU ambitions to reduce CO_2 emissions might change the fuel choice for residential heating. Several emerging and established alternative technologies could facilitate the energy transition towards a more sustainable heat supply. However, in order to maintain reliability and affordability, choosing the appropriate technology for each situation is a key decision.

In areas where waste heat or geothermal heat is available, district heat networks can represent an option to provide domestic heat, as long as the heat source is renewable or can be made renewable in the future. With such a district heat network, the built environment is connected to a heat source (for example a power plant) via a distribution grid of thermally insulated pipelines. The best conditions for this technology exist in urban areas where demand density is high and suitable sources are in close proximity.

The use of heat pumps might be a good alternative to reduce emissions. Countries with a high degree of heating supply via electricity (resistance heating) might benefit from the use of electric heat pumps as it reduces energy demand. For modern, new buildings with a high grade of insulation and relatively low heat demand, a full electric heat pump may be an appropriate solution in countries with mild climate. Buildings with lower grades of insulation are likely to have a substantial peak heat demand during winter time. In case the electricity network is not already dimensioned for heat supply, full electrification of these existing buildings is likely to be very costly due to the high cost of improving insulation or huge investments in new electricity transport infrastructure to support these peaks (see also the figure 2.16 on the previous page).

In this case a hybrid solution, which consists of an electric heat pump combined with a small condensing boiler, seems to be a better option that utilises existing infrastructure. A hybrid installation will use electricity for most of the year but switch to gas during low temperatures. In addition, huge investment in power grids can be avoided and the security of the energy system is safeguarded, because the gas transmission infrastructure will be used for peak winter conditions for which it is already capable.

2.3.2 TRANSPORT

Gas is a key fuel in the residential & commercial, industrial and power generation sectors, but is still developing as a fuel for transportation purposes. In order to gain a better understanding of this potential future in the demand scenarios, TSOs have been asked to provide gas projections for the transportation sector.

The Energy Environmental Agency (EEA) has reported[1] that despite the reductions seen in GHG emissions from the EU, improvements in the transport sector are lagging behind. In 2014, CO_2 emissions from road transportation increased by over 120 million tonnes since 1990 and were up by 7 million tonnes from 2013 due to diesel becoming more prevalent. Emissions from aviation and shipping have also seen considerable increases.

Overall, the transport sector is responsible for around a quarter of all EU GHG emissions and has justified the Directive 2014/94/EU on the deployment of alternative fuels infrastructure adopted on the 29th of September 2014 by the European Parliament and the Council. Member States have to develop national policy frameworks to support alternative fuels and the necessary development of the underlying infrastructure. This requires the construction of an appropriate number of LNG maritime bunkering facilities as well as LNG and CNG (Compressed Natural Gas) refuelling stations on the main European roads up to 2025.

With the right investments in the relevant infrastructure, the use of gas in transport offers the potential to reduce CO_2, NOx and fine particle emissions and improve air quality thus helping the EU achieve its environmental goals in a cost effective manner, whilst not radically altering consumer/user driving behaviour and needs. This is especially true in the heavy goods, commercial and shipping fleets where options for implementation of electrical solutions are restricted. Further possibilities are being developed with the production of hydrogen from excess renewables (power to gas) that could be used in fuel cell vehicles.

2.3.2.1 Current state

CNG for road transportation (mainly in light duty vehicles – LDV) is currently the most mature market in Europe with nearly 1.3 million natural gas vehicles and more than 3,000 CNG stations[2] (EU28 + EFTA). The highest numbers of filling stations are found in Italy, Germany, Austria, Sweden, Netherlands, Switzerland, Czech Republic and Bulgaria

LNG has less polluting emissions and higher energy efficiency. LNG could be used as a replacement for heavy oil fuel in sea-born transportation and diesel for in-land water transportation. On-shore LNG bunker facilities[3] for vessels and refuelling

1) http://www.eea.europa.eu/highlights/eu-greenhouse-gas-emissions-at?utm_medium=email&utm_campaign=GHG%20inventory%202016_press&utm_content=GHG%20inventory%202016_press+CID_76990cecd46fb8184a17970a3a13c1a3&utm_source=EEA%20Newsletter&utm_term=Read%20more

2) NGVA Europe. Report of activities 2015/2016

3) Bunker facilities are referring to LNG refilling station for ships.

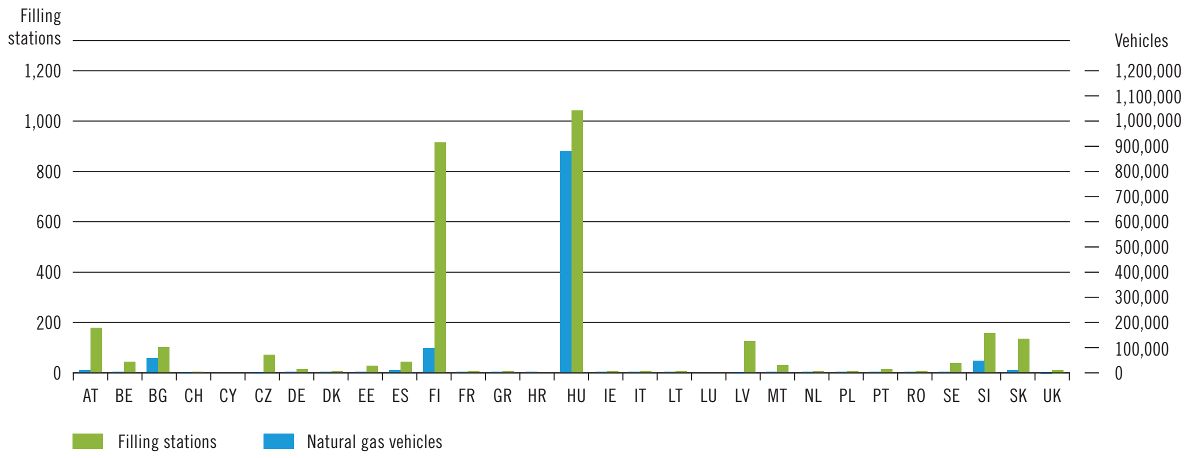


Figure 2.17: Quantities of Natural gas vehicles (October 2014) and CNG filling stations (2016), country detail (Source: Eurogas/NGVA Europe)

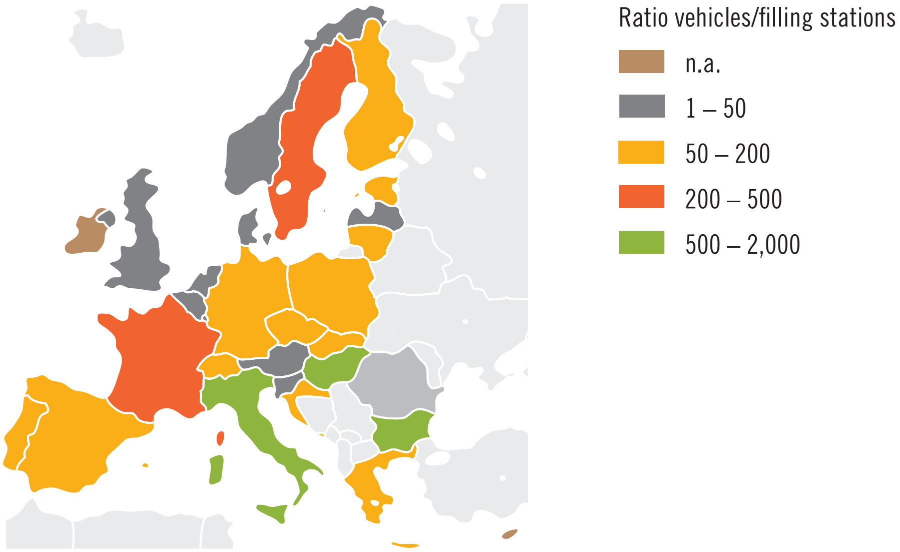


Figure 2.18: Ratio of vehicles per CNG filling station, ENTSOG depiction (Source: Eurogas/NGVA Europe)

stations for trucks are increasing continuously in Spain (36 operational installations), Norway (35), UK (22), but also in the Netherlands, Sweden, France, Belgium, Germany, Portugal, Finland.[1)]

In road transportation LNG could also replace gasoil/diesel as it would offer the same advantages especially for truck fleets. LNG refuelling stations are well developed in the Netherlands and in Spain as well as in the UK. A few stations are also present in Italy, France, Belgium, Germany and Switzerland where their number is expected to quickly increase[2)].

TSO projections indicate a continuous growth of the use of gas as a fuel in the transportation sector for the four scenarios relating to the different storylines and parameters discussed later in this chapter.

1) GIE SSLNG Map, May 2015.

2) Blue Corridor Initiative from the EC http://lngbc.eu/

2.3.3 POWER

As previously covered in the current state section of the demand chapter, gas continues to play a significant role with regards to power generation in the EU, but coal has dominated production from fossil fuels in recent years due to market conditions. Due to climate targets with a focus on reducing GHG emissions, there has been a continual development of RES generation since the power generation sector is considered to be able to reduce CO_2 significantly compared to historic levels by 2030 and onto 2050.

Natural gas, including carbon neutral green gas options such as biomethane, is a cleaner alternative to other fossil fuels. It also offers a highly flexible back-up source of generation to variable RES generation and through the vast energy storage capacity of gas infrastructure it is a means of coping with seasonal variations and winter peaks.

Although the exact mix of renewable generation that will be added to the EU system is difficult to predict, it is likely to involve the continued development of sources of variable RES generation in the form of solar and wind generation. When looking at installed capacities in the visions from the ENTSO-E TYNDP 2016, potential capacities in 2030 range between roughly double to triple the current capacity as shown in figure 2.19.

This increase in capacity means the electricity transmission system will need to be able to call upon high levels of dispatchable generation to balance the system. An example of the steep ramp rates from wind generation that could be seen at time of high demand can be seen in figure 2.20, with a loss of over 500 MW in an hour. This may coincide with the more predictable rise in generation from solar if conditions are suitable, but this is more of a challenge in winter especially for some countries. Whilst some of this may be met by current hydro solutions or the development of battery technology for short term storage, currently the most viable option both in terms of costs, reliability and flexibility is represented by natural gas.

With this potentially high gas demand variability, and to compensate for the unpredictability of variable RES, the gas system will have to have sufficient flexibility to provide quick and flexible reaction. This increased requirement for system and supply flexibility should drive an increase in both flexible supply sources and interconnection of markets to ensure the availability of flexibility in the areas where it is required.

Depending on the role of gas fired power plants between either back-up/peak situations or higher load factors, open cycle gas turbine (OCGT) with lower efficiency but shorter lead times may become more economical compared to high efficient closed cycle gas turbine (CCGT) but both are predicted to offer significantly lower capex investment than alternative fuel sources.[1)]

Other considerations in the power generation sector involve the Power to Gas technologies which convert renewable electrical power into hydrogen which can subsequently be turned into synthetic methane. This provides enhanced flexibility to the electricity system as gas infrastructure benefits from its energy storage potential and contributes towards an efficient utilisation of energy infrastructures. More details about Power to Gas may be found in the Energy Transition Chapter of this report.

1) https://setis.ec.europa.eu/sites/default/files/reports/ETRI-2014.pdf

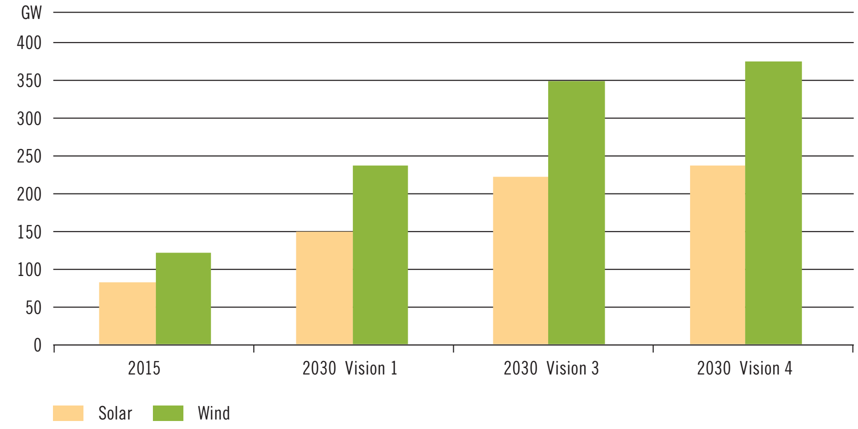


Figure 2.19: Potential increase in variable RES installed generation capacity (e-TYNDP 2016) (Source: ENTSO-E, ENTSOG depiction)

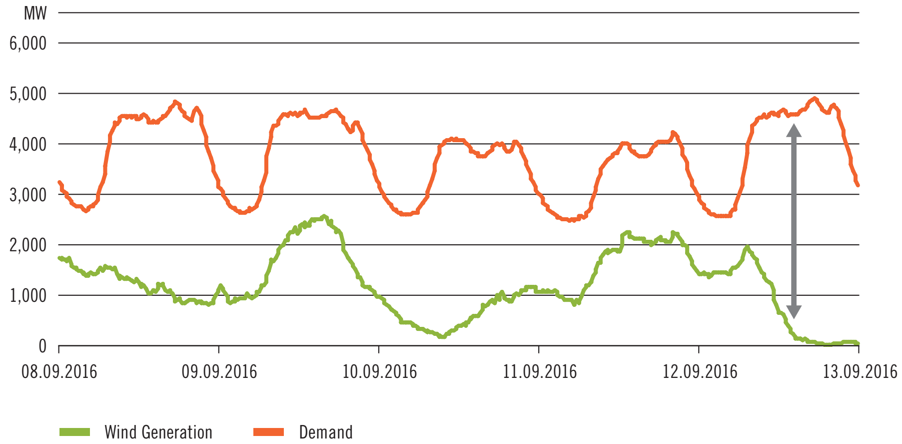


Figure 2.20: Variability of wind generation in comparison to demand profile for Ireland (Sept 2016) (Source: Eirgrid data)

2.4 Demand scenarios

2.4.1 OVERVIEW

The long term evolution of gas demand depends on many factors, including demography, macroeconomic parameters, energy and emissions prices as well as targets set by energy and environmental policies.

The scenarios for TYNDP 2017 were initially developed by ENTSOG with the help of TSO experts, to create an envelope of gas demand that would enable the TYNDP assessment to test the infrastructure with a range of possible futures. Storylines and parameters were established for each scenario and shared as part of the stakeholder joint working sessions, where feedback was incorporated into the development. These would later form the guidelines for TSO to provide data that represented these visions of the future in their country. Cooperation with ENTSO-E also enabled the alignment of these scenarios with the visions presented as part of the electricity TYNDP 2016.

2.4.2 KEY DRIVERS

In order to define the scenarios required for TYNDP 2017, two main axes were considered, Economic Growth and Green Ambition, as shown in figure 2.21. Along these axes, four scenarios have been developed that range from Slow Progression where there is little to no stimulus to change the energy sector radically from what we see today, through to the green scenarios where decarbonisation targets have caused fundamental changes to the energy landscape. There are two scenarios that cover this, Green Evolution and EU Green Revolution, the former which takes a national perspective and the latter that takes accelerated European or even global perspective on the energy transition, in light of recent developments such as the Paris Agreement and the latest EU Climate Package. Green Evolution represents the standard bottom-up data collection process from TSOs, with data for EU Green Revolution being developed using a combined approach between TSO bottom-up data and top-down adjustment with EU climate targets that could be achieved earlier leading to a faster decline in gas consumption with which to perform TYNDP assessment. More details on this methodology can be found in the Annex C4.

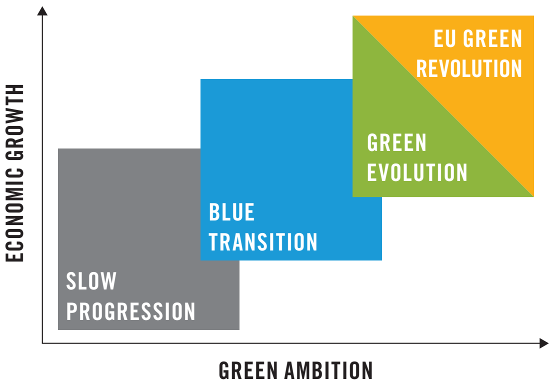


Figure 2.21: TYNDP 2017 Demand Scenario Axis Diagram

Blue Transition provides a view on the future that ENTSOG believes has not been sufficiently explored or considered by other organisations but offers a viable, cost effective way of reducing emissions through using as much of the existing energy infrastructure. This can be achieved by gas:

- dominating fossil fuel power generation sector through regulation
- having a high penetration in the Heavy Goods Vehicles (HGV) and shipping transport sectors
- still providing large amount of heating requirements, especially in peak situations therefore reducing the requirement for and cost related to electricity grid expansion and reinforcement.

2.4.3 STORYLINES

Each of the scenarios has a storyline developed to reflect a possible future of gas demand. A number of parameters is defined using these storylines, which are used to support the data collection process.

SLOW PROGRESSION

The economic growth is limited in this scenario. Green ambitions are the lowest and so the energy generation mix stays generally the same as today. Penetration of RES is at the lowest level as the incentives for renewables are limited in combination with a low CO_2 price. Green solutions are mostly not realised because of financial reasons; energy efficiencies are at the slowest level of improvement. European member states are well functioning but show a low level of cooperation which leads to less ambition to find a common CO_2 emissions reduction goal. Hence, the EU 2050 targets are not realistically reachable. Overall, this scenario shows stagnation in natural gas demand at EU level.

Slowest levels of improvement in energy efficiency are seen as there is almost no financial support. Insulation and device replacement just play a minor role; carbon-neutral buildings are too expensive for the masses. Heating for existing houses stays mainly with their current installation; however the merit order for heating for new building follows the order district heating, heat pumps and gas.

Limited economic growth combined with slow improvements in energy efficiencies are the main characteristics of the commercial sector, with the industrial sector showing similar characteristics.

Lax European incentives lead to the lowest RES development and low pressure regarding the change in usage of less polluting fuels. Due to this fact, coal is mostly used as the preferred economical fuel for power generation instead of gas. Hydro-storages are developed on a national level, nuclear power remains at the same level, depending on national policies. Back-up capacities for RES fluctuation are coming from both gas and coal-fired capacities. However, economically coal is being used more often as back-up. A slow development in energy efficiency and limited penetration in the usage of electricity for heating and transport leads to just a slightly increasing electricity demand.

In the transport sector, due to the limited economic growth and consequently low financial support, improvements and penetration of both gas and electricity technology has limited success in this sector. LNG as fuel becomes slightly more popular for smaller ships. However, container ships will not change. Cars, trucks and commercial vehicle fleets will run mostly on oil products even though there is some electrification in the vehicles market and penetration of LNG (even if slower than in the other two scenarios) in Heavy Goods Vehicles (HGV)/Heavy Duty Vehicles (HDV). Overall, oil keeps its position as the mostly used fuel in transportation and will not be replaced in the future energy mix.

BLUE TRANSITION

This scenario shows efficient achievement in terms of green ambitions under a context of moderate economic growth. Thus, the penetration of RES is higher than in the Slow Progression scenario but does not reach the level of the Green scenarios. Europe is mainly on track with the 2050 carbon targets supported by public acceptance and backed by a moderate CO_2 price. However, the realisation of some infrastructure projects supporting RES is constrained due to financial reasons. The internal energy market is well functioning.

European member states cooperate, but to a lesser extent than in the Green scenarios which leads to a lack of aligned ambitions regarding the reduction of CO_2 emissions. Efficiencies for given technologies undergo a moderate development process. European regulation paves the way for the successive closure of coal-fired power plants to foster the use of more environmental-friendly fuels. As the coal capacities will almost disappear gas becomes more favoured as base-load and back-up capacity. Due to this trend, this scenario expects overall an increasing gas demand in the future.

Improvement of energy efficiency is at a moderate level as there is lower financial support for insulation and device replacement. Carbon-neutral buildings are too expensive for the majority of the consumers and are rarely built. Heating for existing houses remains predominantly with their current proven technologies (largely based on gas). When existing (gas and oil) boilers are replaced, the old ones are substituted by condensing boilers, where gas is available. However the order for heating for new buildings follows the order district heating, heat pumps and gas.

Moderate economic growth combined with improvements in energy efficiencies are the main characteristics of the commercial sector with the industrial sector showing similar characteristics.

EU regulation will lead to a successive closure of coal-fired power plants. No approvals for new coal-fired power plants are given; there is only a limited extension of existing ones. However, this “closing process” does not start immediately and with a different speed depending on the country. In contrast, a legal framework supports efficient electricity production from gas. Thus, gas-fired power plants are used more often in base-load and remain as back-up capacity for RES intermittency. Hydro-storages are developed on national levels, nuclear power remains at the same level, depending on national policies. Efficiency gains almost balance the usage of electricity for heating and transportation so the overall electricity demand increases moderately.

In the transport sector, high financial support of natural gas, along with favourable economic conditions, lead to the usage of this fuel in private cars and commercial car fleets. LNG becomes more favoured as fuel in sea-born transportation. Smaller ships switch to this fuel and container ships will change fuel as well. Electrification in the transport sector shows a moderate penetration, electric cars receive financial support but not to the same extent as the Green scenarios.

There is a tendency to replace significant market shares of oil as the main fuel in transportation.

GREEN EVOLUTION

This scenario is characterised by favourable economic conditions and high green ambitions with high RES development. Realisation of environment targets and their fulfilment is set at a high priority and backed by public acceptance but are dealt with using more national policies than in the EU Green Revolution scenario. The European economy is prospering enabling a high support for renewable energy in the long-term perspective. This scenario is on track with the EU 2050 targets.

Efficiencies for current technologies undergo a fast development, the CO_2 price is at highest level. The internal energy market is well working, European member states are characterised by a strong cooperation, especially regarding the reduction of CO_2 emissions.

Infrastructure projects which have a positive impact to reach the environmental targets will be realised in time. As a significant part of the energy generation comes from renewables, this scenario expects generally an overall decreasing trend in fossil fuel usage, especially in coal but also in gas demand.

Strong financial support leads to higher penetration of initially uneconomic energy solutions like heat pumps and energy from biomass and also supports enduring device replacement as well as a high rate of house insulation. Energy efficiency shows the highest improvements and leads overall to lower energy intensity. Carbon-neutral buildings are very popular and backed by a high performance of energy certificates. Buildings mainly get heated through the access to district heating and heat pumps, less so by conventional gas.

The industrial sector shows similar characteristics as the residential one. Moreover, high efficiency and lower energy intensity leads to a stable industrial energy demand. Energy from biomass and more electrification ("power to heat") are used for industrial purposes. Carbon Capture Storage or Utilisation ("CCS" / "CCU") contributes to the reduction of CO_2 emissions.

The highest penetration of renewables supported by regulation fosters the use of less polluting fuels. Hydro-storages are centralised, nuclear power remains at the same level, depending on national policies. RES backup-capacities come mainly from gas-fired power plants. Heating demand and the spread of electric cars are overcompensating gained energy efficiency and leads to an increasing electricity demand.

Gas in the transportation sector shows a moderate penetration with some financial support. LNG becomes the main fuel for ships (small and container ships) and HGV/HDV. The high overall RES development leads also to the highest penetration of electrification in the transport sector with cars mostly running on electricity. In addition, electrification in this sector is backed by a strong financial support.

On the long-run oil is being replaced as the main fuel in the transportation sector and plays a minor role in the future energy mix.

EU GREEN REVOLUTION

The storyline for the EU Green Revolution scenario is largely based on the same assumptions as Green Evolution, however a number of elements have been altered in order to provide opportunities to meet the EU 2050 climate targets earlier.

There are favourable economic conditions and high green ambitions that support the highest RES development. Global political decisions and public approval result in the highest priority being set to fulfil or even go beyond the environment targets. High support for renewable energy is enabled by strong growth in the European economy in the long-term perspective. This scenario is on track with the EU 2050 targets, with the potential to reach them earlier than planned.

Efficiencies for given technologies undergo a fast development, the CO_2 price is at the highest level. The internal energy market is well working, European member states are characterised by their strongest cooperation, especially regarding the reduction of CO_2 emissions.

Through a combination of economic and political factors, infrastructure projects which have a positive impact to reach the environmental targets are realised in time and large amounts of energy generation comes from renewables. This scenario expects the quickest overall decreasing trend in fossil fuel usage, especially in coal but also in gas demand.

Energy efficiency shows high levels of improvement and leads overall to lower energy intensity. Strong financial support and consumer engagement leads to higher penetration of cost intensive energy solutions like heat pumps and energy from biomass and also supports enduring device replacement as well as a high rate of buildings insulation. Carbon-neutral buildings are very popular and backed by a high performance of energy certificates. Buildings mainly get heated through the access to district heating and heat pumps, less so by conventional gas. There is a higher penetration of hybrid heat pumps expected in this scenario when compared to Green Evolution, leading to lower yearly consumption but equivalent demand in peak situations.

The industrial sector shows similar characteristics as the residential one. High efficiency and lower energy intensity leads to a stable industrial energy demand. Energy from biomass and more electrification ("power to heat") are used for industrial purposes. Carbon Capture Storage or Utilisation ("CCS"/"CCU") contributes to the reduction of CO_2 emissions.

The highest penetration of renewables supported by regulation fosters the use of less polluting fuels. Hydro-storages are centralised, nuclear power remains at the same level, depending on national policies. RES backup capacity is mainly supplied by gas-fired power plants. Heating demand and the spread of electric cars are overcompensating gained energy efficiency and leads to an increasing electricity demand.

Gas in the transportation sector shows a moderate penetration with some financial support. LNG becomes the main fuel for ships (small and container ships) and HGV/HDV. The high overall RES development leads also to the highest penetration of electrification in the transport sector with cars mostly running on electricity. In addition, electrification in this sector is backed by a strong financial support.

On the long-run oil is being replaced as the main fuel in the transportation sector and plays a minor role in the future energy mix.

2.4.4 PARAMETERS

TYNDP 2017 DEMAND SCENARIO PARAMETERS

TYNDP 2017 SCENARIOS	SLOW PROGRESSION	BLUE TRANSITION	GREEN EVOLUTION	EU GREEN REVOLUTION
ENERGY POLICIES / REGULATION	2030/2050 targets not realistically reachable	On track with 2030/2050 targets	On track with 2030/2050 targets	On track with 2030/2050 targets, potential to achieve early
ECONOMIC CONDITIONS	Limited growth	Moderate growth	Strong growth	Strong growth
GREEN AMBITIONS	Lowest	Moderate	High	Highest
CO_2 PRICE	Lowest CO_2 price (limited spread of carbon taxes)	Moderate CO_2 price (carbon taxes mainly spread)	Highest CO_2 price (carbon taxes well spread)	Highest CO_2 price (carbon taxes well spread)
FUEL PRICES	Highest fuel prices [expected gas price > coal price]	Moderate fuel prices [expected gas price > coal price]	Lowest fuel prices [expected gas price > coal price]	Lowest fuel prices [expected gas price > coal price]
INTERNAL ENERGY MARKET	Well-functioning, low MS cooperation	Well-functioning, moderate MS cooperation	Well-functioning, strong MS cooperation	Well-functioning, strongest MS cooperation
RENEWABLES DEVELOPMENT	Lowest	Moderate	High	Highest
HEATING SECTOR				
ENERGY EFFICIENCY	Slowest improvement	Moderate improvement	Fastest improvement	Fastest improvement
COMPETITION WITH ELECTRICITY	Limited gas displacement (new buildings)	Limited gas displacement (new buildings)	Some gas displaced (district heating, heat pumps)	Some gas displaced (district heating, heat pumps)
ELECTRIFICATION OF HEATING	Lowest	Moderate	High	Highest
POWER SECTOR				
GAS VS COAL	Coal before Gas	Gas before Coal (on regulatory basis)	Gas before Coal (on regulatory basis)	Gas before Coal (on regulatory basis)
TRANSPORT SECTOR				
Gas in transport	Lowest penetration	Highest penetration	Moderate penetration	Moderate penetration
Electricity in transport	Lowest penetration	Moderate penetration	Highest penetration	Highest penetration
EXPECTATIONS REGARDING EU OVERALL GAS DEMAND	EXPECTED TO REMAIN STABLE	EXPECTED TO INCREASE	EXPECTED TO DECREASE	EXPECTED TO DECREASE FASTER AFTER 2020
RELATED ENTSO-E 2030 VISIONS	VISION 1	VISION 3	VISION 4	VISION 4

Table 2.4: TYNDP 2017 Demand Scenario Parameters

2.4.5 SCENARIO ALIGNMENT WITH EXTERNAL SOURCES OF INFORMATION

TYNDP data is based on the expertise of gas TSOs. However, ENTSOG also uses the expertise from other sources to provide information relating to the progression of commodity prices and the development of the electricity sector under different scenarios. As a result, TYNDP 2017 is aligned with two external publications that are detailed below, which were discussed and supported during the stakeholder engagement process.

2.4.5.1 Electricity Sector

In order to help create more consistent scenarios for power generation from gas, data from the ENTSO-E TYNDP 2016 was used during the development process, which included electricity demand, installed capacity, thermal efficiency and utilisation. This interaction is in line with the requirements of the EU Regulation 347/2013 (with reference to the interlinked model), and it will be further strengthened in future editions of both the gas and electricity TYNDPs.

Each scenario of TYNDP 2017 is linked to demand for power generation relevant to the Visions covered by ENTSO-E's TYNDP 2016 (see Annex C3 for more details about those visions):

- **Vision 1 – "Slow Progression"**
- **Vision 3 – "Blue Transition"**
- **Vision 4 – "Green Evolution"**
- **Vision 4 – "EU Green Revolution"**

The production from some electricity sources shows little sensitivity to market conditions. That may be the case for nuclear production coming usually base load, or RES like wind, hydro or solar where the production, having zero to low marginal costs, will only depend on the availability of the driving source.

The share of other sources in the power generation mix will generally depend on the market conditions. That is the clear case for coal and gas. Here the balance between emissions price, coal price and gas price will favour the predominance of one source against the other whenever both sources are available. There is a direct market competition between coal-fired and gas-fired power generation.


Image courtesy of REN

Within the scenario storylines, there is a clear distinction between coal and gas merit orders, with gas before coal on a regulatory basis in the Blue Transition and Green scenarios. Due to the fuel and CO_2 prices used in the ENTSO-E TYNDP 2016, this merit order may not have been reflected within the modelling. As a result ENTSOG has applied a methodology, the thermal gap approach, to help TSO's use the data from ENTSO-E to determine the gas demand required for power generation (see Annex C4 for more details about this methodology).

The implementation of this methodology requires a significant number of assumptions, including electricity generation from alternative sources, the electricity exchange with neighbouring countries, assumptions regarding the usage of CHP (those facilities earn their money in both the heat and the electricity market) and limitations in the utilisation of coal and gas. These assumptions are based on the actual electricity mix, along with feedback from stakeholders and inputs from TSOs, reflecting the specific factors for each country.

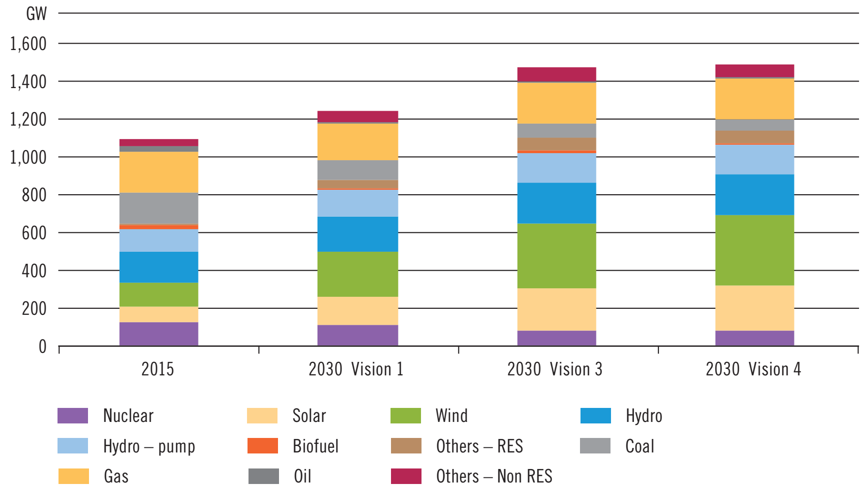


Figure 2.22: Power generation installed capacities for Vision 1 (Slow Progression), Vision 3 (Blue Transition) and Vision 4 (Green Evolution and EU Green Revolution). (Source: ENTSO-E)

Peak day and 2-week high demand cases[1)]

There are different assumptions on the climatic dependence of the generation data between the defined probabilities of the high demand situations and those ones in the available information. ENTSO-E market modelling uses a specific climatic year, while the ENTSOG 2-week and peak day demand cases are representing 1-in-20 or national design case situations. Therefore adequate data was requested by gas TSOs during the data collection process.

The peak gas consumption is expected on a day of high electricity demand for which the availability of variable sources is low. The gas consumption on a day when the availability of variable sources is high allows the estimation of the flexibility required from the gas system in order to compensate for variability.

1) For more details on the definition of high demand cases and how they are considered in the assessment, please refer to Annex F: Methodology

2.4.5.2 Commodity Prices

For each of the scenarios, ENTSOG has used the information provided by the IEA World Energy Outlook (WEO) 2015, which considers the global context and development that influences commodity prices.

This achieves a level of consistency with ENTSO-E which also used WEO as a source for prices. Although the ENTSO-E electricity TYNDP 2016 used an older version than what was available during the development of this TYNDP, analysis of the data shows that the merit order between gas and coal is the same.

Table 2.5 summarises the alignment between the scenarios of the different publications.

ENTSOG Scenario	ENTSO-E Vision	IEA Scenario
Slow Progression	Vision 1	WEO 2015 Current Policies
Blue Transition	Vision 3	WEO 2015 New Policies
Green Evolution	Vision 4	WEO 2015 450
EU Green Revolution	Vision 4	WEO 2015 450

Table 2.5: Scenario alignment

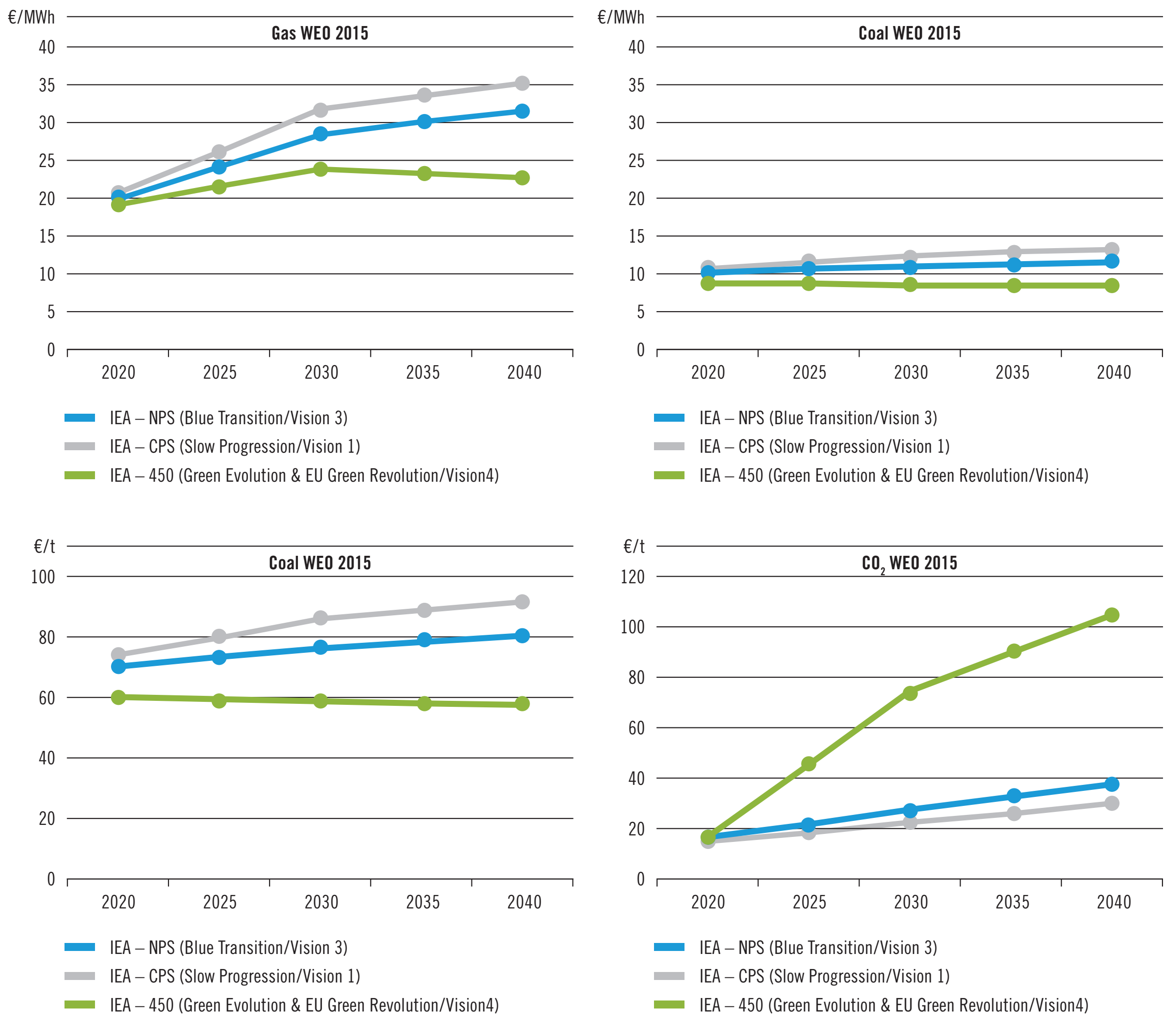


Figure 2.23: Prices for gas, coal and CO_2. Source IEA WEO 2015

2.5 TYNDP Demand Data

The demand data represented here corresponds to the data submitted from TSO in accordance with the demand scenario storylines and parameters. Volume data represents average yearly demand and as such indicates non-climatic variations that would naturally occur. This input data for the TYNDP assessment was shared with stakeholders as part of an early transparency workshop, along with the supply production and projects submitted.

2.5.1 FINAL GAS DEMAND (RESIDENTIAL & COMMERCIAL, INDUSTRIAL AND TRANSPORT)

The following figures show the evolution of the final gas demand in the TYNDP assessment years for all scenarios, including sectoral data. This covers information regarding yearly average volume, as well as the high demand cases of the peak day (1-day Design Case, DC) and the 2-week high demand case (14-day Uniform Risk, 2W) average daily demand.

2.5.1.1 Volume

The scenario parameters have affected the EU28+ yearly final demand volumes in different ways to give a range of evolutions.

In the Slow Progression scenario final gas demand is expected to marginally decline between 2017 and 2035 (-3.3%) as the poor economic conditions and green ambition see little growth or decarbonisation, but some energy efficiency would still be expected.

Blue Transition volumes remains almost completely stable across the time period, as increased demand from transport and industrial sectors balance reductions in the residential and commercial sector driven by moderate efficiencies and green technology developments.

Final gas demand for Green Evolution drops 12 % by 2035 as energy efficiency suppresses any increases seen due to favourable economic output in the industrial sector. Electrical vehicle development subdues gas demand increase for transport and residential & commercial sees significant reductions as decarbonisation of the heating sector develops.

EU Green Revolution is subject to an acceleration of the same developments seen in Green Evolution after 2020. The result is a final gas demand reduction of 18 % by 2035.

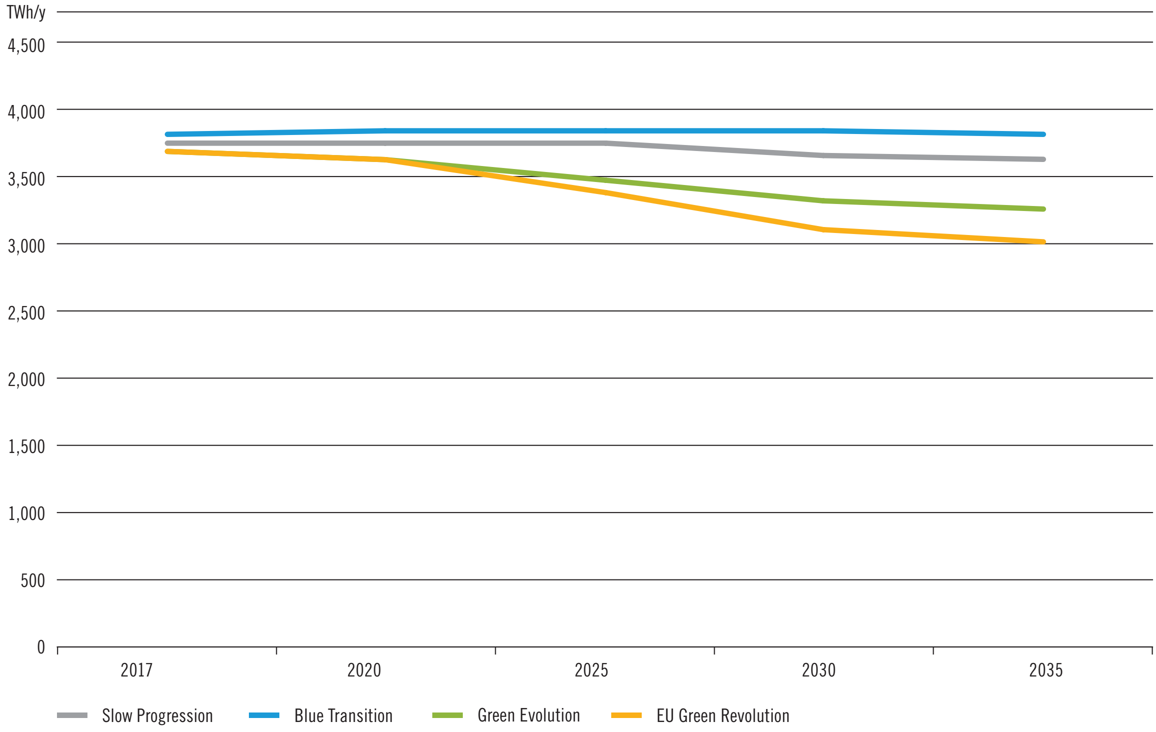


Figure 2.24: Final gas demand

Sectoral

Driven by some of the factors described above, figure 2.25 displays the percentage share of demand from each sector within final demand and how these change between 2017 and 2035. Sectoral breakdown of final demand was provided by a number of countries[1], so this data is not representative of the EU28+ as a whole.

Country level development on Final Gas Demand

Although the final demand development follows the expected trends at a EU28+ level, there are significant differences between the evolutions of demand at country level. Figure 2.26 shows the percentage increase or decline seen on a country level for each of the scenarios, which can be driven by a number of reasons, for example increases seen in the Green scenarios can be down to the shift to gas from more polluting fuels. For more information on the assumptions behind the country level evolution of demand, please refer the Country Specifics document (Annex C1).

1) BA, BE, CZ, DE, DK, ES, GR, HR, IT, SK, UK

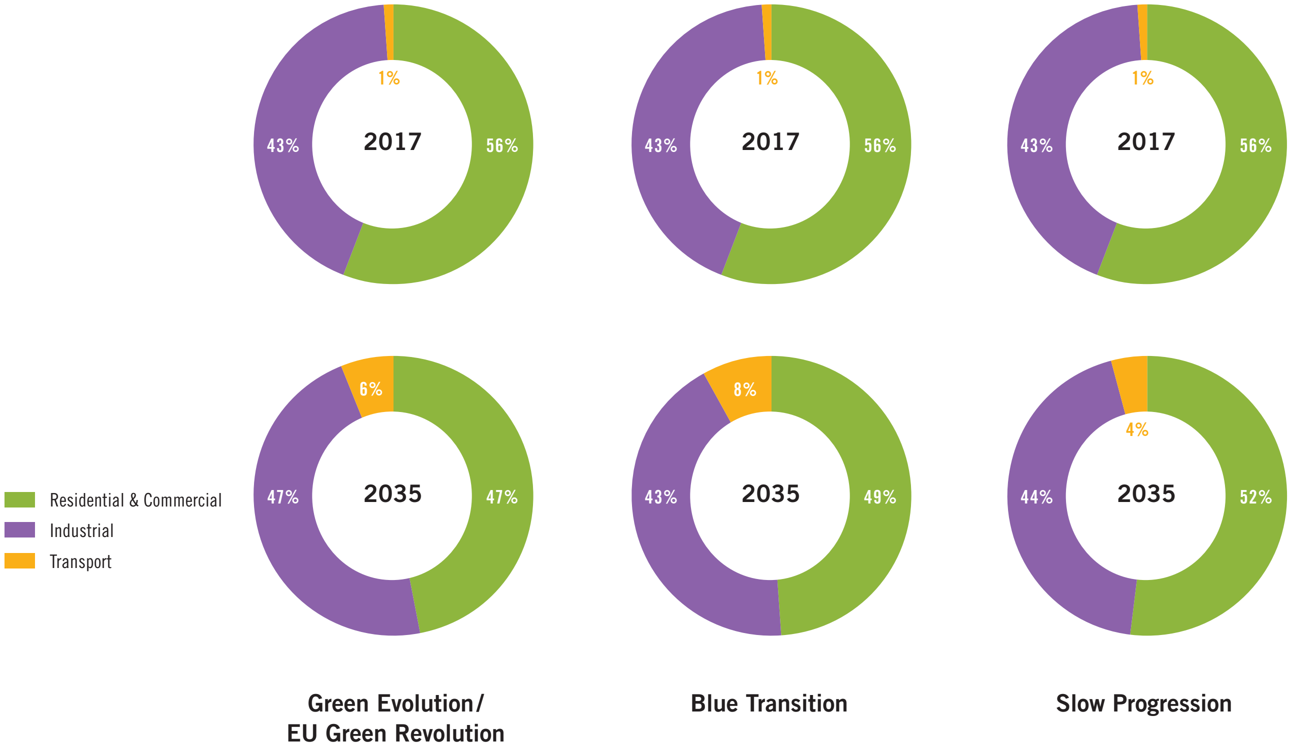


Figure 2.25: Final demand sector evolution

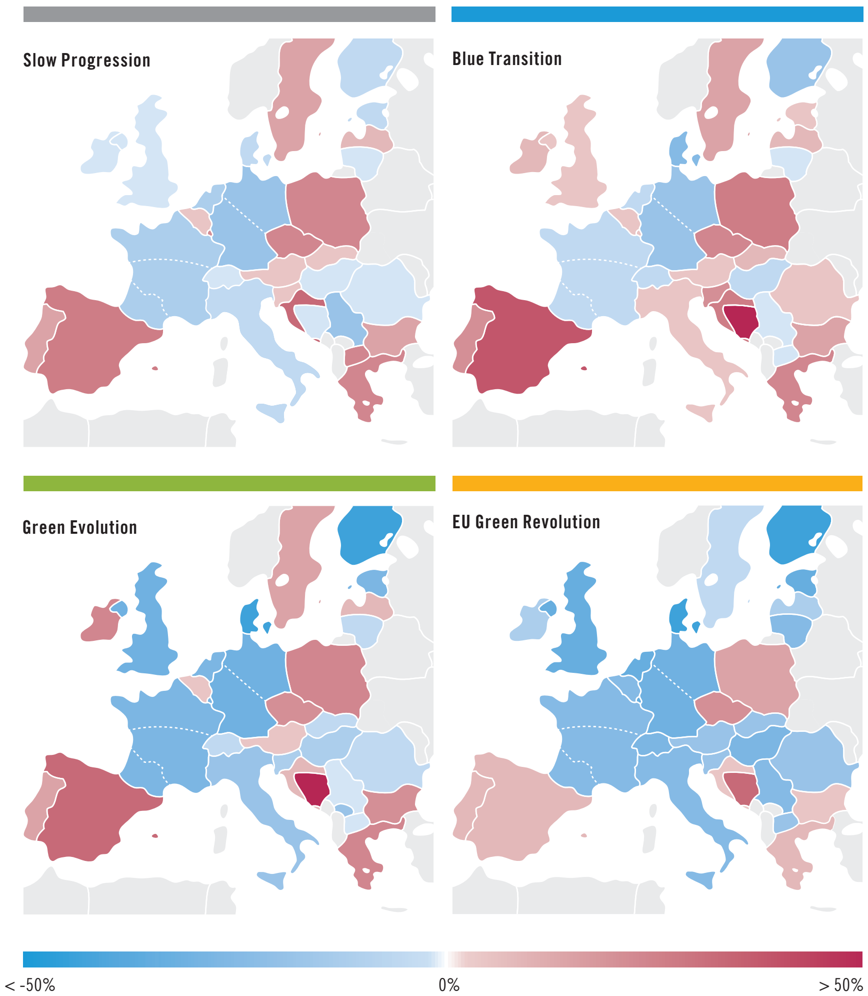


Figure 2.26: Evolution of annual final gas demand in the period 2017 – 2035

2.5.1.2 High demand cases

Final demand levels for the peak day reflect the same order for the scenarios as seen in the volume data, with the highest demand in Blue Transition through to the Green scenarios at the lower end of the spectrum. However, all scenarios show a decreasing trend ranging from -15 % for Green Evolution and EU Green Revolution to roughly a -7 % change for both Blue Transition and Slow Progression by 2035.

Once again these trends do not necessarily reflect the differences between the individual countries, for which the peak demand evolution between 2017 and 2035 varies between -50 % and +57 % depending on the scenario.

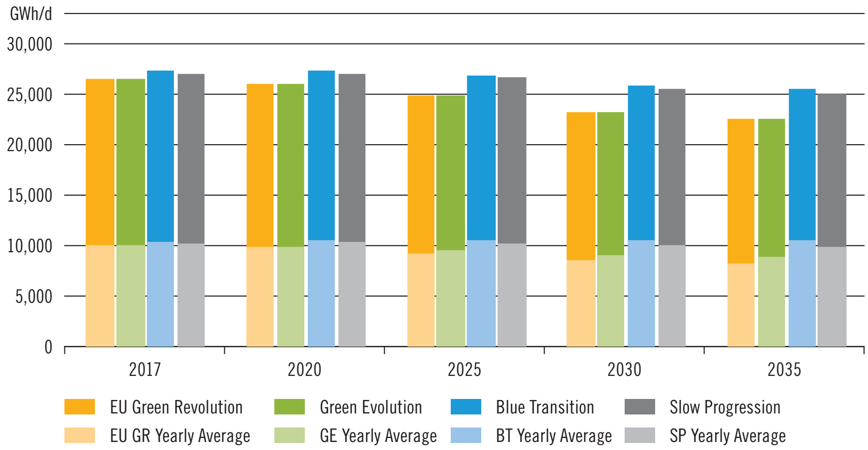


Figure 2.27: Final peak gas demand

Figure 2.28 compares the final gas demand for the peak day and the 2-week high demand case average daily demand with the yearly average daily demand. The 2-week high demand case follows the same decreasing trend as the peak day with a reasonably consistent variance between the values of 19 to 20%.

Sectoral data

Peak demand in final demand sectors as shown in figure 2.29, reflects that regardless of the scenario, residential & commercial still dominates the percentage share of demand in 2035 driven largely by the requirements for space heating. Sectoral breakdown of final demand was provided by a number of countries[1] so please note this data is not representative of the EU28+ as a whole.

1) BA, BE, CZ, DE, DK, ES, GR, HR, IT, SK, UK

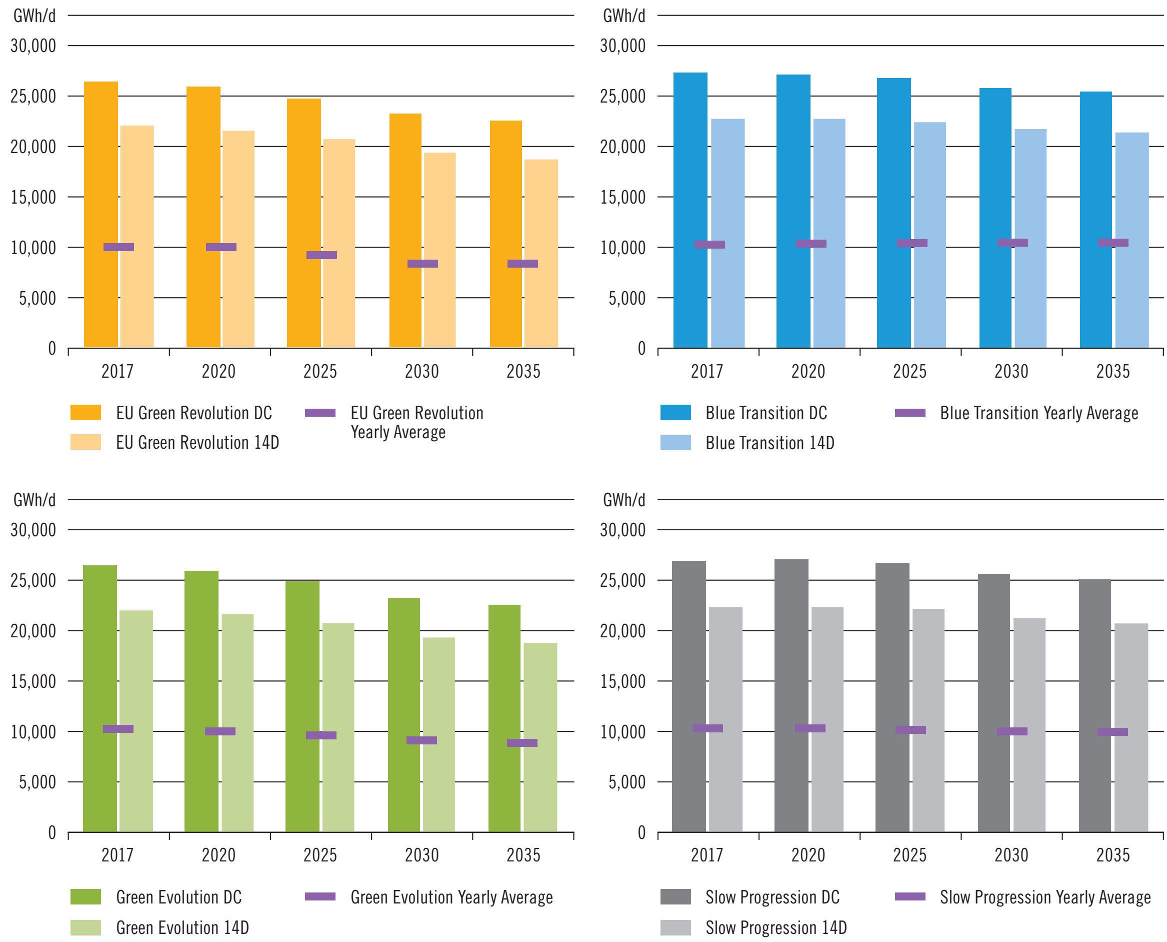


Figure 2.28: Comparison between final gas demand for the Peak day, the 2-week and the Yearly Average in different scenarios

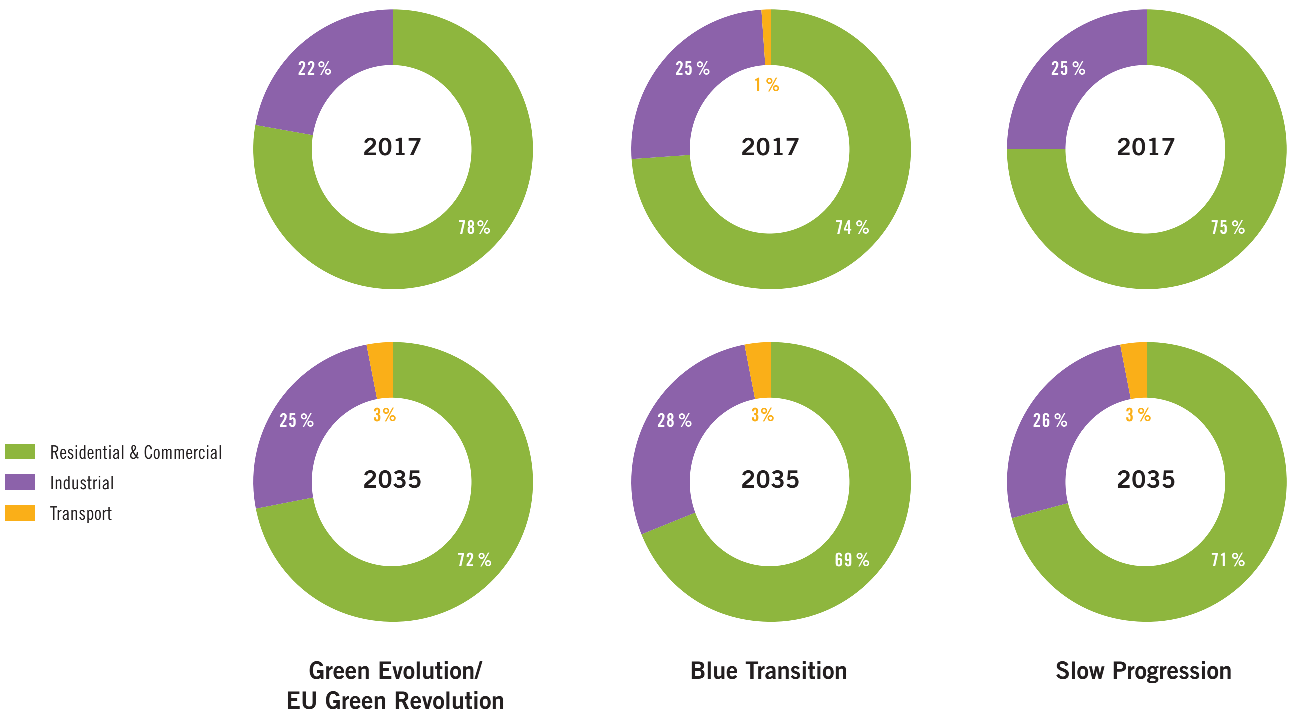


Figure 2.29: Final peak demand sector evolution

2.5.2 GAS FOR POWER GENERATION

The following figures show the evolution of the gas demand for power generation in the TYNDP assessment years for all scenarios. This covers information regarding yearly average volume, as well as the high demand cases of the Peak day and the 2-week high demand case average daily demand.

2.5.2.1 Volume

Gas demand for power generation shows a significant divergence between all scenarios, but unlike final demand there are increases and variable paths of evolution. The effect of these variations on the CO_2 emissions for the entire power sector can be found in section 2.6.2 of this Demand Chapter.

Slow Progression is the only scenario that has less demand for power in 2035 than 2017 (-4 %), despite the fact that there would be less renewable installed capacity in this scenario, which is because coal is expected to be the favoured fossil fuel for power generation.

Blue Transition displays a continually increasing trend across the time period, reaching a 49 % increase by 2035. This is due to the closure of coal plants and merit order switch to gas following regulation designed to reduce CO_2 emissions from the power sector, combined with increased economic output but the development of RES lower than levels seen in the Green scenarios.

Gas demand for power generation in the Green Evolution scenario also increases due to the same switch from coal to gas in the merit order, but peaks in 2030 before reducing in 2035 as more RES capacity comes online mitigating base load generation.

EU Green Revolution sees accelerated progress of RES power generation developments, leading to a plateau of gas demand for power between 2025 and 2030 before decreasing in 2035 although it remains 9 % above levels seen in 2017.

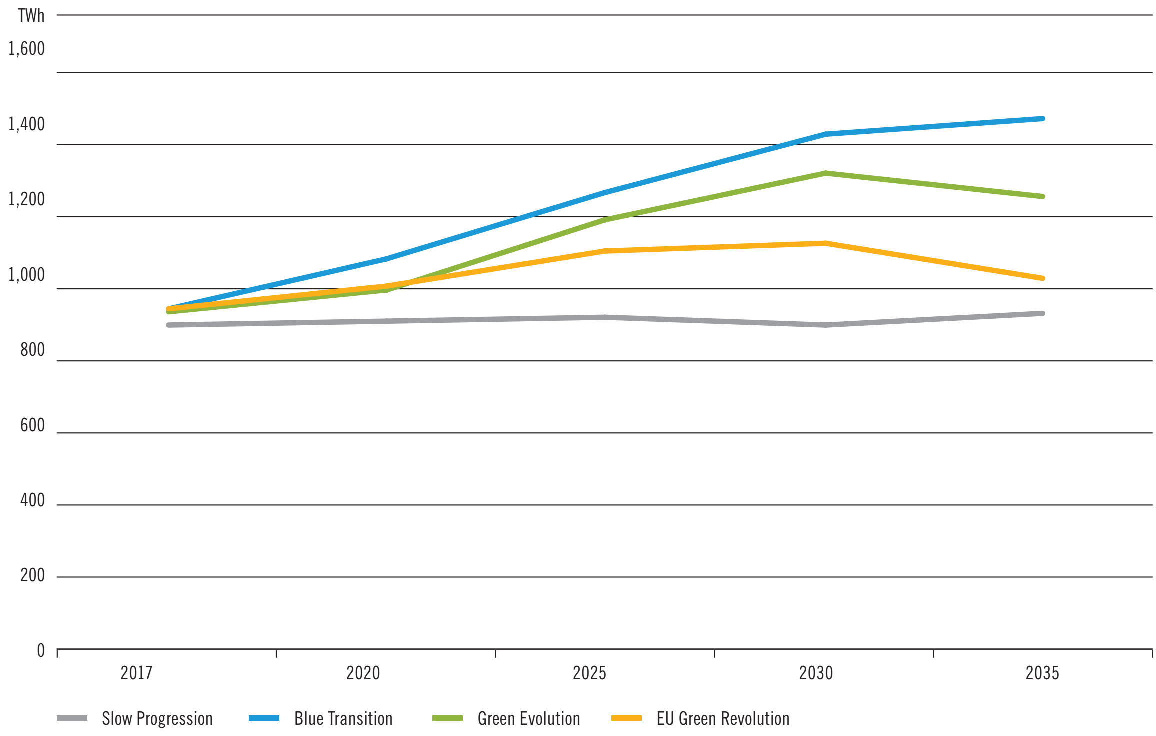


Figure 2.30: Gas demand for power generation

Country level development on Gas for Power Generation

Similar to final demand, gas demand for power generation shows notable differences between the evolutions of demand at country level. Figure 2.31 shows the percentage increase or decline seen on a country level for each of the scenarios. Some countries show a mix of increases and decreases between scenarios, whereas others always evolve in the same direction which can be driven by a number of reasons in the power sector aside from those mentioned regarding RES and coal, for example political decisions on the future of nuclear generation. For more information on the assumptions behind the country level evolution of demand, please refer the Country Specifics document (Annex C1).

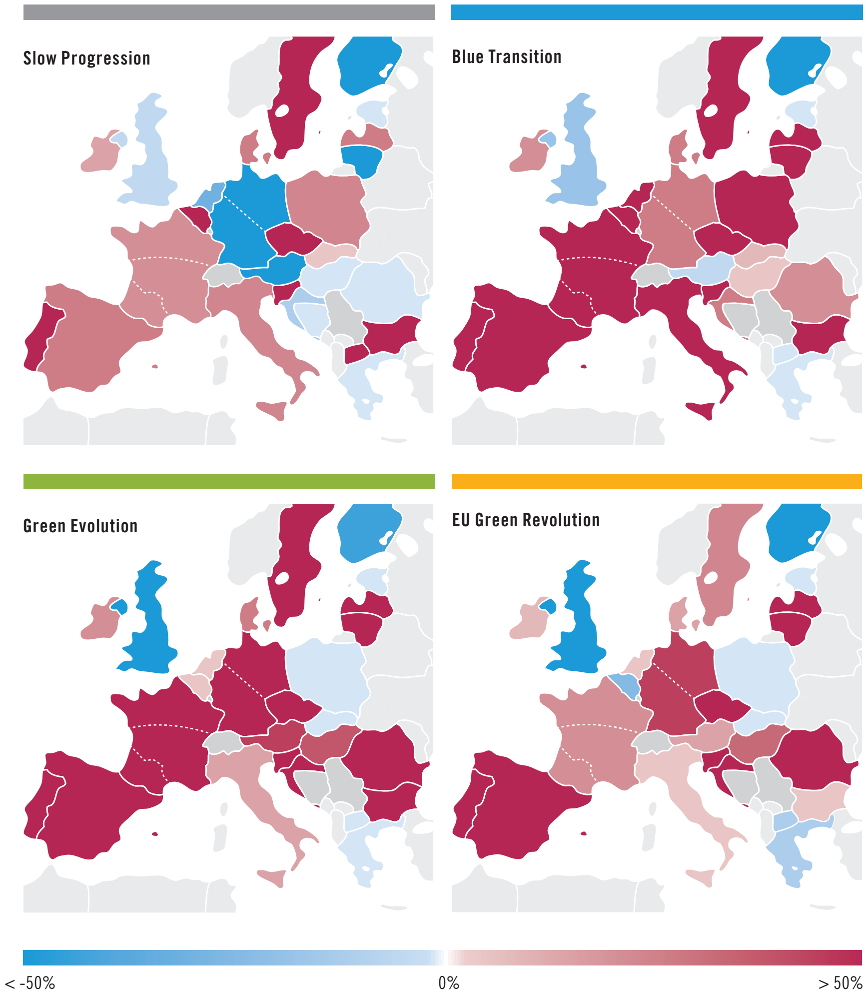


Figure 2.31: Evolution of annual gas demand for power generation in the period 2017–2035.

2.5.2.2 High demand cases

Reflecting the yearly volume data, Slow Progression and Blue Transition peak day gas demand for power generation decrease and increase the most respectively. The key differences lie in the Green scenarios, where the reduction between 2030 and 2035 is not as pronounced due to the requirement for providing generation in peak times that coincide with low RES generation. Back-up to the variability of RES is a key strength of gas-fired power plants.

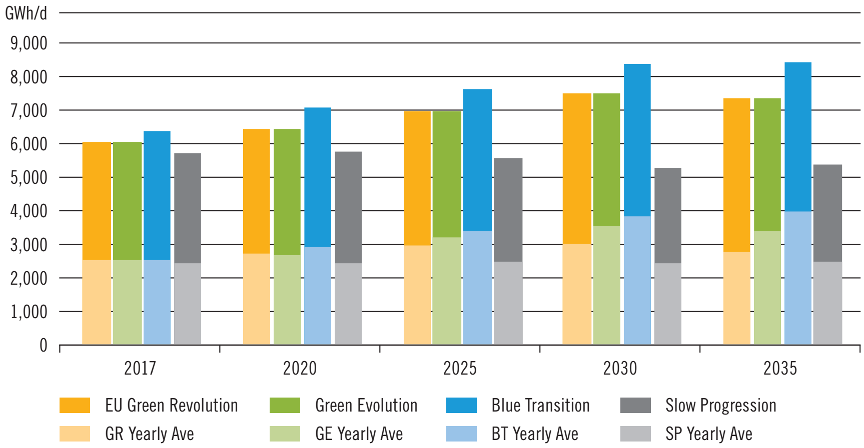


Figure 2.32: Peak gas demand for power generation

The 2-week high demand case follows the same trends displayed by the peak day, but shows a greater variance between the values depending on the scenario, with Slow Progression stable around 18–19%, but Blue Transition moving from a 22% down to a 16% difference between values in 2035.

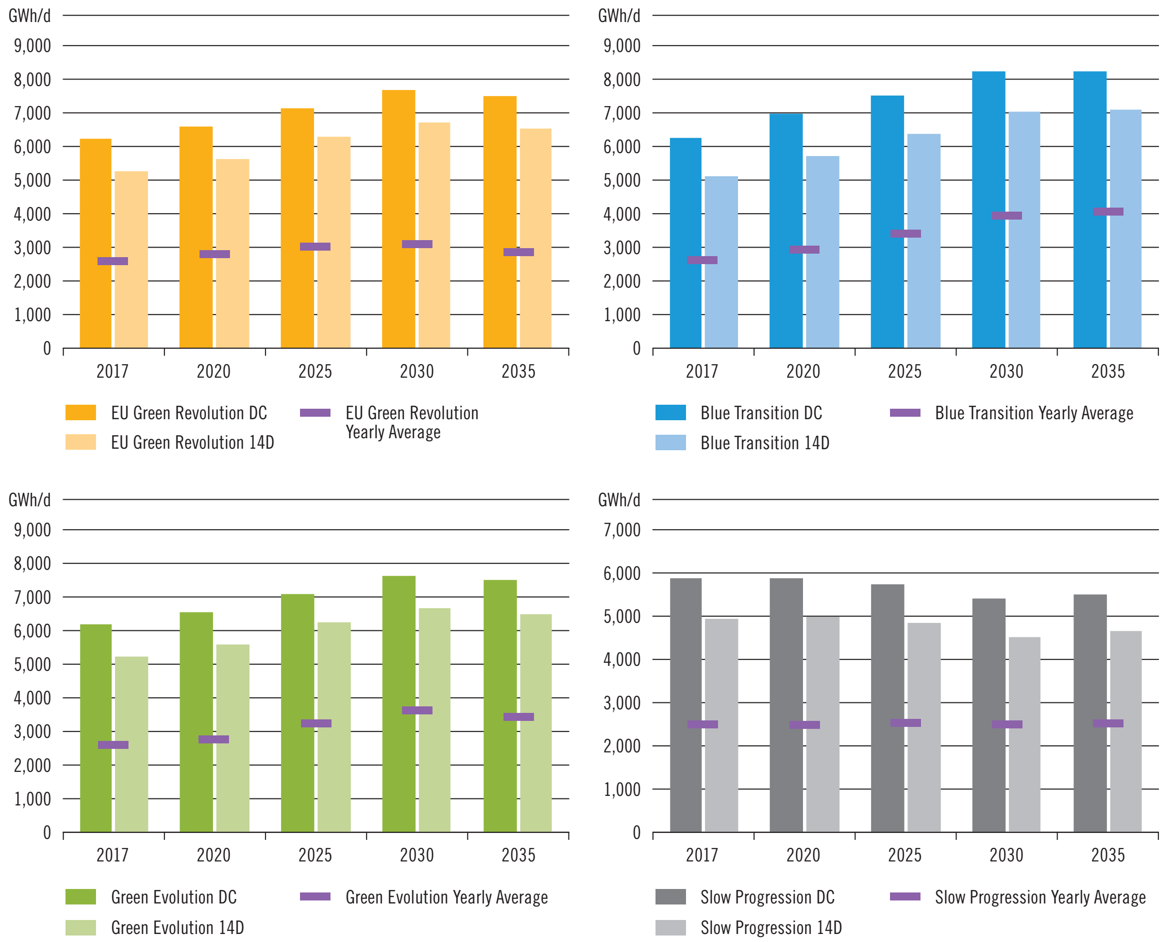


Figure 2.33: Comparison between power generation gas demand for the Peak day, the 2-week high demand case and the Yearly Average in different scenarios

Image courtesy of Gasum

2.5.3 TOTAL DEMAND

The following figures show the evolution of the total gas demand in the TYNDP assessment years for all scenarios. This covers information regarding yearly average volume, as well as the high demand cases of peak day and 2–week high demand case average daily demand.

2.5.3.1 Volume

When combining the final gas demand and gas demand for power generation, the varying trends driven by the scenario parameters produces some interesting results.

Slow Progression, as expected, has a relatively stable gas demand across the assessment period. However, Green Evolution shows a similar profile as the reductions seen in the final demand sector are balanced by the increase in gas demand for power as coal is phased out and back up for RES generation is required. Both scenarios decrease by just over 3% in 2035 when compared to 2017.

Blue Transition produces an upward trend across the period reaching a 10 % increase by 2035, whereas by the same point the EU Green Revolution decreases by 12.5 %, offering the extremes of the demand envelope for TYNDP 2017.

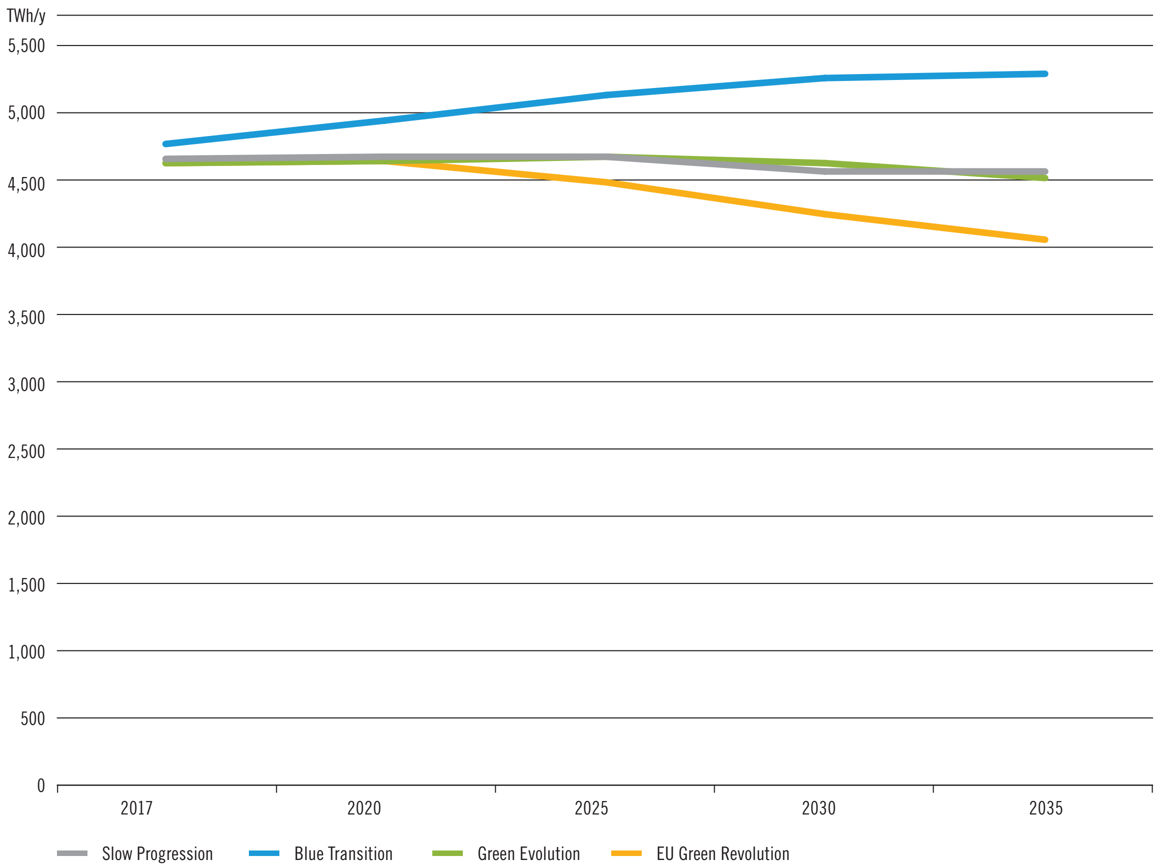


Figure 2.34: Total gas demand

Country level development

Figure 2.35 shows the percentage increase or decline in total gas demand resulting from each of the scenarios at a country level. Some significant differences can be seen across the EU, but as would be anticipated from the EU level aggregated data, the most substantial changes occur in the Blue Transition and EU Green Revolution scenarios.

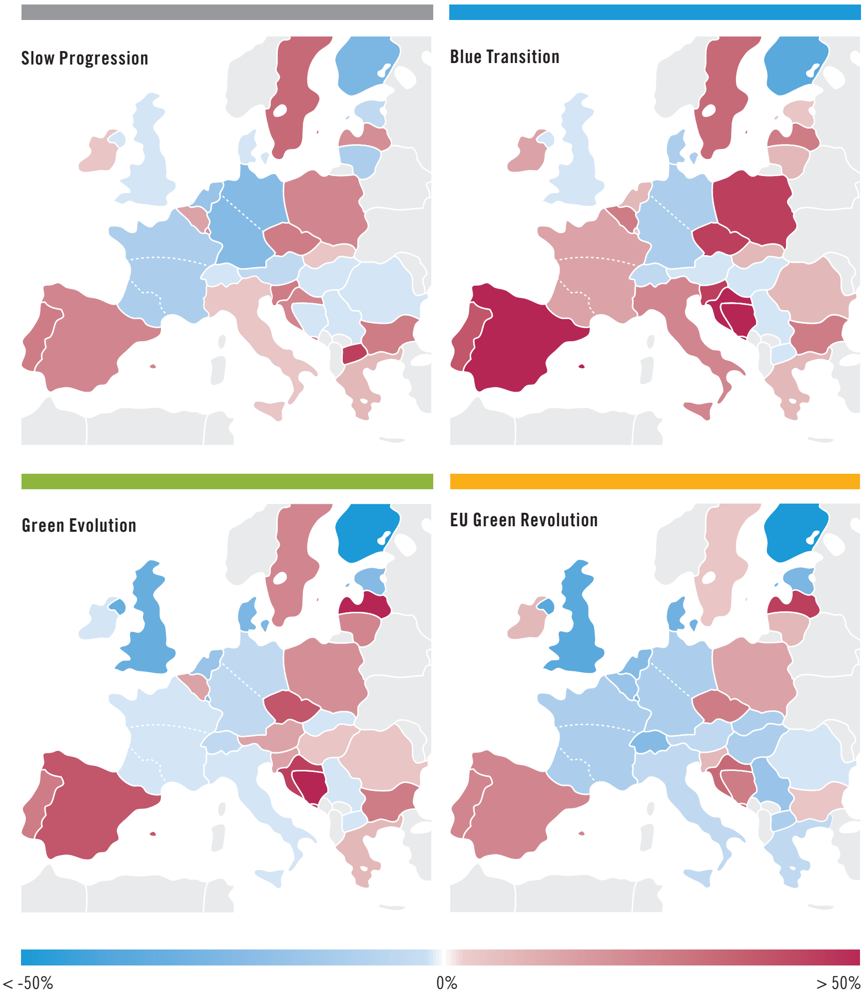
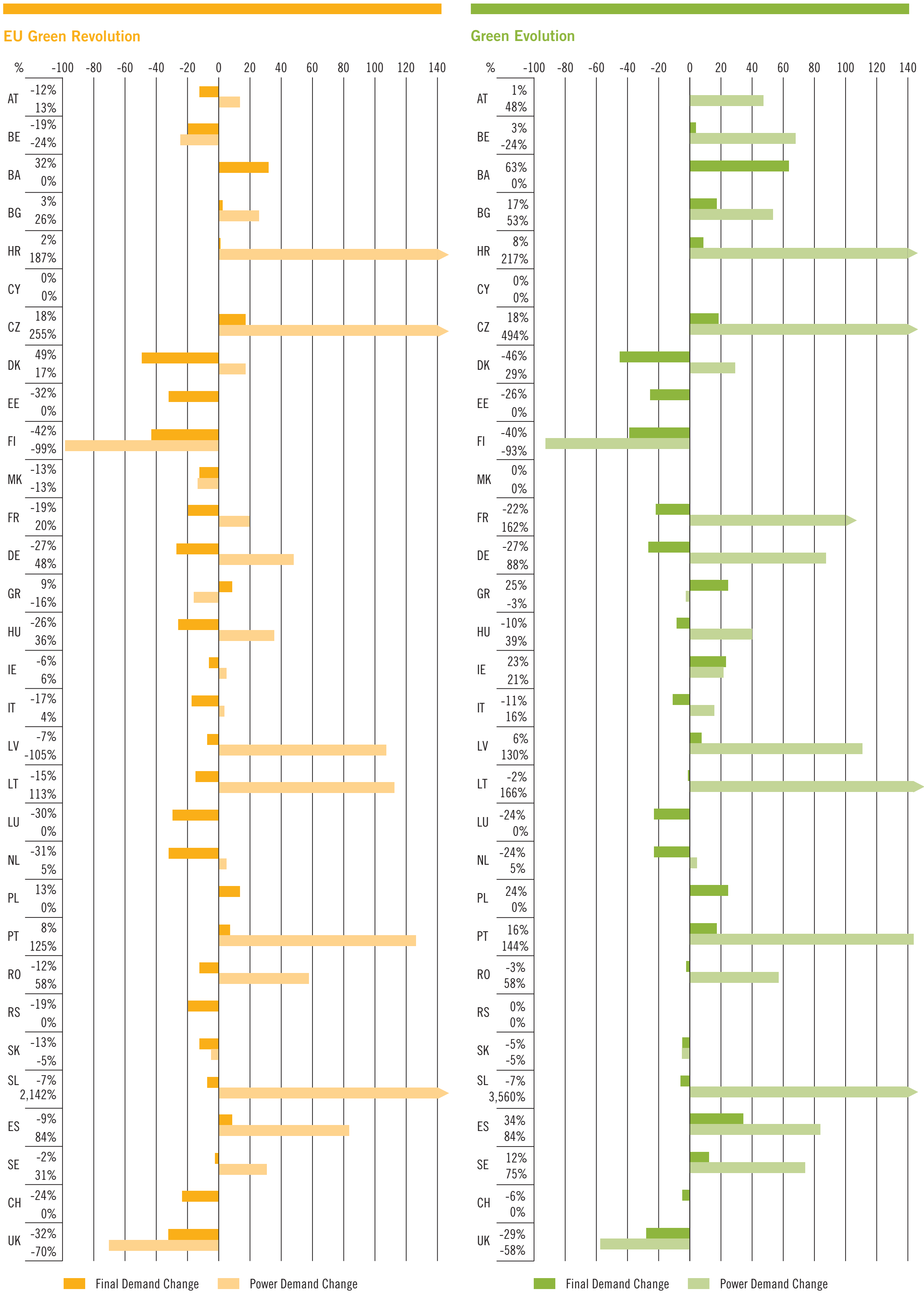


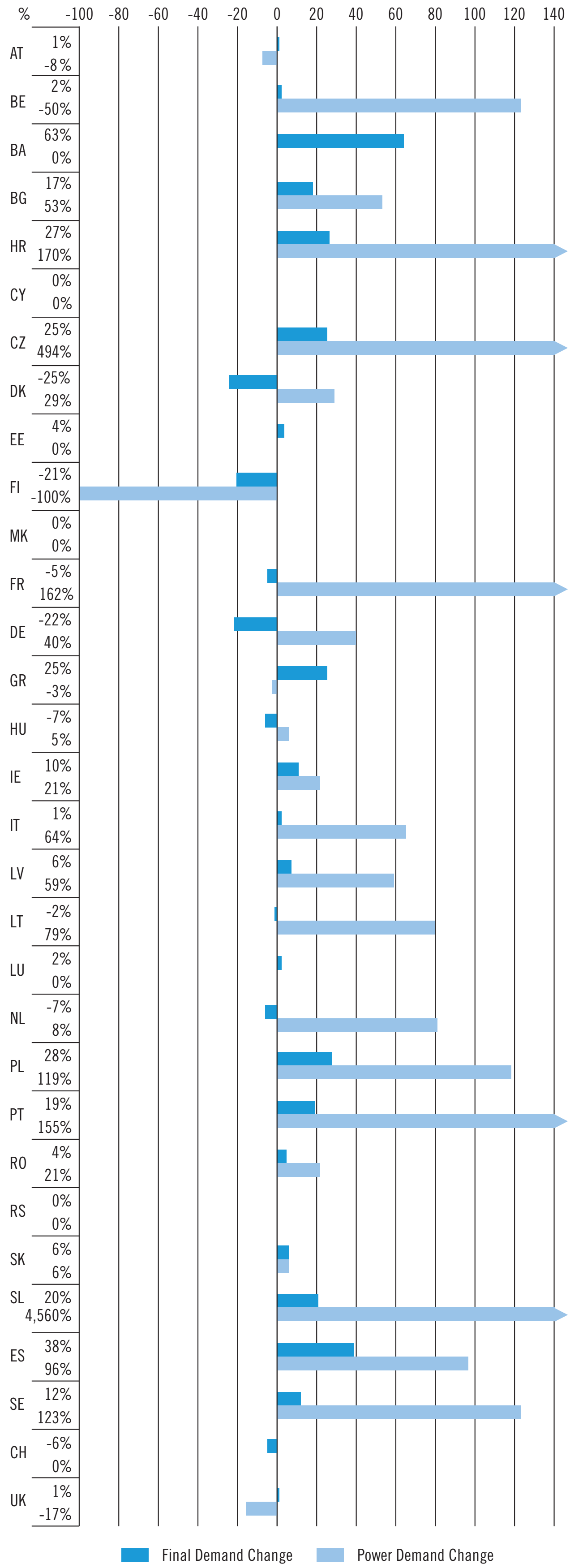
Figure 2.35: Evolution of total annual gas demand in the period 2017 – 2035



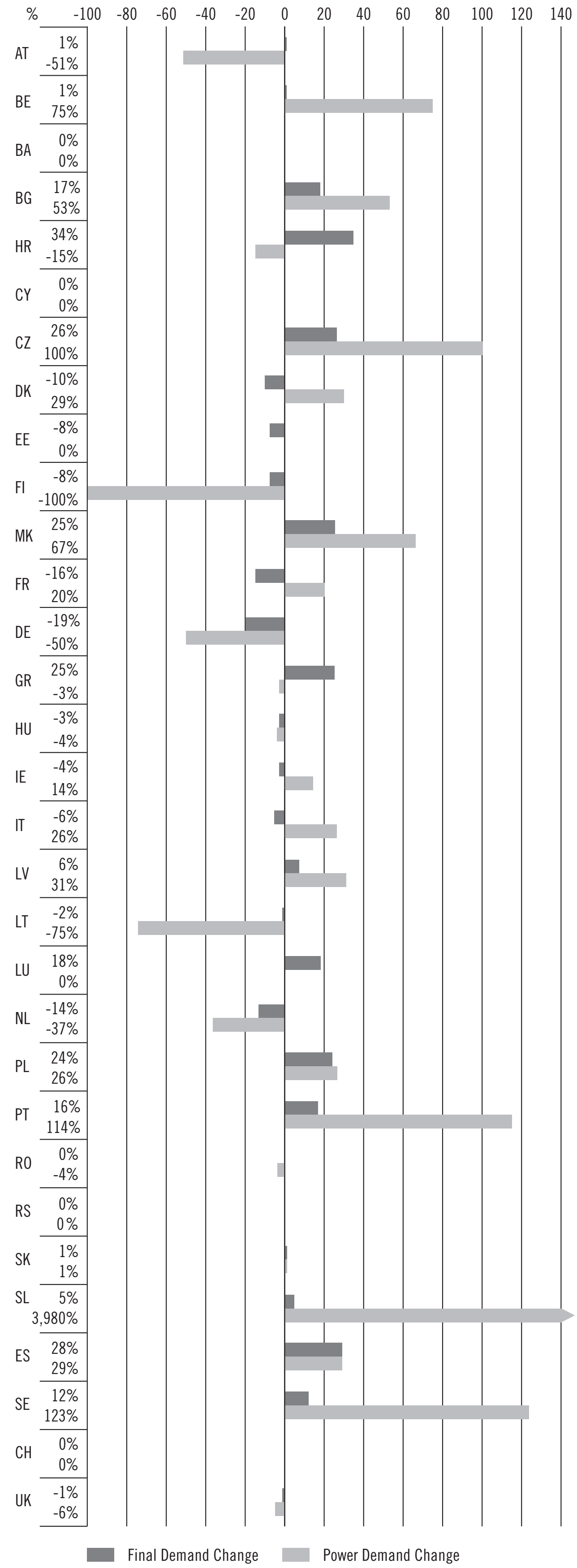
Please note in the instance of extremely high percentage increases in gas demand for power generation, this is the result of very low values for 2017.
Please refer to Annex C3 Power Generation Assumptions for more details.

Figure 2.36 Evolution of total gas demand in the period 2017 – 2035 per sector and country.

Blue Transition



Slow Progression



Please note in the instance of extremely high percentage increases in gas demand for power generation, this is the result of very low values for 2017.
Please refer to Annex C3 Power Generation Assumptions for more details.

2.5.3.2 High demand cases

The combination of final and gas for power generation peak day demand results in very similar levels for both the Slow Progression and Green scenarios, with a declining trend seen across the period reaching 93 % and 92 % respectively. Blue Transition stands apart and is relatively stable from 2017 to 2035, but peaks in 2025 with a 2.4 % increase.

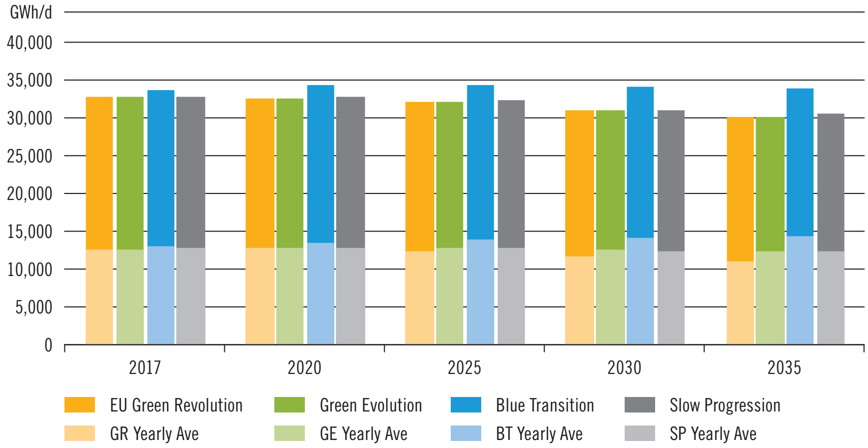


Figure 2.37: Total peak gas demand

The differences between the peak day with the 2-week high demand case average daily demand largely reflect the results seen in the final demand sector, due to the fact that final demand takes up a larger percentage of the overall demand.

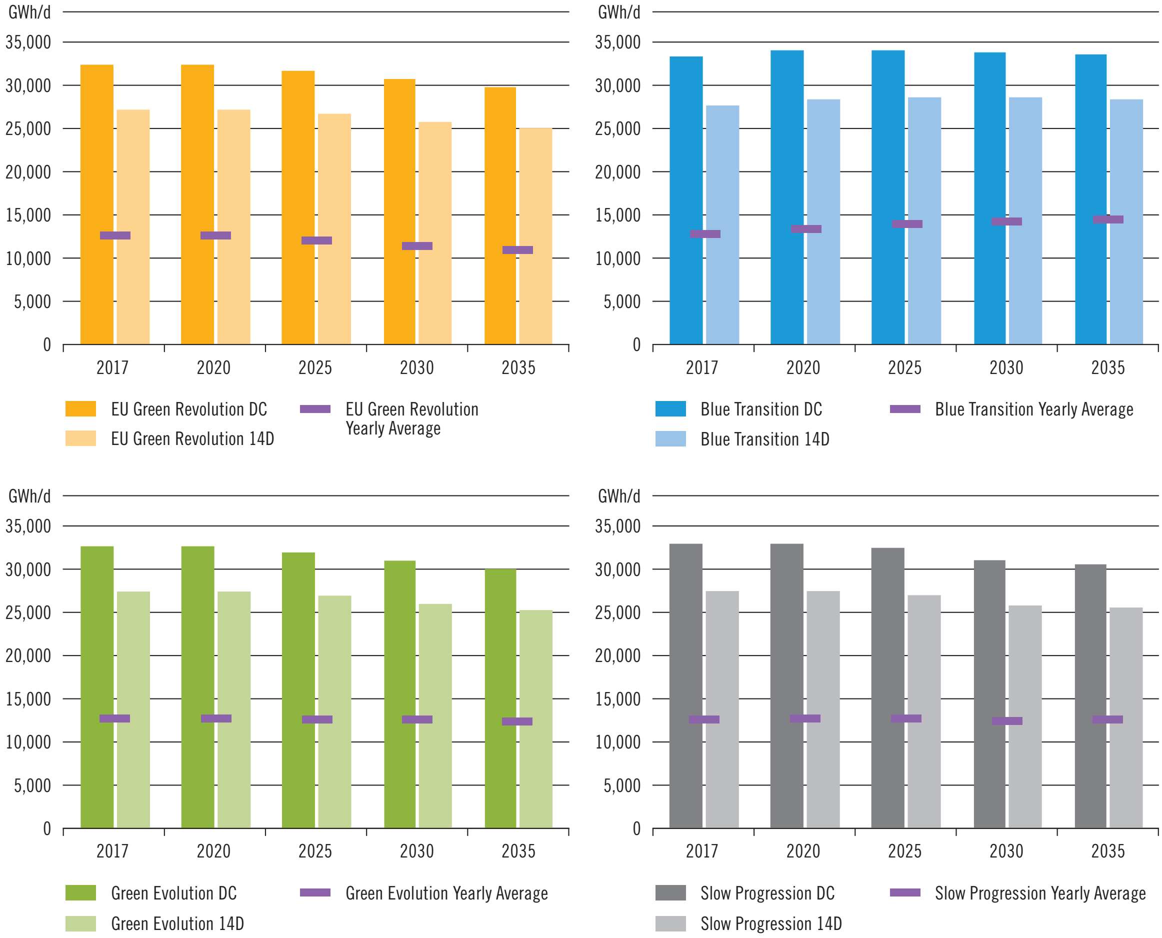
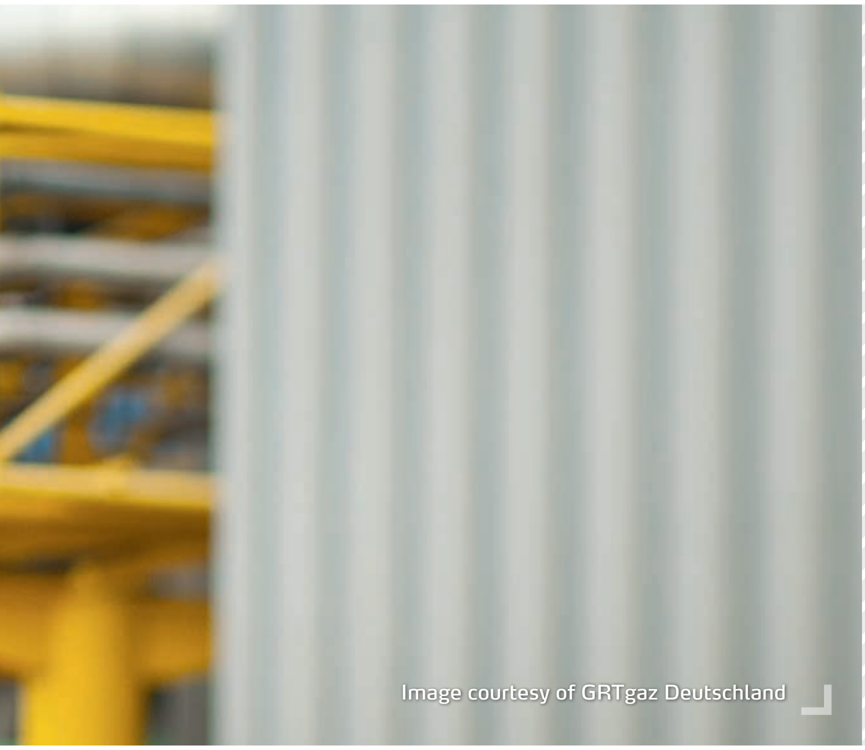


Figure 2.38: Comparison between power generation gas demand for the Peak day, the 2-week high demand case and the Yearly Average in different scenarios



2.5.4 NON-NETWORK DEMAND

The non-network demand represents gas consumption in areas that are not connected to the gas network. This demand is treated apart from the standard gas demand and is covered directly from LNG supply. Data was provided by Spain and Italy.

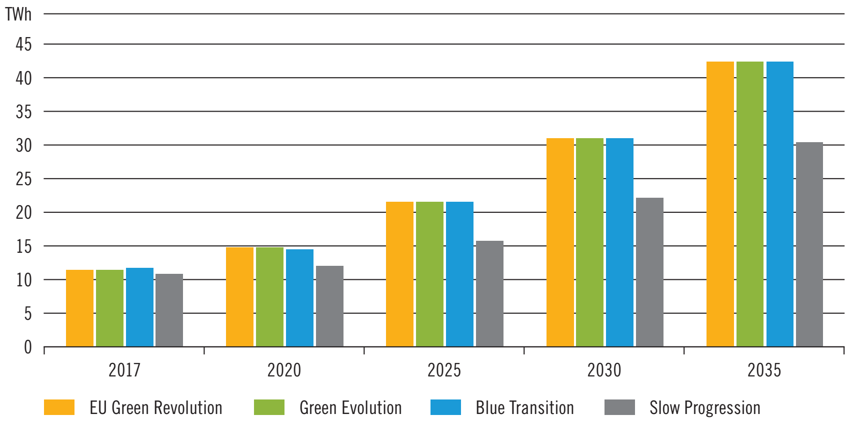


Figure 2.39: Non-network gas demand (Spain and Italy)

2.5.5 GASIFICATION DEMAND

Data for gas demand in newly to be gasified areas is collected separately from the existing gas demand, which is following the evaluation defined in the storylines of the scenarios. Information was received from Bosnia and Herzegovina, Cyprus, FYROM and Malta; country level breakdown is provided in Annex C2.

Figure 2.40 represents the data that was submitted and ENTSOG has since ompleted analysis against existing and expected capacities after the implementation of projects that have been submitted. Where mismatches occurred, different demand levels were assessed at the respective infrastructure levels. The Country Specifics document (Annex C1) contains more details.

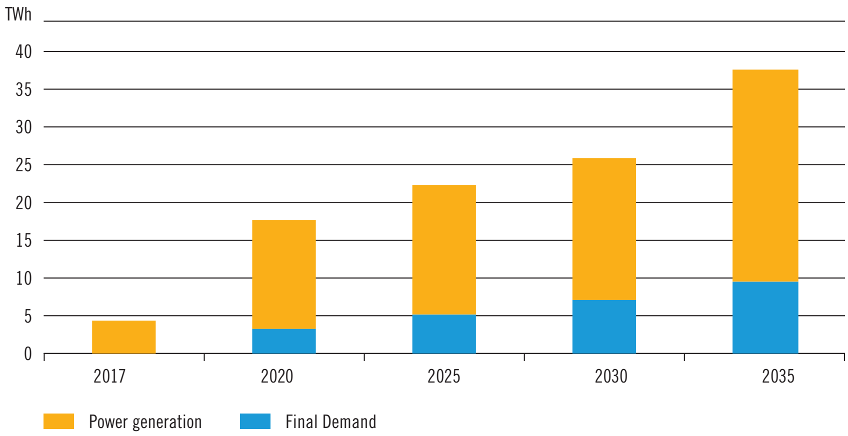


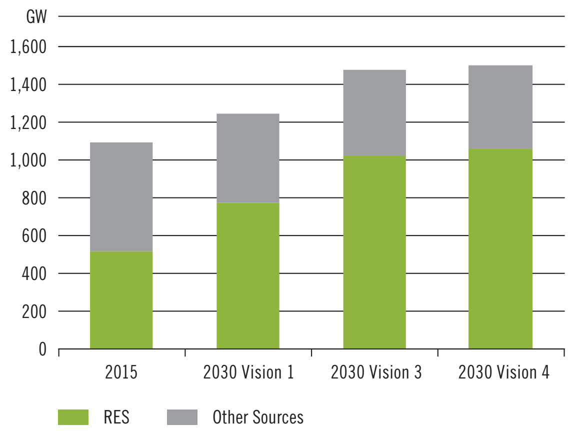
Figure 2.40: Gasification demand (Bosnia and Herzegovina, Cyprus, FYROM and Malta)

2.6 Climate data

2.6.1 RENEWABLE ENERGY SOURCES IN THE DEMAND SCENARIOS

Power generation from RES sources

The following figures show the RES installed generation capacities and their share in power generation, including hydro, wind (onshore and offshore), solar, biofuel and other uncategorised RES sources based on data from ENTSO-E TYNDP 2016.



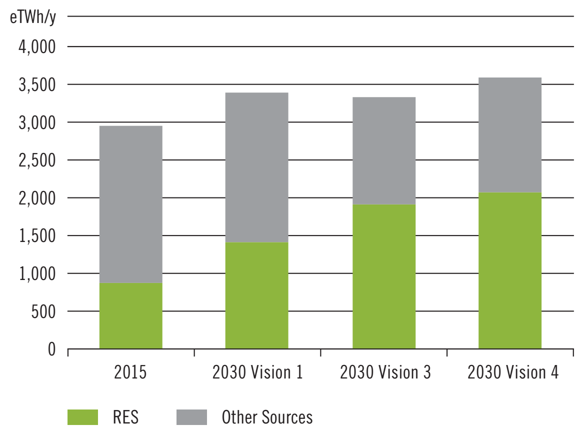


Figure 2.41: RES installed generation capacities (left) and share of power generation from RES (right) (Data source ENTSO-E, ENTSOG depiction)

Installed RES generation capacities increase significantly in all ENTSO-E visions from the current base. Vision 3 and 4, that are used in the Blue Transition and Green scenarios exceed 55 % of generation from renewable sources in 2030 and as such these visions and scenarios can be considered to be achieving the EU climate targets in this sector.

2.6.2 GREEN HOUSE GAS (GHG) EMISSIONS

The climate targets apply to overall GHG emissions, including the emissions associated with all energy consumption, including households, industry and transportation. The estimation of CO_2 emissions in TYNDP 2017 only relate to the gas final demand and the power generation sector relating to gas, coal, oil and other non-RES.

For the power generation sector, the demand scenarios use the thermal gap methodology (see Annex C4), where gas and coal are in competition and as such ENTSOG analyses the impact this competition has on emissions depending which fuel is in favour. Demand for oil in power generation has been considered as constant according to the methodology. Further details of what constitutes Other Non-RES are not available so ENTSOG is considering an average emission factor based on the other fossil fuels.

To calculate the emissions in ENTSOG demand scenarios, the following emission factors and efficiencies have been used:

CONSIDERED EMISSION AND EFFICIENCY FACTORS FOR THE DIFFERENT FUELS FOR POWER GENERATION

FUEL	CO_2	Output	EFFICIENCY
GAS	200	kg/MWh	50 %
COAL	350	kg/MWh	35 %
OIL	280	kg/MWh	35 %
OTHER NON-RES	277	kg/MWh	37 %

Table 2.6: Considered emission and efficiency factors for the different fuels for power generation (Source: Based on data from IPCC and IEA)

Annual emissions have also been calculated for the final energy consumption from gas and fossil fuel power generation data in the report "EC EU Reference Scenario 2016 – Energy, transport and GHG emissions – Trends to 2050" published by DGENERGY released in July 2016, using the same factors to offer a comparison.

Power Generation

In the power generation sector, all demand scenarios are showing significant reductions in yearly CO_2 emissions except in the Slow Progression, as shown in figure 2.42.

Apart from the initial few years of the time period, Blue Transition shows the least emissions from fossil fuel generation, as the highest gas demand for power generation forces out coal and also impacts generation requirements from other non-RES sources. However, it should be noted that in Green Evolution and EU Green Revolution, the storylines include some Carbon Capture Storage or Utilisation, which are expected to reduce the amount of CO_2 released to the atmosphere and explain the marginally higher coal usage in the power sector. Emissions plateau after 2030 is largely due to the extrapolation of ENTSO-E Vision data.

Figure 2.42: Estimated CO_2 emissions from power generation

In comparison to the European Commission EU Reference Scenario 2016 generation data, similar emissions are seen to the Slow Progression scenario up to 2030 reflecting the lack of developments beyond the current landscape. It is likely that after 2030, ENTSOG demand scenario CO_2 emissions would show a further decline which is not covered by the calculations based on the extrapolated data for electricity generation.

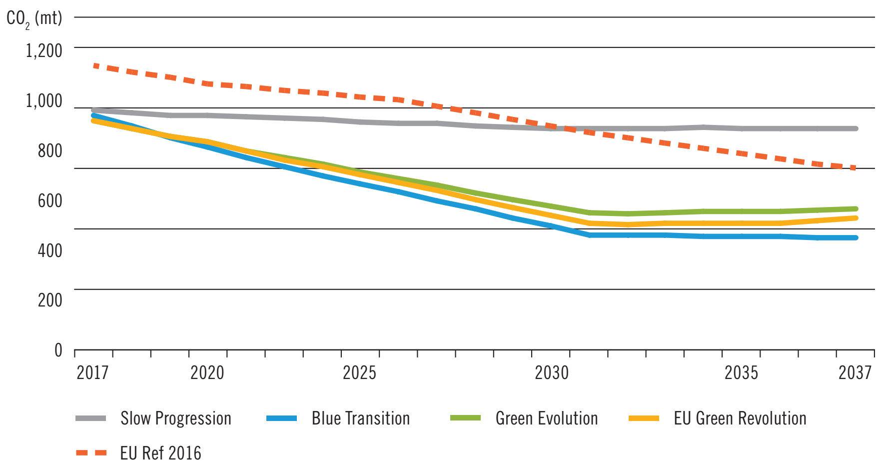


Figure 2.43: Estimated CO_2 emissions from power generation

Image courtesy of Fluxswiss

Total Gas Demand and Power Generation

When combining the sectors of power generation and gas final demand, the reduced volumes required for final demand in the Green scenarios means that both overtake Blue Transition in decarbonisation terms. The EU Reference Scenario is showing less gas demand in the sectors making up final demand than all of the ENTSOG scenarios and as a result now shows a significant move towards the Blue and Green scenarios, away from Slow Progression.

When considering the total demand, the data collected from TSO regarding the development of biomethane as a green gas supply can be applied; this makes minimal change regarding Slow Progression but reduces emissions more significantly in the other scenarios as shown in figure 2.44. For further information concerning the production of biomethane, please refer to the Supply Chapter.

Again it is worth noting that in the Green scenarios CCS or CCU would have the potential to reduce emissions further in these scenarios if applied in the power and industrial sectors.

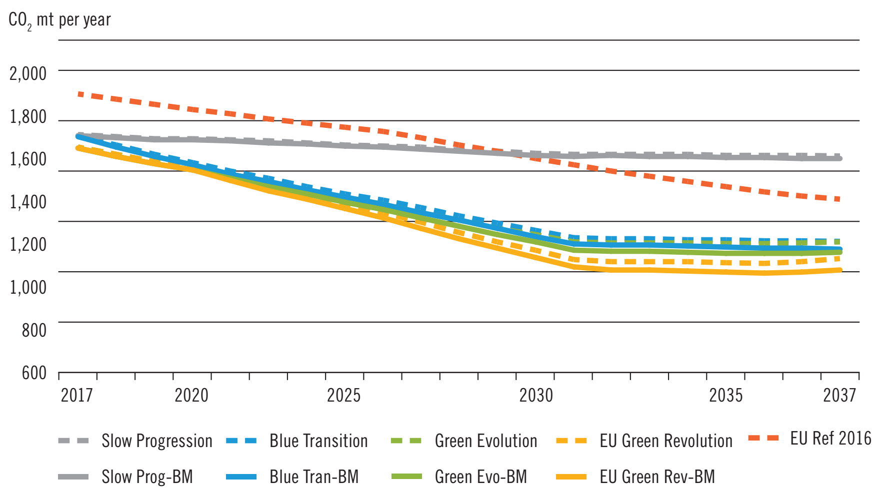


Figure 2.44: Estimated CO_2 emissions from the power generation sector and gas final demand

Looking at 2030, Blue Transition, Green Evolution and EU Green Revolution offer reductions in CO2 emissions of 41 %, 42 % and 46 % respectively. When comparing to the EU target of a 40 % reduction compared to 1990 levels, all scenarios apart from Slow Progression go beyond this level.

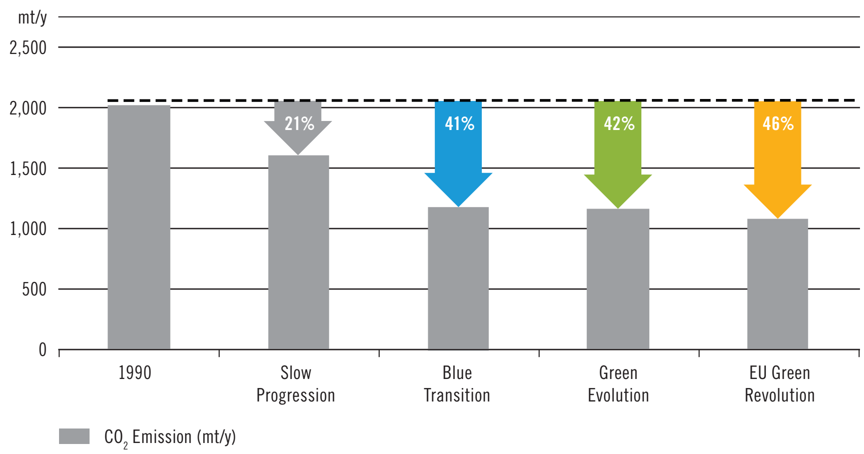


Figure 2.45: Estimated CO_2 emissions from the power generation and gas final demand sectors

2.6.3 ENERGY EFFICIENCY

As part of the European Commission 2030 Framework for climate and energy policy, there is an indicative target for energy savings of at least 27 %. The role of energy efficiency was further explored in the Energy Efficiency Impact Assessment 2014[1], which looked at the effect of differing levels of energy efficiency on both gross inland energy consumption and primary energy consumption, using the 2007 Baseline projections for 2030[2].

When evaluating the TYNDP 2017 demand scenarios using the same approach, against the 2005 gross inland consumption figures[3] available from the EU Reference Case 2016, a reduction in energy use of 18.5 % would be needed to meet the 27 % target, and 22.1 % if energy efficiency levels were deemed to reach 30 %.

As shown in figure 46, the scenarios are either in line with or exceed these targets and would be further improved when considering the higher efficiency of the gas-fired power plants applied to the displacement of coal-fired generation in the power sector, as these targets apply to all primary energy sources. Equally the use of gas for transportation, which is highest in Blue Transition scenario, would see the displacement of oil in this sector but ENTSOG does not have the required level of detail to make these calculations.

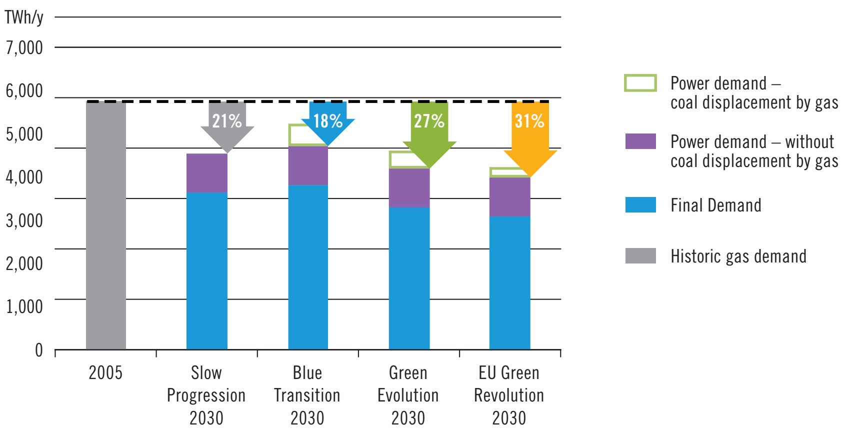


Figure 2.46: Estimated CO_2 emissions from the power generation and gas final demand sectors

1) https://ec.europa.eu/energy/sites/ener/files/documents/2014_eec_ia_adopted_part1_0.pdf

2) https://ec.europa.eu/energy/sites/ener/files/documents/trends_to_2030_update_2007.pdf

3) ENTSOG uses the Gross Inland Consumption as a comparison, as this is the demand collected from TSO.

2.7 Comparison with other demand scenarios

ENTSOG has compared the demand scenarios for TYNDP 2017 with those produced by other organisations as a benchmarking exercise. Assumptions underlying these scenarios are given below:

IEA World Energy Outlook 2015: New Policies, Current Policies and 450 Scenario (IEA, 2015)

- **Current policies (CPS):** This scenario only considers policies which implementing measures had been formally adopted (as of mid-2015) along with the assumption that these will remain unchanged.
- **New policies (NPS):** This scenario, in addition to the considerations for the current policies, adds relevant policy intentions that have been announced even if they have not yet been fully defined. For example this includes the Intended Nationally Determined Contributions (INDCs) submitted in October 2015 by governments in the lead up to COP21. Policies are introduced in a cautious manner relating to renewable energy, energy efficiency, alternative fuels in transport, carbon pricing, energy subsidies and the future of nuclear power.
- **450 Scenario (450 S):** This scenario takes the goal of limiting the increase in the global average temperature to two degrees Celsius by assuming a range of policies that reduce GHG emissions to a stable concentration of 450 parts per million by 2100.

European Commission – EU Reference Scenario 2016 – Energy, Transport and GHG Emissions – Trends to 2050[1]

The EU Reference Scenario is a projection of where the current set of policies coupled with market trends are likely to lead. The EU has set ambitious objectives for 2020, 2030 and 2050 on climate and energy, so the Reference Scenario allows policy makers to analyse the long-term economic, energy, climate and transport outlook based on the current policy framework.

- Despite a projected decrease in EU fossil fuel production, net fuel imports will decrease and the EU's import dependency will only slowly increase over the projected period. That is mainly due to the higher share of renewable energy sources (RES) and significant energy efficiency improvements, while nuclear production remains stable.
- The EU power generation mix will change considerably in favour of renewables. Gas maintains its role in the power generation mix in 2030, at slightly higher levels compared to 2015, but other fossil fuels will see their share decrease.
- There will be significant energy efficiency improvements, driven mainly by policy up to 2020 and then by market/technology trends post-2020. Primary energy demand and GDP will continue to decouple.

1) The "EU Reference Scenario 2016 – Energy, transport and GHG emissions - Trends to 2050" publication report describes in detail the analytical approach followed, the assumptions taken and the detailed results.

- Transport activity shows significant growth, with the highest increase during 2010–2030, driven by developments in economic activity. The decoupling between energy consumption and activity is projected to continue and even to intensify in the future.
- Decarbonisation of the energy system progresses, but falls short of agreed longer term climate objectives. Total GHG emissions are projected to be 26 % below 1990 levels in 2020, 35 % below by 2030 and 48 % by 2050. The share of renewables in the energy mix will continue to grow, from 21 % in 2020 to 24 % in 2030 and 31 % in 2050.
- Non-CO_2 emissions decrease until 2030 even more strongly than CO_2 emissions, by 29 % below 2005 levels in 2030 (–46 % compared to 1990 levels). The net sink provided by the land use, land use change and forestry sector declines from –299 Mt CO_2 eq. in 2005 to –288 Mt CO_2-eq in 2030, mainly with the sink in existing forests decreasing, but partly compensated by other activities such as afforestation.
- Energy-related investment expenditures increase substantially until 2020, driven by RES and energy efficiency developments. Overall energy system costs increase from 11.2 % of EU GDP in 2015 to about 12.3 % of EU GDP by 2020, also driven by projected rising fossil fuel prices. They stabilise at such levels until 2030 and decrease thereafter, reaping the benefits of the investments made.

Figure 2.47 displays the yearly volume for total gas demand for these external scenarios and the ENTSOG scenarios across the assessment period. Different assumptions and modelling techniques will always lead to variances in output, as can be seen from the differing demand evolution shown between the **WEO CPS** after 2020 and the EU Reference scenario, despite the fact they are both based on current policies. **Slow Progression** represents the ENTSOG scenario with the least change from today, and this follows a similar profile to the reference case, although with lower level of demand across the assessment period.

Blue Transition is a scenario that ENTSOG believes offers a worthwhile and credible view of the future with reduced emissions, that is not currently being appropriately assessed by other organisations in consideration of its environmental and economic benefits. This is reflected in its deviation from other scenarios, although it does follow a similar evolution to **WEO NPS**, albeit with a higher level of demand from 2025 onwards.

The **WEO CPS** exceeds Blue Transition demand levels from 2020 and although these two scenarios have fundamental differences in their storylines, it reinforces the need to assess infrastructure at this demand level.

WEO 450S and the **Green Evolution** scenarios are comparable until 2030. After this point, gas demand decreases in the 450S due to a reduction in the power sector partly due to RES, but also significant amounts of nuclear generation. **EU Green Revolution** has the lowest demand trend of all the scenarios until 2035.

The TYNDP 2017 scenarios indicate different possible paths for the overall gas demand, where achieving the European energy and climate 2030 targets could either be met with a continued decrease or a limited rebound of the demand.

The Slow Progression demand level falls within the range of the other scenarios and as a result, the TYNDP assessment will only cover the three on target scenarios.

The comparisons in figure 2.47 were presented during the stakeholder and transparency processes for the TYNDP. However, just prior to the draft TYNDP 2017 release in December 2016, the WEO 2016 publication became available. As a result, ENTSOG has provided a table to show how these scenarios have evolved.

For gas demand, the trends are similar to the previous edition. There is an increase in demand across all WEO 2016 scenarios in 2020, bringing them all into line with the demand seen in the Blue Transtion scenario. WEO 2016 450S has a reduced gas demand in 2030 and 2040, taking it beyond EU Green Revolution a year earlier in 2034 and more aggressively after that date.

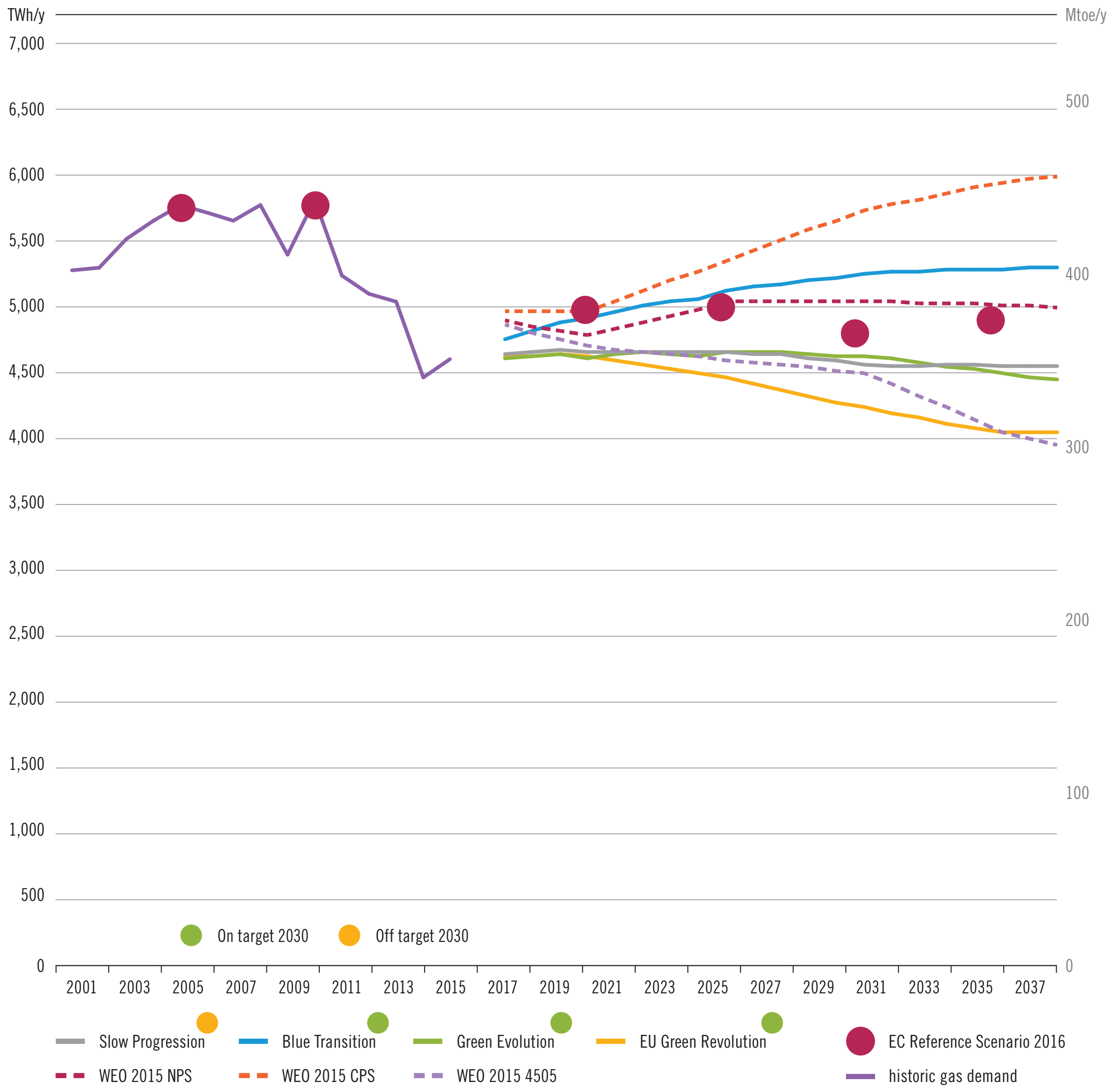


Figure 2.47: Comparison of TYNDP scenarios to European Commission Reference Scenario 2016 and IEA World Energy Outlook 2015 scenarios

ENERGY DEMAND (TWh GCV) FOR WEO 2015 AND 2016 SCENARIOS						
	GAS	2020	2025	2030	2035	2040
2015	New Policies	4,793	5,051	5,059	5,032	4,934
2015	Current Policies	4,981		5,753		6,171
2015	450S	4,711		4,513		3,615
2016	New Policies	4,870	5,038	5,059	5,023	4,859
2016	Current Policies	5,019		5,739		6,211
2016	450S	4,837		4,468		3,460
VARIANCE	New Policies	77	–14	0	–8	–74
VARIANCE	Current Policies	38		–14		40
VARIANCE	450S	126		–44		–155

Table 2.7: Comparison of WEO 2015 vs WEO 2016 gas demand (Source: IEA WEO reports, TWh GCV)

3 Supply

Image courtesy of Enagás

3.1 Introduction

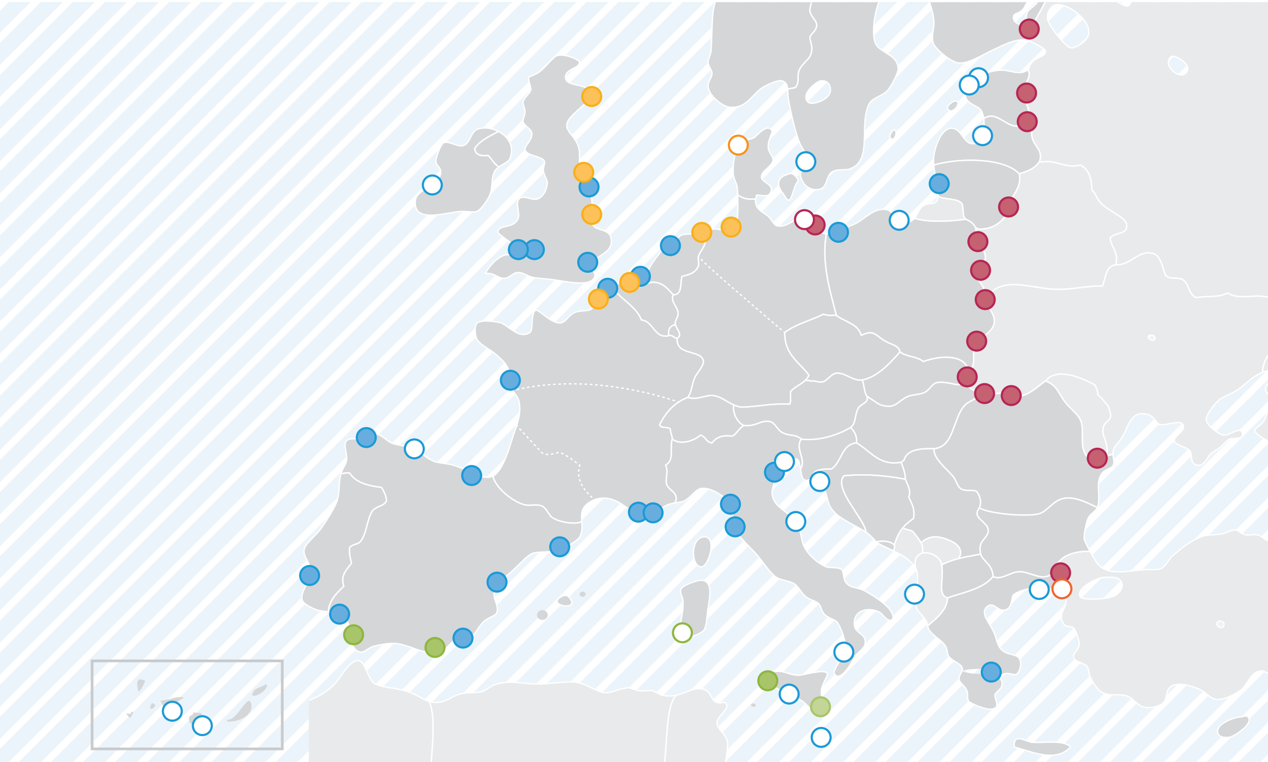
This chapter aims at defining future ranges of gas supply. This is not only an interesting task of its own but also a crucial basis for subsequent tasks. ENTSOG relies on publicly available input and studies from third parties to incorporate external knowledge into a resilient and reliable future assessment. The supply potentials as presented in this chapter have been developed for this TYNDP for the purposes of the EU supply adequacy outlook and the assessment of the gas infrastructure. These supply potentials should not be considered as forecasts.

Starting from the historical supply of the various sources (indigenous production, pipeline import and LNG) the supply potentials are outlined following the logic of the previous TYNDP edition.

European gas supply is divided between indigenous production and gas imports. From the perspective of the network assessment, ENTSOG distinguishes between pipeline-bounded imports from Russia, Norway, Algeria, Libya and Azerbaijan on one hand and LNG on the other hand.

In the TYNDP, Norwegian production is considered as an import and is not reported as part of the European indigenous production. Whenever a source exports gas through both LNG and pipe, the LNG part is always reported separately from the overall supply of this source and is gathered in the LNG supply potential. As a reported supply source, LNG aggregates the potential production of over 20 producing countries including Russia, Norway and Algeria. With this approach ENTSOG recognises the global nature of the LNG market.

In addition to the gas supply source, ENTSOG uses the concept of "import routes" defining the entry points into Europe. The different routes considered in this Report are listed in table 3.1 on the following page.



Existing import point
Planned import point
from LNG, Norway, Russia, Azerbaijan, Algeria, Libya

For the border of Greece and Turkey the delivered gas is contractually Turkish gas without regard to its physical origin.

Figure 3.1: Existing and planned import routes by source

IMPORT ROUTES OF GAS

Source	Route	Sub-route
LNG	United Kingdom	
	The Netherlands	
	Belgium	
	France	
	Spain	
	Portugal	
	Italy	
	Greece	
	Poland	
	Sweden	
	Ireland	
	Malta	
	Lithuania	
	Croatia	
	Estonia	
	Latvia	
ALGERIA	Spain	
	Italy	

Source	Route	Sub-route
LIBYA	Italy	
NORWAY	United Kingdom	
	Germany	
	The Netherlands	
	France	
	Belgium	
	Denmark	
RUSSIA	Finland	
	Germany	
	Estonia	
	Latvia	
	Belarus	Lithuania
		Poland
	Ukraine	Poland
		Slovakia
		Hungary
		Romania
AZERBAIJAN	Georgia – Turkey	Greece

Table 3.1: Existing and planned import routes by source

3.2 Historic supply

3.2.1 EVOLUTION AT SOURCE LEVEL

The following tables illustrate the continuous decline of European indigenous production during the last decade which has induced an increasing dependence on gas imports. However, in the last few years this effect has been mitigated by the reduction in gas demand.[1)]

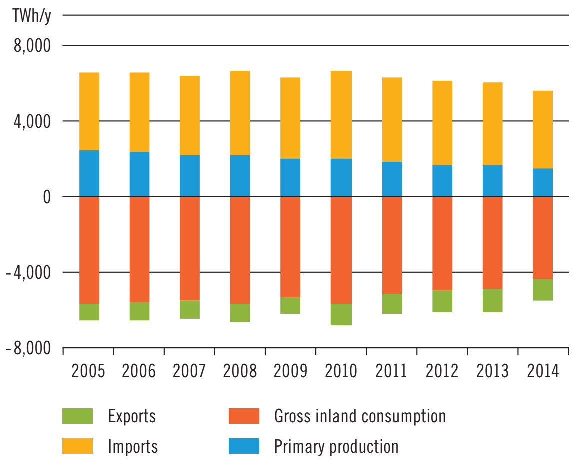


Figure 3.2: European gas balance: Entries vs Exits[1)] 2005–2014 (Source: Eurostat)

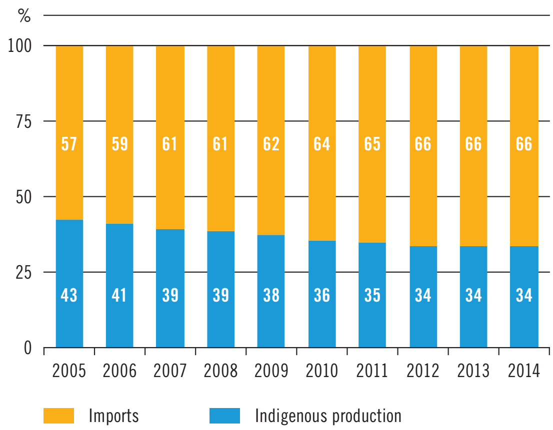


Figure 3.3: Evolution of indigenous production vs. import 2005–2014 (Source: Eurostat)

Below figures show the evolution of the imports from the different sources during the last seven years. The decrease in indigenous production has been mainly compensated for by the increase of Russian and Norwegian imports. The LNG import level fluctuates following price changes in the global LNG market.

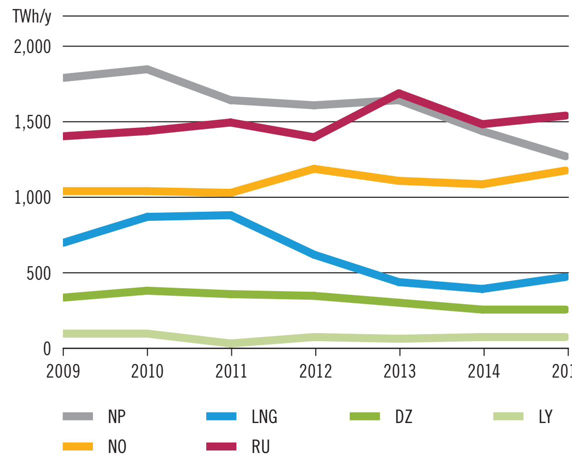


Figure 3.4: Evolution of imports 2009–2015

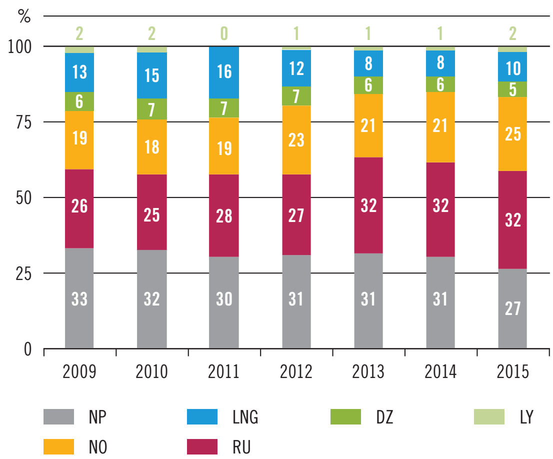


Figure 3.5: Evolution of supply shares 2009–2015

1) Gas exports cover flows towards Turkey, Kaliningrad and St. Petersburg (LNG reloading is not included).

The following figure shows the range of daily supply coming from each source[1]. The daily supply from each source is influenced by the severity of the peak consumption, the decisions of the markets and the availability of gas in storage.

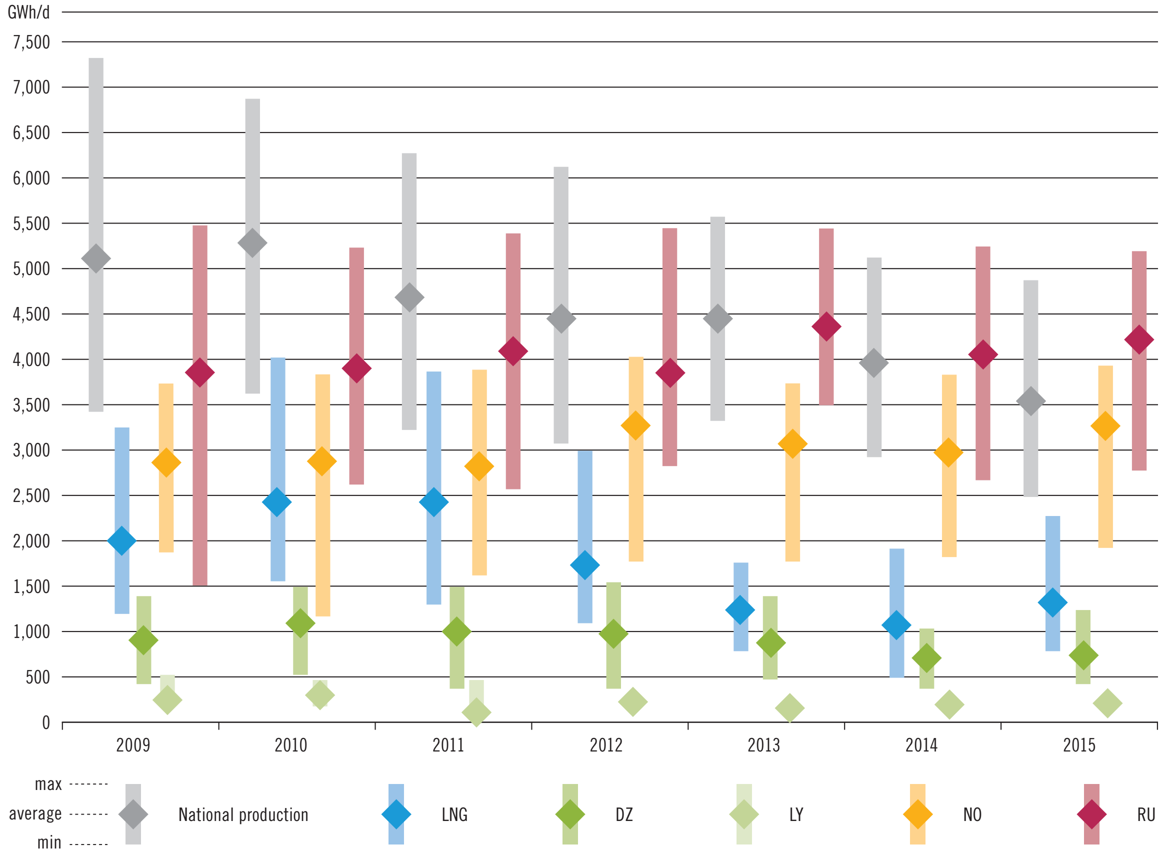


Figure 3.6: Daily flexibility (max, average, min)

1) For LNG this means regasified gas which has been delivered to the transmission systems.

3.2.2 EVOLUTION AT IMPORT ROUTE LEVEL

3.2.2.1 Russian pipeline gas import routes

Since 2012, with the commissioning of Nord Stream linking Russia directly with Germany, a significant volume of Russian imports has moved from the Ukrainian route to Nord Stream. Despite this reduction, the Ukrainian route continued to be the larger one and transited 42 % of the total Russian imports in 2015.

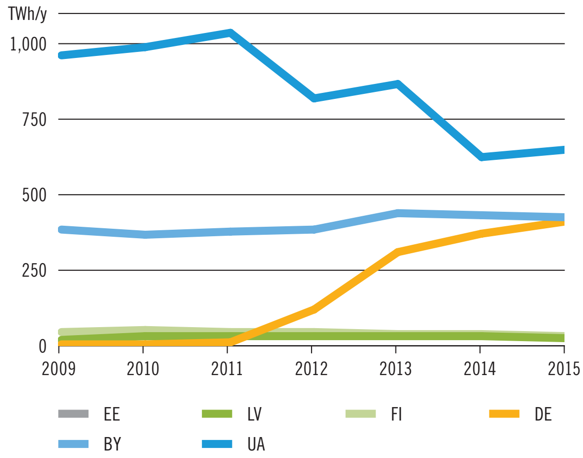


Figure 3.7: Split of the Russia supplies by route 2009 – 2015

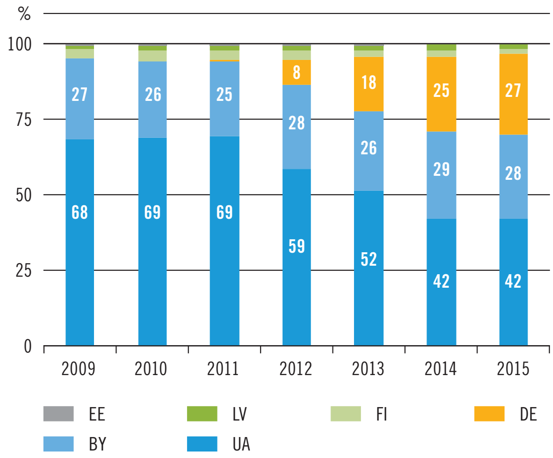


Figure 3.8: Shares of Russian import routes 2009 – 2015

3.2.2.2 Norwegian pipeline gas import routes

The split of the Norwegian imports since 2009 has generally remained stable between the different import routes with an exception in 2011, when a decrease in the flows to UK and Belgium was compensated with increasing flows to the remaining routes. This increase was particularly sharp for Germany in 2012, decreasing again to 2009 levels in 2013 and remaining stable since then.

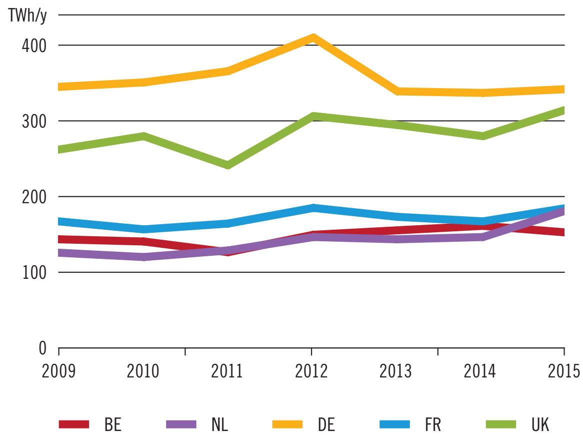


Figure 3.9: Split of the Norwegian supply by route 2009 – 2015

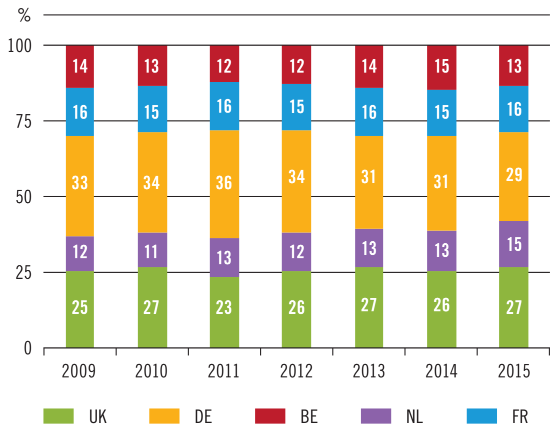


Figure 3.10: Shares of Norwegian import routes 2009 – 2015

3.2.2.3 Algerian pipeline gas import routes

In 2015, the pipeline imports from Algeria that go to Italy and Spain were 34 % lower than the maximum registered in 2010.

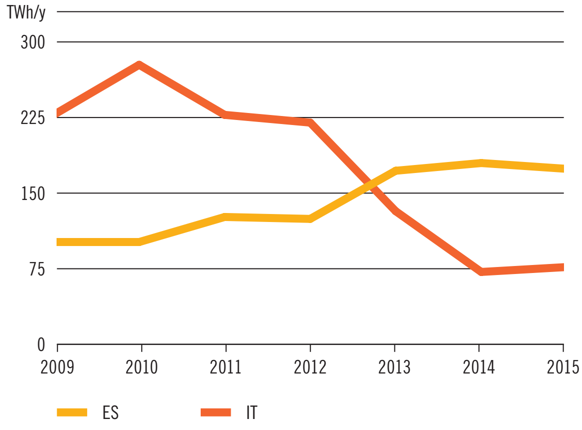


Figure 3.11: Split of the European Algerian supply by route 2009 – 2015

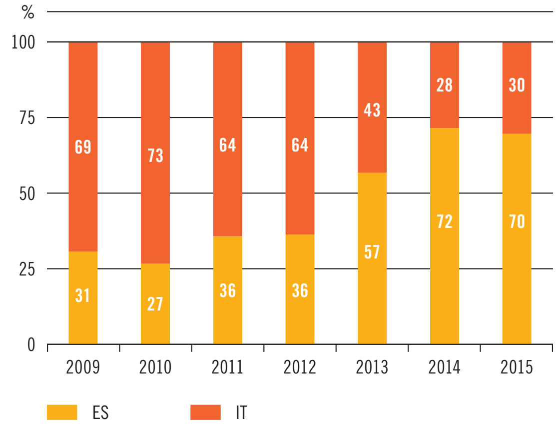


Figure 3.12: Shares of Algerian import routes 2009 – 2015

There has been a divergence between these two countries in the evolution of the Algerian exports. Italy had a share of 73 % in 2010 which has decreased to 30 %, meanwhile Spain has risen from 27 % to 70 %, partly linked to the commission of the MEDGAZ pipeline in 2011.

3.2.2.4 LNG import routes

The split of the LNG supply between its importing routes has also changed during the past few years. After having reached their maximum in 2011 LNG imports decreased for all routes. Compared to 2011, the send-out into the European network decreased on average by 56 % in 2014 and recovered by 23 % in 2015.

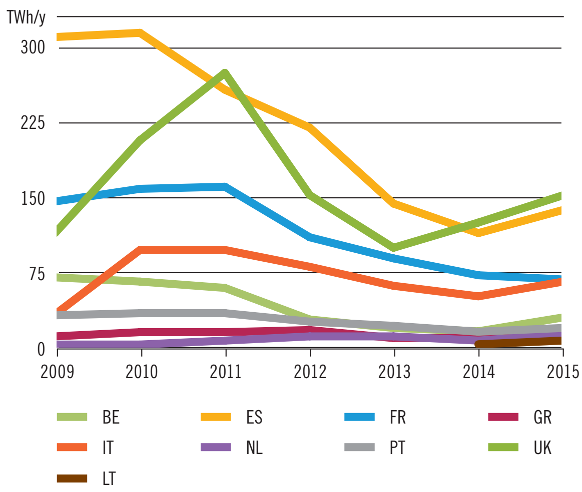


Figure 3.13: Split of European LNG supply by route 2009 – 2015

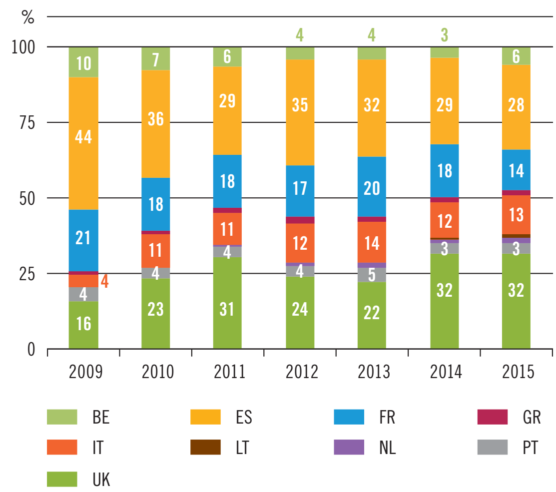
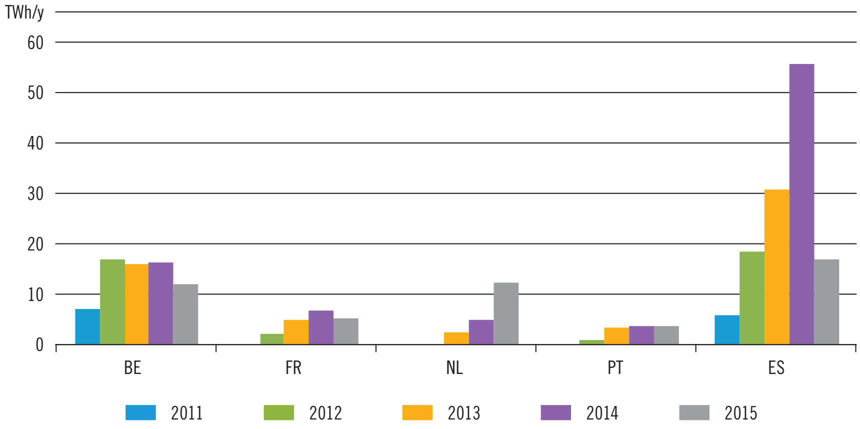


Figure 3.14: – Shares of LNG import routes 2009 – 2015

The re-export of LNG vessels significantly decreased the last year in Europe. The evolution varies between countries and can be seen in figure 3.15[1]. Depending on the country, in 2015 between 57 % (NL) and 8 % (FR) of the LNG initially imported was re-exported. Not shown in the graph, the UK has also become a small LNG re-exporting country (only 2 %) for the first time during 2015.



% of re-exported LNG per country compared to the total LNG initially imported, years 2014 & 2015					
Year	**BE**	**FR**	**NL**	**PT**	**ES**
2014	54	9	45	20	33
2015	31	8	57	19	12

Figure 3.15: Split of European LNG re-exported (as energy source, not volume of fuel)
(Own depiction, based on data from GIIGNL)

This demonstrates how the global LNG market functions and how the higher prices in other regions, especially in Asia, have been attracting vessels despite the existence of European destination clauses.

1) According to GIIGNL data

3.3 Supply potentials

For the purpose of this Report the supply assumptions define the potential supply from a given source. The word "potential" implies that these gas supplies cannot be considered as forecasts of future flows.

In order to capture the uncertainty in the development of supply, minimum and maximum potentials have been defined for each source. The development of such potentials is based on publicly accessible literature, reports, daily news and members' and stakeholders' feedback.

These scenarios cover both:

- **Supplies from outside EU coming from Russia, Norway, Algeria, Libya, Azerbaijan, and LNG**
- **Supplies from inside EU coming from conventional national production, non-fossil sources like biomethane and unconventional fossil sources like shale gas**

In the TYNDP analysis the assumed minimum and maximum potentials for each source are used as lower and upper limits for the imports from this given source.

In this respect upstream investments in neighbouring countries will be a key factor in driving new production dedicated to Europe. It will support not only new exploration but also new technical solutions enhancing recovery of existing fields. This will enable the production of the most challenging reserves and their export to Europe by pipeline. To see this potential materialise Europe needs to give long term and robust signal on the role of gas. Otherwise there is a risk of reduction of surrounding gas reserves or their production and export to other destinations in the form of LNG.

It is important to highlight that all potential gas supplies are regarded as pipeline bounded gas supplies except LNG. LNG is treated as a single source gathering the potential supply of all producing countries. For those exporting gas, both as pipeline-bounded gas and LNG, the potential supplies have been treated separately in order to avoid double counting. Each supply potential is developed independently and no specific likelihood is defined.

The first assessment year in the TYNDP is 2017. Taking into account stakeholder feedback, it was determined that using supply potentials based on recently observed data would be more realistic. As a result, the supply potentials for the year 2017 are not based on the same literature/studies like the supply sources for the other time snapshots (2020, 2025, 2030, 2035).

Based on the expertise developed by ENTSOG for the seasonal outlooks, the maximum supply potential is built by using the average of the two maximums of ENTSOG Summer and Winter Supply Outlooks 2015/16 for each source.

The minimum supply potential is developed by using the minimum yearly supply observed in the calendar years 2009–2015 for each source (2011 is disregarded for Libya).

SUPPLY POTENTIALS 2017 (GWh/d)	MINIMUM	MAXIMUM
RUSSIA	3,503	4,748
NORWAY	2,810	3,320
ALGERIA	674	1,007
LIBYA	165	235
LNG	1,061	2,101

Table 3.2: Supply potentials 2017

3.3.1 PIPELINE IMPORTS

Pipeline imports represent the main way to import gas into Europe. Considering the reasonable distance between many producing countries and the European consumers, pipelines represent an economical way to import gas.

3.3.1.1 Russia

The Russian Federation is currently the main gas supplier of the EU, providing 140 bcm (1,541 TWh) in 2015, meaning 32 % of EU supply share. It is expected to remain a major import source over the whole time horizon of this Report. The future production of gas will depend on investments in the upstream sector and increased competition for Russian supply from other export destinations such as China.

Reserves

Russia has the second largest proven gas reserves in the world, behind Iran, with 32,271 bcm at the end of 2015[1)]. In the past decade the proved gas reserves of Russia slightly increased (+14 % between 2000 and 2015). According to Gazprom most of the production and reserves are located in the Ural Federal District, with significant reserves also in the continental shelf.

Production

In 2015, Russia was the second largest natural gas producer of the world behind the United States with 573 bcma.

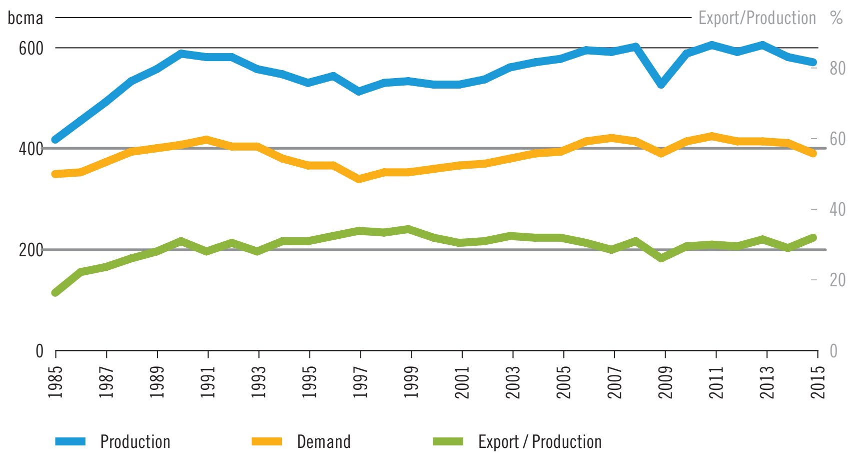


Figure 3.16: Natural gas production and demand of Russia (Source: BP statistical review 2016)

In the period 2005–2015 the natural gas production of Russia was on average 585 bcma. There is one significant outlier in 2009 with a decrease that could be linked to the economic down-turn and the Ukraine transit disruption. Contrary to Norway, Russia has its own domestic demand that can influence its export potential. This internal demand of Russia remained stable around 400 bcma.

1) BP statistical review of world energy 2016

Exports

Gas is exported to Europe through three main pipelines:

- **Nord Stream:** Twin offshore pipeline across the Baltic Sea with the first line established in 2011, and the second one in 2012. It transmits gas along 1,220 km between Vyborg (Russia) and Greifswald (Germany) and has an annual capacity of around 55 bcma.
- **Yamal-Europe I**: Entered in operation in 1994 and transmits gas along 2,000 km to Poland and Germany via Belarus. Its annual capacity is around 33 bcma.
- **Brotherhood (Urengoy-Pomary-Uzhgorod pipeline):** Entered into operation in 1967 and is the largest gas pipeline route from Russia to Slovakia. Transiting through Ukraine, it brings gas to Central and Western European countries as well as Southern East Europe countries to finally end up in Turkey. The total annual capacity of the Brotherhood is around 100 bcma[1].

Other export gas pipelines of Russia bring gas to other markets:

- **Blue Stream:** A 1,210 km-long gas offshore pipeline directly connecting Russia to Turkey across the Black Sea. It came on line in 2003 and its annual capacity is around 16 bcma.
- **North Caucasus:** Carries Russian gas to Georgia and Armenia and its annual capacity is around 10 bcma.
- **Gazi-Magomed-Mozdok:** it traverses 640 km through Russia and Azerbaijan. Initially this pipeline was used to export Russian gas to Azerbaijan, but it has been reversed and from 2010 it can carry 6 bcma of gas from Azerbaijan to Russia.

In the last five years the largest recipients of Russian gas exports via pipeline in the European Union were Germany and Italy. In 2015, these two countries accounted for half of the Russian imports into the EU. Outside the European Union the largest recipients of Russian gas were Turkey and Belarus.

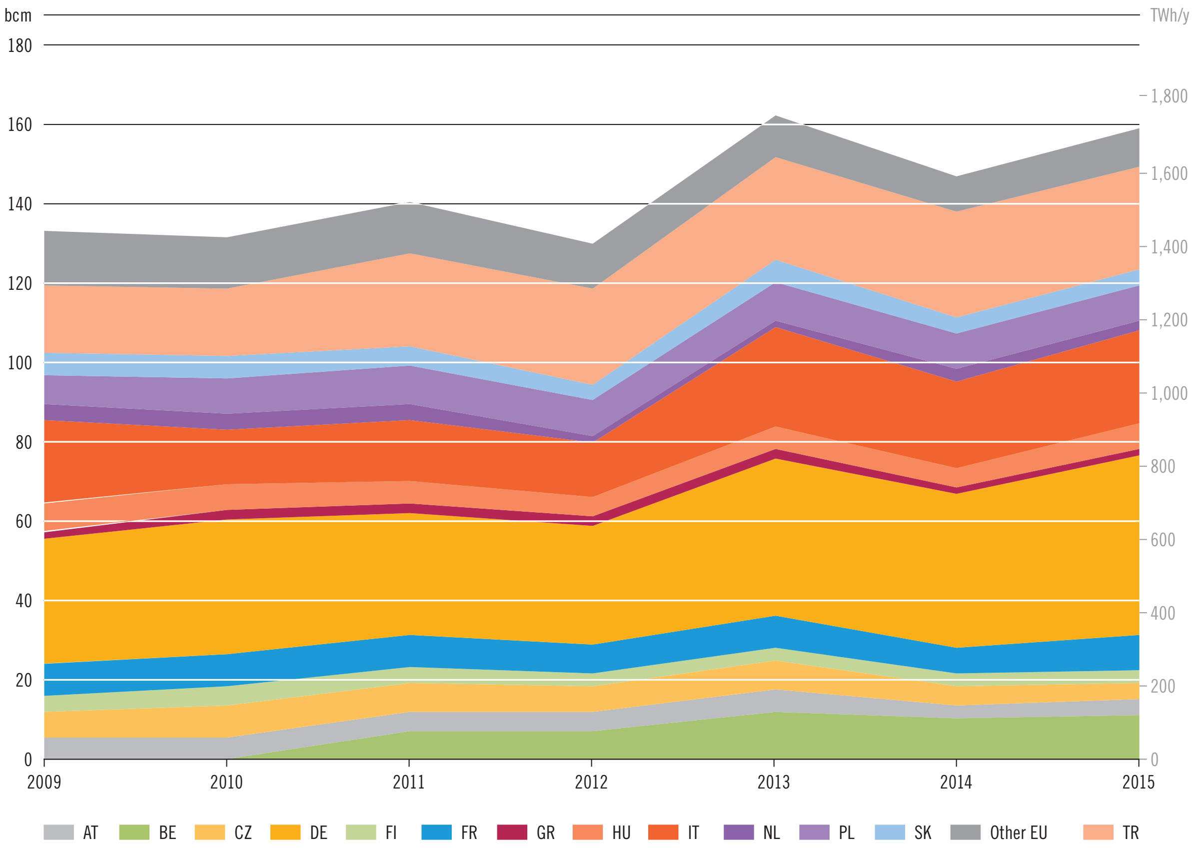


Figure 3.17: Russian natural gas trade movements by pipeline (Source: BP statistical reviews 2010 – 2016)

1) According to Gazprom Export website

Besides the gas exports via pipeline, Russia is also an exporter of LNG. The Sakhalin liquefaction plant was commissioned in 2009 and the majority of the LNG was exported to Japan and South Korea. In 2015 Russia exported around 15 bcm of liquefied natural gas. However, it is still a small amount in comparison to the EU pipeline-bounded gas exports. The Yamal LNG plant could increase the LNG exports of Russia to Europe.

In addition, Russia is extending its interest to far Eastern markets. In 2014, Russia signed a supply contract with China to deliver 38 bcma of natural gas as of 2018 via the 2,200 km long Power of Siberia pipeline that runs from the Chayandinskoye field in Yakutia to the city of Blagoveshchensk on the Russian-Chinese border.

Supply potentials

The supply potentials for Russia reflect continuity from the previous TYNDPs taking into account the unchanged information about the resources. Exports in the form of LNG are part of the LNG analysis featured later in this report.

Maximum Russian pipe gas potential:

This potential was directly taken from the estimated "Gas exports to EU" published by the Institute of Energy Strategy (Gromov 2011). These figures show a shift in the exports to Asia-Pacific. The figures between 2030 and 2037 are extrapolated from the 2020–2030 trend.

Minimum Russian pipe gas potential:

This potential was determined based on the following publication: "Potential impact of new Asian contracts on Russian gas exports in a worst case scenario in Europe" – "Europe 70 % ToP", "The Political and Commercial Dynamics of Russia's Gas Export Strategy" (Oxford Institute for Energy Studies, James Henderson & Tatiana Mitrova, September 2015).

The below graph shows the Minimum and Maximum Russian pipe gas potentials. The graph also highlights the historical range from 2009 to 2015.

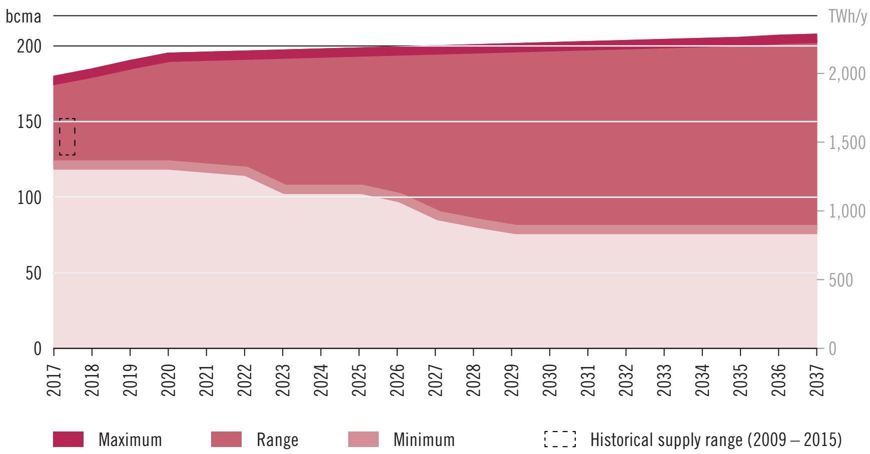


Figure 3.18: Pipeline gas potentials from Russia

PIPELINE GAS POTENTIALS FROM RUSSIA						
GWh/d	2017*	2020	2025	2030	2035	2037
MAXIMUM	5,294	5,762	5,869	5,977	6,085	6,128
MINIMUM	3,623	3,623	3,148	2,346	2,346	2,346

* Supply potentials 2017 as shown in table 3.2 are used for the assessment

Table 3.3: Pipeline gas potentials from Russia (GWh/d)

3.3.1.2 Norway

Norway is currently the second largest gas supplier of the EU, providing a delivery of 107 bcm (1,179 TWh) in 2015. It is expected to remain a key import source. Further into the future, there is uncertainty over the volume of Norwegian gas that can be produced from existing fields which are in decline. This means that new exploration, production and upstream pipeline investments are required to maintain the volumes produced currently. The potential for this development may vary depending on market conditions.

Norwegian gas is exported via a well-developed offshore pipeline network that connects to Germany, UK, France, the Netherlands and Belgium.

EXPORT CAPACITY OF THE GASSCO OFFSHORE SYSTEM		
Pipeline	**Country**	**Capacity (MSm³/d)**
Europipe	Germany	46
Europipe II	Germany	71
Franpipe	France	55
Norpipe	Germany, The Netherlands	32
Tampen Link	UK	10–27
Vesterled	UK	39
Zeepipe	Belgium	42
Langeled	UK	72–75
Gjøa Gas Pipeline	UK	17

Table 3.4: Export capacity of the GASSCO offshore system (Source: GASSCO website)

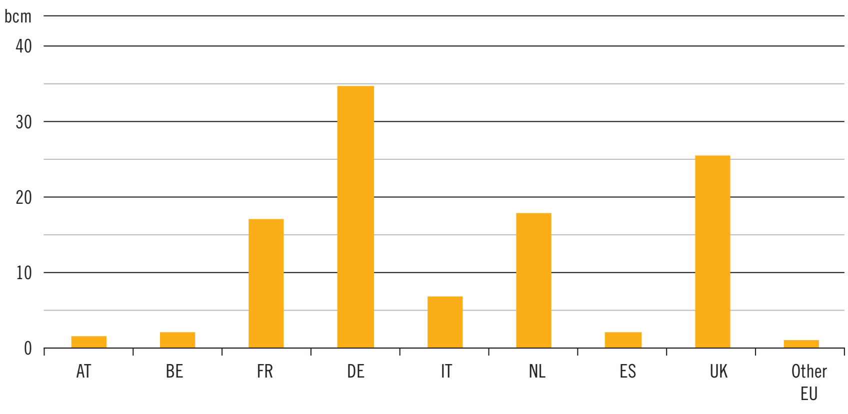


Figure 3.19: Norwegian pipeline exports by destination in 2015 (Source: BP Statistical Review 2016)

In addition to the direct import countries shown in table 3.4 above, the Norwegian gas is also transited through the pipeline network across Europe (as shown in figure 3.19).

Reserves

Norway has been supplying natural gas to Europe for more than 40 years since production began in the early 1970s. Since then, the development of new fields has enabled the continuous increase of gas volumes exported by Norway. However for the past decade the sold and delivered volumes have increased faster than new discoveries have progressed (Reserves and contingent resources[1]). Roughly half of the reserves still remain but the overall production could fall below current levels during the 20-year time horizon of this report.

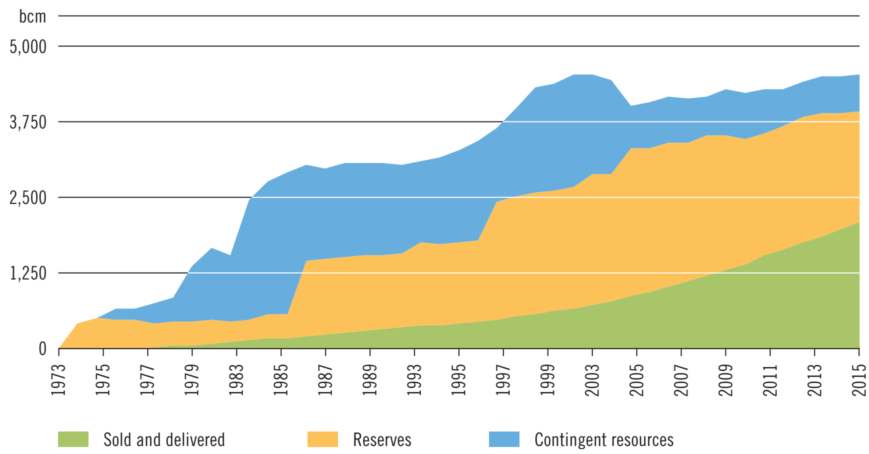


Figure 3.20: Evolution of Norwegian gas reserves 1973 – 2015
(Source: Norwegian Petroleum Directorate)

One of the main challenges for Norway is to decide about the most beneficial way to export the future production. It is not decided yet whether to expand the offshore network to connect new fields to the existing grid and export this production to Europe or to export LNG globally. However, for this solution to materialise, strong signals from European market are required.

1) Contingent resources mean the estimated recoverable volumes from known accumulations that have been proven through drilling but which do not yet fulfil the requirements for reserves.

Supply Potentials

The supply potentials define a possible range of Norwegian gas exports to Europe via pipeline; exports as LNG are part of the LNG analysis featured later in this report. The Norwegian supply potentials are based on data coming from the Norwegian Petroleum Directorate (NPD)/Ministry of Petroleum and Energy (MPE) and GASSCO. The potential range of Norwegian supply has been estimated as follows:

Maximum Norwegian pipeline gas scenario

This potential represents the exports from Norway, where the maximum level, foreseen to be reached in 2019, based on information estimated by GASSCO, is maintained until 2037. This level of production and exports would require the development of current discoveries and yet to find gas fields, alongside the existing fields and to develop the required interconnection infrastructure.

Minimum Norwegian pipeline gas scenarios

This potential takes the lowest of the minimum imports of 2009–2015 (93 bcma) and the production sales forecast of resources in existing fields (GASSCO information), extrapolated between 2035 and 2037.

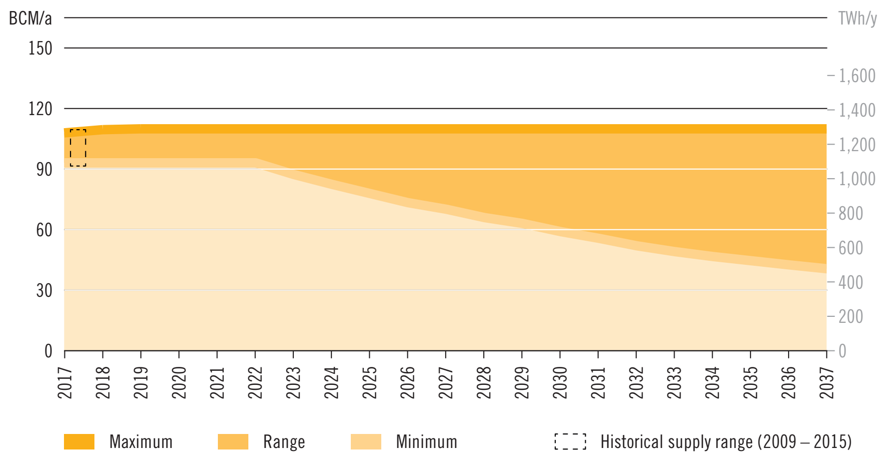


Figure 3.21: Pipeline gas potentials from Norway

PIPELINE GAS POTENTIALS FROM NORWAY						
GWh/d	2017*	2020	2025	2030	2035	2037
MAXIMUM	3,208	3,267	3,267	3,267	3,267	3,267
MINIMUM	2,762	2,762	2,317	1,752	1,322	1,203

* Supply potentials 2017 as shown in table 3.2 are used for the assessment

Table 3.5: Pipeline gas potentials from Norway (GWh/d)

3.3.1.3 Algeria

Algeria is one of the main producers in Africa and currently the third largest gas supplier to Europe by pipeline and also when considering both pipeline and LNG. In 2015 it provided to Europe around 23 bcm (252 TWh), 5 % of the EU supply share.

Algeria is expected to play an important role as gas exporter also in the future. However the availability of Algerian gas will depend on future production developments and competition between pipeline gas and the global LNG market.

Reserves

With its 4,500 bcm (49,557 TWh) of proven natural gas reserves Algeria ranks in the top ten of countries with the largest gas reserves in the world[1] and is the second largest in Africa after Nigeria. More than half of the reserves (2,400 bcm – 26,476 TWh) are located in the centre of the country to the northwest, in the Hassi R'Mel field. The rest of the reserves come from fields situated in the Southern and South-eastern parts of the country. Besides that, Algeria holds vast untapped unconventional gas resources. According to an EIA study[2] Algeria has 20 Tcm of technically recoverable shale gas resources, being the third-largest country worldwide after China and Argentina.

Production and Consumption

Since 2005 some of the Algerian largest gas fields have begun to deplete and hence the production is slowly but steadily declining. Algeria aims to invert this situation bringing new gas fields on stream but many of those projects have been repeatedly postponed because of delayed governmental approval, difficulties in attracting investment partners and technical problems. Algeria state-owned company Sonatrach plans to invest 73 billion dollars between 2016 and 2020, two thirds of which will be allocated to exploration and production[3].

ALGERIA'S UPCOMING NATURAL GAS PROJECTS

Project name	Partners	Output (bcma)	Start year
In Salah (Expansion)	BP/Sonatrach	14.0	2016
Touat	Engie/Sonatrach	4.3	2016
Reggane Nord	Repsol/Sonatrach/DEA/Edison	4.3	2017
Timimoun	Total/Sonatrach/Cepsa	1.8	2017
Ahnet	Total/Sonatrach/Partex	3.9	2018
Hassi Ba Hamou	Sonatrach	1.4	2018
Hassi Mouina	Sonatrach	1.8	Tdb
Isarene (Ain Tsila)	Petroceltic/Sonatrach	3.6	2018
TINHERT, ILLIZI BASIN	Sonatrach	9.3	2018
MENZEL LEDJMET SE	Sonatrach	4.3	2019

Table 3.6: Algeria's upcoming natural gas projects (Source: EIA 2016, country report Algeria)

1) Country report Algeria, EIA, March 2016
2) Technically Recoverable Shale Oil and Shale Gas Resources, September 2015
3) http://www.aps.dz/en/economy/12788-sonatrach-will-invest-more-than-usd73-billion-by-2020

Natural gas production shows uncertainty in the short-term and may recover in the mid-term. On the other hand, domestic gas consumption in Algeria has increased since 2004 and shows an ongoing upward trend that could influence export potential.

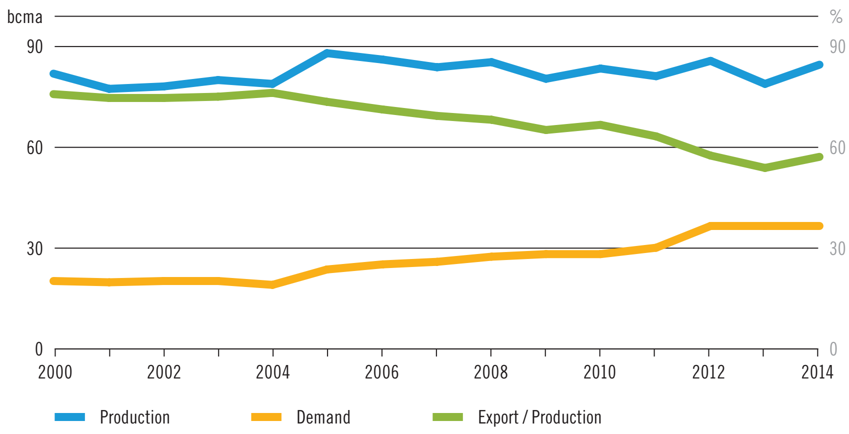


Figure 3.22: Algerian dry natural gas production and consumption (Source: EIA 2016, country report Algeria)

Exports

Pipelines

Gas is exported to Europe through three main pipelines crossing the Mediterranean sea:

- **Pipeline Enrico Mattei (GEM):** It came on line in 1983 and transports gas along 1,650 km from Algeria to Italy via Tunisia. According to Sonatrach, its capacity is around 33 bcma.
- **Maghreb–Europe Gas Pipeline (MEG):** it came on line in 1996 and transports gas along 520 km to Spain via Morocco. Its capacity is around 13 bcma.
- **MEDGAZ pipeline:** it came on line in 2011 and transports gas along 200 km onshore and offshore, from Algeria to Spain. Its capacity is around 9 bcma.

LNG plants

Currently, Algeria has four liquefaction plants, three in Arzew in the West and one in Skikda in the East of teh country. Combined LNG production capacity of all four plants is 44 bcma of equivalent gas[1] (484 TWh/y).

In 2015 Algeria exported 20.7 bcm (228 GWh) to Europe via pipeline, 58 % to Spain, 32 % to Italy and 10 % to other EU Countries via either Spain or Italy.

With the commissioning of the MEDGAZ pipeline in 2011 Algerian exports to the Iberian Peninsula have increased while flows toward Italy have shown a decline in the past few years, which could be linked to the renegotiation of long-term contracts between ENI and Sonatrach[2] (see figure 3.24).

1) Sonatrach: http://www.sonatrach.com/en/aval.html

2) http://www.argusmedia.com/pages/NewsBody.aspx?id=848890&print=yes

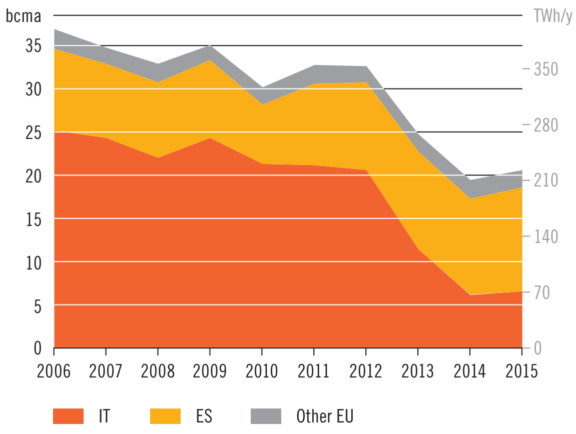


Figure 3.23: Algerian pipeline gas exports to Europe 2006 – 2015 (Source: BP statistical review 2016)

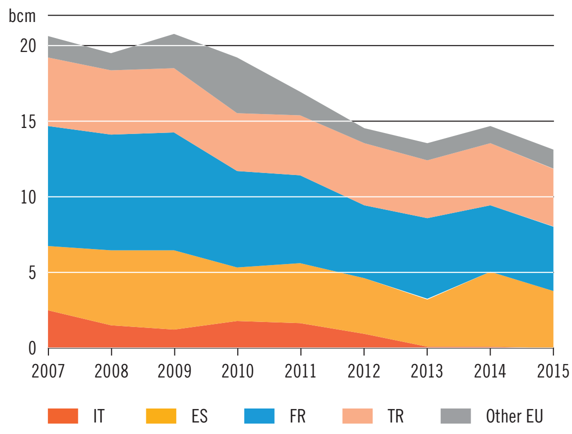


Figure 3.24: Algerian LNG exports to EU and Turkey 2007 – 2015 (Source: BP statistical review 2016)

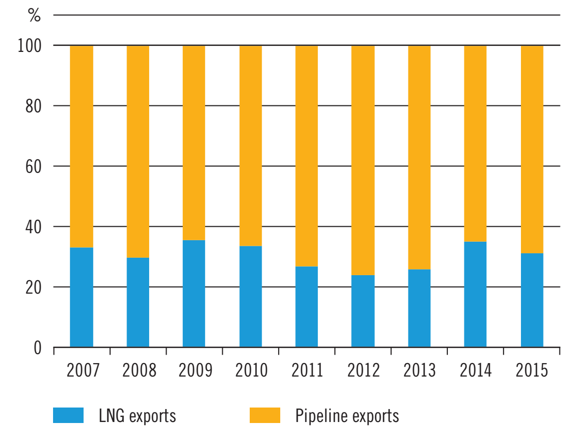


Figure 3.25: Breakdown of Algerian gas exports to Europe. (Source: BP statistical review 2016)

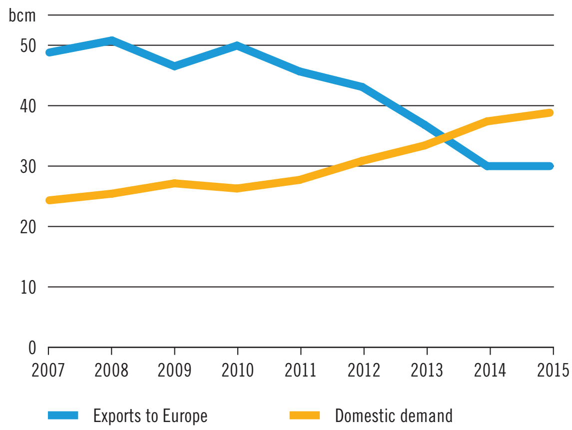


Figure 3.26: Algeria: gas exports to the EU vs. domestic gas demand (Source: BP statistical review 2016)

Over the past years a slight majority of Algerian LNG was exported to Europe with France and Spain as the main destinations. With 13.1 bcm in 2015, those two countries counted respectively for 33 % and 28 % of Algerian LNG exports to Europe, 29 % of this LNG was exported to Turkey and 10 % to other countries. Outside of Europe small quantities were also delivered to African and Asian countries, counting 3 bcm in total for 2015 (see figure 3.25).

Figure 3.26 shows a close correlation between Algeria's national demand and total exports to EU (considering pipeline and LNG). In the period 2007 – 2015, Algerian national gas demand has increased from 24 bcm in 2007 to almost 40 bcm in 2015, representing an increase of 55 %. On the other hand Algerian gas exports to Europe have fallen from 50 bcm to 30 bcm, with a decrease of 25 %

This represents the challenge for Algeria of developing gas production facing both national demand and export expectations.

Supply potentials

In order to define its maximum and minimum supply potentials ENTSOG considered different combination of production, national demand trends, also taking into account different shares between LNG and gas via pipeline. Exports as LNG are part of the LNG analysis featured later in this report.

Maximum Algerian pipeline gas potential

Production future figures were defined applying the trend in production expected by Medpro[1], to 2014 production level (according to BP Statistical Review 2015[2]), while consumption figures were taken directly from Medpro forecasts scenarios. From the total potential export, defined as the difference between production and internal consumption, the potential export only to the EU was derived by deducting the share of export to be allocated to other African Countries (according to BP Statistical Review 2015 historical figures and WEO 2015 New Policy Scenario evolution of African demand forecast) and of the LNG share (based on historical average 2010–2014).

Minimum Algerian pipeline gas potential

Production future figures were defined applying the trend in production and demand increase expected by the WEO 2015 NPS to the BP statistical figures. From the total potential export, defined as the difference between production and inland consumption, the potential export only to EU was then derived deducting the share of export to be allocated to other African Countries (according to BP Statistical Review 2015 and WEO 2015 NPS figures and of LNG (based on the historical maximum for the period 2010–2014).

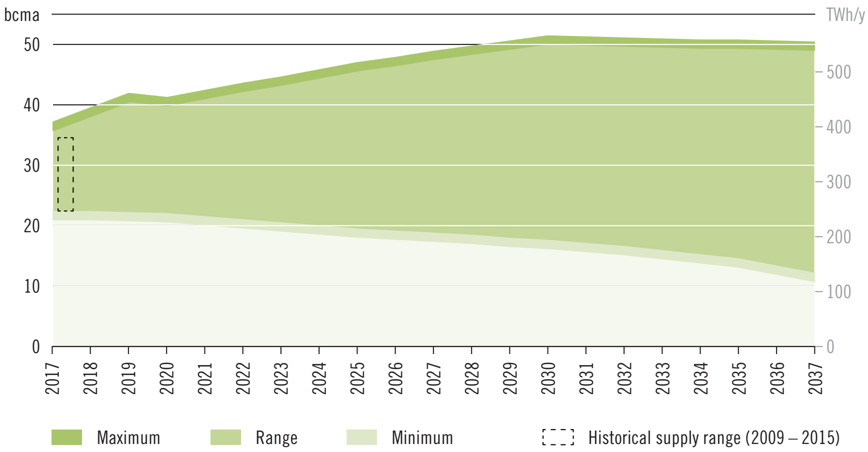


Figure 3.27: Pipeline gas potentials from Algeria

PIPELINE GAS POTENTIALS FROM ALGERIA						
GWh/d	2017*	2020	2025	2030	2035	2037
MAXIMUM	1,083	1,204	1,379	1,508	1,486	1,476
MINIMUM	646	633	556	501	413	339

* Supply potentials 2017 as shown in table 3.2 are used for the assessment

Table 3.7: Pipeline gas potentials from Algeria (GWh/d)

1) Outlook for Oil and Gas in Southern and Eastern Mediterranean Countries, October 2012

2) BP Statistical Review 2016 was not available when supply potentials were elaborated

3.3.1.4 Libya

Libya is currently the smallest gas supplier of the EU via pipeline. In 2015 it provided to Europe around 7 bcm (75 TWh), 2 % of the supply share. This is expected to remain almost unchanged along the time horizon of this Report.

Reserves

With its 1,500 bcm[1] (16,500 TWh) of proven natural gas reserves Libya ranks among the African countries with the largest gas reserves of the continent. Prior to the civil turmoil since 2011, new discoveries and investments in natural gas exploration had been expected to raise Libya's proved reserves but they have not occurred.

Production

Most of the country's production is coming from the onshore Wafa field as well as from the offshore Bahr Essalam field. Production grew substantially from 5.5 bcm (59 TWh) in 2003 to nearly 17 bcm (187 TWh) in 2010. In 2011 Libyan production was almost entirely shut down due to the civil war. Compared to 2010, more than a 50 % drop was registered, with the production decreasing to 8 bcm (88 TWh). According to BP Statistical Review, natural gas production has since recovered to approximately 13 bcm (143 TWh/y) in 2015.

Exports

Piped exports are transported via the Green Stream pipeline which came online in 2004. This 520 km offshore pipeline connects Libya to Italy through Sicily. This infrastructure has a total capacity of around 12 bcma.

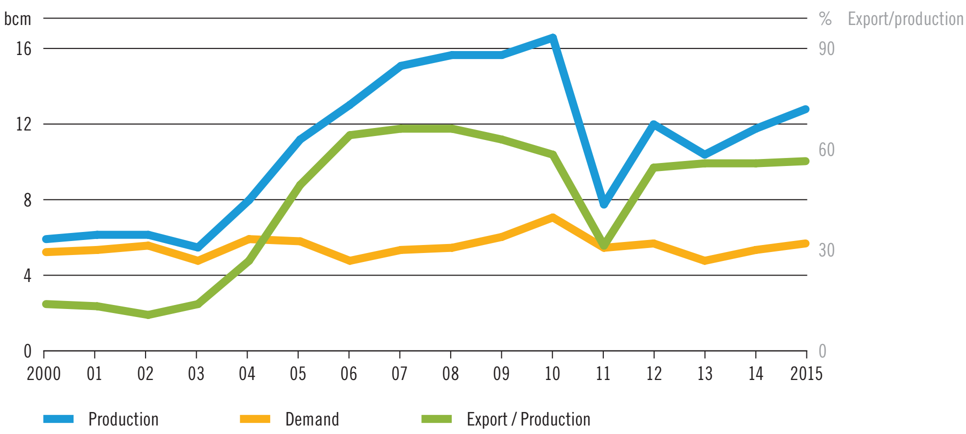


Figure 3.28: Libyan gas production, consumption and export ratio 2000 – 2015. (Sources: BP statistical review, EIA and Snam Rete Gas)

In 1971, after the United States and Algeria, Libya became the third country in the world to export liquefied natural gas. Processed in Masra El-Brega LNG plant, LNG was mostly exported to Spain. The plant was damaged in 2011 and since then Libya has not exported LNG.

From March to mid-October 2011 Libyan exports to Italy were completely interrupted due to the civil turmoil. Exports soon recovered in 2012 to 6.5 bcm and stayed relatively unchanged in the years after.

1) BP Statistical Report 2016

Supply Scenarios

Based on different assumptions on production and consumption ENTSOG considers a maximum and a minimum potential for Libyan export.

Maximum Libyan pipeline gas scenario

Based on the technical export capacity of GreenStream pipeline (354 GWh/d), the maximum potential assumes a 95 % load factor of the pipeline (336 GWh/d).

Minimum Libyan pipeline gas scenario

This potential is based on Mott MacDonald's report[1]. According to its low case, the production potential ranges from 16 bcm (176 TWh) in 2015 to 20 bcm (220 TWh) in 2030. For the period 2031–2037 the production figures have been then extrapolated. Total exports have been derived applying the minimum export/production ratio used in the last TYNDP edition (34 % according to the historical OPEC data). Then pipeline exports have been estimated at 97 % of overall Libyan gas exports.

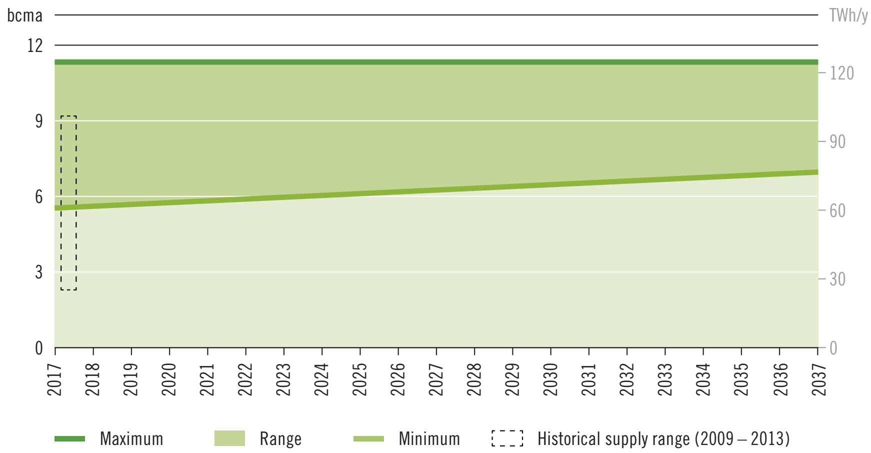


Figure 3.29: Pipeline gas potentials from Libya

PIPELINE GAS POTENTIALS FROM LIBYA						
GWh/d	2017*	2020	2025	2030	2035	2037
MAXIMUM	336	336	336	336	336	336
MINIMUM	167	173	184	195	206	211

* Supply potentials 2017 as shown in table 5.2 are used for the assessment

Table 3.8: Pipeline gas potentials from Libya (GWh/d)

1) Supplying the EU Natural Gas Market November 2010, Mott MacDonald

3.3.1.5 Azerbaijan

Reserves

Azerbaijan's proven reserves amount to roughly 1,100 bcm (12,100 TWh)[1]. The vast majority of these reserves come from the Shah Deniz field which turned Azerbaijan into a net exporter of natural gas in 2007. Besides that, gas is also produced from the Absheron and Umid fields. As it is shown in the next figure, domestic consumption has been stable for the past decade. Around half of the country's natural gas consumption is currently for power generation and it could further increase if Azerbaijan continues to install new gas fired power plants.

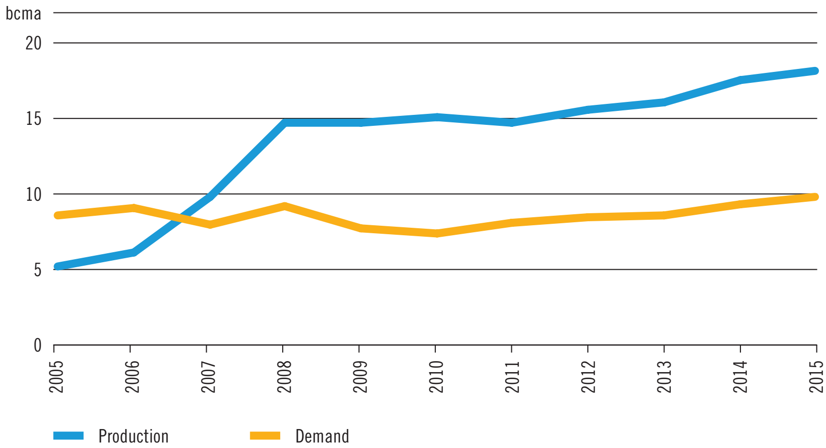


Figure 3.30: Azerbaijan's natural gas production and consumption 2001 – 2015.
(Source: BP Statistical Review 2016)

Most of Azeri gas is exported to Turkey via the South Caucasus Pipeline from Baku to Erzurum as the main export pipeline. Some volumes are also exported to Russia via the Gazi-Magomed-Mozdok Pipeline and to Iran via the Baku-Astara Pipeline

Shah Deniz Field

The potential exports of Azeri gas to Europe are closely linked to the development of this field. Discovered in 1999, it holds approximately 1,000 bcm (11,000 TWh) of natural gas reserves and its development is undertaken by a BP-led consortium. Gas production began in early 2007 and it has increased since then, reaching a production of almost 10 bcm (110 TWh/y) in 2015[2]. Phase 2 will add another 16 bcma (176 TWh/y) of gas production with the first deliveries estimated in 2019, of which 6 bcma (66 TWh/y) are already contracted by Turkey. The additional 10 bcma (110 TWh/y) are contracted by Southern Europe countries expecting supply via Turkey through the Trans Anatolian Pipeline (TANAP) and Trans Adriatic Pipeline (TAP) projects, in combination with the extension of the South Caucasus Pipeline.

1) Source: BP Statistical Review 2016
2) EIA Country Analysis Brief 2016: Azerbaijan

Supply Potentials

Shah Deniz phase 1 production has already started and will remain stable and limited to regional markets. ENTSOG considers as potential Azeri supply for EU gas coming from phase 2 starting as of 2019.

Maximum Azeri pipeline gas potential

This potential considers the 10 bcma (110 TWh/y) for the EU market as it was done in TYNDP 2015. The ramp-up phase gradually increases the gas imports from 2019 to 2022.

Minimum Azeri pipeline gas potentials

With the final decision of the aforementioned transit route, the likelihood of receiving some gas can now be considered high. Hence, this minimum potential has been set at 80 % of the maximum one.

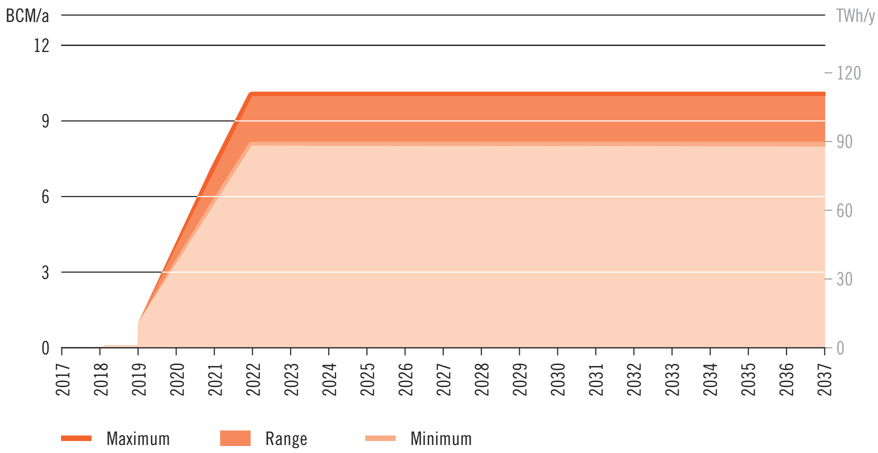


Figure 3.31: Pipeline gas potentials from Azerbaijan

PIPELINE GAS POTENTIALS FROM AZERBAIJAN						
GWh/d	2017*	2020	2025	2030	2035	2037
MAXIMUM	0	119	297	297	297	297
MINIMUM	0	95	238	238	238	238

* Supply potentials 2017 as shown in table 3.2 are used for the assessment

Table 3.9: Pipeline gas potentials from Azerbaijan (GWh/d)

3.3.2 LNG

LNG enables the connection of Europe to the global market and a large number of producing countries in the Middle East, the Atlantic (including the Mediterranean) and the Pacific basins. It gives access to reliable and diversified supply offering the shippers arbitrage opportunities at a global scale between different sources and regional markets.

3.3.2.1 LNG production

Global production reached its historical maximum level of 333 bcm (3,663 TWh) in 2015 recovering after decreasing in 2012. Since 2001, production has more than doubled. The growth has been more significant in Middle East where LNG production has been multiplied by four. In the same period the LNG production in the other regions grew as well but to a lesser extent.

The different evolutions followed by the three basins have derived in a significant change in their shares. Middle East and Pacific basins are the biggest LNG sources with roughly the same market share in 2015, around 40 % share each, while Atlantic basin share has been reduced to 22 %.

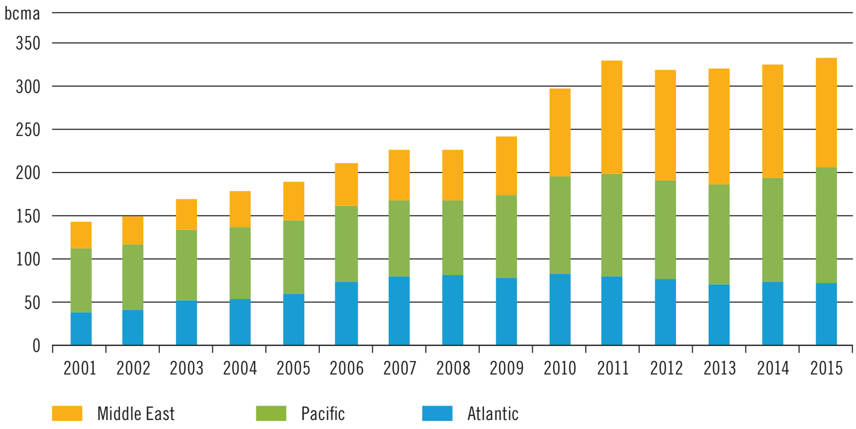


Figure 3.32: Evolution of LNG production by basin 2001–2015
(Source: BP statistical reports 2002–2016)

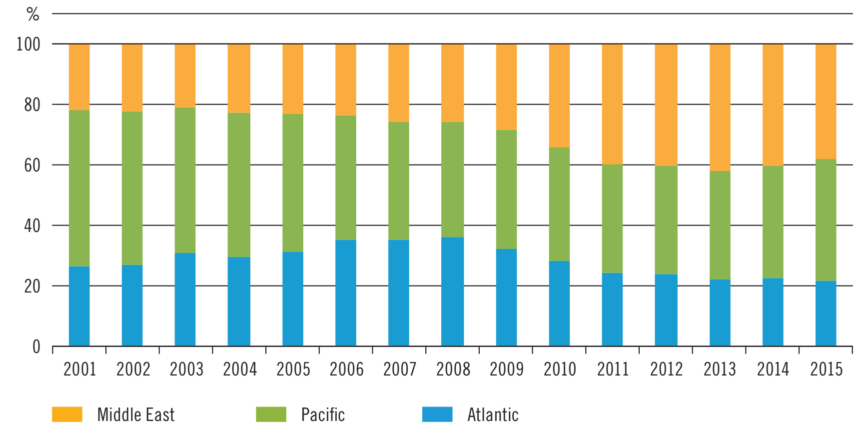


Figure 3.33: LNG Shares by basin 2001–2015 (Source: BP statistical report 2002–2016)

Atlantic basin

The LNG production in the Atlantic basin reached its maximum in 2010 with 83.5 bcm (918 TWh), since then it decreased by 14 % to 71.7 bcm. In 2015, the biggest Atlantic basin LNG producer was Nigeria (38 %), followed by Trinidad and Tobago (24 %) and Algeria (23 %).

Middle East

The LNG production in the Middle East showed a steady increase until 2009. The production increased sharply in 2010 and 2011 thanks to the commissioning of new liquefaction trains in Qatar. Since then the evolution of this basin is stable, reaching 126 bcm (1,386 TWh) in 2015, mainly dominated by Qatar with a market share between 75 and 84 % of the Middle East production in the past 5 years. Other producers in the region are Oman and Arab Emirates (with market shares below 10 %).

Pacific basin

The LNG production in the Pacific basin reached a maximum in 2015 with 136 bcm (1,496 TWh). Australia has experienced a substantial increase in LNG production over the last few years reaching a market share of 29 % of the Pacific Basin in 2015, overtaking Malaysia (25 %) as the main LNG producing country in the Pacific basin, followed by Indonesia (16 %).

Image courtesy of REN

3.3.2.2 LNG imports

The next figures show the clear dominance of Asia Pacific in the evolution of the breakdown by geographical area of LNG imports for the period 2001 – 2015. In this period the share of Asia Pacific in the LNG market has oscillated between 62 % and 74 %. Far from these shares, the second main LNG market has been Europe (including Eurasia). Their maximum share of the global LNG imports was reached in 2009 with 29 % before dropping down to 17 % in 2015. Since 2010 the American markets have compensated each other with a simultaneous decrease of North American imports and an increase of South American imports.

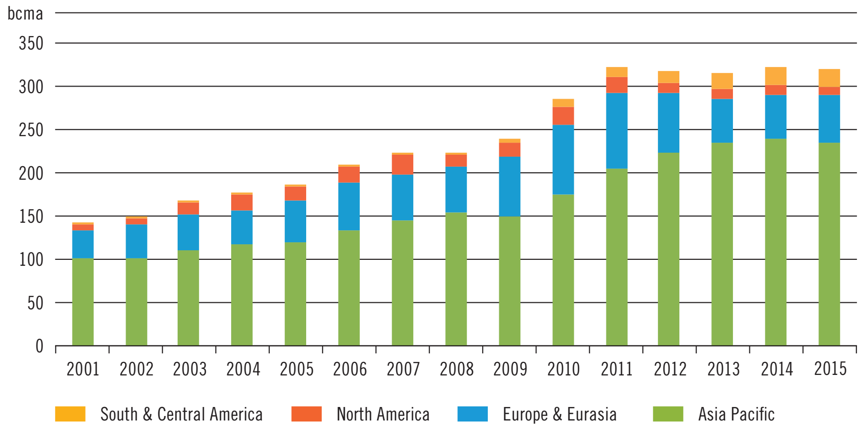


Figure 3.34: Evolution of LNG imports. Breakdown by geographical area. 2001 – 2015 (Source: BP statistical reports 2002 – 2016)

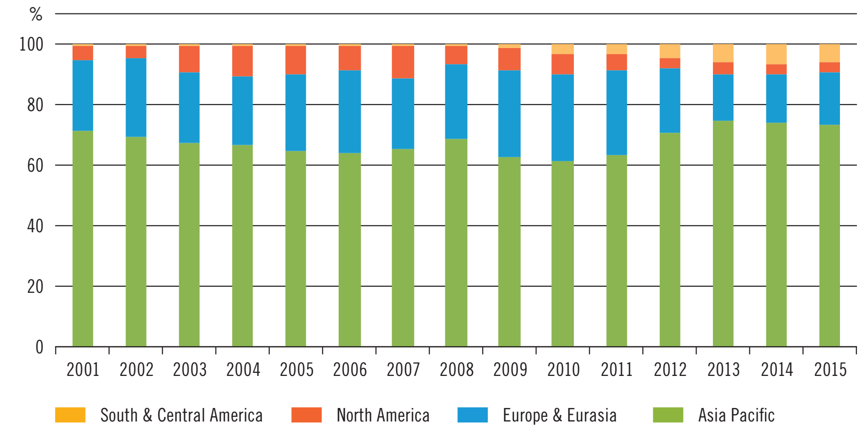


Figure 3.35: LNG imports share. Breakdown by geographical area. 2001 – 2015 (Source: BP statistical report 2002 – 2016)

Asia Pacific

The Asia Pacific gas market is strongly dominated by Japan and South Korea. Japanese LNG imports grew from 2011 following the nuclear accident in Fukushima, reaching 121 bcma in 2014. In 2015 Japan showed a market share of 49 % followed by South Korea with 18 %. The remaining countries in the region, like China, India and Taiwan, account for roughly one third of the market. However, these countries showed a sharp increase in consumption in the last few years, which is expected to continue in the future.

EU and Turkey

After a period of growth, the LNG consumption fell sharply by 43 % to about 55 bcm in 2015 compared to the peak of 82 bcm in 2011. European LNG import down to almost 50 bcma while Turkish LNG import remained relatively stable at about 5 bcma.

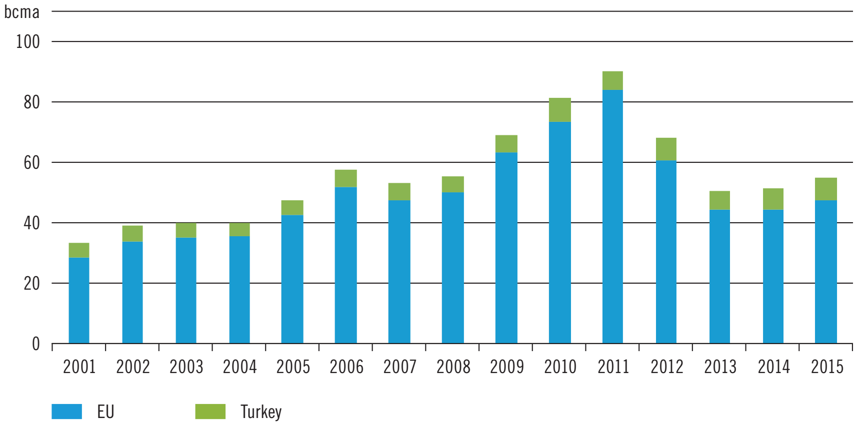


Figure 3.36: Evolution of LNG imports in Europe-Eurasia. 2001 – 2015 (Source: BP statistical reports 2002 – 2016)

North America

From 2001, the North American market was limited to the US, where a strong growth was expected to be met by increasing imports. After the shale gas revolution, decrease of US LNG imports since 2007 (22 bcma) has been partially replaced by Mexico. Mexican LNG imports started in 2006 and accounted for 69 % (7 bcma) of the LNG in the area in 2015.

South and Central America

Until 2008 only small volumes were imported to Puerto Rico and Dominican Republic. Since 2008 Chile, Brazil and Argentina have become LNG importers. Brazil and Argentina account together for two thirds of the market and Chile has a market share of 20 %.

Liquefaction vs. regasification capacity[1)]

As shown in the next figure, in 2015 the regasification capacity remains more than twice higher than the liquefaction capacity.

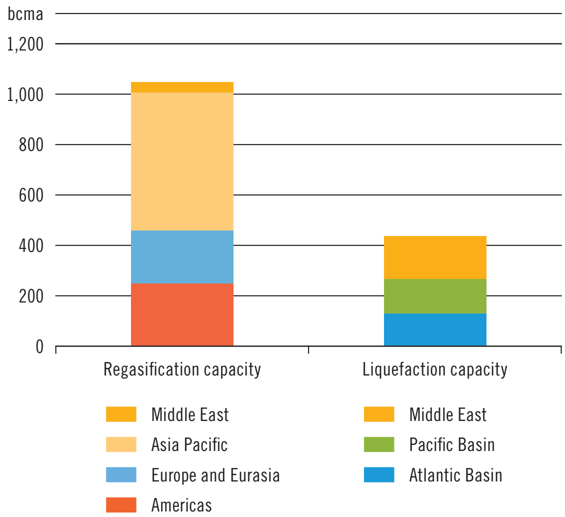


Figure 3.37: Liquefaction vs. Regasification capacity (Source: GIIGNL 2015)

Regasification capacity

The regasification capacity was expanded in 2015 by 32 bcma with three new onshore terminals, two in Japan and one in Indonesia, and four offshore terminals, in Egypt (two), Jordan and Pakistan. One more expansion project was also completed in Chile. In Europe, 2016 saw the start of commercial operation of the Polish Swinoujscie and French Dunkirk terminals.

Moreover, there are fifteen terminals currently under construction with a total regasification capacity of 99 bcma, of which 71 bcma are located in Asia (with eight terminals in China).

1) liquefaction capacities are converted from MTPA. The volume and energy content depend on the composition and the reference conditions of the LNG. The following approximation has been considered: 1 MTPA (liquid volume) = 1.37 bcma (gas volume)

Liquefaction capacity

The existing liquefaction capacity increased by around 20 bcma in 2015 with three new projects, two in Australia and one more in Indonesia. Another 58 new bcma are expected to come on line shortly, for 2016 these are mainly located in Australia (38 bcma).

Additionally, around 200 bcma of new liquefaction capacity is currently under construction, mainly based in the United States (85 bcma) and Australia (70 bcma). Another five new FIDs were taken during 2015, four of which are also located in the United States, demonstrating that the gap shown in the previous figure might shrink during the following years.

Maximum LNG potential

The maximum supply potential has been defined for the EU at the maximum LNG market share recorded for the EU applied to an increasing global LNG market. The maximum market share has been set at 30 % (historical record in 2011).

New LNG export capacity are based on the WEO 2015 New Policy scenario trading mix from Middle East, Australia, North America, Sub Saharan Africa and Latin America in 2025 and 2040.

Minimum LNG potential

The minimum supply potential has been defined on the assumption of a decrease of the imports to a 70 % of the minimum EU imports between in 2009–2014, and is kept constant for the future.

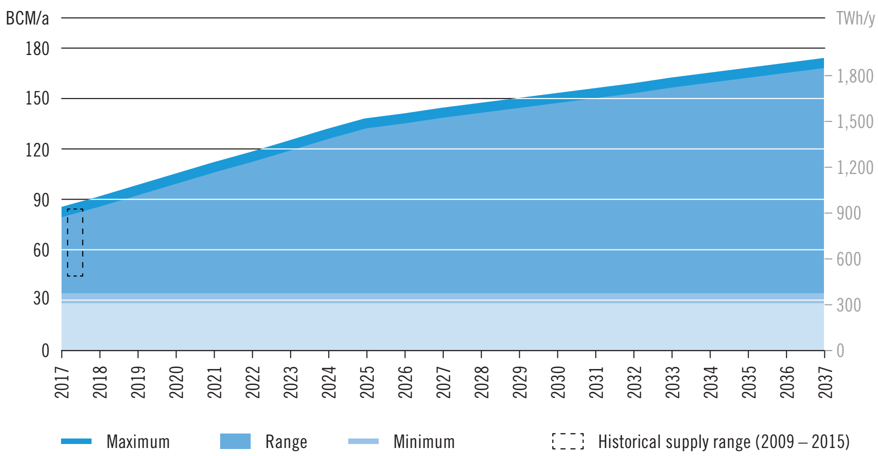


Figure 3.38: LNG supply potentials

LNG SUPPLY POTENTIALS						
GWh/d	2017*	2020	2025	2030	2035	2037
MAXIMUM	2,435	3,030	4,021	4,467	4,912	5,091
MINIMUM	920	920	920	920	920	920

* Supply potentials 2017 as shown in table 5.2 are used for the assessment

Table 3.10: LNG supply potentials (GWh/d)

LNG as a multi-source

LNG is traded in a global market which has been constantly growing during the last decades. By giving access to a large variety of sources and routes, LNG makes gas reserves around the world accessible to the EU market.

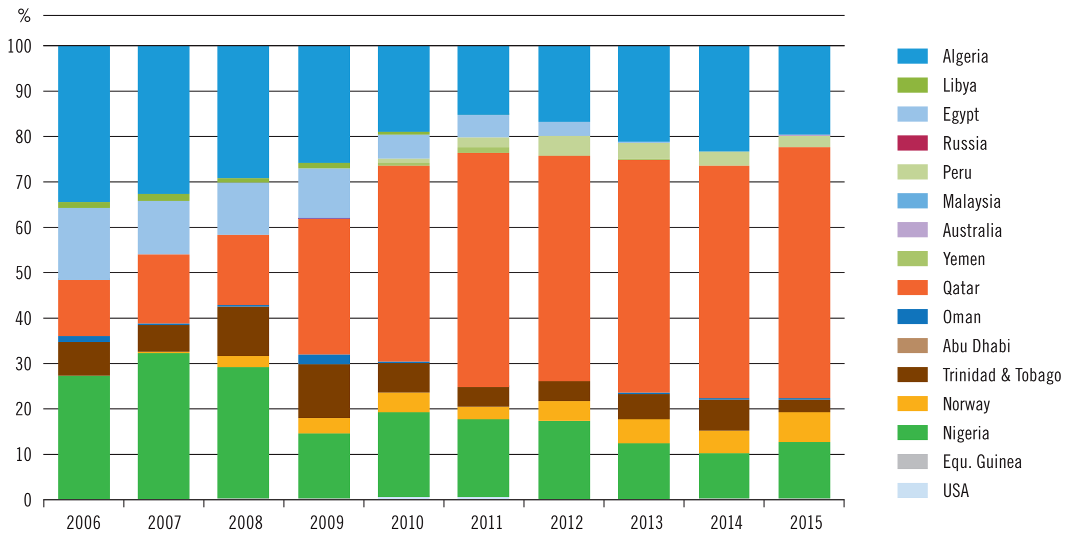
An LNG terminal is therefore a gateway to many different producers and sources of gas located in different parts of the world. LNG implies a diversification by itself, diversifying supply sources on both a long term and a short term basis, which is a strong insurance against supply disruptions of a given country and/or producer as long as the country is prepared to pay the price. Furthermore, LNG not only provides diversification of supply but also adds to competition and effective market functioning. LNG volumes can enter the EU market and compete with and/or complement traditional pipeline gas supplies, thus putting additional pressure on gas suppliers.

In 2015, the EU imported LNG from more than 9 different origins around the world. The number of different origins supplying LNG to the EU has remained between 7 and 12 during the last decade. Nothing indicates that the number of origins is going to decrease in the future. On the contrary, with new trends emerging on the global LNG market (e.g. increasing LNG volumes on the supply side, decreasing EU domestic production, etc.) an increased number of LNG liquefaction plants located in an increased number of countries will be entering the market and a higher number of LNG cargoes are expected to arrive in Europe in the upcoming years. This is contributing further to increasing diversification, supply competition and security of supply for the benefit of the EU consumer.

In case of a supply disruption within the EU, increased LNG deliveries in BE, ES, FR, GR, IT, LT, NL, PL, PT and UK will help to meet Europe's needs and free up pipe-gas for other parts of the EU.

LNG has already demonstrated it is an effective tool in addressing emergencies and mitigating supply shortfall/demand spikes. For instance, following the Fukushima tragedy, by accepting higher LNG prices, Japan was able to attract additional LNG supplies from all over the world and increased its LNG consumption for power generation from 50 bcma to more than 70 bcma in 2012. Other examples where LNG played a key role in mitigating supply emergencies are: Chile post curtailment of imports from Argentina (mid 2007), Brazil droughts impacting hydro-based power production (2014), Israel & Jordan post curtailment of imports from Egypt (2012). This demonstrates that LNG offers a fast track solution from the perspective of both the molecule as well as the infrastructure.

Source: GLE



Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
EU LNG Imports (bcm)	49	45	48	60	75	76	55	41	41	45
Number of origins	8	8	9	12	12	11	7	9	8	9

Figure 3.39: Contribution of each LNG origin to the total EU LNG imports

3.3.3 INDIGENOUS PRODUCTION

This section covers the national production of gas from EU countries including conventional sources, biomethane and shale gas.

3.3.3.1. Conventional sources

Conventional gas production in Europe decreased by 34 % between 2010 and 2015. The evolution was not homogeneous. Indigenous production increased slightly in Bulgaria, Czech Republic and Romania. The decreases since 2009 of the Netherlands by 39 % and the UK by 36 %, accounted for the majority of the decline in the EU over the period. The decline observed in the Netherlands is not only caused by depletion of gas reserves, but is also the result of additional restrictions on the production of the Groningen field that were introduced by the Dutch Government since 2014 in response to the earthquakes in the Groningen area.

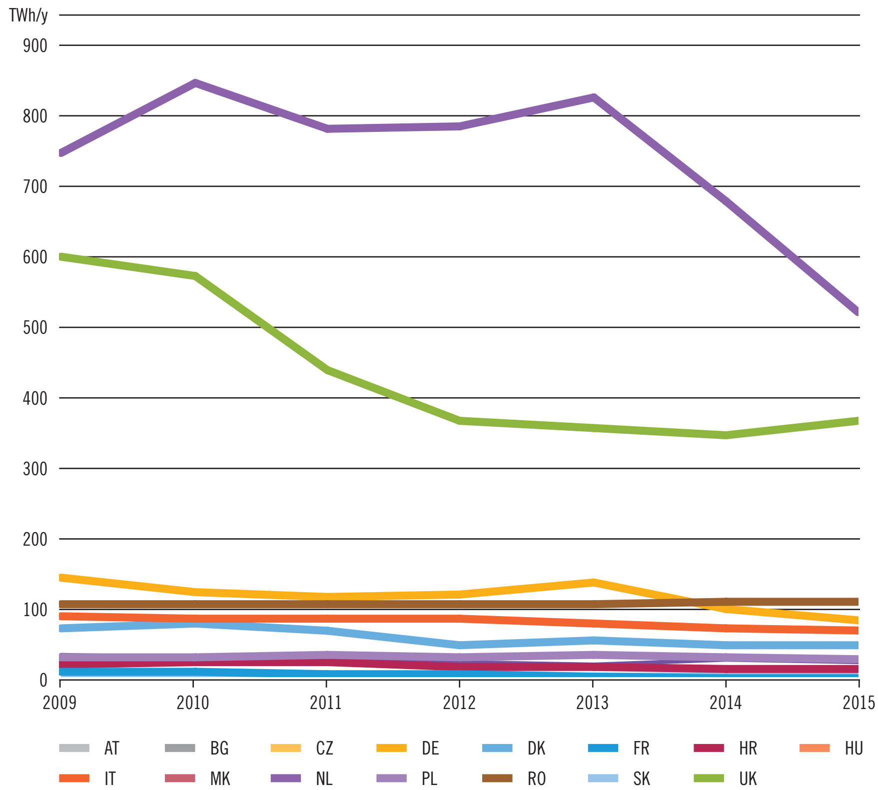


Figure 3.40: EU indigenous production 2009 – 2015. Country detail

The information on EU indigenous production has been collected from TSOs. The EU indigenous production is expected to continue decreasing significantly over the next 20 years. This decrease could be slightly mitigated with the development of production fields in the Romanian sector of the Black Sea and Cyprus[1]. However except for Romania, projects, enabling production are considered as Non-FID and are included only in the High Infrastructure Level due to their lack of maturity (see Annex F on Methodology).

1) Cyprus does not have a domestic market and as it is located far from European markets there is uncertainty where the gas might flow either as pipe-bounded gas or as LNG. For modelling purposes it is assumed that a large proportion of Cyprus production will be delivered to Europe

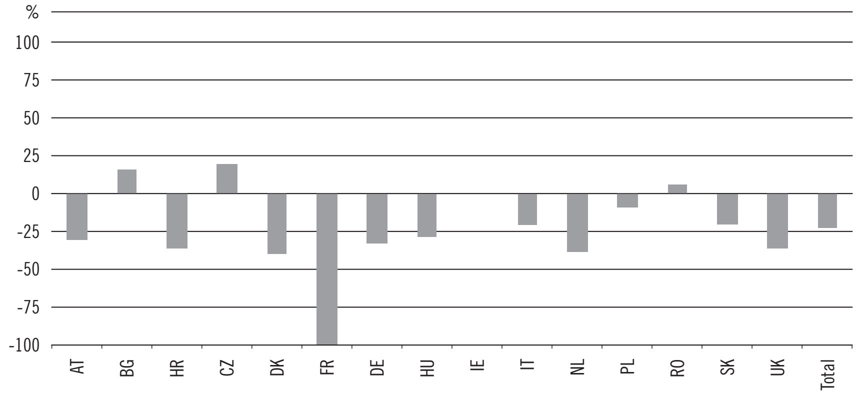


Figure 3.41: Evolution of EU indigenous production (%) between 2010 and 2015

Next figure shows EU conventional production, including the one coming from Non–FID projects. Overall production could decrease by 59 % by 2037 or even more if Non-FID developments are finally not commissioned.

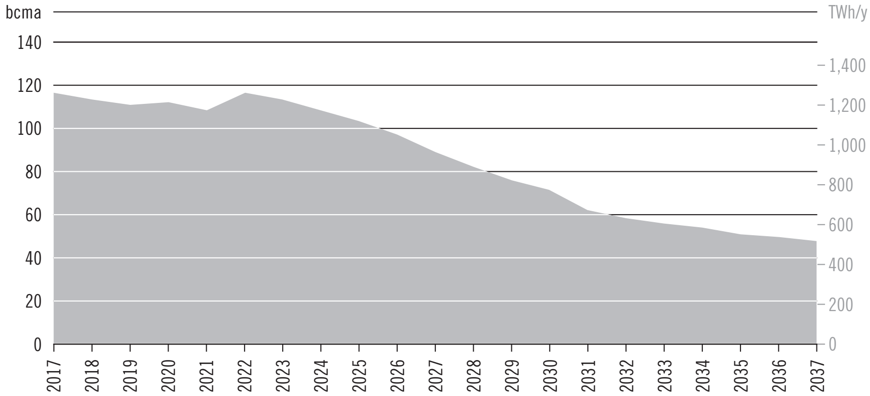


Figure 3.42: Potential of EU conventional production 2017 – 2037 (incl. Non-FID)

POTENTIAL EU CONVENTIONAL PRODUCTION 2017 – 2037 (INCL. NON-FID)

GWh/d	2017	2020	2025	2030	2035	2037
CONVENTIONAL PRODUCTION	3,460	3,337	3,063	2,110	1,834	1,418

Table 3.11: Potential EU conventional production 2017 – 2037 (incl. Non-FID)

Next figures show the potential evolution of conventional production by country. From 2020 the production in the Netherlands and the UK would decrease more significantly than in other countries in the absence of new discoveries. After 2035 Cyprus could become the second biggest EU producer after the Netherlands.

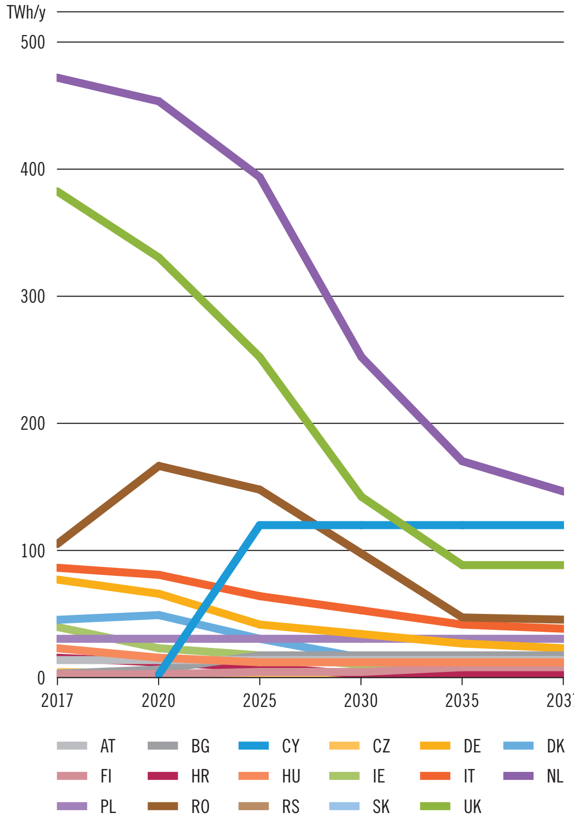


Figure 3.43: Potential of EU conventional production (incl. non-FID) 2017 – 2037

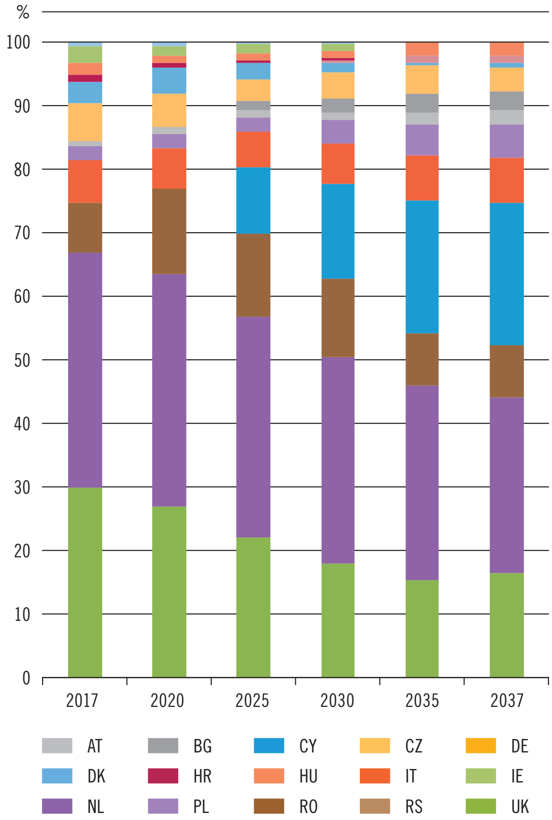


Figure 3.44: Shares of EU potential conventional production (incl. non-FID) 2017 – 2037

Conventional gas potentials

Compared to imports, there is relatively little uncertainty on the evolution of European conventional production. The main uncertainty is related to the development of the necessary infrastructures to connect new gas fields to the rest of the European gas system.

3.3.3.2 Renewable gases

Currently renewable gases are biomethane, hydrogen and synthetic methane produced with power-to-gas technologies.

They represent carbon neutral energies that can be produced continuously and injected and stored in the existing gas infrastructures.

Given these common characteristics and their relatively low individual share in the energy mix, for this TYNDP renewable gases are summoned up for statistics reason as "biomethane".

Biomethane

Its chemical characteristics are the same of natural gas. It can be produced from all kinds of organic materials using digesters or capturing it directly in landfill sites. Liquid manure, agricultural waste, energy crops and effluent from sewage treatment plant can be fed into biogas plants.

Unblended biogas can be used for a range of applications including heating, cooling and power generation. When biogas is upgraded to biomethane (after removal of its high CO_2 content) it can also be used in the transport sector and be injected into the natural gas grids and storage facilities as its composition is similar to that of natural gas.

The biomethane output in 2014 was approximately 1.1 bcm (12.2 TWh), produced from over 255 upgrading plants with injection into the transmission or distribution grids in 13 countries[1]. According to the European Biogas Association[2], by 2030 40 % of the produced biogas is expected to be upgraded to biomethane (around 18 bcm).

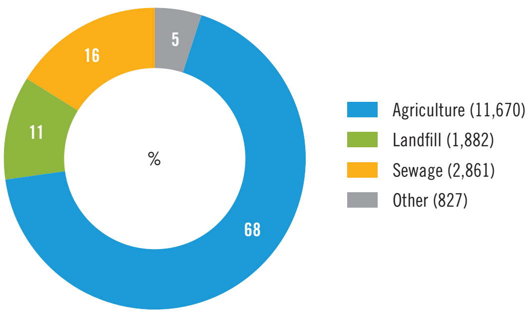


Figure 3.45: European biogas plants by the end of 2014 (Source: European Biogas Association).

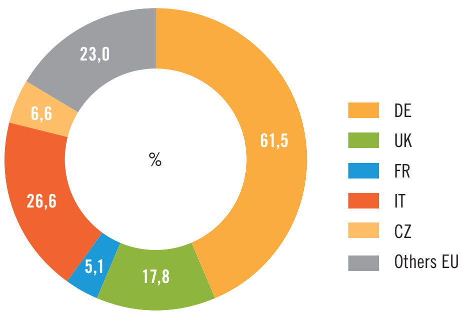


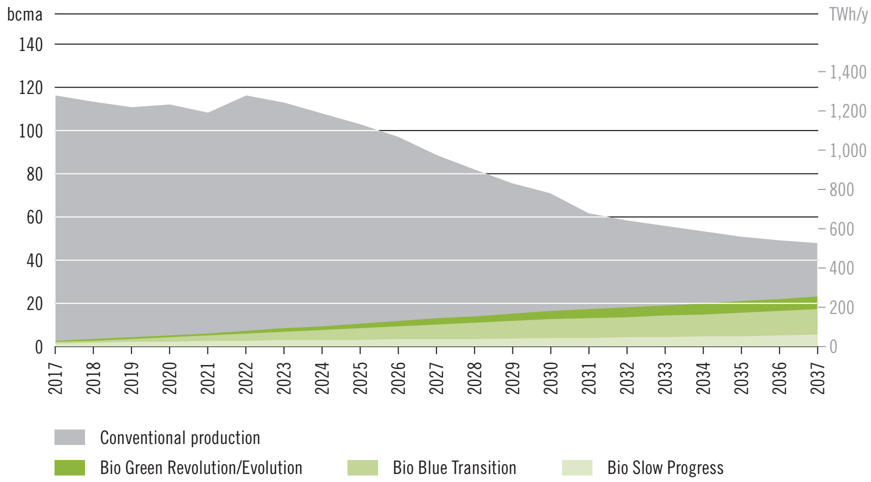
Figure 3.46: Biogas production in Europe 2014 (Source: European Biogas Association).

1) EBA Biomethane & Biogas Report 15: AT, CH, DE, DK, FI, FR, HU, IT, LU, NL, SE, ES and UK

2) Green Gas Grids: Proposal for a European Biomethane Roadmap, European Biogas Association, December 2013

Biomethane supply potentials

These potentials only cover the share of biogas upgraded to biomethane as only this proportion can be injected into the distribution or transmission grids (including power to gas by hydrogen or methane injection). In creating the EU Green Revolution, Green Evolution, Blue Transition and Slow Progression scenarios, ENTSOG has used TSO estimates on biomethane injection in their grids.



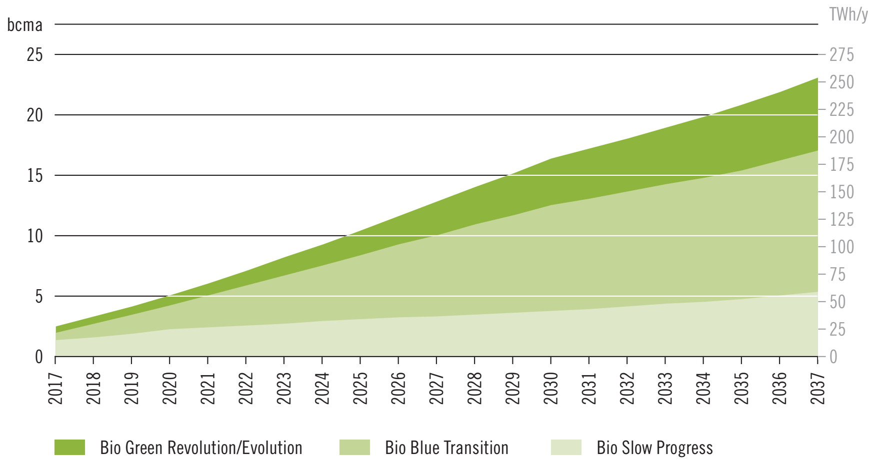


Figure 3.47: Potentials for injected biomethane (in comparison with/without conventional production)

POTENTIALS FOR INJECTED BIOMETHANE (GWh/d)						
GWh/d	**2017**	**2020**	**2025**	**2030**	**2035**	**2037**
Conventional Production	3,460	3,337	3,063	2,110	1,834	1,418
Biomethane EU Green Revolution/Green Evolution	75	153	315	494	628	696
Biomethane Blue Transition	59	128	254	378	465	515
Biomethane Slow Progression	41	68	93	113	144	161

Table 3.12: Potentials for injected biomethane (GWh/d)

According to the TSO estimates in the EU Green Revolution and Green Evolution scenarios, the largest share of biomethane injection in 2037 will take place in Italy, reaching up to 42 %, and in the Netherlands, 24 %. In 2037 Italy, France, United Kingdom and the Netherlands could account for over 90 % of biomethane supply in Europe.

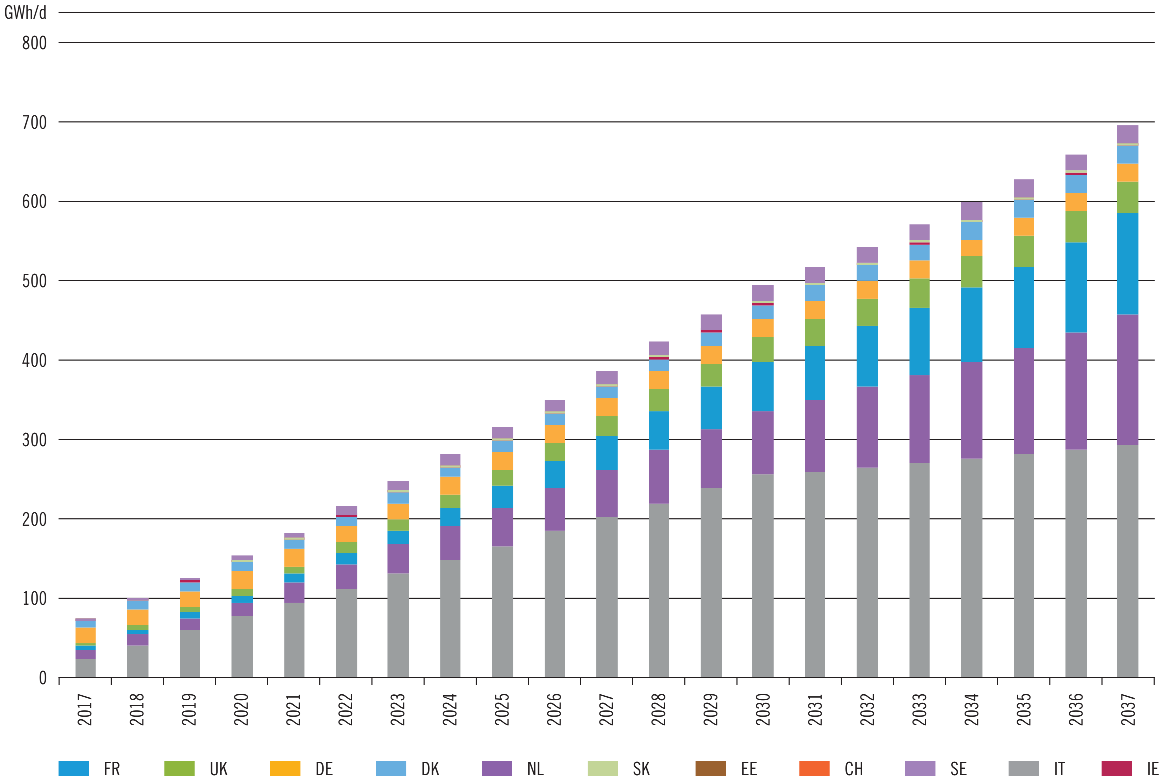


Figure 3.48: Biomethane Green Revolution/Evolution potential (Split by country)

Power-to-gas

Irrespective to the approach to combine biomethane and power-to-gas technologies statistically ENTSOG considers power-to-gas as an important technology to foster the convergence of energy systems. Power-to-gas enables long-term storage and efficient transport of excess of renewable energies discontinuously produced. For the first time TYNDP dedicates a chapter to their contribution to the European energy transition (See Energy Transition chapter).

3.3.3.3 Shale gas

In recent years, potential EU shale gas production has become a more visible topic. Driven by the shale gas boom in the US, the tension between Ukraine and Russia and the growing dependency of the EU on gas imports, a significant number of European stakeholders believe that this indigenous source should be high on the European energy agenda. Shale gas has led to controversial debates regarding its environmental impacts. In comparison to the US, the European geological conditions are quite different. The first appraisal wells have been drilled in Poland and the UK, however the exploration phase is still at an initial stage and therefore it is likely that commercial flows from EU shale gas will not be delivered within the next few years.

Reserves

As the exploration of shale gas is currently not as mature as for conventional gas, estimations of reserves are quite diverse. EIA estimates European technically recoverable shale gas resources at around 13,000 bcm (143,000 TWh) whereas Pöyry's estimates are more conservative with figures ranging from 8,000 to 11,000 bcm (88,000 – 121,000 TWh) in their "Some Shale Gas" and "Boom Shale Gas" scenarios. These figures can be compared with the annual European gas demand (418 bcm/4,595 TWh in 2015) and US recoverable resources (around 17,600 bcm[1]).

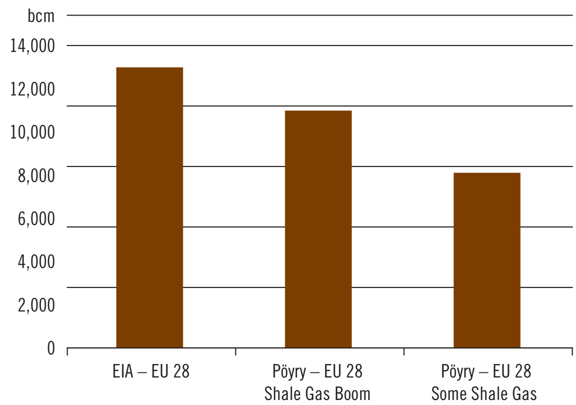


Figure 3.49: Technically recoverable shale gas resources in the EU (own depiction based on Pöyry 2013 "Macroeconomic Effects of European Shale Gas Production")

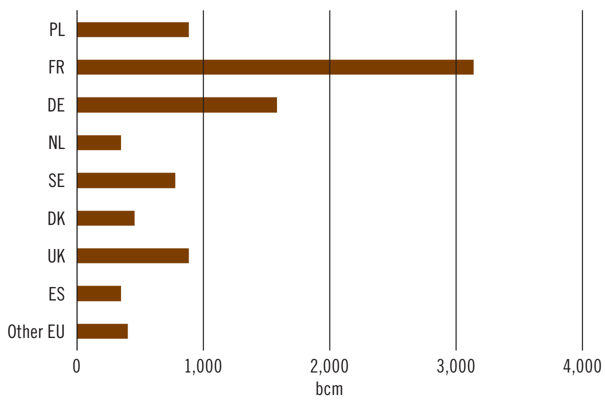


Figure 3.50: Technically recoverable shale gas in EU (source Pöyry "Some Shale Gas" scenario)

The term "technically recoverable" refers to the volume of shale gas that theoretically could be extracted with current technologies[2] taking into account shale mineralogy, reservoir properties and geological complexities. Most of this technically recoverable shale gas can be found in France, Germany, UK, Poland and Sweden.

The EU is far from having a clear legal framework regarding fracking. Due to political, historical and geographical differences European Member States have very different positions on shale gas. Some countries have taken measures preventing exploration and production whereas appraisal wells have been drilled in the UK and Poland without bridging big results for the moment. In parallel other Member States have been working on establishing a national consensus on a legislative framework covering fracking and the associated environmental impacts.

1) EIA 2015: https://www.eia.gov/analysis/studies/worldshalegas/

2) Pöyry, Macroeconomics Effects of European Shale Gas Production, page 15, November 2013

Shale gas supply potential

To determine potential shale gas production, ENTSOG has taken into consideration a range of data including information from Pöyry and TSO estimates. Due to the uncertainty around the development of shale gas on EU territory, plus the information received from TSOs of the complete lack of shale gas production expected, the below potential is not taken into account in the assessment and therefore does not relate to any of the TYNDP scenarios (EU Green Revolution/Green Evolution, Blue Transition and Slow Progression).

Some shale gas potential

Given the uncertainty surrounding EU shale gas production, this potential is based on the conservative "Some Shale Gas" estimate included within Pöyry's 2013 report. It includes the application of environmental and planning constraints (limiting the number of possible drilling areas because of environmental and planning concerns) as well as constraints regarding practical (drilling rig trained staff availability) and financial (cost of production exceeding possible future market prices) issues. Due to the high uncertainty ENTSOG assumes the start of this potential should be delayed for a period of at least 5 years.

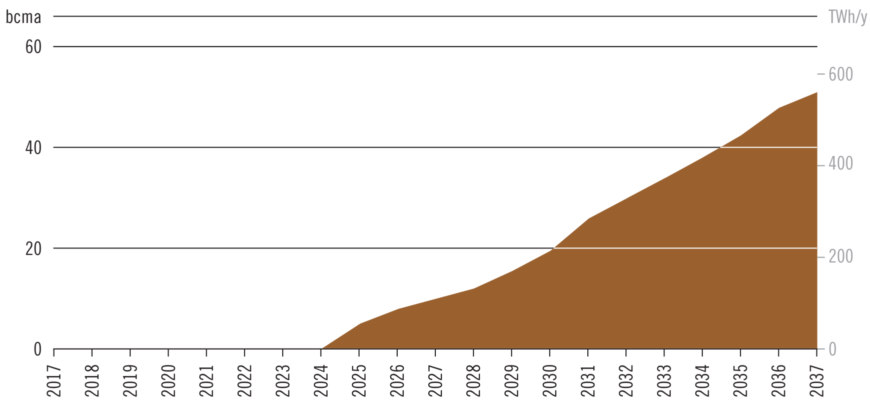


Figure 3.51: Potential for shale gas

POTENTIAL FOR SHALE GAS (GWh/d)						
GWh/d	2017	2020	2025	2030	2035	2037
SOME SHALE GAS	0	0	149	579	1,262	1,515

Table 3.13: Potential for shale gas (GWh/d)

It should be noted that TSOs estimates of shale gas production, collected by ENTSOG in 2016, provided no data on shale gas production in any country due to the high uncertainty based on the weak results of shale gas extraction in Europe, difficult geological formations, the lack of available trained staff and technologies, and also public and governmental opposition due to the risks associated to the extraction technics.

3.3.4 OTHER POTENTIAL SOURCES

Other potentially interesting sources of gas supply for the future have been investigated but not included in the assessment. This is due to the fact there are currently no facilities to export this gas to Europe and no Final Investment Decision has been taken yet in any foreseen project, as a result they are still considered of high uncertainty. These potential sources are Israel, Egypt, Iran and Turkmenistan.

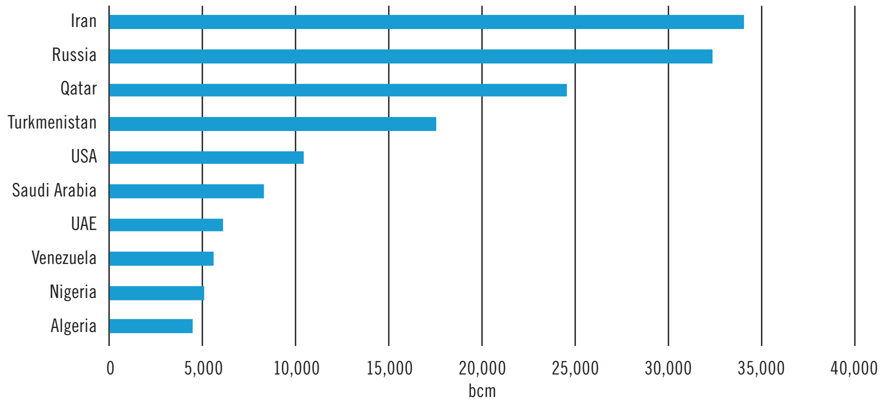


Figure 3.52: Proved natural gas reserves worldwide by Country
(Source: BP Statistical Report 2016)

Turkmenistan

Turkmenistan ranks in the top countries with the largest gas reserves in the world. The idea of exporting gas from Turkmenistan through a Southern corridor to Europe is widely discussed but transmission infrastructures are still missing. A possible opportunity is the Trans Caspian Pipeline (TCP) which would connect Turkmenistan with Azerbaijan across the Caspian Sea, an area with a particular legal status. The White Stream Pipeline project could then transport the gas through the Black Sea to the European border with landfall in Romania. The alternative option would be to use the future Trans-Anatolian Pipeline (TANAP) but this one is dedicated to Azeri gas imports in this Report.

Iran

According to BP Statistical Report, Iran is the country with the largest gas reserves in the world. Although the international sanctions linked to the development of nuclear programme are over, current production levels and current transmission infrastructures are considered as big limitations in order to conclude that the gas from Iran could reach EU market in the short term. Even if Iran plans to boost its gas sector during the next years, the additional exported volumes would probably reach direct neighbours first. Moreover, large investments would be needed to bring Iranian gas to Europe by pipeline but for the moment this option doesn't look probable in the near future.

Egypt

According to the EIA country report 2015, Egypt is currently the second largest producer and has the fourth largest proven reserves of natural gas in Africa. However, production has declined in recent years. Development of natural gas discoveries has been delayed due to a lack of investment driven by economic and political factors. LNG exports from Egypt stopped in 2014 as reported by IGU (International Gas Union) 2016 World LNG Report and the country became an importer in 2015 to cope with increasing domestic demand, particularly in the power sector, as petroleum usage is replaced. The giant Zohr gas field in the Mediterranean Sea, with estimated reserves of around 850 bcm, could grant energy independence to Egypt for many years[1)].

Egypt has an exportation pipeline, the Arab Gas Pipeline (AGP) which connects it to Jordan, Syria and Lebanon. There are also two LNG plants, for which the BP Statistical Report reported exported volumes of 3.7 bcm in 2013, of which 79 % went to Asia reflecting the global LNG market at the time. Europe was the second largest export destination that year, highlighting the potential for deliveries of LNG in future.

Israel

Israel currently has 200 bcm of proved gas reserves according to BP Statistical Report 2016 but the two offshore fields Leviathan and Tamar in the Eastern Mediterranean Sea could reach total estimated reserves of almost 1 Tcm[2)].

Israel's current priority is to protect its energy security and in June 2013 approved an export cap of 40 % of the country's natural gas reserves as an estimation to supply the national domestic demand for 25 years. On the other hand, Israel is more open to export additional gas to neighbouring countries like Jordan first, with the initial natural gas pipeline scheduled to begin operation in 2017 and to which Leviathan partners have already agreed to supply 45 bcm during the next 15 years. Another remote export options for Israeli gas would be to supply Egypt by pipeline and also to export gas directly to Turkey or Greece, the latter through the Trans-Med project considered in this TYNDP.

1) Source: https://www.eni.com/enipedia/en_IT/international-presence/africa/enis-activities-in-egypt.page

2) Source: http://www.delek-group.com/Portals/0/delek/presentation/present.pdf

3.4 Total potential supply to Europe

The potential supply to Europe is based on the aggregation of the potentials defined in this chapter. As shown in the graph below, the total potentials follow divergent trends. The maximum potential represents a moderate increase (18%), while the minimum potential represents a significant decrease (44%).

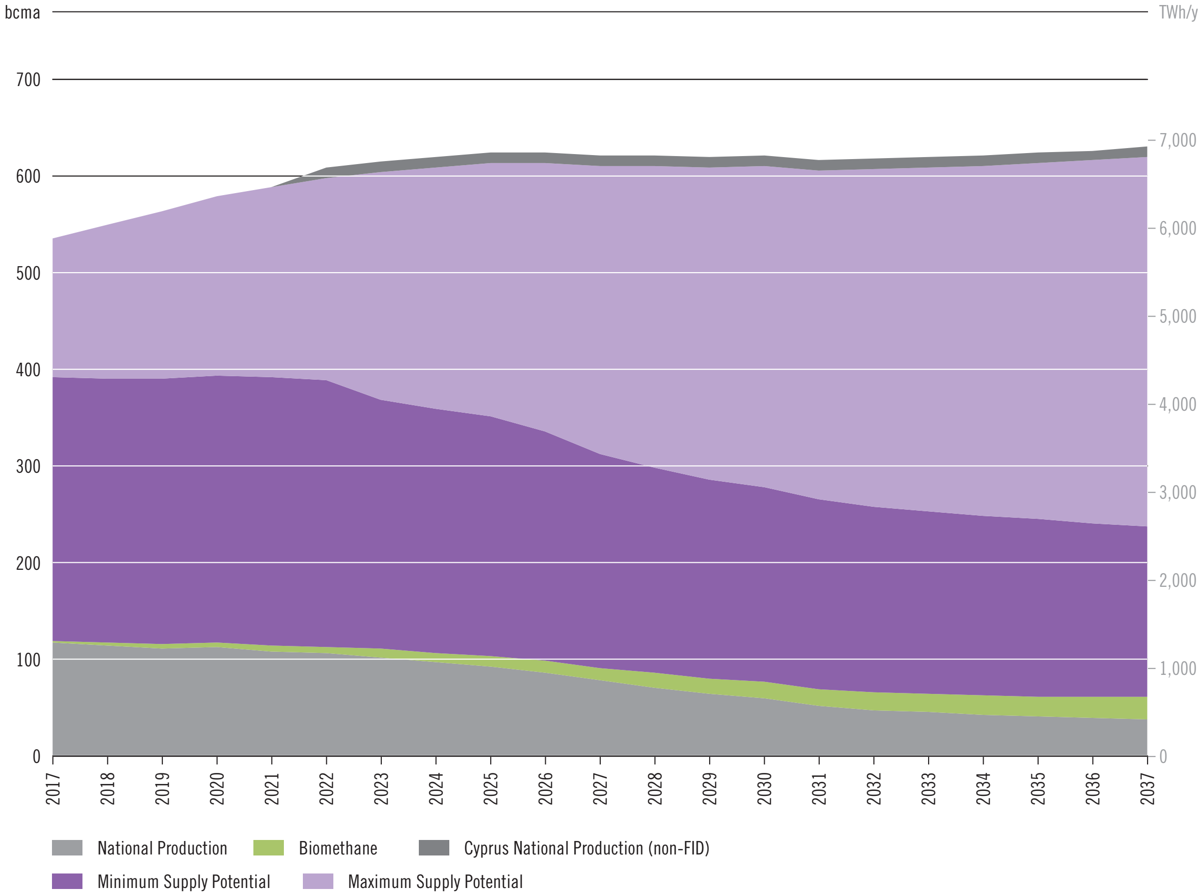


Figure 3.53: Total supply potential to Europe

The following graph shows the evolution of the spread between the Minimum and Maximum supply potentials. In absolute values, the maximum spread is found in LNG and Russian supply.

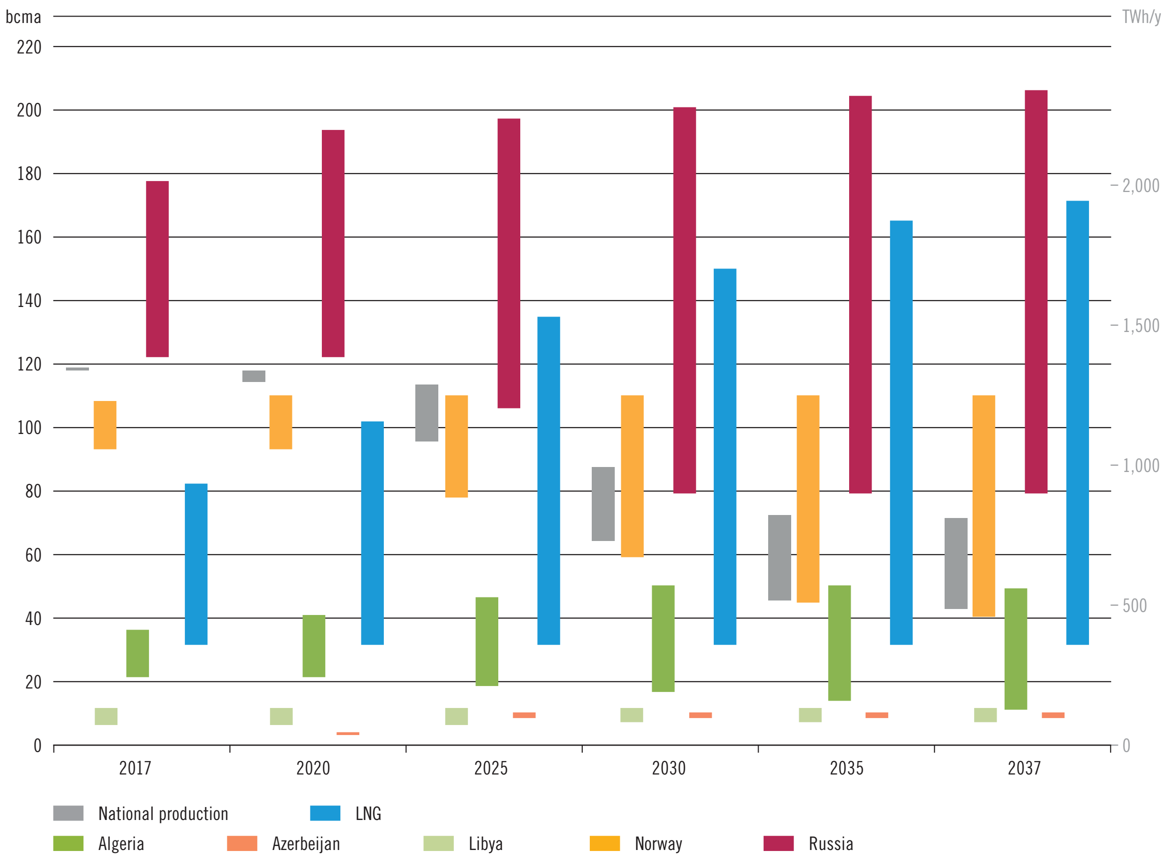


Figure 3.54: Evolution of supply ranges – Spread between potential maximum and minimum scenarios by source

4 Infrastructure

Image courtesy of Reganosa

4.1 Introduction

With the entry into force of Regulation 347/2013 (TEN-E Regulation), the role of TYNDP has significantly increased as all PCI candidate projects must be included within it ahead of the PCI selection process. This TYNDP, as with the previous edition, together with the PCI selection process, are key to the development of gas infrastructures. Gas infrastructures, along with the implementation of harmonised business rules, are fundamental steps towards the European Internal Energy Market.

Since the past edition of the TYNDP, ENTSOG has received valuable feedback that has been taken into account for this new edition. For example, in TYDNP 2017 ENTSOG provides for the first time a map with the collected projects, increasing transparency and offering readers the overview of TYNDP projects and project costs. They appear appropriate in relation to the aim of an integrated internal energy market, and are further investigated in this chapter.

The TYNDP intends to provide transparent and thorough information to stakeholders. Project information provided in this TYNDP covers basic technical data, the status of infrastructure projects and, outlined in the Assessment Chapter, the overall impact of projects relating to all four pillars of the European Energy policy: competition, security of supply, market integration and sustainability.

Projects submitted for TYNDP 2017 are at different level of maturity and their inclusion in the TYNDP does not make their development legally binding.

4.2 Gas infrastructures and European energy policy

Existing European gas infrastructures already provide a high level of market integration, security of supply and competition in many parts of Europe. Further developments covering the whole European system are necessary in order to ensure that such benefits will be strengthened and maintained in the long term.

The Third Energy Package should ensure a sound climate for a market-based development of gas infrastructures. However the timing of its implementation, the recent economic crisis, the lack of vision on the medium and long-term role of gas in the energy transition and CO_2 emissions prices have hampered the delivery of investments. In that context the TEN-E Regulation aims at facilitating the delivery of key infrastructures.

New infrastructure projects may contribute to market integration through additional flexibility and diversification of gas supply sources or routes. As a result, both competition and security of supply should increase.

Regarding the sustainability pillar of the EU Energy Policy, gas infrastructures already offer a flexible system able to support the development of renewable energies. These infrastructures are able to transport a low carbon fuel to support the development of intermittent renewable power production and enable a large scale injection of non-fossil gas (biogas or gas from power-to-gas processes). Gas infrastructures provide the advantage of storing renewable energy as well as transporting energy at relatively low costs.

4.3 Project data collection process

ENTSOG has improved the transparency on the process, strengthened the communication with project promoters and further developed its Project Data Portal to ensure the best possible availability, consistency and quality of the collected project data. This in turns ensures the quality of the assessment.

In order to provide a holistic view of the European gas system over the next 20-year period, it is important that all relevant infrastructure projects are incorporated into the TYNDP. ENTSOG has endeavoured to run an open and transparent data collection process, and actively encouraged project promoters to submit their projects.


Image courtesy of Terranets

To ensure the proper information and preparedness of all project promoters, ENTSOG has informed them on the project submission process starting well in advance and on numerous occasions.

As the submission of comprehensive project data is a critical prerequisite for the infrastructure analysis, ENTSOG provides a Project Data Portal open to all project promoters to support the process.

Only projects actively submitted by promoters through the Project Data Portal have been considered in this edition of the TYNDP. This process ensures transparency and non-discrimination between projects. Ahead of the submission phase, to better support project promoters, ENTSOG provided a documentation kit with a handbook on how to use the Project Data Portal and other documents[1)].

In order to increase transparency and accuracy of the information and to facilitate coordination among promoters, ENTSOG has improved the Project Data Portal by implementing project capacity monitoring interfaces. This allows project promoters to actively monitor their submission through specific reports and check the final capacity value resulting from the application of the "lesser-of-rule"[2)].

When submitting projects, the promoters commit to report accurate and up-to-date information. In very few instances ENTSOG has directly undertaken corrective actions in line with pre-defined rules[3)]. Furthermore, for a given project, the related TYNDP code is assigned automatically by the Project Data Portal when the project is first submitted. Updates of the project in future TYNDPs are handled by the promoter under the same project code. This allows using the project code as another key for the monitoring of projects along the different TYNDP editions and for the PCI selection process.

In line with ACER Opinion on TYNDP 2015, project promoters have been asked to indicate whether the submitted projects are included in the latest National Development Plan, and if not to provide the background for their submission.

Promoters were requested to provide comprehensive information including detailed project implementation scheduling and estimated costs. Refer to Annex A for detailed information per project and to Annex D for information on capacities.

The first full year of operation used in the assessment is the first full calendar year following the commissioning date[4)]. For projects where the promoter has not submitted a capacity increment[5)] or has not specified the commissioning year within the time horizon the commissioning date is reported as unavailable in the Annex A.

The project submission phase took place from 11 April to 8 May 2016 followed by an inter-promoters validation phase until 25 May. **As a consequence this TYNDP reflects project status as of May 2016.**

To ensure an early transparency on the TYNDP input data, ENTSOG has organized on 13 July 2016 a public workshop to share advanced information with stakeholders on the projects to be included in TYNDP 2017. The material provided in this public workshop, including a list of submitted projects, has been published on ENTSOG website[6)].

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1) http://www.entsog.eu/public/uploads/files/publications/TYNDP/2016/TYNDP042-16%20Project%20Data%20Portal%20Documentation%20Kit_ver1_2.zip
2) The "lesser-of-rule" is applied at interconnection points to ensure consistent technical capacity figures.
3) See note 1.
4) For each project, the commissioning year relates to the date when the first capacity increment of the project is commissioned in the case where there is more than one increment.
5) The amount in GWh/d of the new capacity at a specific point.
6) http://www.entsog.eu/events/6th-stakeholder-joint-working-session-sjws6-on-tyndp-2017#downloads

4.4 Project status and Infrastructure Levels

4.4.1 PROJECT STATUS

In the TYNDP 2015, projects are categorised along two different project status: FID and non-FID. In this edition the non-FID status has been sub-categorised into non-FID Advanced and non-FID Less-Advanced. Each project status is directly derived from the information provided by its promoter.

The **Advanced status** has been introduced in this edition based on the past TYNDP and on recommendations expressed by ACER in their Opinion[1)] on TYNDP 2015, to better reflect the different project maturities. This status has been defined in close cooperation with ACER and the European Commission, and in consultation with stakeholders. Based on this, projects of advanced status are defined as the ones that are planned to be commissioned within the next seven years[2)] and in addition either the front-end engineering design phase[3)] or permitting phase has been started.

4.4.2 INFRASTRUCTURE LEVELS

The project status are used to define three infrastructure levels. A fourth infrastructure level is considered in relation to the previous PCI list[4)]. These infrastructure levels are used in the TYNDP for the assessment of the European gas system.

- **Low Infrastructure Level:** existing Infrastructures + Infrastructure projects having a FID status (whatever their PCI status is)
- **Advanced Infrastructure Level:** existing infrastructures + Infrastructure projects having a FID status + Advanced non-FID projects
- **PCI 2nd list Infrastructure Level:** existing Infrastructures + Infrastructure projects having a FID status (whatever their PCI status is) + Infrastructure projects labelled PCIs according to the previous selection (not having their FID taken). This Infrastructure Level is handled in line with the CBA methodology in force, and consistently with what has been done in the previous edition, to build a bridge between two sequential PCI selection rounds and to enable the assessment of the cumulative effects of the 2nd list of PCI projects.
- **High Infrastructure Level:** existing Infrastructures + Infrastructure projects having a FID status (whatever their PCI status is) + Infrastructure projects not having a FID status (whatever their PCI status is)

The following figure illustrates the different Infrastructure Levels.

1) http://www.acer.europa.eu/official_documents/acts_of_the_agency/opinions/opinions/acer%20opinion%2011-2015.pdf
2) That is by 31 December 2022.
3) Projects having received TEN-E grants for FEED studies can be considered by promoters as fulfilling this criterion.
4) https://ec.europa.eu/energy/sites/ener/files/documents/5_2%20PCI%20annex.pdf

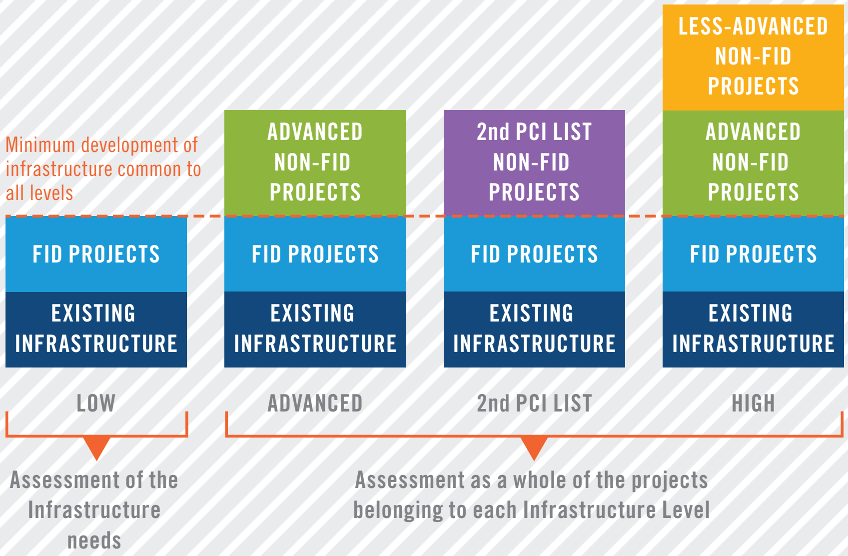

Figure 4.1: Infrastructure Levels

Based on the experience of TYNDP 2015 and 2nd PCI selection process, ENTSOG identified that the High Infrastructure level, due to the elevated number of competing initiatives included, had limited added-value, for both the TYNDP Energy System Wide assessment and the Project-Specific cost-benefit analysis of projects. However, the infrastructure level is maintained in line with the CBA methodology in force. Yet, following ACER Opinion on TYNDP 2015 on better and more realistic handling of projects, the Assessment Chapter covers the comprehensive evaluation of the Low, Advanced and 2nd PCI list Infrastructure Levels. Results of the assessment of the High Infrastructure Level are made available in Annex E.

In line with the TEN-E Regulation and the CBA methodology the TYNDP provides a common basis for the Project-Specific CBA of each PCI candidate (see Annex F). This involves the assessment of different infrastructure levels of the gas infrastructure based on the level of maturity and PCI status of the projects. The TYNDP will be used by the Regional Groups as a background when considering the Project Specific CBAs of the candidate projects for the 3rd PCI List.

4.5 Analysis of project submission

The full detail of projects submitted for inclusion in the TYNDP 2017 can be found in Annex A of this Report. This section of the report provides a general overview of the submitted projects.

4.5.1 TYPE OF INFRASTRUCTURES

Projects are classified according to infrastructure categories as defined in Reg. 347/2013 Annex II into the three following:

- **TRA** Transmission, incl. Compressor Stations
- **LNG** LNG Terminal
- **UGS** Storage Facility

4.5.2. OVERVIEW OF THE PROJECTS SUBMITTED TO TYNDP 2017

Overall, 234 projects have been submitted to the TYNDP 2017.

Some projects have been commissioned and new ones have appeared. Others have been postponed or not resubmitted.

This high level of projects has to be understood in the light of the following considerations.

- **Firstly:** If a project that has a number of separate parts, developed by more than one promoter, TYNDP considers this to be as many projects as there are promoters.
- **Secondly:** For projects developed in different phases, each phase can be considered as an individual project and the whole project as multiple projects.
- **Thirdly:** Some promoters have submitted individual facilities as separate projects (e.g. compressor station and pipe as individual project submissions) whereas others have joined together a number of schemes in one project (e.g. compressor station and pipe as a combined project submission).

Figure 4.2 provides the overview on those projects, compared to TYNDP 2015.

From the figure the following conclusions can be drawn:

- thanks to the completion of 20 projects the European infrastructure has been reinforced in the last two years
- the number of projects as of TYNDP 2015 were reduced for TYNDP 2017 by first of all completion but also by cancelation or not resubmissions[1].

1) However some projects have not been re-submitted under their TYNDP 2015 project code – therefore considered as not resubmitted - but under a new project code – therefore counted as new projects.

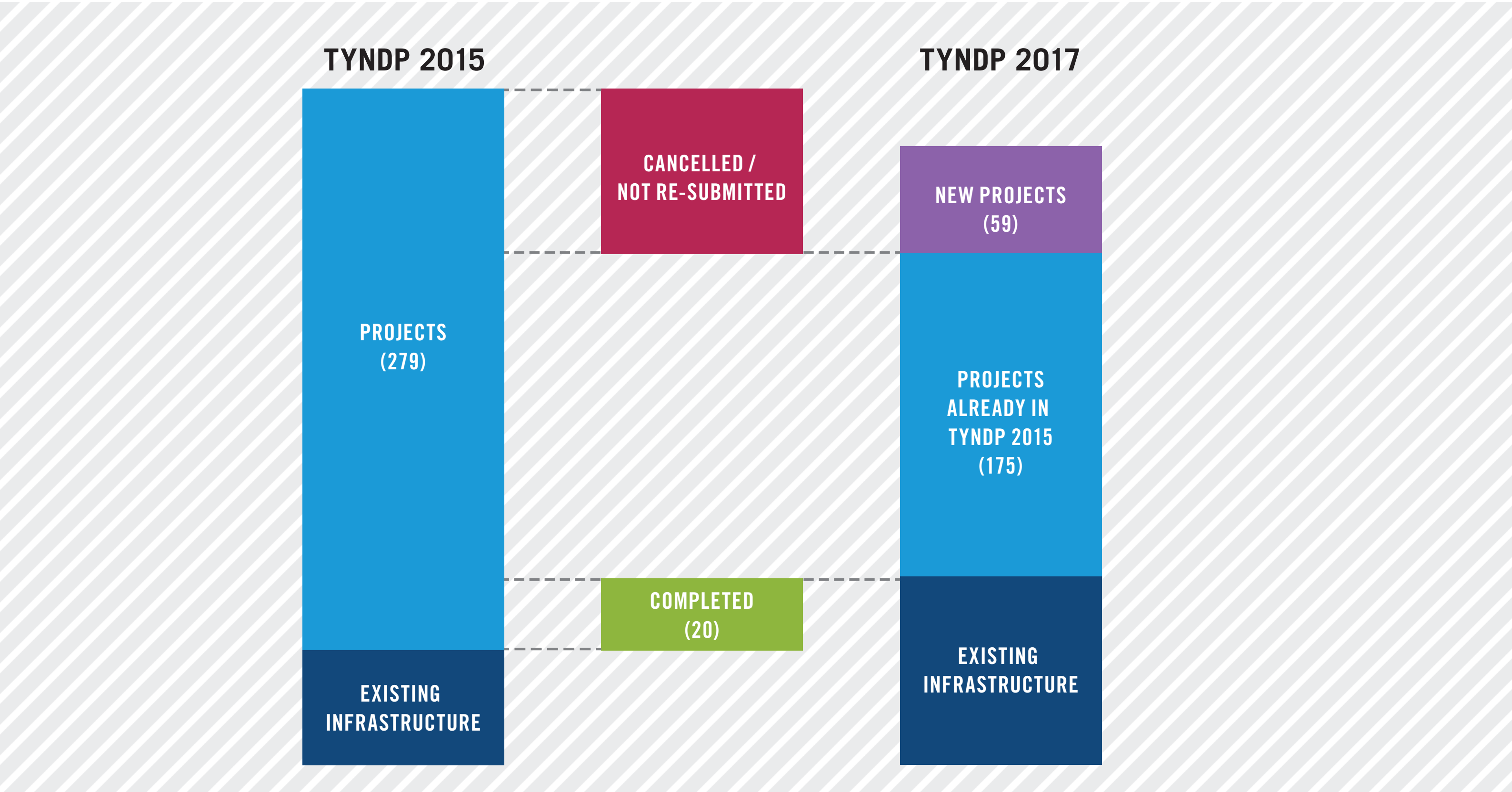

Figure 4.2: Comparison between TYNDP 2015 and TYNDP 2017

4.5.3 PROJECTS COMMISSIONED SINCE TYNDP 2015

The following map shows all projects from TYNDP 2015 that have been completed. Nine projects were from the PCI 1st List.

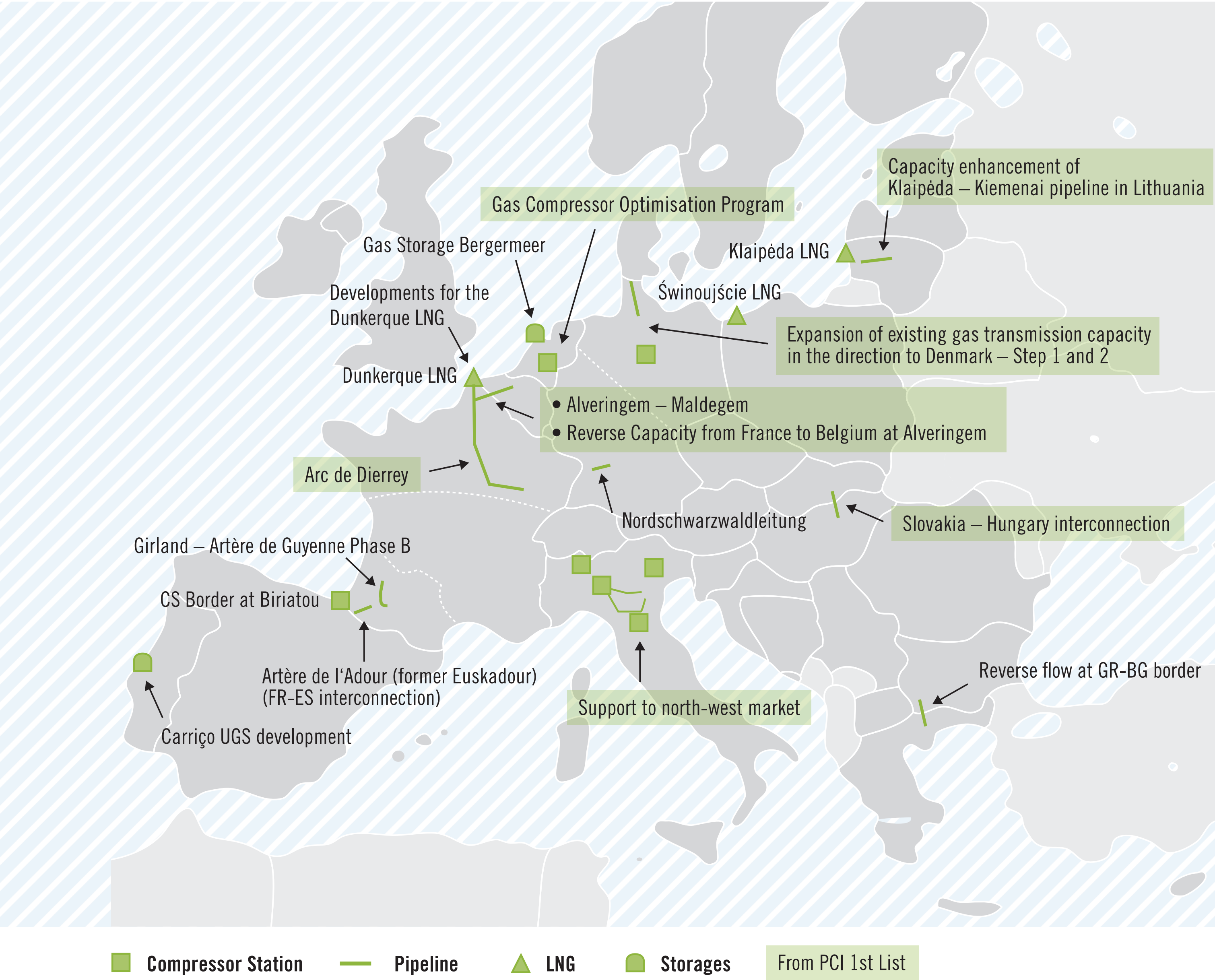

Figure 4.3: Map of commissioned projects between TYNDP 2015 and TYNDP 2017

4.5.4 OVERVIEW PER PROJECT STATUS

When compared to the 279 projects submitted for TYNDP 2015 we observe a reduction to 234 projects submitted for inclusion in the 2017 edition.

This reduction stems, in part, for the requirement introduced by ENTSOG for TYNDP 2017 that projects being part of the previous TYNDP need to be actively resubmitted to be part of the current TYNDP. This has allowed identifying projects that were not active anymore but for which promoters had missed to previously report the information to ENTSOG.

The following figures and tables provide a statistical overview of the projects (see Annex A for project details) based on information such as the type of infrastructure or the FID/PCI status. Those reports reflect all details entered as part of the data collection process explained above.

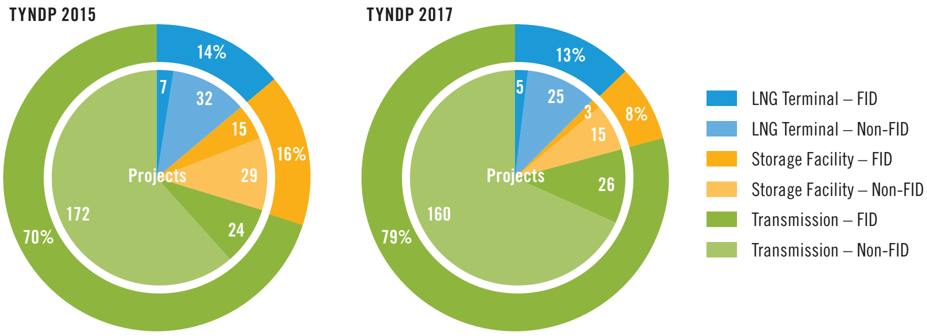

Figure 4.4: Comparison of project submission in TYNDP 2017 and TYNDP 2015 per type of infrastructure and FID status. The inner circle represents absolute numbers; the outer circle represents the share of each project type.

The above graph refers to the only two project status defined in TYNDP 2015: FID and non-FID. We observe a reduction in LNG and UGS projects, but an increase in pipeline projects. Around 60 % of new transmission projects refer to South-East Europe and the Baltic region. Several projects, especially for storage facilities, were cancelled or not re-submitted.

NUMBER OF PROJECTS FROM TYNDP 2015 COMPLETED, STILL PLANNED, NOT-RESUBMITTED AND CANCELLED

	UGS	LNG	TRA
COMPLETED	2	3	15
STILL PLANNED	15	26	134
NOT RE-SUBMITTED	14	5	7
CANCELLED	13	5	40

Table 4.1: Number of projects from TYNDP 2015 completed, still planned, not-resubmitted and cancelled

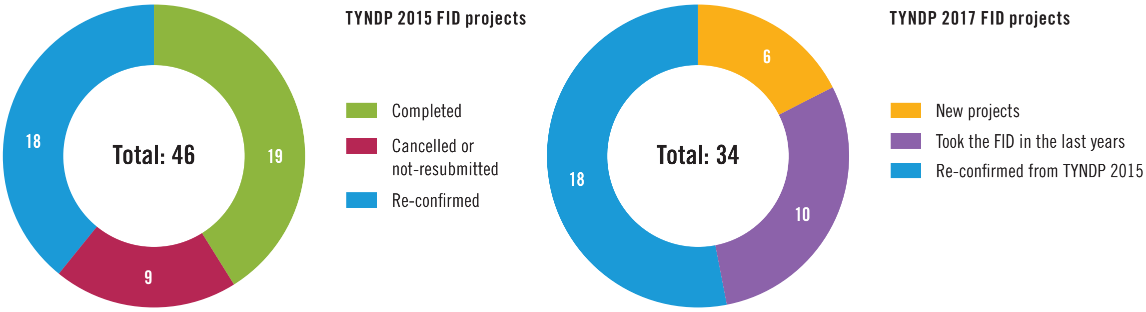

Figure 4.5: Comparison of project with FID status in TYNDP 2017 and TYNDP 2015

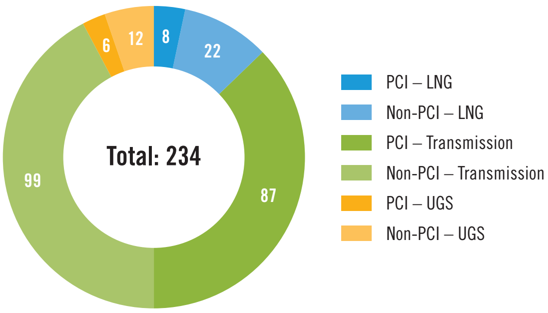

Figure 4.6: Breakdown of the projects in TYNDP 2017 per 2nd PCI List and per type of infrastructure

BREAKDOWN OF PROJECTS IN TYNDP 2017 BY FID STATUS AND PCI STATUS

	PCI	Non-PCI
FID	10	24
NON-FID	91	109
TOTAL	**101**	**133**

Table 4.2: Breakdown of projects in TYNDP 2017 by FID status and PCI status

The share of projects with FID status has slightly decreased with respect to the TYNDP 2015.

Among the submitted projects 10 projects with FID status and 91 projects with non-FID status are part of the 2nd PCI List.

As previously covered in this chapter, there are three defined project status (FID, Advanced Non-FID and Less Advanced Non-FID). Figure 4.7 shows the breakdown of the projects by status and type of infrastructure.

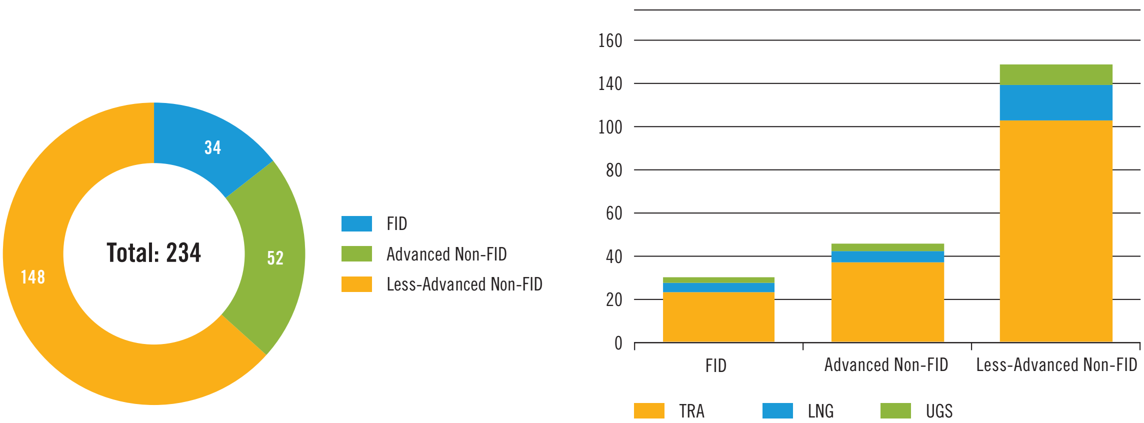

Figure 4.7: Breakdown of projects in TYNDP 2017 by infrastructure type and project status

4.5.5 OVERVIEW OF PROJECTS PER GEOGRAPHICAL LOCATION

The following charts provide a summary of projects based on their:

- geographical location
- infrastructure type
- project status.

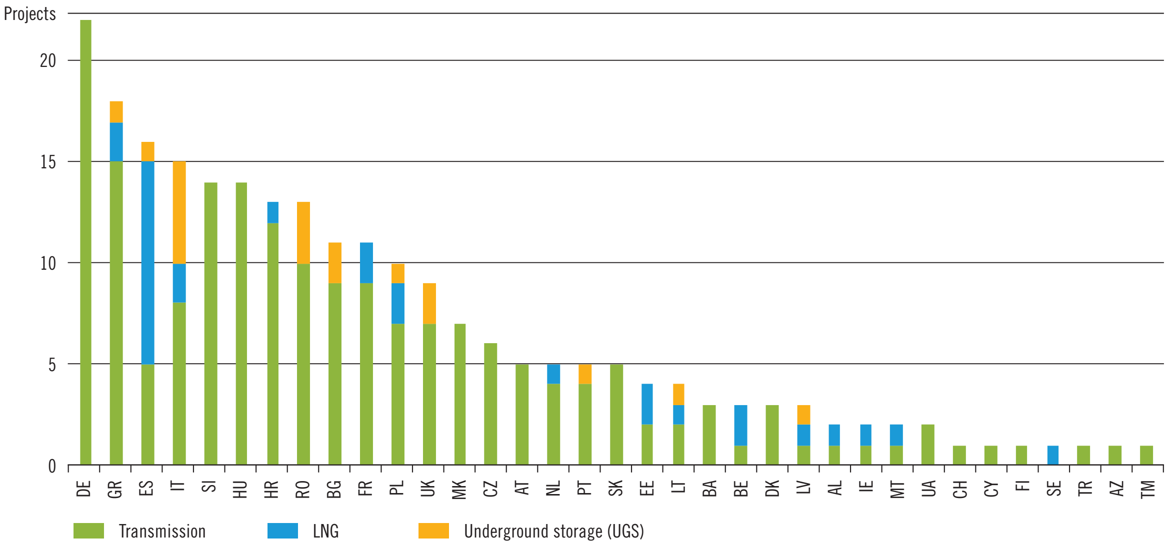

Figure 4.8: Number of projects per country and type

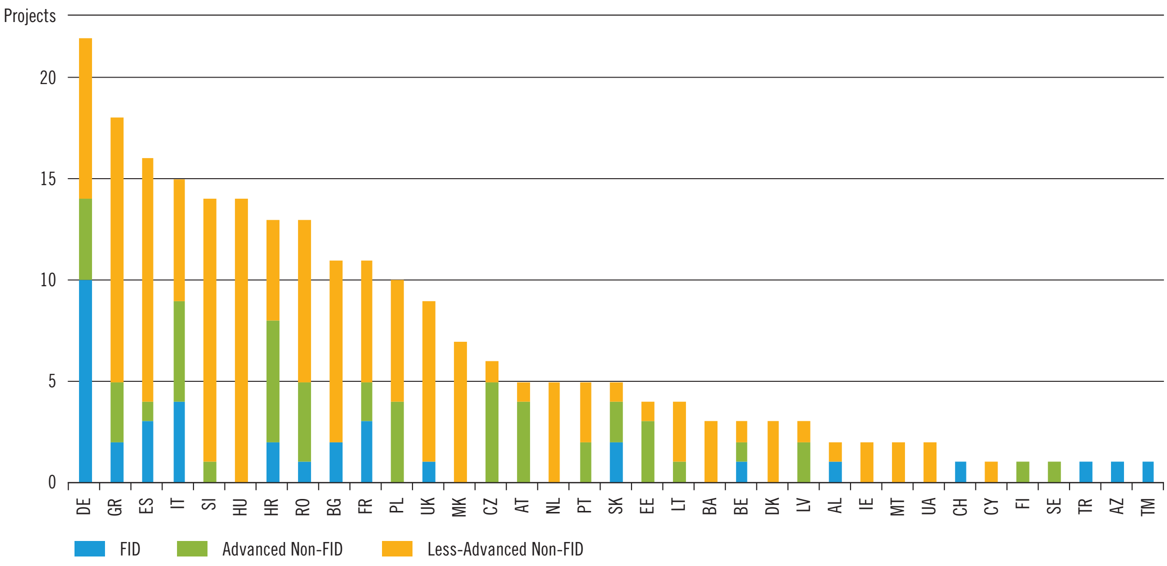

Figure 4.9: Number of projects per country and project status

Almost 43 % of submitted projects are planned in that countries that have joined most recently the European Union[1)], while only 8 % refers to non-EU Member State.

1) The European Union (EU) was established on 1 November 1993 with 12 Member States, and 3 other countries (Austria, Finland and Sweden) joined it. After 30th April 2004 the European Union was further enlarged to other 13 countries (with Croatia joining EU from 1st July 2013).

4.5.6 ANALYSIS OF PROJECTS SCHEDULE

Figure 4.10 and figure 4.11 show the distribution of submitted projects according to the expected commissioning year, also in an aggregated way.

The analysis of project submissions shows:

- An average of 10 months between the planned FID and the expected start of construction
- An average of 2 years and 2 months between the expected dates of start of construction and commissioning

The way FID is taken by each promoter may differ. Some may take FID after the granting of permits and some, before initiating the permitting procedure. Those permitting procedures often make out the longest phase of the whole project schedule which then often lasts more than 5 years. Moreover, the analysis is not necessarily indicative of the project lead time for any future projects as there are, among the projects, some small and some very complex ones.

ENTSOG has analysed the advancement of projects between TYNDP 2015 and TYNDP 2017. Out of the 234 projects included in TYNDP 2017, 175 were already part of TYNDP 2015 (FID and non-FID), from which 137 have reported an expected commissioning year in both editions.

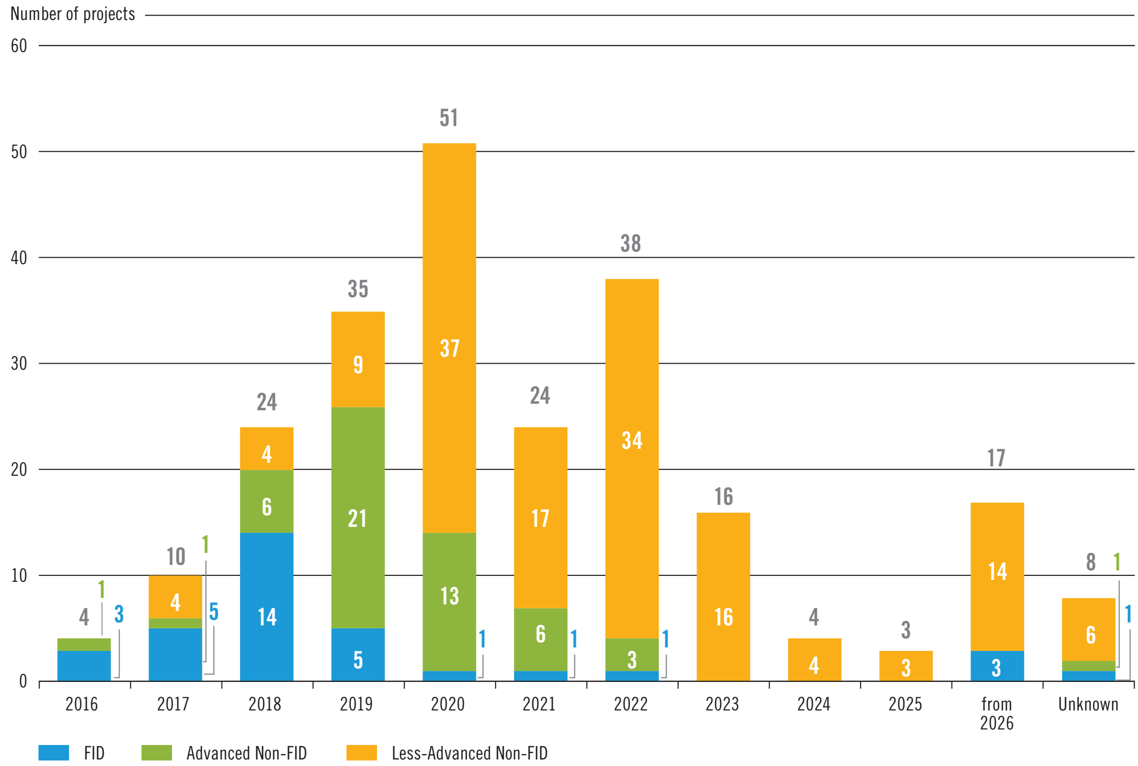

Figure 4.10: Projects by commissioning year and by project status

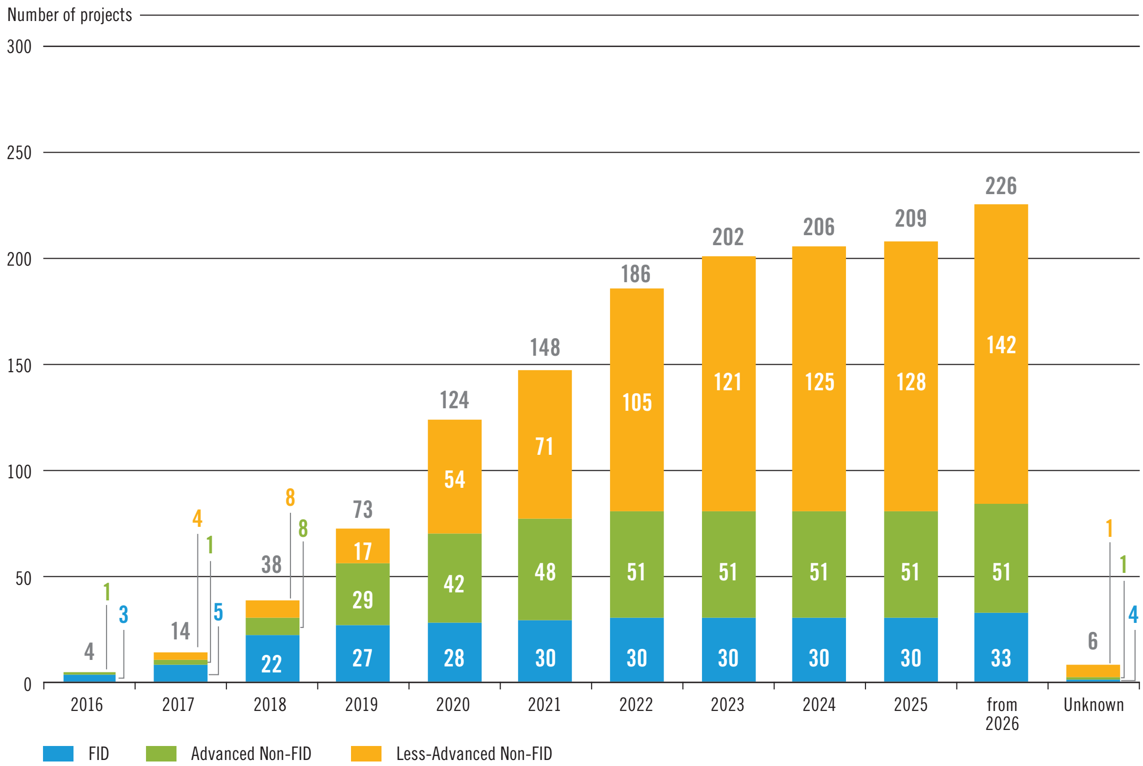

Figure 4.11: Projects by commissioning year (cumulative) and by infrastructure level

Figure 4.12 illustrates the status of those common projects according to TYNDP 2015 submission.

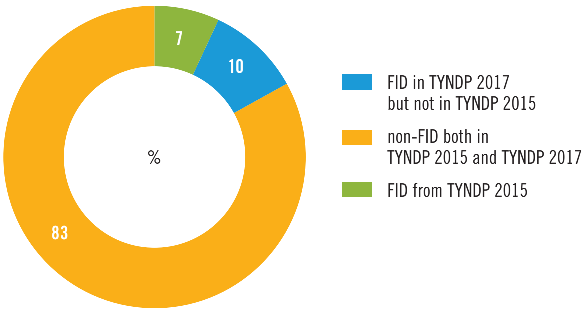

Figure 4.12: Status in TYNDP 2017 for the projects submitted to both TYNDPs 2015 and 2017

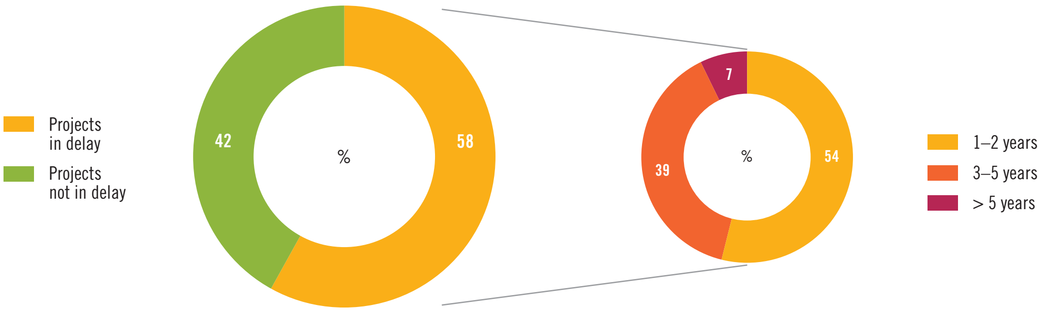

Figure 4.13: Share of common projects in TYNDP 2015 and TYNDP 2017 by commissioning status

The charts above illustrate the share of those projects for which a delay has been reported regarding their expected commissioning date and the length of this delay. Among the projects without delay, 8 projects have been submitted with an earlier commissioning date

More than half of the projects already submitted in TYNDP 2015 have reported experiencing delays since the last edition. Listed below are the main reasons for delays indicated by project promoters:

- worsened and uncertain market conditions
- delays in permitting/authorisations from competent authorities
- lack of coordination between hosting countries/political uncertainties
- delays in contract award procedure
- lack of funds/financing
- delay following findings from concluded pre-feasibility study

4.5.7 INVESTMENT COSTS

Investment costs are for project promoters in many cases commercially sensitive information and might have the potential to negatively affect the competitive position of project promoters vis-à-vis contractors.

However, as part of the transparency process adopted, ENTSOG has collected information from promoters on indicative investment costs for the submitted projects.

Given the sensitivity of the data, in this report this information is displayed only in an aggregated way.

Cost information is available for more than 90% of projects with FID or Advanced status. Figure 4.14 shows the total cost (CAPEX) per project status.[1)]

Costs are available for around 190 projects, for a total of around 86bn€. According to available information for FID and Advanced projects their total costs amount to approximately 45bn€. The distribution of the total expected CAPEX across different categories of projects is displayed in Figure 2.14. These sums include cost estimates derived by ENTSOG, where cost information was missing on the basis of provided project technical information[2)], and on ACER Report on Unit Investment Cost for Electricity and Gas[3)] published in July 2015.

Those figures are indicative. In the PS-CBA phase project costs will have to be specified in more detail for the financial and economic assessment.

According to project promoters' submission, investments are highly concentrated in 2018–2020, with around 60% of the total expected cost to be experienced in those years.

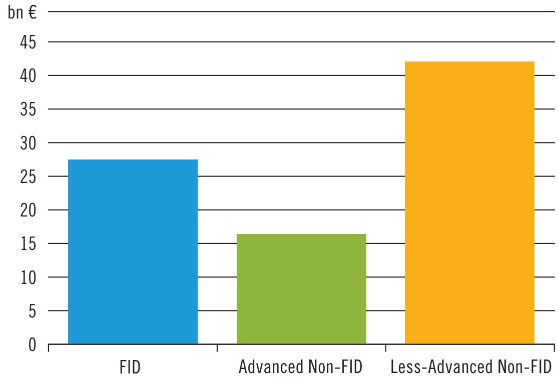

Figure 4.14: Overview of total cost by project status (Billion €)

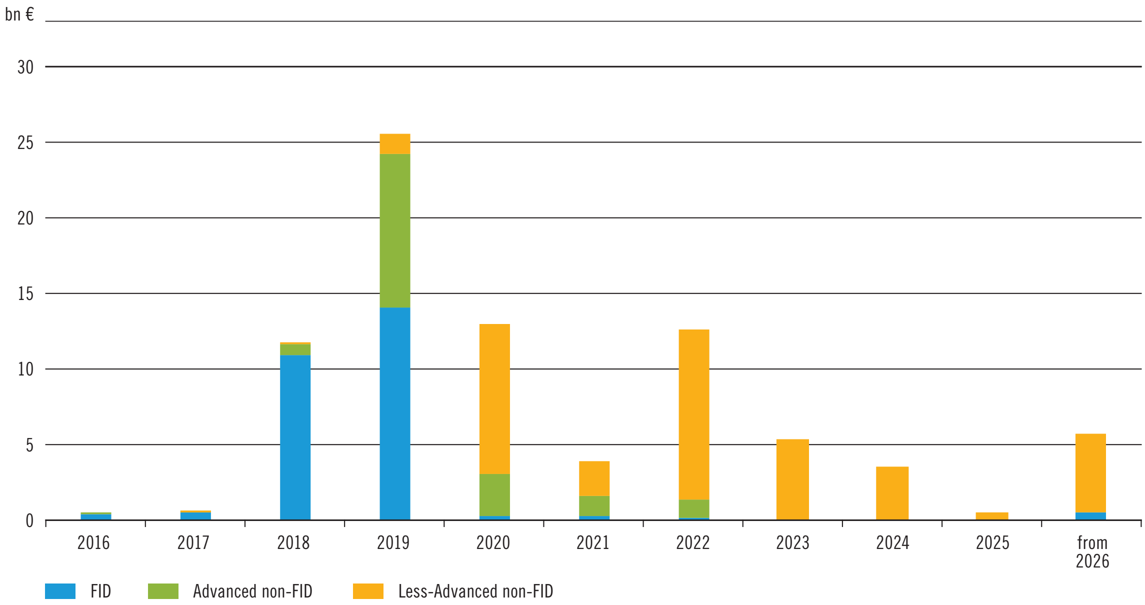

Figure 4.15: Overview of total cost by commissioning year (Billion €).

1) Promoters have provided a minimum and a maximum range for costs. The values reported in the TYNDP Report have been therfore calculated as average of those minimum and maximum values.
2) In cases where such information was not available costs could not be established.
3) http://www.acer.europa.eu/official_documents/acts_of_the_agency/publication/uic%20report%20-%20gas%20infrastructure.pdf


Image courtesy of GRTgaz

4.5.8 LIST OF PROJECTS

FID PROJECTS

Type	Code	Name	Country	Promoter	PCI 2nd List	Commission-ing Year
Pipeline including CS	TRA-F-334	Compressor station 1 at the Croatian gas transmission system	Croatia	Plinacro Ltd	Yes	2017
Pipeline including CS	TRA-F-241	MONACO section phase I (Burghausen-Finsing)	Germany	bayernets GmbH	No	2017
Pipeline including CS	TRA-F-291	NOWAL - Nord West Anbindungsleitung	Germany	GASCADE Gastransport GmbH	No	2017
Pipeline including CS	TRA-F-768	Extension Receiving Terminal Greifswald	Germany	NEL Gastransport, Fluxys Deutschland, Gasunie Deutschland	No	2017
LNG Terminal	LNG-F-147	Revythoussa (2nd upgrade)	Greece	DESFA S.A.	No	2017
Pipeline including CS	TRA-F-137	Interconnection Bulgaria – Serbia	Bulgaria	Ministry of Energy	Yes	2018
Pipeline including CS	TRA-F-378	Interconnector Greece-Bulgaria (IGB Project)	Bulgaria	ICGB a.d.	Yes	2018
Pipeline including CS	TRA-F-43	Val de Saône project	France	GRTgaz	Yes	2018
Pipeline including CS	TRA-F-45	Reverse capacity from CH to FR at Oltingue	France	GRTgaz	No	2018
Pipeline including CS	TRA-F-331	Gascogne Midi	France	TIGF - GRTgaz	Yes	2018
Pipeline including CS	TRA-F-208	Reverse Flow TENP Germany	Germany	Fluxys TENP GmbH & Open Grid Europe GmbH	Yes	2018
Pipeline including CS	TRA-F-337	CS Rothenstadt	Germany	GRTgaz Deutschland GmbH	No	2018
Pipeline including CS	TRA-F-343	Pipeline project "Schwandorf-Finsing"	Germany	Open Grid Europe GmbH	No	2018
Pipeline including CS	TRA-F-344	Compressor station "Herbstein"	Germany	Open Grid Europe GmbH	No	2018
Pipeline including CS	TRA-F-345	Compressor station "Werne"	Germany	Open Grid Europe GmbH	No	2018
Pipeline including CS	TRA-F-753	West to East operation of the IP Waidhaus	Germany	GRTgaz Deutschland GmbH	No	2018
Pipeline including CS	TRA-F-214	Support to the North West market and bidirectional cross-border flows	Italy	Snam Rete Gas S.p.A.	Yes	2018
Pipeline including CS	TRA-F-230	Reverse Flow Transitgas Switzerland	Switzerland	FluxSwiss	No	2018
Pipeline including CS	TRA-F-221	TANAP – Trans Anatolian Natural Gas Pipeline Project	Turkey	SOCAR (The State Oil Company of the Azerbaijan Republic)	Yes	2018
LNG Terminal	LNG-F-229	Zeebrugge LNG Terminal – 5th Tank & 2nd Jetty	Belgium	Fluxys LNG	No	2019
Pipeline including CS	TRA-F-86	Interconnection Croatia/Slovenia (Lučko – Zabok – Rogatec)	Croatia	Plinacro Ltd	Yes	2019
Pipeline including CS	TRA-F-937	Nord Stream 2	Germany	Nord Stream 2 AG	No	2019
Pipeline including CS	TRA-F-051	Trans Adriatic Pipeline	Greece	Trans Adriatic Pipeline AG	Yes	2019
Storage Facility	UGS-F-1045	Bordolano Second phase	Italy	STOGIT S.p.A.	No	2019
LNG Terminal	LNG-F-183	Tenerife LNG Terminal	Spain	Gascan	No	2020
LNG Terminal	LNG-F-163	Gran Canaria LNG Terminal	Spain	Gascan	No	2021
Pipeline including CS	TRA-F-1028	Albania - Kosovo Gas Pipeline	Albania	Min. of Energy and Industry of AL & Min. of Economic Development of KO	No	2022
Storage Facility	UGS-F-260	System Enhancements – Stogit – on-shore gas fields	Italy	STOGIT	No	2026
Pipeline including CS	TRA-F-017	System Enhancements – Eustream	Slovakia	eustream, a.s.	No	2026
LNG Terminal	LNG-F-178	Musel LNG terminal	Spain	Enagás Transporte, S.A.U.	No	2026
Pipeline including CS	TRA-F-025	Industrial Emissions Directive (IPPC) – FID	United Kingdom	National Grid Gas plc	No	Unknown

1) The 3 following projects were already commissioned by end 2016, and are therefore not reported in the table: Bordolano First Phase (UGS-F-259), Romania –Bulgaria Interconnection (TRA-F-029) and Exit Capacity Budince (TRA-F-1047).

ADVANCED NON-FID

Type	Code	Name	Country	Promoter	PCI 2nd List	Commissioning Year
Pipeline including CS	TRA-N-814	Upgrade IP Deutschneudorf and Lasow	Germany	ONTRAS Gastransport GmbH	No	2016
Storage Facility	UGS-N-235	Nuovi Sviluppi Edison Stoccaggio	Italy	Edison Stoccaggio S.p.A.	No	2017
LNG Terminal	LNG-N-082	LNG terminal Krk	Croatia	LNG Hrvatska d.o.o. za poslovanje ukapljenim prirodnim plinom	Yes	2018
Pipeline including CS	TRA-N-90	LNG evacuation pipeline Omišalj – Zlobin (Croatia)	Croatia	Plinacro Ltd	No	2018
Pipeline including CS	TRA-N-429	Adaptation L-gas – H-gas	France	GRTgaz, GRDF and Storengy	No	2018
LNG Terminal	LNG-N-062	LNG terminal in northern Greece/Alexandroupolis – LNG Section	Greece	Gastrade S.A.	Yes	2018
Pipeline including CS	TRA-N-063	LNG terminal in northern Greece/Alexandroupolis – Pipeline Section	Greece	Gastrade S.A.	Yes	2018
Pipeline including CS	TRA-N-357	NTS developments in North-East Romania	Romania	SNTGN Transgaz SA	No	2018
Pipeline including CS	TRA-N-361	GCA 2015/08: Entry/Exit Murfeld	Austria	GAS CONNECT AUSTRIA GmbH	Yes	2019
Pipeline including CS	TRA-N-066	Interconnection Croatia – Bosnia and Herzegovina (Slobodnica – Bosanski Brod)	Croatia	Plinacro Ltd	No	2019
Pipeline including CS	TRA-N-136	Poland – Czech Republic Interconnection (CZ)	Czech Rep.	NET4GAS, s.r.o.	Yes	2019
Pipeline including CS	TRA-N-752	Capacity4Gas (C4G) – DE/CZ	Czech Rep.	NET4GAS, s.r.o.	No	2019
Pipeline including CS	TRA-N-918	Capacity4Gas (C4G) – CZ/SK	Czech Rep.	NET4GAS, s.r.o.	No	2019
Pipeline including CS	TRA-N-895	Balticconnector	Estonia	Elering AS	Yes	2019
Pipeline including CS	TRA-N-915	Enhancement of Estonia-Latvia interconnection	Estonia	Elering AS	Yes	2019
Pipeline including CS	TRA-N-928	Balticconnector Finnish part	Finland	Baltic Connector Oy	Yes	2019
Pipeline including CS	TRA-N-763	EUGAL –– Europäische Gasanbindungsleitung (European Gaslink)	Germany	GASCADE Gastransport GmbH	No	2019
Pipeline including CS	TRA-N-012	GALSI Pipeline Project	Italy	Galsi S.p.A.	Yes	2019
Storage Facility	UGS-N-237	Palazzo Moroni	Italy	Edison Stoccaggio S.p.A	No	2019
Storage Facility	UGS-N-374	Enhancement of Incukalns UGS	Latvia	JSC "Latvijas Gāze"	Yes	2019
LNG Terminal	LNG-N-912	Skulte LNG	Latvia	AS Skulte LNG Terminal	No	2019
Pipeline including CS	TRA-N-341	Gas Interconnection Poland-Lithuania (GIPL) (Lithuania's section)	Lithuania	AB Amber Grid	Yes	2019
Pipeline including CS	TRA-N-212	Gas Interconnection Poland-Lithuania (GIPL) (PL section)	Poland	GAZ-SYSTEM S.A.	Yes	2019
Pipeline including CS	TRA-N-247	North – South Gas Corridor in Western Poland	Poland	GAZ-SYSTEM S.A.	Yes	2019
Pipeline including CS	TRA-N-273	Poland – Czech Republic interconnection (PL section)	Poland	GAZ-SYSTEM S.A.	Yes	2019
Pipeline including CS	TRA-N-275	Poland – Slovakia interconnection (PL section)	Poland	GAZ-SYSTEM S.A.	Yes	2019
Storage Facility	UGS-N-233	Depomures	Romania	Engie Romania SA	Yes	2019
Pipeline including CS	TRA-N-190	Poland – Slovakia interconnection	Slovakia	eustream, a.s.	Yes	2019
Pipeline including CS	TRA-N-902	Capacity increase at IP Lanžhot entry	Slovakia	eustream, a.s.	No	2019
Pipeline including CS	TRA-N-021	Bidirectional Austrian – Czech Interconnector (BACI, formerly LBL project)	Austria	GAS CONNECT AUSTRIA GmbH	Yes	2020
Pipeline including CS	TRA-N-423	GCA Mosonmagyaróvár	Austria	GAS CONNECT AUSTRIA GmbH	Yes	2020
Pipeline including CS	TRA-N-801	Břeclav – Baumgarten Interconnection (BBI) AT	Austria	GAS CONNECT AUSTRIA GmbH	No	2020
Pipeline including CS	TRA-N-500	L/H Conversion	Belgium	Fluxys Belgium	No	2020
Pipeline including CS	TRA-N-075	LNG evacuation pipeline Zlobin – Bosiljevo – Sisak – Kozarac	Croatia	Plinacro Ltd	Yes	2020
Pipeline including CS	TRA-N-133	Bidirectional Austrian Czech Interconnection (BACI)	Czech Rep.	NET4GAS, s.r.o.	Yes	2020
Pipeline including CS	TRA-N-919	Capacity4Gas (C4G) – CZ/AT	Czech Rep.	NET4GAS, s.r.o.	No	2020
LNG Terminal	LNG-N-079	Paldiski LNG Terminal	Estonia	Balti Gaas plc	Yes	2020

ADVANCED NON-FID

Type	Code	Name	Country	Promoter	PCI 2nd List	Commissioning Year
Pipeline including CS	TRA-N-807	Expansion NEL	Germany	Gasunie Deutschland, NEL Gastransport, Fluxys Deutschland	No	2020
Pipeline including CS	TRA-N-010	Poseidon Pipeline	Greece	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Yes	2020
Pipeline including CS	TRA-N-358	Development on the Romanian territory of the NTS (BG – RO – HU – AT Corridor)	Romania	SNTGN Transgaz S.A.	Yes	2020
Pipeline including CS	TRA-N-362	Development on the Romanian territory of the Southern Transmission Corridor	Romania	SNTGN Transgaz SA	Yes	2020
Pipeline including CS	TRA-N-390	Upgrade of Rogatec interconnection (M1A/1 Interconnection Rogatec)	Slovenia	Plinovodi d.o.o.	Yes	2020
LNG Terminal	LNG-N-032	Project GO4LNG LNG terminal Gothenburg	Sweden	Swedegas AB	Yes	2020
Pipeline including CS	TRA-N-302	Interconnection Croatia-Bosnia and Herzegovina (South)	Croatia	Plinacro Ltd	No	2021
Pipeline including CS	TRA-N-808	Transport of gas volumes to the Netherlands	Germany	Gasunie Deutschland Technical Services GmbH	No	2021
LNG Terminal	LNG-N-198	Porto Empedocle LNG	Italy	Nuove Energie S.r.l.	No	2021
Pipeline including CS	TRA-N-283	3rd IP between Portugal and Spain (pipeline Celorico – Spanish border)	Portugal	REN-Gasodutos, S.A.	Yes	2021
Pipeline including CS	TRA-N-320	Carregado Compressor Station	Portugal	REN-Gasodutos, S.A.	No	2021
Pipeline including CS	TRA-N-161	South Transit East Pyrenees (STEP) – ENAGÁS	Spain	Enagás Transporte, S.A.U.	Yes	2021
Pipeline including CS	TRA-N-068	Ionian Adriatic Pipeline	Croatia	Plinacro Ltd	No	2022
Pipeline including CS	TRA-N-252	South Transit East Pyrenees (STEP) – TIGF	France	TIGF	Yes	2022
Pipeline including CS	TRA-N-974	LARINO – RECANATI Adriatic coast backbone	Italy	Società Gasdotti Italia	No	2022

LESS-ADVANCED NON-FID

Type	Code	Name	Country	Promoter	PCI 2nd List	Commissioning Year
Pipeline including CS	TRA-N-524	Enhancement of Transmission Capacity of Slovak – Hungarian interconnector	Hungary	Magyar Gáz Tranzit Zrt.	Yes	2017
Pipeline including CS	TRA-N-636	Development of Transmission Capacity at Slovak – Hungarian interconnector	Hungary	Magyar Gáz Tranzit Zrt.	Yes	2017
Pipeline including CS	TRA-N-645	HU – UA Interconnector (Ukrainian section)	Ukraine	PJSC Ukrtransgaz	No	2017
Pipeline including CS	TRA-N-660	Gas to the West	United Kingdom	West Transmission Limited	No	2017
Pipeline including CS	TRA-N-954	TAG Reverse Flow	Austria	Trans Austria Gasleitung GmbH	No	2018
Pipeline including CS	TRA-N-379	A project for the construction of a gas pipeline BG-RO	Bulgaria	Bulgartransgaz EAD	Yes	2018
Pipeline including CS	TRA-N-545	Infrastructure gas pipeline Skopje – Tetovo – Gostivar – Albanian border	FYROM	GA-MA joint stock company Skopje	No	2018
Storage Facility	UGS-N-203	Preesall Gas Storage	United Kingdom	Halite Energy Group Ltd	No	2018
LNG Terminal	LNG-N-962	Tallinn LNG	Estonia	Vopak E.O.S. AS / Vopak LNG Holdings B.V/ Port of Tallinn AS	Yes	2019
Pipeline including CS	TRA-N-582	Macedonian part of Tesla project	FYROM	GA-MA joint stock company Skopje	Yes	2019
Pipeline including CS	TRA-N-340	VDS Wertingen	Germany	bayernets GmbH	No	2019
Pipeline including CS	TRA-N-941	Metering and Regulating station at Nea Messimvria	Greece	DESFA S.A.	Yes	2019
Storage Facility	UGS-N-034	Syderiai	Lithuania	JSC Lietuvos energija AB	No	2019
Pipeline including CS	TRA-N-139	Interconnection of the NTS with the DTS and reverse flow at Isaccea	Romania	SNTGN Transgaz SA	Yes	2019
Pipeline including CS	TRA-N-964	New NTS developments for taking over gas from the Black Sea shore	Romania	SNTGN Transgaz SA	No	2019
Pipeline including CS	TRA-N-365	M6 Ajdovščina – Lucija	Slovenia	Plinovodi d.o.o.	No	2019

LESS-ADVANCED NON-FID

Type	Code	Name	Country	Promoter	PCI 2nd List	Commission-ing Year
Pipeline including CS	TRA-N-561	Poland-Ukraine Interconnector (Ukrainian section)	Ukraine	PJSC Ukrtransgaz	No	2019
LNG Terminal	LNG-N-328	Eagle LNG and Pipeline	Albania	Burns Srl	No	2020
Pipeline including CS	TRA-N-140	Interconnection Turkey-Bulgaria	Bulgaria	Bulgartransgaz EAD	Yes	2020
Pipeline including CS	TRA-N-298	Rehabilitation, Modernisation and Expansion of the NTS	Bulgaria	Bulgartransgaz EAD	Yes	2020
Pipeline including CS	TRA-N-1057	Compressor stations 2 and 3 at the Croatian gas transmission system	Croatia	Plinacro Ltd	Yes	2020
Pipeline including CS	TRA-N-1146	Cyprus Gas2EU	Cyprus	Ministry of Energy, Commerce, Industry and Tourism	Yes	2020
LNG Terminal	LNG-N-225	Montoir LNG Terminal Expansion	France	Elengy	No	2020
LNG Terminal	LNG-N-227	Fos Cavaou LNG Terminal Expansion	France	Fosmax LNG	No	2020
Pipeline including CS	TRA-N-949	Oude(NL) – Bunde(DE) GTG H-Gas	Germany	Gastransport Nord GmbH	No	2020
Pipeline including CS	TRA-N-951	Embedding CS Folmhusen in H-Gas	Germany	Gasunie Deutschland Transport Services GmbH	No	2020
Pipeline including CS	TRA-N-128	Compressor Station Kipi	Greece	DESFA S.A.	Yes	2020
Pipeline including CS	TRA-N-330	EastMed Pipeline	Greece	Natural Gas Submarine Interconnector Greece-Italy Poseidon S.A	Yes	2020
Pipeline including CS	TRA-N-631	Greek part of Tesla project	Greece	DESFA S.A.	Yes	2020
Pipeline including CS	TRA-N-940	Metering and Regulating station at Komotini	Greece	DESFA S.A.	Yes	2020
Pipeline including CS	TRA-N-957	Metering Station at Komotini to IGB	Greece	DESFA S.A.	No	2020
Pipeline including CS	TRA-N-967	Nea-Messimvria to FYROM pipeline	Greece	DESFA S.A.	No	2020
Pipeline including CS	TRA-N-1090	Metering and Regulating Station at Alexandroupoli	Greece	DESFA S.A.	No	2020
Pipeline including CS	TRA-N-286	Romanian-Hungarian reverse flow Hungarian section 1st stage	Hungary	FGSZ Ltd.	Yes	2020
Pipeline including CS	TRA-N-325	Slovenian-Hungarian interconnector	Hungary	FGSZ Ltd.	Yes	2020
Pipeline including CS	TRA-N-585	Hungarian section of Tesla project	Hungary	FGSZ Ltd.	Yes	2020
Pipeline including CS	TRA-N-586	HU-UA reverse flow	Hungary	FGSZ Ltd.	No	2020
Pipeline including CS	TRA-N-382	Enhancement of Latvia-Lithuania interconnection (Latvian part)	Latvia	JSC "Latvijas Gaze"	Yes	2020
Pipeline including CS	TRA-N-342	Enhancement of Latvia-Lithuania interconnection (Lithuania's part)	Lithuania	AB Amber Grid	Yes	2020
LNG Terminal	LNG-N-050	Gate terminal phase 3	Netherlands	Gate	No	2020
Pipeline including CS	TRA-N-191	Blending	Netherlands	Gasunie Transport Services B.V.	No	2020
Pipeline including CS	TRA-N-192	Entry capacity expansion GATE terminal	Netherlands	Gasunie Transport Services B.V.	No	2020
Pipeline including CS	TRA-N-882	H-gas conversion of L-gas export border points	Netherlands	Gasunie Transport Services B.V.	No	2020
LNG Terminal	LNG-N-272	Upgrade of LNG terminal in Świnoujście	Poland	GAZ-SYSTEM S.A.	Yes	2020
Pipeline including CS	TRA-N-621	Poland – Ukraine Gas interconnection (PL section)	Poland	GAZ-SYSTEM S.A.	No	2020
LNG Terminal	LNG-N-947	FSRU Polish Baltic Sea Coast	Poland	GAZ-SYSTEM S.A.	No	2020
Pipeline including CS	TRA-N-094	CS Kidričevo, 2nd phase of upgrade	Slovenia	Plinovodi d.o.o.	Yes	2020
Pipeline including CS	TRA-N-108	M3 pipeline reconstruction from CS Ajdovščina to Šempeter/Gorizia	Slovenia	Plinovodi d.o.o.	No	2020
Pipeline including CS	TRA-N-112	R15/1 Pince – Lendava – Kidričevo	Slovenia	Plinovodi d.o.o.	Yes	2020
Pipeline including CS	TRA-N-389	Upgrade of Murfeld/Ceršak interconnection (M1/3 Interconnection Ceršak)	Slovenia	Plinovodi d.o.o.	Yes	2020
LNG Terminal	LNG-N-296	Mugardos LNG Terminal: 2nd Jetty	Spain	Reganosa	No	2020
Pipeline including CS	TRA-N-950	Guitiriz – Zamora pipeline	Spain	Reganosa	No	2020
Pipeline including CS	TRA-N-829	PCI 5.1.1 Physical Reverse Flow at Moffat interconnection point (IE/UK)	United Kingdom	GNI (UK) Limited	Yes	2020

LESS-ADVANCED NON-FID

Type	Code	Name	Country	Promoter	PCI 2nd List	Commission-ing Year
Pipeline including CS	TRA-N-1064	Moffat Physical Reverse Flow	United Kingdom	National Grid Gas plc	Yes	2020
Pipeline including CS	TRA-N-1138	South Caucasus Pipeline Future Expansion – SCPFX	Azerbaijan	SOCAR Midstream Operations LLC	Yes	2021
Pipeline including CS	TRA-N-851	Southern Interconnection pipeline BiH/CRO	Bosnia and Herzegovina	BH-GAS d.o.o.	No	2021
Pipeline including CS	TRA-N-654	Eastring – Bulgaria	Bulgaria	Bulgartransgaz EAD	Yes	2021
Pipeline including CS	TRA-N-965	Interconnection Macedonia-Serbia	FYROM	MER JSC Skopje	No	2021
Pipeline including CS	TRA-N-976	Interconnection Macedonia-Bulgaria	FYROM	MER JSC Skopje	No	2021
Pipeline including CS	TRA-N-980	Interconnection Macedonia-Greece	FYROM	MER JSC Skopje	No	2021
Pipeline including CS	TRA-N-329	ZEELINK	Germany	Open Grid Europe GmbH	No	2021
Pipeline including CS	TRA-N-656	Eastring – Hungary	Hungary	FGSZ Ltd.	Yes	2021
Pipeline including CS	TRA-N-831	Vecsés – Városföld gas transit pipeline	Hungary	Magyar Gáz Tranzit Zrt.	No	2021
LNG Terminal	LNG-N-217	Onshore LNG terminal in the Northern Adriatic	Italy	Gas Natural Rigassificazione Italia	No	2021
Pipeline including CS	TRA-N-873	Capacity expansion OSZ related to West Stream	Netherlands	Gasunie Transport Services B.V.	No	2021
Pipeline including CS	TRA-N-655	Eastring – Romania	Romania	SNTGN Transgaz SA	Yes	2021
Pipeline including CS	TRA-N-628	Eastring – Slovakia	Slovakia	Eastring B.V.	Yes	2021
Pipeline including CS	TRA-N-092	CS Ajdovščina, 1st phase of upgrade	Slovenia	Plinovodi d.o.o.	No	2021
Pipeline including CS	TRA-N-168	Interconnection ES-PT (3rd IP) – 1st phase	Spain	Enagás Transporte, S.A.U.	Yes	2021
Pipeline including CS	TRA-N-027	Physical reverse flow from NI to GB and IE via SNIP pipeline	United Kingdom	Premier Transmission Limited	Yes	2021
Storage Facility	UGS-N-294	Islandmagee Gas Storage Facility	United Kingdom	Islandmagee Storage Limited	Yes	2021
LNG Terminal	LNG-N-742	Zeebrugge LNG Terminal – 3rd Jetty	Belgium	Fluxys LNG	No	2022
Storage Facility	UGS-N-138	UGS Chiren Expansion	Bulgaria	Bulgartransgaz EAD	Yes	2022
Pipeline including CS	TRA-N-592	Looping CS Valchi Dol – Line valve Novi Iskar	Bulgaria	Bulgartransgaz EAD	Yes	2022
Pipeline including CS	TRA-N-593	Varna-Oryahovo gas pipeline	Bulgaria	Bulgartransgaz EAD	Yes	2022
Pipeline including CS	TRA-N-594	Construction of a Looping CS Provadia – Rupcha village	Bulgaria	Bulgartransgaz EAD	Yes	2022
Pipeline including CS	TRA-N-135	Connection to Oberkappel	Czech Republic	NET4GAS, s.r.o.	No	2022
Pipeline including CS	TRA-N-394	Gassled – Danish upstream system	Denmark	Energinet.dk	No	2022
Pipeline including CS	TRA-N-428	(Mirror) Baltic Pipe	Denmark	Energinet.dk	Yes	2022
Pipeline including CS	TRA-N-780	Nybro-Interconnector PL – DK – reinforcement	Denmark	Energinet.dk	No	2022
Pipeline including CS	TRA-N-966	Interconnection Macedonia – Kosovo	FYROM	MER JSC Skopje	No	2022
Pipeline including CS	TRA-N-998	Interconnection Macedonia – Albania	FYROM	MER JSC Skopje	No	2022
Pipeline including CS	TRA-N-047	Reverse capacity from France to Germany at Obergailbach	France	GRTgaz	Yes	2022
Pipeline including CS	TRA-N-258	Developments for Montoir LNG terminal 2.5 bcm expansion	France	GRTgaz	No	2022
Pipeline including CS	TRA-N-269	Developments for Fosmax (Cavaou) LNG 8.25 bcm expansion	France	GRTgaz	No	2022
Storage Facility	UGS-N-385	South Kavala Underground Gas Storage facility	Greece	Hellenic Republic Asset anagement Fund	No	2022
Pipeline including CS	TRA-N-971	Compressor station at Nea Messimvria	Greece	DESFA S.A.	No	2022
Pipeline including CS	TRA-N-1091	Metering and Regulating station at Megalopoli	Greece	DESFA S.A.	No	2022
Pipeline including CS	TRA-N-018	Városföld – Ercsi – Győr	Hungary	FGSZ Ltd.	Yes	2022
Pipeline including CS	TRA-N-061	Ercsi – Szazhalombatta	Hungary	FGSZ Ltd.	Yes	2022

LESS-ADVANCED NON-FID

Type	Code	Name	Country	Promoter	PCI 2nd List	Commissioning Year
Pipeline including CS	TRA-N-123	Városföld CS	Hungary	FGSZ Ltd.	Yes	2022
Pipeline including CS	TRA-N-377	Romanian – Hungarian reverse flow Hungarian section 2nd stage	Hungary	FGSZ Ltd.	Yes	2022
Pipeline including CS	TRA-N-071	Physical Reverse Flow on South North Pipeline	Ireland	Gas Networks Ireland	No	2022
Pipeline including CS	TRA-N-271	Poland - Denmark interconnection (Baltic Pipe) – PL section	Poland	GAZ-SYSTEM S.A.	Yes	2022
Storage Facility	UGS-N-659	RENC-8 Carriço UGS cavern	Portugal	REN - Armazenagem, S.A.	No	2022
Pipeline including CS	TRA-N-053	White Stream	Romania	White Stream Ltd	No	2022
Storage Facility	UGS-N-371	Sarmasel undeground gas storage in Romania	Romania	Societatea Națională de Gaze Naturale ROMGAZ S.A.	Yes	2022
Pipeline including CS	TRA-N-093	CS Ajdovščina, 2nd phase of upgrade	Slovenia	Plinovodi d.o.o.	No	2022
Pipeline including CS	TRA-N-099	M3/1a Šempeter – Ajdovščina	Slovenia	Plinovodi d.o.o.	No	2022
Pipeline including CS	TRA-N-101	M8 Kalce – Jelšane	Slovenia	Plinovodi d.o.o.	No	2022
Pipeline including CS	TRA-N-107	M6 Interconnection Osp	Slovenia	Plinovodi d.o.o.	No	2022
Pipeline including CS	TRA-N-261	M3/1c Kalce – Vodice	Slovenia	Plinovodi d.o.o.	No	2022
Pipeline including CS	TRA-N-262	M3/1b Ajdovščina – Kalce	Slovenia	Plinovodi d.o.o.	No	2022
LNG Terminal	LNG-N-297	Mugardos LNG Terminal: Storage Extension	Spain	Reganosa	No	2022
Pipeline including CS	TRA-N-727	Iberian – French corridor: Eastern Axis – Midcat Project	Spain	Enagás Transporte, S.A.U.	Yes	2022
Pipeline including CS	TRA-N-224	Gaspipeline Brod – Zenica	Bosnia and Herzegovina	BH-Gas d.o.o.	No	2023
Pipeline including CS	TRA-N-910	Western interconnection BiH/CRO	Bosnia and Herzegovina	BH-Gas d.o.o.	No	2023
Pipeline including CS	TRA-N-070	Interconnection Croatia/Serbia (Slobdnica – Sotin – Bačko Novo Selo)	Croatia	Plinacro Ltd	No	2023
Pipeline including CS	TRA-N-1058	LNG Evacuation Pipeline Kozarac – Slobodnica	Croatia	Plinacro Ltd	Yes	2023
Pipeline including CS	TRA-N-755	CS Rimpar	Germany	GRTgaz Deutschland GmbH	No	2023
Pipeline including CS	TRA-N-809	Additional East-West transport NL	Germany	Gasunie Deutschland Transport Services GmbH	No	2023
Pipeline including CS	TRA-N-825	Compressor station “Legden”	Germany	Open Grid Europe GmbH	No	2023
Pipeline including CS	TRA-N-014	Komotini-Thesprotia pipeline	Greece	DESFA S.A.	Yes	2023
Pipeline including CS	TRA-N-1092	Metering and Regulating Station at UGS South Kavala	Greece	DESFA S.A.	No	2023
Pipeline including CS	TRA-N-007	Development for new import from the South (Adriatica Line)	Italy	Snam Rete Gas S.p.A.	Yes	2023
Pipeline including CS	TRA-N-354	Interconnection with Slovenia	Italy	Snam Rete Gas S.p.A.	No	2023
Pipeline including CS	TRA-N-245	North – South Gas Corridor in Eastern Poland	Poland	GAZ-SYSTEM S.A.	Yes	2023
Storage Facility	UGS-N-366	New undergound gas storage in Romania	Romania	Societatea Națională de Gaze Naturale ROMGAZ S.A.	Yes	2023
Pipeline including CS	TRA-N-959	Further enlargement of the BG – RO – HU – AT transmission corridor (BRUA) phase 3	Romania	SNTGN Transgaz SA	Yes	2023
Storage Facility	UGS-N-127	Underground Gas Storage in salt leached caverns in the Bages area (ES)	Spain	Gas Natural	No	2023
LNG Terminal	LNG-N-295	Mugardos LNG Terminal: Send-out Increase	Spain	Reganosa	No	2023
Pipeline including CS	TRA-N-256	Iberian-French corridor: Eastern Axis – Midcat Project	France	GRTgaz and TIGF	Yes	2024
Pipeline including CS	TRA-N-380	BG – RO – HU – AT transmission corridor	Hungary	FGSZ Ltd.	No	2024
LNG Terminal	LNG-N-824	LNG Terminal in Klaipėda	Lithuania	AB Klaipėdos Nafta	No	2024
Pipeline including CS	TRA-N-114	R61 Dragonja – Izola	Slovenia	Plinovodi d.o.o.	No	2024
Pipeline including CS	TRA-N-284	3rd IP between Portugal and Spain (Compressor Station)	Portugal	REN-Gasodutos, S.A.	Yes	2025
Pipeline including CS	TRA-N-285	3rd IP between Portugal and Spain (pipeline Cantanhede-Mangualde)	Portugal	REN-Gasodutos, S.A.	Yes	2025

LESS-ADVANCED NON-FID

Type	Code	Name	Country	Promoter	PCI 2nd List	Commission-ing Year
Pipeline including CS	TRA-N-729	Interconnection ES-PT (3rd IP) – 2nd phase	Spain	Enagás Transporte, S.A.U.	Yes	2025
Pipeline including CS	TRA-N-303	Interconnection Croatia-Bosnia and Herzegovina (west)	Croatia	Plinacro Ltd	No	2026
Pipeline including CS	TRA-N-336	Interconnection Croatia/Slovenia (Umag – Koper)	Croatia	Plinacro Ltd	No	2026
Pipeline including CS	TRA-N-031	Connection of Malta to the European Gas Network – Pipelines	Malta	Office of the Prime Minister (Energy)	Yes	2026
Storage Facility	UGS-N-914	UGS Damaslawek	Poland	GAZ-SYSTEM S.A.	No	2026
Pipeline including CS	TRA-N-376	Azerbaijan, Georgia, Romania Interconnector – AGRI	Romania	AGRI LNG Project Company SRL (RO)	No	2026
LNG Terminal	LNG-N-165	Gran Canaria send out increase	Spain	Gascan	No	2026
LNG Terminal	LNG-N-185	Tenerife Send-Out increase	Spain	Gascan	No	2026
Pipeline including CS	TRA-N-955	GUD: Complete conversion to H-gas	Germany	Gasunie Deutschland Transport Services GmbH	No	2030
Pipeline including CS	TRA-N-975	Sardinia Gas Transportation Network	Italy	Società Gasdotti Italia	No	2031
LNG Terminal	LNG-N-211	Connection of Malta to the European Gas Network – LNG Regasification	Malta	Office of the Prime Minister (Energy)	Yes	2031
Pipeline including CS	TRA-N-008	Import developments from North-East	Italy	Snam Rete Gas S.p.A.	No	2034
Pipeline including CS	TRA-N-009	Additional Southern developments	Italy	Snam Rete Gas S.p.A.	No	2034
Storage Facility	UGS-N-141	Construction of new gas storage facility on the territory of Bulgaria	Bulgaria	Bulgartransgaz EAD	No	Unknown
Pipeline including CS	TRA-N-065	Hajduszoboszlo CS	Hungary	FGSZ Natural Gas transmission Company limited by Shares.	No	Unknown
LNG Terminal	LNG-N-030	Shannon LNG Terminal and Connecting Pipeline	Ireland	Shannon LNG	Yes	Unknown
LNG Terminal	LNG-N-162	Gran Canaria 2° LNG Tank	Spain	Gascan	No	Unknown
LNG Terminal	LNG-N-184	Tenerife 2° LNG Storage Tank	Spain	Gascan	No	Unknown
Pipeline including CS	TRA-N-339	Trans-Caspian	Turkmeni-stan	W-Stream Caspian Pipeline Company Ltd	Yes	Unknown
Pipeline including CS	TRA-N-346	Industrial Emissions Directive (LCP)	United Kingdom	National Grid Gas plc	No	Unknown
Pipeline including CS	TRA-N-349	Industrial Emisssion Directive (IPPC) – Non-FID	United Kingdom	National Grid Gas plc	No	Unknown

Table 4.3: List of projects

5 Barriers to investment

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5.1 Introduction

This TYNDP focuses on existing and planned infrastructure projects, and how they could contribute to the improvement of the European gas system over the years. Nevertheless, infrastructure projects will only come on-line if there is a stable and attractive investment climate. Therefore it is vital that the market and the legislative policy makers understand the potential risks and barriers to future investment in gas infrastructure.

In order to provide a realistic context for the continuous decrease of projects (especially the reduction in the number of FID projects experienced in the past TYNDPs), this chapter analyses those barriers, combining the views of all TSOs and other project promoters.

5.2 Overall impact of energy policies

The energy mix of each Member State is driven by its unique circumstances, and is influenced by European regulation policies and targets (such as the 2030 Framework for climate and energy[1]) and global factors (e.g. current low coal and CO_2 prices).

However, many Member States are currently still lacking a clear political vision on how to deliver the energy transition and achieve the climate objectives while ensuring both energy security and affordability. This is for example illustrated in the power sector by the increasing share of polluting coal-fired electricity generation plants that endangers the required development of more flexible power generation, including gas-fired generation, to support the development of renewable energy sources. The gas infrastructure can also directly contribute to the reduction of CO_2 supporting the development of non-intermittent renewable sources such biomethane[2]. In that respect the market needs to meet the long term political targets in the most efficient way and this will require an appropriate framework to be set by the European Commission.

1) https://ec.europa.eu/energy/en/topics/energy-strategy/2030-energy-strategy

2) In ENTSOG TYNDP, for statistical reasons, biomethane includes all renewable gases

5.3 Project Promoter Perspective

In addition to the aforementioned impact of energy policies, project promoters are facing various challenges in the completion of their projects. As part of the TYNDP 2017 infrastructure project data collection process, ENTSOG has gathered information on perceived investment barriers. Out of the 97 promoters having submitted projects for this TYNDP edition, 49 have indicated at least one barrier for 102 projects.

Below are listed the submitted barriers for the global perspective of the TYNDP. This list groups in main categories and broad terms barriers reported in different European contexts, not necessarily detected in each country.

- Insufficient rate of return
- Regulatory framework instability
- Lack of funding
- Lack of long-term commitment
- Uncertainty on the realisation of the upstream projects and/or the respective gas source development
- Capacity booking quotas
- Market uncertainty
- Lack of stability in the energy legal framework
- Geopolitical issues

The reported barriers for national perspectives are listed in the following figure:

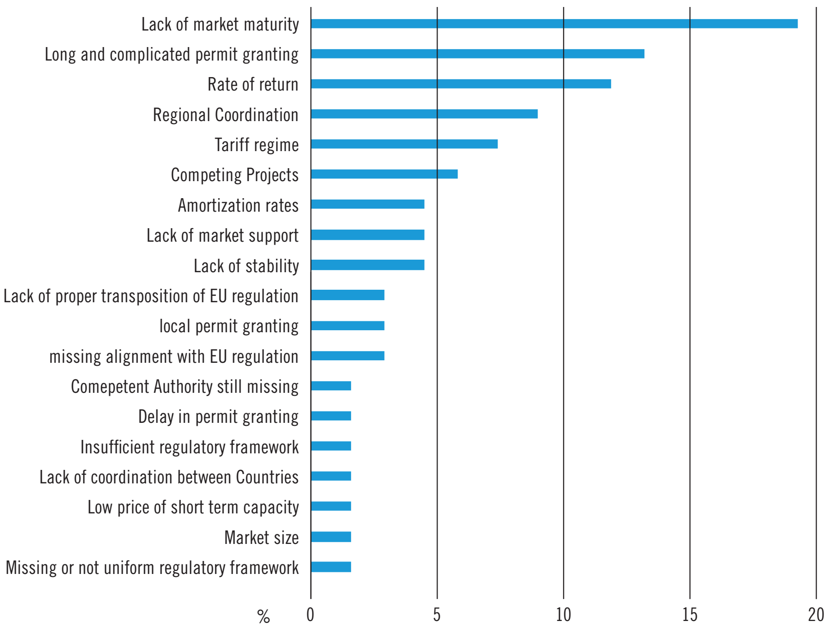

Figure 5.1: National Barriers to investment (when reported)

The detailed description of the reported investment barriers per project are listed in Annex A. Investment barriers have been grouped as indicated in the next table (with sub-groups where proposed):

REGULATORY	Rate of Return (level and stability)
	Low price of short term capacity
	Capacity quotas
	– Lack of proper transposition of EU regulations – Significant changes in national and EU legislation – A missing or not uniform regulatory framework
	Other
MARKET	Lack of market support
	– Lack of market maturity – Market uncertainty
	Other
PERMIT GRANTING	
FINANCING	Availability of funds
	Amortisation rates
	Other
POLITICAL	
OTHER	

Table 5.1: Categories of barriers to investment

Figure 5.2 presents the breakdown of the barriers.

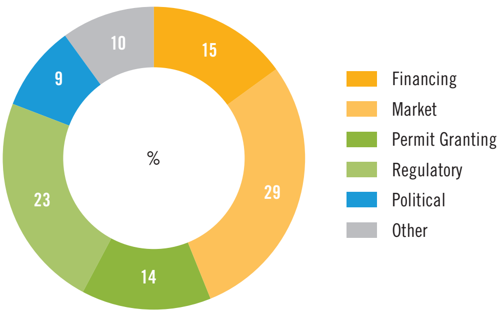

Figure 5.2: Combined overview of project barriers, as submitted by the promoters

The most largely reported barriers are related to the regulatory and market frameworks. The next graphs show that the predominance of those two barriers is common to all types of infrastructures:

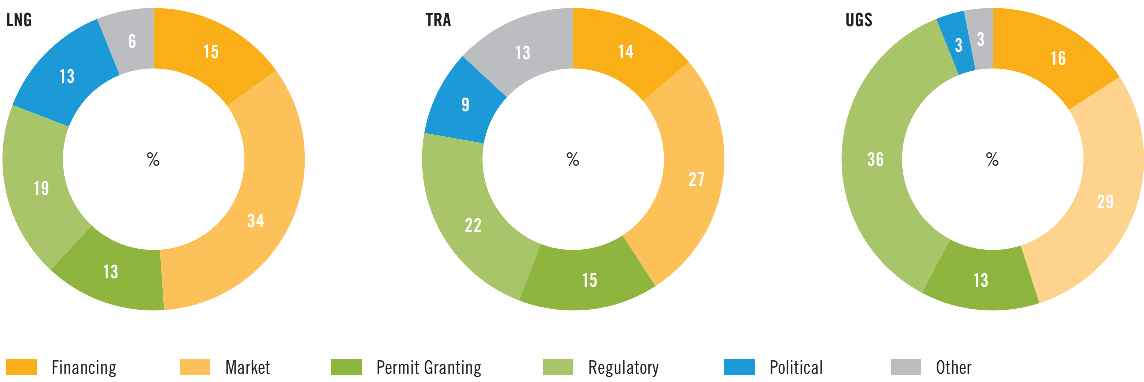

Figure 5.3: Overview of project barriers by project type, as submitted by the promoters (LNG – TRA – UGS)

5.3.1 REGULATORY FRAMEWORK

For many projects the regulatory framework is perceived as not being appropriate to ensure the delivery of new infrastructures even when they have been identified as necessary to complete the integration of the European gas market. The following graph shows in more detail the regulatory challenges faced by promoters according to their project submission. The category "Other" covers promoter responses where a specific category of barrier was not provided and the comments did not allow it to be further categorised[1].

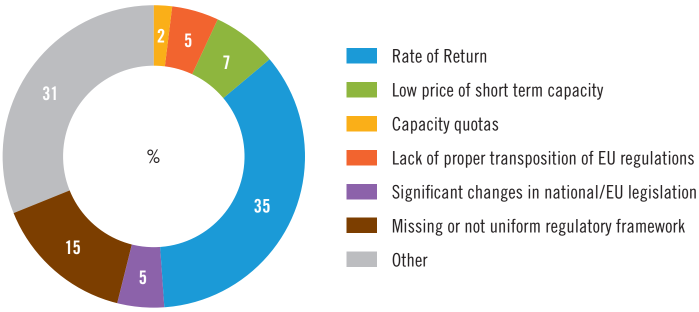

Figure 5.4: Overview of Regulatory related project barriers

The level of rate of return is perceived as one of the major obstacles. Setting such level is subject to European or national regulatory regimes, but these should encourage long-term investments with a reasonable return. A rate of return that is too low or is subject to high risks hampers new investments in gas infrastructure and may hinder the completion of the internal gas market. The setting of the rate should strike the right balance between the benefits of further market integration and the impact on transmission tariffs which represent a moderate share of the wholesale market price of gas. Besides, this barrier can be mitigated, as stated in ACER's Recommendation No. 03/2014[2], by ensuring that the remuneration of the project promoter includes a premium in certain projects.

The practice of applying incentives, such as premium rates of return for some categories of projects, has already been adopted and applied by some Member States.

Some NRAs have followed the request of some market players in favouring low priced short term capacity products and quotas.

Short term capacity products should be priced in line with the value they have for users in providing them with flexibility in terms of associated profiling possibilities. If short term products are priced too low and users move to short term bookings, this is likely to have a detrimental effect on long term capacity, relevant in providing signals to TSOs on the future peak requirements of the system and congestion reduction.

The introduction of quotas of newly built capacity for medium and short-term use could distort the process for creating new capacity leading to the risk of over-investment.

In addition, within the development process of the draft Tariff Network Code some network users have claimed the right to cancel all or part of their capacity bookings linked to tariff changes. Such partial or total cancellation of initial users' commitments could lead to cross-subsidies between network users as a result of revenue neutrality for the operators. Furthermore the value of any long term commitment would be weakened, with possible impacts also on planning and commissioning for new projects. This would constitute a major risk for investment realisation.

1) Further explanation can be found in Annex A

2) http://www.acer.europa.eu/official_documents/acts_of_the_agency/recommendations/acer%20recommendation%20 03-2014.pdf

Finally, significant and unexpected changes in national and EU policies and in the regulatory framework can negatively affect investment decisions which, considering the long-term and capital-intensive nature of the gas industry assets, requires a stable and well-defined context.

5.3.2. MARKET ENVIRONMENT

Many promoters are facing challenges in triggering investment on a market basis.

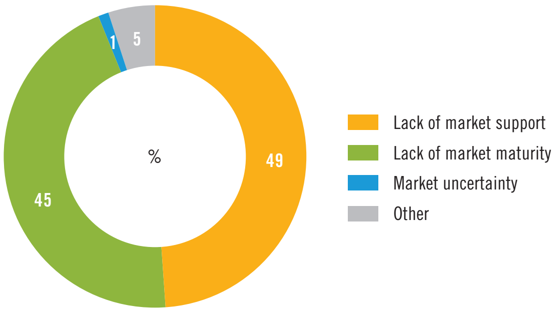

Figure 5.5: Overview of the Market related project barriers

The lack of market maturity is also identified as a barrier with regard to the number of users and the development of the commercial arrangements.

In some regions, promoters are facing additional challenges as the gas market is not sufficiently mature to give the appropriate signals and provide sufficient financial commitment. These regions are often at the same time suffering from a lack of adequate diversification of supply sources and infrastructure integration compared to the rest of the European gas market.

For some project promoters, typically in mature gas consumer economies, the uncertainty about the evolution of natural gas demand does not help in providing the right signals for investment decisions.

Within the framework of the TEN-E Regulation, European Commission has emphasised that co-financing will only apply for key projects not affordable solely within the concerned markets. Nevertheless, the expectation persists that co-financing would reduce the need of long term commitment by the market.

5.3.3. FINANCIAL ENVIRONMENT

Gas infrastructure projects are capital intensive assets with a very long economic lifetime therefore project financing is a major part of the process of enabling the investment. Financial tools put in place to support new investments are not always attractive to investors.

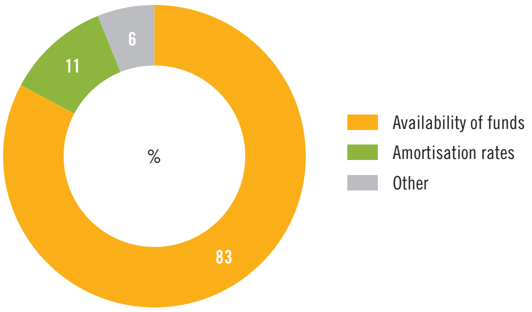

Figure 5.6: Overview of the Financing related project barriers

The number of proposed projects submitted for TYNDP 2017 illustrates the willingness of promoters to invest in European gas infrastructures. There is sufficient capital in the financial market to fund a significant proportion of these projects, the challenge is to ensure that these projects access funding. The main prerequisite to unbridle this financial potential is a stable and attractive regulatory framework for investors. However, as also mentioned before, not all Member States offer a regulatory environment with conditions favouring investments.

Project amortisation rates and long-term capacity contracts associated with projects differ significantly. Infrastructure assets economic lifetime tends to last more than capacity and supply contracts. The amendment of the Capacity Allocation Mechanism Network Code (CAM) will introduce a new standard procedure for allocating incremental capacity, this procedure will only allow to book incremental capacity for a maximum duration of 15 years, in exceptional cases 20 years. Then, there will be a gap of more than 30 years in which there is no explicit commercial commitment for a new asset.

This raises the question of whether a project promoter should be entitled to recover investment expenditures within a limited time-framework and recoup as much commitments as possible in the available contractual timeframe, due to the lack of certainty in the long term. The solution would also avoid cross-subsidies between different categories of users (present/future, infrastructure users/general system users, etc.). This situation of general uncertainty is also triggered by negative signals from carbon emissions prices due to ongoing European ETS policies.

5.3.4. PERMITTING

The streamlined permit granting introduced by the Energy Infrastructure Guidelines for Projects of Common Interest (PCI) is a concrete step in the right direction. Nevertheless many Member States are late in establishing such arrangements, especially when permits are expected at different levels (from local to national level).

Such situation results to be detrimental to the development of necessary infrastructures as streamlined permitting is especially important for cross-border projects where the phasing of stages in each country is a key factor in delivering the benefits of the projects.

These arrangements are intended to strike a balance between public consultation and certainty on the duration of the process. If these arrangements deliver expected benefits, they should be enlarged to Non-PCI projects as well.

5.3.5. POLITICAL

Political decisions also have an impact on the willingness to invest in long-term assets, influencing market confidence (e.g. how to reach long-term environmental targets).

Political decisions need to be clear and consistent. Investment in gas infrastructure is a long term financial commitment. Inconsistent or partially contradictory political decisions can have a direct effect on whether the market feels confident to invest or not. On the one hand the market is stimulated by initiatives like the Energy Infrastructure Package which promotes the construction of Projects of Common Interest. On the other hand the European Commission Roadmap 2050 envisages a European energy mix in which the role of gas is severely diminished by 2050. In that respect, ENTSOG has introduced a third scenario called Blue Transition that highlights the role of natural gas and gas infrastructures in support of the European energy agenda.

A stable and predictable regulatory framework is paramount to tackling the barriers to investment in efficient gas infrastructure. TSOs are dedicated to facing the challenges ahead, based on engagement and co-operation with policy makers. By working together, based on a common view on a future environmentally and economically sustainable, the Internal Energy Market can be completed to the benefit of all European end consumers.

Image courtesy of Gas Connect Austria

5.4 TSO perspective

According to the Third Energy Package market-based investments should be primarily triggered by market testing. It might prove difficult, if not impossible, to secure sufficient financial ex-ante commitments for projects which cannot find direct and explicit users but are at the benefit of the overall system, such as the investments delivering security of supply or guaranteeing network flexibility and transmission services security.

For market-based investment, TSOs' role within the investment process involves enabling the market to signal necessary projects through market consultation. This includes national, regional and European plans, and also the incremental capacity process, integrated into the Capacity Allocation Mechanism Network Code. The final identification of this kind of infrastructure projects requires reliable commitments from market players. Finally, as stated in Regulation 347/2013, there are some projects that should be built taking into consideration contributions to security of supply, market integration, competition and sustainability (mainly, PCI projects).

ENTSOG's role in the investment process is to ensure an objective assessment of infrastructure development and to provide supporting information.

The main risk stemming from the list of barriers identified in this Chapter is a delay in the delivery of necessary projects. The bi-annual repetition and continuous development of the TYNDP process should ensure an efficient and appropriate infrastructure assessment based on the latest developments in the European and global energy markets.

Image courtesy of FGSZ

6 Assessment

Image courtesy of National Grid

6.1 General consideration on assessment results

ENTSOG has carried out an extensive assessment of the European gas system in order to identify potential investment needs and how projects submitted to TYNDP help to mitigate these needs. This TYNDP was developed applying the Energy-System Wide Cost Benefit Analysis (CBA) methodology[1] that was approved by the European Commission in February 2015.

This assessment represents the TYNDP-Step of the Energy System-Wide CBA (ESW-CBA) and as such it focuses on different levels of infrastructure development rather than on single projects. In preparation to the individual assessment of PCI candidates, which will take place outside of TYNDP as part of the 3rd PCI selection process, the report focuses on the Low and Advanced Infrastructure levels. A specific section of the assessment chapter is dedicated to the analysis of the 2nd PCI list Infrastructure level. It gives a view of the overall impact of the current list of Projects of Common Interest from the 2nd PCI selection in 2015[2].

The results of the assessment have been structured to have a strong alignment with both the third energy package and the TEN-E regulation. In particular the identification of investment gaps, notably with respect to cross-border capacities, is understood as the assessment of the low infrastructure level. The first section of this chapter is specifically dedicated to this assessment. The low infrastructure level is based mainly on the currently existing gas infrastructure, complemented by the FID projects for which realisation is considered almost certain.

The assessment of the investment needs is presented before the European system-wide costs and benefits, stemming from the infrastructure projects in the advanced infrastructure level. In both parts, the infrastructure levels are evaluated towards the market integration and operability, competition, security of gas supply and sustainability. The benefits from the 2nd PCI list are shown through the assessment of the 2nd-PCI list infrastructure level.

The assessment is made in accordance with the above mentioned CBA methodology. However, based on stakeholders' feedback, ENTSOG has enlarged this TYNDP assessment scope on a voluntary basis, in particular by proposing further monetisation. For this edition, an EU-wide approach to value of lost load is proposed, based on the recent years' ratio between the EU-28 gross domestic production and gross inland consumption. This approach allows a valuation of cases where high demand

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1) http://entsog.eu/public/uploads/files/publications/CBA/2015/INV0175-150213_Adapted_ESW-CBA_Methodology.pdf

2) https://ec.europa.eu/energy/en/topics/infrastructure/projects-common-interest

simulations lead to identifying a demand disruption risk. This TYNDP also introduces the Import Price Spread configuration. It shows the benefits of infrastructure for limiting monopolistic supply behaviour by mitigating price spread effects between different import routes. Also, the monetisation for the different supply mixes has been carried out on a country level accompanying the European perspective. Additionally, modelling the high demand cases based on the storage level stemming from the average year simulation leads to improved results. The continuous cooperation with GIE helped to improve the modelling of storages and LNG terminals. This includes the modelling of gas storages by the definition of injection and withdrawal curves and LNG terminals during high demand situations (see Annex F).

Four demand scenarios have been developed for this edition of TYNDP: Slow Progression, Blue Transition, Green Evolution and EU Green Revolution. All these scenarios are fully-fletched in terms of related data and have been analysed in the Demand chapter. Yet as the Slow Progression demand situation falls within the range of the other scenarios, the TYNDP assessment will cover all but this scenario. The three assessed scenarios, Blue Transition, Green Evolution and EU Green Revolution, all achieve the European energy and climate 2030 targets while taking different paths in terms of the overall gas demand, from a continued decrease to a limited rebound.

The assessment in the TYNDP 2017 is done for the years 2017, 2020, 2025, 2030 and 2035 for the following dimensions:

- **Demand Scenarios:** Blue Transition, Green Evolution and EU Green Revolution (see chapter 2: Demand)[1]
- **Infrastructure Level:** Low, Advanced, High[2] and 2nd PCI list (see chapter 4: Infrastructure)

For all combinations of these scenarios and infrastructure levels, specific assessments analyse both the whole year and high demand situations, as the gas infrastructure needs to be fit for those circumstances:

- **The whole year** refers to an average climatic year and consists of an average summer (AS)[3] and an average winter (AW)[4]. For this period, analysis consists of:
  - The Supply Configurations: Balanced, minimisation and maximisation of each extra-EU supply source in the supply mix and the import price spread configuration (see Annex F). This allows conclusions towards different feasible supply mixes and flow situations, monetisation effects on EU level and the alignment of marginal prices. In line with what has been proposed to stakeholders when elaborating the TYNDP concept, the analysis focuses on a limited number of meaningful configurations.
  - The Supply and price dependence per country[5]
  - The Price diversification potentials per country[6]

1) The total gas demand (overall for the residential, commercial, industrial, transport and power sectors) is a direct input into the modelling.
2) The results for the High infrastructure level are shown exclusively in Annex E, in line with reasons highlighted in the Infrastructure chapter
3) 7 month storage injection period April to October, 214 days
4) 5 month storage withdrawal period November to March, 151 days
5) Supply Source Price Dependence (SSPDe), Cooperative Supply Source Dependence (CSSD) and Uncooperative Supply Source Dependence (USSD) indicators
6) Supply Source Price Diversification (SSPDi) indicator

- **The High demand situations** are the peak day (DC) corresponding to each national design case and the 2-week high demand case (14-day, 2W)[1] corresponding to the highest 2-week demand as would occur over a 20-year period. They are analysed using:
  - High demand situation occurring under an otherwise normal situation (No Route Disruption)
  - Disruption Cases: Russian transit through Ukraine (UA), Russian transit through Belarus (BY), Langeled pipeline between Norway and UK (Langeled), Franpipe pipeline between Norway and France (Franpipe), GreenStream pipeline between Libya and Italy, Transmed pipeline between Algeria and Italy (Transmed), MEG pipeline between Algeria and Spain including supply to Portugal (MEG), TANAP pipeline between Azerbaijan and Greece (TANAP). This allows conclusions towards different feasible flow situations, disrupted demand of countries and the remaining flexibility of countries.

While the term country is mainly used for the explanations in the chapter, it must be noted that the granularity of the assessment is higher in some instances. In Germany the results can also refer to the balancing zones GASPOOL (DEg) and NetConnect Germany (DEn), in France[2] to the North (FRn), South (FRs) and TIGF (FRt) zones[3] and in Belgium to the L- and H-gas balancing zones (BEl, BEh).

In addition to this, the resilience and diversification potentials of the gas infrastructures in the different countries are assessed independently from the network modelling approach by calculations based on the capacities and demand[4].

The assessment is done for the EU-28 countries as well as Switzerland, Bosnia and Herzegovina, Serbia and FYROM. The interaction with the gas sources at the borders of the assessment are reflected by the supply potentials detailed in the Supply chapter. In addition to this, the following exports have been considered for all years and all scenarios: Russia (Kaliningrad area and St. Petersburg region)[5], Ukraine[6] and Turkey[7].

The assessment is carried out from a European perspective, under the assumption of perfect market functioning. This ensures to focus on conclusions where solving the identified gap cannot be managed by market or regulatory rules and would presumably require infrastructure development with cross-border significance. The degree to which the European gas market is functioning and its evolution are already addressed in various other reports and consequently is not part of this TYNDP. The reader, when interpreting the results, should keep in mind this perfect market functioning as an assumption which can differ from real market behaviours, influenced by commercial and technical limitations, commercial strategies and/or local circumstances.

The following assessment results offer a robust approach for identifying the capability of the European gas infrastructure to deal with a range of scenarios. This means that the identified evolution of indicators over time, and from one infrastructure level to another, is at least as meaningful as the absolute values.

This chapter focuses on the main results of the multi-criteria analysis, reflecting the main trends in the evolution of the European gas system. Therefore, it only covers a selection of indicators, years, scenarios and supply mixes. Additional detailed results are available in Annex E. The description of the modelling approach, indicators and monetisation can be found in Annex F, which also provides an overview of the input data for the modelling tool and all modelled cases.

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1) Both high demand situations are based on the results (e. g. storage fill levels) of the whole year simulation. The peak day takes place on 31 January, the 2-week high demand case during the last two February weeks.
2) The French North and South zones are foreseen to be merged by end 2018. The infrastructure projects necessary for this merger and related capacity increase are part of this TYNDP.
3) The French "Trading Region South", in place since April 2015, still covers two balancing zones: France South and France TIGF.
4) N-1 and Import Route Diversification (IRD) indicators
5) 21,7 TWh/year – transit from Russia. Kaliningrad: summer 46 GWh/d, winter 79 GWh/d, 2-week 98 GWh/d, Peak 104 GWh/d, St. Petersburg: winter, Peak, 2-week 34 GWh/d
6) 124 TWh/year. 339 GWh/d for all temporal periods (summer, winter, 2-week, peak)
7) 135 TWh/year – transit from Russia. Summer 366 GWh/d, winter 379 GWh/d, 2-week 478 GWh/d, peak 478 GWh/d

6.2 Supply Adequacy outlook

The Supply Adequacy Outlook is based on the supply potentials and the demand scenarios (see Supply and Demand chapters). For 2017, the results reflect the "tomorrow as today" approach applied for the definition of the supply potentials.

The supply demand adequacy including exports to extra-EU countries, is achievable for all demand scenarios, as illustrated in Figure 6.1.

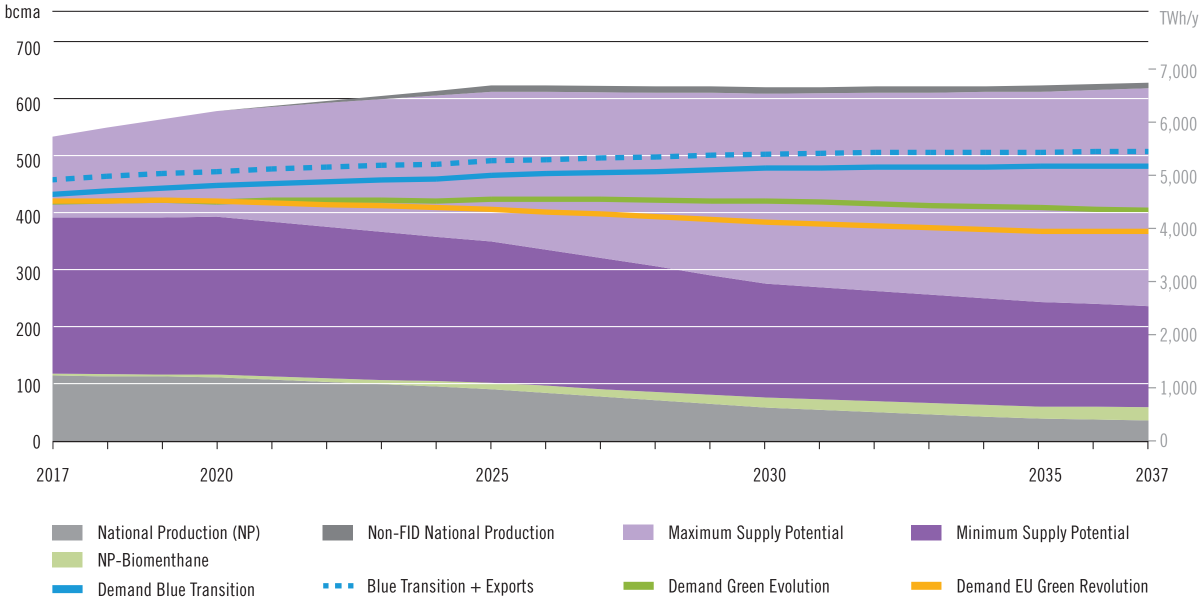


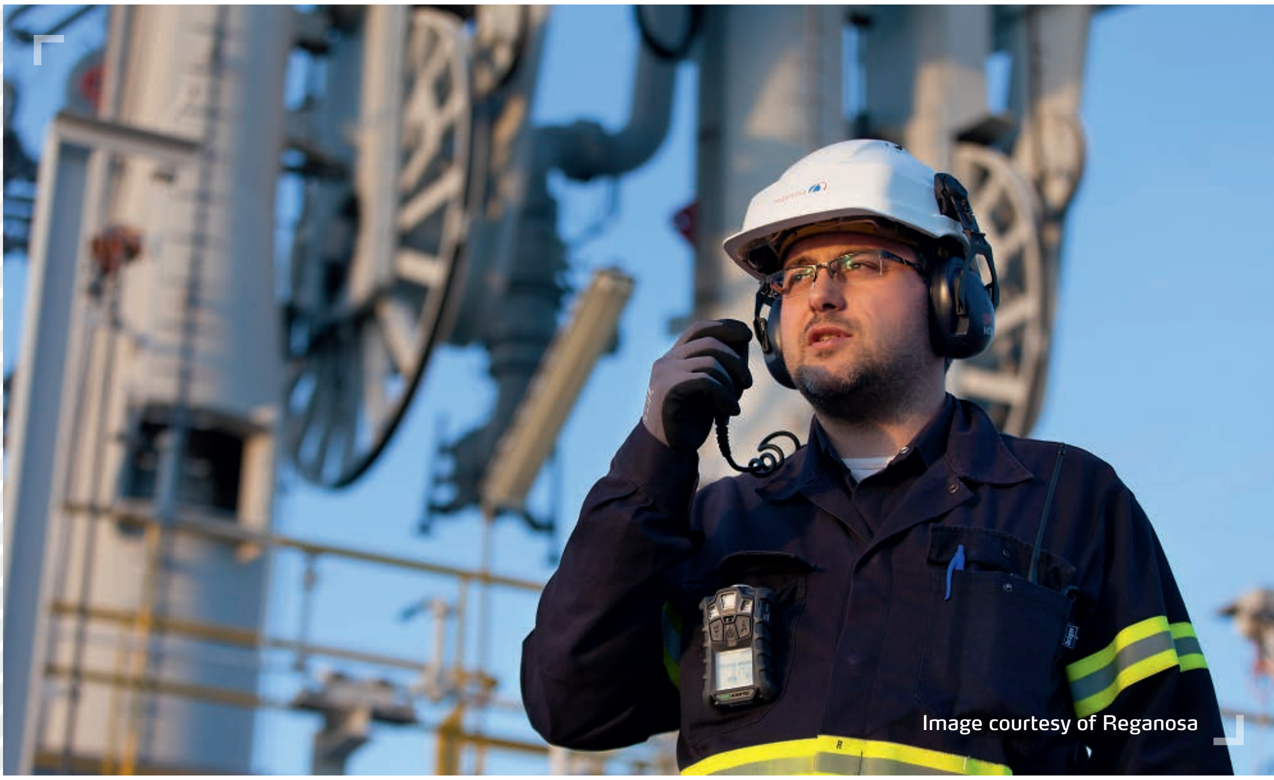
Figure 6.1: Supply Adequacy Outlook

The Supply Adequacy Outlook takes into account the yearly demand of the EU-28 countries together with the relatively small demand of the other countries considered in the assessment that are supplied via the EU[1]. It also considers the yearly exports from EU to extra-EU countries[2], which on Figure 6.1 have been represented by the dotted line on top of the EU Blue Transition scenario demand.

The minimum/maximum supply potentials consist of the indigenous production and the minimum/maximum supply potentials of each extra-EU supply sources (Russia, Norway, Algeria, Libya, LNG and Azerbaijan). In addition to this the Cypriot production is made accessible through a project with a non-FID less-advanced status, therefore it is only considered in the High infrastructure level. Biomethane production is an additional inner-EU supply source[3].

The fact that demand, including on the short-term, exceeds the minimum supply potential indicates that supply demand adequacy requires that not all sources are at their lowest level at the same time.

1) Bosnia and Herzegovina, FYROM, Serbia and Switzerland
2) Russia (Kaliningrad area and St. Petersburg region), Ukraine and Turkey
3) The volume of the biomethane production potential depends on the scenario, as detailed in the Supply Chapter. The supply adequacy outlook shows the highest potential



The EU supply needs are defined as the difference between the EU demand and the indigenous production, taking into account the biomethane production, as presented in the Supply and Demand chapters. In this assessment, the EU supply needs are only covered by extra-EU imports. Depending on future developments, higher indigenous production (from biomethane, hydrogen from power-to-gas facilities, new conventional and unconventional production) could also help to meet the supply needs.

The combination of the different demand scenarios, with decreasing expectations for the indigenous production, except for biomethane, leads to increasing supply needs over time in the Blue Transition and Green Evolution scenarios. The EU Green Revolution is the only scenario where the lower demand together with the biomethane production nearly compensates the decrease of the conventional production and leads to more stable needs over time.

Different supply mixes for meeting the Supply Adequacy Outlook over the time horizon are analysed as part of the assessment, they are described in section 6.3.2.4.

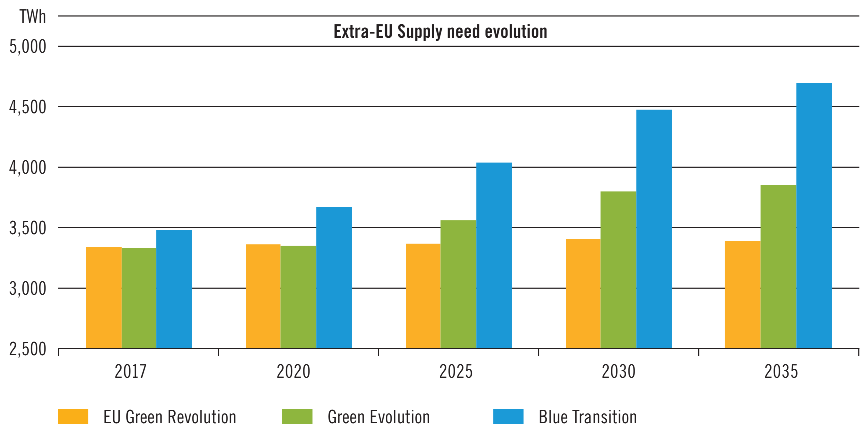


Figure 6.2: Evolution of extra-EU supply needs in the different scenarios

Supply Adequacy in North-West Europe: the challenge of L-gas areas

Most of North-West Europe is supplied with high-calorific gas (H-gas), apart from specific areas covering parts of the Netherlands, Germany, Belgium and France. These areas are supplied with low-calorific gas (L-gas) coming from the Groningen field (Netherlands), German fields and H-gas conversion facilities (e.g. by injection of nitrogen) through specific infrastructures with limited connections to the respective neighbouring H-gas network. The average yearly L-gas energy demand is currently about 600 TWh/y.

The decline of the European production is an EU-wide concern. It is even more significant with regard to L-gas production due to the fact L and H-gas are not substitutable and due to the limited number of L-gas production fields. Earthquakes related to the production of Groningen field led the Dutch authorities to limit the production for the coming years while leaving some flexibility to adapt to cold situations.

Considering on the one hand the end of the Dutch L-gas exports to Belgium, France and Germany by 2030 as well as the declining German production and on the other hand the current L-gas demand in Belgium, France and Germany (around 330 TWh/y), it is necessary to engage a continuous process of converting areas currently supplied by L-gas to H-gas. Belgium, France and Germany have already prepared national conversion plans coordinated at bilateral and multilateral levels (e.g. the Gas Platform). The foreseen conversion process includes the development of specific gas transmission infrastructure to integrate the L-gas and the H-gas networks.

The required conversion of areas currently supplied by L-gas in a part of the North-West region is assessed in the related North-West Gas Regional Investment Plan based on the TYNDP CBA methodology and using data consistent with the TYNDP.

The TYNDP assessment further presented in this chapter focuses on the market perspective (as experienced by network users) and therefore considers indifferently L and H-gas demand, supplies and network capacities[1]. A specific assessment of the situation for the L-gas area, covered in the North-West GRIP to be published shortly after the TYNDP, complements this main assessment. Additionally, as part of this TYNDP data collection, ENTSOG has collected the L and H-gas data supporting this specific assessment.

1) In TYNDP flow limitations have been introduced between specific countries (or balancing zones) to reflect L-gas related limitations.

6.3 Assessment of reasonable infrastructure needs and investment gaps

The low infrastructure level[1] is the basis for the identification of priority areas facing an investment gap. It consists of the existing infrastructure and the FID projects[2]. 34 FID projects have been submitted for this TYNDP edition.

The following Table 6.1 and Table 6.2 list those projects[3]. The FID projects represent an overall investment cost of 27.5 bn€[4]. It incorporates large scale projects for which costs have been publicly reported (Nord Stream 2 around 8 bn€, TANAP around 10 bn$, TAP around 6 bn€) which represent a large share of the overall costs of FID projects.

FID PROJECTS WITH A DIRECT CAPACITY IMPACT IN THE LOW INFRASTRUCTURE LEVEL

Code	Name	Country	Commissioning Year
TRA-F-241	MONACO section phase I (Burghausen-Finsing)	Germany	2017
TRA-F-291	NOWAL - Nord West Anbindungsleitung	Germany	2017
TRA-F-768	Extension Receiving Terminal Greifswald	Germany	2017
LNG-F-147	Revythoussa (2nd upgrade)	Greece	2017
TRA-F-137	Interconnection Bulgaria – Serbia	Bulgaria	2018
TRA-F-378	Interconnector Greece-Bulgaria (IGB Project)	Bulgaria	2018
TRA-F-43	Val de Saône project	France	2018
TRA-F-331	Gascogne Midi	France	2018
TRA-F-208	Reverse Flow TENP Germany	Germany	2018
TRA-F-214	Support to the North West market and bidirectional cross-border flows	Italy	2018
TRA-F-45	Reverse capacity from CH to FR at Oltingue	France	2018
TRA-F-230	Reverse Flow Transitgas Switzerland	Switzerland	2018
TRA-F-221	TANAP – Trans Anatolian Natural Gas Pipeline Project	Turkey	2018
TRA-F-051	Trans Adriatic Pipeline	Greece	2019
UGS-F-1045	Bordolano Second phase	Italy	2019
UGS-F-260	System Enhancements – Stogit – on-shore gas fields	Italy	2026
LNG-F-178	Musel LNG terminal	Spain	2026

Table 6.1: FID projects with a direct capacity impact in the low infrastructure level

1) Also see the infrastructure chapter, section 4.4.2
2) See Annex A
3) The 3 following projects were already commissioned by end 2016, and are therefore not reported in the table: *Bordolano First Phase* (UGS-F-259), *Romania –Bulgaria Interconnection* (TRA-F-029) and *Exit Capacity Budince* (TRA-F-1047)
4) ENTSOG has committed towards promoters to keep the individual project costs confidential

FID PROJECTS WITHOUT A DIRECT CAPACITY IMPACT IN THE LOW INFRASTRUCTURE LEVEL

- **FID projects requiring an additional advanced or less-advanced project to produce a capacity impact**
- **Internal FID projects enabling cross-border capacity development**
- **FID projects not connected to the European mainland gas infrastructure**

Code	Name	Country	Commissioning Year
LNG-F-229	Zeebrugge LNG Terminal – 5th Tank & 2nd Jetty	Belgium	2019
TRA-F-86	Interconnection Croatia/Slovenia (Lučko – Zabok – Rogatec)	Croatia	2019
TRA-F-937	Nord Stream 2	Germany	2019
TRA-F-1028	Albania – Kosovo Gas Pipeline	Albania	2022
TRA-F-334	Compressor station 1 at the Croatian gas transmission system	Croatia	2017
TRA-F-337	CS Rothenstadt	Germany	2018
TRA-F-343	Pipeline project "Schwandorf-Finsing"	Germany	2018
TRA-F-344	Compressor station "Herbstein"	Germany	2018
TRA-F-345	Compressor station "Werne"	Germany	2018
TRA-F-753	West to East operation of the IP Waidhaus	Germany	2018
LNG-F-183	Tenerife LNG Terminal	Spain	2020
LNG-F-163	Gran Canaria LNG Terminal	Spain	2021
TRA-F-017	System Enhancements – Eustream	Slovakia	2026
TRA-F-025	Industrial Emissions Directive (IPPC) – FID	United Kingdom	Unknown

Table 6.2: FID projects without a direct capacity impact in the low infrastructure level [1) 2)]

The projects are considered in the low infrastructure level assessment starting from the year after their expected commissioning date. The relevant capacities for this infrastructure level can be found in the Annex D[1)]. As a result of this assessment, the investment gaps, notably with respect to cross-border capacities, have been identified and are presented in the following sub-chapters.

The assessment results are shown based on a representative selection of the investigated cases. This means where there is little to no difference between investigated cases, not all are displayed in order to improve the user-friendly experience. All other results are published in Annex E.

1) Sheets LNG, Storage and Transmission, "Low" in column I

6.3.1 SUSTAINABILITY

In the low infrastructure level, the assessment of the European gas infrastructure over the whole time horizon shows that the supply and demand adequacy can be achieved with different supply mixes for all demand scenarios. This is the case including for the peak demand[1] corresponding to national design cases. These supply mixes represent ways of meeting the reasonable needs of the different network users.

This indicates that the gas infrastructure in the low infrastructure level is capable of enabling the EU 2030 climate targets to be achieved, including in terms of supporting renewable generation, as such fulfilling the TEN-E sustainability pillar.

Additional elements related to sustainability criteria are available in the Demand chapter (CO_2 emissions savings related to the different scenarios, electricity generation), the Supply chapter (power-to-gas and biomethane) and the Energy Transition section of the Infrastructure chapter.

6.3.2 SECURITY OF SUPPLY NEEDS

6.3.2.1 Introduction to Remaining Flexibility and Disrupted Rate

The Remaining Flexibility indicator measures resilience at a country level. The indicator is calculated for the high demand situations as the additional share of demand each country is able to cover before an infrastructure or supply limitation is reached. This calculation is made independently for each country, meaning that they do not share the European supply flexibility. The higher the indicator value is, the better the resilience. In cases where countries experience disrupted demand, the Remaining Flexibility is equal to zero.

The Disrupted Rate represents the share of the gas demand that cannot be satisfied. It is calculated as a daily volume. The level of disruption is assessed considering a cooperative behaviour between European countries in order to mitigate its relative impact. This means that countries try to reduce the disrupted rate of other countries by sharing it. Non-alignment of the Disrupted Rate between countries indicates an infrastructure bottleneck. Distribution of Disrupted Rate among countries is therefore a strong indication of infrastructure needs.

For these indicators, the high demand situations are assessed: peak day (DC) corresponding to each national design case and the 2-week high demand case (14-day, 2W) corresponding to the highest 2-week demand as would occur over a 20-year period. The results are presented for the Peak situation.

The remaining flexibility and the disrupted rate are sensitive to the demand. Hence, the results shown are based on the most contrasted scenarios, the Blue Transition and the EU Green Revolution scenario, ensuring the robustness of the analysis. The years 2017 (where relevant), 2020 and 2030 have been selected for the illustration. All results are available in Annexes E.02, E.03 and E.04.

1) See 6.3.2.1 for more details, including on Croatia for which on the long term, the demand development may require additional infrastructure reinforcement

6.3.2.2 Remaining Flexibility and Disrupted Rate under high demand situations (normal situation)

This section analyses the results under an otherwise normal situation in the sense that all supply routes are available (no route disruption).

The results indicate that the European gas infrastructure is able to cope with high demand situations. In the long term the demand increase in Croatia, foreseen in all demand scenarios and primarily related to power generation, may require additional infrastructure reinforcement to cope with its high demand situations. The related demand information is available in Annex C2.

If the Romanian indigenous production would indeed decrease as reported by 2035, the country may also have difficulty in covering its high demand situations. It should be noted these situations occur in the later simulated years.

It is also worth noting that the current firm infrastructure capacity between Germany and Denmark is just sufficient for Denmark and Sweden to face their high demand situations in the Blue Transition scenario (Remaining Flexibility is close to 0%). Additionally, in 2030 in the Blue Transition scenario, the demand increase in Poland, in particular related to gas displacing higher-carbon coal generation in the power sector, contributes to a lower remaining flexibility.

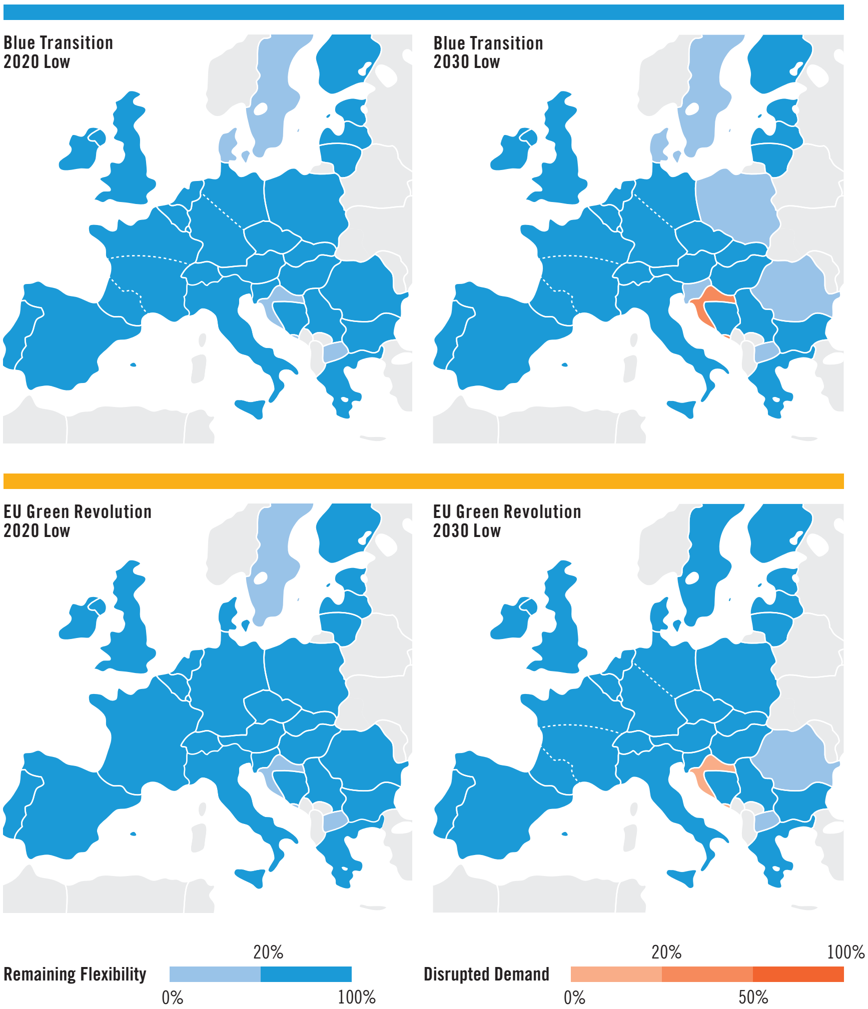


Figure 6.3: Disrupted Rate and Remaining Flexibility, EU Green Revolution and Blue Transition, DC, Low infrastructure level

6.3.2.3 Disrupted Demand and Remaining Flexibility under Route Disruption

This section investigates the effect of a supply route disruption during a high demand situation. Only the additional effect compared to the result from the situation without the route disruptions are shown. Results are shown for the European Green Revolution and the Blue Transition scenarios.

The gas infrastructure is resilient to most of the route disruptions cases investigated. The Ukraine transit disruption leads to disrupted demand. In some of the scenarios, the Belarus transit disruption also leads to disrupted demand on the long term.

Franpipe, GreenStream, Langeled, MEG, TANAP and Transmed route disruptions

The disruption cases have been modelled for Franpipe, GreenStream, Langeled, MEG, TANAP and Transmed. Results do not show significant differences in terms of remaining flexibility for security of supply needs, compared to the case without route disruption covered in 6.3.2.1. The results as illustrated below are the same for all cases.

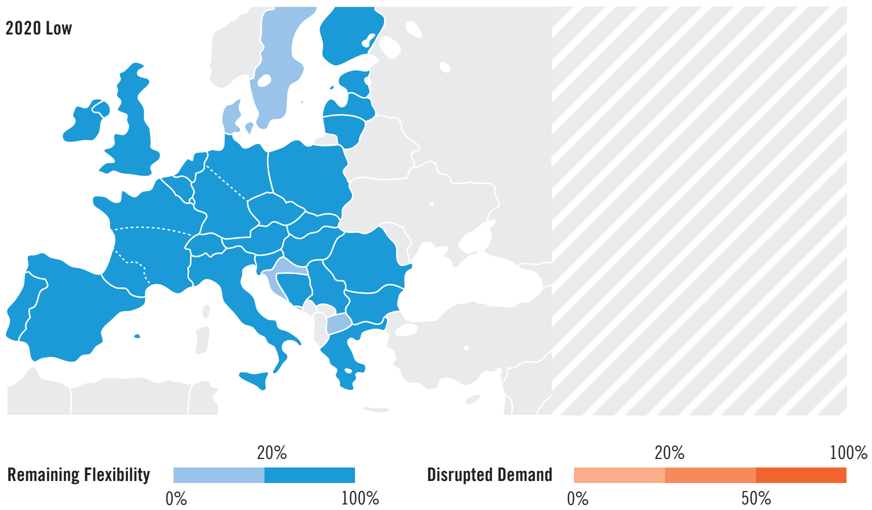


Figure 6.4: Remaining Flexibility for Langeled, Franpipe, Transmed, GreenStream, MEG and TANAP route disruption, Low infrastructure level, all Demand Scenarios and High Demand Situations

Belarus transit disruption

Under a Belarus transit disruption, in the short-term, Poland, Lithuania and Latvia experience a decreased remaining flexibility. The Lithuanian Klaipėda LNG FSRU is currently in operation. However, from 2025 it is not considered anymore in the low infrastructure level, reflecting the expiration of the FSRU time charter party (leasing agreement) by then[1], and the fact that the operator has not yet taken a decision about possibly purchasing the FSRU[2]. This leaves the Baltic States without access to LNG. A Belarus transit disruption would therefore cause Lithuania to curtail more than 50% of its demand, and Latvia to face limited demand curtailment. In addition, Poland and Estonia face a risk of demand disruption from 2025 onwards in the Blue Transition scenario. This indicates an investment need in Poland and the Baltic States to increase the resilience towards a Belarus transit disruption, though this need may depend on the scenario.

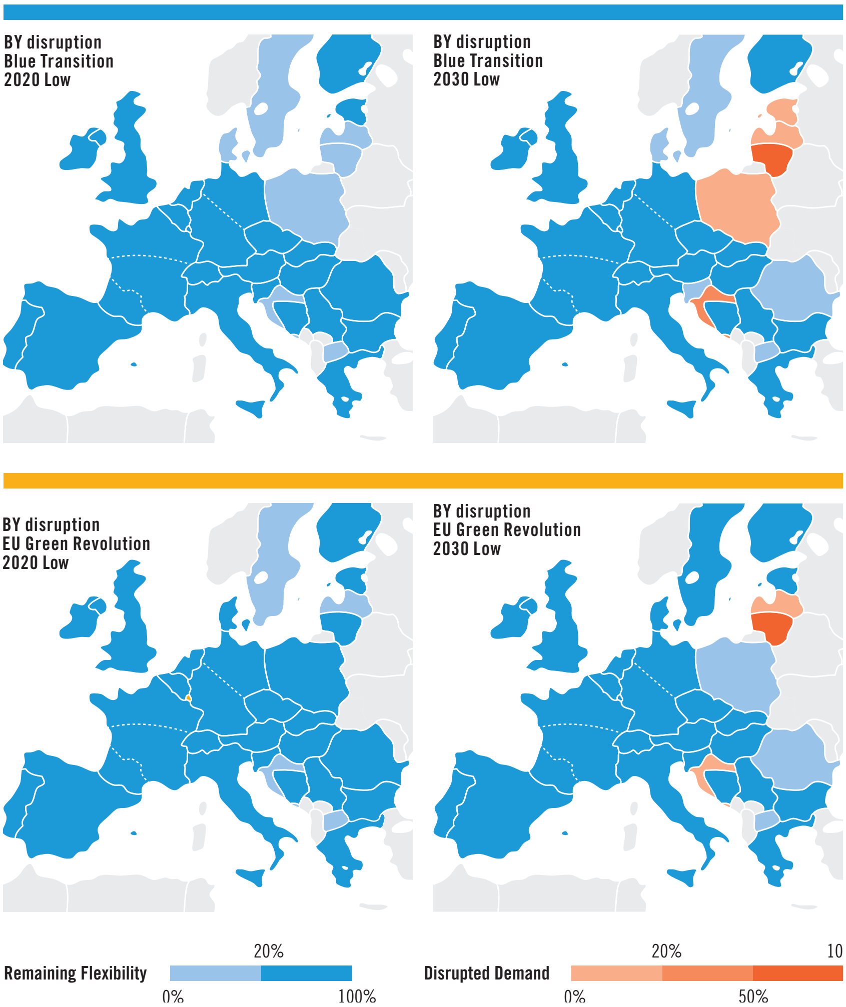


Figure 6.5: Disrupted Rate and Remaining Flexibility under Belarus route disruption, EU Green Revolution and Blue Transition, DC, Low infrastructure level

1) See Annex D, Sheet "Capacity changes"

2) The Klaipėda LNG terminal continued operation is considered in the high infrastructure level

Ukraine transit disruption

The Ukrainian transit disruption case shows a potential demand disruption in Bosnia and Herzegovina, Bulgaria, Croatia, Hungary, Romania, FYROM and Serbia. Infrastructure gaps can be observed between these countries and the surrounding EU countries. Additionally, such disruption has an impact for remaining flexibility in South-East Europe and Poland.

The situation improves from 2017 to 2020 following the commissioning of projects. Greece is not affected anymore by a Ukrainian route disruption thanks to the expansion of the Revythoussa LNG terminal. Bulgaria receives additional gas through the TAP and IGB connection and can share demand disruption with the surrounding countries thanks to the increased capacity from Serbia resulting from the commissioning of the Interconnection Bulgaria Serbia.

The Ukrainian route disruption impacts South-East Europe in 2030 for all demand scenarios whereas Western Europe and Greece remain with a high flexibility. The surrounding countries with high remaining flexibility are reaching a limitation for sending more gas to the South-East region of Europe. In addition, in the Blue Transition scenario, Poland has a very low remaining flexibility (2 %).

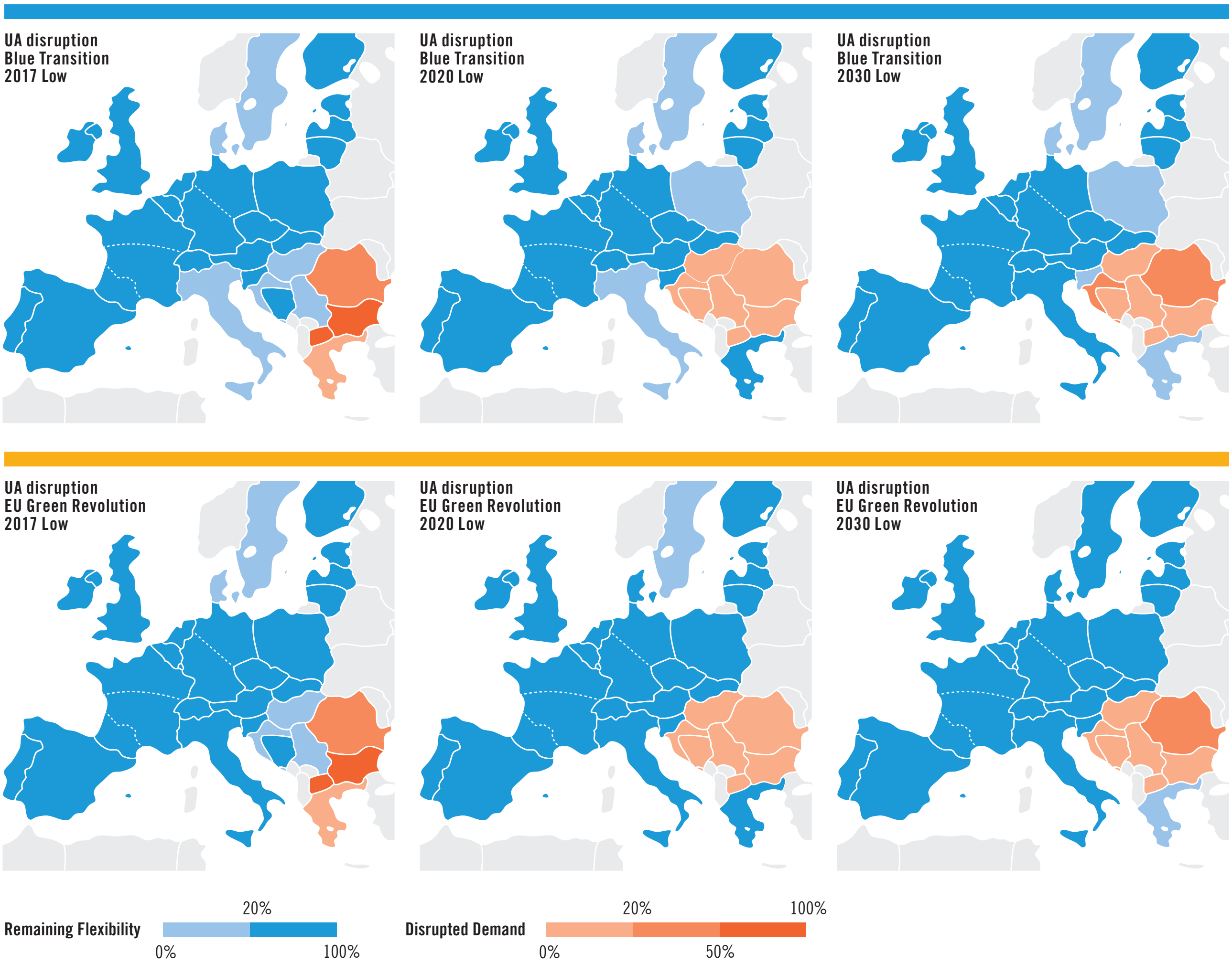


Figure 6.6: Disrupted Rate and Remaining Flexibility under Ukrainian route disruption, EU Green Revolution and Blue Transition, DC, Low infrastructure level. Some countries like Croatia are not additionally influenced by the Route Disruption but keep the same results already explained in the previous chapter 6.3.2.2 (normal situation).

6.3.2.4 N-1 infrastructure assessment

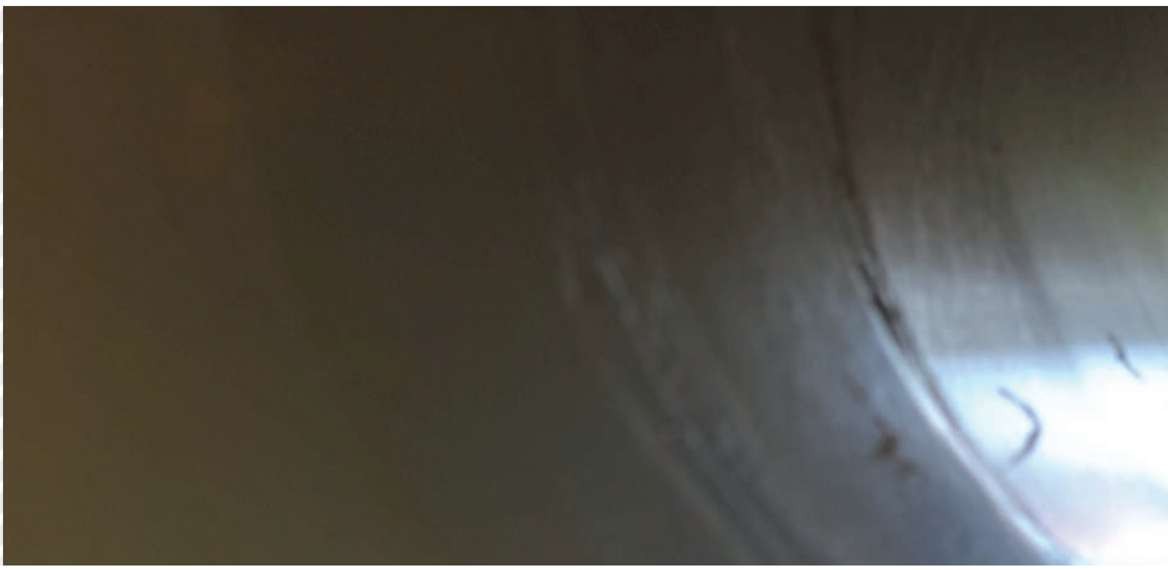
The section covers the results for the N-1 indicator, as calculated under the CBA methodology (N-1 for ESW-CBA). This capacity-based indicator[1)] is calculated for each country. It is intended to measure if countries would have the necessary capacities to cover their peak demand, even in the case that the single largest infrastructure would be unavailable. The indicator is expressed as the percentage of the peak demand that remaining capacities allow to cover.

The indicator derives from Regulation (EC) 994/2010 on Security of Supply, but shows some differences with the N-1 indicator calculated by Competent Authorities. Indeed, it is computed over the whole TYNDP time horizon and is established based on the capacities used in the TYNDP: for interconnection points where the reported capacities are not the same on both sides of the border, the calculation is done with the lower capacity (lesser-of-rule). Additionally, it is calculated considering nominal withdrawal capacities for storages, whereas the actual withdrawal capacities depend on the inventory level. Interconnectors that are located in one given country but cannot contribute to the demand of the country are not included in the N-1 indicator calculation for this country.

Figure 6.7 shows the assessment results for the N-1 indicator in the Blue Transition and EU Green Revolution scenario for the years 2020 and 2030. The low infrastructure level allows most countries to deal with unavailability of the largest infrastructure during high demand situations. Some needs can be identified in Bosnia and Herzegovina, Croatia, Estonia, Finland, FYROM, Greece, Ireland, Luxemburg, Portugal, Romania, Slovenia and Sweden. Bulgaria in 2017 and Denmark and Poland in the Blue Transition scenario in the later years also show some needs. The appearance of needs for Lithuania in 2030 relates, as mentioned earlier in the chapter, to the Klaipėda LNG FSRU not being considered anymore in the low infrastructure level from 2025, reflecting the expiration of the FSRU leasing agreement.

For those poorly connected countries where the N-1 indicator is not only below 100 % but very low (Finland close to 0 %, but also Sweden or Ireland) or where the demand is highly variable (possibly related to the role of gas in the power sector) a N-1 situation can induce demand disruption for demand levels well below and/or for occurrences much more frequent than those of the peak demand. Finally, the indicator may picture a too optimistic situation as it assumes that transmission and withdrawal capacities can be fully used, which may not be the case in case of upstream bottleneck or if storages are already partly empty.

1) It is based on capacities (which are an input to the TYNDP modelling) and not on outputs of the modelling.



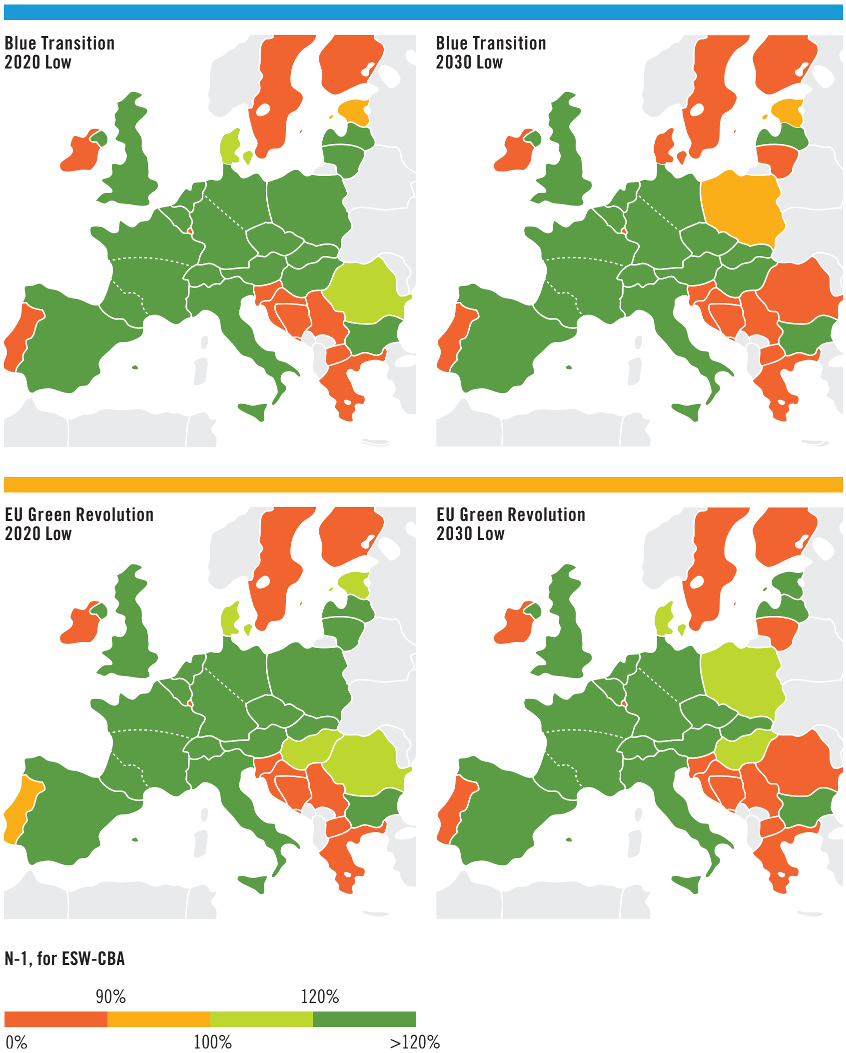


Figure 6.7: N-1, Blue Transition and EU Green Revolution, DC, Low infrastructure level

6.3.2.5 EU supply mixes

On annual basis

The TYNDP analyses the impact of contrasted EU supply mixes on the EU supply and demand balance and gas infrastructure. This is achieved through supply configurations intended at maximising or respectively minimising specific supply sources such as Russian gas and LNG. The results relate to the supply potentials retained for the different sources, as presented in the Supply chapter.

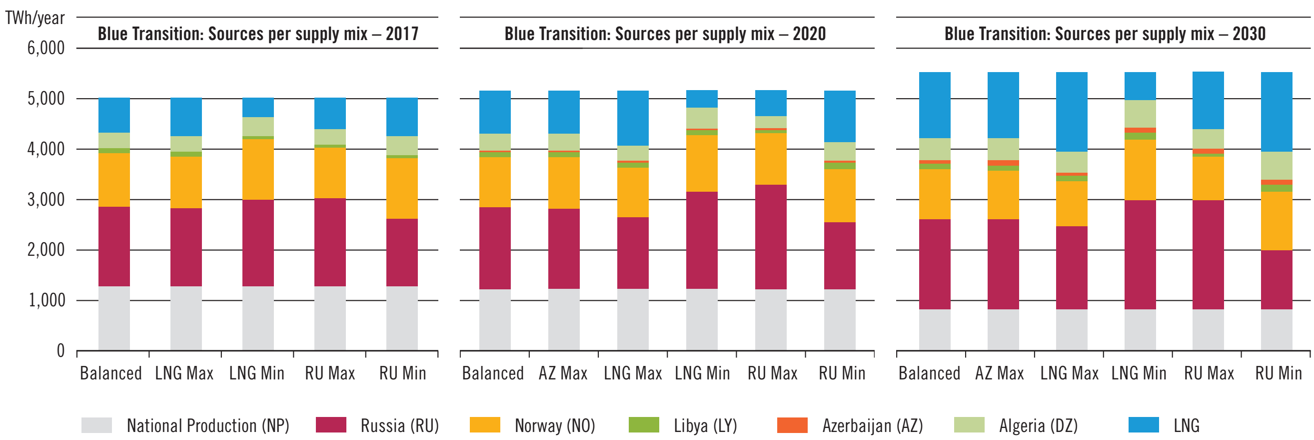
The next figure shows the EU annual supply and demand balance for the years 2017, 2020 and 2030 for these contrasted supply mixes and the range for each supply source.

At EU-level, the low infrastructure level allows each source to reach its maximum potential, under the corresponding contrasted supply mix. At country-level, some infrastructure limitations exist. They are identified in other parts of this chapter.

The infrastructure in the Low infrastructure level also provides high flexibility at EU-level. This is shown by the wide range of possible supply mixes. This can be mainly observed on the long run, where the supply flexibilities are wider in line with the retained supply potentials (see Supply chapter for more details). The tomorrow as today approach retained for supply potentials for the specific 2017 time horizon results in a lower supply flexibility.

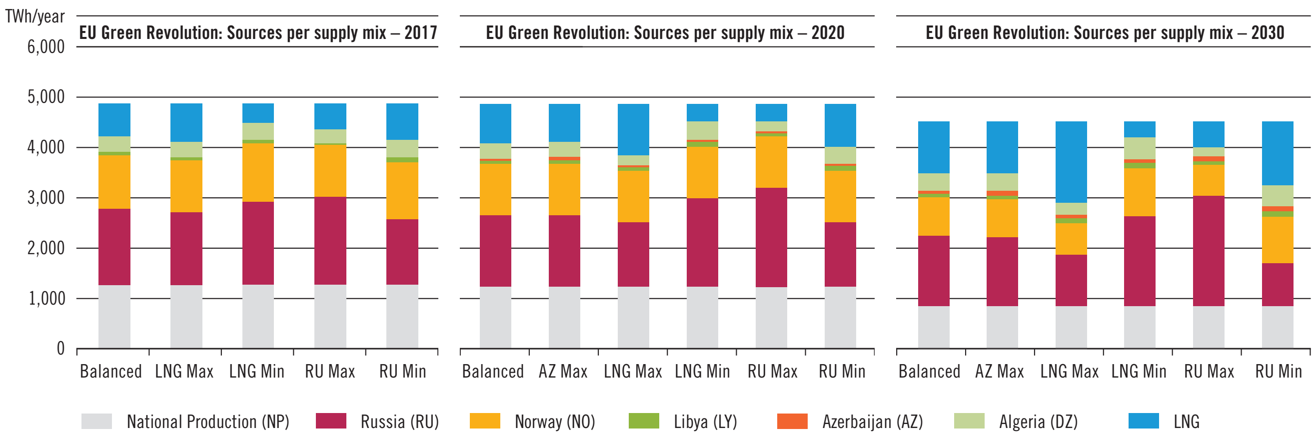
While in the Blue Transition scenario the higher demand leads to high imports and less flexibility on the supply mixes, in the EU Green Revolution the possible import variability is increased.

The low infrastructure level does not allow the internal market to make full use of the Romanian indigenous production over the whole time horizon.



SUPPLY RANGES IN BLUE TRANSITION

	NP	RU	NO	DZ	LY	AZ	LNG
2017	25 %	27–34 %	20–24 %	6–7 %	1–2 %		7–15 %
2020	24 %	25–40 %	19–21 %	4–8 %	1–2 %	1 %	6–21 %
2030	14 %	21–39 %	15–21 %	7–10 %	2 %	2 %	11–29 %



SUPPLY RANGES IN EU GREEN REVOLUTION

	NP	RU	NO	DZ	LY	AZ	LNG
2017	26%	26–35 %	21–24 %	5–7 %	1–2 %	–	8–15 %
2020	25%	27–41 %	20–21 %	5–8 %	1–2 %	1 %	7–21 %
2030	18%	19–48 %	14–22 %	4–10 %	2 %	2 %	7–35 %

Figure 6.8: Yearly supply mixes at EU level in Blue Transition and EU Green Revolution scenarios over time

Under high demand situations

Under high demand situations the supply and demand adequacy relies on a significant share of storage injection. Over time the storages together with the Russian supply replace the disappearing flexibility from National production. This is sensitive to the demand evolution explored in the scenarios. The following charts illustrate the evolution in the Blue Transition and EU Green Revolution scenarios.

Russian gas is the only source showing an increasing share on every analysed configuration. Regarding LNG, available LNG flexibility in the tanks is used in addition to the LNG deliveries from carriers. The volumes in tanks are the difference between the operative fill level of the LNG tanks and their technically required minimum fill level. In total, the regasification capacities are fully used on the peak day, while UGS in particular could still provide additional flexibility.

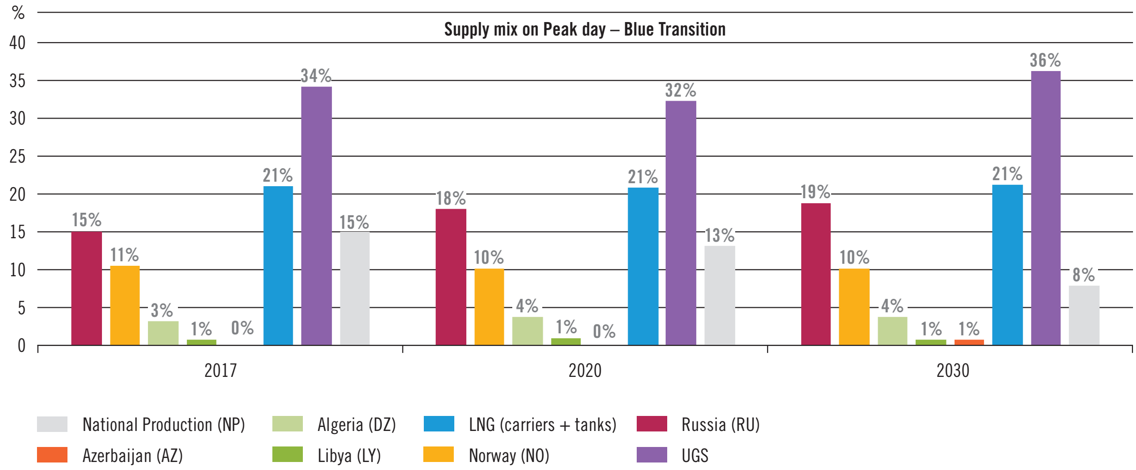


Figure 6.9: Supply mix peak day, Blue Transition

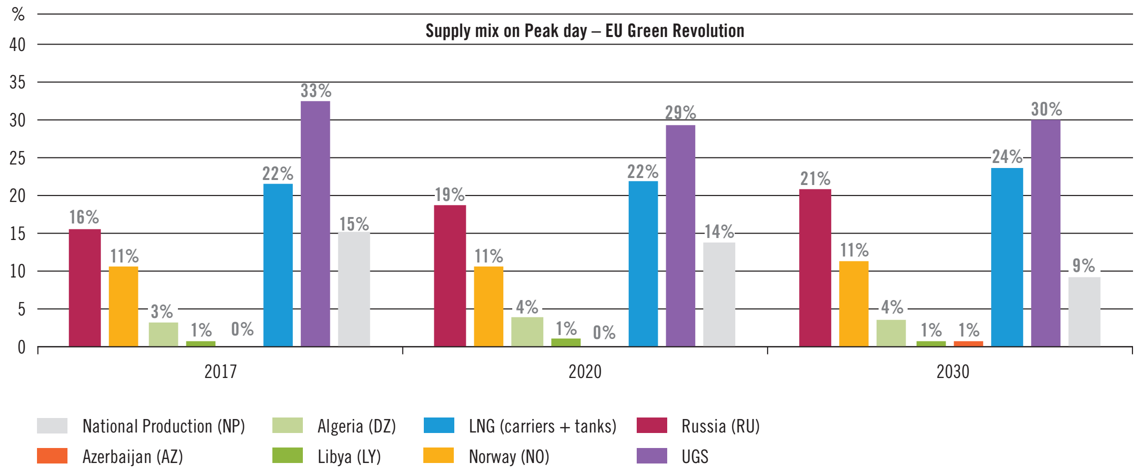


Figure 6.10: Supply mix peak day, EU Green Revolution

6.3.2.6 Conclusions on security of supply related needs

The existing gas infrastructure in Europe - which is the majority of the low infrastructure level (along with the foreseeable reinforcements) - is already providing sufficient flexibility for transmitting supplies to the demand areas in most of Europe. It also proves to be highly resilient. It can stand a high number of route disruption situations (Langeled, Franpipe, Transmed, MEG), as well as for most countries the disruption of the largest single infrastructure (N-1 situation), including under a high demand situation. The assessment of supply source dependence (see 6.3.3.2) provides additional insight on the high resilience of the gas infrastructure.

Nevertheless the assessment of the security of supply related needs, under the low infrastructure level, shows that some additional capacity could be needed in the following areas:

- Croatia on the long run, if their demand outlook materialises
- Romania, if the foreseen increased production would not be maintained over time.
- Poland and the East Baltic countries, which show needs for additional import capacity from alternative sources to cover the risk of a Belarus route disruption on the long run.
- Countries in South-East Europe which would need additional import and potentially interconnection capacity (Bosnia and Herzegovina, Bulgaria, Croatia, FYROM, Hungary, Romania and Serbia) to cover the risk of a Ukraine route disruption.
- Bosnia and Herzegovina, Croatia, Estonia, Finland, FYROM, Greece, Ireland, Luxemburg, Portugal, Romania, Slovenia and Sweden, and potentially on the longer run Estonia and Lithuania, to cover an N-1 situation.
- The L-gas areas in Germany, Belgium and France to allow for the conversion to H-gas and connection to neighbouring H-gas infrastructure.

The assessment under the different scenarios shows a sensitivity of the different results based on the demand evolution. Where infrastructure needs exist regardless of the demand scenario, the needs assessment can be regarded as robust.


Image courtesy of DESFA

6.3.3 COMPETITION NEEDS

6.3.3.1 Access to supply sources

The access to different supply sources is a prerequisite for competition. The ability to attract different supplies, as well as the volumes of these supplies[1)], is taken into account for the identification of diversification.

In order to give a geographical view of the diversification for each country, an aggregated index was defined as the number of supply sources considered as significantly influencing the gas bill of each country. This index is built based on the Supply Source Price Diversification indicator (SSPDi). Calculated independently for each supply source, this indicator measures the simultaneous ability of each country to benefit from a decrease of the price of each import source. A country has been considered as having a significant access to a supply source when the SSPDi to this source is higher than 20 %, which means that a decrease in the price of this supply source would impact at least 20 % of the country supply bill. Alternatively, an SSDPi of 0 % means the country gets no benefit from a low price of the concerned source. The detailed results from Figure 12 allow identifying how a different threshold would impact on the results. The approach is based on marginal gas prices and therefore a country can benefit from a source when having the possibility to commercially access that source. (see figure 6.11)

The SSPDi indicator must be considered keeping in mind the assessment is performed under an assumption of perfect market functioning, explaining results more positive than currently observed. But this way of quantifying the access to supply sources is also conservative, in a way that supply sources are measured against the whole European demand and therefore small sources have little influence on the result. This assessment continues the approach from the TYNDP 2015, with the additional inclusion of indigenous production as a supply source. National production does not only benefit the production country. It is considered as a collective good whose benefit is shared between countries as long as the infrastructure allow for it.

The results are presented for 2017, 2020 and 2030 in the low infrastructure level for the Green Evolution scenario. The results for the Blue Transition and EU Green Revolution scenario show close results, except in 2020, in the Blue Transition scenario, Greece, Bulgaria, FYROM only access three sources, and Romania two.

1) See Supply chapter on supply potentials retained

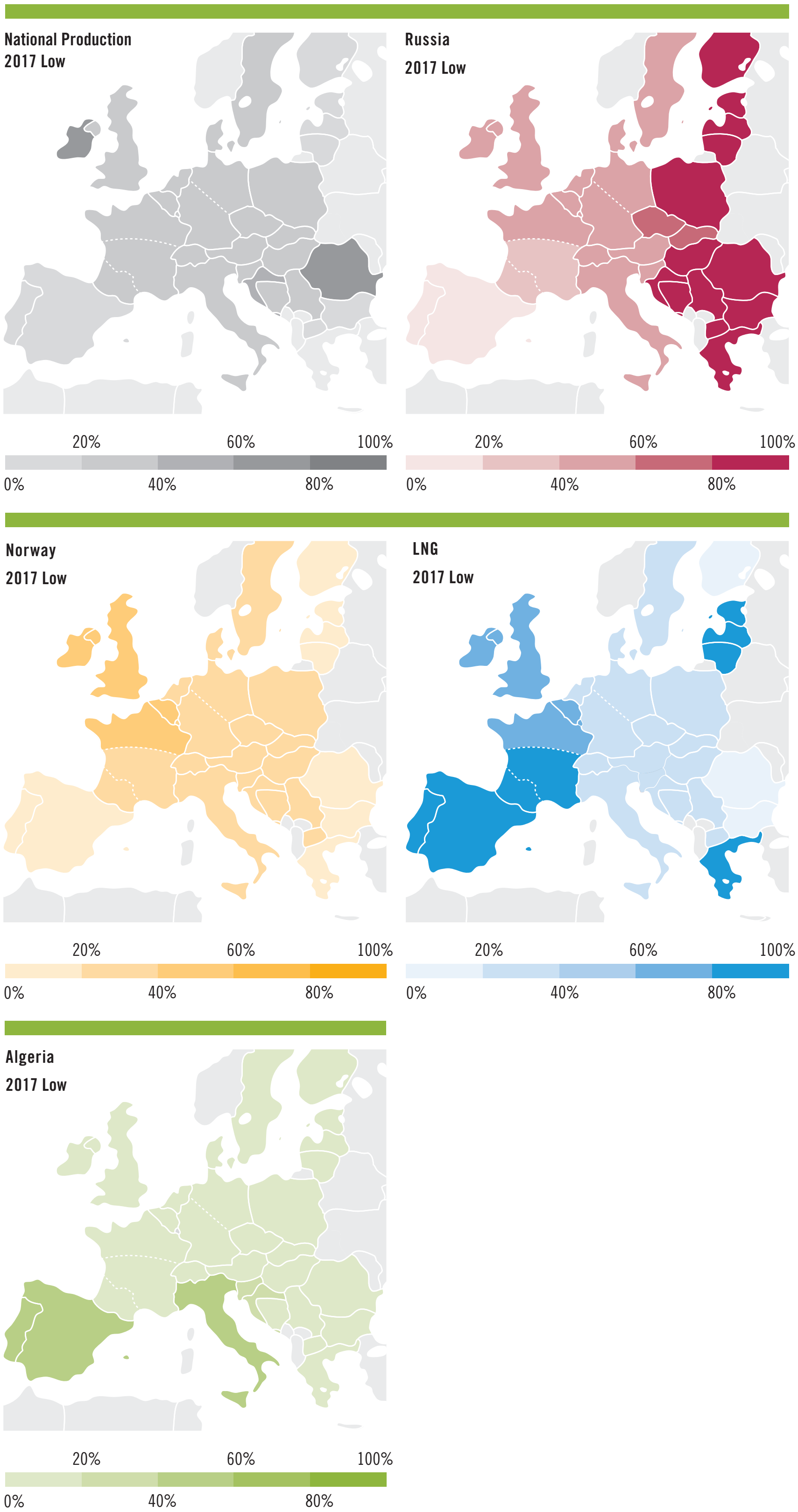


Figure 6.11: SSPDi, Green Evolution, Low infrastructure level, 2017.

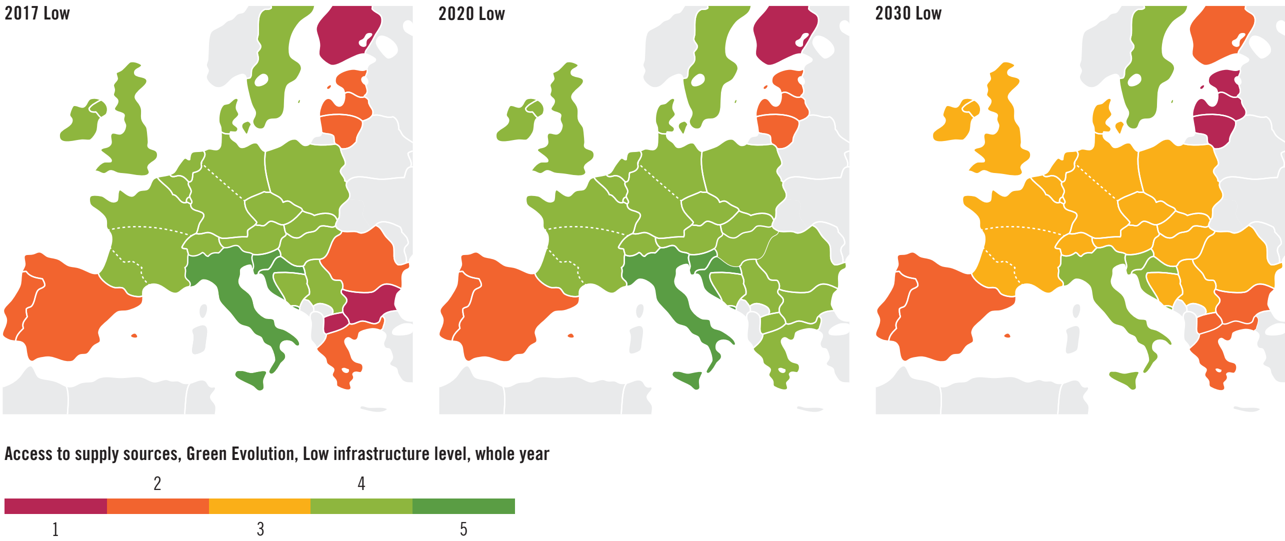


Figure 6.12: Access to supply sources, Green Evolution, Low infrastructure level, whole year

The supply sources per country can be identified when looking at the country level results for the SSPDi indicator for each supply source shown in Figure 6.12. The colour of the bar represents the supply source, whereas the height of the bar represents how much this source can positively impact the country supply bill.

Finland, Estonia, Latvia, Lithuania, Portugal and Spain show a low diversification potential. This is also the case in 2017 for Bulgaria, FYROM, Greece and Romania. The situation improves by 2020 thanks to the foreseen commissioning of a number of projects in this area, such as the extension of the Revythoussa LNG terminal in Greece or the Greece-Bulgaria interconnection. The deterioration in the Baltics in 2030 relates, as mentioned earlier in the chapter, to the Klaipėda LNG FSRU not being considered anymore in the low infrastructure level from 2025, reflecting the expiration of the FSRU leasing agreement.

The situation for countries accessing LNG (in particular the Iberian Peninsula and Greece) is more diversified than the indicator result since the LNG supply source consists of gas from various countries exporting gas as LNG. For details see the GLE analysis in section 3.3.2 in the supply chapter. However, the results can have an impact on competition and a better access to alternative supply sources would enhance the results for this indicator for Greece, Portugal and Spain.

Italy has infrastructure in place allowing the higher diversification degree, which only Slovenia and Croatia can currently benefit from.

The number of supply sources decreases from 2020 to 2030 for most of the countries due to the European-wide decrease of the indigenous production, which does not make it over the threshold of 20%. Additionally the diversification potential of the Baltic States decreases post-2025 since the Lithuanian Klaipėda LNG FSRU is not considered anymore in the low infrastructure level after this date, reflecting the expiration of the FSRU leasing agreement.

Figure 6.13 on the following double page informs in more details the situation across Europe for the different supply sources.

Regarding LNG, the diversification is triggered starting from countries having a direct access to LNG. Figure 6.13 indicates that Greece and the Baltics can fully benefit from a low LNG price, but are also constrained in sharing this low price benefits with neighbours. The same is visible for the Iberian Peninsula towards the North. The area composed of Ireland, United Kingdom, France, Luxemburg and Belgium has a good level of diversification to LNG which can be shared up to a certain extent with countries further east. The lower level of diversification for Italy and the Netherlands, which also have direct access to LNG, reflects the fact that interconnections allow them to share this LNG and associated low price benefits within a wide area.

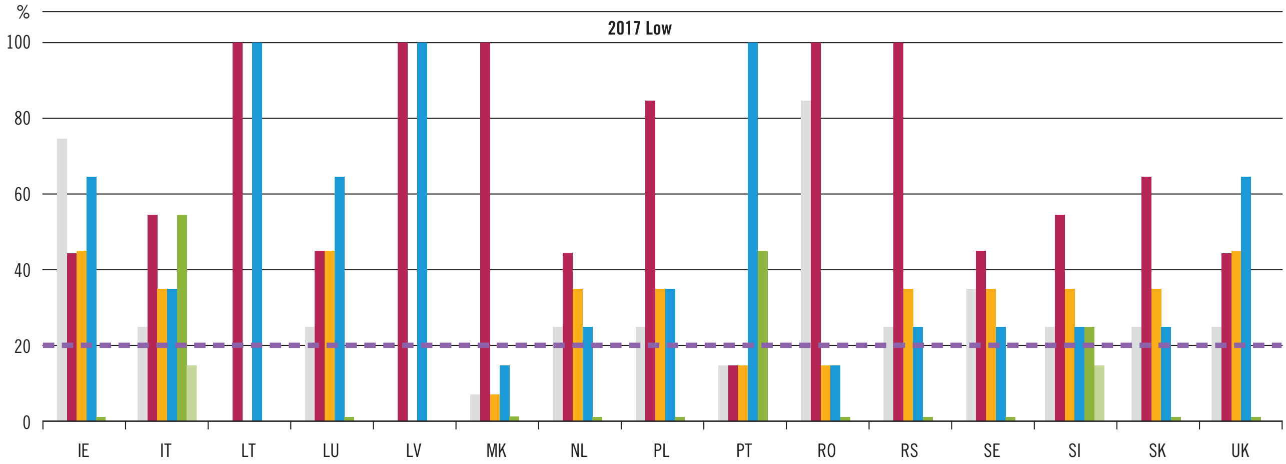
The same analysis can be done on Figure 6.13 for the other supply sources. For the Russian supply, the benefit of a low Russian price is the highest for countries having Russian gas as their main supply, and fades progressively for countries further west. The Iberian Peninsula is the area with the lowest benefit of a low Russian price.

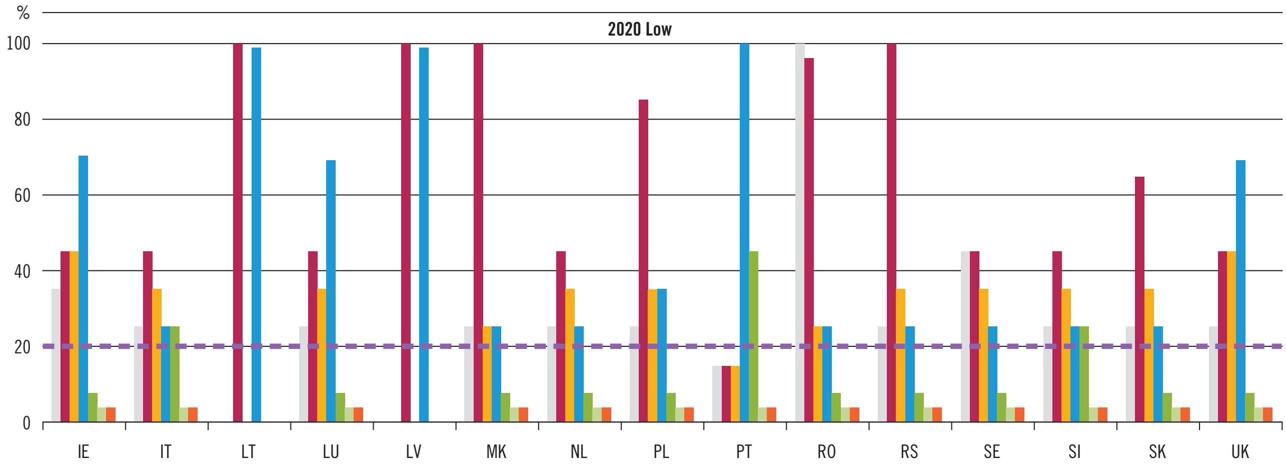
In terms of Norwegian supply the benefit of a low price is rather evenly distributed among a number of European countries, indicating that between those countries there are no infrastructure limitations to the commercial access to this source. There are noticeable exceptions to this evenly distribution for the Baltic States and Finland, and to a lesser extent for the Iberian Peninsula and the area composed of Bulgaria, Greece and FYROM. This indicates local infrastructure limitations.

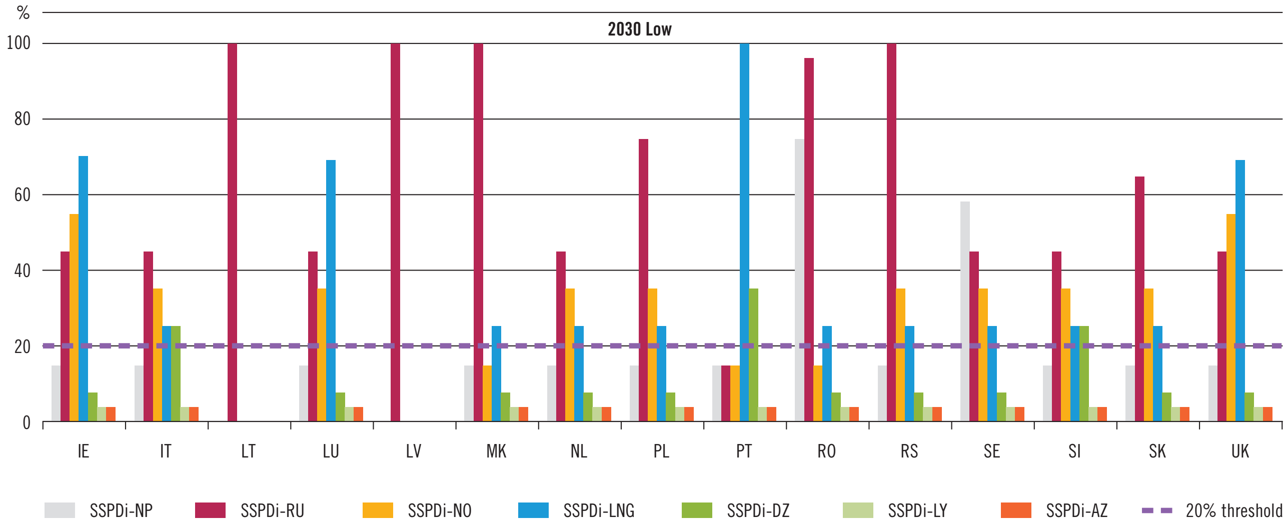
In the case of Algerian gas, infrastructures in Italy allow Slovenia and Croatia to significantly benefit from this source.

Finally, in the case of indigenous production, in 2017, local infrastructure limitations prevent Ireland, Croatia and Romania to share their production with neighbouring countries. This is lifted from 2020 for Ireland and Croatia, thanks to projects commissioned by this date, but remains for Romania for the full time horizon.

Figure 6.13: SSPDi per country, Green Evolution, Low infrastructure level, whole year


%
2017 Low
100
80
60
40
20
0
IE
IT
LT
LU
LV
MK
NL
PL
PT
RO
RS
SE
SI
SK
UK


%
2020 Low
100
80
60
40
20
0
IE
IT
LT
LU
LV
MK
NL
PL
PT
RO
RS
SE
SI
SK
UK


%
2030 Low
100
80
60
40
20
0
IE
IT
LT
LU
LV
MK
NL
PL
PT
RO
RS
SE
SI
SK
UK
SSPDi-NP
SSPDi-RU
SSPDi-NO
SSPDi-LNG
SSPDi-DZ
SSPDi-LY
SSPDi-AZ
20% threshold

6.3.3.2 Supply source dependence

The supply source dependence should be understood as the minimum share of a given source in the supply mix, or said differently the share of this source which cannot be substituted by the other supply sources. The analysis is done over the whole year. It has both a European and a country-level dimension. On a European level, it relates to the overall demand and supply volumes that are available. The European-level situation therefore reflects a supply gap and not an infrastructure gap.

The cooperative supply source dependence[1)] (CSSD) is assessed independently for each extra-EU supply **under the assumption that countries interact in a cooperative way**. This means that they try to share the level of dependence with other countries. As a consequence of such cooperative behaviour, different levels of dependence between neighbouring countries indicate an infrastructure limitation. This can be mitigated by new infrastructure.

The results are shown for the Green Evolution scenario for the years 2017, 2020 and 2030. The country-level results have a low sensitivity to the demand and are similar for the other scenarios. For 2017, the results reflect the "tomorrow as today" approach applied for the definition of the supply potentials, as described in the supply chapter.

The gas infrastructure does not show any dependence to Algerian, Azerbaijan or Libyan supply, already now as well as on the long-run. The volume of any of these sources is low enough to be substituted by the other supply sources (no supply gap), and there is no infrastructure gap preventing this substitution, neither at European-level nor at country-level. This indicates that from a security of supply perspective the current gas infrastructure would be resilient to a long-term disruption of any of these sources.

This is not the case for Norwegian, Russian or LNG supplies which show an European-level dependence, indicating these sources are needed to achieve the European supply and demand balance. At country-level, only Russian supply and LNG show local high dependence. High dependence to Russian supply is both a security of supply and a competition issue. In the case of LNG, dependence is only a competition issue. Indeed, as LNG is a diversified supply per se (see GLE analysis in section 3.3.2 in the supply chapter), security of supply is not at stake.

1) The results for the uncooperative supply source dependence (USSD) and supply source price dependence (SSDPe) indicators from the CBA methodology are provided in Annex but not presented in this chapter. Indeed USSD points at the most dependent country from a supply perspective, but is poorly relevant for the infrastructure gap identification as it does not provide information on infrastructure limitations. SSPDe results show a very high correlation to CSSD results and therefore do not provide further insight compared to CSSD. More methodology-related information on these indicators is available in Annex F.

Norwegian supply

The results for the CSSD indicator for Norwegian supply show a dependence for all of Europe on Norwegian gas only for 2017 (slightly below 15%), linked to the limited supply flexibility of other sources (tomorrow as today approach) for this specific time horizon. On the longer time horizon the availability of Russian gas and LNG mitigates the European dependence on Norway completely. In the Blue Transition scenario, a slight dependence (below 5%) reappears after 2030 for all countries. This is shown in Figure 6.14.

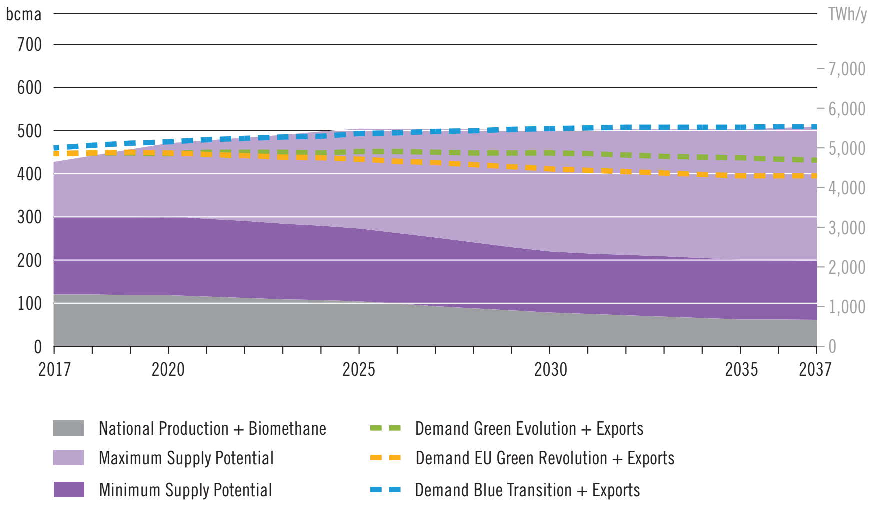


Figure 6.14: European level supply and demand adequacy with no supply from Norway

From 2017 onwards this dependence can be shared equally within all of Europe meaning that no infrastructure limitations are identified, as indicated by Figure 6.15. The following figure shows the results for CSSD – Norway at country level for the Green Evolution scenario.

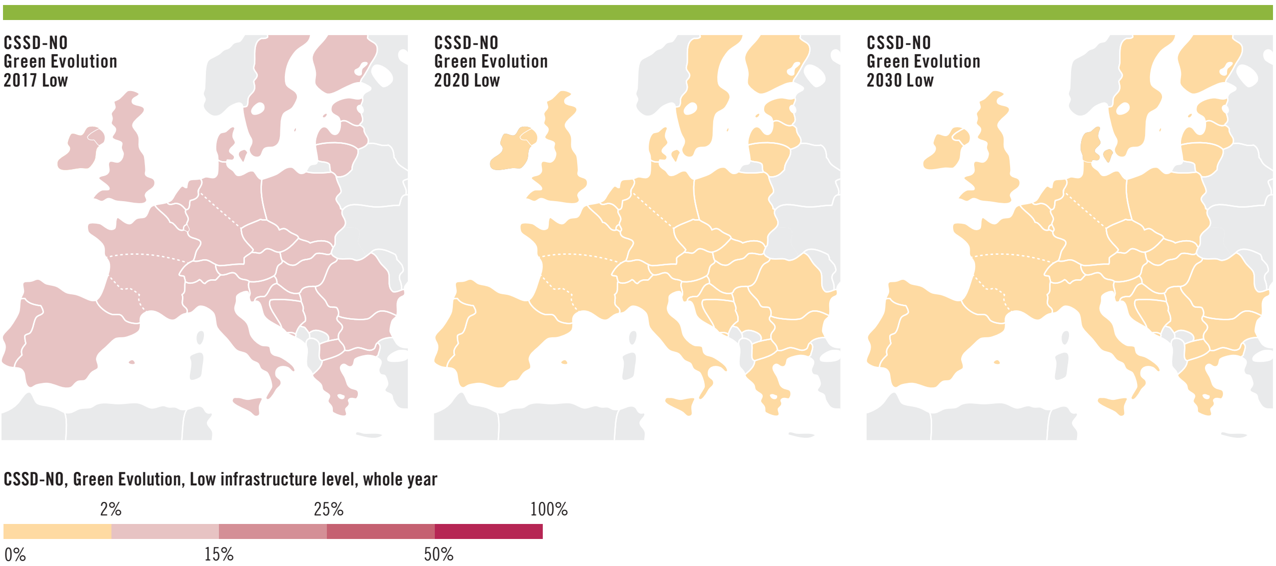


Figure 6.15: CSSD-NO, Green Evolution, Low infrastructure level, whole year

Russian supply

The results of the CSSD indicator for Russian supply show dependence for all of Europe on Russian gas. Nevertheless, at EU level, the gas infrastructure allows accessing the maximum supply potential of all other sources. This indicates that the European-level situation is purely a supply gap, reflecting that Europe relies on a minimum share of Russian gas to achieve its supply and demand balance. The increasing flexibility on other sources over time reduces accordingly the dependence to Russian gas. Yet, some country-level limitations exist and are detailed below.

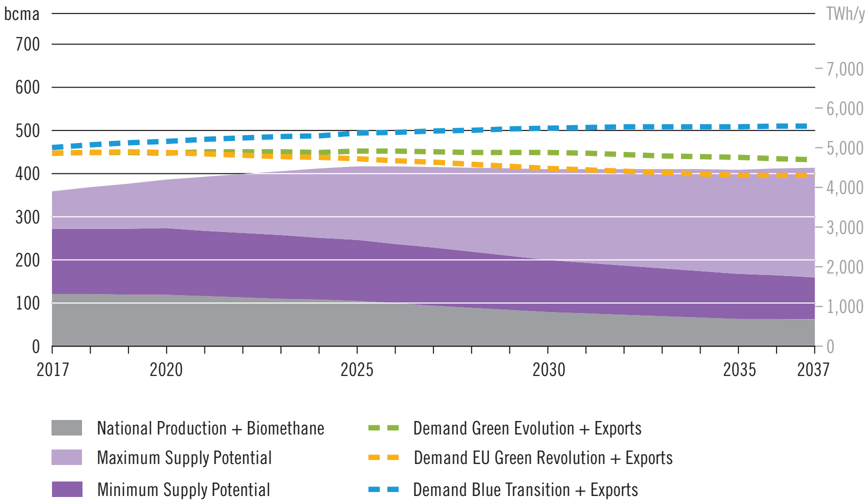


Figure 6.16: European level supply and demand adequacy with no supply from Russia

At country-level, the dependence can be shared equally within most of Europe. This even level of Russian dependence reflects the overall EU-level dependence and should be understood as the infrastructure allowing the evenly distribution of other sources, as a whole, among those countries. The results should be interpreted accordingly. These results reflect the assumptions applied in the TYNDP and the cooperative approach between the EU countries.

Still some areas show higher dependence. In the Baltics and Finland this results from their isolation. In 2017 in South-Eastern Europe, Bulgaria and FYROM higher dependence, as well as Romania lower dependence related to its national production, reveal infrastructure limitation between these countries and their neighbours. From 2020 the wider sharing of the dependence in this region relates to the foreseen commissioning of a number of projects in the region (TAP, Interconnector Greece-Bulgaria, Interconnector Bulgaria-Serbia), but the isolation of Romania remains.

Over time the increased LNG supply potential mitigates the results. In the longer-term perspective, infrastructure limitations can be observed in the countries in Central-Eastern Europe (Poland, Czech Republic, Slovakia, Hungary and Croatia) resulting in increased dependence compared to 2020. The Baltic States increased dependence in 2030 relates, as mentioned earlier in the chapter, to the Klaipėda LNG FSRU not being considered anymore in the low infrastructure level from 2025, reflecting the expiration of the FSRU leasing agreement. Infrastructure limitations prevent the Baltic States from mitigating the situation. Within the other countries, marginal changes in CSSD are seen.

The demand evolution in the Blue Transition scenario shows a higher dependence on a European level with similar conclusions towards the infrastructure.

The dependence to Russian supply is both a security of supply and a competition issue.

Figure 6.17 shows the results for CSSD to Russian supply at country level for the Green Evolution scenario.

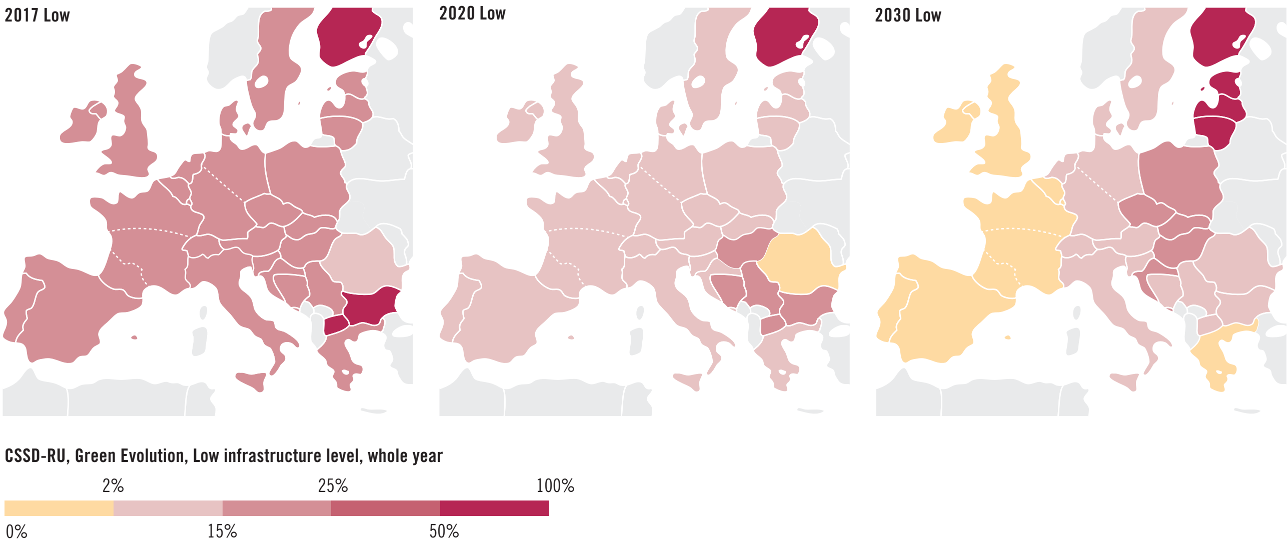


Figure 6.17: CSSD-RU, Green Evolution, Low infrastructure level, whole year

LNG

The results of the CSSD indicator for LNG supply show limited dependence for all of Europe on LNG. At EU-level, the gas infrastructure allows accessing the maximum supply potential of all other sources. This indicates that the European-level situation is purely a supply gap, reflecting that Europe relies on a minimum share of LNG to achieve its supply and demand balance. Yet, some country-level limitations exist and are detailed below.

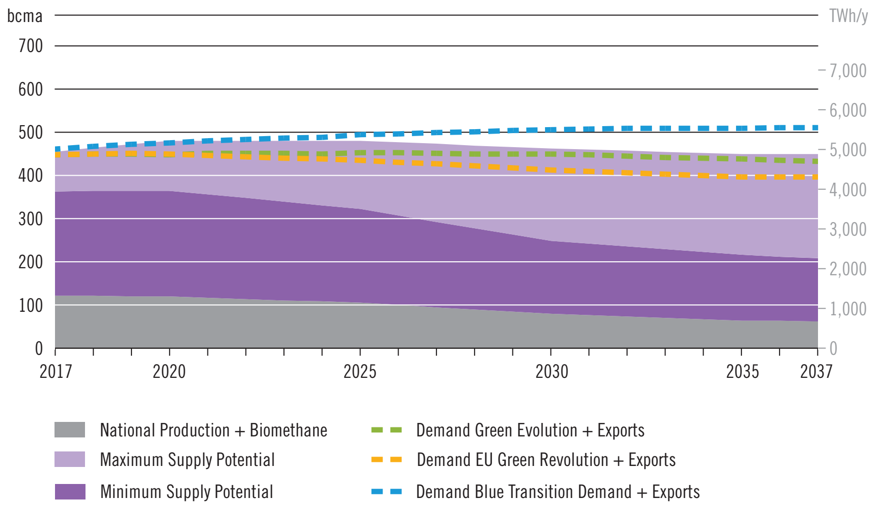


Figure 6.18: European level supply and demand adequacy with no LNG

The results for the CSSD indicator for LNG show dependence for the Iberian Peninsula on the global LNG market, reflecting an infrastructure limitation preventing further substitution of LNG by pipe supply. The realisation of the Val de Saône and Gascogne Midi projects in France mitigates the country dependence by 2020.

Since the LNG supply for the European gas grid consists of gas from various LNG exporting countries, it should not be compared directly to the other indicators. For details see the GLE analysis in section 3.3.2 in the supply chapter. Dependence consequently relates to a competition issue, but security of supply is not at stake.

In 2017 and again from 2030 in the Blue Transition scenario, all other European countries show a slight dependence (below 10%) on LNG imports which relates to the EU-level supply dependence on LNG and can be equally shared between countries.

Figure 6.19 shows the results for CSSD to LNG supply in the Green Evolution scenario.

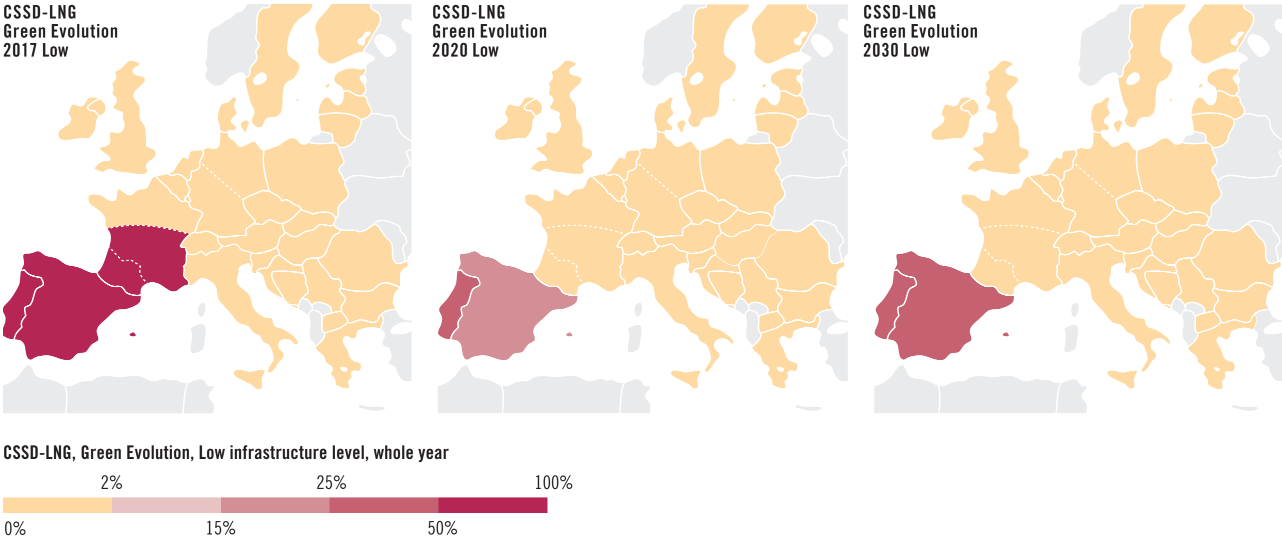


Figure 6.19: CSSD-LNG, Green Evolution, Low infrastructure level, whole year

6.3.3.3 Import Route Diversification

The Import Route Diversification indicator (IRD) is capacity-based[1]. It focuses on how balanced the import capacity of a given country is. For example, a country is better diversified from an import infrastructure perspective, if its entry capacity is equally split between four borders rather than having one predominant. The indicator formula is similar to a Herfindahl-Hirschman-Index (HHI) and hence, the lower the value, the better the diversification.

There is no obvious threshold for this indicator, hence three ranges have been defined from a theoretical behaviour of the indicator. The highest possible value of the indicator is 10,000 for a country with one single entry point representing 100 %. A country with two supply sources with equal entry capacity shares would have an IRD of 5,000 while a country with three supply sources with equal entry capacity shares would have an IRD of 3,333.

The results of the IRD indicator are independent from the scenarios. As the majority of the FID projects are expected to be commissioned by 2020, this time horizon has been selected to illustrate the results.

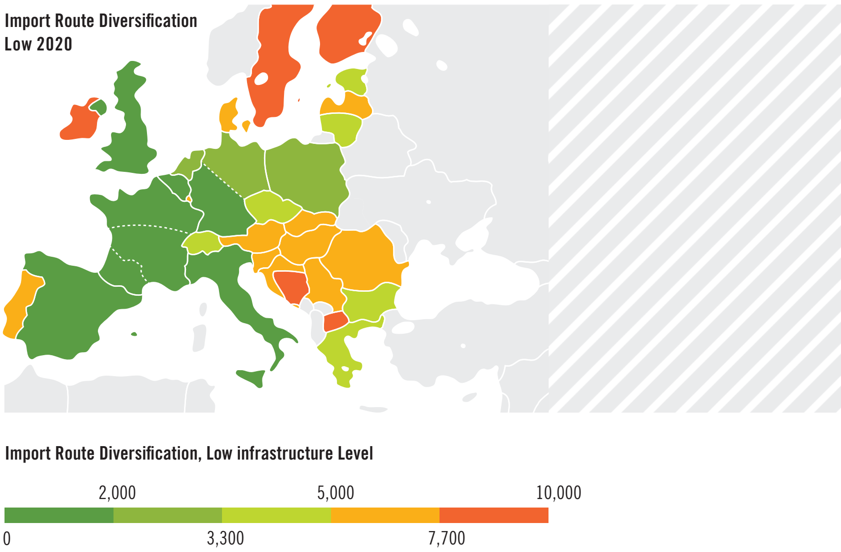


Figure 6.20: Import Route Diversification, Low infrastructure level

The results of the IRD show a contrasted route diversification potential among countries. For countries with a high transit, the IRD can show under-diversification, because the import capacity of the transit source is outweighing the other entries. These cases occur mainly in Slovakia and Czech Republic.

In instances where several physical connection points are handled as one Virtual Interconnection Point, these points are handled as one for the purpose of the calculation of this indicator. The physical import diversification would therefore be higher than the actual indicator result. Also the GLE analysis in section 6.3.2 in the supply chapter regarding the contribution of LNG to diversification should be taken into consideration for the proper understanding of this indicator.

1) It is based on capacities (which are an input to the TYNDP modelling) and not on outputs of the modelling.

6.3.3.4 EU Bill and monetisation on country level

This section analyses how the EU Bill evolves for contrasted supply configurations and how this translates at country-level based on the information derived from the supply dependence and diversification indicators presented in previous sections of this assessment.

EU Bill

The main component of the EU Bill is the supply price[1]. The extra-EU supply sources have a price curve around the Reference price of the respective scenario in the respective year[2]. The Reference price per scenario and time horizon has been set using price information from IEA World Energy Outlook 2015 and is detailed in the Demand chapter.

For the purpose of maximising and minimising supply flows from individual sources in order to assess extreme transportation potentials of the grid a standardised approach has been defined. For the minimisation and maximisation of supplies the price curves of these supplies are set higher or lower by an arbitrary spread of 5€/MWh making this supply the least or the most attractive extra-EU gas source. Additionally the standardised approach assumes that the import price of any given source is the same whatever the import point. In the assessment, indigenous production is set as the preferred supply source by having a price 7€/MWh below the reference price, ensuring it is preferred even over the most attractive extra-EU source[3].

Differences in the EU Bill between years are mainly caused by the price assumptions. It is not the expectation that the Reference price or arbitrary price spread retained will materialise in reality, or that prices determined at internal EU hubs by the modelling can fully reflect internal demand and supply drivers. ENTSOG is aware that the actual development of prices is so volatile that the source used for the Reference price is probably already outdated at the time of publication of the TYNDP report and there are new forecasts available.

Yet the respective supply volumes for the contrasted supply configurations analysed are independent from the price assumptions.

The following supply configurations were analysed:

- Balanced (balanced shares of the different supply sources – same price curve for all sources)
- Russian gas maximised (low Russian price)
- Russian gas minimised (high Russian price)
- LNG maximised (low LNG price)
- LNG minimised (high LNG price)
- Azeri gas maximised (low Azeri price)

1) Other components of the EU Bill are technical weights for the transportation costs and the LNG infrastructure cost. These infrastructure costs only represent a very limited share of the supply costs. See Annex F for more information.

2) For details on how the price curves are determined, see Annex F.

3) For further details about the modelling, see Annex F.

In all cases the modelling optimises the EU Bill by making the best possible use of the supply sources, depending on their respective price. The results for the EU bill in the Green Evolution scenario in the years 2017, 2020 and 2030 for the relevant price configurations are shown in the table below.

EU BILL RESULTS IN THE GREEN EVOLUTION SCENARIO (MILLION €/d)			
	2017	2020	2030
BALANCED (REFERENCE CASE)	257.9	228.8	302.7
AZ MAXIMISATION	–*	–	-1.5
LNG MAXIMISATION	-10.3	-13.7	-21.3
LNG MINIMISATION	+5.8	+5.4	+6.2
RU MAXIMISATION	-23.4	-26.4	-28.9
RU MINIMISATION	+17.8	+18.2	+12.9
*Not relevant since there is no Azeri supply in 2017 and only low volumes during the ramp-up in 2020			

Table 6.3: EU Bill results in the Green Evolution scenario (million €/d)

This table illustrates that individual project costs represent a very small proportion of supply costs. It also shows that the flexibility of the gas infrastructure and diversification allows for huge benefits in terms of optimising the supply mix. The asymmetric results obtained for maximisation and minimisation of a given source demonstrate the value of supply diversification in mitigating the impact of the high price of a source on the supply bill.

Country-level monetisation

The country level monetisation uses as basis the total EU bill resulting from the modelling under the given assumptions as well as information related to the supply dependence and supply diversification assessment. The outcome is the average supply price at country level for the different supply configuration. The marginal price at country-level in these configurations, calculated together with the EU Bill, is covered in below section 6.3.4.1.

In the balanced supply mix all countries have the same average supply price which derives from the price assumptions. The prices for the different scenarios reflect the input data and are not a valuable result on their own. The below table provides for information the price results for the balanced supply configuration in the Green Evolution scenario.

PRICE RESULTS FOR ALL COUNTRIES IN THE BALANCED SUPPLY CONFIGURATION, GREEN EVOLUTION, €/MWh, WHOLE YEAR	2017	2020	2030
PRICE	19.17	17.00	22.45

Table 6.4: Price results for all countries in the Balanced supply configuration, Green Evolution, €/MWh, whole year

For minimisation supply configurations, in order to get a country-level perspective, the differences in the EU bill between each supply configuration and the balanced one are split per country based on the supply dependence of the respective countries to the investigated supply source. The dependence is weighted according to the CSSD indicator results (see Annex F).

For maximisation supply configurations in order to get a country-level perspective, the differences in the EU bill between each supply configurations and the balanced one are split per country based on the supply access potential of the respective countries to the investigated supply source. The access potential is weighted according to the SSPDi indicator results (see Annex F).

The following figures show the results for the country level monetisation in the years 2017, 2020 and 2030 in the Green Evolution scenario for the different supply configurations.

The tables show the results for the average supply prices per demand unit in Euro per MWh on a country level, while the maps illustrate how the price in the respective supply configuration changes compared to the balanced supply mix.

The following two comparisons are a valuable input for determining infrastructure needs:

- Difference between countries within one supply configuration within the same year and the same scenario
- Difference between supply configurations for a given country within the same year and the same scenario.

In the country-level analysis, the price differences between countries reflect the results of the dependence and diversification assessment and depend on the price assumptions presented above. Nevertheless the actual existence of such difference between countries is independent from the spread assumption.

Since the price level results are strongly influenced by the assumptions being the reference price and the price spread of 5 €/MWh for minimised/maximised sources, the monetisation results would change with these assumptions. ENTSOG provides interested parties the opportunity to reflect their own/updated assumptions. Annex E.09 provides a tool where different reference prices and price spreads can be entered and corresponding results can be generated.

Maximisation of Russian gas

A lower price for Russian gas can have an influence on nearly all European countries in terms of country-level average supply price. The effect appears stronger for the Eastern part of the EU. Only Spain and Portugal have low benefits from cheap Russian gas under the low infrastructure level. (see figure 6.21)

The potential to access Russian gas when its price is low, as represented in the below figure, is weighted according to the SSPDi indicator results as analysed in 6.3.3.1. Figure 6.22 ranks countries in terms of ability to benefit from a low Russian price, from best to worst.

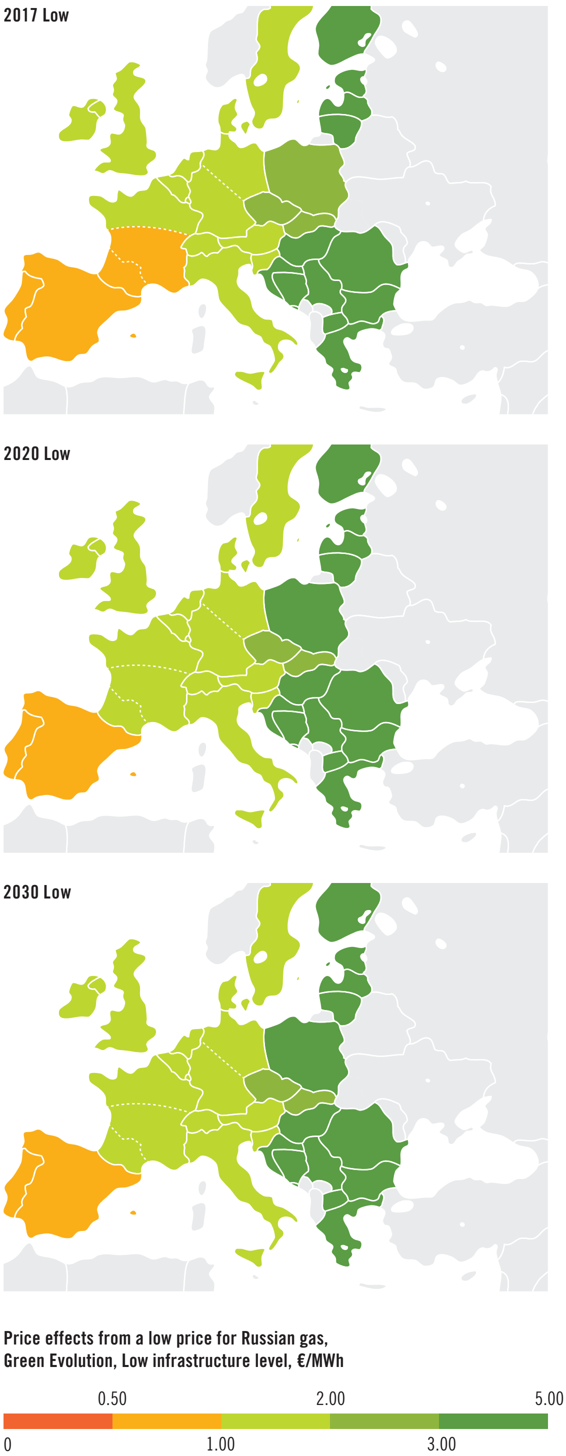


Figure 6.21: Price effects from a low price for Russian gas, Green Evolution, Low infrastructure level

Figure 6.22: SSPDi – Russian gas per country, Green Evolution, Low infrastructure level

Minimisation of Russian gas

A higher price for Russian gas can have an influence on the average supply price of nearly all European countries. The widespread impact is related to the cooperative approach taken towards dependence to the high price supply.

On the long term, the EU impact of high Russian price decreases thanks to increased supply flexibility on other sources. In this context, Finland, the Baltic States and Central-Eastern countries (Croatia, Czech Republic, Hungary, Poland, Slovakia) are most exposed to high Russian gas price. This indicates infrastructure limitations that limit the access of the abovementioned countries to other supply sources compared to the rest of the EU.

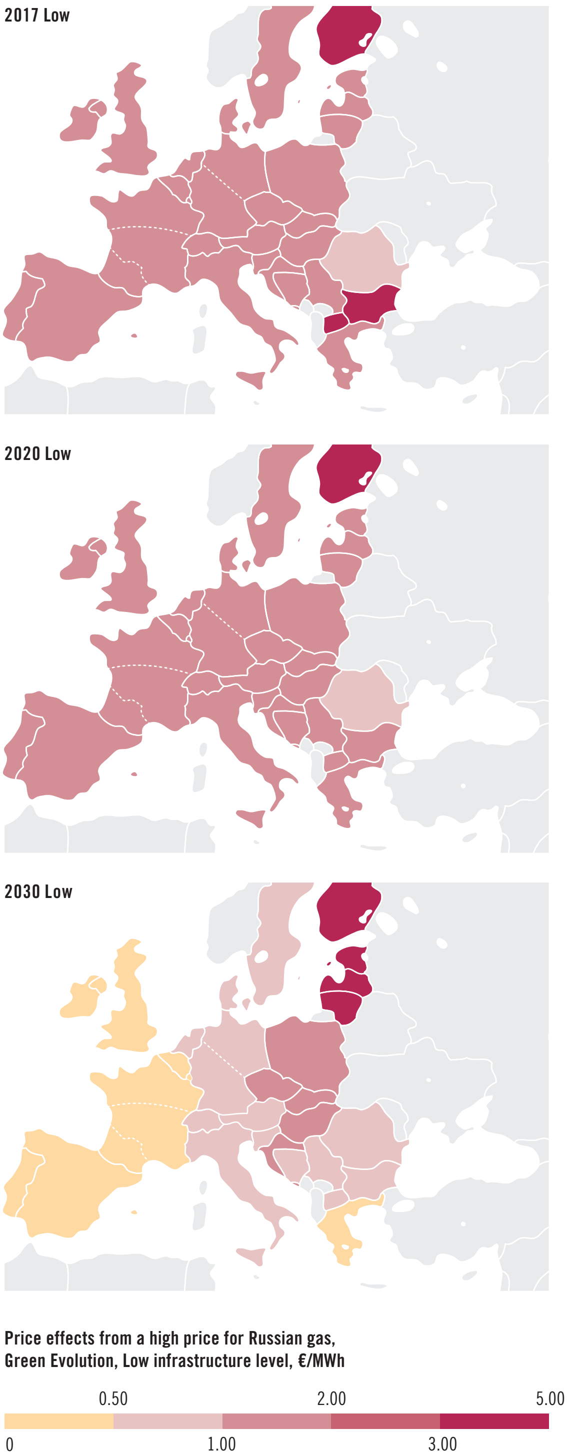


Figure 6.23: Price effects from a high price for Russian gas, Green Evolution, Low infrastructure level

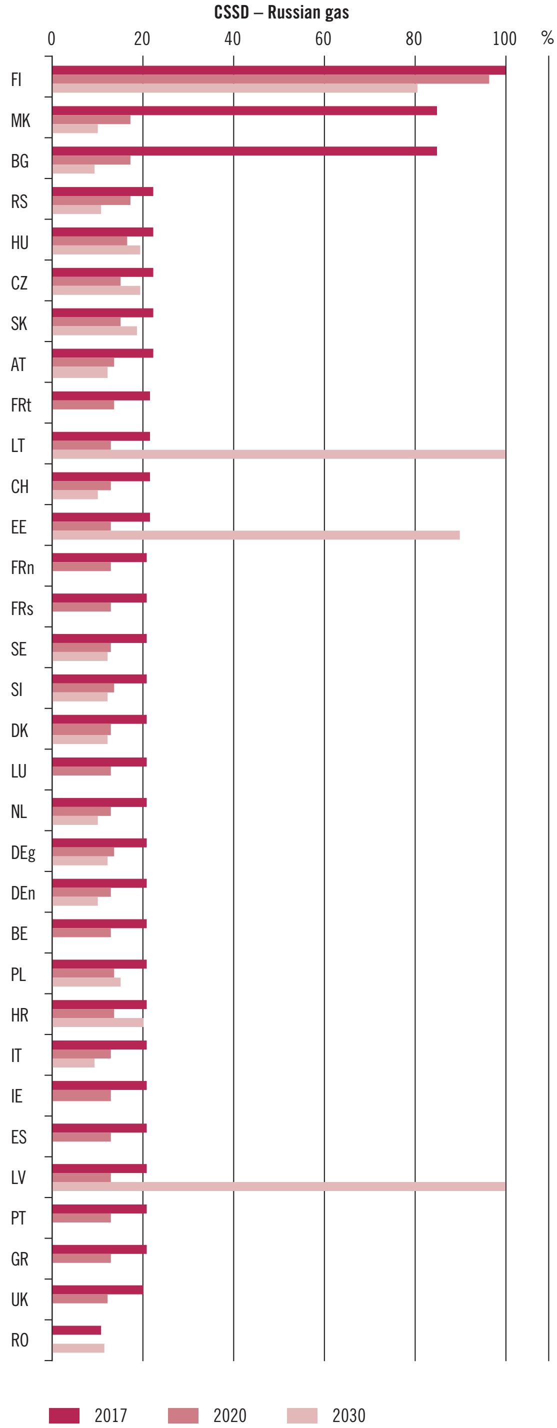


Figure 6.24: CSSD – Russian gas per country, Green Evolution, Low infrastructure level

Maximisation of LNG

A low LNG price can influence several countries within Europe. The biggest impact is expected in the countries with a direct connection to LNG supply. Depending on the interconnections this impact is or not able to propagate further to other countries. The overall EU impact evolution over time relates to the increasing available LNG flexibility. The below map indicates that Greece and the Baltics are constrained in sharing low LNG price benefits up to the maximum with neighbours. The same is visible to a lesser extent for the Iberian Peninsula towards the North and for the Ireland, United Kingdom, France and Belgium area towards further East countries. The situation for Italy and the Netherlands, which also have direct access to LNG, reflects the fact that interconnections allow them to share the low LNG price within a wide area. The potential to access LNG when its price is low, as represented in the below figure, is weighted according to the SSPDi indicator results as analysed in 6.3.3.1. The below figure rank countries in terms of ability to benefit from a low LNG price, from best to worst.

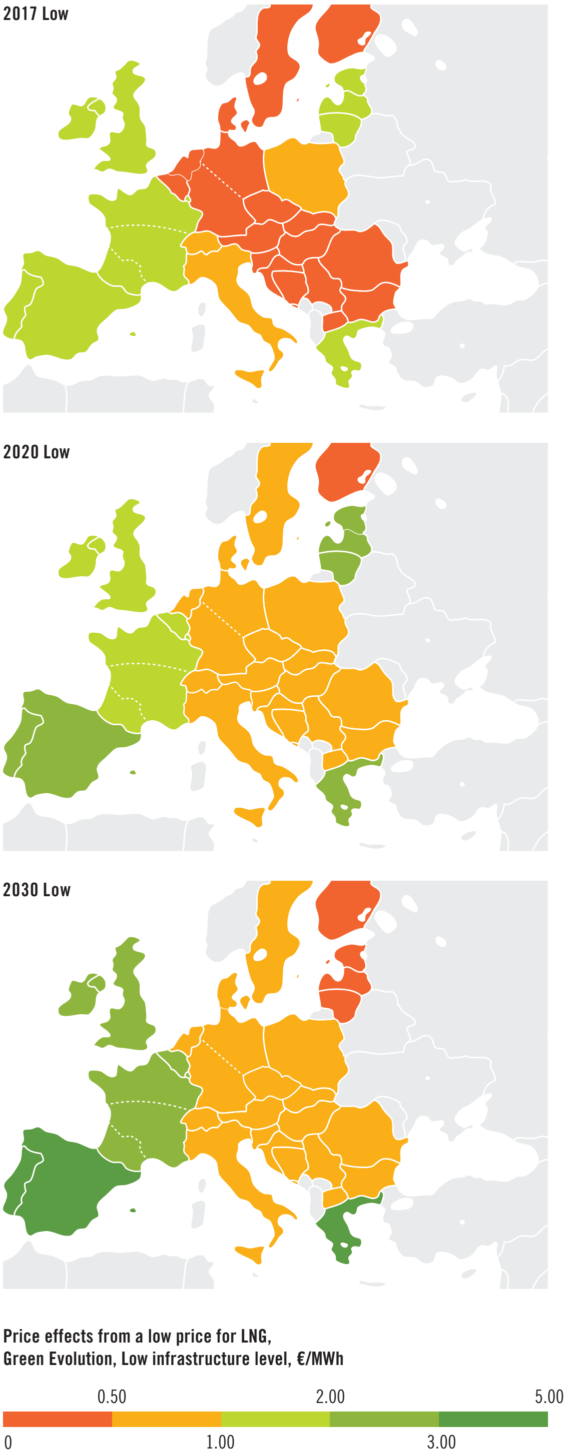


Figure 6.25: Price effects from a low price for LNG, Green Evolution, Low infrastructure level

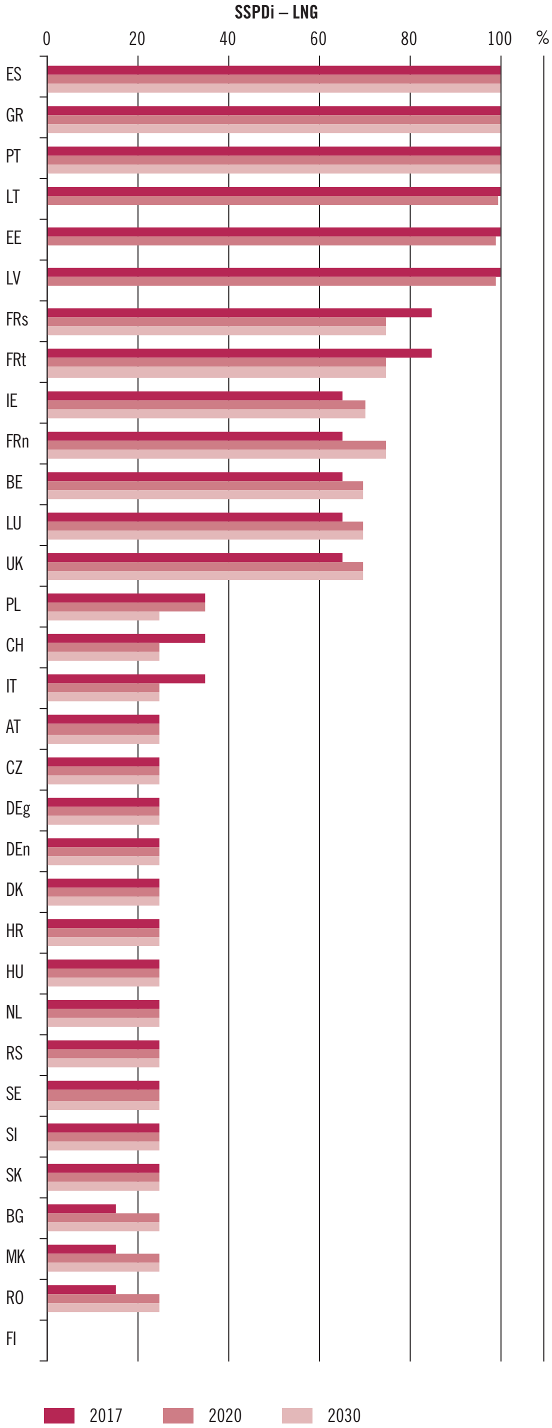


Figure 6.26: SSPDi – LNG per country, Green Evolution, Low infrastructure level

Minimisation of LNG

A high LNG price can influence the gas price all over Europe on a low level. In line with the supply dependence results, the biggest impact is expected in Spain and Portugal, as infrastructure limitations constrain the ability of those countries to substitute LNG with pipe gas. The situation in the South of France is mitigated by 2020 thanks to the expected commissioning of the Val de Saône and Gascogne Midi projects.

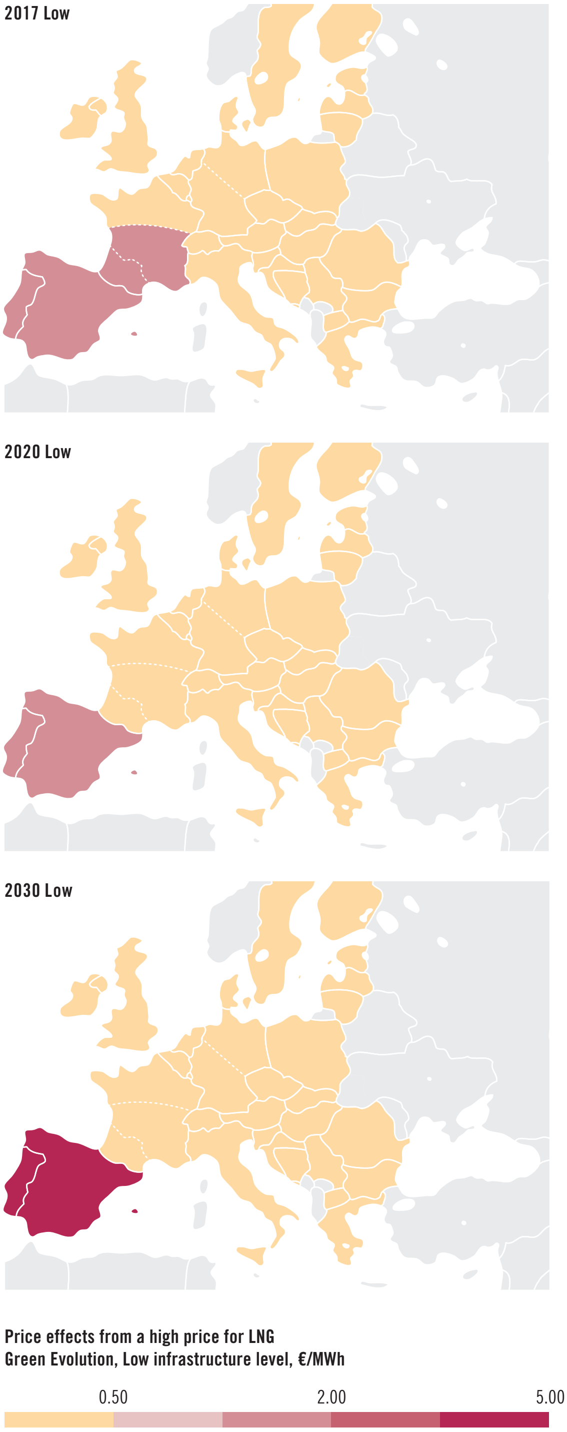


Figure 6.27: Price effects from a high price for LNG, Green Evolution, Low infrastructure level

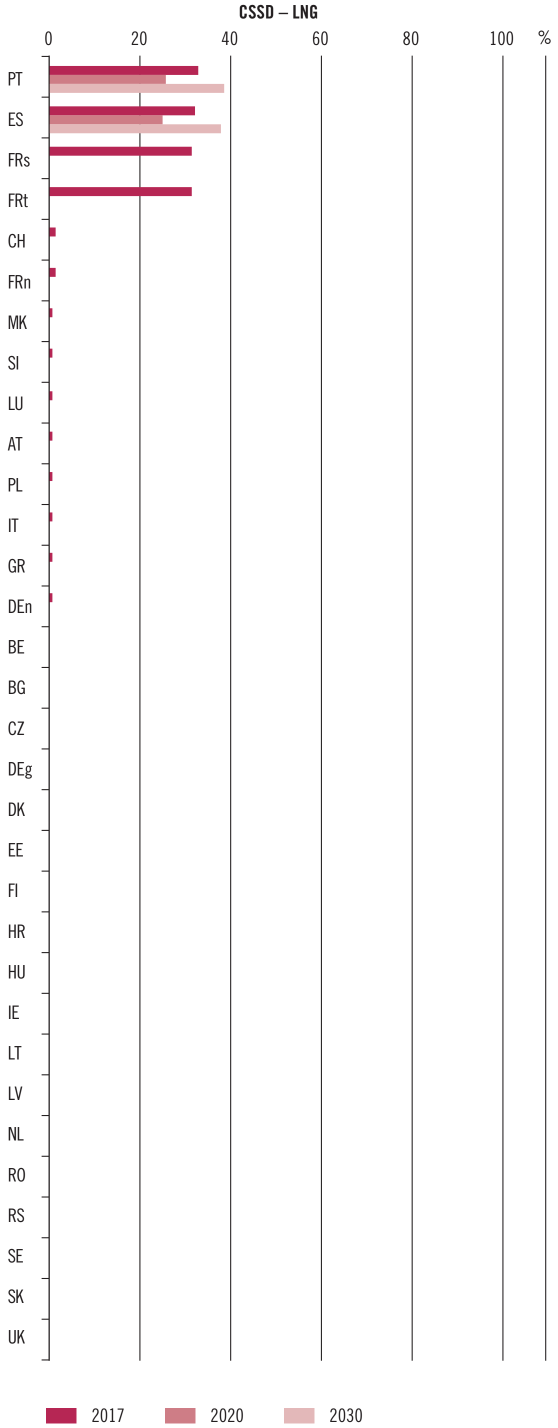


Figure 6.28: CSSD – LNG per country, Green Evolution, Low infrastructure level

Maximisation of Azeri gas

The country level monetisation results for the minimisation of Azeri gas are only shown for the year 2030, since there is no or limited Azeri gas in the years 2017 and 2020.

Since the Azeri supply is small compared to the European demand, the estimated impacts of cheap Azeri gas on overall EU prices are small. A price effects (around -0.2 €/MWh in each country) can be observed all over Europe except for the Baltic States and Finland.

6.3.3.5 Conclusions on competition related needs

The infrastructure gaps hampering competition are identified by assessing the ability of countries to prevent a too high dependence to a given source and symmetrically to benefit from diversified supplies. These results have been complemented with a monetary perspective. The IRD indicator, by taking an HHI approach to countries entry capacities, help support the analysis.

The gas infrastructure generally allows most countries to cooperate in mitigating the dependence to a given source by ensuring access to diversified supplies.

Nevertheless the assessment of the competition related needs, under the low infrastructure level, shows potential needs in the following areas, often resulting from the same limitations as identified in terms of security of supply:

- Cyprus and Malta which are currently completely disconnected from Europe mainland
- In the Baltics area
  - Finland isolation makes it almost fully dependent on Russian supply
  - Baltic States rely only on LNG and Russian supply
- In the South-Eastern and Central-Eastern area
  - South-Eastern countries are highly dependent on Russian supply, with in particular Bulgaria and Romania showing infrastructure limitations with their neighbours
  - Greece faces infrastructure limitations in sharing LNG with neighbouring countries
  - The Central-Eastern area faces an increased dependence on Russian gas on the long run, highlighting the need for additional investments to improve diversification of supply sources.
- In the Western area
  - The Iberian Peninsula, which have access mainly to LNG and Algerian gas when other Western countries access other sources.
- Some potential limitations preventing some countries with a direct access to LNG to share this LNG completely with neighbouring countries
  - At European-level, a general degradation of the diversification potential over time related to the decrease of the European indigenous production

6.3.4 MARKET INTEGRATION NEEDS

6.3.4.1 Marginal price

In the economic theory, the supply price to pay increases with the level of demand to cover. The Marginal price represents the price to pay for supplying the last increment of demand.

In the TYNDP assessment, Marginal prices are calculated on a country level. The Marginal prices are a direct output of the optimisation of the EU supply bill in the modelling[1].

The results presented in this section relate to the supply configurations presented in section 6.3.3.4, including the standardised approach to import prices which assumes that for any given source this import price is the same whatever the import point. The results of the marginal price calculation show price convergence between nearly all countries of Europe (except for Romania which enjoys a lower marginal price in some years due to its excess of National Production and limited export capacity). This observation is true for the minimisation and maximisation (i.e. high and low price) supply configurations.

The results need to be appraised in the view of the modelling assumptions, especially regarding perfect market functioning, no consideration of actual infrastructure tariffs, same import price for a given source whatever the import point and standardised price spreads between sources. These assumptions, retained to ensure focus on the infrastructure limitations, explain that the results are in line with the situation currently generally observed on the Western markets, but not with the situation on some other markets.

From an infrastructure perspective, the assessment results show that the infrastructure in the low infrastructure level does not prevent a price convergence from a European perspective under the assumptions retained for this assessment. This should be taken as an indication that progressing towards price convergence at European level is primarily a matter of full implementation of the Third Energy Package provisions.

6.3.4.2 Import price spread configuration

The European Commission Quarterly Report, together with other publications, indicates differences in pricing policies from suppliers towards different countries.

Based on this observation, the Import price spread configuration has been introduced in this edition of the TYNDP as a complement to the standardised supply configurations approach referred to earlier in this chapter. It uses different supply prices on different supply routes for the same supply source and analyses the resulting effects on the marginal price of countries (also see Annex F).

The analysis is based on an initial situation derived from actual market data that could be found in the COMEXT data base[2] for the first quarter 2016. The German border price is used as a reference to calculate the spreads listed in table 6.5. For example, the spread of 2.90€/MWh for Slovakia results from the Slovakian border price being 2.90€/MWh higher than the German border price in the COMEXT data base for the first quarter 2016. All import routes not listed are considered as having a spread of zero: the same price assumption retained is the same as in the balanced supply configuration.

1) The marginal price is the dual value of the linear optimisation performed in the modelling. See Annex F for more information.

2) Use of the European Border Price (EBP) information from the COMEXT database. This database is used as input in the European Commission Quarterly reports

Information on border price for Finland, Poland and FYROM were missing from the COMEXT data base and were derived from other countries border price information (see footnotes). The results should be interpreted accordingly.

PRICE SPREADS PER ROUTE FOR THE IMPORT PRICE SPREAD CONFIGURATION		
ROUTE TO	FROM	Price Spread (€/MWh)
Bulgaria	Romanian transit system	3.20
Czech Republic	Czech transit systems	2.40
Estonia	Russia	3.00
Finland[1]	Russia	4.90
FYROM[2]	Bulgarian transit system	3.20
Greece	Bulgarian transit system	0.20
Hungary	Ukraine	3.00
Latvia	Estonian transit system	6.70
Lithuania	Belarus	4.90
Poland[3]	Belarus, Yamal-Europe pipeline, Ukraine	4.90
Romania	Ukraine	4.40
Slovakia	Ukraine	2.90

[1] Information not directly available in the COMEXT database: use of average price for Baltic states
[2] Information not directly available in the COMEXT database: use of Bulgarian price
[3] Information not directly available in the COMEXT database: use of Lithuanian price

Table 6.5: Price spreads per route for the Import Price Spread configuration

The modelling follows the assumption that a price spread resulting from monopolistic supply behaviour stops once a certain level of alternative supply can be purchased, creating a breaking point in the monopolistic supply behaviour. While the supplier was previously incentivised to maximise its turnaround by applying a price spread, reaching this level will change this strategy towards focusing on keeping the market share instead. Therefore the previous pricing policy with the price spread on certain routes needs to be abandoned[1].

Figure 6.29 represents the spread in countries marginal prices compared to the German reference price, as resulting from optimising the EU supply bill considering the above border price assumptions as well as a perfect market functioning assumption. The results relate to the diversification potential of the different countries. This does not represent any forecast on prices. In Figure 6.29, the difference in colour between countries indicate infrastructure limitations.

The results for 2017 show already that the low infrastructure level enables overcoming some of the import price spreads. In the EU Green Revolution scenario all impacts from the price spread in the EU have disappeared, except for Finland which remains isolated.

In the Baltic States, the access to LNG through the Klaipėda LNG terminal enables to overcome monopolistic supply behaviour and have marginal price converging with well diversified markets. From 2025 these benefits disappear due to the Klaipėda LNG FSRU not being considered anymore in the low infrastructure level from 2025, reflecting the expiration of the FSRU leasing agreement.

In 2020 and subsequent years, in the Blue Transition scenario, Poland is suffering again from a high price due to a considerable increase of its demand (around 25 % between 2017 and 2020).

1) 80 % of the modelled flows in the initial situation (2016) are used as the basis of the modelling for the following years

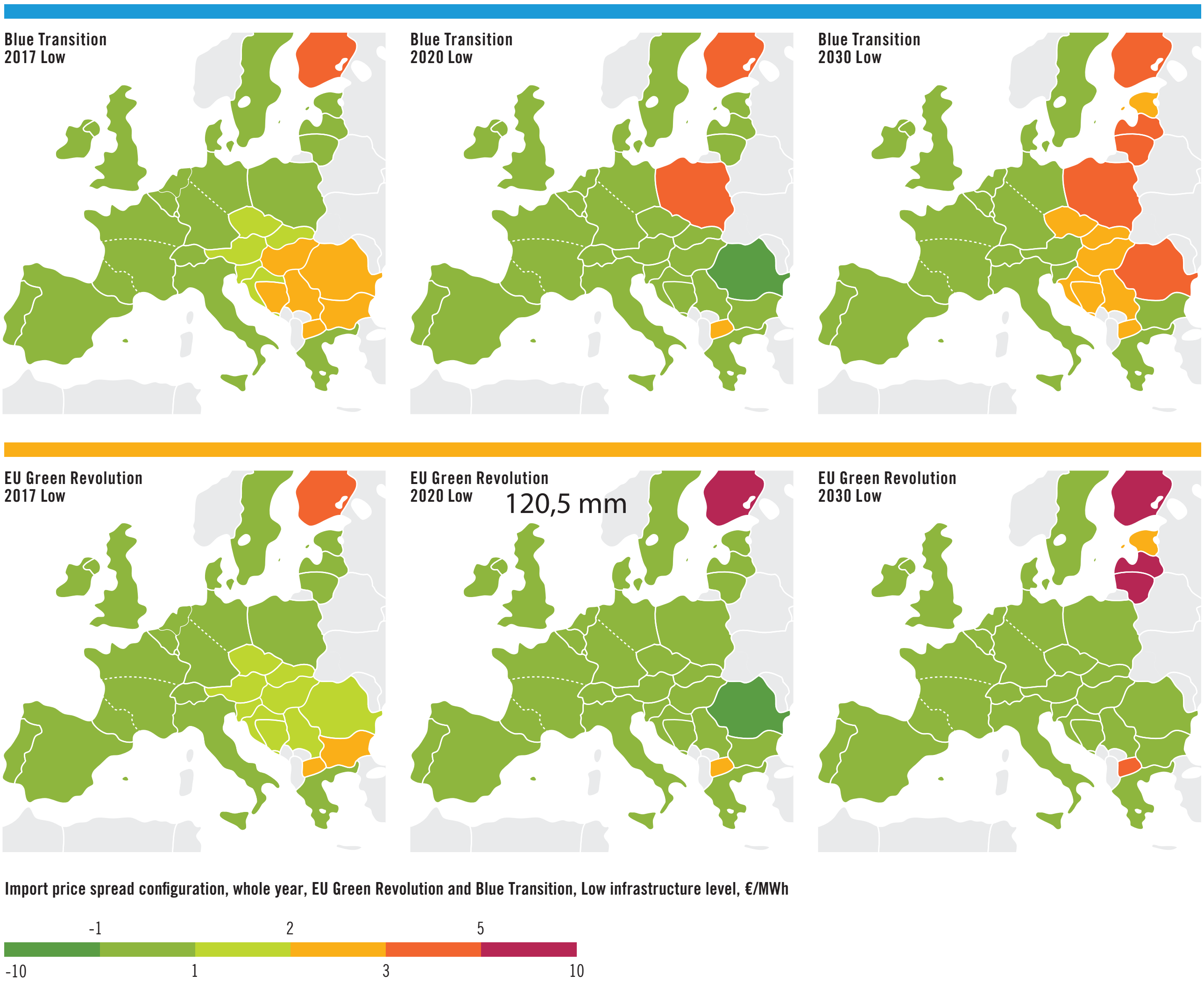


Figure 6.29: Import price spread configuration, whole year, Low infrastructure level, Blue Transition and EU Green Revolution

In 2017 and in the Blue Transition scenario, a number of barriers are identified. Barriers to have a lower price exist for Austria, Croatia, Czech Republic, Slovenia and Slovakia. These barriers are mainly related to the complete use of available capacity between Italy and Slovenia, Germany and Austria as well as between Germany and Czech Republic. Slovakia, Czech Republic, Austria, Slovenia and Croatia share the same price, indicating absence of congestion between these countries. More barriers are identified between these countries and countries further East, showing infrastructure limitations towards Bosnia and Herzegovina, Bulgaria, FYROM, Hungary, Romania and Serbia.

In 2020, the capacity from Italy to Austria allows Austria, Croatia, Czech Republic, Slovenia and Slovakia to be connected to Italy in terms of marginal price. This allows in turn for the interconnection between Germany and Austria to be less used, which also links the marginal prices to Germany. The increase of Romanian production and exports to neighbouring countries lowers the use of some infrastructure, allowing price convergence in the area. Nevertheless, Romania remains price decoupled as its exit capacities are fully used, preventing it from further sharing the benefits of its indigenous production.

In 2030 in the Blue Transition scenario, following the demand increase in these countries and the decreased production in Romania, Croatia, Czech Republic, Hungary and Slovakia are potentially influenced by the price spreads again.

6.3.4.3 Conclusions on market integration related needs

The TYNDP assessment concludes that, if liquid hubs were in place all over Europe, market were perfectly functioning and diversification would allow a sufficient competition between supply sources, the infrastructure would presumably allow marginal prices to converge across most of Europe.

Nevertheless, previous sections results related to competition have also shown that inability to ensure sufficient diversification hampers competition in some areas of Europe. The import spread configuration further highlights where this lack of competition hampers bargaining power and prevents convergence of marginal prices with neighbouring countries. The assessment identifies infrastructure limitations in terms of market integration, and subsequently diversification of supplies, in particular for the following areas:

- Between Baltic States and Finland
- Between Poland and Baltics States
- Between countries south of Poland and Poland
- Between Greece and countries further North (in 2017)
- Between Romania and its neighbours
- Between Poland, Germany, Italy and countries further South-East (in particular in 2017)
- Between Czech Republic, Slovakia, Austria, Slovenia, Croatia and the countries further East (in particular in 2017), dependent on the demand scenario


Image courtesy of GRTgaz Deutschland

6.4 Energy System-wide costs-benefits analysis of Advanced Projects

The previous section provided a thorough analysis of what the current infrastructure, complemented with FID projects, already achieves. It concludes that the low gas infrastructure level already offers a high resilience and market integration. Nevertheless, some remaining needs can subsist in specific areas in order to achieve the European internal energy market. These needs persist on the long run while taking into account the evolution of the gas demand pattern to achieve the European energy and climate targets.

This section therefore assesses the overall further impact of the projects having an advanced status, by comparing the results of the Advanced infrastructure level[1] to those of the Low infrastructure level. The projects of advanced status are defined as the ones that are planned to be commissioned until 2022 and in addition either the front-end engineering design phase or permitting phase has been started (see Infrastructure chapter for further details).

The 52 projects with advanced status are listed in Table 10. They represent an overall investment cost of 16 Bn €. Although having an advanced status, some of these projects may not all materialise.

Projects are taken into account in the assessment from the year after their commissioning. The relevant capacities for this infrastructure level can be found in the Annex D[2].

1) See Annex A

2) Sheets LNG, Storage and Transmission, "Advanced" in column I

ADVANCED PROJECTS WITH A DIRECT CAPACITY IMPACT IN THE ADVANCED INFRASTRUCTURE LEVEL*

Code	Name	Country	Commissioning Year
TRA-N-814	Upgrade IP Deutschneudorf and Lasow	Germany	2016
UGS-N-235	Nuovi Sviluppi Edison Stoccaggio	Italy	2017
LNG-N-082	LNG terminal Krk	Croatia	2018
TRA-N-90	LNG evacuation pipeline Omišalj – Zlobin (Croatia)	Croatia	2018
LNG-N-062	LNG terminal in northern Greece/Alexandroupolis – LNG Section	Greece	2018
TRA-N-063	LNG terminal in northern Greece/Alexandroupolis – Pipeline Section	Greece	2018
TRA-N-136	Poland – Czech Republic Interconnection (CZ)	Czech Rep.	2019
TRA-N-273	Poland – Czech Republic interconnection (PL section)	Poland	2019
TRA-N-895	Balticconnector	Estonia	2019
TRA-N-915	Enhancement of Estonia-Latvia interconnection	Estonia	2019
TRA-N-928	Balticconnector Finnish part	Finland	2019
TRA-N-763	EUGAL – Europäische Gasanbindungsleitung (European Gaslink)	Germany	2019
TRA-N-012	GALSI Pipeline Project	Italy	2019
UGS-N-237	Palazzo Moroni	Italy	2019
UGS-N-374	Enhancement of Incukalns UGS	Latvia	2019
TRA-N-341	Gas Interconnection Poland-Lithuania (GIPL) (Lithuania's section)	Lithuania	2019
TRA-N-212	Gas Interconnection Poland-Lithuania (GIPL) (PL section)	Poland	2019
TRA-N-275	Poland – Slovakia interconnection (PL section)	Poland	2019
TRA-N-190	Poland – Slovakia interconnection	Slovakia	2019
UGS-N-233	Depomures	Romania	2019
TRA-N-902	Capacity increase at IP Lanžhot entry	Slovakia	2019
TRA-N-752	Capacity4Gas (C4G) – DE/CZ	Czech Rep.	2019
TRA-N-918	Capacity4Gas (C4G) – CZ/SK	Czech Rep.	2019
TRA-N-919	Capacity4Gas (C4G) – CZ/AT	Czech Rep.	2020
TRA-N-021	Bidirectional Austrian – Czech Interconnector (BACI, formerly LBL project)	Austria	2020
TRA-N-133	Bidirectional Austrian Czech Interconnection (BACI)	Czech Rep.	2020
TRA-N-801	Břeclav – Baumgarten Interconnection (BBI) AT	Austria	2020
TRA-N-075	LNG evacuation pipeline Zlobin – Bosiljevo – Sisak – Kozarac	Croatia	2020
LNG-N-079	Paldiski LNG Terminal	Estonia	2020
TRA-N-358	Development on the Romanian territory of the NTS (BG – RO – HU – AT Corridor)	Romania	2020
TRA-N-390	Upgrade of Rogatec interconnection (M1A/1 Interconnection Rogatec)	Slovenia	2020
LNG-N-032	Project GO4LNG LNG terminal Gothenburg	Sweden	2020
TRA-N-808	Transport of gas volumes to the Netherlands	Germany	2021
LNG-N-198	Porto Empedocle LNG	Italy	2021
TRA-N-320	Carregado Compressor Station	Portugal	2021
TRA-N-161	South Transit East Pyrenees (STEP) – ENAGÁS	Spain	2021
TRA-N-252	South Transit East Pyrenees (STEP) – TIGF	France	2022
TRA-N-068	Ionian Adriatic Pipeline	Croatia	2022

Table 6.6: Advanced projects with a direct capacity impact in the advanced infrastructure level.

ADVANCED PROJECTS WITHOUT A DIRECT CAPACITY IMPACT IN THE ADVANCED INFRASTRUCTURE LEVEL*

– **Advanced projects requiring an additional less-advanced project to produce a capacity impact**
– **Internal Advanced projects enabling cross-border capacity development**

Code	Name	Country	Commissioning Year
TRA-N-429	Adaptation L-gas – H-gas	France	2018
TRA-N-357	NTS developments in North-East Romania	Romania	2018
TRA-N-361	GCA 2015/08: Entry/Exit Murfeld	Austria	2019
TRA-N-066	Interconnection Croatia – Bosnia and Herzegovina (Slobodnica – Bosanski Brod)	Croatia	2019
LNG-N-912	Skulte LNG	Latvia	2019
TRA-N-136	Poland – Czech Republic Interconnection (CZ)	Czech Rep.	2019
TRA-N-247	North – South Gas Corridor in Western Poland	Poland	2019
TRA-N-918	Capacity4Gas (C4G) – CZ/SK	Czech Rep.	2019
TRA-N-423	GCA Mosonmagyaróvár	Austria	2020
TRA-N-801	Břeclav – Baumgarten Interconnection (BBI) AT	Austria	2020
TRA-N-500	L/H Conversion	Belgium	2020
TRA-N-807	Expansion NEL	Germany	2020
TRA-N-010	Poseidon Pipeline	Greece	2020
TRA-N-362	Development on the Romanian territory of the Southern Transmission Corridor	Romania	2020
TRA-N-302	Interconnection Croatia-Bosnia and Herzegovina (South)	Croatia	2021
TRA-N-283	3rd IP between Portugal and Spain (pipeline Celorico – Spanish border)	Portugal	2021
TRA-N-974	LARINO – RECANATI Adriatic coast backbone	Italy	2022

*The corresponding Investment Cost are shown in section 4.5.8 of the Infrastructure chapter

Table 6.7: Advanced projects without a direct capacity impact in the advanced infrastructure level.

6.4.1 SECURITY OF SUPPLY BENEFITS

The results of this section are compared to section 6.3.2 of the low infrastructure level assessment and refer to the peak day situation.

6.4.1.1 Disrupted Demand and Remaining Flexibility under high demand situations (normal situation)

In Croatia, the risk of demand disruption from 2025 onwards identified in the Low infrastructure level is mitigated in the advanced infrastructure level. This improved situation results from the new LNG terminal in Croatia and the strengthened connection to Slovenia, which itself is better connected to other markets via Austria.

The remaining flexibility during high demand situations is significantly improved in Poland, Sweden and Slovenia. In Denmark this is also the case but in the Blue Transition scenario the remaining flexibility remains low.

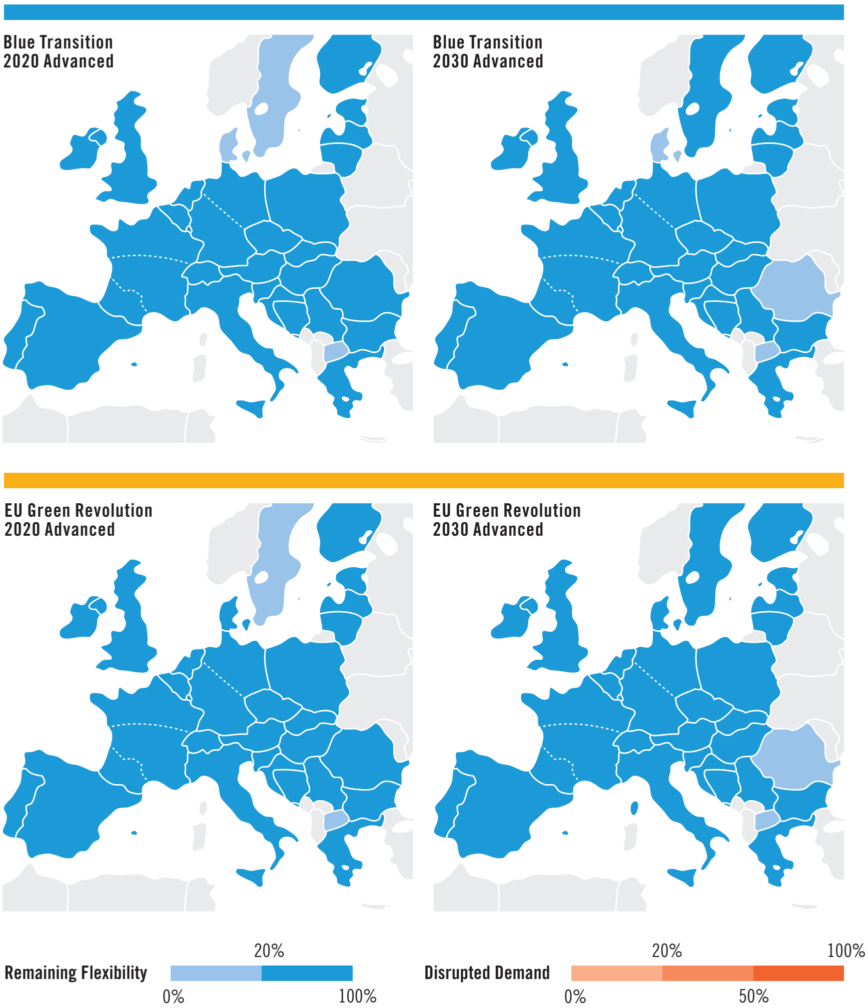


Figure 6.30: Disrupted Rate and Remaining Flexibility, Blue Transition, EU Green Revolution, Advanced infrastructure level, DC

6.4.1.2 Disrupted Demand and Remaining Flexibility under Route Disruption

Belarus transit disruption

In the Low infrastructure level and Blue Transition scenario, Poland and the Baltic States were facing a risk of demand disruption on the long run in case of Belarus transit. The additional infrastructure remedies most of this risk mainly thanks to the new infrastructure linking Poland to other countries: this allows Poland to access additional gas and to support Lithuania: the demand disruption risk is lifted for Poland, reduced but not completely lifted for Lithuania.

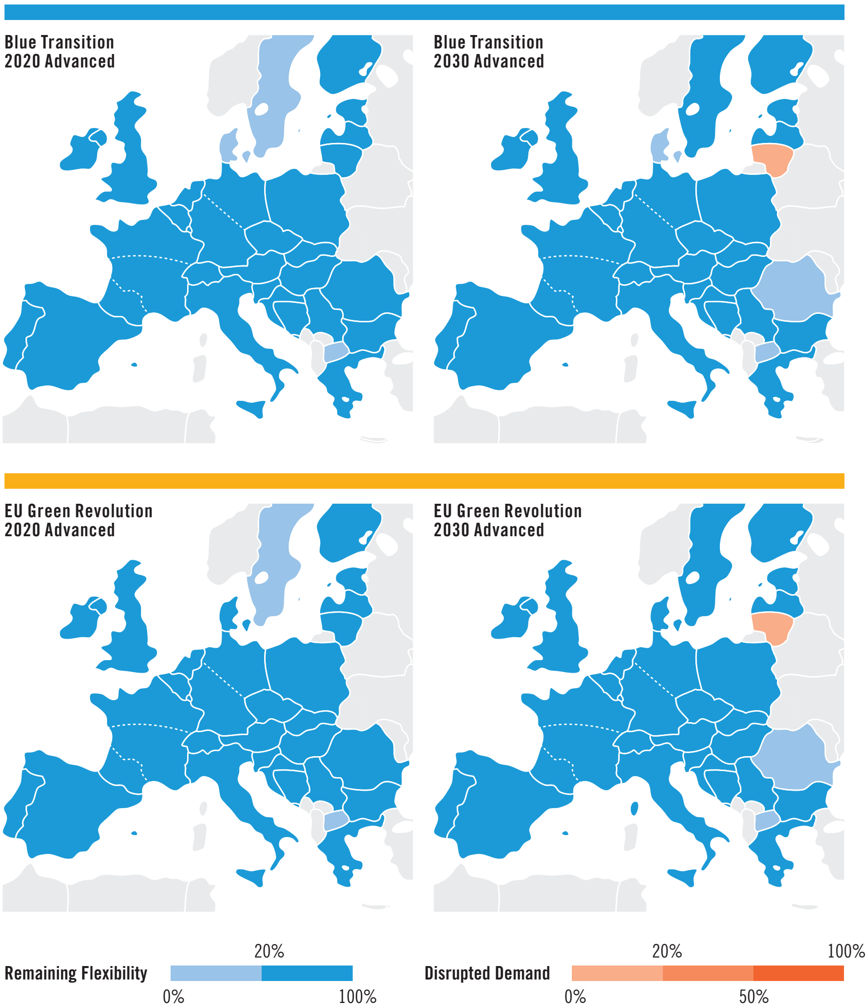


Figure 6.31: Disrupted Rate and Remaining Flexibility under Belarus disruption, Blue Transition and EU Green Revolution, DC, Advanced infrastructure level

Ukraine transit disruption

For the Ukrainian transit route disruption also the situation is significantly improved.

The new infrastructure linking South-East Europe to the Western markets and the new connections to LNG in that region have beneficial effects. While not fully lifting the infrastructure limitations and resulting demand disruption risk, they allow to decrease the demand disruption rate from 13 % to 3 % for Bosnia and Herzegovina, Bulgaria, Croatia, FYROM, Hungary and Serbia. There is also a slight improvement from 2020 to 2030. In 2030 the situation in Romania (demand disruption rate of 22 %), related to the reported decreasing indigenous production over time is not improved by the advanced infrastructure level and remains more tense than for neighbouring countries, due to remaining infrastructure limitations in accessing this country.

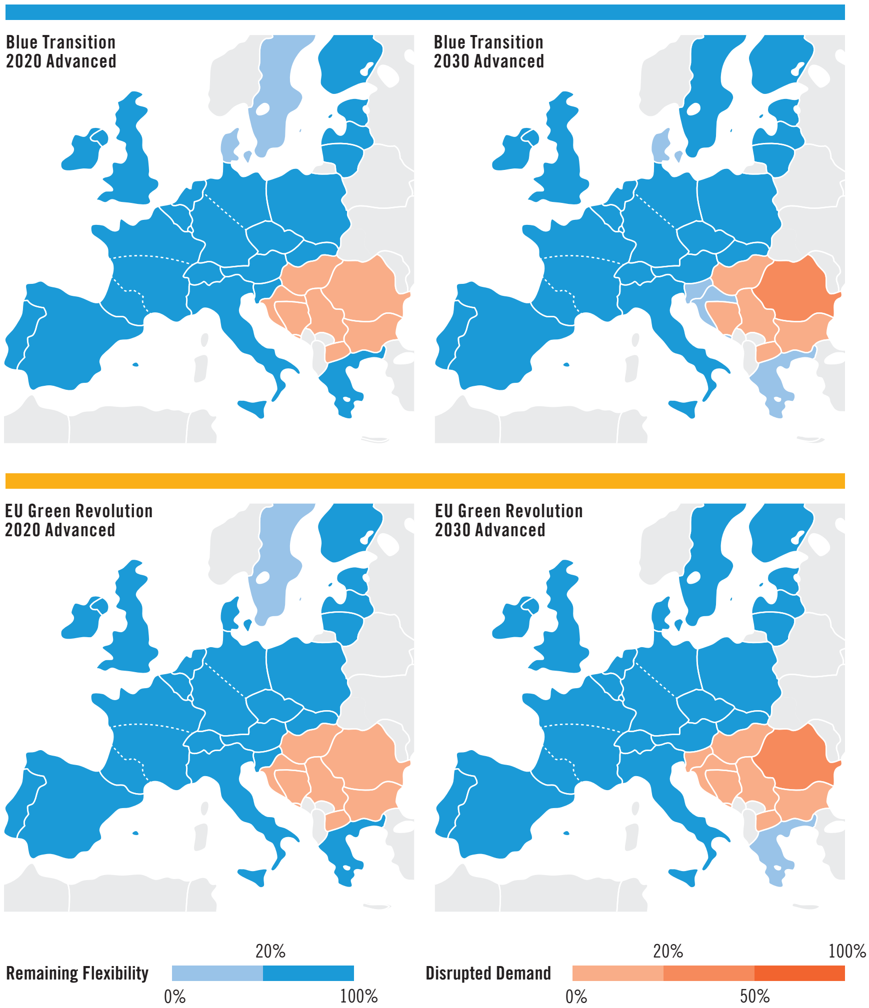


Figure 6.32: Disrupted Rate and Remaining Flexibility under Ukrainian route disruption, Blue Transition and Green Revolution, DC, Advanced infrastructure level

6.4.1.3 N-1 infrastructure assessment

For Croatia, Estonia, Greece, Lithuania and Slovenia the N-1 indicator improves significantly, mainly thanks to new connection to LNG and additional interconnection capacity in between these countries and with other countries commissioned around 2020. In Estonia, Greece and Slovenia the improvement is up to exceeding 100 % in all scenarios.

In Finland, where the N-1 was only ensured by its limited indigenous production in the Low infrastructure level, the connection to the Baltic States brings significant improvement, while not still ensuring a 100% level along the whole time horizon.

The N-1 is not improved for Ireland, Denmark and Portugal. Results for the following modelling results: N-1 for ESW-CBA

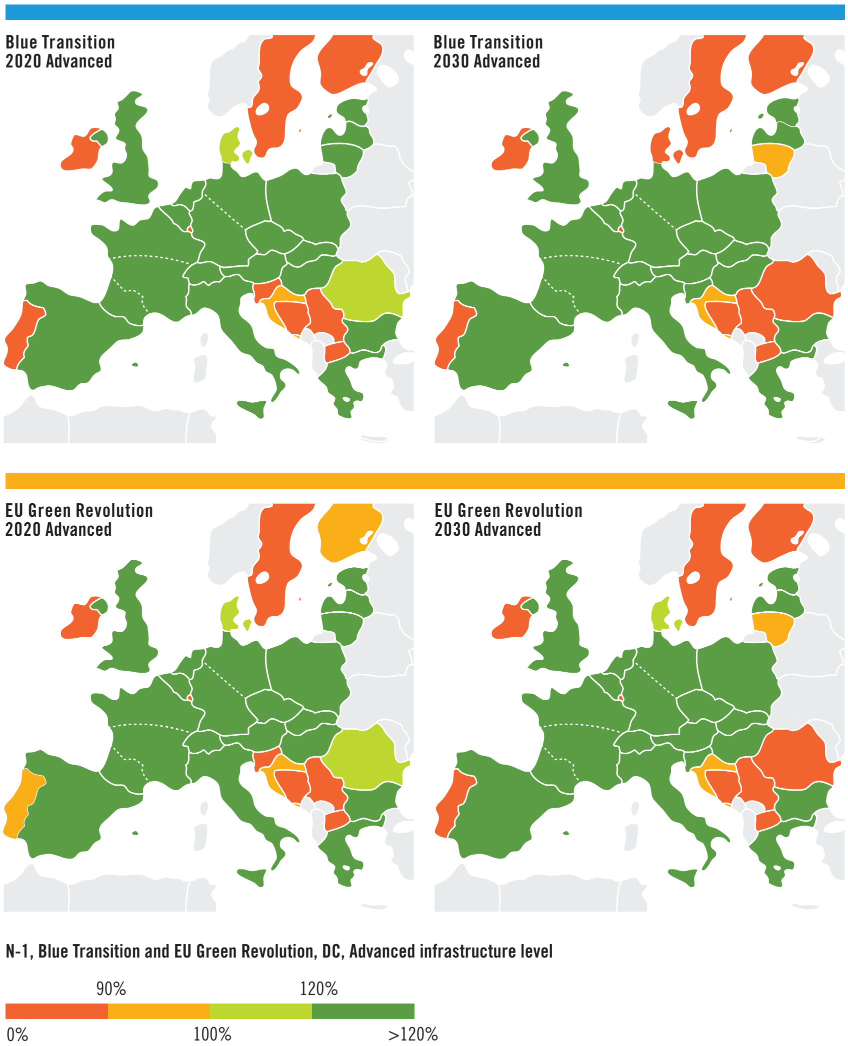


Figure 6.33: N-1, Blue Transition and EU Green Revolution, DC, Advanced infrastructure level

6.4.2 COMPETITION BENEFITS

6.4.2.1 Access to supply sources

Already from 2020 the access to supply sources in the advanced infrastructure level is significantly improved for the Baltic States and Finland. This is thanks to the new infrastructure ending the isolation for Finland by connecting it with the Baltic States, the interconnection from Poland towards the Baltic States and the additional LNG terminals in the area.

On the longer run, the overall deterioration of the diversification situation, resulting from the EU-wide decline of the indigenous production, is still observed in the advanced infrastructure level.

Figure 6.35: SSPDi per country, Green Evolution, whole year, Advanced infrastructure level

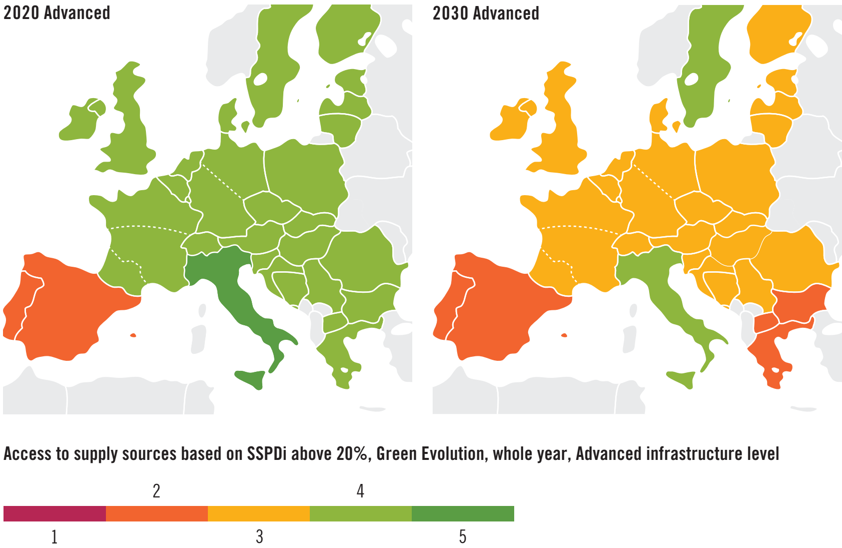
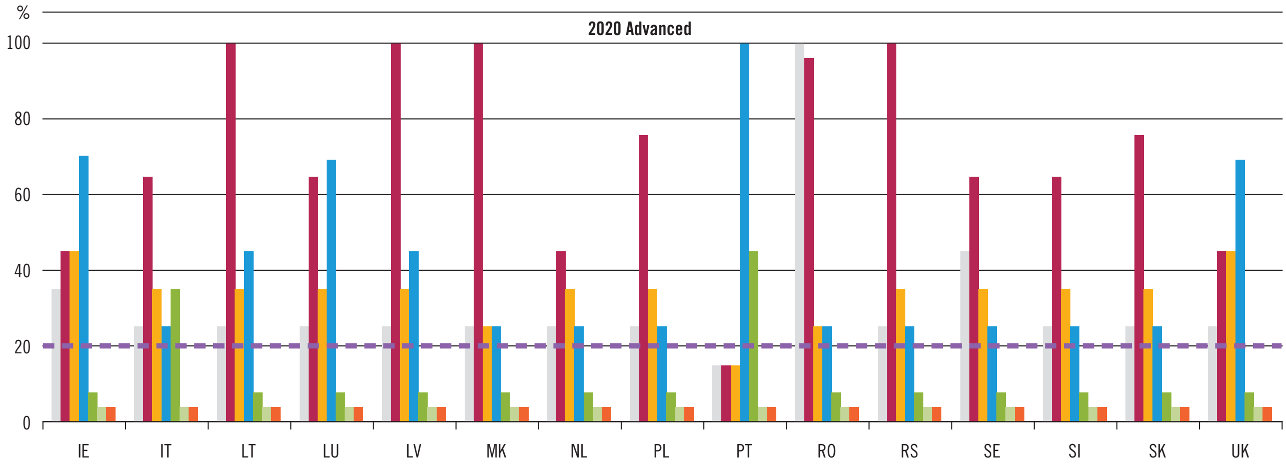
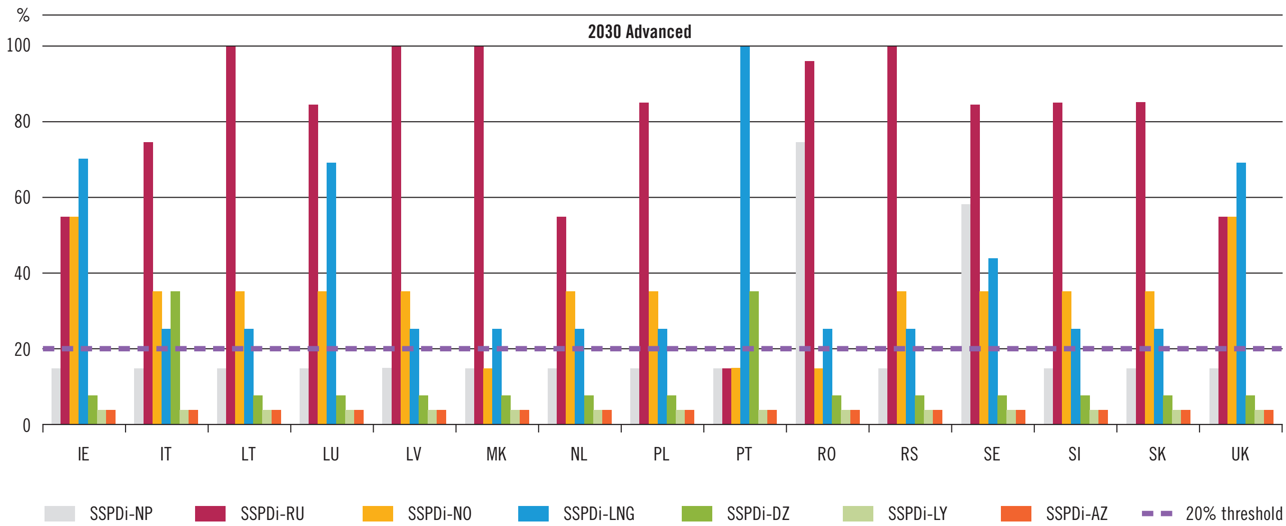


Figure 6.34: Access to supply sources based on SSPDi above 20%, Green Evolution, whole year, Advanced infrastructure level





6.4.2.2 Supply source dependence

From 2020 the advanced projects allow South-Eastern countries to share the same level of the dependence on Russian gas than their neighbours, apart from Romania whose infrastructure limitations prevents that it shares the benefits of its indigenous production with neighbours. The difference further West remains.

In 2030, the Advanced infrastructure level improves the dependence in Finland and the Baltic States from more than 90% to 40%, but a difference to the rest of Europe is still visible. The improvement is the most significant for Finland which benefits from the connection to the Baltic States.

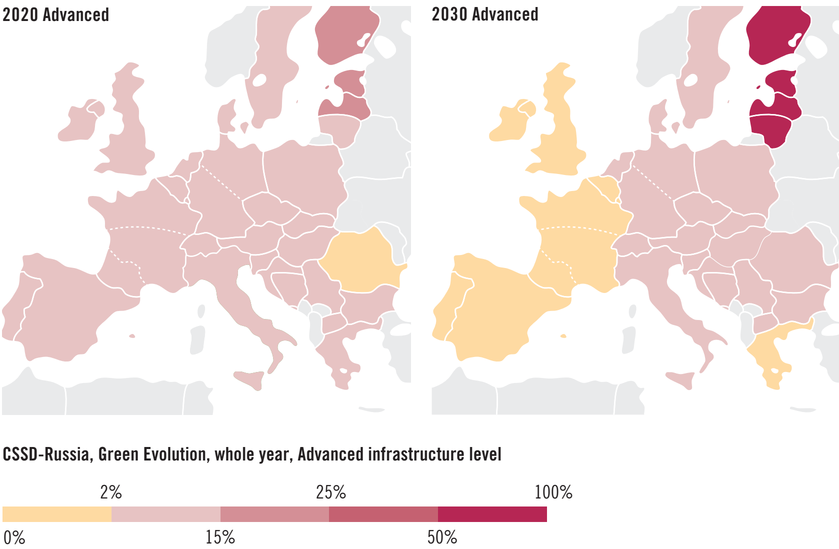


Figure 6.36: CSSD-Russia, Green Evolution, whole year, Advanced infrastructure level

In the low infrastructure level, dependence to LNG was identified for the Iberian Peninsula. The interconnection reinforcement project between France and Spain (STEP project) has an advanced status. Yet no firm capacities were reported for this project as the result of a technical evaluation developed by concerned TSOs in summer 2015 showed capacities linked to UGS, LNG and climatic assumptions. ENTSOG taking only firm capacities into account for its assessments, the cooperative supply source dependence (CSSD) on LNG remains at the same level as in the low infrastructure level.

6.4.2.3 Import Route Diversification

The results for the import route Diversification indicator are improved for several countries in the Advanced Infrastructure level. On average the score in the IRD indicator improves around 660 points compared to the Low infrastructure level. The most significant changes happen for Central and Eastern Europe (Croatia, Czech Republic, Hungary and Slovakia) and Baltic countries (Estonia, Latvia), which benefit from more diversified import routes. This improvement happens thanks to the connection from Croatia to LNG and other countries, Czech Republics strengthened connection with Germany and Poland, the better interconnections from Czech Republic and Poland to Slovakia, the interconnection between Estonia and Latvia, the Estonian connection to Finland and new LNG terminals. Potential for improving the score of this indicator still remains visible in several countries.

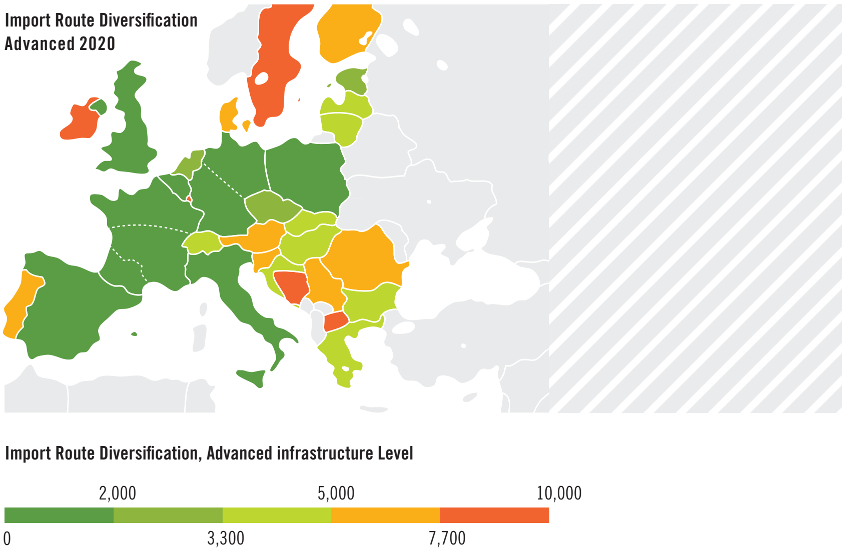
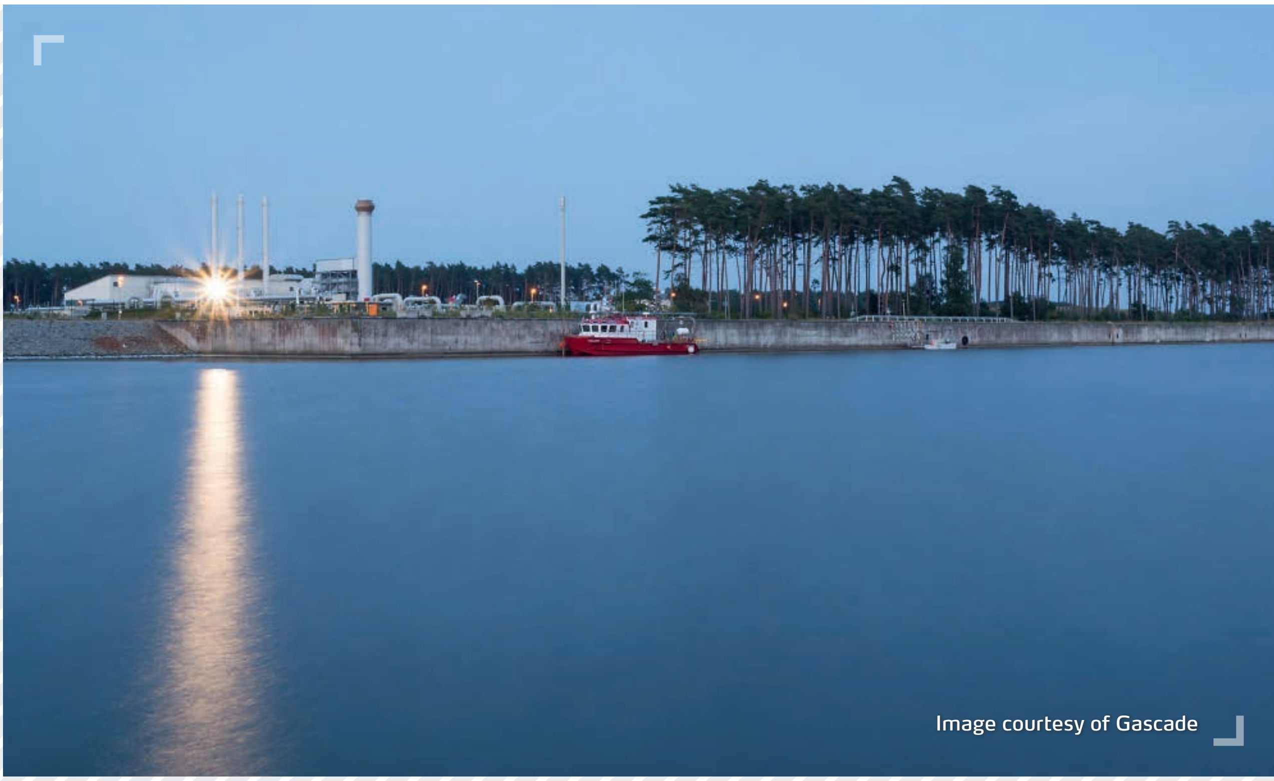


Figure 6.37: Import Route Diversification, Advanced Infrastructure level



6.4.2.4 EU Bill and monetisation on country level

The EU Bill mainly refers to the EU supply bill. Except in very specific cases, the infrastructure projects do not impact on the EU supply mix, whatever the supply configuration considered. As a result, the EU Bill is generally on the same level as in the low infrastructure level[1].

Still, the additional infrastructure allows the usage of the whole Romanian national production in all scenarios. National production being priced lower than other supply sources results in a slight decrease of the EU Bill in 2025.

In case of maximisation of Russian supply with a low Russian gas price, slight benefits from the additional infrastructure can be observed at country-level for Austria, Czech Republic, Denmark, Germany, Italy, Luxembourg, Slovenia, Slovakia, Sweden and Switzerland. (see figure 6.38)

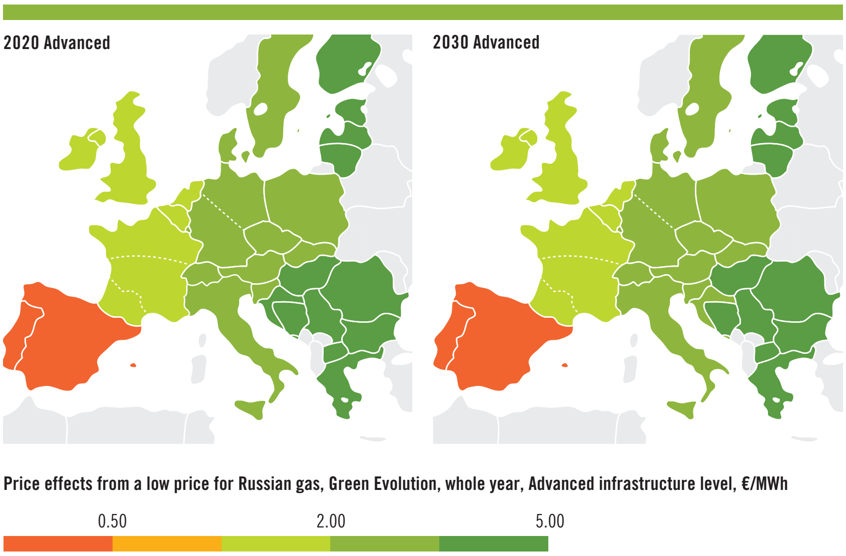


Figure 6.38: Price effects from a low price for Russian gas, Green Evolution, whole year, Advanced infrastructure level

In case of minimisation of Russian supply with a high Russian gas price, Finland significantly benefits its connection to the Baltic States, these last ones also showing an improvement. Whereas in the low infrastructure level Finland, the Baltic States and Central Eastern Europe countries were suffering from a high Russian gas price, in the advanced infrastructure level additional interconnections allow to decrease this local effect by sharing it among a larger number of countries. (see figure 6.39)

In case of LNG maximisation and low LNG price the impact is wider shared by countries. The most noticeable improvement can be observed for Finland (connection to Baltic States) and Sweden (GO4LNG terminal). While the total effect for the EU remains the same the impacts at country level depend on the scenario. In the Blue Transition scenario no significant change is observed for other countries. In the Green Evolution and EU Green Revolution scenarios the following additional countries are slightly benefitting from the low LNG price compared to the low infrastructure level: Austria, Bosnia and Herzegovina, Croatia, Czech Republic, Denmark, Germany, Hungary, Italy, the Netherlands, Poland, Serbia, Slovenia, Slovakia, Sweden and Switzerland. (see figure 6.40)

1) The lower transport costs that are visible in the Annex are a modelling technicality and not an effect of the additional infrastructure.

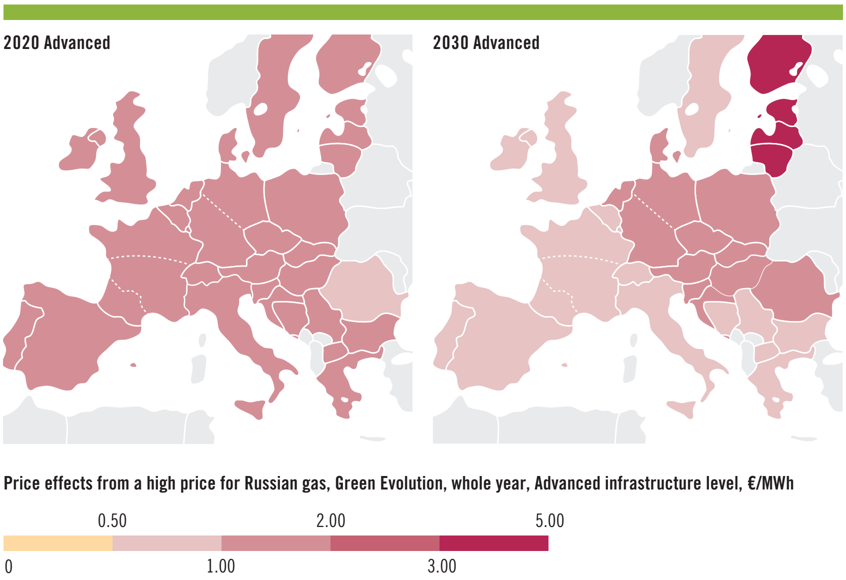


Figure 6.39: Price effects from a high price for Russian gas, Green Evolution, whole year, Advanced infrastructure level

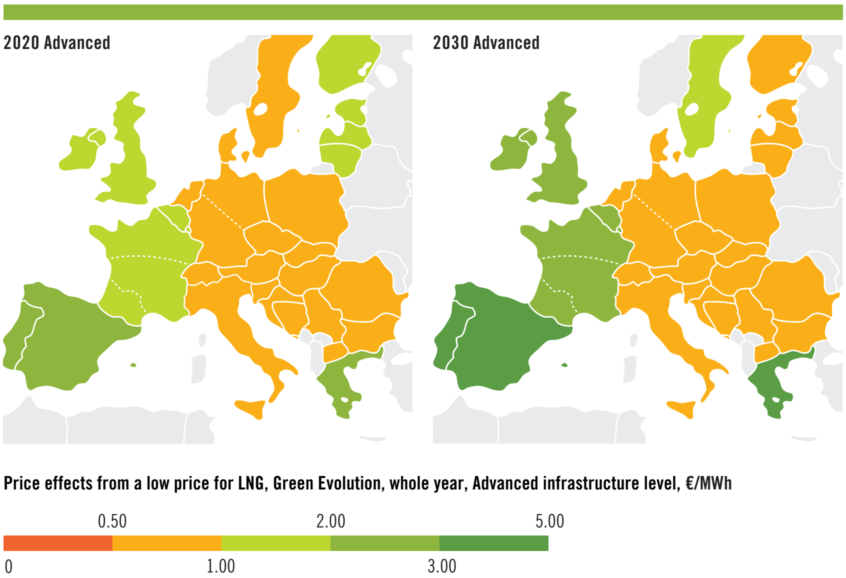


Figure 6.40: Price effects from a low price for LNG, Green Evolution, whole year, Advanced infrastructure level

For the LNG minimisation (high LNG price) the results do not change significantly, in line with the results reported for dependence to LNG in section 6.4.2.2.

In the Azeri maximisation supply configuration the Baltic States and Finland join other European countries in profiting from a lower price for Azeri gas, although the European-wide effect scale is limited by the volumes currently expected to be imported from the Caspian region.

All these price effects relate to the overall improvement of interconnections in different areas all over Europe. Individual project effects are not specifically captured within this European wide assessment.

6.4.3 MARKET INTEGRATION BENEFITS

6.4.3.1 Marginal price

The marginal prices resulting from the standardised supply and price configurations were already aligned in the Low infrastructure level. Additional advanced infrastructures therefore do not change this situation.

6.4.3.2 Import price spread configuration

This section analyses if infrastructures can have an impact on import prices resulting from a monopolistic behaviour, by triggering or reinforcing competition.

As in section 6.3.3.3, analysing the results for the low infrastructure level, this section analyses the spread in countries marginal prices compared to the German reference price, as resulting from optimising the EU supply bill considering the border price assumptions reported in section 6.3.3.3. The assessment is performed under a perfect market functioning assumption. The results relate to the diversification potential of the different countries. This does not represent any forecast on prices.

Compared to the low infrastructure level (section 6.3.3.3), the marginal price differences caused by different import price per supply route may be solved in most parts of the EU. This indicates that some of additional infrastructure deliver in terms of improving competition and avoiding monopolistic behaviour.

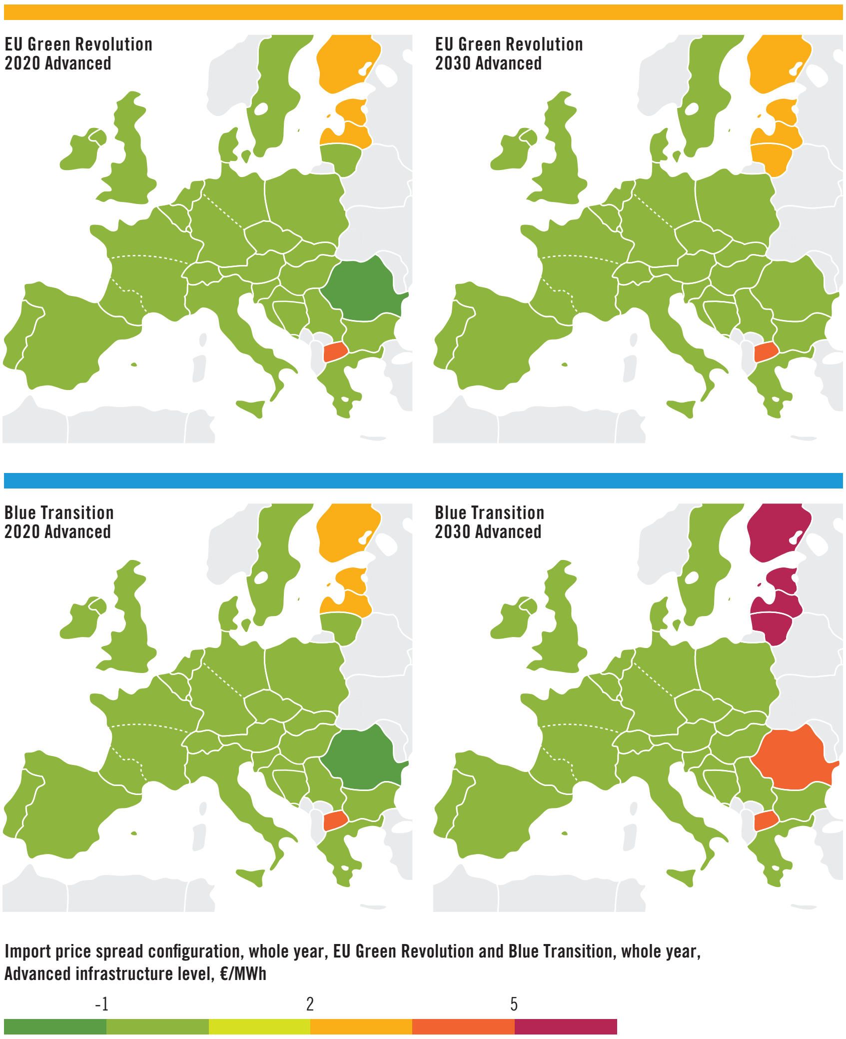


Figure 6.41: Import price spread configuration, Blue Transition and Green Revolution, whole year, Advanced infrastructure level

From 2025, the expiration of the leasing agreement for the Klaipėda LNG FSRU reported in the low infrastructure level, is not compensated by the advanced infrastructure level. Finland and the Baltic States are not protected from monopolistic supply behaviour.

The commissioning of some projects listed in the advanced infrastructure level help Croatia, Czech Republic, Hungary, Slovenia and Slovakia, as well as Poland, to decrease the dependency on differentiated pricing politics. These benefits result from an enhanced market integration in Central and Central-Eastern Europe providing access to competitive supply sources. In Romania, the benefits fluctuate over time based on the reported indigenous production forecast.

6.4.4 CONCLUSION ON THE COSTS-BENEFITS ANALYSIS OF ADVANCED PROJECTS

The TYNDP lists 52 advanced projects.

These projects prove efficient in terms of improving security of supply, diversification and competition.

In terms of security of supply advanced projects provide the following benefits:

- Croatia is protected from demand disruption in case of peak demand, including on the long-run.
- The Baltic States and Poland improve their resilience in case of short-term Belarus route disruption.
- South-Eastern countries are left with a very limited demand disruption in case of short-term Ukrainian route disruption.
- N-1 improves for a number of countries.

The advanced projects additionally deliver in terms of improving competition, by increasing route and supply diversification and consequently lifting local high dependence to specific supply sources. In particular the Baltic States and Finland are connected to the main EU gas grid and can access three supply sources, decreasing their dependence to Russian gas.

Finally the advanced projects, by improving competition and market integration, prevent a large number of Eastern countries to be subject to monopolistic supply behaviour.

The overall investment costs for all advanced projects represent 16 Bn€. The actual costs of achieving the above listed benefits would much certainly be lower as the some advanced projects potentially compete in terms of delivering security of supply, competition and market integration to the areas in need.

Even with the materialisation of advanced projects, some needs would still not be covered:

- In Bosnia and Herzegovina, Finland, FYROM, Lithuania, Ireland, Portugal, Romania, Serbia and Sweden the N-1 remains below 100 % on the long run, and in Denmark the N-1 remains below 120 %.
- In Romania the interconnection with neighbouring countries are still not sufficient for the country to share its indigenous production.
- On the long run diversification decrease for Bulgaria, FYROM and Greece which end up having significant access to only two supply sources.

6.5 Impact of the projects on the second PCI list

This section assesses the impact of projects from the second list of Projects of Common Interest. The benefits of 2nd PCI list projects having a FID status are already covered in the assessment of the Low infrastructure level, where improvement in 2020 compared to 2017 in particular relates to a number of projects listed on the 2nd PCI list.

This section focuses on the benefits of 2nd PCI list projects without a FID status yet, independently from their advancement status[1]. The identification of infrastructure gaps in the low infrastructure level (section 6.3) forms the basis for this impact assessment.

The relevant projects for this infrastructure level can be found in Annex A, the relevant capacities in Annex D[2].

As a general result the implementation of all projects in the second PCI list would be a significant contribution in strengthening the European gas infrastructure.

These results cannot be directly compared to those of the advanced infrastructure level as on one hand a number of advanced projects are not part of the 2nd PCI list, and on the other hand a number of 2nd PCI list projects do not have an advanced status. The assessment will nevertheless focus on where 2nd PCI list projects bring further benefits compared to advanced projects.

6.5.1 SECURITY OF SUPPLY

Belarus transit disruption

In the Low infrastructure level and Blue Transition scenario, Poland and the Baltic States were facing a risk of demand disruption on the long run in case of Belarus transit. The additional infrastructure with a PCI status remedies this risk mainly thanks to the new infrastructure linking Poland to other countries: It allows Poland to access additional gas and to support the Baltic States.

Ukrainian transit route disruption

The advanced projects were mitigating but no completely solving the situation in case of Ukrainian transit disruption. By 2030 PCI 2nd list projects allow to handle most of the demand disruptions. Most of the countries have also a high remaining flexibility. The commissioning of PCI 2nd list projects would also significantly improve the situation for Romania: in the Blue Transition scenario, the demand disruption rate would decrease from around 25% in the low infrastructure level (and around 20% in the advanced infrastructure level) to less than 10%. The situation would be further mitigated if the Romanian indigenous production increase reported for earlier years would be maintained over time.

1) See chapter Infrastructure Projects for the definition of the infrastructure levels.

2) Sheets LNG, Storage and Transmission, “Low” in column I

This indicates that 2nd PCI list projects can make sense in addition to advanced projects in order to further address the risk of demand disruption in case of Ukrainian transit disruption.

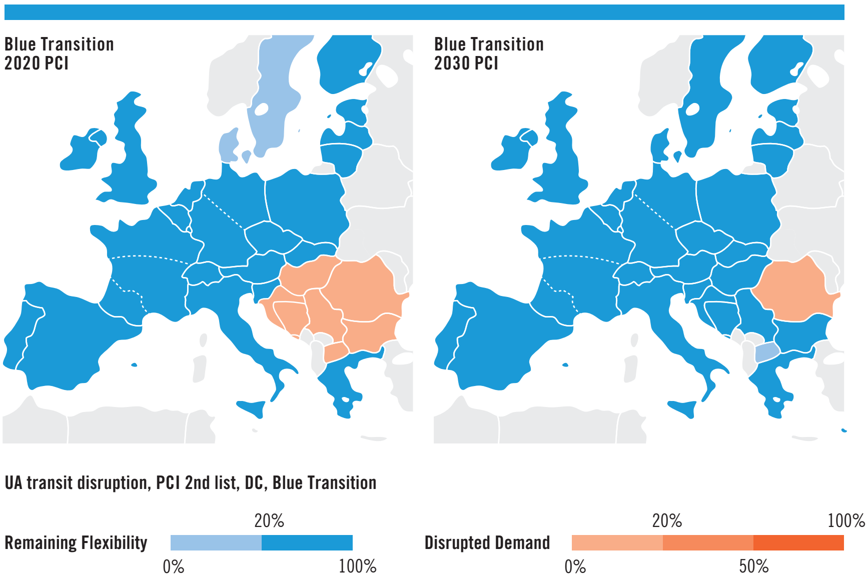


Figure 6.42: UA transit disruption, PCI 2nd list, DC, Blue Transition

N-1 infrastructure assessment

After 2020 the Lithuanian N-1 indicator improves up to exceeding 100 %, mainly thanks to additional interconnection capacity between Latvia and Lithuania. By 2030, Portugal and Slovenia exceed 100 % and FYROM and Serbia improve significantly their N-1s.

Denmark also improves its N-1 indicator above 120 % in 2030 in all scenarios.

In Ireland, Finland and Sweden, the N-1 remains on a low level between 2020 and 2030 by the 2nd-PCI list Infrastructure level. Nevertheless the results for Finland and Sweden are significantly improved compared to the Low infrastructure level.

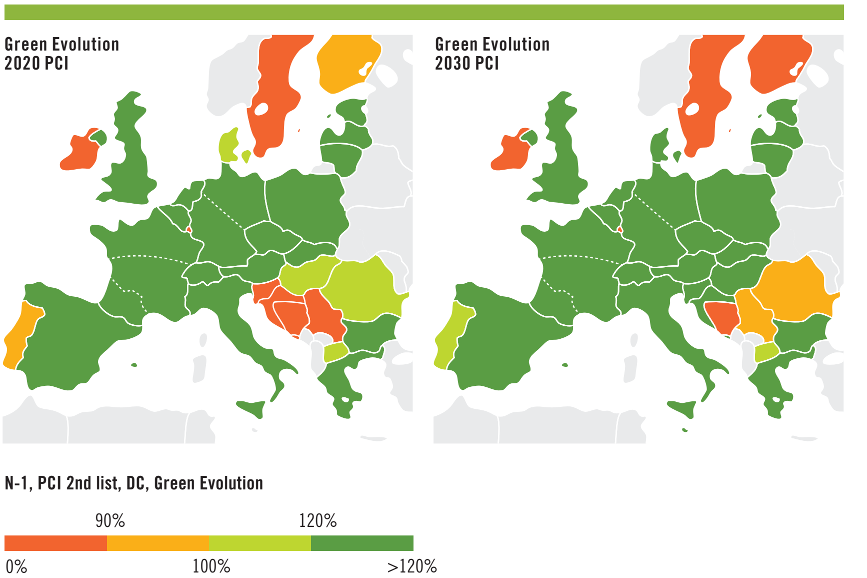


Figure 6.43: N-1, PCI 2nd list, DC, Green Evolution

Competition

On the long run, the overall deterioration of the diversification situation, resulting from the EU-wide decline of the indigenous production, is also observed in the 2nd-PCI list infrastructure level.

By 2030, the 2nd PCI list infrastructure level allows the access to alternative sources in the Iberian Peninsula: the diversification to Norwegian and Russian supply is improved. Infrastructure reinforcement also allow Greece to benefit from improved diversification to Algerian and Norwegian supply.

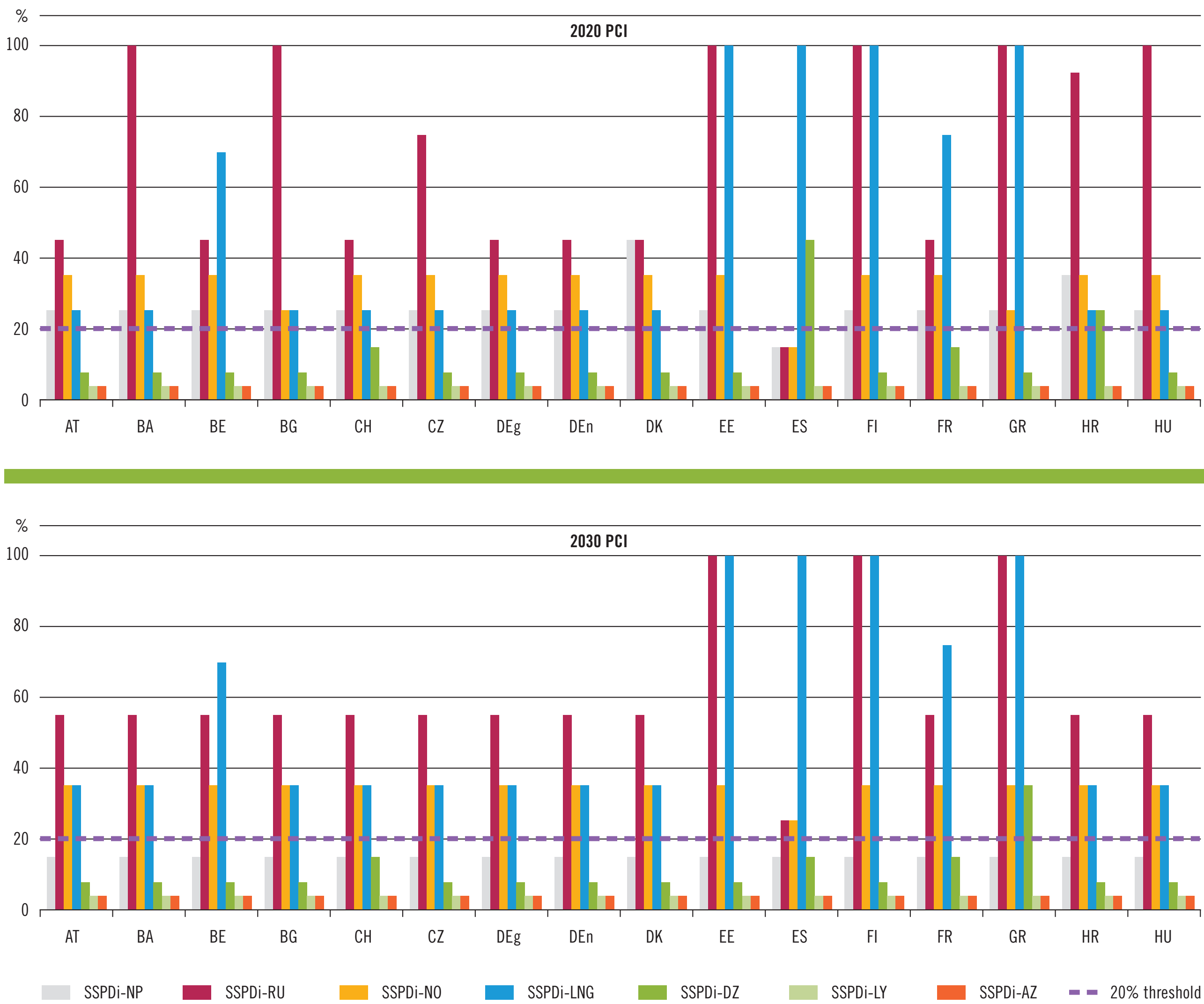


Figure 6.45: SSPDi, PCI 2nd list infrastructure level, whole year, Green Evolution

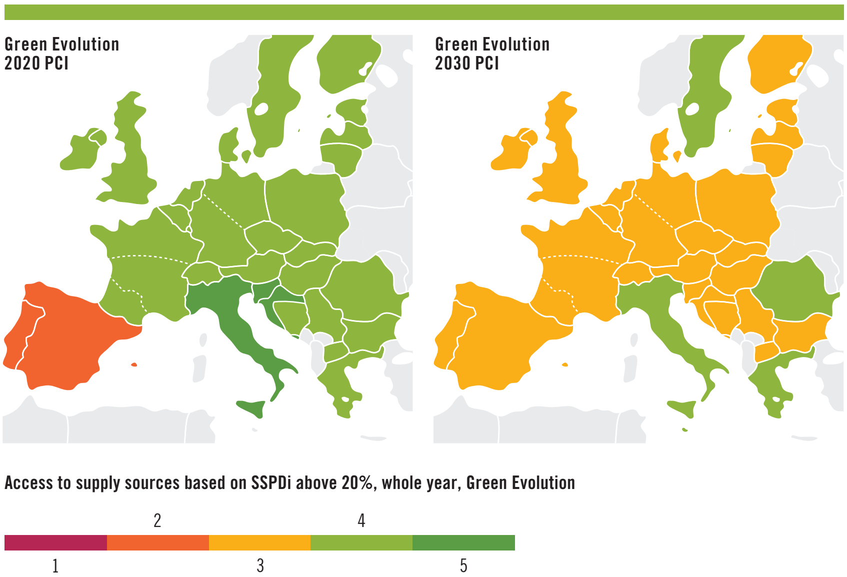
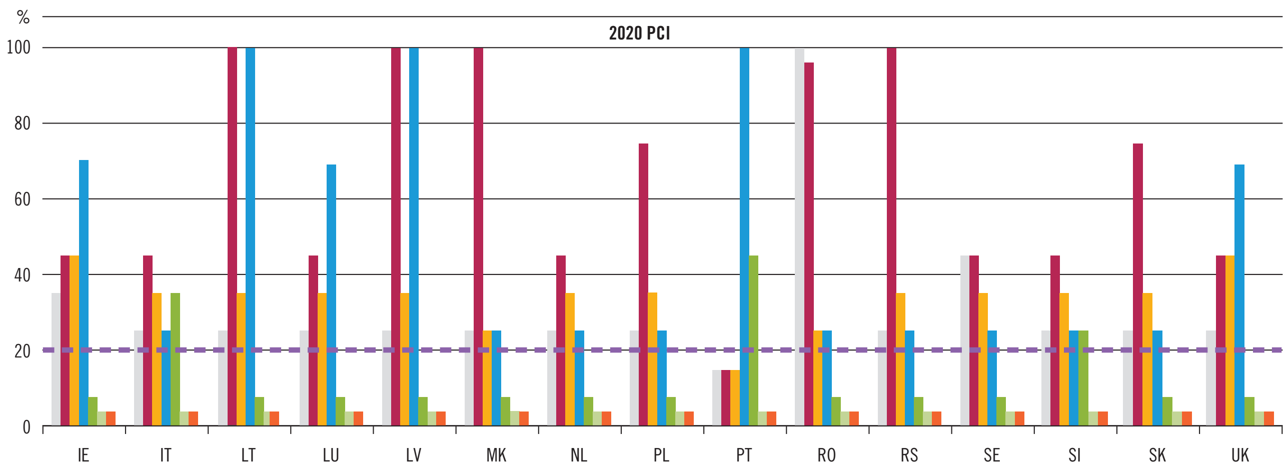
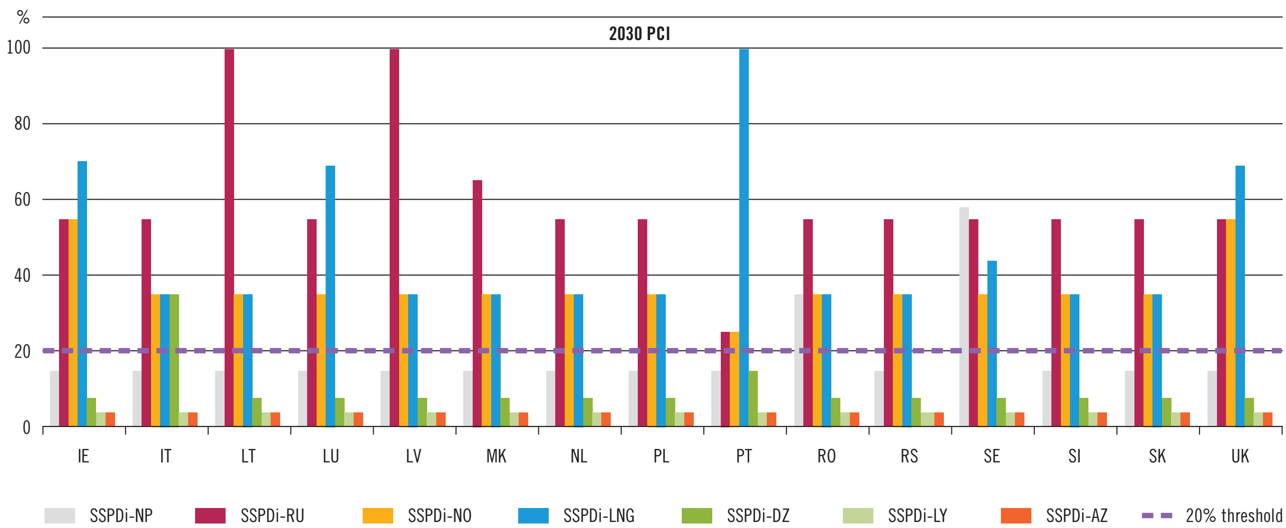


Figure 6.44: Access to supply sources based on SSPDi above 20 %, whole year, Green Evolution





Supply source dependence

From 2020 the 2nd-PCI list projects allow Finland and the Baltic countries to share the same level of the dependence on Russian gas than their neighbours.

The CSSD indicator still shows some infrastructure limitations in South-Eastern Europe where Romania remains isolated limiting the benefits surrounding countries can make from its national production. Infrastructure limitations also prevent Greece from reducing its dependence to the Russian supply.

In the PCI 2nd list infrastructure level the EU-wide dependence on Russian gas can be shared between all countries on the long run thanks to the implementation of projects that provide diversification of supply sources across the EU.

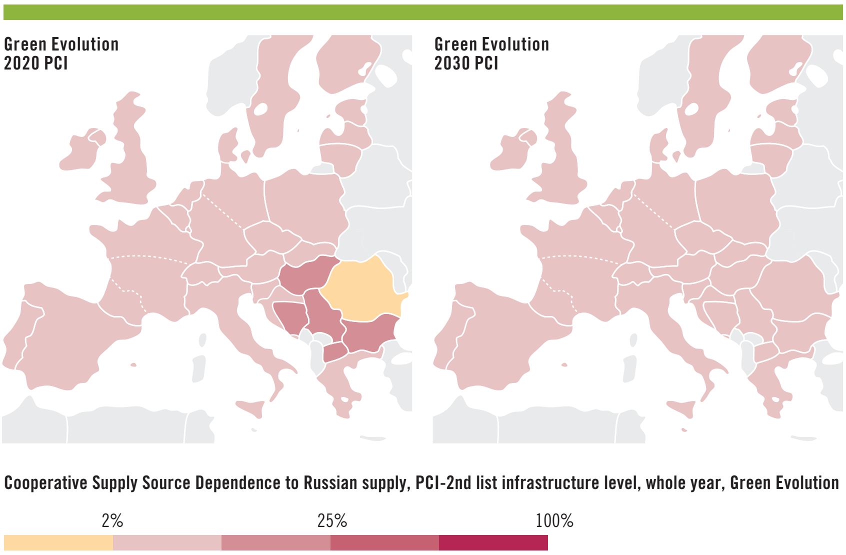


Figure 6.46: Cooperative Supply Source Dependence to Russian supply, PCI-2nd list infrastructure level, whole year, Green Evolution

In terms of dependence of the Iberian Peninsula to LNG, the situation improves compared to the Low infrastructure level with the implementation of the Midcat project soon after 2020, which decreases the dependence to LNG from nearly 40 % to close to 25 %. Even with the commissioning of this project, dependence to LNG would nevertheless remain on the long-run, related to the foreseen increase of the Iberian Peninsula demand.

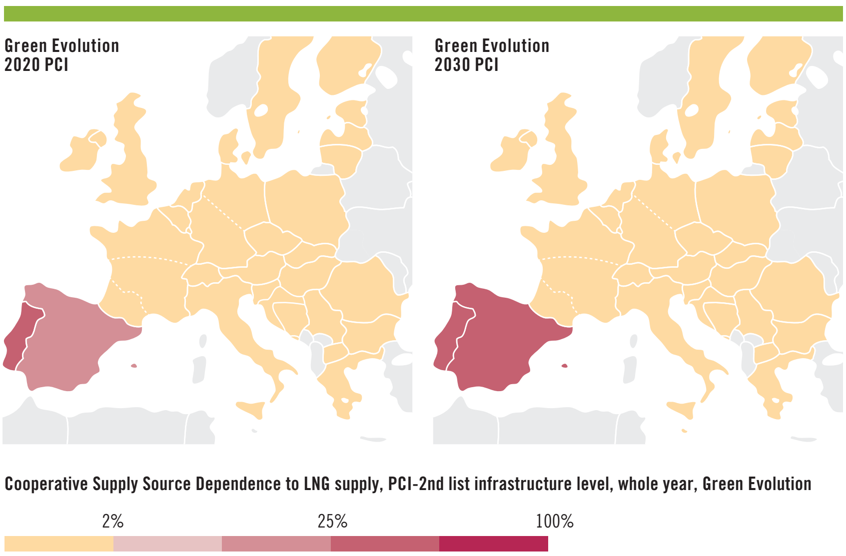


Figure 6.47: Cooperative Supply Source Dependence to LNG supply, PCI-2nd list infrastructure level, whole year, Green Evolution

Conclusions

The projects from the 2nd-PCI list prove efficient in terms of improving security of supply and competition, additionally solving nearly all the assessed issues stemming from different supply prices per supply route.

In terms of security of supply 2nd PCI list projects provide the following further benefits compared to advanced projects:

- South Eastern countries are protected from demand disruption in case of short-term Ukrainian route disruption including on the long-run and in the Blue Transition scenario. In 2030, while the situation for Romania is significantly improved compared to the advanced infrastructure level, the country could still face a limited demand disruption (around 10 %) in case of Ukrainian route disruption.
- The N-1 is improved for Croatia, Estonia, Greece, Lithuania, Portugal and Slovenia.
- The access to supply sources is improved to the point where all European countries have access to a minimum of 3 different supply sources.

Yet, even with the materialisation of the 2nd-PCI list projects, the N-1 would remain below 100% on the long run for Bosnia and Herzegovina, Finland, FYROM, Ireland, Serbia and Sweden.

The 2nd-PCI list projects additionally deliver in terms of improving competition, by increasing route and supply diversification and consequently lifting local high dependence to specific supply sources.

- The access to supply sources is improved to the point where all European countries have access to a minimum of 3 different supply sources from shortly after 2020.
- High dependence to Russian gas is eradicated all over Europe.
- The Iberian Peninsula dependence on LNG is significantly mitigated.

6.6 Conclusions

In this edition of TYNDP, ENTSOG has significantly improved the identification of the infrastructure needs in a dedicated chapter analysing the needs along the different pillar of the TEN-E regulation. ENTSOG has also improved the assessment of projects. Introducing the notion of advanced projects has allowed identifying the benefits of a realistic further development of the gas infrastructure. They have been analysed in regard to the projects costs collected from promoters.

The gas infrastructure has progressively developed over the past decades. It is well connected and ensures an efficient access to LNG in most parts of Europe. It also builds on an impressive storage capability, which has proved its value and reliability winter after winter.

The existing gas infrastructure is already close to achieving the internal energy market. The FID projects planned to be implemented in the very next years will further improve the situation. In terms of sustainability, the gas infrastructure of cross-border relevance is fit for achieving the EU 2030 climate targets. It can support renewable generation. This infrastructure will gradually transport increasing volumes of green gases.

In most parts of Europe the gas infrastructure complemented by FID projects proves highly resilient and ensures access to diversified supplies. This diversification plays a key role in promoting competition and ensuring security of supply. While most areas benefit from a high level of connectivity, the full-scale implementation of the Third Package would be required to achieve proper functioning of gas markets in all parts of the EU.

At European level, the production of a number of fields is set to decline in the coming years, in particular the Groningen field. While Russian gas and LNG could in all likelihood close the European supply gap, preserving or reinforcing the European supply diversification will require supporting the development and connection of new sources. In addition to preserving Europe access to Norwegian and North-African production, connecting Azeri gas and developing new indigenous production, this would also require getting the appropriate support for the development of European green gases.

Some specific areas of Europe would require further gas infrastructure to join the internal energy market. In the South-East part of Europe, the dependence to Russian gas and related limited diversification hampers competition and would expose the region in case of disruption of the Ukrainian transit. Solving this situation will require to further develop the interconnections and to connect the region to new sources.

In the Northern part of Europe, Finland and the Baltic States are still isolated from the European infrastructure. In addition, the Baltic States face the risk of transit disruption via Belarus. In the Baltic States, the operational Lithuanian Klaipėda LNG terminal has already significantly improved the situation. Further improvement is still desirable. It will require developing the interconnections in the region and ensuring that access to alternative sources of supply (like LNG) is maintained over time.

The countries in Central-Eastern Europe share a low level of competition and are exposed to monopolistic behaviour from Russian gas supplies. The competition can be enhanced by diversifying supply sources in the region.

In Western Europe some areas are still not well connected, such as Ireland or the Iberian Peninsula. In this last case, reinforcing the interconnections in the region would increase supply diversification and improve Portugal security of supply. The decline of the Groningen field will require that the current L-gas areas Germany, Belgium and France are converted to H-gas and connected to the H-gas network and the necessary replacing supplies. Malta is currently not connected to Europe mainland.

7 Energy Transition

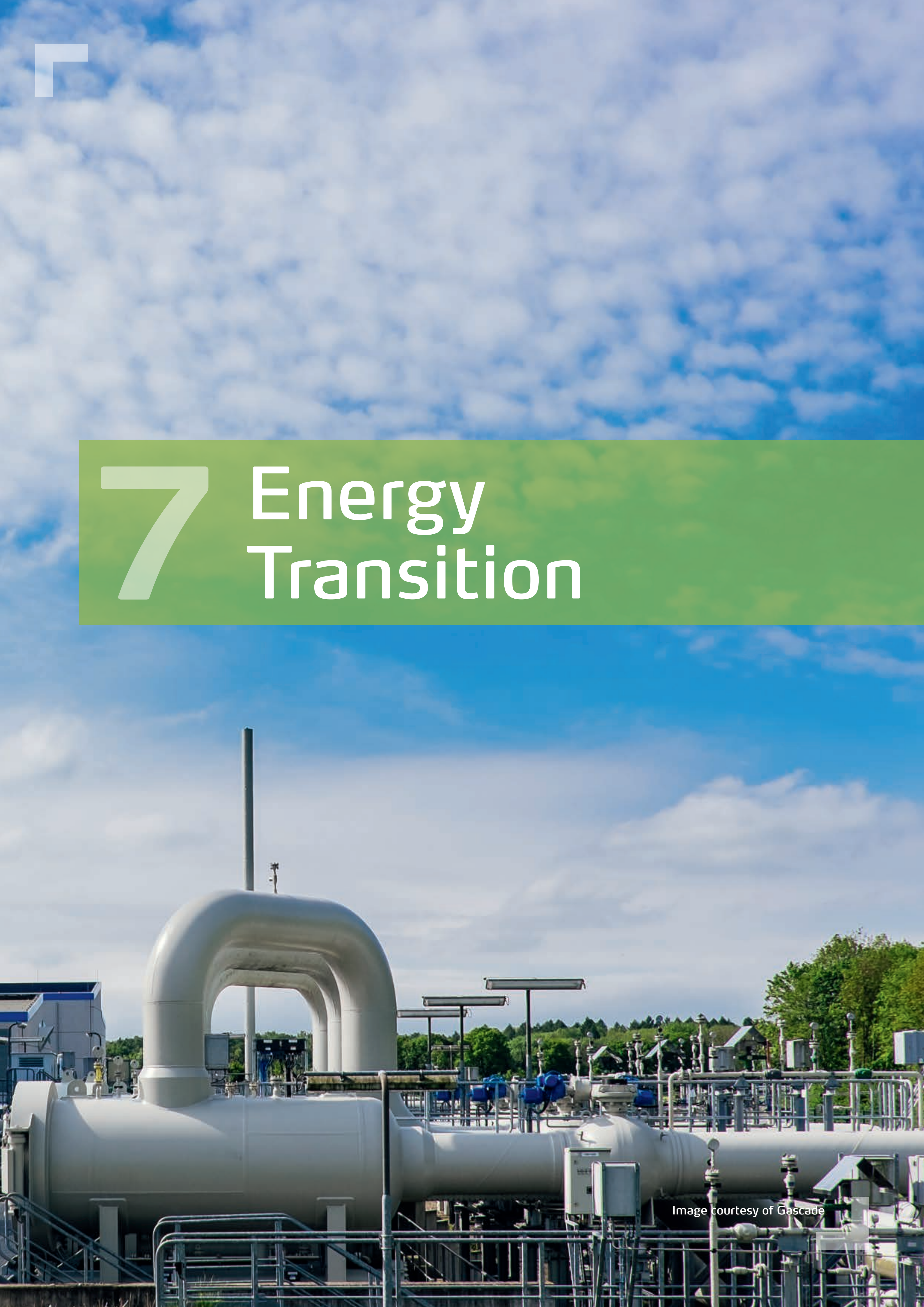


Image courtesy of Gascade

7.1 Introduction

The European gas transmission network has seen decades of investment and development in order to provide a safe and reliable energy system for a wide variety of end users, offering a high level of market integration across the continent.

Some further investment is required to enable the realisation of the EU Energy Union principles, for example allowing for supply diversification in some areas and therefore preventing dependence to a limited number of sources plus increasing competition. However, TYNDP assessment shows that the European gas infrastructure is not only able to accommodate contrasted supply mixes on an annual basis, but would also be resilient to a peak demand situation for a variety of possible demand scenarios.

The European Commission Energy Strategy intends to provide secure, competitive and sustainable energy, with policies driven by three main objectives:

- Secure energy supplies to ensure the reliable provision of energy whenever and wherever needed
- Energy providers operate in a competitive environment that ensures affordable prices for households, businesses and industries
- Energy consumption to be sustainable, through the lowering of greenhouse gas emissions, pollution and fossil fuel dependence

This forms the basis of the EU energy transition and has included key energy strategy[1)] targets for 2020, 2030 and 2050 (more information is available in the Demand Chapter) which focus on the reduction of greenhouse gases, energy efficiency and the share of renewable energy in EU consumption.

The European ambitions for 2050 will have a significant impact on the energy sector, with a target of an 80 to 95 % reduction in greenhouse gas emissions compared to 1990. There are also worldwide influences, such as the Paris Agreement at COP21 that came into force on 4th November 2016, which has the aim of strengthening the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit this even further to 1.5 degrees.

The European gas transmission network, and gas as a fuel source, already plays a key role in achieving these targets and has the potential to continue contributing in the near-term and long-term. It offers flexibility to intermittent renewables and a lower carbon alternative to coal-fired power generation, along with season energy storage and the transmission of carbon neutral gas. TYNDP 2017 covers the next twenty years and contains three scenarios that reach the 2030 targets by following different paths. This shows that there are multiple solutions to reaching the EU goals. ENTSOG wants to highlight those solutions that involve more efficient use of existing infrastructure, which as a result could provide a cost effective way of decarbonising.

This Energy Transition sub-chapter offers some insight into how current gas infrastructure can be an essential part of the future energy system, through both the implementation of existing technologies and the innovative development of carbon neutral gas technologies. These technologies, could offer substantial benefits in reducing GHG emissions very efficiently and therefore deserve thorough consideration. The benefits will best materialise in an integrated energy system based on sector coupling.

1) https://ec.europa.eu/energy/en/topics/energy-strategy

7.2 Sector coupling

ENTSOG's understanding of sector coupling is the physical coupling of gas, power, heat and mobility infrastructures with the aim of making optimal use of the potentials of each. Through this process, renewable energy can be integrated into the system in an ecological and economic manner, whilst ensuring security of supply.

Sector coupling will enable the EU energy system for power, heat and mobility to decarbonise in a cost effective and achievable way, something that a single energy infrastructure will not be capable of. The gas transmission network is already a key element of the energy system and will continue this role with the help of current and developing technologies.

Efficient long-term storage and long-distance transmission are some of the most important advantages and potentials of gas infrastructure compared to other energy systems. Therefore it is vital for successful system coupling and decarbonisation that the European regulatory framework takes a neutral technological approach.

Sector coupling can be realised by the use of hybrid appliances. The term hybrid means that at least two energy carriers are involved. An example of a hybrid application is the hybrid heat pump, which can run on both gas and electricity. This offers a wide variety of opportunities: the hybrid heat pump can use electricity at times that electricity is cheap and abundantly available, thereby avoiding curtailment and lowering the energy bill for the owner. On the other hand, the hybrid heat pump can use gas instead of electricity at times that electricity is expensive and scarce, thus also contributing to a lower energy bill for the owner.

Instant switchable hybrid appliances enable consumers to use instantaneously the energy carrier of their choice thus minimising cost and network congestion. Hybrid appliances offer flexibility to avoid network congestion and increase security of supply. Flexibility in energy carrier choice at consumer level should be utilised before turning to conversion between energy carriers. Therefore, hybrid systems can act as an economic way to connect gas and electricity infrastructure through end-user appliances

Image courtesy of NET4GAS

7.3 Storage and Transmission

7.3.1 ENERGY STORAGE

Gas infrastructure offers both flexible short term and seasonal long term storage potential, both in the capacity and capability of the pipeline network itself, plus the specific storage infrastructure connected to the network which includes onshore cavern systems, onshore and offshore depleted fields and LNG storage facilities. As previously mentioned, this has largely been developed in order to cope with the seasonal and operational demand variations driven by the current needs, but also has potential in years to come.

When considering the requirements of the future energy system, the use of intermittent renewables and the growing share of solar but especially wind in the power sector, means that it will become more challenging for electricity grid operators to balance the system. Hydro generation, demand side frequency response and battery technology are all potential solutions for short term frequency issues, with most focus on the latter two due to limited possibilities for hydropower sites and potentially high environmental impacts from land use and conversion.

Current developments for battery storage technology are progressing as short term energy solutions[1)]. European decarbonisation may lead to an electrification of the heating sector, where the challenges of seasonal variations in demand are far greater.

Current UGS working gas volumes are over 1,200,000 GWh, with a maximum withdrawal capacity of over 20,000 GWh/d. Even during the mild winter of 2015/16 UGS provided over 10,000 GWh of gas on the peak day. This is approximately the same value of energy required on the peak day for the electricity transmission system in 2015.

The seasonal and peak requirements of gas storage infrastructure could change as the energy system transitions, with greater energy efficiency and increased electrification of some sectors. However, gas infrastructure offers vast seasonal or annual energy storage, which when combined with renewable gases offer a long term low carbon solution that utilises infrastructure that is already in place.

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1) In the USA, the Southern California Edison battery project that is linked to a wind power generation site will provide 400 MWh (100 MW for 4 hours). Also South Korea plans to build the largest battery-based energy storage systems (BESS) in the world representing 500 MWh in 2017 – http://energystoragemedia.com/worlds-largest-frequency-regulation-battery-energy-storage-system-installed-in-south-korea/battery-energy-storage-system-installed-in-south-korea/

7.3.2 ENERGY TRANSMISSION

Energy transmission and a well interconnected EU, allowing energy to move to areas of need or offer competition, is one of the key elements of the European Commission energy strategy and achieving the completion of the internal energy market.

Gas is an extremely efficient way of transporting energy and the transmission network has been designed to transmit energy over long distances, with minimal losses as a result. Equally, it offers a cost efficient method of energy transmission as shown in a study[1] comparing the Bacton-Balgzand gas pipeline and the BritNed electricity interconnector. Both projects connected the UK to the Netherlands, with the gas pipeline traversing a distance of 230 km compared to 260 km for BritNed, and both projects cost in the region of € 600 m. However, the gas pipeline has a capacity of 20 GW, twenty times that of the electricity interconnector, reducing the cost per kw/100 km to € 11 versus € 230.

The cost of energy transition is already being felt in some countries that are moving at pace to high shares of renewable generation in the power sector. A study from the Düsseldorf Institute for Competition Economics on the German transition[2], which has involved the abandonment of nuclear power, highlights the substantial costs by 2025 for just the electricity sector. This is not only from the development and support of the renewable technology itself, but also the required expansion of the transmission and distribution networks. They calculate the cost for an average four-person household in contributions to this development could cumulatively exceed € 25,000 by 2025. This comes at a time where fuel/energy poverty[3] is becoming an increasing concern across Europe, for example in England[4] in 2014 an estimated 2.4 million households (10.6% of total) were considered in fuel poverty by the UK Government, highlighting the need to consider energy transition in the most optimal and cost efficient way.

One factor that can influence costs in the electricity transmission sector is the choice between overhead and underground lines. Although new overhead lines seem to offer the lower cost solution[5], land use must be taken into account and the fact that they are generally publically opposed for health concerns and aesthetic reasons. As a result, overhead powerline projects are often subject to cost increases and/or delays. The gas network is available as a means of energy transmission that avoids the issues highlighted above and without the need for significant investment.

1) Source: DNV-GL presentation "The Changing Role of Gas as a Sustainability Enabler 2016" based on Gasunie data.

2) http://www.insm.de/insm/Presse/Pressemeldungen/Pressemeldung-Studie-EEG.html

3) For statistical purposes Fuel poverty in England is measured using the Low Income High Costs indicator, which considers a household to be fuel poor if: they have required fuel costs that are above average (the national median level) and were they to spend that amount, they would be left with a residual income below the official poverty line.

4) https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/557400/Annual_Fuel_Poverty_Statistics_Report_2016_-_revised_30.09.2016.pdf

5) https://setis.ec.europa.eu/sites/default/files/reports/ETRI-2014.pdf

7.3.3 CARBON CAPTURE AND STORAGE

Carbon Capture and Storage (CCS) is the technology used to capture the carbon dioxide (CO_2) emissions produced by fossil fuels in electricity generation and industrial processes. Application of this technology could prevent large amounts of CO_2 from being released into the atmosphere, plus if used in combination with energy forms like renewable biomass, can even remove carbon dioxide from the atmosphere.

CCS technology consists of three main parts, capturing the carbon dioxide through the separation of CO_2 from other gases, transporting it compressed via pipelines or other methods, and storing the carbon dioxide emissions in depleted oil/gas fields or other compatible geological storage formations, which could be facilitated through the gas infrastructure currently in place.

CCS technology may not become commercially viable until 2030 or beyond. Prior to this, significant reductions in CO_2 can be achieved by switching from coal-fired power generation to gas-fired power plants, which may see the closure of coal fuelled plants in the short to medium term. With its flexibility to intermittent renewables, gas-fired power plants with CCS technology can be a key part of the energy mix for the long term, utilising either existing reserves or the increasing share of renewable gases.


Image courtesy of Open Grid Europe

7.4 Renewable Gases

7.4.1 BIOMETHANE

Biomethane is created by upgrading the biogas produced by organic matter in biogas plants. These plants can produce gas from many different sources, the most common of which are from landfill and agricultural waste. Biogas largely consists of methane and CO_2, and by cleaning the impurities and removing the CO_2 it can be upgraded to biomethane[1)].

Biomethane is a renewable fuel with several benefits:

- it can be produced in a constant output and quality
- it can be used in many sectors like households, industry, power and transportation
- it produces energy from what would otherwise be considered waste streams

Once it is compatible with the quality standards of the natural gas grids, it is possible to compress it to high pressures and inject it into the transmission network along with natural gas. Biomethane can then be stored, traded and transported efficiently over long distances as discussed earlier in this chapter.

As this gives this renewable gas access to the entire gas infrastructure in Europe, it gives the potential for biomethane to offer an efficient and cost effective way to decarbonise sectors which are currently highly dependent on fossil fuels.

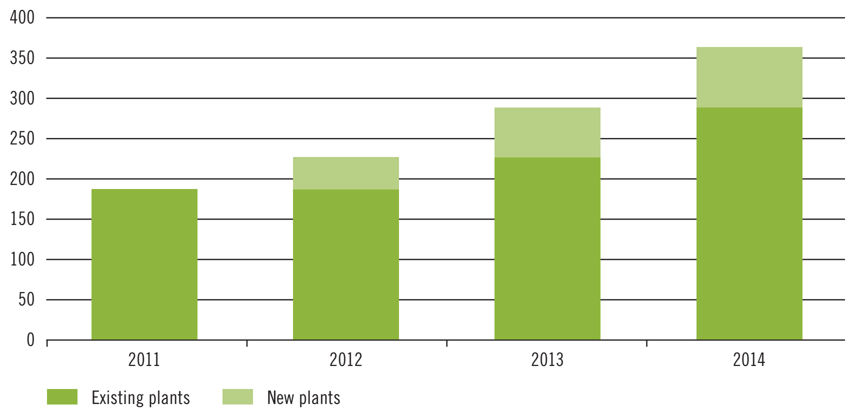


Figure 7.1: Number of commissioned European biomethane plants
(Source: ENTSOG depiction of European Biogas Association)

There has been a significant increase in the number of biomethane plants connected to the gas network, almost doubling their number between 2011 and 2014 as shown in figure above. This has led to biomethane markets developing but only on a national basis, based on national plans. There are national schemes in place in many EU Member States that label biomethane and other carbon neutral gases for trading. The current lack of a Union-wide labelling of biomethane is a major barrier to develop a single market for trading green gases and maintaining the idea of a single European Gas Market for the carbon neutral era.

1) For more information visit the European Biogas Association website: www.european-biogas.eu

7.4.2 POWER TO GAS

Power to gas (P2G) is the name for technology and process that converts electrical power into a gaseous energy. Through this process, the excess production of renewable electricity which would normally be curtailed can be used to produce hydrogen by electrolysis. This technology is considered an important element in turning system and sector coupling into a reality[1].

This could offer a solution to the challenges of balancing electricity production and consumption, especially in a world of increased intermittent renewable generation, and offers a highly flexible means of renewable energy storage. Although using this hydrogen to generate electricity involves further efficiency losses, there are other uses which avoid this, such as the use of hydrogen as fuel for transport.

P2G does not only offer the possibility to store renewable energy but also to transport it over long distances by using the gas transmission network, saving costs to the European energy system by utilising the existing infrastructure.

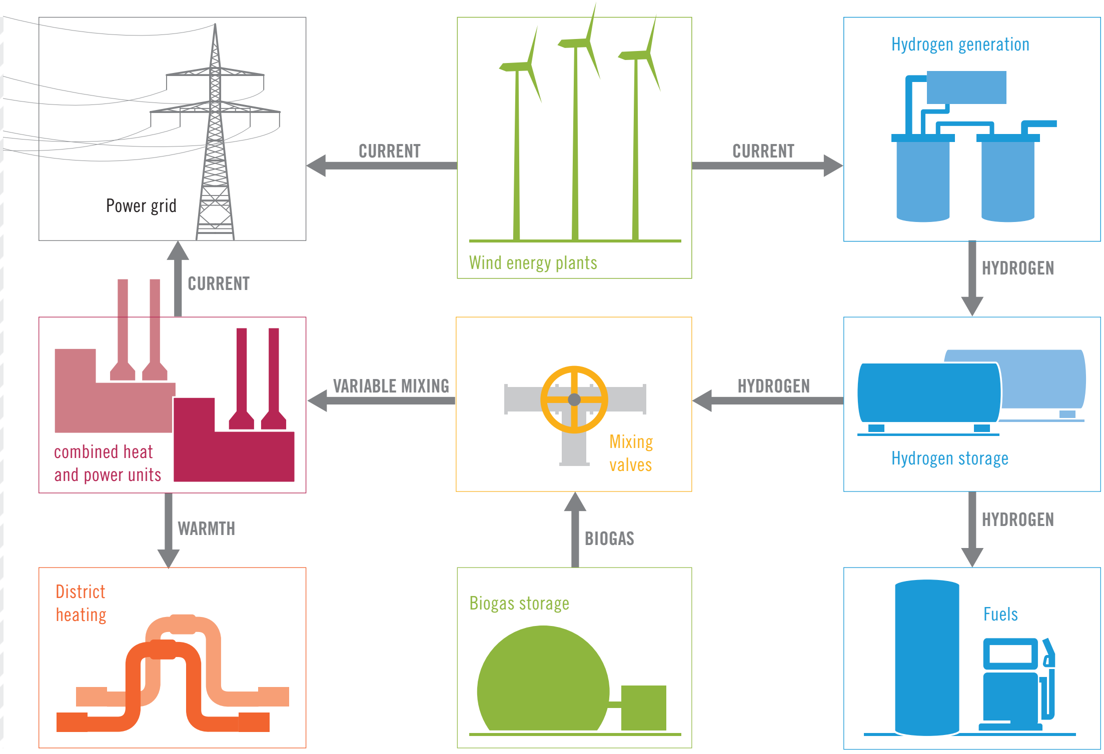


Figure 7.2: Example of P2G filling station installation (Berlin 2011) (Source: Enertag 2013)

As Hydrogen changes the quality of natural gas and has an impact on the heating value, there are currently doubts and restrictions on the hydrogen percentage that can be injected into the gas grids. However, there has been intense research[2] aiming at defining optimum injection rates and identifying measures to make current gas infrastructure fit for hydrogen. On top of this, there is the option to combine the hydrogen in a second step with CO_2 by a methanation process, producing synthetic methane that can be injected easily into the natural gas grids, and used in any gas application e.g. as heating energy in modern hybrid systems or as a fuel for transport.

As CO_2 is also retained from other sources, the synthetic methane is carbon neutral. P2G as a green energy storage could make an important contribution to the energy transition.

1) http://etogas.com/fileadmin/documents/news/2015_Fraunhofer_ISE_Study_PtG.pdf
2) http://www.dbi-gruppe.de/hips-net.html

7.5 Gas in the transport sector

The current state of gas in the transport sector is covered in the Demand chapter, along with the alternative fuel initiatives that are being implemented. In addition, the Energy Transition chapter raises the potential for the further benefits that could be seen from the increase in the amount of renewable gases in the transmission system.

Gas infrastructure can support new filling stations and LNG bunkering facilities, which will enable the supply of gas as an alternative fuel for transport in a variety of forms. This represents energy transition in the transport sector, by providing a lower cost option for consumers but also fulfilling long distance and heavy goods vehicles (HGV) requirements, and does not compete with the electric vehicle development.

4.5.1 CNG AND LNG

Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) are technologies that are necessary, among others, to substitute oil as the dominant energy supply for transport. They are mature technologies and only lack the related refuelling infrastructure level to enable mass exploitation. In the particular case of CNG and LNG, progressive results can be achieved in emissions reduction when combined with the renewable gases also described in this chapter.

For light duty vehicles, CNG engines produce fewer emissions (CO_2, NO_X, SO_X …) than from oil engines and their consumption is proved to be economically competitive versus diesel. In large population areas with heavy traffic problems, issues like particle and noise pollution could also be improved by promoting this technology, while in long distance roads it offers higher autonomy than electric vehicles.

Additionally, for heavy duty vehicles and fleets, LNG is a clean, non-toxic technology that can extend the life of the vehicle longer than other engines and also requires less servicing.

4.5.2 MARITIME

LNG in maritime transport offers a clear advantage especially for both construction and conversion of ships in the focus of emission regulations. Conventional oil-based fuels are currently the main fuel option for most vessels, however offer limited potential to comply with air emission limits through the installation of additional process technology. LNG technology is the only option that can meet existing and upcoming requirements for emissions[1)].

1) International Maritime Organisation: http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Default.aspx

Image courtesy of National Grid

4.5.3 HYDROGEN

Hydrogen fuelled vehicle technology is another possible alternative to oil in the long-term. The standard hydrogen engine converts its chemical energy to mechanical energy by combustion. Fuel cell vehicles (FCV) generate electricity, by reacting compressed hydrogen with oxygen, to power an electric motor. Fuel cell vehicles are classified as electric vehicles and they are considered as a good solution for applications where zero-emissions are important to the air quality standards.

Hydrogen is typically derived from reformed natural gas. However as previously commented, hydrogen can also be produced using renewable sources, such as P2G plants.

7.6 Summary

As shown in this chapter, gas infrastructure should be a key part of a European energy transition that is sustainable not only from an environmental, but also from an economical point of view. Sector coupling should be achieved through the optimal application of all energy systems and a technologically neutral approach in European regulation is a prerequisite to allow it to reach its full potential. Equally, for renewable gases to enable efficient energy transition, the development of a single European CO_2 neutral gas market is required.

8 Gas Quality Outlook

Image courtesy of Gazprom

8.1 Introduction

Article 18 of the Network Code on interoperability and data exchange rules (Commission regulation EU 2015/703) requires ENTSOG to publish, alongside TYNDP, a long-term gas quality monitoring outlook (Gas Quality Outlook – GQO) for transmission systems in order to identify the potential trends of gas quality parameters and respective potential variability within the next 10 years.

The GQO shall cover at least the gross calorific value (GCV) and the Wobbe Index (WI), produce different forecasts for different regions and be consistent and aligned with TYNDP.

The GQO covers existing and new supply sources, based on measured gas quality values collected from previous years when available or on contractual values otherwise. For each region, the forecast consists of a range within which each parameter is likely to evolve.

As part of the TYNDP, stakeholders are invited to provide their views on the evolution of gas quality parameters.

TYNDP 2017 is the first edition incorporating the Gas Quality Outlook and the methodology of how this has been done is included in Annex G.

8.2 Input data

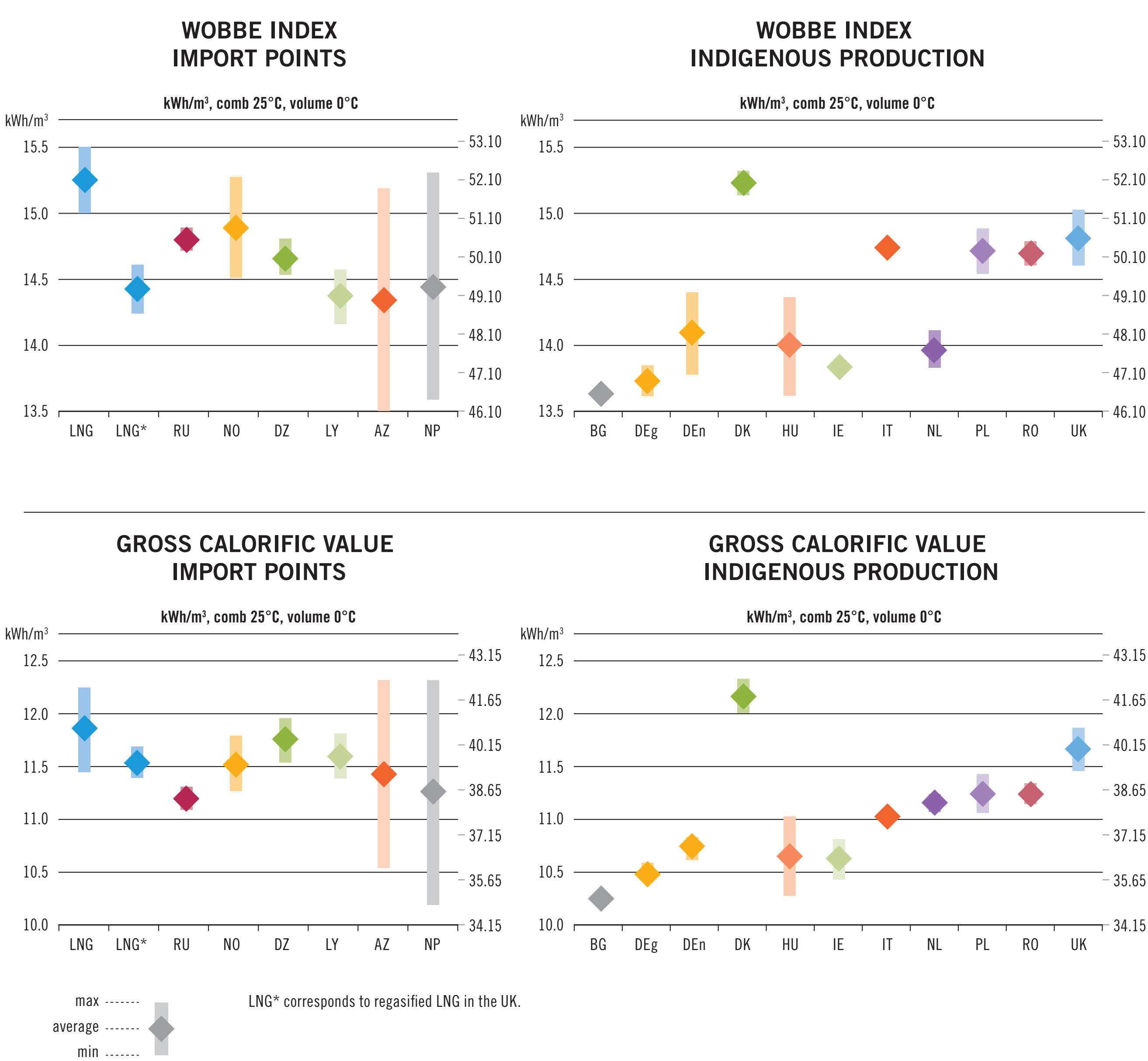


Figure 8.1: Wobbe Index and Gross Calorific Value of import points and indigenous production

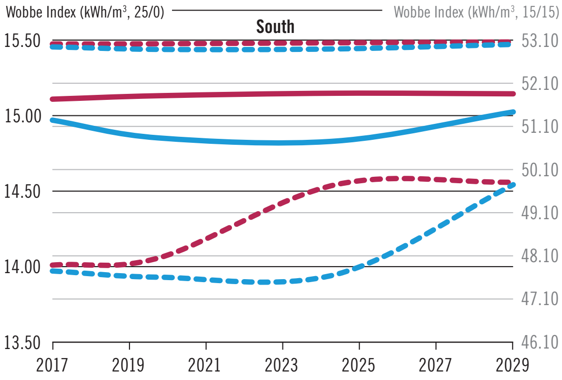
8.3 Results

The WI and GCV overviews are presented here, for further detail and results, please refer to Annex G. For each of the analysed regions, all TYNDP supply scenarios have been assessed to determine the two yielding the widest and the narrowest bandwidths for WI and GCV.

In order to identify trends in WI and GCV, the following figures present a plot of the median (50 percentile) of the resulting probability distribution.

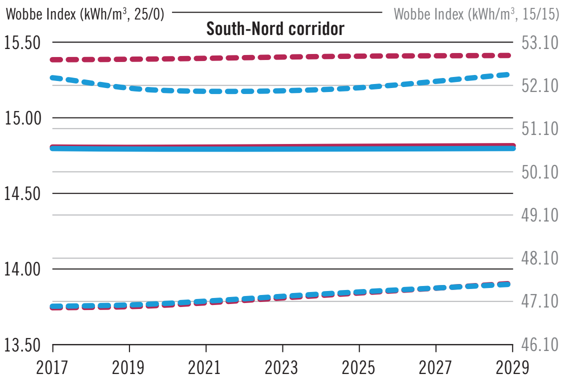
The variability of gas quality parameters is depicted using 2.5 and 97.5 percentiles plotted in dotted lines to show the extreme values in the forecast.

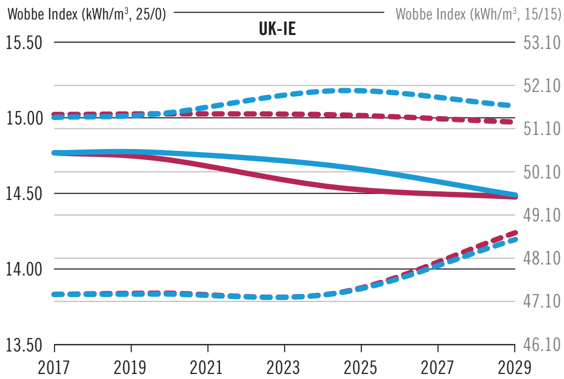
8.3.1 WOBBE INDEX OVERVIEW

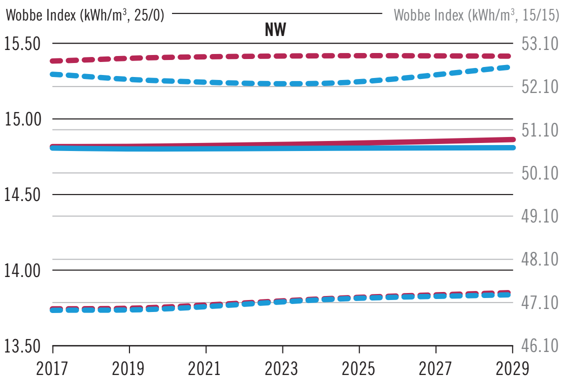


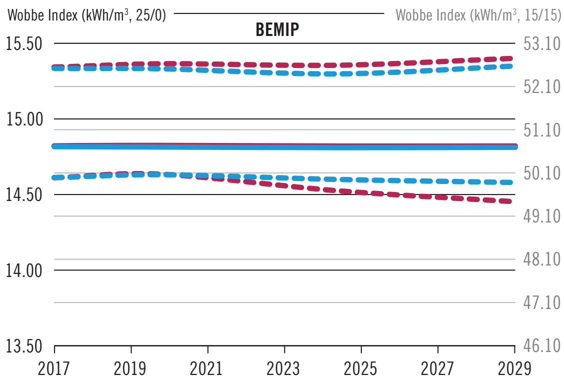
The WI ranges depicted depend more strongly on regions than on any other factor and seem to remain relatively stable for the next ten years.

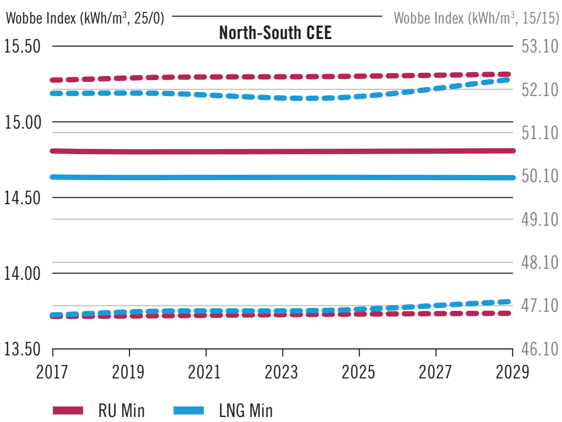
Trends seem to be in general not very sensitive to different price configurations. However, within one region, ranges may actually differ depending on the influence of different sources: LNG rising the higher limit and indigenous production the lower.

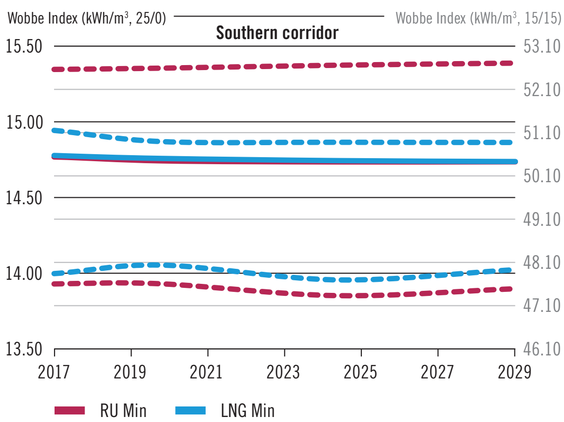




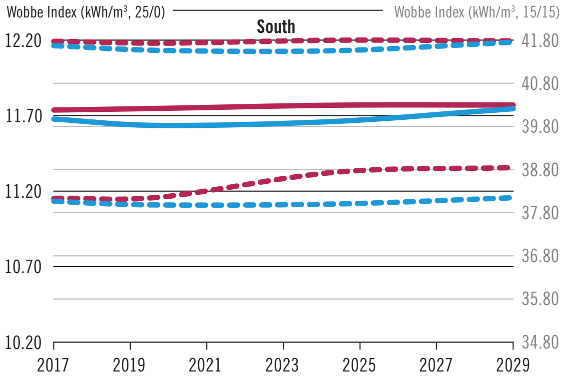






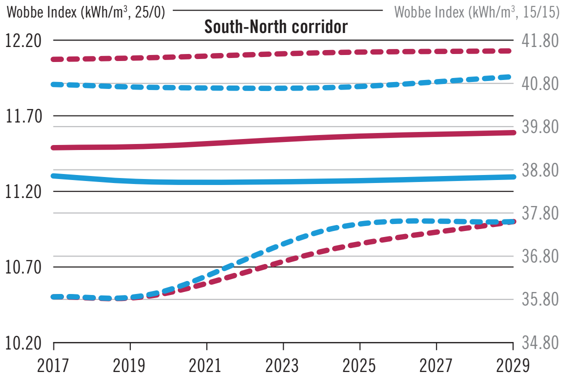


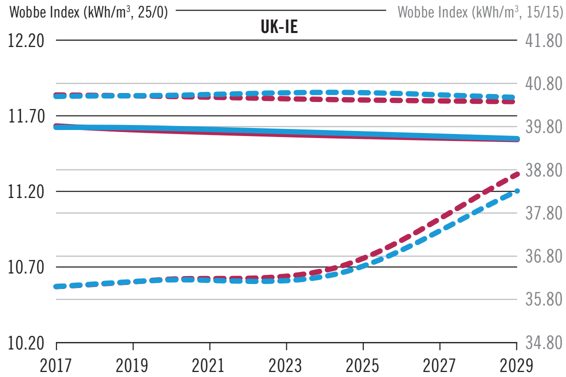
8.3.2 GROSS CALORIFIC VALUE OVERVIEW

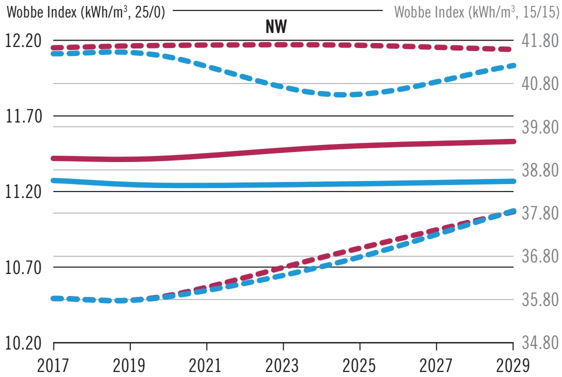


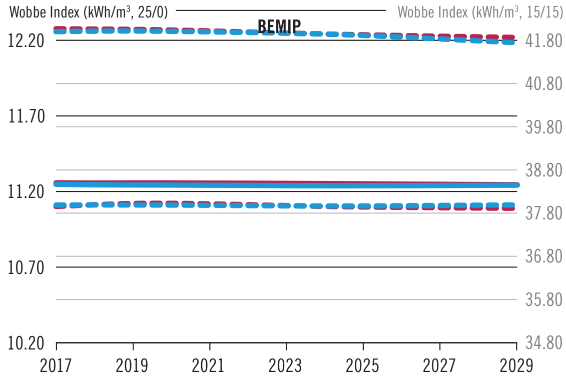
The GCV ranges depicted depend more strongly on regions than on any other factor and seem to remain relatively stable for the next ten years with a tendency to narrow down in certain regions.

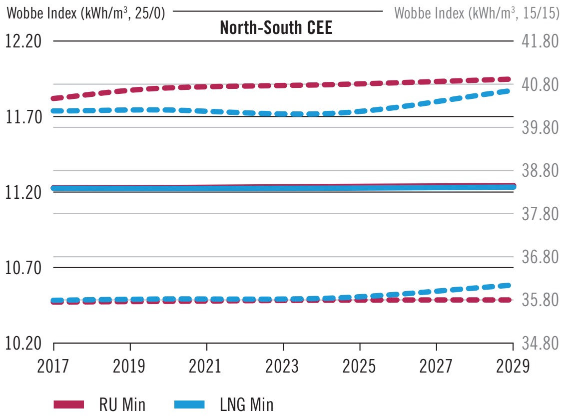
Trends seem to be in general not very sensitive to different supply scenarios. However, within one region, ranges may actually differ depending on the influence of different sources: LNG rising the higher limit and national production the lower.

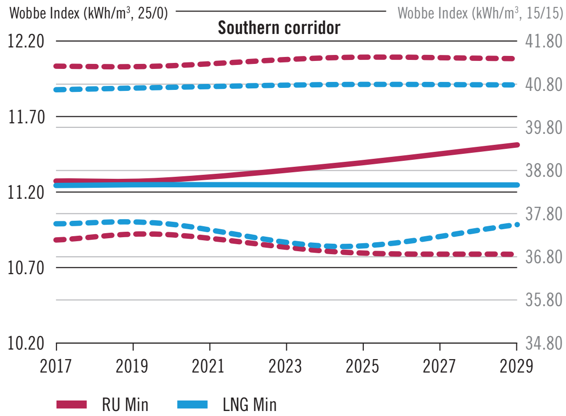












9 Conclusions

Image courtesy of GAZ-SYSTEM

9.1 Introduction

This fifth edition of the Union-wide Ten-Year Network Development Plan (TYNDP) demonstrates the process of continuous improvement from one edition to the next. Whilst the fundamental objectives are unchanged, analysing the long-term supply and demand adequacy, identifying the investment needs and assessing projects, this TYNDP edition has been significantly enhanced.

This edition benefits from a comprehensive scenario development process, building both on gas TSOs and, through ENTSO-E, electricity TSOs expertise, and reflecting the challenges for the energy sector of achieving the EU climate targets.

This TYNDP provides a clear analysis of the infrastructure needs along the different pillars of the EU Energy policy. It has also improved the assessment of projects by collecting and reflecting projects costs and by introducing the notion of advanced projects which provides for a realistic further development of the gas infrastructure.

The TYNDP is also enriched by the new perspective provided by the long-term gas quality monitoring outlook.

9.2 An inclusive and highly transparent TYNDP

For this edition, ENTSOG delivered in-depth stakeholder engagement:

- TYNDP kick-off workshop
- Five full-day Stakeholder Joint Working Sessions (SJWS)
- Concluding workshop to present the TYNDP final concept

This engagement has covered all of the TYNDP building blocks: project collection process, consideration of projects in the assessment, scenario storylines, supply potentials, modelling and outputs. It has enabled ENTSOG to receive valuable feedback. The way this feedback has been taken into account was part of presenting the TYNDP final concept.

ENTSOG has also worked in close cooperation with ENTSO-E on the development of scenarios and with project promoters on the submission of projects.

ENTSOG ensured a highly transparent TYNDP by:

- Informing stakeholders on all TYNDP input data and publishing this data on its website in July 2016
- Publishing for the first time a TYNDP project Map in October 2016
- Presenting the preliminary results of the identification of infrastructure needs to promoters and Regional Groups in October and November 2016.

This high level of transparency has encouraged further stakeholder involvement. Publication of the TYNDP demand and project data in July 2016 has allowed concerned stakeholders to review this data and start making use of it. Presentation of the TYNDP infrastructure needs assessment ahead of the report publication has supported the Regional Groups members - Members States, NRAs and promoters - to get prepared for the PCI selection process.

9.3 Several paths to achieving the EU targets

TYNDP looks twenty years ahead. Performing the TYNDP assessment in a meaningful way requires defining and assessing infrastructure along scenarios that cover the reasonable scope of the gas and energy sector evolution.

Four demand scenarios were developed for this fifth edition of TYNDP:

- **A Slow Progression scenario**, picturing a "tomorrow as today" situation with limited energy efficiency gains, limited renewable development and commodity prices still favouring coal against gas for power generation. This scenario falls short of achieving the EU 2030 climate targets.
- **A Green Evolution scenario**, builds on high national ambitions towards achieving the EU climate targets, while having as pre-requisite a strong economic growth to support the high economic costs implied by strong energy efficiency gains, penetration of expensive energy solutions (such as heat pumps), overall costs of electrifying the residential sector and strong renewable generation development. Low-carbon gas-fired generation supports this development and it is favoured against coal supported by regulation paving the way to coal-fired generation phase out.
- **An EU Green Revolution scenario**, which storyline generally follows the one of the Green Evolution scenario, while under the assumption of even higher European level ambitions, potentially allowing for an earlier achievement of the climate targets. It requires strong economic growth, while being even more ambitious in terms of energy efficiency gains and renewable development.
- **A Blue Transition scenario** picturing achievement of the climate targets at a lower cost, taking advantage of the existing energy infrastructure, this allowing its materialisation even under a context of a realistic, moderate economic growth. The scenario gives a role to gas as a low-carbon substitute to high-carbon fuels. This materialises in the power sector where it supports renewable generation and substitutes coal, making use of existing gas-fired generation capacities and supported by regulation-based phasing-out of coal-fired generation. This allows achieving comparable CO_2 gains as in the two previous scenarios with possibly less investment in developing and integrating renewable generation. Compressed and liquefied natural gas also plays an important role in the decarbonisation of the transport sector, for private and commercial car fleets as well as for maritime transport.

Scenarios also consider the role biomethane will take in the European supply mix. Volumes vary across scenarios in accordance with the economic growth and green ambitions considered, reaching up to 20 bcma in 2035.

ENTSOG has improved its approach to the power sector by using the electricity demand, generation capacities and generation mix from the ENTSO-E electricity TYNDP 2016 scenario development process as a basis for the annual demand for gas-fired generation. This alignment further allows the TYNDP 2017 scenarios to reflect an overall view of the power sector, not only on gas-fired, but also on coal-fired and renewable generation.

The scenarios show contrasted sectoral evolution over time. In the final sector (residential, commercial, industrial and transport), the gas demand ranges from flat (Blue Transition) to a 15 % reduction (EU Green Revolution) compared to 2017, reflecting the targeted energy efficiency gains and the role of gas and electricity in heating and transport. In the power sector, the evolutions reflect the role of gas in complementing renewable generation and displacing coal. The 2030 gas for power demand subsequently ranges from flat (Slow Progression) to a 50 % increase (Blue Transition) compared to 2017.

The TYNDP scenarios indicate different possible paths for the overall gas demand, where achieving the European energy and climate 2030 targets could either be met with a continued decrease or a limited rebound of the demand, with the off-target Slow Progression scenario falling within the demand range of the other scenarios. It will be the role of policy and decision makers to ensure that the retained path is the most cost-effective and makes the best possible use of the energy infrastructure already in place.

To ensure a meaningful TYNDP, it is fundamental to assess the situation of the gas infrastructure for the three scenarios corresponding to the different paths identified towards achieving the EU energy and climate targets. These scenarios cover a reasonable possible range of future gas demand.

Image courtesy of Gascade

9.4 Europe should maintain a diversified supply portfolio

The Supply chapter investigates the possible evolution of indigenous production, based on national information, and of import sources built on publicly available and recognised information. In particular ENTSOG has cooperated with Gassco on Norwegian production and further developed the approach on LNG based on IEA World Energy Outlook.

Over the coming years, European indigenous natural gas production is set to decline in a number of countries, in particular with the depletion of the Groningen field.

Groningen together with some German fields have a specific gas quality (L-gas) and is therefore transported and supplied to consumers of the nearby area using a dedicated gas infrastructure. As it cannot be substituted with standard quality gas (H-gas) the depletion of those fields creates a specific challenge for the countries of the area to convert to standard gas quality and connect to the related gas infrastructure and necessary gas sources.

Regarding future gas qualities, the long term monitoring outlook included in this TYNDP for the first time provides a view on how diversity of supplies in Europe translates in terms of gas quality parameters. Wobbe Index and Gross Calorific Value will vary significantly across regions but their ranges will remain stable in general for the coming years, showing a slight tendency to narrow down in some cases.

At European level, in a context where achieving the EU climate targets could result from either an increase or decrease of gas demand by 2030, the indigenous production decline leads to European supply needs foreseen to increase or at best remain stable.

While Russian gas and LNG have the ability to address increasing supply needs, maintaining supply diversification would require attracting new supplies. Uncertainty on the future of gas will make it challenging. Caspian gas, and more generally Middle-East gas, would require a strong enough market signal to materialise in Europe at more significant levels.

Norway has the potential to deliver significant volumes by connecting the Barents Sea to the existing offshore network, but the necessary investments is in competition with potential LNG developments targeting the world market.

In this context, additional European sources have a key role to play. There are prospects for conventional gas production in the Black Sea and Cyprus. Green gases could also have a strong role, from biomethane to hydrogen or synthetic methane produced from power-to-gas units converting excess renewable electricity generation. Their potential has not yet been fully investigated. They are an important element of developing sector coupling, which is the physical coupling of the gas, power, heat and mobility infrastructure. This aims at making cost-efficient and optimal use of the respective potentials of these infrastructures, including the existing and already well developed gas infrastructure.

Natural and green gas sources exist both in Europe and the surrounding regions. They would ensure a diversified supply. Europe can benefit from them if it sends the appropriate message about the role natural and green gases can have in achieving a cost-efficient decarbonised EU energy mix.

9.5 Market integration is at hand

The TYNDP assessment confirms that the gas infrastructure is close to achieving market integration in most parts of Europe. Once the required infrastructure is commissioned, completing the internal energy market will be a matter of fully implementing the Third Package.

The gas infrastructure has continuously developed over the past decades. In most parts of Europe it is well connected and ensures an efficient access to LNG. It also builds on an impressive storage capability, which has proved its value and reliability. Over the last years additional progress has been made in terms of infrastructure development. Since TYNDP 2015, around 20 projects have been implemented, among which 9 were listed on the 1st PCI list adopted in 2013.

As a consequence, the gas infrastructure is well equipped to face the challenges of the future: it can cope with the evolution that the gas demand will undergo to achieve the climate targets. Being well connected in most parts of Europe, it allows countries to access diversified supply sources, in turn playing a key role, both in terms of security of supply and competition. The gas infrastructure generally shows high resilience and ability to accommodate a number of route or supply disruption situations if the necessary cooperation between Member States is in place.

However, some specific areas suffer from limited diversification of supply sources, resulting from a lack of integration or even isolation. This is the case in South-Eastern and Central-Eastern Europe, still highly dependent to Russian gas, exposed to Ukraine transit disruption and facing limited or poor competition. In the Baltic region the situation has been improved since the commissioning of the Klaipėda LNG terminal in 2014, whose continuation from 2024 would need to be confirmed for its benefits to carry on. Still, the region is poorly connected and Finland isolated, leading to poor supply diversification and competition, and security of supply issues. In addition, some of the Baltic countries are exposed to disruptions of supply via Belarus from 2025. In Western Europe, in addition to the specific challenge of converting L-gas markets to H-gas, the Iberian Peninsula low diversification potential to pipe-bound sources raises a competition concern.

The projects necessary to solve the identified investment needs exist and most of them are foreseen to be commissioned by or around 2020. Among these projects some have a FID status and most, although non-FID, already have an advanced status. In some cases additional less-advanced projects listed on the 2nd PCI list could be needed. Leaving aside the large-scale import projects, **the investment costs for implementing the FID and advanced projects is reported below 20 bn€**. Taking into account that some initiatives may be in competition, the actual implementation costs would presumably be lower.

9.6 A more comprehensive approach to energy infrastructure is needed

The existing gas infrastructure is the result of development and investment over many decades. It includes a well-connected network of transmission pipelines, LNG terminals and storage infrastructure. Progress accomplished over recent years has further improved this system. Limited additional infrastructure is necessary to ensure that the internal energy market becomes a reality all across Europe. The required infrastructure is already identified and an important part of it is planned to be commissioned around 2020.

Tomorrow, this system will not only transport natural gas. Increasing volumes of biomethane are produced and injected into the gas grid. The future of gas infrastructure is also about synthetic gasses and hydrogen. Power-to-gas units are a unique opportunity to optimise renewable generation by connecting it to the highly interconnected gas infrastructure, offering efficient and low cost energy transmission and storage in the gas system, when compared to electric transmission expansion and reinforcement.

In getting prepared for the challenges of the European energy transition and decarbonisation it is fundamental to take a holistic view on the whole energy system. In this perspective, sector coupling should a central point of attention. Sector coupling consist in the physical coupling of the power, heat and mobility infrastructure with the aim of making the optimal use of their respective potentials.

The gas infrastructure is a powerful asset. It ensures efficient and low-cost energy transmission and storage. It is mature in most European regions, in particular in Western Europe which gathers most of the European energy consumption and where the energy transition is on its way. It should to be used in the optimal way in the future to achieve the European energy and climate targets in the most cost-effective manner. This will require decision and policy makers to recognise the role that gas infrastructure has to play and to provide the necessary framework for this to be possible.

9.7 Way forward

TYNDP 2017 will be a cornerstone of the 3rd PCI selection taking place. ENTSOG endeavours to offer its expertise in this process. As the TYNDP is an ever-improving process, ENTSOG invites stakeholders to provide their feedback for the preparation of the next edition.

TYNDP 2017 has also a key role to play in the 3rd PCI selection process. Indeed it supports the identification of the infrastructure needs in each Regional Group. ENTSOG has contributed to it since October 2016 by presenting elements of the TYNDP assessment ahead of the report publication. The TYNDP 2017 data and assessment will also constitute the common base for the cost-benefit analysis of all projects that are candidates to the PCI label. In this regard, ENTSOG will support the promoters by handling the modelling of their project-specific CBAs, in line with the formal invitation received from the European Commission.

Collecting stakeholders' feedback is vital for ENTSOG. Following its release, the TYNDP will be presented to stakeholders. To support the ever-improving process, a public consultation will be opened and workshops will be organised to collect stakeholder feedback. Stakeholders are warmly encouraged to participate in these events. ACER Opinion will also constitute a key feedback element, as well as a basis for improvements to be further considered. ENTSOG intends to publish the final version of the TYNDP in spring 2017, incorporating stakeholders' feedback and ACER opinion where manageable in a timely manner. Where consideration of these inputs would require more time, ENTSOG will consider it for the TYNDP 2018.

ENTSOG has already started developing TYNDP 2018 and the draft version is intended to be released in the second half of 2018. For this new edition, ENTSOG and ENTSO-E have engaged in a fully common scenario development process, which relies on an intense day-to-day cooperation between both associations' experts and a joint engagement of stakeholders to ensure a cross-sectoral approach. The joint ENTSOs Scenario Report is intended to be published by mid-2017.

This joint scenario development will be one of the key elements of the "gas and electricity consistent and interlinked model" that the ENTSOs will deliver to the European Commission and ACER by the end of 2016 in line with the requirement set by Art 11(8) of Regulation (EU) 347/2013.

Additionally, in view of TYNDP 2018, ENTSOG intends to develop an updated version of the CBA methodology. The update process will be initiated shortly. It will take due consideration of European Commission and ACER expectations, and will engage stakeholders.

Stakeholders are warmly encouraged to take part in the upcoming consultations processes. This is vital to improve both the TYNDP and CBA methodology.

Definitions

1-day Design Case (DC) The aggregation of the level of demand used for the design of the network in each country to capture maximum transported energy and ensure consistency with national regulatory frameworks.

2-week high demand case (14-day, 2W) The aggregation of the level of demand reached on 14 consecutive days once every twenty years in each country to capture the influence of a long cold spell on supply and especially storages.

Advanced Non-FID Project ENTSOG has defined a rule which will govern which infrastructure Projects are considered in the "Advanced Non-FID" infrastructure level.

According to this rule, a project will be considered as Advanced if, and only if:

- The project is commissioned by the 31st of December 2022 at the latest.
  - In case such a project also includes increments commissioned after 2022, such increments will not be included in the Advanced infrastructure level.

AND

- Permitting phase of the project has started before the 1st of April 2016 close-of-business.

OR

- FEED has started or the project has been selected for receiving CEF grants for FEED before the 1st of April 2016 close-of-business.

Biomethane Biogas produced from biomass and waste which has been upgraded to natural gas quality for the purpose of grid injection and Power-to-gas volumes.

Capacity-based Indicator Concerns indicators which reflect the direct impact of infrastructures on a given country as their formulas are limited to capacity and demand of a country or a Zone.

Capacity Modification Capacity Modification is a "Project-like" data submission within the Data Portal by a Promoter. Capacity Modification is any capacity change (positive or negative) on a modelled Operational Point, whereby no actual physical work or financial investment is necessary to carry out the capacity modification. Consequently, it is not considered as an actual Project but as a Capacity Modification and will be labelled accordingly in ENTSOG publications, including TYNDP annexes. Capacity Modifications can be the result of the following actions:

- Change in future demand assumptions, leading to capacity recalculations
- Dynamic storage behaviour
- Shifting of capacity between IPs
- Decrease of capacity due to degradation of the transmission system
- Decrease of capacity due to gas depletion
- Technical Agreements between TSOs
- Etc.

In case the Project Promoter indicates when submitting the data that the submission is a Capacity Modification, the submitted data is not labelled as a Project but as a Capacity Modification

CBA (Cost-Benefit-Analysis) Analysis carried out to define to what extent a project is worthwhile from a social perspective.

CSSD Cooperative Supply Source Dependence indicator as defined under section 4.2.4. in Annex F.

Deliverability The rate at which the storage facility user is entitled to withdraw gas from the storage facility.

Enabled Project An Enabled Project is a Project, which cannot realize its incremental capacity potential partially or fully within an Entry/Exit system at an Entry/Exit point (IP point; UGS Entry/Exit Point; LNG Entry/Exit Point) without an Enabler Project.

Enabler Project A Project can be considered as an Enabler Project, when it is necessary for another Project (the Enabled Project) to realise its full capacity potential. An Enabler Project can take place inside a Balancing Zone, with no direct access to another Balancing Zone or Entry/Exit Point (e.g. compressor station, transmission Project solving internal bottleneck, etc.). An Enabler Project shall be realised without a capacity increment on a Point.

An Enabler Project can enable a single Project or multiple Projects as well to realize its/their full potential(s).

ESW-CBA Methodology Integrated methodology (Energy System Wide) under Regulation (EC) 347/2013 supporting the selection of Projects of Common Interest (PCIs) composed of two steps:

- TYNDP-CBA step, providing an overall assessment of the European gas system under different levels of infrastructure development
- Project Specific-CBA step, providing an individual assessment of each project's impact on the European gas system based on a common data set.

Existing Capacity The Existing Capacity designates the firm technical capacity for a specific operator, point and flow direction available on the first gas day of the first year of the TYNDP.

The Existing Capacity is a single figure. For the purposes of the TYNDP it is used as a constant baseline over all the years of the TYNDP period; any change (positive or negative) to the Existing Capacity can only come from an Increment or from a Capacity Modification submitted by a Promoter.

FID (Final Investment Decision) The decision to commit funds towards the investment phase of a project. The investment phase is the phase during which construction or decommissioning takes place and capital costs are incurred (EU No 256/2014).

FID project A project where the respective project promoter(s) has(have) taken the Final Investment Decision.

Firm capacity Gas transmission capacity contractually guaranteed as uninterruptible by the transmission system operator.

First Full Year of Operation The first year (from the 1st of January until the 31st December) of commercial operation of the project. For multi-phased projects, the First Full Year of Operation is the one of the first phase.

Flow Direction A flow direction is a piece of information that qualifies the direction in which gas is flowing relatively to an operator. There are two possible directions:

- Entry: a capacity provided by an operator in the entry direction designates the amount of gas that can enter into the operator's system.
- Exit: a capacity provided by an operator in the exit direction designates the amount of gas that can exit from the operator's system.

Incremental Capacity Possible future increase via market-based procedures in technical capacity or possible new capacity created where none currently exists that may be offered based on investment in physical infrastructure or long-term capacity optimisation and subsequently allocated subject to the positive outcome of an economic test, in the following cases:

(a) at existing interconnection points,

(b) by establishing a new interconnection point or points;

(c) as physical reverse flow capacity at an interconnection point or points, which has not been offered before.

Gas Quality Natural gas is made up of several component gases and is therefore subject to natural variation. This inconsistency affects the energy contained within a given volume of gas; the measure used is the Calorific Value (CV) of the gas. The Wobbe Number or Wobbe Index, is another important characteristic which describes the way in which the gas burns and is calculated as a factored ratio of CV and Specific Gravity (SG otherwise known as Relative Density).

Injectability The rate at which the storage facility user is entitled to inject gas into the storage facility.

Interconnector A transmission pipeline which crosses or spans a border between Member States for the sole purpose of connecting the national transmission systems of those Member States.

Interconnection Point Meaning physical or virtual points connecting adjacent entry-exit systems or connecting entry-exit systems with an interconnector.

IRD The Import Route Diversification indicator measures the diversification of paths that gas can flow through to reach a zone as defined under section 4.1.1. in Annex F.

Lesser-Of-Rule The rule applied, to ensure consistent and conservative available firm capacity values on the modelled Points in the network modelling exercise. The rule means, that on a Point with Entry and Exit capacities, the minimum of the two values will be considered as the firm capacity available for use.

Example: Promoter A submits an Exit capacity on Point P in the value of 100. Promoter B submits an Entry capacity on the other side of the Point P, in the value of 200. After the application of the rule, the firm capacity considered for modelling will be 100.

LNG Terminal A LNG Terminal is a facility at which liquefied natural gas is received, stored and “regasified” (turned back into a gaseous state) after shipment by sea from the area of production.

Mixed fuels Power generation facilities that can run on two or more different fuels. Therefore the identification of the primary source cannot be clearly defined.

N-1 The indicator measuring the impact of the loss of the single largest infrastructure of a given country adapted to the context to the TYNDP and CBA. Levels for each country are available under section 4.1.2. in Annex F.

National Production Indigenous production coming either from off- or onshore gas sources in a country and covered in the TYNDP. An allocation per zone in a country has been carried out where relevant.

Network User A customer or a potential customer of a transmission system operator, and transmission system operators themselves in so far as it is necessary for them to carry out their functions in relation to transmission.

Non-FID project A project where the Final Investment Decision has not yet been taken by the respective project promoter(s).

Number formatting Comma (,) is used as a 1,000 separator.
Point (.) is used as a decimal separator.

PCI (Project of Common Interest) A project which meets the general and at least one of the specific criteria defined in Art. 4 of the TEN-E Regulation and which has been granted the label of PCI Project according to the provisions of the TEN-E Regulation.

Power-to-Gas Power-to-Gas is the process of converting surplus renewable energy into hydrogen gas by rapid response electrolysis.

Project A Project designates any initiative, event or development that:

- creates new capacities
- or modifies existing capacities
- or aims at creating the necessary infrastructure for enabling such capacity changes.

At points of the following types:

- Cross-Border Points between Transmission Systems
- Cross-Balancing Zone Points between Transmission Systems
- LNG Entry Points
- Storage Entry-Exit points

Such Projects do have to be submitted to ENTSOG in order for ENTSOG to take into account the induced changes to the existing capacities. All Projects submitted to ENTSOG are listed in the Annex A of the TYNDP. A Project is submitted by one Project Promoter.

A Project can fall into two specific categories :

- Project with Associated Investment is a Project which requires financial investment and actual construction works will take place

- Capacity Modification is a "Project-like" data submission within the Data Portal by a Promoter. Capacity Modification is any capacity change (positive or negative) on a modelled Operational Point, whereby no actual physical work or financial investment is necessary to carry out the capacity modification. Due to this, it is not considered as an actual Project but as a Capacity Modification and will be labelled accordingly in ENTSOG publications, including TYNDP Annexes. Capacity Modifications can be the result of the following actions:

  - Change in future demand assumptions, leading to capacity recalculations
  - Dynamic storage behaviour
  - Shifting of capacity between IPs
  - Decrease of capacity due to degradation of the transmission system
  - Decrease of capacity due to gas depletion
  - Technical Agreements between TSOs
  - Etc.

Project Promoter A Project promoter is a registered legal entity, which has the capacity to undertake legal obligations and assume financial liability in order to realize the Project it promotes and submits during the course of the ENTSOG data collection procedure.

Reference Case Means the reference price configuration for which the supply curve for each import source varies between the same price assumptions.

Report The referenced TYNDP including all Annexes. Report and Plan are used interchangeably.

RF Remaining Flexibility indicator which measures the resilience of a zone as defined in section 4.2.1. in Annex F. The value of the indicator is set as the possible increase in demand of the Zone before an infrastructure or supply limitation is reached somewhere in the European gas system.

Scenario A set of assumptions for modelling purposes related to a specific future situation in which certain conditions regarding gas demand, fuel prices and biomethane.

Seasonal Factor Factor applied to average yearly demand to determine the seasonality of the gas market as defined in section 3 of Annex C4.

Shale gas Natural gas that is trapped within shale formations.

SSPDe Supply Source Price Dependence indicator which measures the price exposure of each Zone to the alternative increase of the price of each supply source and as defined in section 4.2.6. in Annex F.

SSPDi Supply Source Price Diversification indicator which measures the ability of each Zone to take benefits from an alternative decrease of the price of each supply source and as defined in section 4.2.5. in Annex F.

Supply Potential The capability of a supply source to supply the European gas system in terms of volume availability. A Supply Potential is the range defined through Maximum and Minimum. Supply Potentials for a supply source have been developed independently with no assessment on the likelihood of their occurrence.

Route Disruption (formerly known as Supply Stress) Supply situation which is marked by an exceptional supply pattern due to a supply route disruption. Specific route disruptions have been defined in section 2.2.7. in Annex F.

Technical capacity The maximum firm capacity that the Transmission System Operator can offer to the network users, taking account of system integrity and the operational requirements of the transmission network (Art. 2(1)(18), REG-715).

Ten-Year Network Development Plan (TYNDP) The Union-wide report carried out by ENTSOG every other year as part of its regulatory obligation as defined under Article 8 para 10 of Regulation (EC) 715/2009.

Transmission The transport of natural gas through a network, which mainly contains high-pressure pipelines, other than an upstream pipeline network and other than the part of high-pressure pipelines primarily used in the context of local distribution of natural gas, with a view to its delivery to customers, but not including supply (Art. 2(1)(1), REG-715).

Transmission System Any transmission network operated by one Transmission System Operator (based on Article 2(13), DIR-73).

Transmission System Operator Natural or legal person who carries out the function of transmission and is responsible for operating, ensuring the maintenance of, and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transport of gas (Article 2(4), DIR-73).

USSD Uncooperative Supply Source Dependence indicator which identifies zones whose physical supply and demand balance depends strongly on a single supply source when each zone tries to minimize its own dependence and as defined in section 4.2.3. in Annex F.

Wobbe Index The Wobbe Index is a measure of the interchangeability of fuel gases and their relative ability to deliver energy.

Zone A country or balancing zone at which level the market shall balance gas demand and supply.

Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
Bcm/Bcma	Billion cubic meters/Billion cubic meters per annum
CAM NC	Capacity Allocation Mechanism Network Code
CAPEX	Capital expenditure
CBA	Cost-Benefit Analysis
CIS	Commonwealth of Independent States
DEg	Balancing Zone of GASPOOL (DE)
DEn	Balancing Zone of NetConnect Germany (DE)
DIR-73	Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.
EBP	European Border Price
EC	European Commission
EIA	Energy Information Administration
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	European Trading Scheme
EU	European Union
FEED	Front End Engineering Design
FID	Final Investment Decision
FRn	Balancing Zone of GRTgaz North Zone (FR)
FRs	Balancing Zone of GRTgaz South Zone (FR)
FRt	Balancing Zone of TIGF (FR)
GCV	Gross Calorific Value
GIE	Gas Infrastructure Europe
GHG	Greenhouse Gases
GLE	Gas LNG Europe
GRIP	Gas Regional Investment Plan
GSE	Gas Storage Europe
GWh	Gigawatt hour
e-GWh	Gigawatt hour electrical
GQO	Gas Quality Outlook
HHI	Herfindahl-Hirschman-Index
H-gas	High calorific gas
HDV	Heavy duty vehicles
HGV	Heavy goods vehicles
IEA	International Energy Agency
IP	Interconnection Point
ktoe	A thousand tonnes of oil equivalent. Where gas demand figures have been calculated in TWh (based on GCV) from gas data expressed in ktoe, this was done on the basis of NCV and it was assumed that the NCV is 10% less than GCV.

L-gas	Low calorific gas
LDV	Light Duty Vehicles
LNG	Liquefied Natural Gas
mcm	Million cubic meters
MMBTU	Million British Thermal Unit
MS	Member State
MTPA	Million Tonnes Per Annum
mtoe	A million tonnes of oil equivalents. Where gas demand figures have been calculated in TWh (based on GCV) from gas data expressed in mtoe, this was done on the basis of NCV and it was assumed that the NCV is 10 % less than GCV.
MWh	Megawatt hour
e-MWh	Megawatt hour electrical
NCV	Net Calorific Value
NERAP	National Energy Renewable Action Plans
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
OPEX	Operational expenditure
PCI	Project of Common Interest
P2G	Power-to-Gas
REG-703	REGULATION (EU) 2015/703 of 30 April 2015 establishing a network code on interoperability and data exchange rules
REG-347	Regulation (EU) No 347/2013 of the European Parliament and of the council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009
REG-715	Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks.
REG-SoS	Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 concerning measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC.
RES	Renewable Energy Sources
SIF/SWF	Seasonal Injection Factor/Seasonal Withdrawal Factor
SoS	Security of Supply
Tcm	Tera cubic meter
TRS	Trading Region South, consisting of the balancing zones FRs and FRt
TSO	Transmission System Operator
TWh	Terawatt hour
e-TWh	Terawatt hour electrical
TYNDP	Ten-Year Network Development Plan
UGS	Underground Gas Storage (facility)
WI	Wobbe Index

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	FYROM
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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