european network
of transmission system operators
for gas

TEN YEAR NETWORK DEVELOPMENT PLAN 2015

TYNDP 2015

MAIN REPORT

ENTSOG – A FAIR PARTNER TO ALL!

Ten Year Network Develoment Plan 2015

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Foreword

This is the fourth time that I have the honour to preface the Union-wide Ten Year Network Development Plan (TYNDP) of the European Network of Transmission System Operators for Gas (ENTSOG). This report illustrates TSOs' willingness to provide, through ENTSOG, a common platform for the gas industry and institutions to share their knowledge and vision of the future of the European gas market and gas networks.

With each edition, ENTSOG endeavours to go beyond regulatory requirements and to deliver analysis bringing real added-value to all stakeholders and decision-makers. This ambition is made more challenging with the entry into force of the TEN-E Regulation and the resulting higher expectations. I like to consider that we have succeeded to a large extent, even if it is difficult to address everyone's concerns.

I am particularly proud of the way ENTSOG has taken up the two main challenges of this edition. First, a high degree of convergence has been ensured between ENTSOG and ENTSO-E, by modelling gas demand for power generation based on the ENTSO-E visions and market data. Secondly, the implementation of the Cost-Benefit Analysis methodology in the TYNDP provides a solid base for the second selection round of Projects of Common Interest.

Beyond the positive aspects of the continuous improvement of the report, we should not ignore the implications of its wide and robust assessment. From an infrastructure perspective, market integration has been achieved and is delivering benefits for many gas consumers. Nevertheless, this is not the case for all of them and the completion of the Internal Energy Market is at risk.

Image courtesy of Swedegas

New investments are necessary for connecting isolated regions and for further integrating other areas. Unfortunately, some investment decisions have been delayed because of a strong focus on the short term and of the absence of a clear long term vision for gas demand and supply. Failing to deliver these new infrastructures will leave the whole of Europe unprepared to face its continuously increasing import dependency.

This report confirms the existence of projects which would support a more secure, competitive and sustainable energy future for Europe. These projects cover the construction of gas pipelines, interconnections, storages and LNG terminals as well as the development of new internal and external gas supplies. They will only materialize if decision-makers give appropriate signals to the market and focus on the implementation of existing regulations.

On behalf of ENTSOG, I would like to thank all parties involved in the TYNDP process and I hope that this edition will see a large support of all stakeholders.

I am confident that this TYNDP edition will prove to be both useful and stimulating. Now it is time for me to let you discover its findings. I would welcome your feedback on the report and its related production and assessment processes, which you can provide through our consultation process.

Stephan Kamphues

ENTSOG President

Executive Summary

This document, produced by the European Network of Transmission System Operators for Gas (ENTSOG), is the fourth edition of the pan-European Ten Year Network Development Plan (TYNDP). To comply with the Cost-Benefit Analysis (CBA) requirement of the TEN-E Regulation, this TYNDP covers an extended time period ranging from 2015 to 2035 and provides a wide ranging view of how European gas infrastructure and supply adequacy could develop over the next two decades.

The regulatory requirement on ENTSOG to publish the Union-wide TYNDP every two years stems from the 3rd Energy Package. The original aims were to identify possible investment gaps and to assess the evolution of the supply adequacy. With the entry into force of the TEN-E Regulation in May 2013, the TYNDP has acquired a new dimension as it is now the first step of the Project of Common Interest (PCI) process. Every PCI candidate must submit its project to ENTSOG for inclusion in TYNDP. ENTSOG will then apply the Cost-Benefit Analysis (CBA) methodology, which has been developed for this TYNDP.

In order to ensure the consistency of the TYNDP and the CBA methodology, ENTSOG has merged the two consultation processes. The main objectives were the adaptation of the methodology, first published in November 2013, and the definition of the associated data set. It also offered the opportunity to run a case-study on a sample of projects. This consultation process represented a key step in the preparation of the PCI assessment by ENTSOG as it was supposed to gather the knowledge of all stakeholders. This is of particular importance for data related to supply and price scenarios which are beyond ENTSOG remit.

The development and maintenance of gas infrastructure supports the three pillars of the European energy policy: security of supply, competition and sustainability. It facilitates a liquid and hence a competitive internal gas market by increasing physical market integration. The resulting flexibility of the European gas system will enable and enhance supply diversification and Security of Supply, even in the case of declining indigenous production. Gas infrastructure will also play an important role in improving sustainability in the EU by helping to meet its environmental targets.

FROM PROJECTS TO COMMISSIONED INFRASTRUCTURE

ENTSOG has received submissions for 259 projects from transmission, storage and LNG terminal promoters by the deadline of September 2014. The withdrawal of the South Stream project, approved by the promoter and the European Commission, is the only exception because of its possible major impact on the assessment. The project list includes the PCI resulting from the first selection and all candidates for the second round of the PCI assessment.

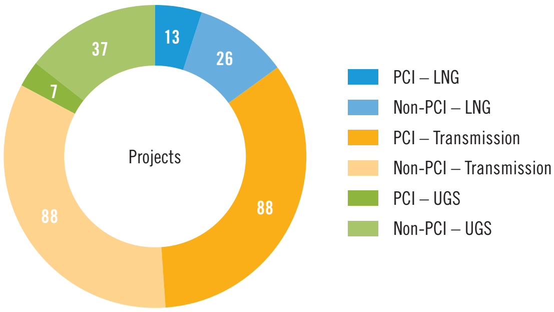

Figure 1: Projects submitted to the TYNDP 2015 (PCI refers to the 2013 approved list)

The number of projects is slightly lower than in the previous TYNDP edition, but there are still sufficient infrastructure projects to deliver market integration as shown in the present Report.

While construction works are normally completed on time, the final investment decision for many projects is postponed. Therefore, ENTSOG asked promoters to identify the main challenges they have been facing and derived the following chart.

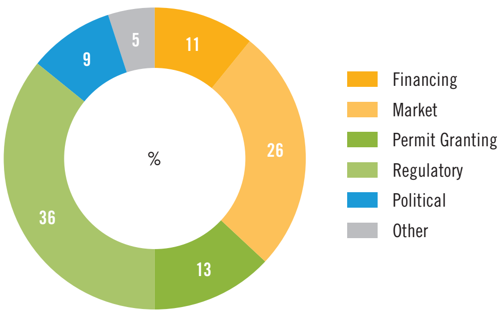

Figure 2: Investment barriers identified by promoters

The first barriers mentioned by promoters are related to various aspects of the regulatory frameworks. In some cases these stem from a lack of implementation of European regulation preventing a well-functioning market which is a major prerequisite for investment decisions. In other cases, some national frameworks are perceived as excessively focusing on the reduction of the regulated tariff, not recognizing the economic benefits of further market integration and therefore granting unsufficient rate of return.

The second group of barriers stems from a short term focus of the market which is not providing sufficient financial commitment. This is a result of the combination of an unfavourable economic environment with regulation, which is nowadays favouring the short term perspective. This can result in a higher reliance on other solutions, such as the socialization of cost or co-financing, and can lead to a higher risk of stranded assets.

One of the main reasons for this lack of market commitment is the uncertainty in the long term use of gas in definition of the European energy mix. Only a relative small share of investment can be triggered for security of supply reason. Market players, NRAs and infrastructure operators need the guarantee of sufficient use of the infrastructure in order to support the economically efficient development of projects.

A STABLE DEMAND DRIVEN BY GLOBAL CONTEXT

Since 2010 European gas demand has continuously decreased mainly due to a lower use of gas-fired power generation. This results from the combination of European policies, such as the development of renewable sources (RES) and an inefficient European Trading System (ETS), as well as the global context of low coal prices and still ongoing economic downturn.

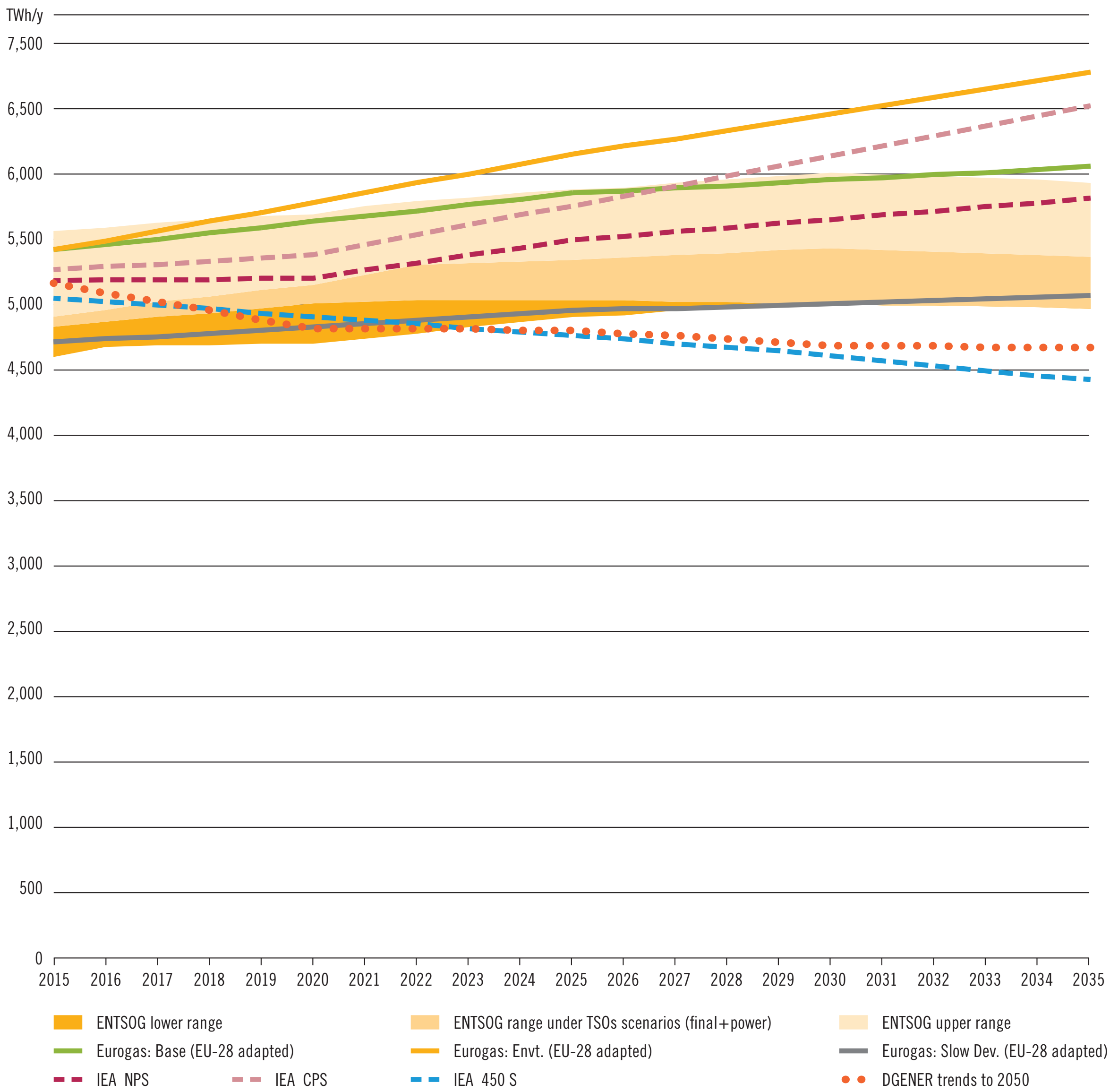

Figure 3: Comparison of gas demand outlooks

The TYNDP assessment indicates that over the next two decades the evolution of gas demand is likely to be driven mostly by the use of gas in the power generation sector. Therefore, most gas demand outlooks evolve in a narrow range which depends on the equilibrium between gas, coal and CO_2 prices. The most divergent scenarios are the “DGENER trends to 2050” and the “IEA 450 S” where environmental targets are achieved with a higher level of RES and a better efficiency.

This overall slow increase of gas demand (0.4 % per annum on the next twenty-one years) hides a heterogeneous situation among countries. This is particularly the case in the Green scenario due to very different national strategy to achieve environmental targets.

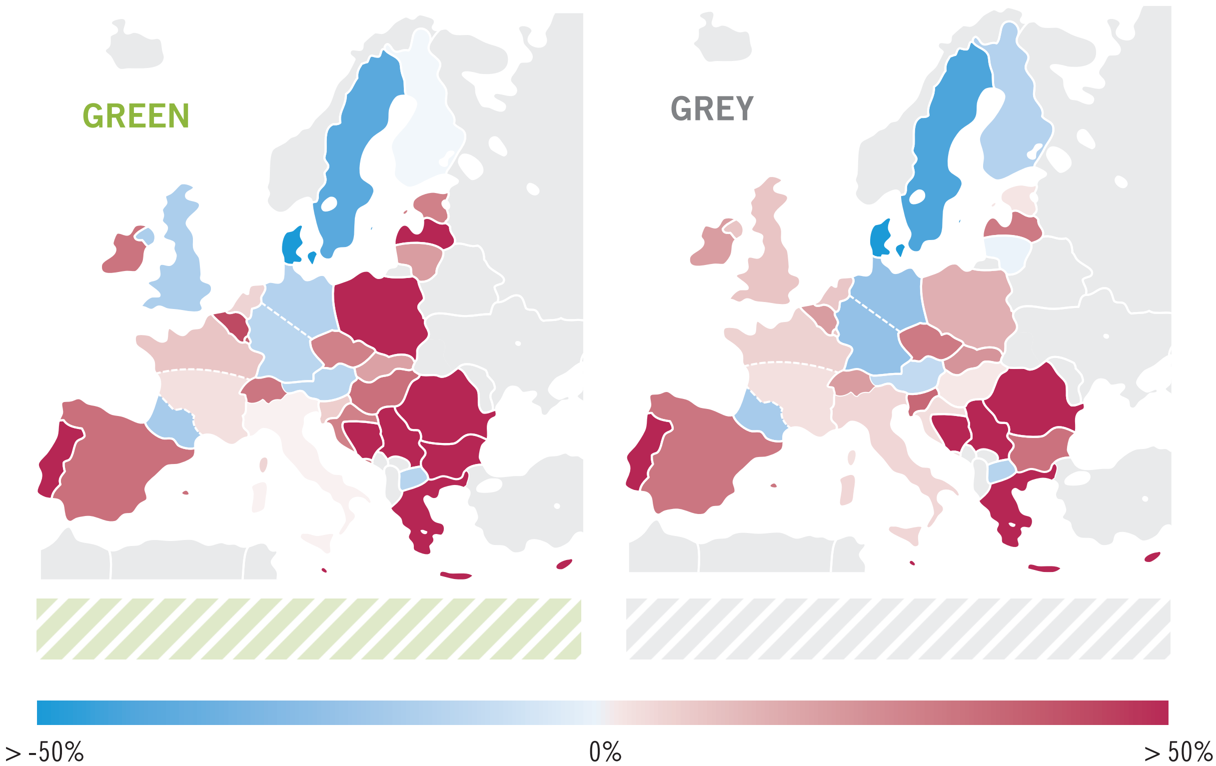

Figure 4: Evolution of total annual gas demand on 2015 – 2035 period
(Gas demand for electricity is based on data from ENTSO-E SO & AF 2014 – 2030)

ENTSOG is now deriving the level of gas demand for power generation based on ENTSO-E and price data. The seasonal swing is now modelled through the use of summer and winter cases. E NTSOG has kept the 1-day Design Case and the 2-week Uniform Risk Case representing the extreme situation to be covered by the European gas system.

EUROPE NEEDS TO ENLARGE ITS SUPPLY PORTFOLIO

When gas demand does not show a clear evolution, the requirements for gas imports are driven by the decreasing indigenous production. Under the current perspective the induced need for additional imports is likely to be met by Russian gas and LNG, especially under the Green scenario. In such a situation Europe would be in a challenging position resulting in a reduced market power.

Other sources are likely to stay at the current level (pipe gas from Algeria and Libya) or would only have a limited influence (Caspian gas) in absence of stronger market signals. Norway is a very particular case as there is a potential to deliver significant volumes from the Barents Sea gas fields from the mid 2020s. Nevertheless, the investments connecting this production to the existing European gas network is not yet decided and is in competition with potential LNG developments as a result of the lack of long term attractiveness of the continent. Other producers (e.g. North Africa and Middle-East) are facing the same challenges. Appropriate signals from Europe would enable the delivery of new supply to Europe improving both its energy security and its competitiveness while supporting high environmental standards.

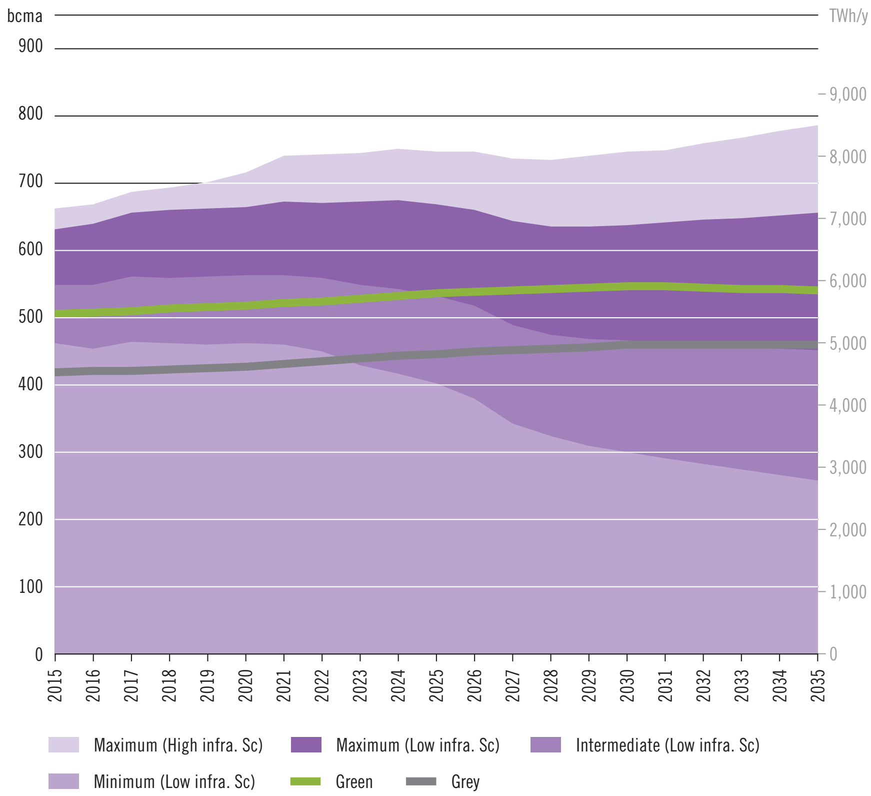

Figure 5: Comparison of gas demand and gas supply scenarios

MARKET INTEGRATION, A CONSTANT CHALLENGE

The TYNDP assessment confirms a predominant position of Russian gas and LNG supplies under the Green scenario even with all other sources at high deliverability. This situation could be improved with the commissioning of new infrastructure and the connection of new supplies. The following graphs compare the minimum supply share of Russian gas and LNG between the Low and High Infrastructure scenarios along the time horizon.

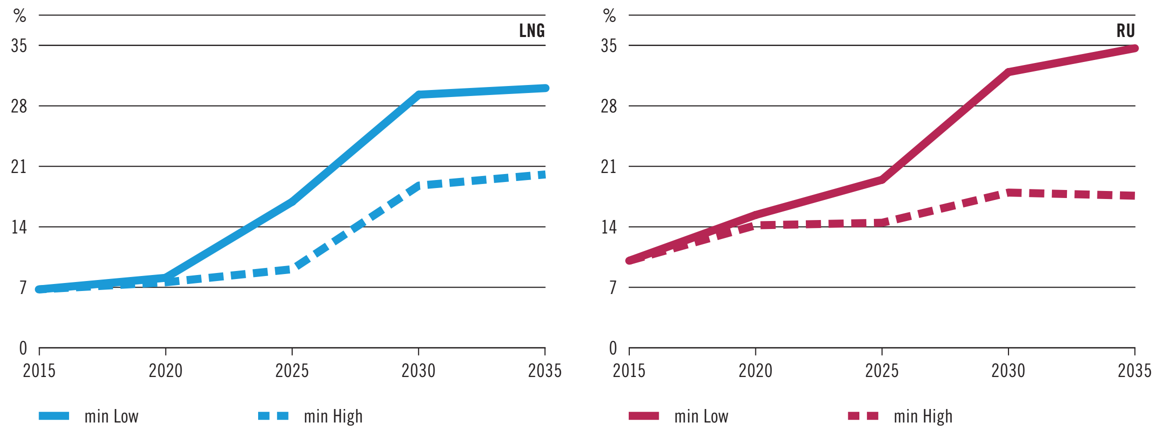

Figure 6: Evolution of the supply share of Russian gas and LNG according to the Low and High Infrastructure scenarios

TYNDP findings show that regions not sufficiently integrated often suffer from a lack of supply security and competition. This is especially the case for the Baltic region, Central-Eastern and South-Eastern Europe, where the development of infrastructures has been unsufficient due to the historical gas supply from Russia, and also for South-Western Europe where LNG has a significant role. The latter case is not an issue in terms of security of supply, but in terms of exposure to the global LNG price.

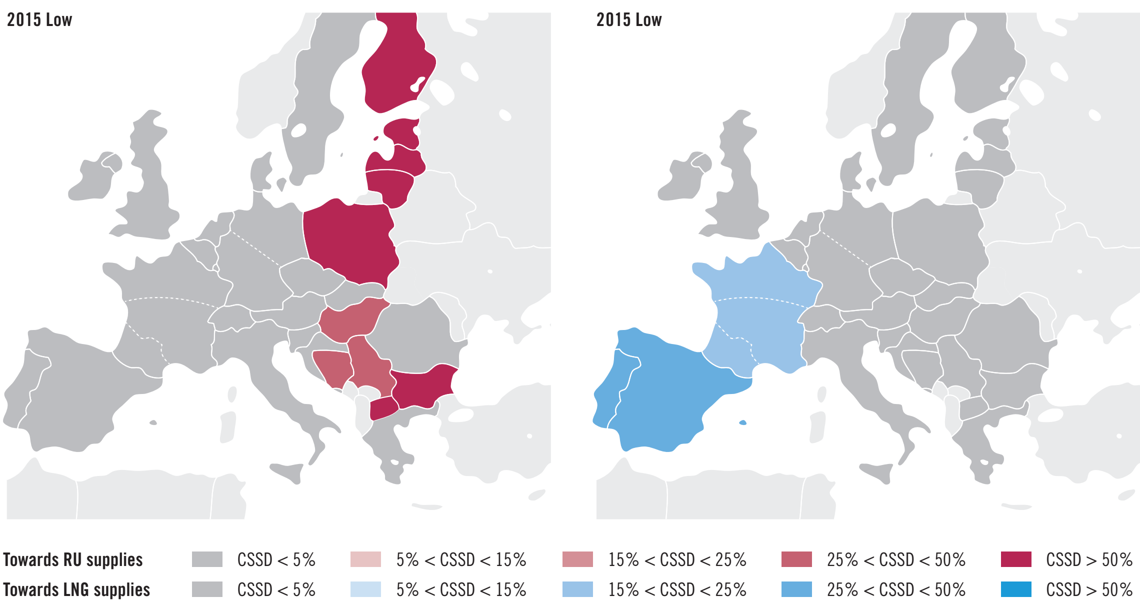

Figure 7: Cooperative Supply Source Dependence towards Russian (red) and LNG (blue) supplies

This situation may improve across Europe in the future if sufficient new investment decisions are taken. But the increasing need of imports and the predominance of Russian and LNG supplies could put Europe in a difficult situation despite the completion of market integration.

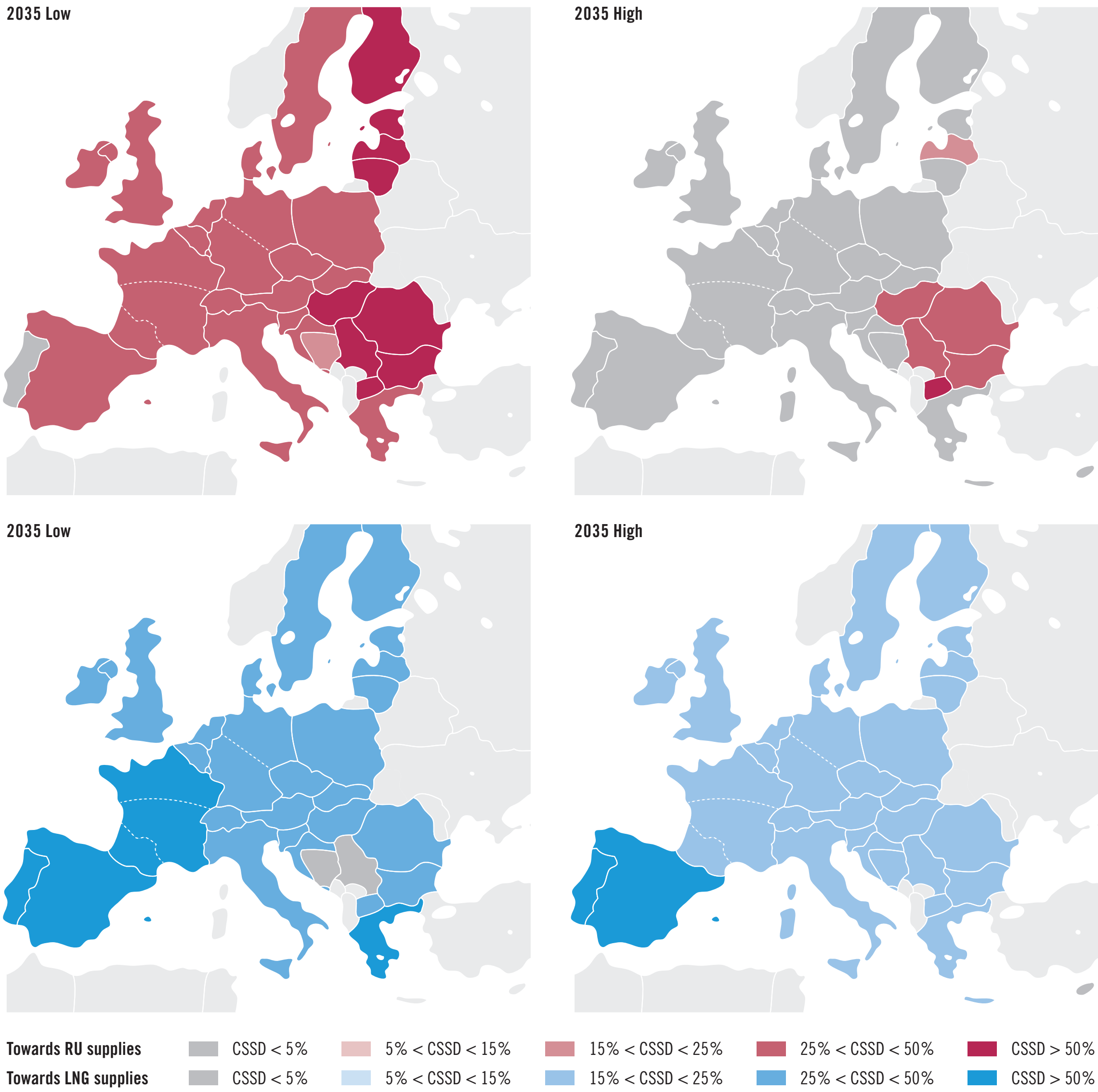

Figure 8: Cooperative Supply Source Dependence towards Russian (red) and LNG (blue) supplies

The analysis also shows that from a price perspective most of the supply sources may already have a large influence across Europe. The picture resulting from the assessment is influenced by the assumptions of a well-functioning markets and a single price per import source. Such assessment is not necessarily reflecting a physical access to import sources.

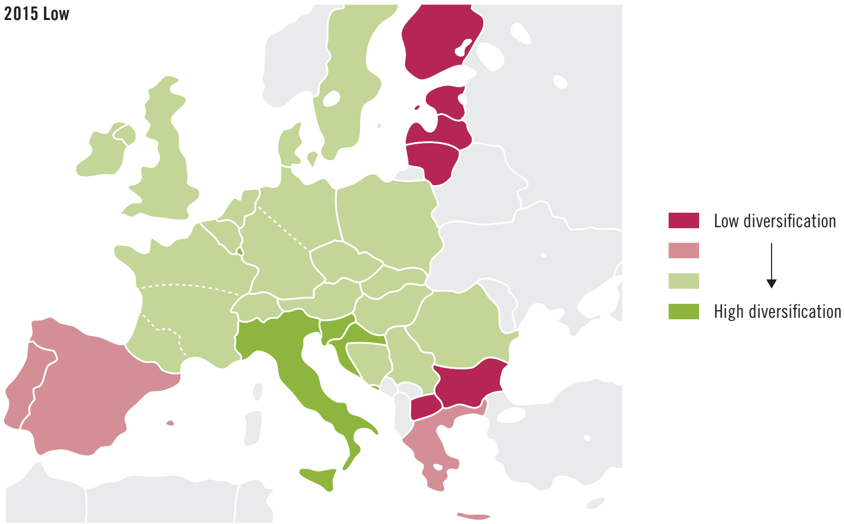

Figure 9: Level of supply source price diversification

Only the development of new indigenous production such as biomethane, shale gas or new conventional fields can limit the need of additional imports.

WAY FORWARD

As in previous editions, this TYNDP confirms that market integration in Europe can be achieved if necessary projects are decided. From a regulatory perspective, such decisions will require a full and timely implementation of European regulation taking into consideration the economic benefit of well-developed infrastructures. These investment decisions will also require that energy policies recognize the role of gas in achieving high environmental targets in a cost-efficient way preserving European competitiveness.

But there is actually a risk that these requirements might not be met. This will mean that some regions will stay isolated in Europe, and also, that necessary investments will not be realized endangering the situation for all Europe.

ENTSOG will continue to offer a transparent and objective platform to stakeholders and institutions to assess the possible evolution of the European gas system and its contribution to the European energy policy. Therefore, you are invited to take part in the consultation process and to bring your own knowledge and vision for the development of gas infrastructures in Europe.

1 Introduction

Image: fotolia

This 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). The TEN-E Regulation has introduced a new regulatory obligation resulting in the implementation of the Energy System-Wide Cost-Benefit Analysis (CBA) as part of TYNDP (Art. 11(1)(b), REG-347). This regulation also put the obligation on each promoter to submit their projects to TYNDP if they want to take part into the selection of Projects of Common Interest (PCI).

This Ten Year Network Development Plan 2015 (TYNDP) represents the fourth edition of the report published by ENTSOG since 2010. The entry into force of the TEN-E Regulation has resulted in major upgrades, one of the most obvious being the extension of the time horizon from ten to twenty-one years for CBA purposes. In order to ensure the robustness of the assessment on this extended time horizon ENTSOG has further developed its multiple scenario approach. In that context TYNDP aims to measure from an infrastructure perspective the level of completion of the three pillars of the EU Energy Policy (security of supply, competition and sustainability).

ENHANCEMENTS OF THIS FOURTH TYNDP EDITION

Since the first publication of the Plan, ENTSOG has strived to increase the quality of its reports in close co-operation with stakeholders. In order to ensure consistency, ENTSOG has unified the stakeholder engagement process on TYNDP and CBA methodology development. Based on feedback collected during the TYNDP 2013 consultation as well as other sources, four key areas for further improvement have been identified:

- Development of the modelling approach for gas demand in power generation sector
- Development of new indicators and monetization approach following new regulatory requirements
- Definition of an alternative gas demand scenario
- Improvement of the background of gas supply scenarios

STAKEHOLDER ENGAGEMENT PROCESS

For the development of this TYNDP, ENTSOG has carried out an open and transparent stakeholder engagement process. This has been particularly important as most of the above improvements rely on knowledge and data beyond TSOs' remit. The Stakeholder Joint Working Sessions (SJWS) were based on the approach initiated for the Network Code development process. They covered the following areas:

- Network and market modelling principles
- Input data (demand, supply and prices)
- Infrastructure projects
- Case studies on CBA methodology applicability

Additionally, ENTSOG has intensified its collaboration with ENTSO-E to improve consistency between the TYNDPs of both associations.

ADDITIONS TO THE TYNDP

The stakeholder engagement process together with the formal opinion of ACER and the European Commission on the first CBA methodology have resulted in the following additions to the TYNDP:

- New indicators reflecting the pillars of EU Energy Policy
- Enhancement of the modelling approach to cover seasonality and power generation
- Introduction of commodity prices scenarios

The current energy policies do not succeed in taking full advantage of the environmental benefits of gas as the cleanest fossil fuel. Europe is rather facing a parallel development of coal and renewable power production which may not be perceived as the most cost-effective way on the long term. This situation results in a significant uncertainty about the role of gas in Europe. The growing uncertainty of the role of gas, the extension of the time horizon for CBA purposes and the need to provide a robust basis to the selection of PCI have made it necessary to significantly expand the number of scenario combinations assessed within this TYNDP.

Image courtesy of GRTgaz

STRUCTURE OF THE REPORT

The first chapter of this TYNDP provides a detailed overview of gas infrastructure projects as submitted by their promoters. In addition to the FID criterion used in previous editions, projects are now further differentiated according to their PCI status resulting from the first selection done by the European Commission in 2013. This section also covers the identification of barriers to investment factoring the promoters' experience. A description of each project can be found in annexes.

The Supply and Demand chapters contain a detailed description of the twenty year range of scenarios used to support the Supply Adequacy Outlook. These scenarios are fundamental for the assessment of gas infrastructure. The European gas demand projections are based on TSO data and include an increased focus on the role of gas for power generation as a result of further collaboration with ENTSO-E. Supply scenarios are derived from publicly available data from governmental and other recognised sources. ENTSOG's assumptions regarding interpretation of the data are included to ensure transparency.

The Assessment Results chapter represents the outcome of the TYNDP-step for the Energy System-Wide Cost-Benefit Analysis. This is also an initial input for the process related to the second selection of PCIs. It also provides feedback on the impact of aggregated first PCI list. The relevant part of the methodology can be found in Annex F. For each scenario combination results identify:

- system resilience under diverse infrastructure and supply perspectives supporting the identification of potential investment
- physical and price dependence of each zone on gas import sources
- diversification of supply and diversification of routes
- price convergence across Europe

The TYNDP Annexes provide access to the input data for the ENTSOG network model, detailed information on all TYNDP infrastructure projects and additional historical information regarding the covered zones of the European gas system.

This TYNDP shows the ambition of the European TSOs to tackle the joint challenges of increasing stakeholder expectations and new regulatory requirements. The close working relationship of TSOs within ENTSOG has been decisive in that respect. ENTSOG would also like to highlight that all necessary improvements could not have materialized without stakeholder commitment. ENTSOG welcomes feedback on the TYNDP report and development process. This will constitute the basis for the continuous improvement of this deliverable.

2 Infrastructure

Introduction

Gas infrastructures and European energy policy

Data collection process | Projects of Common Interest

Analysis of project submission

Image courtesy of Gas Connect Austria

2.1 Introduction

The completion of the European Internal Energy Market is intended to deliver secure, competitive and sustainable energy for every gas consumer. The development of gas infrastructures, together with the implementation of harmonized business rules are necessary steps in that direction.

Since the last edition of the TYNDP some projects have been commissioned, others suspended and new ones have appeared. Their number remains very high illustrating the fact that the gas industry has identified projects that would benefit the completion of the European market.

In this perspective the TYNDP intends to provide transparent and thorough information to decision makers, although the inclusion of projects within the TYNDP does not make it legally binding for those projects to be developed. This information covers basic technical data, the status of infrastructure projects and the overall impact of projects along the pillars of the European Energy policy. With the entry into force of the 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. The TYNDP must also provide a basic assessment that will be factored into the further steps.

2.2 Gas infrastructures and European energy policy

European gas infrastructures already ensure a high level of market integration in many parts of Europe. Further development is necessary in order to ensure that such integration will cover the whole European system and will be 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 economic crisis and the uncertainty of gas demand in the medium and long term have hampered the delivery of all necessary investments. In that context the TEN-E Regulation aims to facilitate the delivery of key infrastructures.

In that respect new infrastructure projects may contribute 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 can transport a low carbon fuel to support the development of intermittent renewable power production and enable a large scale injection of synthetic gas (biogas or power-to-gas). It will also bring to the electricity industry the advantage of energy storability. Nevertheless the current setting of gas, coal and CO_2 prices endangers thi capital on the medium term.

2.3 Data collection process

The quality of the assessment carried out in the TYNDP depends on the availability, consistency and quality of the collected data. Collecting the data to assess infrastructure projects has been particularly challenging as there are a wide variety of promoters and stakeholders involved which are very different in their features.

The TEN-E Regulation puts an obligation on PCI candidate project promoters to submit their projects to ENTSOG for inclusion in the TYNDP. This goes with an additional responsibility for ENTSOG to put in place an adequate process to collect this data.

Only projects actively submitted by promoters through the ENTSOG Data Portal have been considered in this edition of the TYNDP. This process ensures transparency and non-discrimination between projects.

The additional data required for the PCI selection process and the necessity to track projects from one TYNDP edition to the next one led ENTSOG to put in place the Data Portal, a permanent online portal open to all project promoters. This tool together with the close cooperation with the European Commission has ensured that all possible candidates for gaining or maintaining PCI status have been included in the TYNDP. ENTSOG endeavours to improve the collection process and welcomes stakeholder feedback.

The information supplied in this report is up-to-date as of 12 September 2014.


Image courtesy of Energinet.DK

2.4 Projects of Common Interest

According to the TEN-E Regulation all PCI candidates have to be included in the TYNDP, starting with this edition.

Some projects were not in a position to provide the data necessary to be fully assessed through a CBA following ENTSOG methodology. These projects are nevertheless listed within Annex A of this Report, to ensure that they fulfil the minimum requirement of the TEN-E Regulation.

To build a bridge between two sequential PCI selection rounds, ENTSOG has introduced the **PCI Infrastructure scenario**[1]. This additional scenario enables the assessment of the cumulative effects of the previous PCIs including their interaction.

In line with the TEN-E Regulation ENTSOG has provided a common basis for the Project-Specific CBA of each PCI candidate (see Annex F). This involves the assessment of different development levels of the gas infrastructure based on the FID and PCI status of the projects. TYNDP will be used by the Regional Groups as a background when considering the Project Specific CBAs of the candidate projects.

2.5 Analysis of project submission

The full detail of the 259 projects submitted for inclusion in the TYNDP 2015 can be found in Annex A of this Report, which also provides enhanced search and sorting functionalities on all projects. This section of the report provides a general overview of the submitted projects.

Projects are classified according to the five types of infrastructures as follows:

- TRA — Transmission, incl. Compressor Stations
- LNG — LNG Terminal
- UGS — Storage Facility
- PRD[2] — Production Facility
- POW[3] — Interconnection with a gas-fired power plant

The code assigned to each project serves as a key for the different TYNDP editions and the PCI selection process.

1) ENTSOG Cost-Benefit Analysis Methodology – 3.6.2 Infrastructure Scenarios p.g.21.

2), 3) For the purpose of the project overview and as in previous TYNDP, such projects are included in the transmission category

For each project, the commissioning year is related to the first capacity increment of the project in the case where there is more than one increment. For projects where the commissioning date is not available (N/A) in the Annex A, it means that the promoter has not submitted a capacity increment or did not specify a year within the time horizon. The first full year of operation used in the assessment is the first full calendar year following the commissioning date.

The following figures 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.

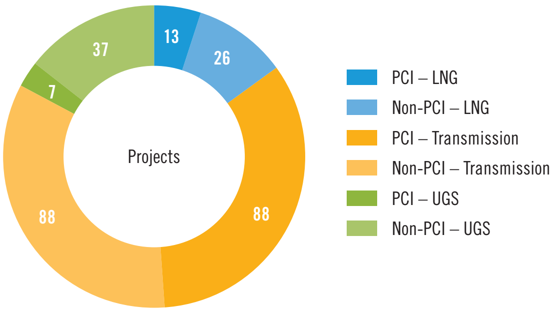

Figure 2.1: Breakdown of the projects in TYNDP 2015 per PCI status (as approved in 2013) and per type of infrastructure

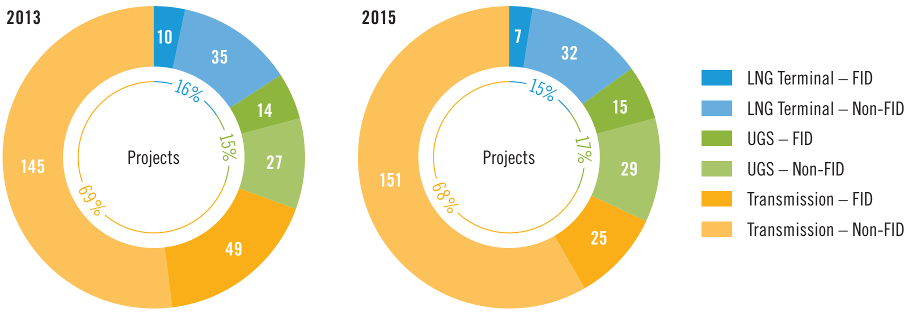

Figure 2.2: Comparison of project submission in TYNDP 2015 and TYNDP 2013 per type of infrastructure and FID status. The outer circle represents absolute numbers; the inner circle represents the share of each project type.

BREAKDOWN OF PROJECTS IN TYNDP 2015 BY FID STATUS AND PCI STATUS

	PCI	Non-PCI	TOTAL
FID	13	34	47
NON-FID	95	117	212
TOTAL	108	151	**259**

Table 2.1: Breakdown of projects in TYNDP 2015 by FID status and PCI status

The number of projects submitted for inclusion in the TYNDP remains high showing the need to expand market integration benefits to the whole of Europe.

There may be a link between current LNG price and the decrease in the number of LNG project submissions. The slight increase in the number of storage projects may reflect the recent concerns about energy security of Europe.

The following chart provides a summary of projects based on their geographical location and by type of infrastructure.

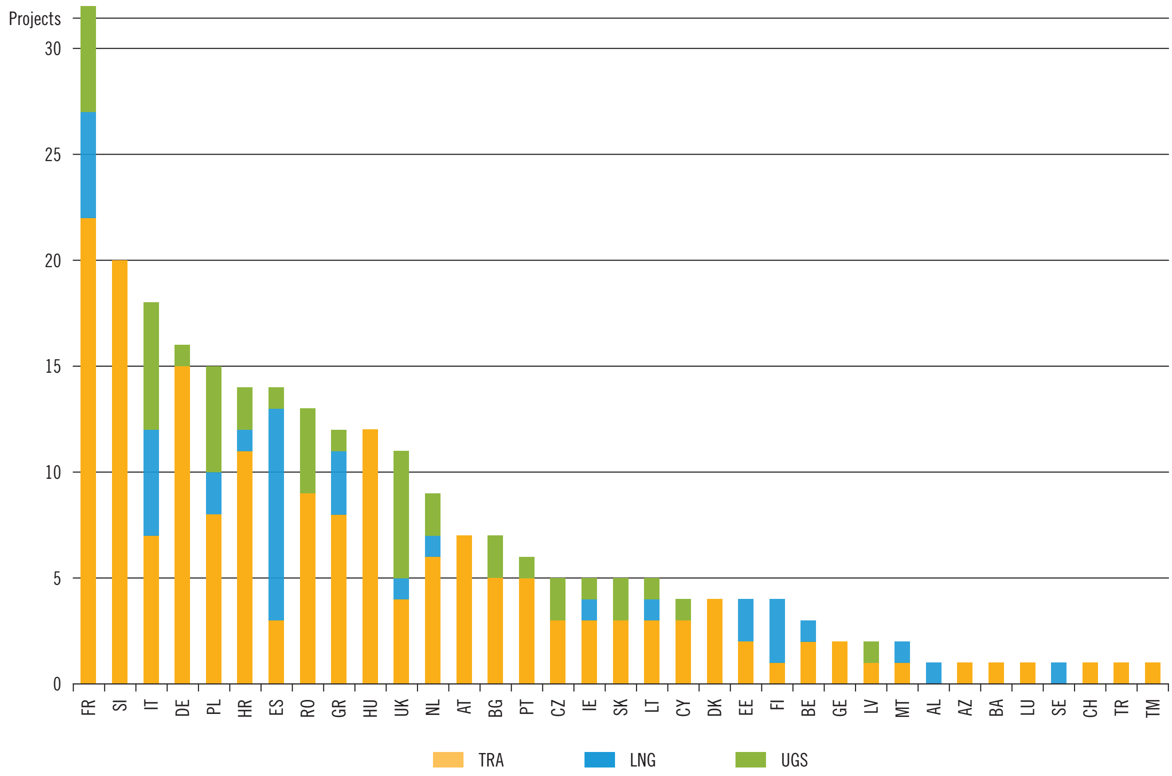

Figure 2.3: Number of projects per country and type

The content of promoters' submissions in term of granularity differs strongly. 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). Such lack of consistency influences the number of projects submitted in each country.

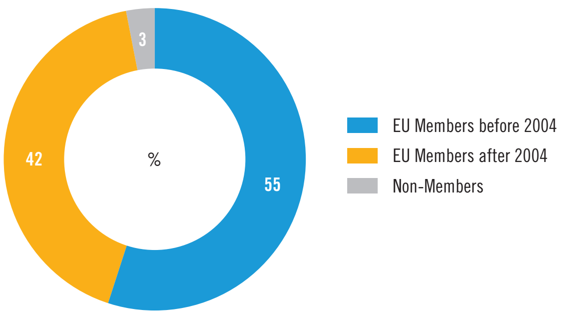

Figure 2.4: Overview of all projects by EU Membership

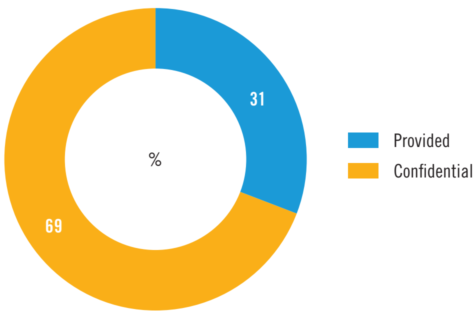

Figure 2.5: Overview of cost information

Compared to their number and relative economic weight within the European Union, projects from new Member States (13 countries joined since 2004) represent a very significant share of the 259 submissions as shown in the graph above. This provides evidence that there is a need for further infrastructure developments to allow these new Member States to catch up with the level of network integration across Europe.

As shown in figure 2.5, investment costs are in many cases commercially sensitive, which is the reason why this information is not mandatory for inclusion within the TYNDP. The number of projects for which this information is available in Annex A is too low to draw any conclusion on the overall value of investment projects proposed by promoters.

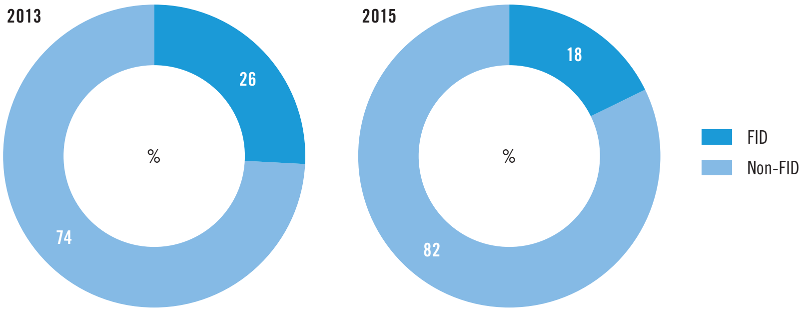

Figure 2.6: Overview of the FID status of the projects as submitted by the promoters for TYNDP 2015 and for TYNDP 2013

As shown above, the ratio of projects with an FID status has slightly decreased compared to the previous TYNDP. This may result from many factors that delay promoters' decisions, which are detailed in the Barriers to Investment Chapter.

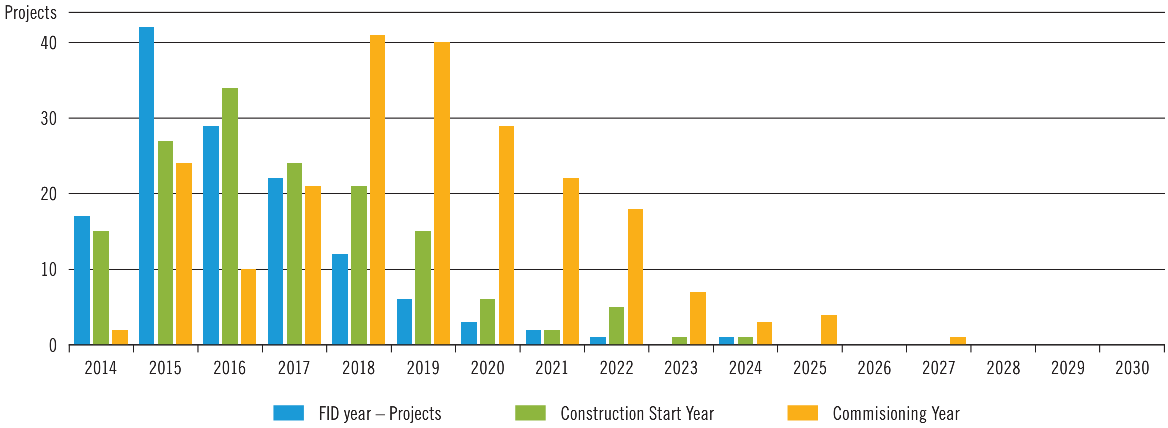

Figure 2.7: Overview of project scheduling

The analysis of project submissions above shows:

- An average of 9 months between the planned FID and the expected start of construction
- An average of 2 years between the expected date of start of construction and the commissioning of the first capacity increment

The analysis is not necessarily indicative of the project lead time for any future projects. Moreover, the way FID is taken by each promoter may differ. Some may take FID after the issue of permits and some, before initiating the permitting procedure.

Out of the 259 projects included in TYNDP 2015, 181 were already part of TYNDP 2013. The following chart illustrates the FID status of those common projects according to TYNDP 2015 submission:

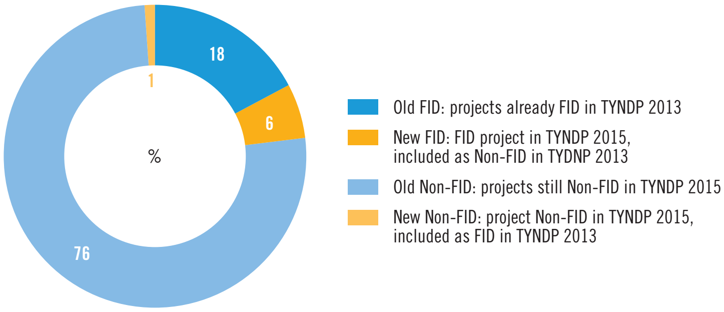

Figure 2.8: FID status in TYNDP 2015 for the 181 projects submitted to both TYNDP 2013 and 2015

Out of those common projects, 86 have reported in both TYNDPs when they plan to take their FID. The following chart illustrates the share of these 86 projects whether they have reported some delay in their expected FID date:

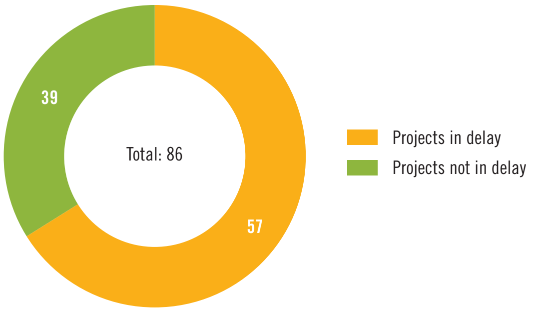

Figure 2.9: Share of projects reporting their expected FID date in both TYNDP 2013 and 2015

Out of those common projects, only 71 projects have reported when they plan to start construction. The following chart compares for these 71 projects the evolution of the estimated construction start date between TYNDPs 2013 and 2015:

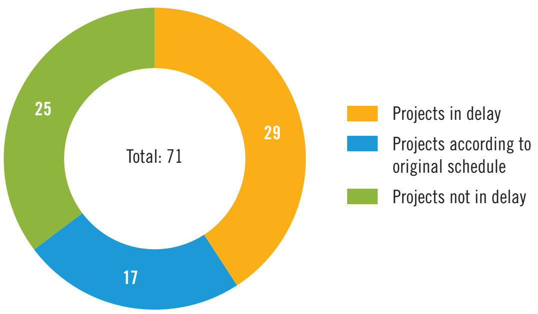

Figure 2.10: Share of projects reporting their expected construction start date in both TYNDP 2013 and 2015

This overview of project progression from one edition to the other shows promoter commitment to commission on time once FID has been taken. The current economic and legislative environment seems to have prevented many promoters from taking their FID within their original expected timeframe.

3 Barriers to investment

Introduction | Overall impact of energy policies
Project promoter perspective policies
TSO perspective

image courtesy of Snam Rete Gas

3.1 Introduction

In TYNDP 2013, ENTSOG introduced its first analysis of barriers to investment. In this edition, ENTSOG is combining the views of all TSOs and other project promoters regarding barriers to investment. This will help to better understand the continuous decrease of FID projects since TYNDP 2011.

3.2 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 (such as the EU Emission Trading System) and global factors (e.g. current low coal and CO_2 prices). As a result, there is currently no clear political vision on how to deliver the CO_2 reduction targets while ensuring both energy security and affordability, as illustrated by the increasing share of polluting coal-fired generation. The lack of a clear political vision is endangering the required development and refurbishment of flexible power generation including gas-fired generation, alongside the development of renewable energy sources, to ensure electricity security of supply. 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.

3.3 Project promoter perspective policies

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 2015 infrastructure project data collection process, ENTSOG has gathered information on perceived investment barriers. Out of the 88 promoters having submitted projects, 61 have indicated at least one barrier for 134 projects. Investment barriers have been grouped as indicated in the next table (with sub-groups where proposed):

REGULATORY	Rate of Return
	Low price of short term capacity
	Capacity quotas
	Lack of proper transposition of EU regulations
	Other
MARKET	Lack of market support
	Lack of market maturity
	Other
PERMIT GRANTING	
FINANCING	Availability of funds
	Amortization rates
	Other
POLITICAL	
OTHER	

Table 3.1: Categories of barriers to investment

The following graph presents the breakdown of the barriers.

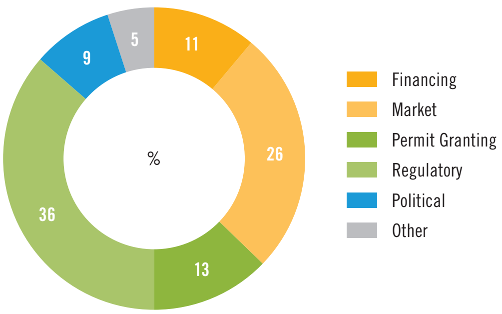

Figure 3.1: Combined overview of project barriers, as submitted by the promoters

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

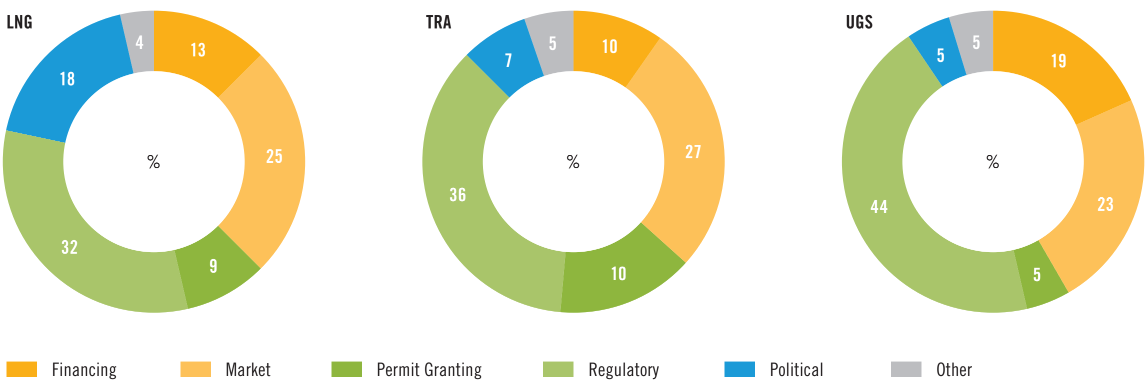

Figure 3.2: Overview of project barriers by project type, as submitted by the promoters (LNG – TRA – UGS)

3.3.1 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 promoters responses where a specific category of barrier was not provided and the comments did not allow it to be further categorized[1].

The level of rate of return is perceived as a major obstacle. Setting the level is exclusively subject to the national regulatory regimes but should encourage long-term investments with a reasonable rate of return. If the rate is too low or not sufficiently stable, then investments will be put at risk and consequently 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.

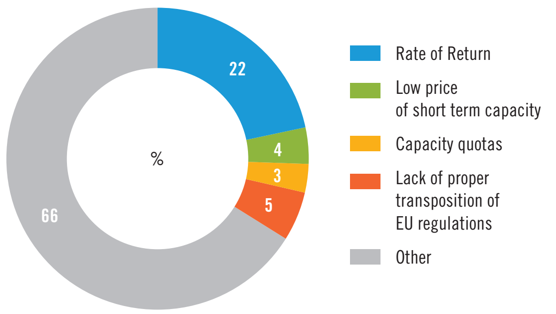

Figure 3.3: Overview of Regulatory related project barriers

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

As part of the Framework Guidelines and Network Code processes on Capacity Allocation Mechanism and Harmonised Transmission Tariff Structures for Gas, NRAs have followed the request of some market players in favouring low priced short term capacity products and quotas. In addition to revenue recovery issues, which such mechanisms could induce, they are inadequate for triggering new investments.

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. If such situation would emerge, this will 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. This would be major risk for investment realization.

The TEN-E Regulation was designed to support the delivery of key infrastructure projects necessary to the completion of the Integrated Energy Market. Many network users presume that associated EU financing will reduce their need of financial commitment. Such expectation could result in an even lower willingness of the market to commit in new infrastructures. In parallel, the cross-border cost allocation, which was anticipated as new tool to foster investment decision, now appears to many promoters as a source of delay and uncertainty.

The second selection of PCIs should address some concerns regarding the efficiency of the selection process and could also help to identify good practices in terms of permitting and regulatory incentives. Such mechanisms should then be extended to all projects to help the market to deliver the required infrastructure projects.

Feedback from some project promoters suggests that the TEN-E Regulation, Gas Target Model discussions and recent emphasis on Security of Supply seem to have shifted the focus away from the full implementation of the Third Energy Package and market-based solution across Europe. As identified by promoters, the resulting lack of implementation in some parts of Europe is an obstacle to new investment decisions.

1) Further explanation can be found in Annex A

3.3.2 MARKET ENVIRONMENT

Many promoters are facing challenges in triggering investment on a market basis as it is supposed to be the rule under the Third Energy Package.

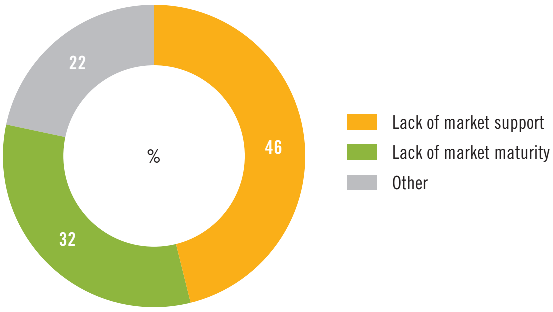

Figure 3.4: Overview of the Market related project barriers

The difficulty in receiving sufficient market commitment is one of the main barriers highlighted by promoters. The focus on short-term capacity products, as a result of the way European regulation has been implemented, the current economic situation and unclear signals from EU energy policy, do not deliver the necessary investment signals and long-term financial commitment to trigger new infrastructure projects. 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 infra-structure integration compared to the rest of the European gas market.

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.

3.3.3 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.

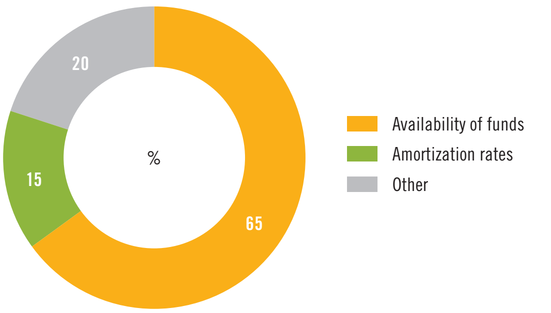

Figure 3.5: Overview of the Financing related project barriers

The number of proposed projects submitted for TYNDP 2015 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, not all Member States offer a regulatory environment with conditions favouring investments.

3.3.4 PERMITTING

The streamlining of the permitting process (e.g. "one-stop-shop") is a long-awaited improvement by promoters. Nevertheless many Member States are late in establishing such arrangements.

Such situation would 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.

3.4 TSO perspective

According to the Third Energy Package new investments should be triggered by market testing. It might prove difficult to secure sufficient financial commitment for projects delivering security of supply or network flexibility. 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 upcoming incremental capacity procedure, which will be integrated into the Capacity Allocation Mechanism Network Code. The final identification of the infrastructure projects requires market commitment and hence sufficient participation of the market players.

ENTSOG's role in the investment process is to ensure an objective assessment of infrastructure development and to provide supporting information. In that respect, a second demand scenario and the dynamic modelling of power generation have been introduced to mitigate the risk of overestimating investment needs. ENTSOG does not perceive a risk of underestimating investment needs. The main risk is a delay in the delivery of enough projects identified in TYNDP 2015. The bi-annual repetition and continuous development of this process should ensure an efficient and appropriate infrastructure assessment based on the latest developments in the European and global energy markets.

4 Demand

Introduction | Current state
Demand scenarios
Climate and energy policies
Comparison with other demand outlooks

Image courtesy of DESFA

4.1 Introduction

The demand chapter provides an outlook of the European gas demand for the period 2015 – 2035 from an ENTSOG perspective. This chapter has two specific aims. The first is to provide demand scenarios for the supply adequacy outlook as stipulated in REG 715/2009. The second is to provide the detailed demand data used for the network modelling.

The demand scenarios show the evolution of the gas demand on a yearly basis. Whilst this information facilitates the comparability between scenarios, it is hourly or daily demand which are the key parameters for network design and operation. The demand scenarios, on a single day or over a sustained period, indicate the capacity a transmission system must be able to provide. This information is vital for the safe and sustainable operation of a transmission system. ENTSOG has defined these scenarios as the 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 and industrial sectors). The power generation component has been calculated using an agreed ENTSOG methodology based on ENTSO-E's TYNDP 2014 scenarios and factoring in gas TSO feedback. The bottom-up approach is based on TSO submission of gas demand figures for their system under each scenario. This data is provided separately for final gas demand and power generation sectors. ENTSOG has collected and aggregated these figures to produce the demand scenarios.

TYNDP covers all EU Member States plus adjacent countries that have a current or planned gas market and have provided data to ENTSOG. In addition some areas of the EU such as the islands of Sardinia and Elba in Italy and Corsica in France do not have access to the European gas network. Due to the complexity of the modelling assessment they have not been included. Specific gas demand figures have been submitted for these areas, and are included in the Annex C2 for potential ad-hoc evaluation of projects linking these areas with the European gas system. The same applies to Albania.

4.2 Current state

4.2.1 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, the economic crisis and commodity prices have pushed gas demand back to the 2001 level. The projected evolution of demand for the different gas demand sectors and for the different countries is explored in this chapter.

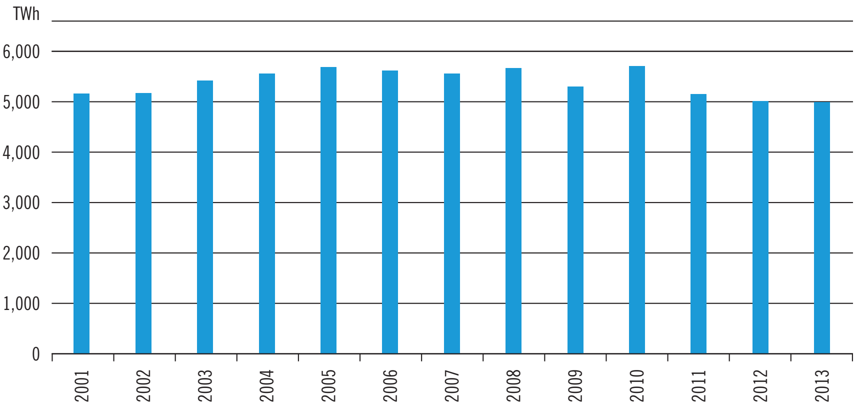

Figure 4.1: Evolution of European gas consumption (Source converted from Eurostat figures)

4.2.1.1 Split between final and power generation demand (last 5 years)

While the evolution of domestic, commercial and industrial consumption has remained stable, the gas consumption for power generation has continuously decreased since 2010. In 2013 the power generation sector share of gas consumption had fallen to just 17 %. Some of the key factors behind these trends are explored in the next section.

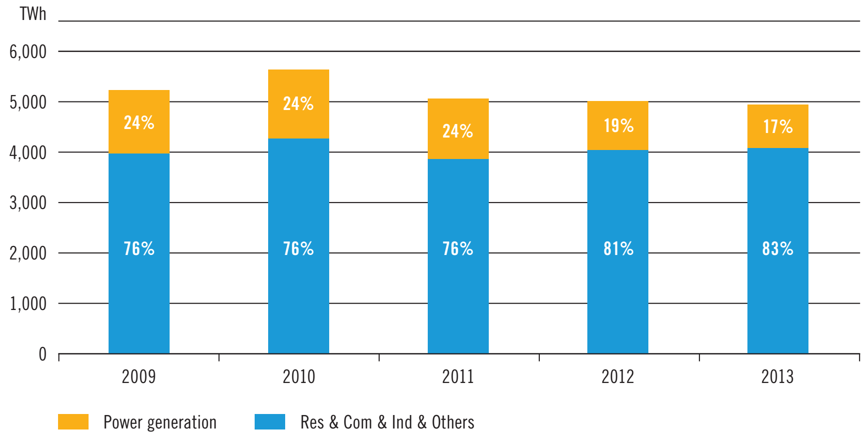

Figure 4.2: Evolution of European yearly gas consumption and its breakdown

BREAKDOWN OF THE YEAR TO YEAR GAS CONSUMPTION EVOLUTION			
	Res & Com & Ind & Others	**Power generation**	**Total**
2009 to 2010	7.2 %	9.0 %	7.6 %
2010 to 2011	-9.4 %	-12.3 %	-10.1 %
2011 to 2012	4.7 %	-19.5 %	-1.0 %
2012 to 2013	0.9 %	-11.3 %	-1.5 %

Table 4.1: Breakdown of the year to year gas consumption evolution

4.2.1.2 Power generation in Europe

Fossils fuels and nuclear remain the main sources of power generation in Europe. Their relative shares have slightly decreased between 2010 and 2012 as a result of the development of renewable sources, which have risen from 21 % to 26 % over that period.

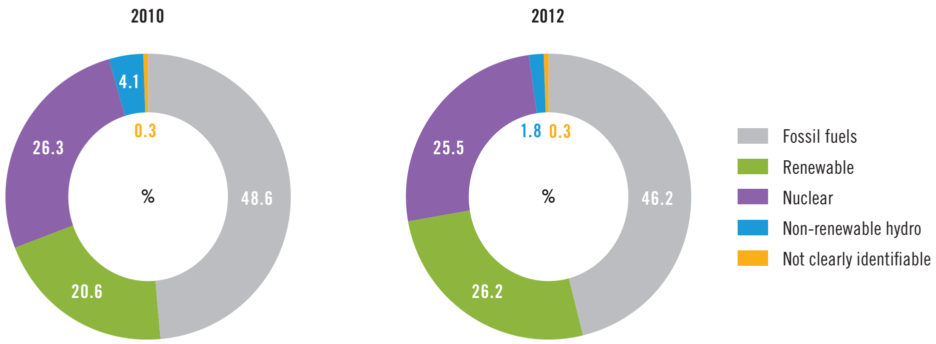

Figure 4.3: European generation mix for power generation 2010 and 2012 (Source Yearly Statistics & Adequacy Retrospect 2012 ENTSO-E, ENTSOG depiction)

The main fossil fuels for power generation are gas then hard coal and lignite. The gas share declined from 44 % in 2010 to 35 % in 2012. Over the same period hard coal showed a stable trend in absolute terms, increasing its relative share from 29 % to 33 %. In aggregate, other fossil fuels have played only a minor role in power generation over the period.

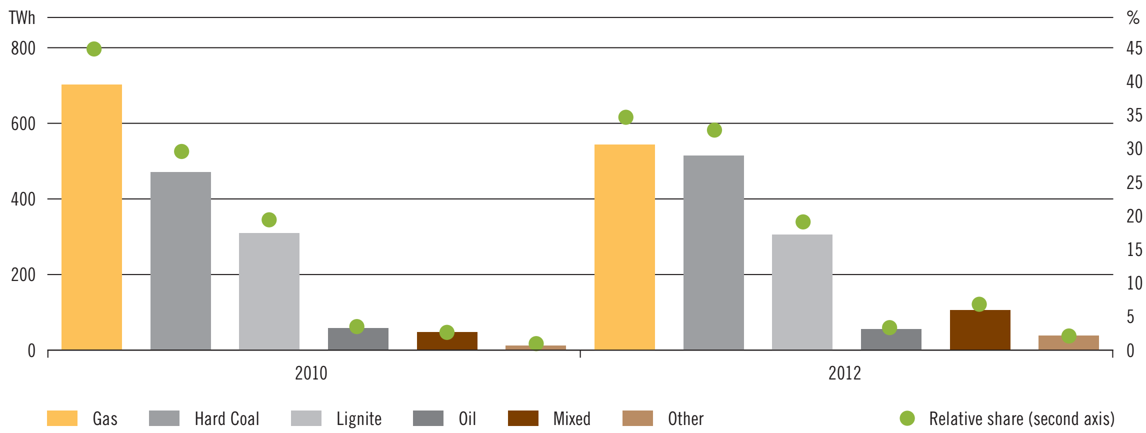

Figure 4.4: Generated power from fossil fuels 2010 and 2012 in absolute and relative terms. (Source Yearly Statistics & Adequacy Retrospect 2012 ENTSO-E, ENTSOG depiction)

From a generation capacity perspective, gas increased by 11 % over the 2010–2012 period, whereas hard coal declined by 3 %. During the same period power generation from gas decreased by 23 % and power generated from hard coal increased by 9 %. These diverging trends of capacity and actual generation put gas-fired power plants in a difficult economic situation.

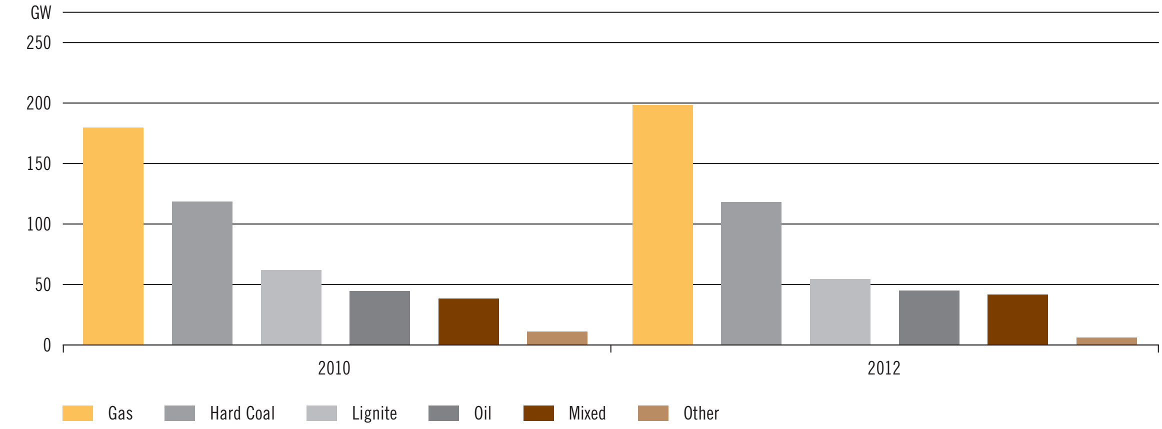

Figure 4.5: Evolution of net generating capacity for fossil fuel power in 2010 and 2012
(Source Yearly Statistics & Adequacy Retrospect 2012 ENTSO-E, ENTSOG depiction)

One reason for the ongoing high use of coal for power generation, at the expense of gas, is the price difference between the two fuels. Considering data from DG Energy, the European coal price has shown a stable downward trend in recent years. This trend has accelerated with a 25 % decrease between January 2012 and November 2014. Gas prices have been at a higher level in the same period. This large price difference might continue as long as the US benefits from the shale gas boom, which has reduced their domestic coal demand. At the same time the Asian region is showing a moderate growth in coal demand. A reversal of this trend cannot be excluded, and could be induced by several factors including:

- Increasing world-wide liquefaction capacity and especially in the US
- A gradual re-commissioning of nuclear power stations in Japan
- Enhanced competition between gas producers

This would result in a reduced LNG price differential between the EU and the Asian gas markets and increasing competitiveness of gas as a power generation fuel.

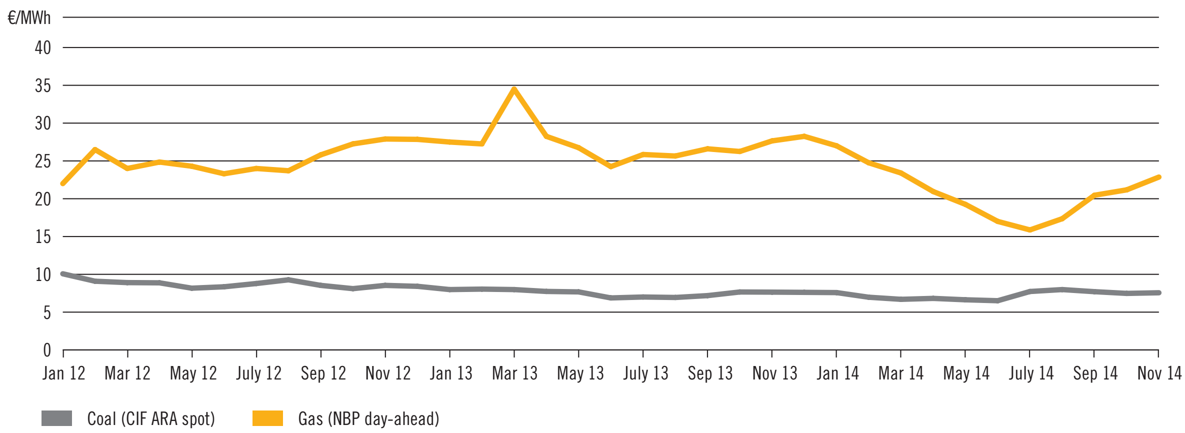

Figure 4.6: Evolution of European spot prices for gas and coal (Source Quarterly Report on European Gas Markets, DG Energy, volume 6 (Q3/Q4 2013) and volume 7 (Q1/Q2 2014), ENTSOG depiction)

In recent years the EU Emissions Trading System (ETS) has been characterized by a surplus of allowances mainly because of an over allocation at the beginning of the ETS and the influence of the economic crisis. The very low price of CO_2 resulting from this situation is not sufficient to favor gas against coal for power generation. This situation has undermined the orderly functioning of the carbon market fostering, indirectly, the use of more carbon intensive fuels such as coal.

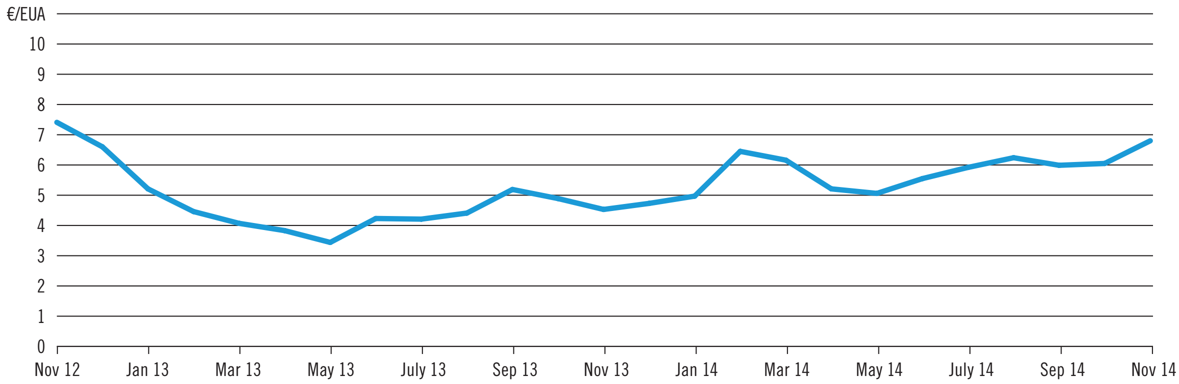

Figure 4.7: Evolution of European spot prices for emission rights for the period November 2012 – November 2014 (Source Data from EEX, ENTSOG depiction)

The first trading period from 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. In the second period from 2008–2012 the yearly amount of certificates decreased but prices still remained low.

Since the start of the third period in 2013, the yearly amount allocated has decreased and will continue to decrease until the end of the period in 2020. Even with this improvement, current emission prices range around 7 €/EUA[1)] which does not seem to be an appropriate price level to incentivize an effective cut of carbon dioxide emissions and hence an actual mitigation of climate change effects.

After 2020 the annual linear reduction factor which determines the EU ETS cap will further increase from the current level of 1.74 % to 2.2 %. This should increase the upward pressure on the CO_2 price, which is necessary to achieve the environmental targets in a sustainable manner.

4.2.1.3 Split by country (last 5 years)

Figure 4.8 contains information on actual gas consumption over the last five years across Europe. When identifying trends it should be considered that data are not climate adjusted and that 2010 was a particularly cold year.

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).

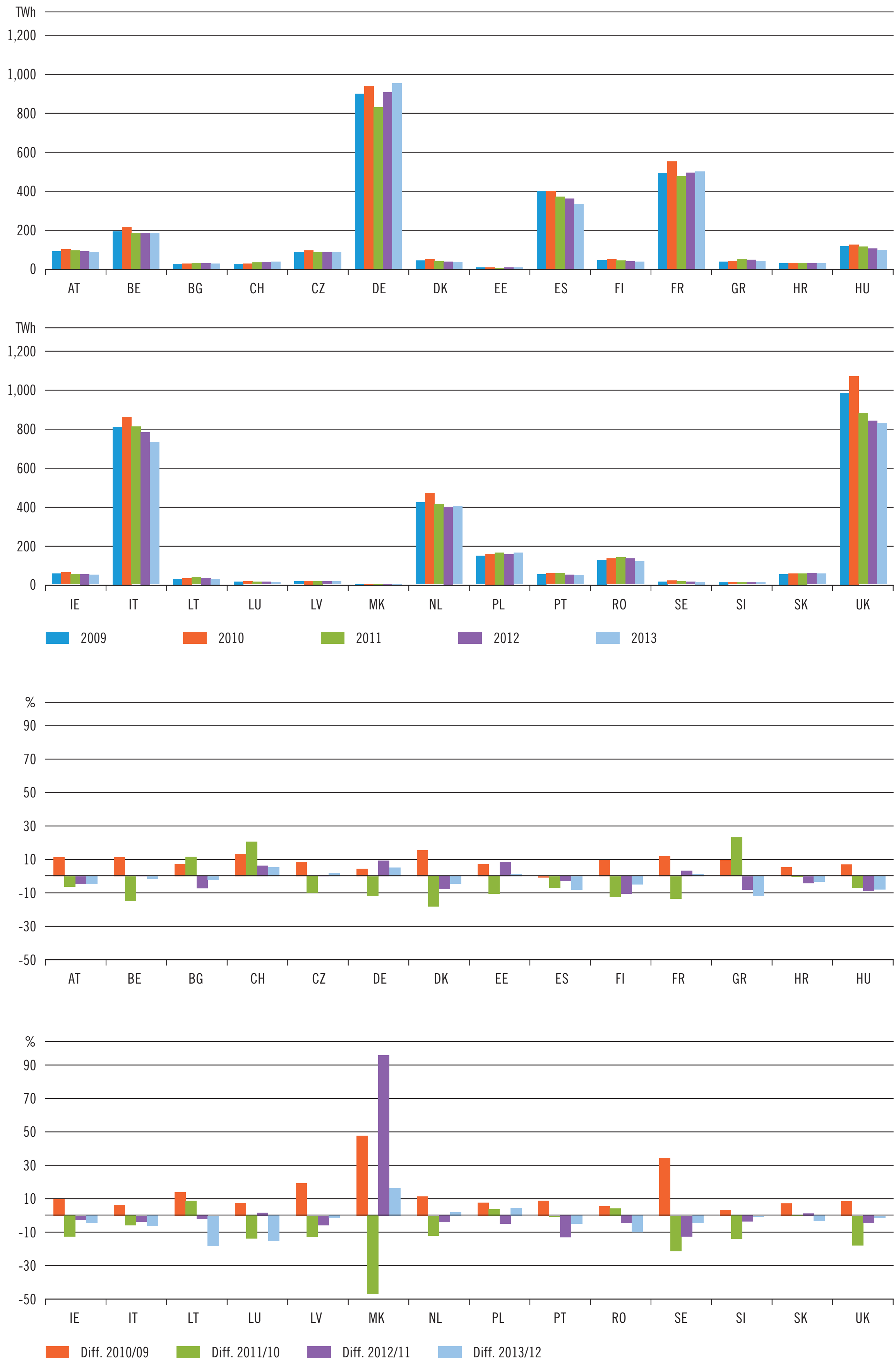

Figure 4.8: Evolution of European yearly gas consumption by country (TWh/y) and year on year percentage difference

4.2.2 PEAK CONSUMPTIONS

4.2.2.1 Peak and 14-day peak

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 the highest 14-day demand period as significant for testing the resilience needs of the system. The table below shows the highest daily consumption, and the highest 14-days average consumption from the last five winters at EU aggregated level.

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	27,432	26/01/2010	24,646	03/01/2010–16/01/2010
Winter 2010/11	27,093	17/12/2010	24,634	09/12/2010–22/12/2010
Winter 2011/12	29,459	07/02/2012	27,853	31/01/2012–13/02/2012
Winter 2012/13	25,778	12/12/2012	23,294	13/01/2013–26/01/2013
Winter 2013/14	21,842	29/01/2014	19,742	21/01/2014–03/02/2014

Table 4.2: High daily and highest 14-day gas consumption

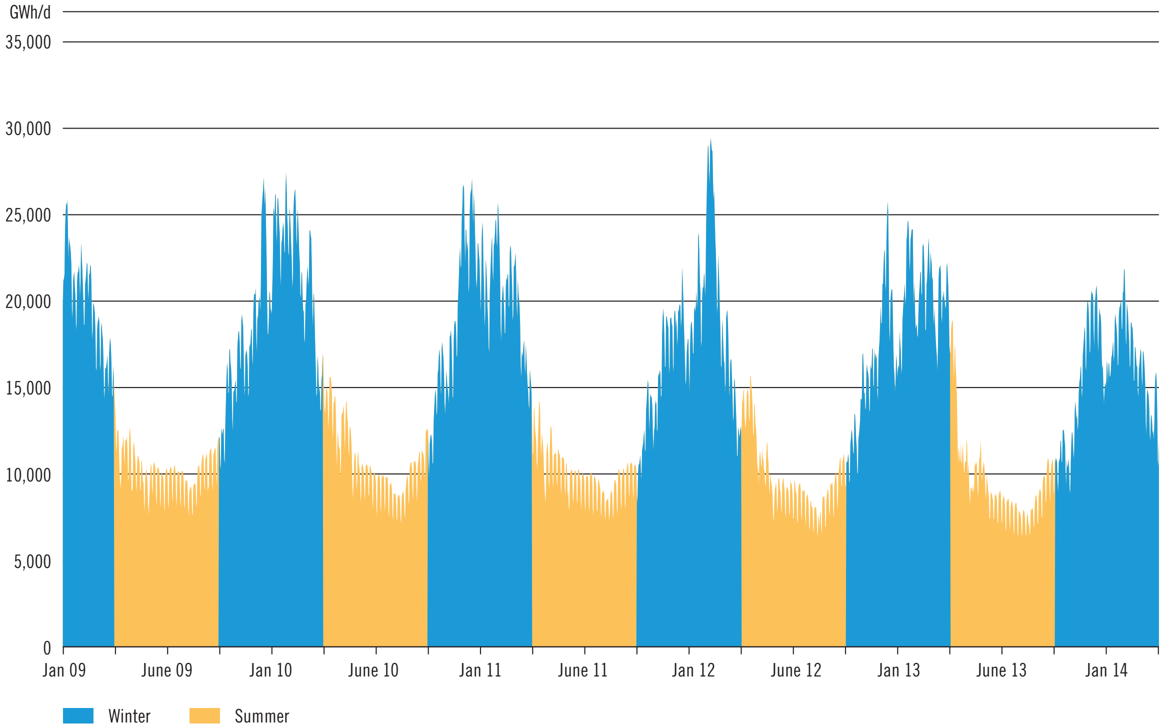

Figure 4.9: Yearly modulation

4.2.2.2 Split by country

For most countries the highest daily consumption over the last five winters[1] was reached during winter 2011/12. There are a few exceptions: in Portugal and Finland it was reached during winter 2010/11, whereas in Bulgaria, Ireland, Spain, Sweden, and United Kingdom it was reached during winter 2009/10.

4.2.2.3 Simultaneity

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 Demand and the sum of all individual country peak demands having occurred non-simultaneously:

EPS = European Peak Demand/Non-simultaneous Peak (%)

Over the past five winters the observed simultaneity in gas consumptions has been high: it has ranged between 93% and 97%. These high levels of observed simultaneity show no clear case for considering lower levels, when carrying out peak planning analysis, as this would run the risk of underplaying security of supply. Consequently, ENTSOG has retained a 100% simultaneity planning assumption.

2009–2014 PEAK GAS CONSUMPTIONS AND THEIR SIMULTANEITY

	Day	Daily peak demand (GWh/d)	EU simultaneity
Winter 2009/10	26/01/2010	27,432	94%
Winter 2010/11	17/12/2010	27,093	93%
Winter 2011/12	07/02/2012	29,459	97%
Winter 2012/13	12/12/2012	25,778	96%
Winter 2013/14	29/01/2014	21,842	94%

Table 4.3: 2009–2014 peak gas consumptions and their simultaneity

1) A winter period stretches from October till the end of March.

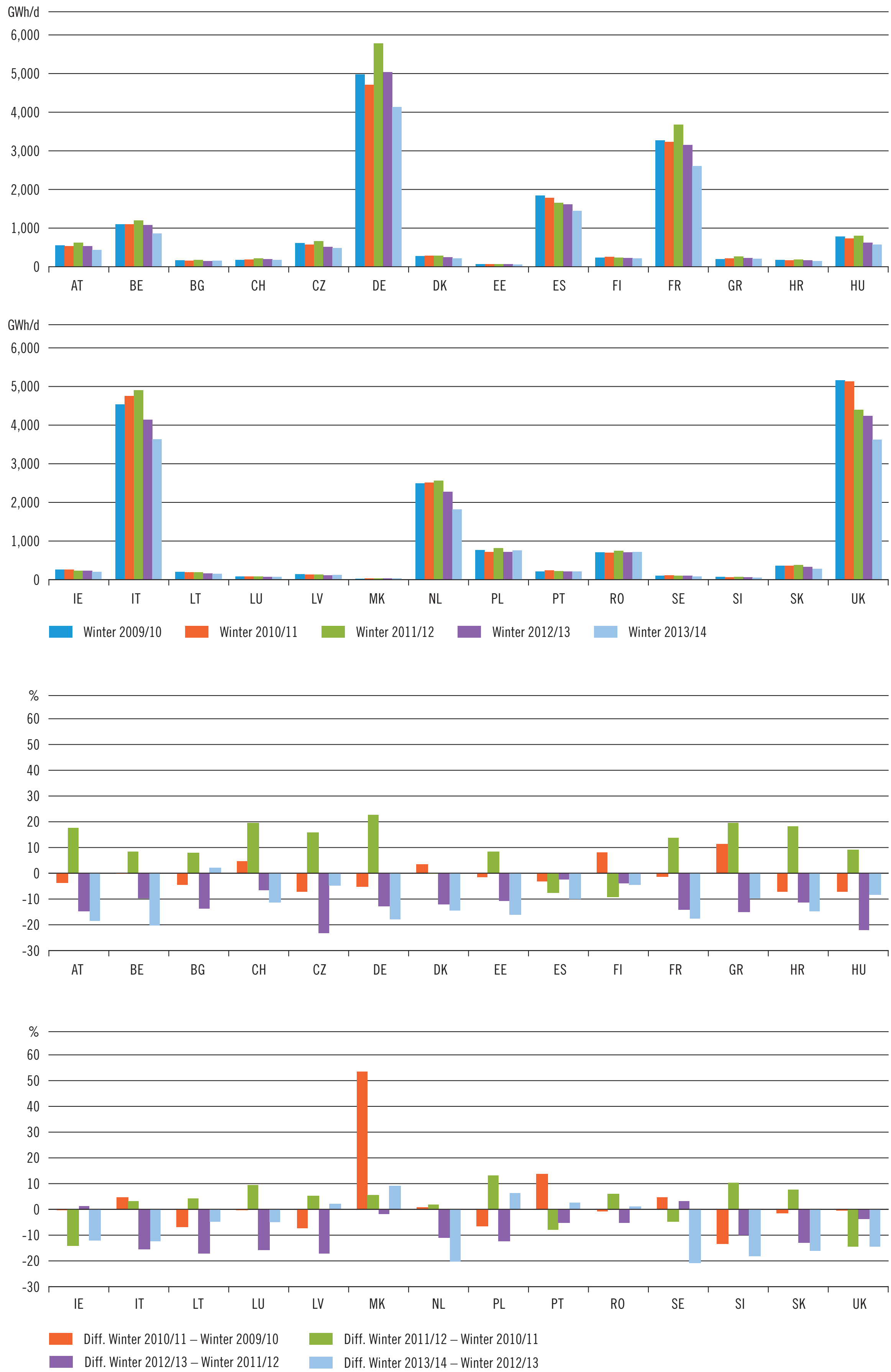

Figure 4.10: Day of the highest consumption by country and year (GWh/d) and year percentage difference

4.3 Demand scenarios

4.3.1 ASSUMPTIONS

The long term evolution of gas demand depends on several factors, including demography, macroeconomic parameters, energy and emission prices as well as targets set by energy and environmental policies. Such evolution is also the main driver for the development of the gas market in each country. In order to assess this wide range of uncertainties, ENTSOG has considered different settings for each of the main parameters influencing gas demand.

4.3.1.1 Global context

The global context covers the price of gas and coal as well as the price of CO_2 emissions. The relative levels of these three prices influence the share of gas and coal in the power generation mix. The two considered global contexts are:

Green – the price scenarios correspond to the "Gone Green" scenario from the UK Future Energy Scenarios (FES)[1] document, which is consistent with:

- A high price of CO_2 emissions due to the introduction of a carbon tax
- A continuous reduction in the oil-price linkage mitigating the increase of gas price when oil prices increase

Grey – the price scenarios correspond to the Current Policies scenario from the IEA WEO 2013[2] document which is consistent with:

- Lower price of CO_2 emissions as no new environmental political commitments are taken
- High energy prices following higher energy demand in absence of new efficiency policies but with prices still too low to trigger the development of renewables

4.3.1.2 Scenarios for the evolution of final gas demand

Final gas demand covers demand for residential, commercial and industrial use as provided by TSOs. The uncertainty about gas demand for these sectors is captured through two contrasting demand scenarios, defined by the following parameters:

- Scenario A covers favorable economic and financial conditions
- Scenario B covers non-favorable economic and financial conditions

1) National Grid July 2014
2) International Energy Agency – World Energy Outlook 2013

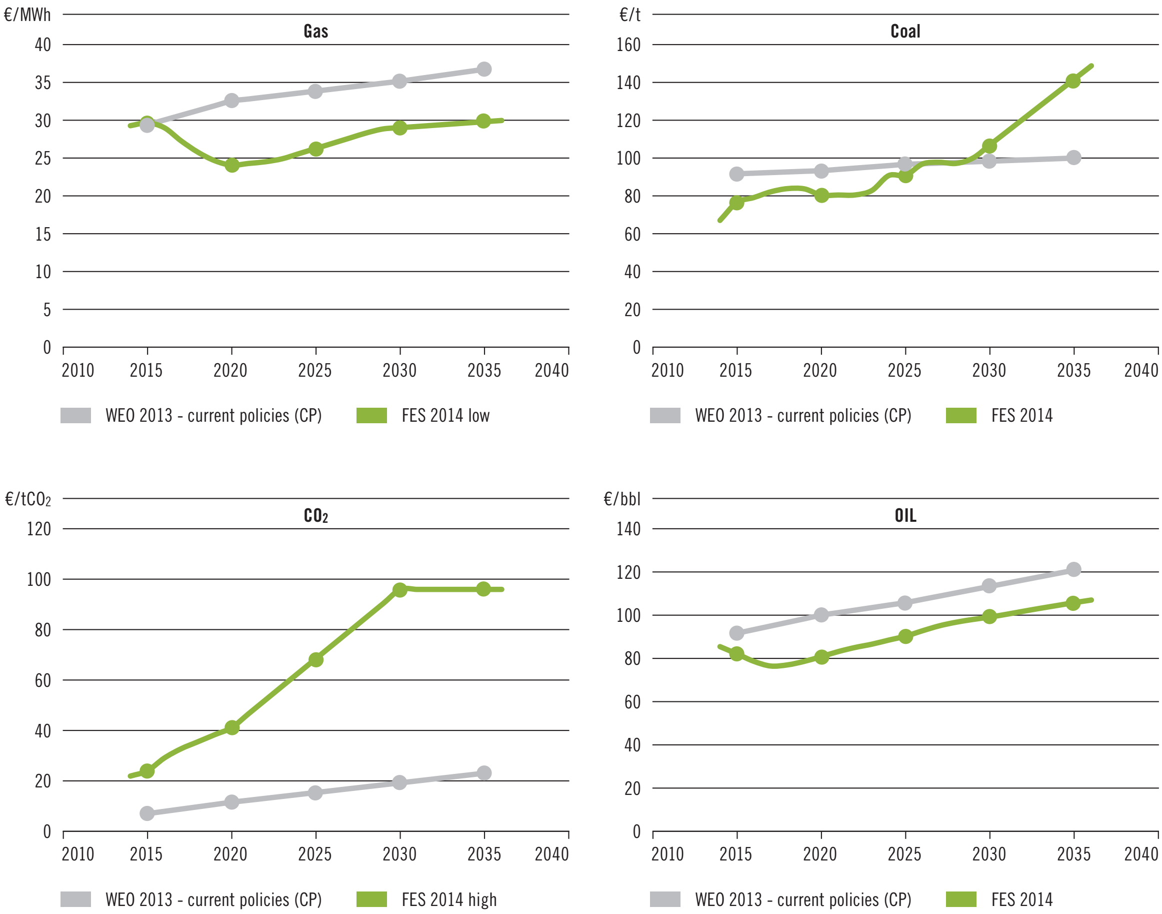

Figure 4.11: Prices for gas, coal, CO_2 and oil

4.3.1.3 Scenarios for power generation sector

The definition of gas demand scenarios for power generation was based on the Visions covered by ENTSO-E's TYNDP 2014 (see Annex F for more details about those visions):

- **Vision 1 – "Slow Progress"**
- **Vision 3 – "Green Transition"**

ENTSOG has applied a simplified methodology with country granularity. This methodology is based on the assumption that some of the sources used to generate electricity show low sensitivity to market conditions. In the case of nuclear energy, generation is mainly base load, while for renewables like hydro, wind or solar, the generation mostly depends on the availability of the driving sources. The contribution of other sources such as gas and coal[1)] is mainly driven by the relative fuel prices.

1) This would also apply to oil-derived fuels. Given the marginal role of such sources in the European generation mix they have been considered fixed. The only exception would be Estonia, where the split of the thermal gap is done between gas and oil.

On this basis, the electricity potentially generated from gas is estimated in two steps:

1. Definition of the Thermal gap

The thermal gap is the amount of electricity to be generated from coal and gas. It depends on the net electricity required minus the calculated electricity generated by the other sources, originating either from nuclear energy or from renewables.

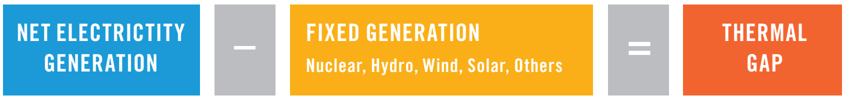

Figure 4.12: Calculation of the thermal gap

2. Split of the thermal gap between gas and coal.

The split of the thermal gap between gas and coal depends on their respective prices under the simulated market conditions and on constraints, such as the installed capacities and the maximum and minimum technical limits. The combination of the technical and economic factors will lead to a range of gas use.

Figure 4.13: Gas/coal breakdown of the thermal gap

The following tables show the evolution of the generation capacity mix under each vision. As ENTSO-E's TYNDP is limited to 2030 the values from 2030 until 2035 have been considered constant. The capacity scenarios in the medium term have been taken from ENTSO-E's Scenario Outlook & Adequacy Forecast 2013 (SO&AF 2013), and the years not covered by any of these publications have been estimated by interpolation.

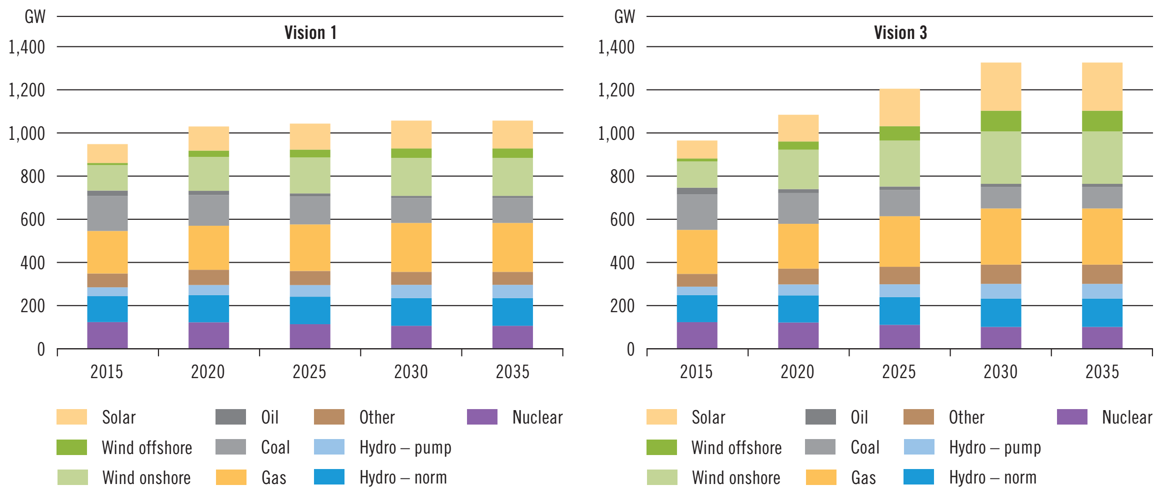

Figure 4.14: Power generation installed capacities for Vision 1 (Slow Progression) and for Vision 3 (Green Transition) (Source ENTSO-E)

The implementation of this methodology requires a significant number of assumptions, including electricity generation from alternative sources and limitations in the utilization of coal and gas. These assumptions are based on the actual electricity mix, along with feedback from stakeholders and inputs from TSOs to reflect the specific factors for each country.

The net electricity generation for each country results from market studies for Visions 1 and 3. In these market studies ENTSO-E modelled the hourly behavior of the power systems in 2030. The main difference between the modeling of the potential annual and peak daily electricity mix comes from the assumptions regarding the availability of alternative (non coal/gas) electricity sources.

In the case of wind, the annual generation can be estimated on average annual values, while low wind availability implies a low daily load factor and hence a potential higher thermal gap. 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. This is consistent with the approach of most TSOs.

Both annual and daily assumptions on the availability of alternative generation sources as well as the technical limits of gas and coal-fired power generation have been defined by TSOs. They are applied to the installed capacities of the different sources defined by the ENTSO-E's Visions 1 and 3 at country level.

In addition to the scenarios for power generation that come out of the application of this methodology, some TSOs have provided their own gas demand scenarios for power generation as detailed in Annex C1. To ensure a consistent approach for all different countries and to ensure consistency with the ENTSO-E's scenarios, the modelling is based on the output of the methodology[1)].

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1) The forecast of gas demand for power generation in some countries may significantly deviate from the selected visions from ENTSO-E which have been used in the assessment chapter. Gas demand forecasts for power generation from TSOs can be found in Annex C1 with country specific assumptions in Annex C3.

Image courtesy of GRTgaz

4.3.1.4 Combinations of scenarios

In order to keep the range of scenarios both meaningful and manageable, the three aforementioned categories have been combined based on the underlying assumptions of each scenario. The following table shows the two combined scenarios:

COMBINATION OF SCENARIOS			
Combination	**Global Context**	**Final gas demand**	**Power generation**
GREEN	Gone Green	A	Vision 3
GREY	Current Policies	B	Vision 1

Table 4.4: Combination of scenarios

4.3.2. ANNUAL GAS DEMAND

4.3.2.1 Final gas demand (residential, commercial and industrial)

The following figures show the evolution of the annual final gas demand in both scenarios. In the short term Scenario A shows a higher aggregated gas demand than Scenario B. This may be linked to the more favorable economic conditions and lower energy prices that characterize this scenario. However, in the long term, these conditions would lead to investment in efficiency measures and higher implementation of low carbon heating solutions. This would result in a reduction in annual demand compared to Scenario B.

Scenarios A and B are very close with Scenario B being 1 % lower than Scenario A in 2015 and 3 % higher in 2035. These small differences at aggregated level hide significantly diverging trends at country level. In 2035, Scenario B ranges between 25 % lower and 38 % higher than Scenario A at individual country level. These different trends are partly due to the varying maturity of individual gas markets but are also influenced by different strategies in the development of the domestic, industrial and commercial markets being pursued by each country.

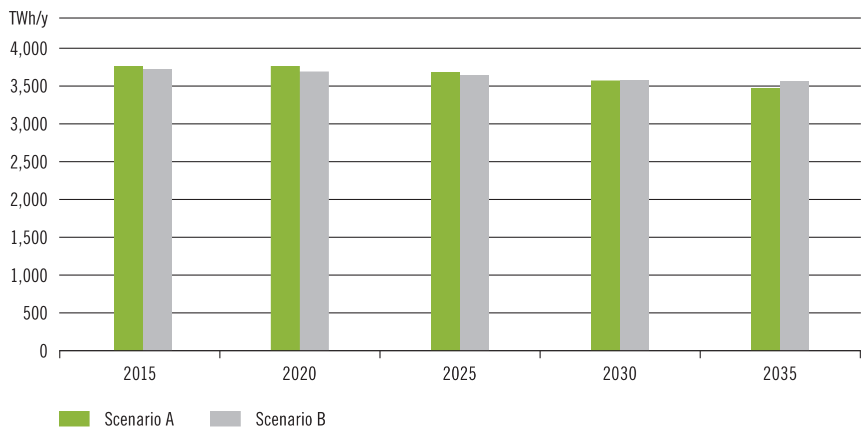


Figure 4.15: Final gas demand

4.3.2.2 Gas for power generation “Vision 1” vs. “Vision 3”

Aggregated gas demand for power generation could vary within a range depending on gas, coal and CO_2 emission prices and on technical limits. The following figures show the evolution of gas demand for power generation under Vision 1 (Slow Progress) and Vision 3 (Green Transition). In both visions, gas demand grows over time. Gas demand is higher for Vision 3 and the divergence between the two visions increases in the long term.

The range between minimum and maximum demand is over 100 % in 2015 and decreases in time for both visions. This effect is clearer for Vision 1, for which the range is limited to 30 % of the minimum by 2035, as a result of reduced installed coal and gas power generation capacity.

The figures also show the evolution of the average minimum and average maximum yearly load-factors for gas generation facilities. While the maximum load-factors are quite stable in the long term at around 50 %, minimum load-factors increase from a 25 % level in 2015 to almost 40 % by 2030.

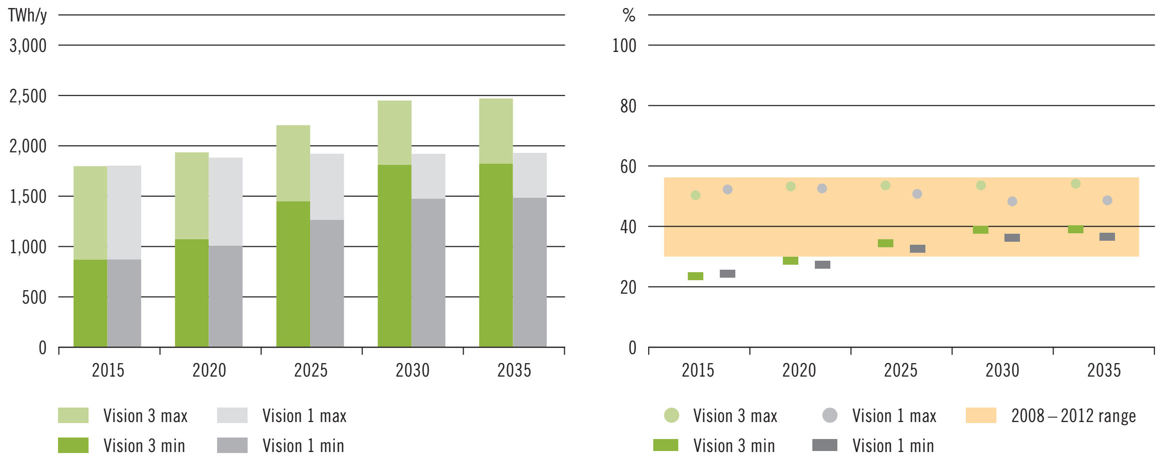


Figure 4.16: Gas demand for power generation (left). EU gas-fired facilities, minimum and maximum yearly load-factors (right)

The evolution of the yearly gas demand for power generation, as seen in the figures above, follows the trends set by the thermal gap. In Vision 3, as seen in the figure below, the thermal gap decreases in the short term driven by the increase in renewable power generation, and increases sharply in the long term, when the increase in renewables does not match the significant growth in electricity demand.[1)]

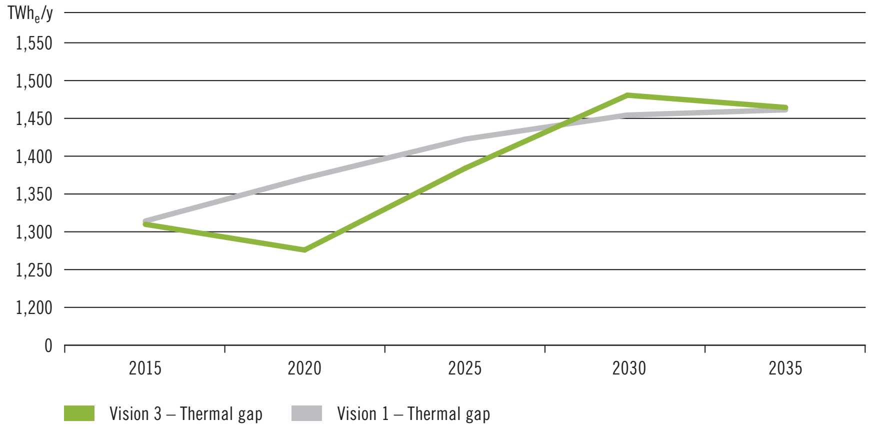
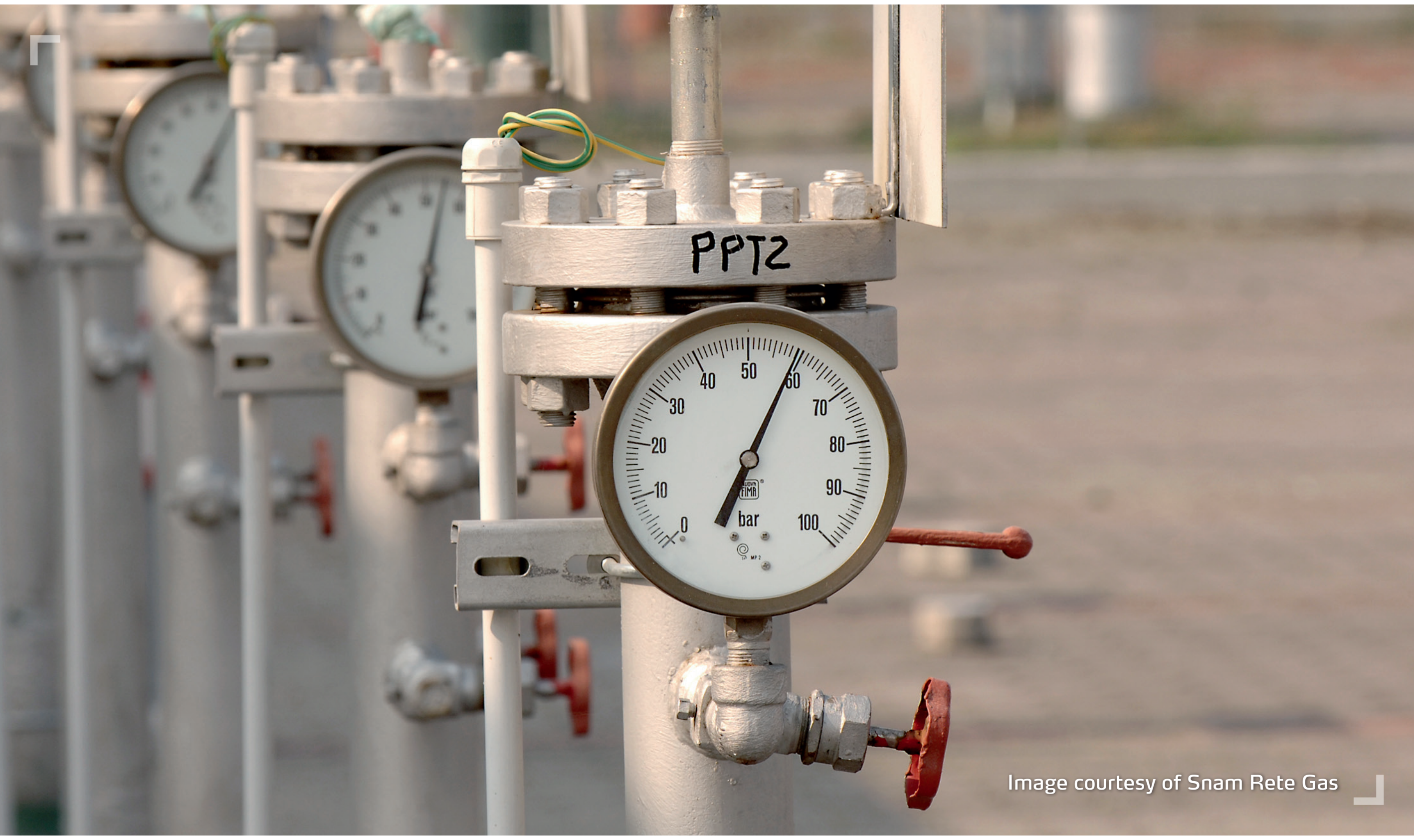


Figure 4.17: Evolution of the yearly thermal gaps for Visions 1 and Vision 3[1)]

1) As the thermal gap defines the electricity generation which has to be provided by coal and/or gas-fired power generation it is expressed in electrical units.



4.3.2.3 Comparison of total annual gas demand between the two scenarios

The following figures compare the evolution of the total gas demand for the GREEN and GREY scenarios. They show the maximum range for the GREEN scenario and the minimum range for the GREY. Both scenarios show a slight increase of total gas demand, although starting from different absolute levels. The discrepancy between the two scenarios for final gas demand is small. In fact, the difference between GREEN and GREY scenarios mostly results from power generation scenarios under Visions 1 and 3. GREEN is 20 % higher than the GREY scenario on average. In addition, the figures also show the range of total gas demand, including TSOs demand scenarios for power generation. TSOs scenarios are consistent with the GREY scenario, especially in the long term.

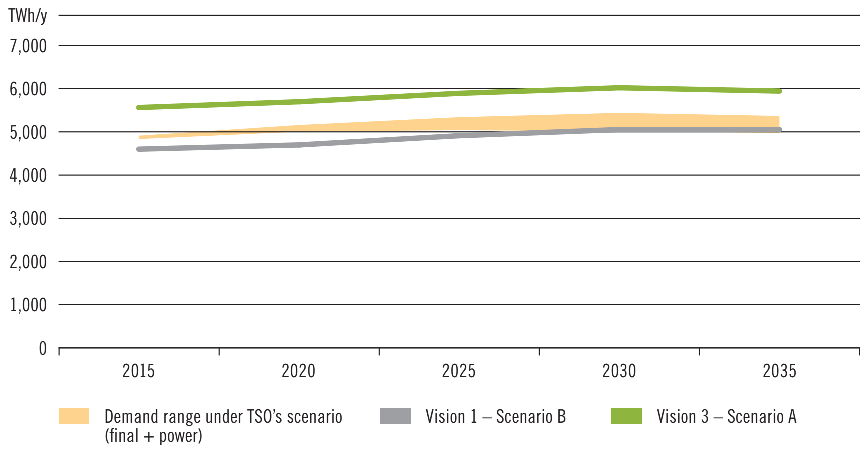


Figure 4.18: Total gas demand and comparison with TSO's submission

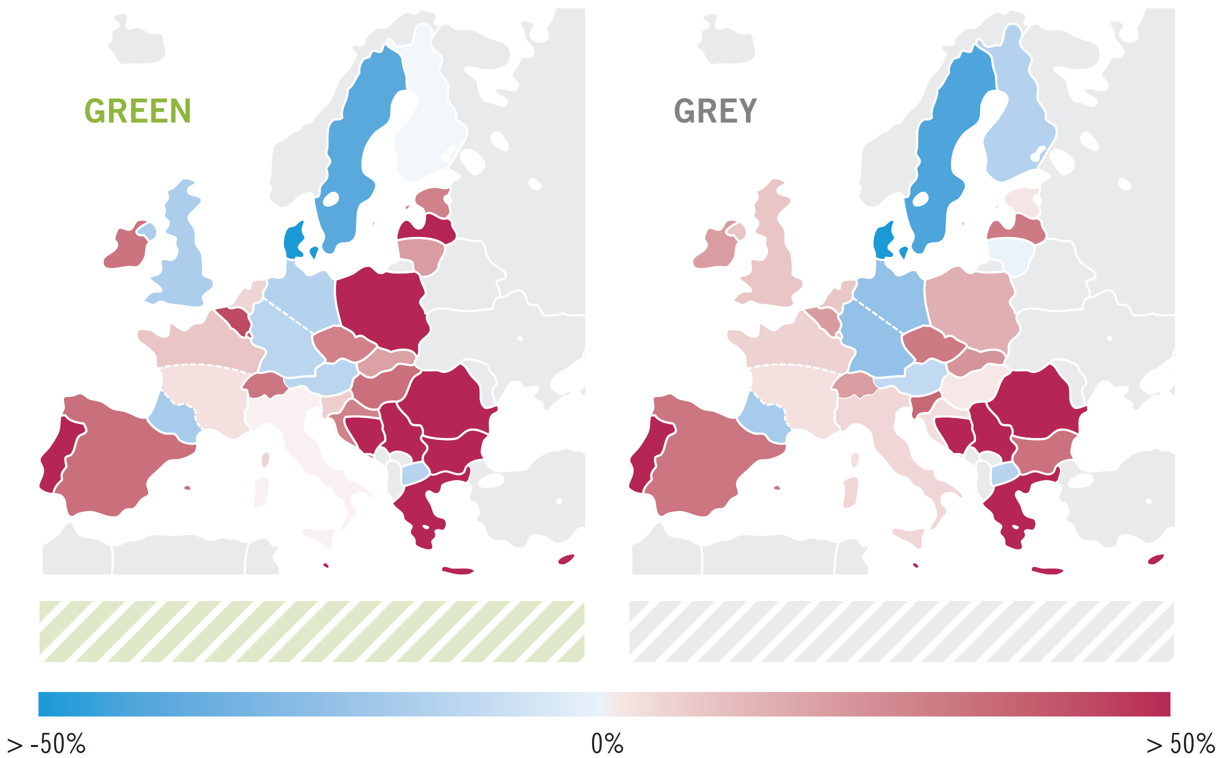
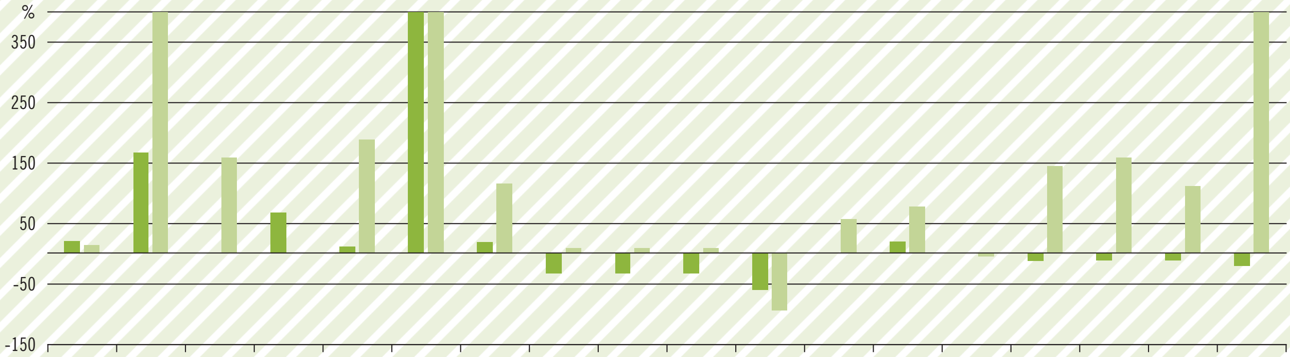


Figure 4.19: Evolution of total annual gas demand in the period 2015 – 2035.
Gas demand for power generation is based on data from ENTSO-E SO&AF 2014 – 2030.

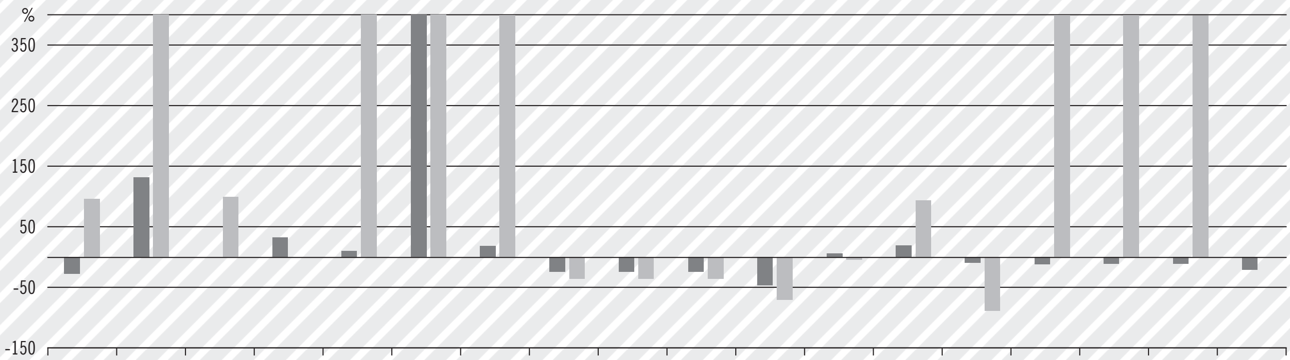
For most of the countries, the demand evolution shown in previous figures comes from the power generation sector (ENTSO-E SO&AF2014-2030 Visions 1 and 3 considering gas TSO feedback) as illustrated in below graphs:



	AT	BA	BE	BG	CH	CY	CZ	DE	DEn	DEg	DK	EE	ES	FI	FR	FRn	FRs	FRt
Final (res., com., ind.)	20%	167%	0%	67%	10%	∞	18%	-34%	-34%	-34%	-61%	0%	19%	-1%	-13%	-12%	-12%	29%
Power generation	13%	∞	158%	0%	188%	∞	115%	8%	8%	8%	-95%	56%	77%	-5%	144%	158%	110%	∞

Final (res., com., ind.) Power generation

Figure 4.20a: GREEN: Evolution of total gas demand in the period 2015–2035 per sector and balancing zone. Gas demand for power generation is based on data from ENTSO-E SO&AF 2014–2030[1].

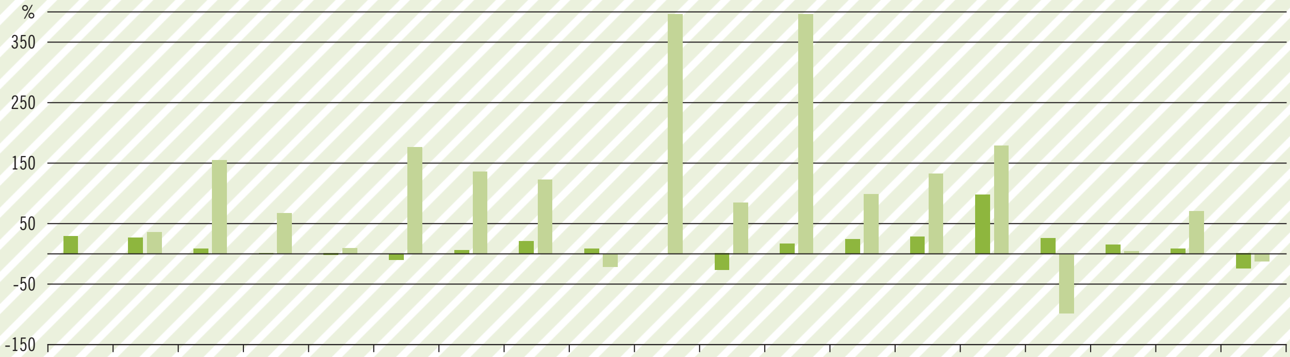


	AT	BA	BE	BG*	CH	CY	CZ	DE	DEn	DEg	DK	EE	ES	FI	FR	FRn	FRs	FRt
Final (res., com., ind.)	-28%	133%	0%	33%	10%	∞	18%	-25%	-25%	-25%	-47%	6%	20%	-10%	-13%	-12%	-12%	-21%
Power generation	97%	∞	100%	0%	680%	∞	572%	-37%	-37%	-37%	-72%	-5%	94%	-90%	784%	834%	662%	0%

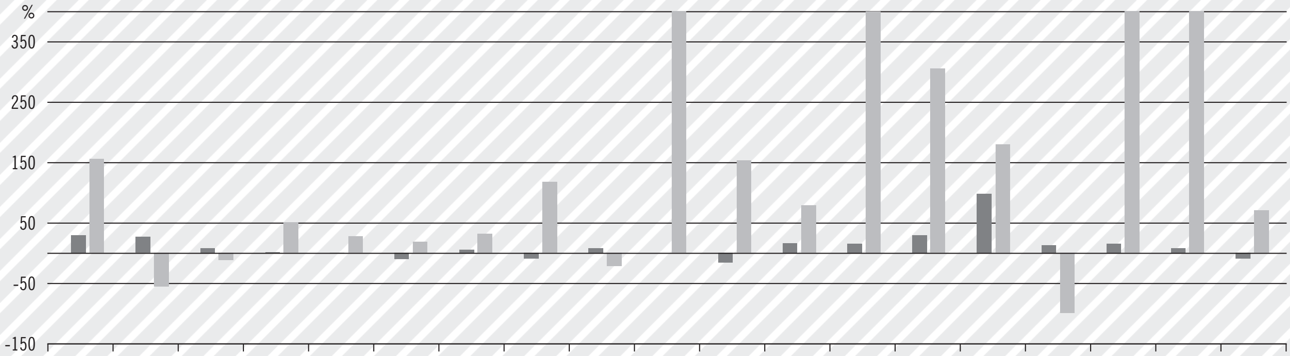
Final (res., com., ind.) Power generation

Figure 4.20b: GREY: Evolution of total gas demand in the period 2015–2035 per sector and balancing zone. Gas demand for power generation is based on data from ENTSO-E SO&AF 2014–2030[1].

1) Gas demand for power generation is not the same in 2015 between GREEN and GREY scenarios due to ENTSO-E Visions, such difference should be considered when comparing evolution under the two global contexts. Necessary data can be found in Annex C2. Ranges for the y-axis have been cut on both graphs for visibility reasons when increase is above 400 %. "∞" means an indefinite increase in gas demand resulting from the absence of gas demand in 2015.



	GR	HR	HU	IE	IT	LT	LU	LV	MK	MT	NL	PL	PT	RO	RS	SE	SI	SK	UK
Final (res., com., ind.)	29%	26%	8%	1%	-3%	-10%	5%	20%	8%	0%	-27%	16%	24%	29%	99%	26%	15%	8%	-25%
Power generation	0%	36%	156%	67%	9%	178%	136%	123%	-22%	∞	85%	520%	99%	133%	180%	-100%	3%	71%	-13%



	GR	HR	HU	IE	IT	LT	LU	LV	MK	MT	NL	PL	PT	RO	RS	SE	SI	SK	UK
Final (res., com., ind.)	29%	26%	8%	1%	-1%	-10%	5%	-10%	8%	0%	-17%	16%	15%	29%	99%	13%	15%	8%	-10%
Power generation	156%	-57%	-12%	51%	28%	18%	31%	118%	-22%	∞	154%	79%	426%	307%	180%	-100%	∞	542%	70%

4.3.2.4 Winter and summer averages

The modelling assessment differentiates between average summer and average winter conditions. The demand data for these climatic cases has been derived from the annual demand information provided by TSO assuming:

- No differentiation between the daily average gas demand for power generation in summer and winter.
- A “winter average factor” specific to each country is calculated as the deviation of the winter average demand from the yearly average demand.

4.3.3 PEAK GAS DEMAND

4.3.3.1 Final gas demand (residential, commercial and industrial)

The following figures describe the demand levels under the 1-day Design Case, and the 14-day Uniform Risk as defined in the Annex F. The 1-day Design Case shows higher values under Scenario A than under Scenario B in the short term, but lower values after 2025. Both scenarios show a moderate decline, the trend being more accentuated for Scenario A. This is consistent with the annual gas demand trend, as seen above.

This trend could be partly explained by an energy efficiency increase in the domestic sector that would reduce the response of gas demand in peak conditions. By 2035, the peak final gas demand is reduced by 13 % in Scenario A and 7 % in Scenario B.

This trend does not reflect the differences between the individual countries, for which the 1-day Design Case demand evolution between 2015 and 2035 varies between -76 % and +46 %.

The following figures compare the aggregated final gas demand for the 1-day Design Case with the 14-day Uniform Risk average daily demand. The differences vary between -14 % and -10 %. In general, the 14-day Uniform Risk follows the same decreasing trend as the peak day.

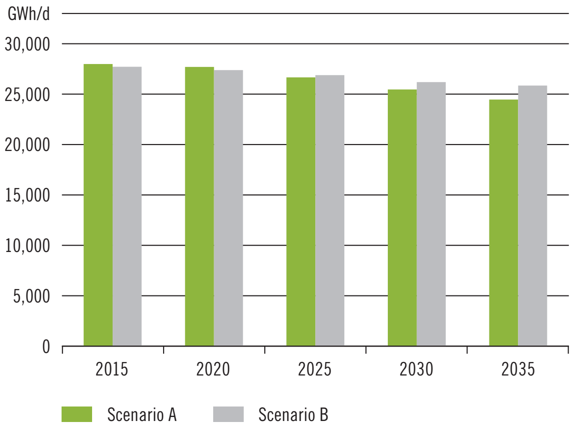


Figure 4.21: Final gas demand for the 1-day Design Case

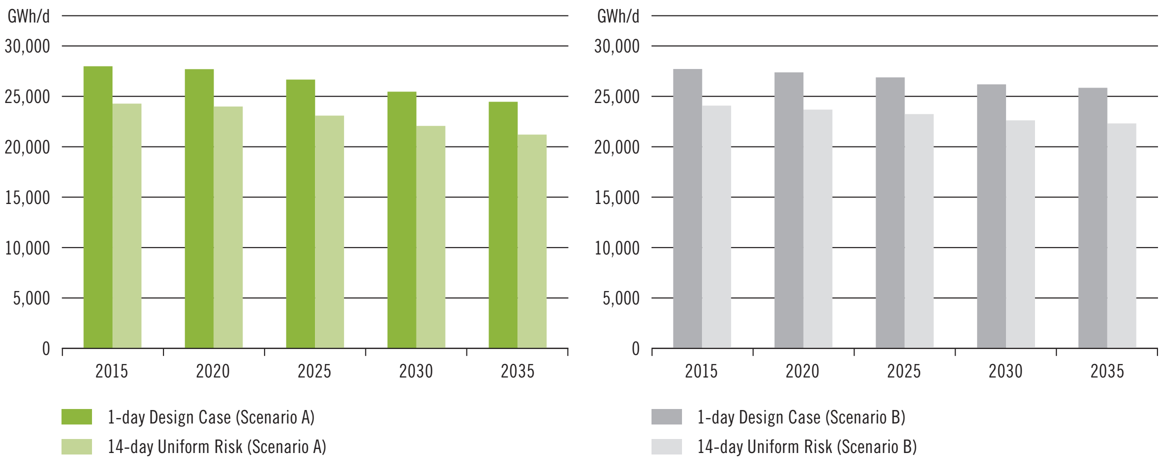


Figure 4.22: Comparison between final gas demand for the 1-day Design Case and the 14-day Uniform Risk in different scenarios

4.3.3.2 Gas for power generation "Vision 1" vs. "Vision 3"

The peak gas demand for power generation will strongly increase over the next 20 years under both Vision 1 and Vision 3. The growth in Vision 3 is significantly stronger than in Vision 1, with a total growth up to 46 % over the 20-year period. Under Vision 1 most of the increase occurs by 2025 and this level is sustained in the long term. Under Vision 3 the growth is sustained until 2030. The TSOs' submissions for the Grey scenario are largely consistent with Vision 1, whereas the submissions corresponding to the Green scenario are slightly lower than Vision 3. (see figure 4.23)

The evolution of the peak gas demand for power generation is mostly driven by the evolution of electricity demand and on the development of alternative generation technologies. The generation from such sources according to ENTSO-E Visions is illustrated by figure 4.24.

The peak electricity generation from these alternative sources mainly depends on the evolution of installed capacities given that load factors stay stable over time. These load factors are very similar in both Visions 1 and 3 as shown in figure 4.25.

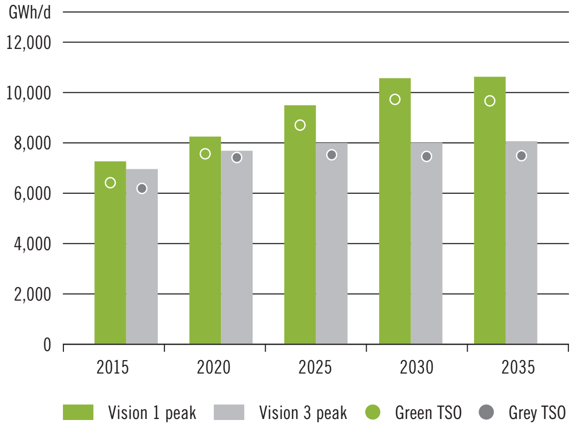


Figure 4.23: Peak gas demand for power generation

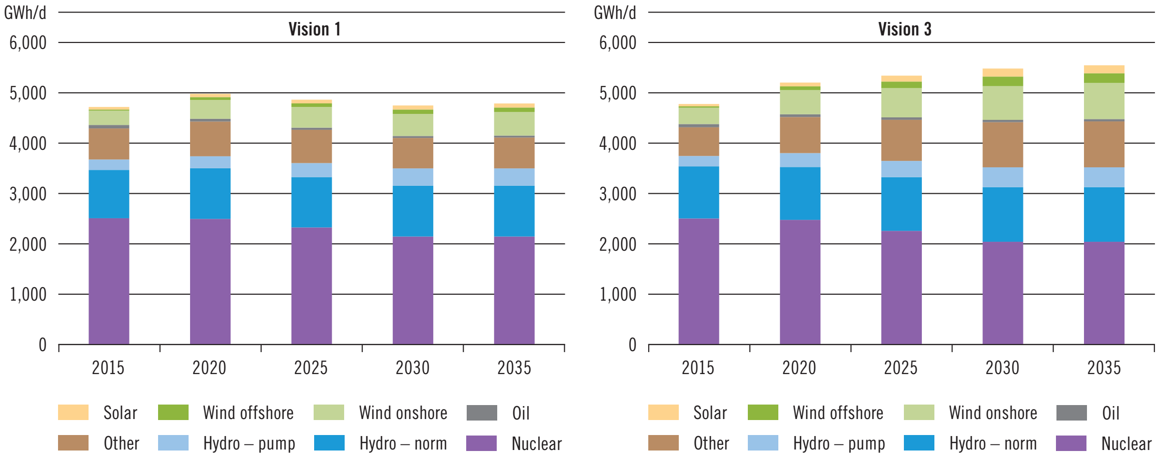


Figure 4.24: Power generation from alternative sources on the peak day

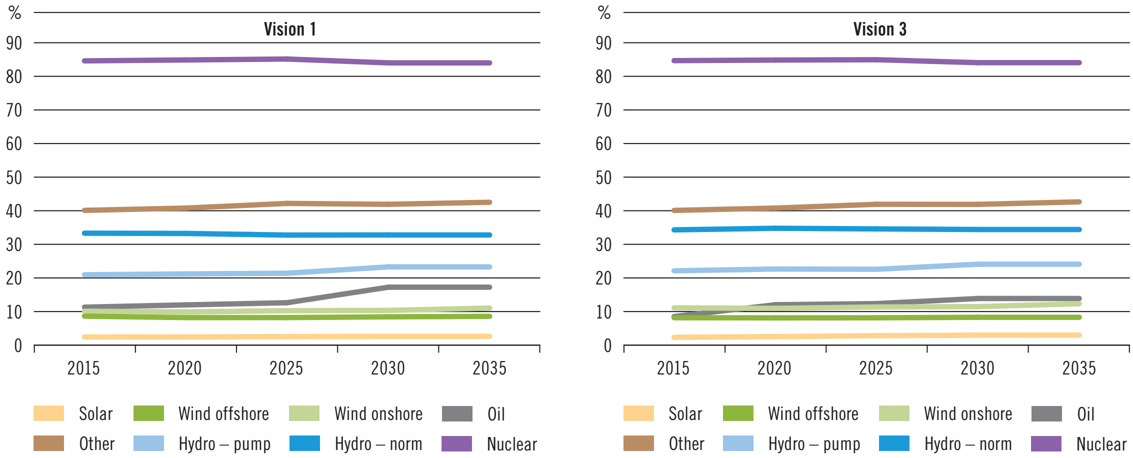


Figure 4.25: Generation load-factors, of alternative sources on a peak day

As a result the difference in peak gas demand between Vision 1 and Vision 3 is driven by the diverging thermal gaps for the peak, as shown in following graph.

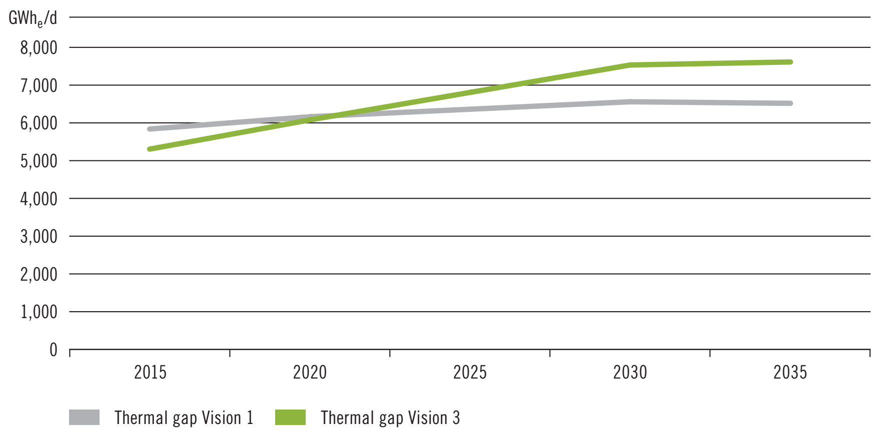


Figure 4.26: Evolution of the thermal gaps on the peak day for Vision 1 and Vision 3[1)]

1) As the thermal gap defines the electricity generation which has to be provided by coal and/or gas-fired power generation it is expressed in electrical units.

4.3.3.3 Total gas demand for the peak day

The figure below shows the evolution of total gas demand for the peak day. The total has been calculated by aggregating the final gas demand for the 1-day Design Case and the peak demand for power generation. The difference between the GREEN and GREY scenarios is small and the evolution along the 20-year period is very limited. This results from the increasing trend in power generation and decreasing trend in non-power generation.

Peak demands in the Green scenario are slightly higher. The reduction in the total gas demand for the peak day is due to the potential increase of RES and the improvement in efficiency in the residential and commercial sectors. The Green scenario assumes a significantly higher electricity demand due to the economic conditions and stricter environmental policies. The increase in the use of electricity for heating and for transportation associated with the Green scenario could induce higher peak demands in the gas system than in the more moderate Grey scenario. Given the back-up role of gas in power generation, the higher electricity demand induces a higher gas demand for peak power generation.

The maximum peak demand is reached in 2020 in the Grey scenario, and in 2025 in the Green scenario. Demand evolution follows a slight decrease over the full period. (see figure 4.27)

The aggregated European trend does not reflect the diversity of individual observed country trends. The maps in the following figures illustrate the differences in the evolution for each country based on the Green and Grey Scenarios (see Annex C2 for country specific information).

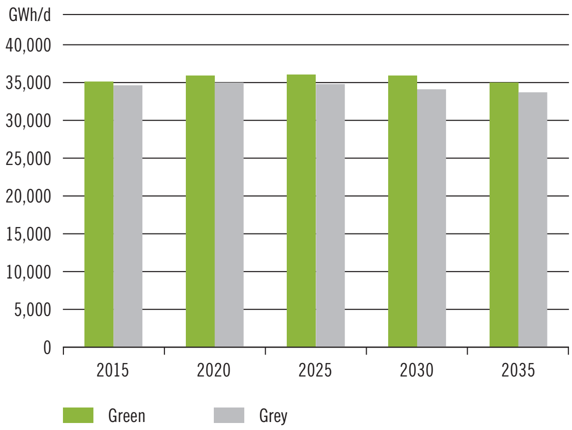


Figure 4.27: Total gas demand on the peak day.

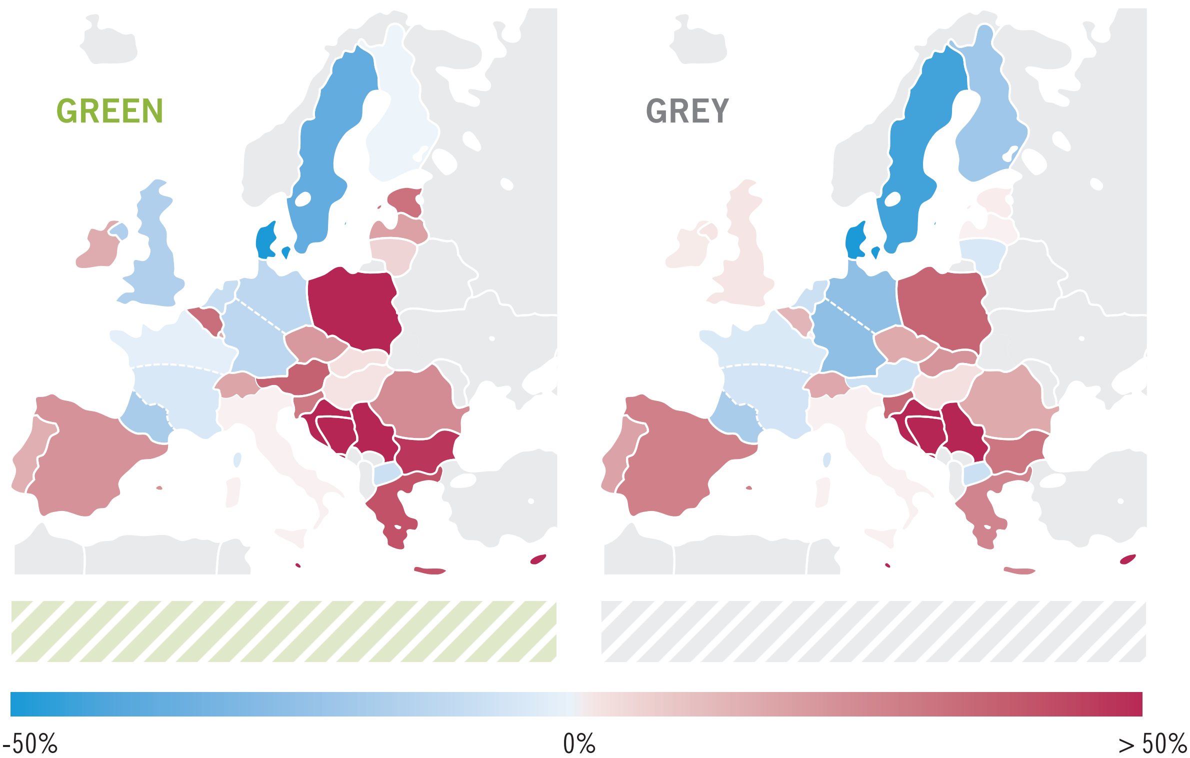
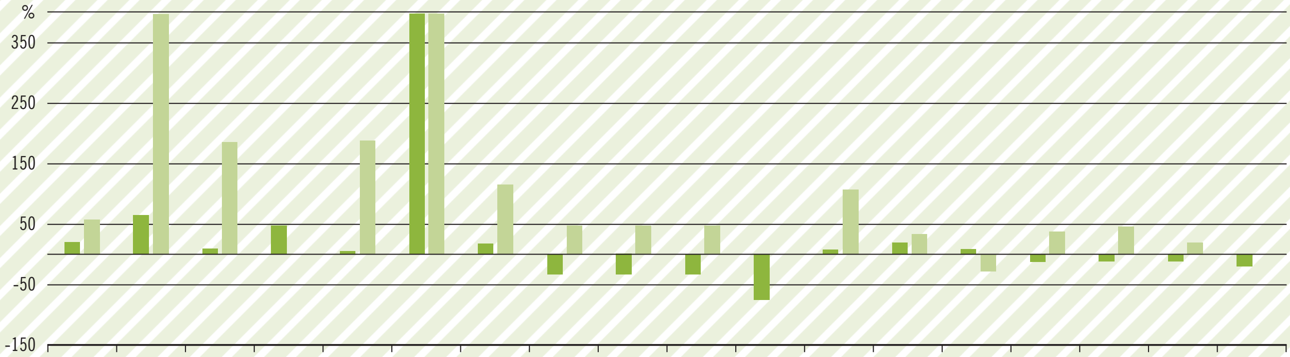


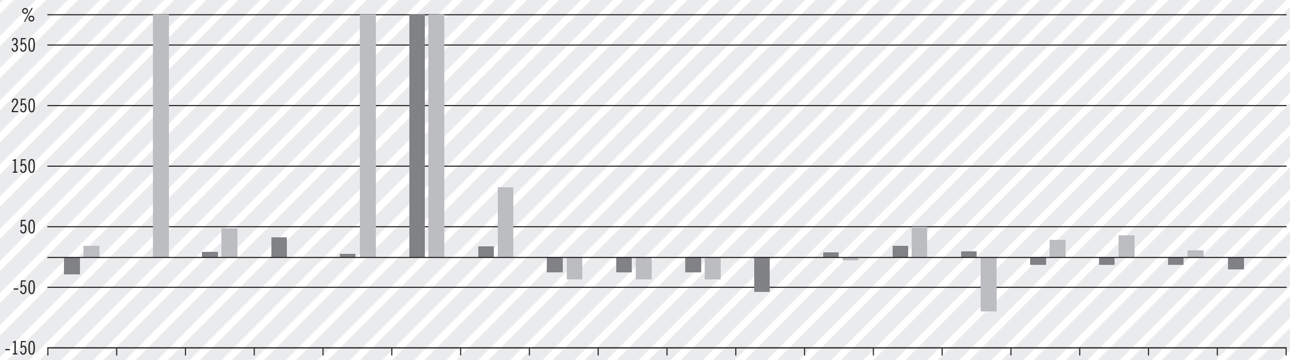
Figure 4.28: Evolution of total peak gas demand in the period 2015–2035.
Gas demand for power generation is based on data from ENTSO-E SO&AF 2014–2030.

As for yearly demand, for most of the countries the evolution of the peak demand is driven by the power generation sector (ENTSO-E SO&AF 2014–2030 Visions 1 and 3 considering gas TSO feedback) as illustrated by the following graphs:



	AT	BA	BE	BG	CH	CY	CZ	DE	DEn	DEg	DK	EE	ES	FI	FR	FRn	FRs	FRt
Final (res., com., ind.)	20%	64%	8%	46%	5%	∞	17%	-34%	-34%	-34%	-76%	7%	18%	8%	-13%	-12%	-12%	-21%
Power generation	57%	∞	186%	0%	188%	∞	115%	47%	47%	47%	0%	107%	33%	-29%	38%	45%	19%	0%

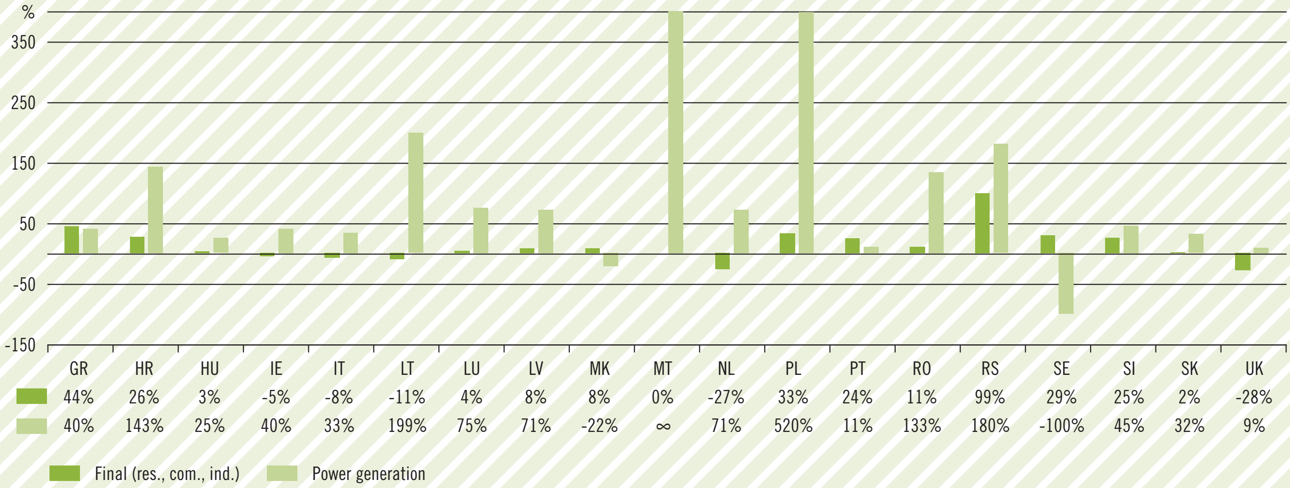
Figure 4.29a: GREEN: Evolution of total gas demand for the peak day in the period 2015–2035 per sector and balancing zone. Gas demand for power generation is based on data from ENTSO-E SO&AF 2014–2030[1].



	AT	BA	BE	BG	CH	CY	CZ	DE	DEn	DEg	DK	EE	ES	FI	FR	FRn	FRs	FRt
Final (res., com., ind.)	-28%	0%	8%	32%	5%	∞	17%	-25%	-25%	-25%	-57%	7%	18%	9%	-13%	-12%	-12%	-21%
Power generation	19%	∞	48%	0%	680%	∞	115%	-37%	-37%	-37%	0%	-5%	50%	-90%	29%	36%	11%	0%

Figure 4.29b: GREY: Evolution of total gas demand for the peak day in the period 2015–2035 per sector and balancing zone. Gas demand for power generation is based on data from ENTSO-E SO&AF 2014–2030[1].

1) Gas demand for power generation is not the same in 2015 between GREEN and GREY scenarios due to ENTSO-E Visions, such difference should be considered when comparing evolution under the two global contexts. Necessary data can be found in Annex C2. Ranges for the y-axis have been cut on both graphs for visibility reasons when increase is above 400%. "∞" means an indefinite increase in gas demand resulting from the absence of gas demand in 2015.


%
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250
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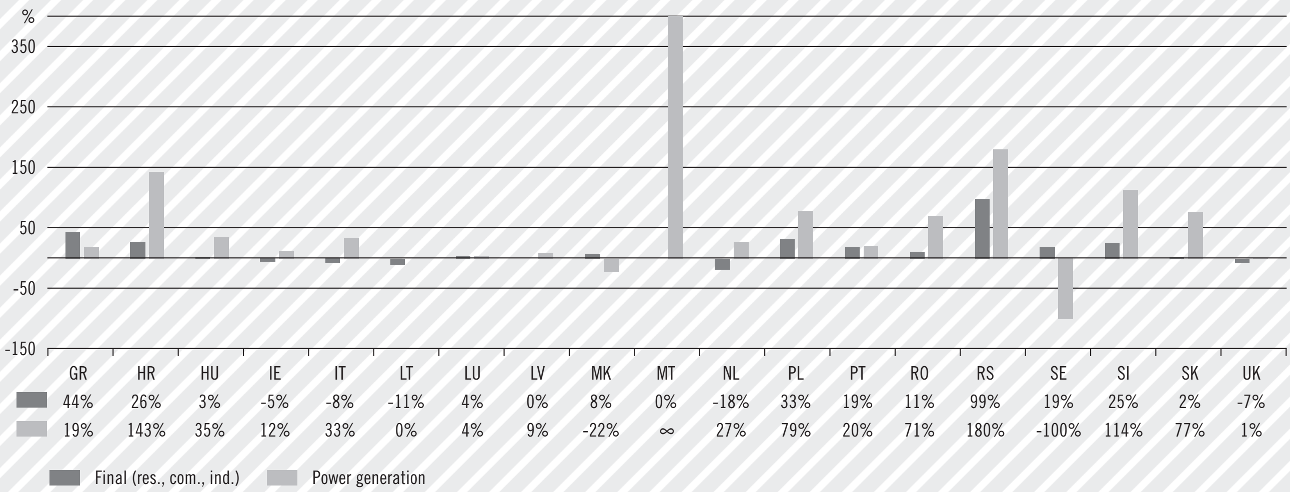
GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK
44% 26% 3% -5% -8% -11% 4% 8% 8% 0% -27% 33% 24% 11% 99% 29% 25% 2% -28%
40% 143% 25% 40% 33% 199% 75% 71% -22% ∞ 71% 520% 11% 133% 180% -100% 45% 32% 9%
Final (res., com., ind.)
Power generation


%
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GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK
44% 26% 3% -5% -8% -11% 4% 0% 8% 0% -18% 33% 19% 11% 99% 19% 25% 2% -7%
19% 143% 35% 12% 33% 0% 4% 9% -22% ∞ 27% 79% 20% 71% 180% -100% 114% 77% 1%
Final (res., com., ind.)
Power generation

4.3.4 GAS DEMAND FOR TRANSPORTATION

Besides being used in the residential, commercial and industrial sectors as well as for power generation, gas is becoming more favored as a fuel for transportation purposes. In order to have a wider range of potential future gas demand scenarios, TSOs have been asked to provide gas projections for the maritime and road transportation sectors based on the same assumption as used for the Green and Grey scenarios .

Compressed natural gas (CNG) for road transportation (mainly light duty vehicles – LDV) is currently the most mature market in Europe with close to 1 million vehicles adapted to this technology and around 3,000 fillings stations. The highest numbers of filling stations are found in Italy, Germany, Austria, Switzerland, Netherlands, Finland and Bulgaria.

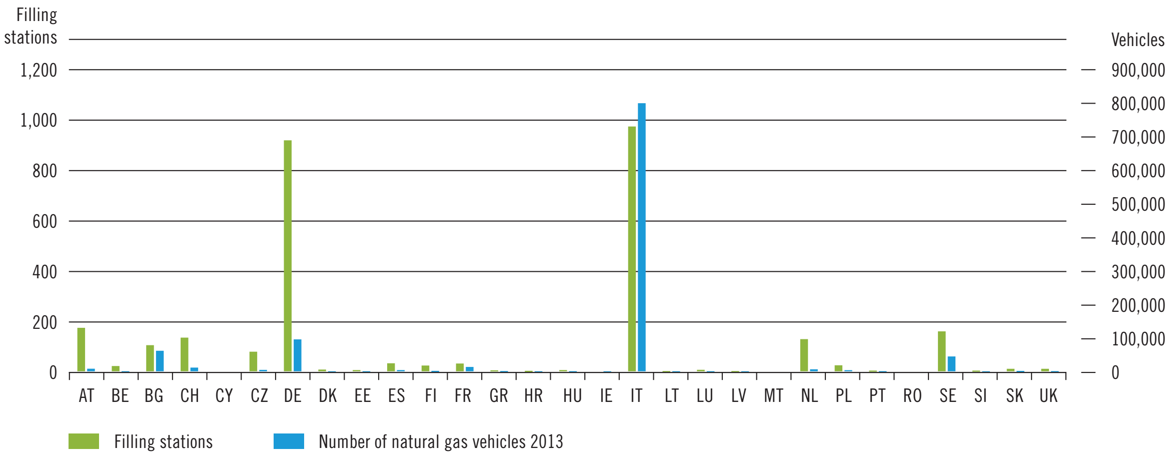


Figure 4.30: Natural gas vehicles (2013) and CNG filling stations (2014), country detail (Source Eurogas/NGVA Europe)

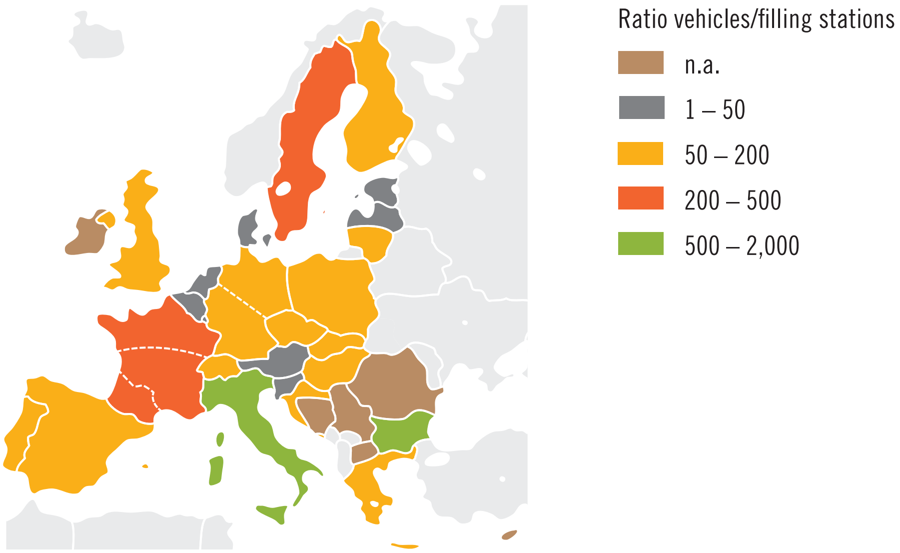


Figure 4.31: Ratio of vehicles per CNG filling station, ENTSOG depiction (Source Eurogas/NGVA Europe)

LNG has cleaner exhaust emissions and higher energy efficiency. LNG could be used as a replacement for heavy oil fuel in sea-born transportation and for diesel in inland-water transportation. On-shore LNG bunker facilities[1] for vessels are already in place

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

in Norway, in the Netherlands and in Belgium and have been announced in Finland, France and Spain. LNG bunker ships can currently be found only in Sweden.

In road transportation LNG could also replace gasoil/diesel as it would offer the same advantages especially for truck fleets. LNG refueling stations are well developed in the UK and the Netherlands as well as in Spain, Portugal, Sweden, Belgium, and one in Italy.

The current lack of infrastructure hampers the wider use of gas as a fuel across Europe (CNG and LNG) and has justified the final 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 consists with the construction of an appropriate number of LNG maritime bunker facilities as well as LNG and CNG refueling stations on the main European roads up to 2025.

TSO projections show a continuous growth of the use of gas as a fuel in the transportation sector for the two scenarios. The increase is slightly smaller in Scenario B [1]as economic and financial conditions are less favorable and efficiency measures and investments are not as developed as in Scenario A. The highest increase is projected for Road LNG fuel, followed by maritime LNG fuel.

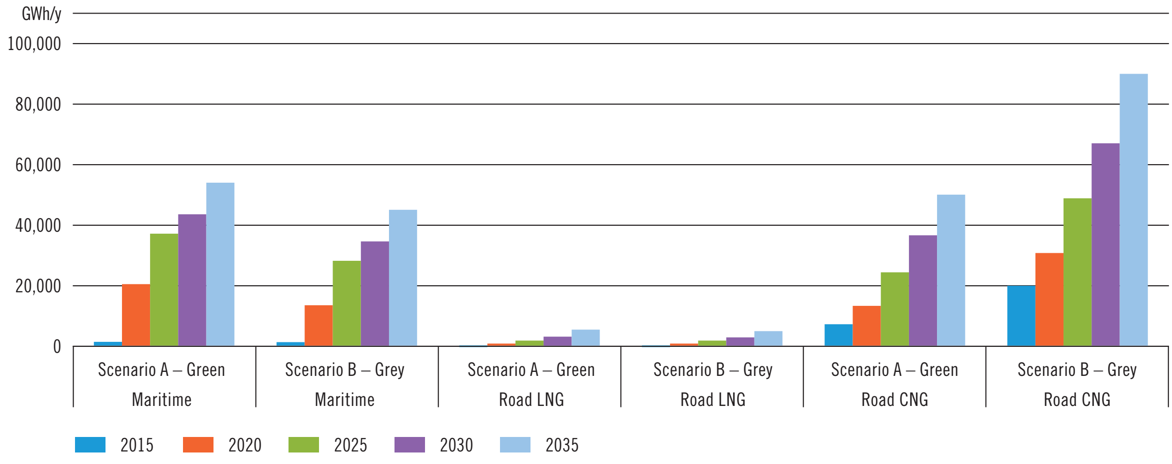


Figure 4.32: TSOs projection for gas as fuel in the transportation sector (maritime and road)

Gas demand in the transportation sector increases over time for both the Eurogas Roadmap 2050 and ENTSOG's scenarios. The difference between the scenarios of both associations is partly explained by the Eurogas inclusion of gas demand for passenger and freight transport by air and by rail. All scenarios show the same upward trend for the use of gas in the transportation sector.

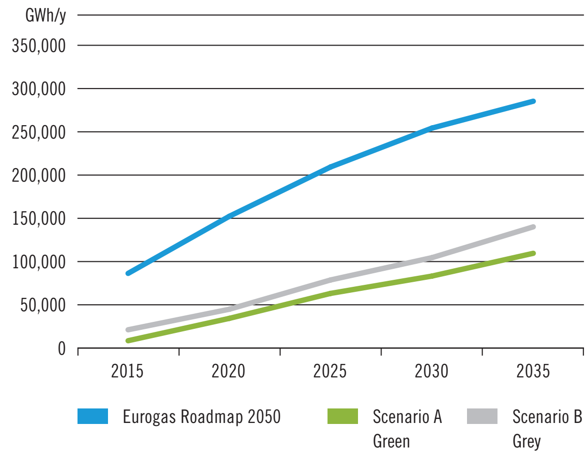


Figure 4.33: Projection for gas as fuel in the transportation sector. Comparison with Eurogas Roadmap 2050

1) Scenario A and B base on the assumption stated above in section "combination of scenarios".

4.4 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) 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 2050 EU Roadmap (agreed in March 2011)

- A 80 % reduction in greenhouse gas emissions from 1990 levels by 2050
- Reductions of the order of 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 make 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 4.5: GHG reductions according to 2050 EU Roadmap

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 %.

Current status

The graph below shows the evolution of the total EU greenhouse gas emissions since 1990. According to latest estimates, total EU greenhouse gas emissions in 2013 fell by 1.8 % compared to 2012, to around 19 % below 1990 levels (scope of the 2009 Climate and Energy package). This keeps the EU on track to meet its 20 % target by 2020 as part of the "20-20-20" target.

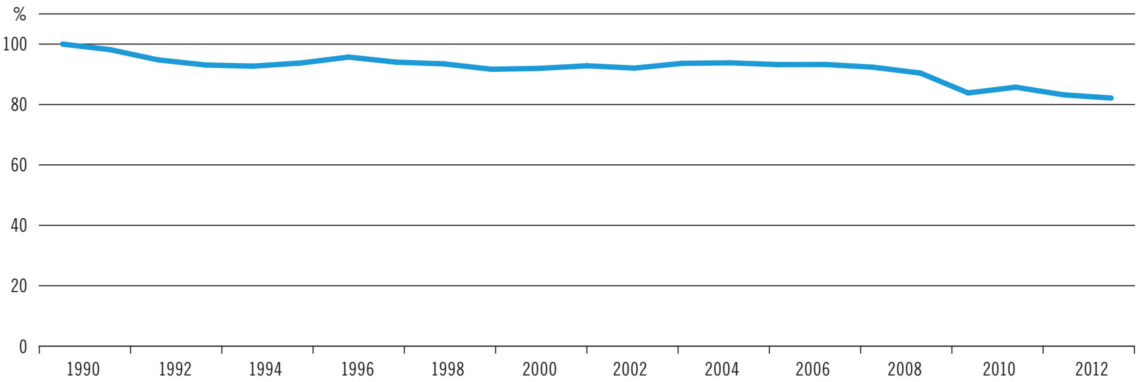


Figure 4.34: Total GHG emissions (in CO_2 equivalent) indexed to 1990. EU-28 (Source Eurostat)

Regarding the overall RES share, in 2012 with around a level of 15 %, the EU-28 were slightly above the target set by the National Renewable Energy Action Plans (NREAPs).

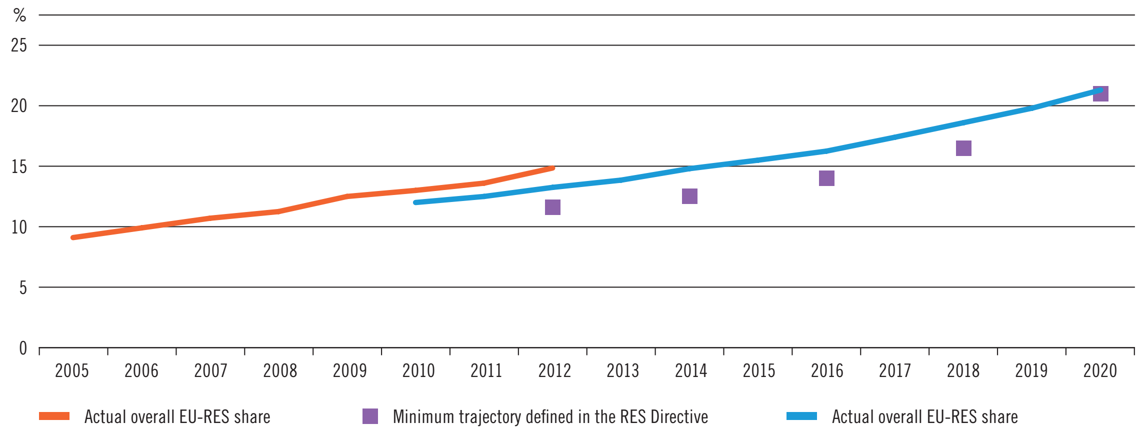


Figure 4.35: RES share in gross final energy consumption (Source Eurostat and NERAP data)

4.4.1 RENEWABLE ENERGY SOURCES IN ENTSOG'S SCENARIOS

4.4.1.1 Power generation from RES sources

The following figures show the evolution of the RES installed generation capacities and its share in power generation, including hydro, wind onshore and offshore and solar, based on ENTSOG's assumptions on the yearly load-factor of the different sources[1)].

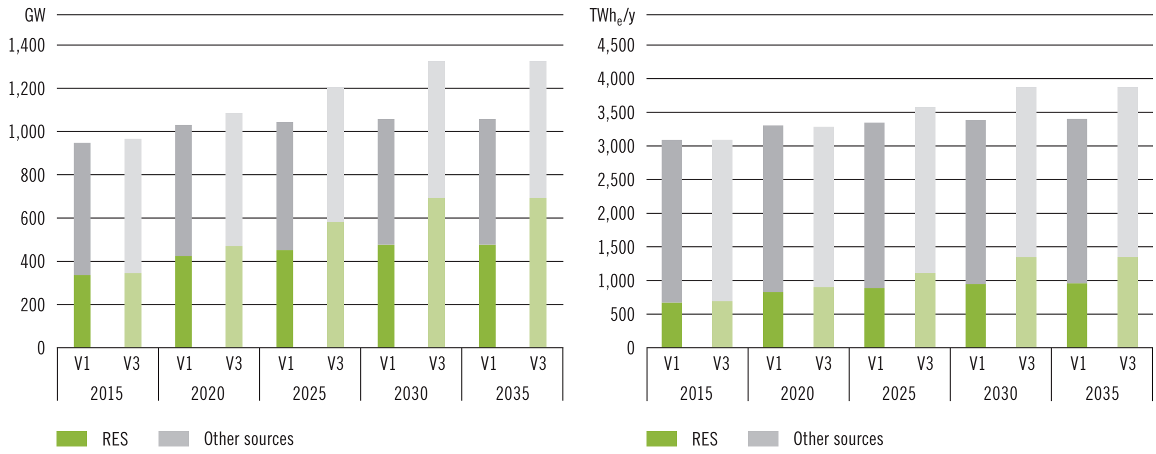


Figure 4.36: RES installed generation capacities (left) and RES annual power generation (right)

Installed RES generation capacities increase significantly under both scenarios between 2015 and 2035 (42 % in Vision 1 and 101 % in Vision 3). The relatively low yearly load-factors expected for some RES along with the increase in electricity demand limit the role of RES in the generation mix to 28 % in Vision 1 and to 35 % in Vision 3 by 2035. Both factors lead to a significant need for other sources compensating these effects.

4.4.1.2 Gas as back-up for RES variability

The variable RES installed generation capacities (solar and wind) will significantly increase over the next 20 years according to Vision 1 and Vision 3 defined by ENTSO-E. This is especially the case under Vision 3, where the aggregated installed capacity for solar and wind power (both onshore and offshore) will almost triple from 2015 to 2035.

Consequently, the gas demand necessary to compensate for the variability of RES is expected to increase accordingly. The magnitude of this variability has been estimated on the basis of the expected maximum and minimum daily load-factors for these sources at country level and aggregated to a European level to represent the daily variability. The maximum and minimum daily load-factors have been estimated by TSOs on the basis of actual behavior of existing sources between 2009 and 2012.

1) The applied methodology does not allow the quantification of the generation of other RES sources such as biomass, that consequently fall within the category "others".

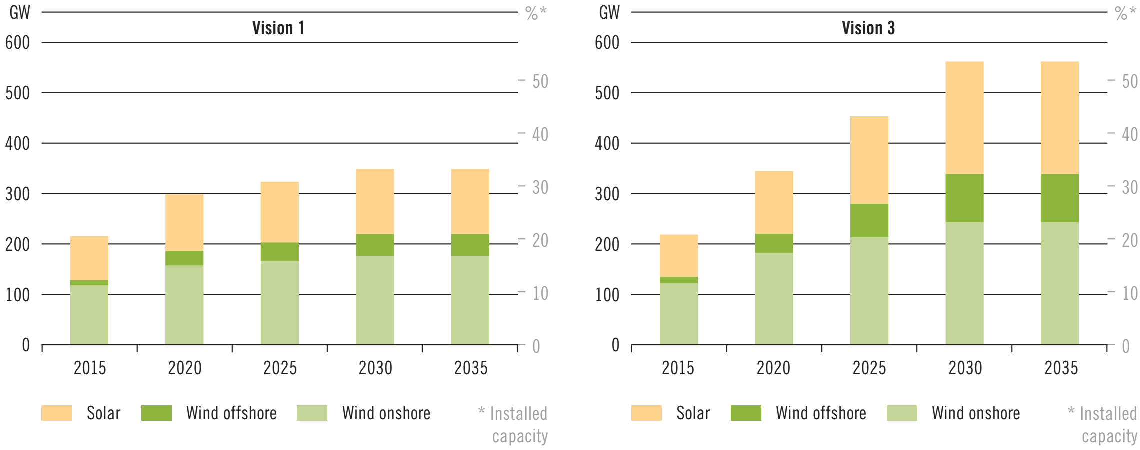


Figure 4.37: Installed generation capacities and share in the total generation capacity mix by source in Vision 1 and Vision 3

The following figures show the daily variability, calculated as the difference between the high and low daily generation levels from the variable sources. The variability increase derives from the evolution of the installed capacity, while the minimum and maximum load-factors are expected to remain stable.[1)]

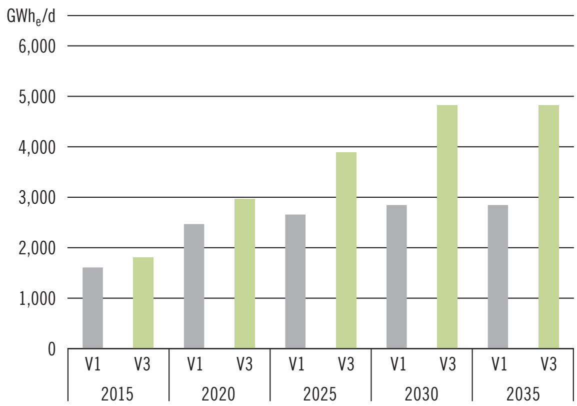


Figure 4.38: Estimated daily variability for wind and solar power.[1)]

MAXIMUM AND MINIMUM WINTER DAILY LOAD-FACTORS FOR THE VARIABLE SOURCES					
Daily load-factor (High) – Winter	**2015**	**2020**	**2025**	**2030**	**2035**
WIND ONSHORE	58 %	58 %	59 %	59 %	59 %
WIND OFFSHORE	74 %	70 %	72 %	72 %	72 %
SOLAR	11 %	11 %	11 %	11 %	11 %
Daily load-factor (Low) – Winter	**2015**	**2020**	**2025**	**2030**	**2035**
WIND ONSHORE	9 %	9 %	9 %	9 %	9 %
WIND OFFSHORE	8 %	8%	8 %	8 %	8 %
SOLAR	2 %	3 %	3 %	3 %	3 %

Table 4.6: Maximum and minimum winter daily load-factors for the variable sources

1) As the graph reflects power generation, it is expressed in electrical units.

Some of the flexibility required to meet the daily variability is provided by hydro pumped storage, reducing the flexibility required from thermal sources. The hydro pumped storage installed generation capacities will increase the flexibility provided by this source by 54 % in Vision 1 and by 82 % in Vision 3 by 2035. The following figure shows the split of the daily variability between sources.

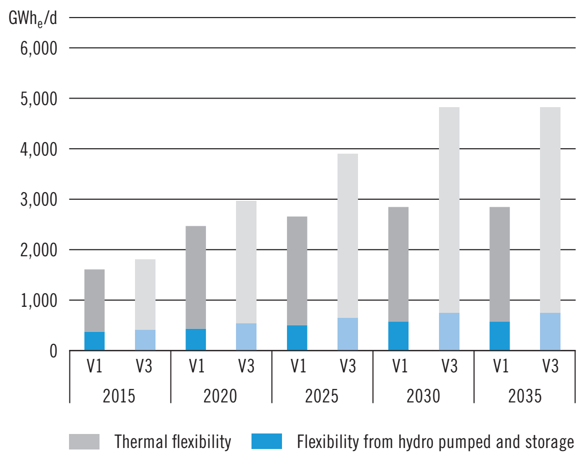


Figure 4.39: Split of the daily variability between hydro pumped storage and thermal sources[1)]

Depending on fuel prices and generators' strategies, the required thermal flexibility could be provided by either coal or gas. The following figure shows the evolution of the daily variability of gas demand in electrical and real quantities associated with variable generation, based on the assumption of a balanced thermal flexibility split between coal and gas. The flexibility provided by gas is likely to be even greater as gas fired (CCGT) power stations are inherently more flexible than coal fired ones.

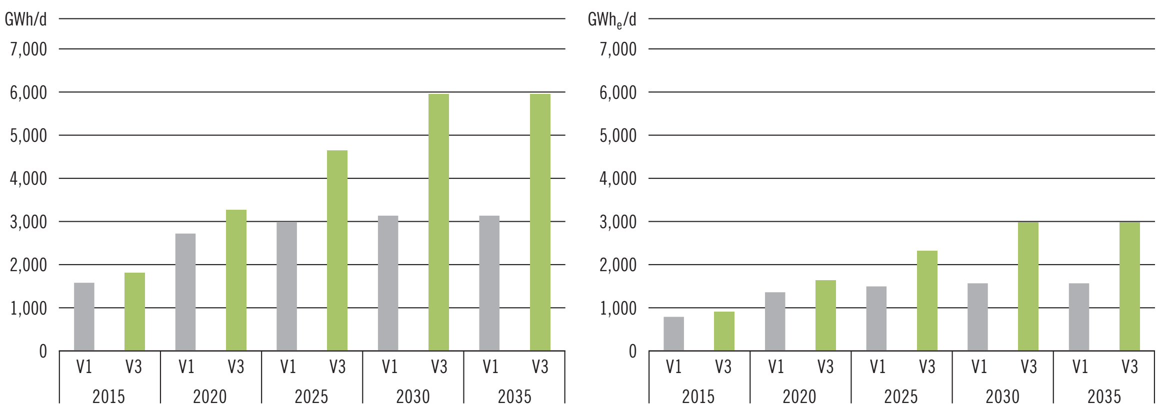


Figure 4.40: Potential variability for Visions 1 and 3 in the daily gas demand (left) and electricity generation from gas (right) as a consequence of RES variability[2)]

To cope with the expected 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 sources of gas. 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.

1) As the graph reflects power generation, it is expressed in electrical units.

2) For the conversion to gas demand 50 % efficiency has been used.

4.4.2 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 ENTSOG's TYNDP is limited to gas, coal and oil in the power generation sector.

While the demand for oil in ENTSOG's scenarios is fixed according to the methodology, the demand for gas and coal depend on market conditions. Consequently, the scenarios include a potential range of demand for both fuels. Two extreme emissions estimates have been defined:

- the high case represents coal predominance
- the lower case represents favorable market conditions for gas over coal

To calculate the emissions in ENTSOG's scenarios, the following emission factors have been used:

CONSIDERED EMISSION FACTORS FOR THE DIFFERENT FUELS FOR POWER GENERATION		
Gas	200	kg/MWh
Coal	350	kg/MWh
Oil	280	kg/MWh

Table 4.7: Considered emission factors for the different fuels for power generation for the variable sources

Annual Emissions have been calculated for the fossil fuel power generation data in the report Energy trends to 2050 from DGENER (update December 2013) using the same emission factors and are shown in the figure below. For simplification purposes, ENTSOG has disregarded emissions associated with the power generation sectors in Cyprus and Malta, as they are not connected with the European gas system under the low infrastructure scenario. ENTSOG scenarios include Switzerland due to its interconnections to EU countries.

As shown in the following, predominant use of gas over coal significantly reduces the CO_2 emissions. A reduction of 23 % in Vision 3 or 36 % in Vision 1 would be required for the period 2035 – 2050, in order to achieve the 2050 emissions target. Despite the high RES in the GREEN scenario, if coal is predominant in filling the thermal gap, the emissions will always be higher than in the DGENER scenario. It should be noted that the gap between the upper and the lower case decreases over time in both scenarios. This is due to decreasing coal-fired power generation installed capacities.

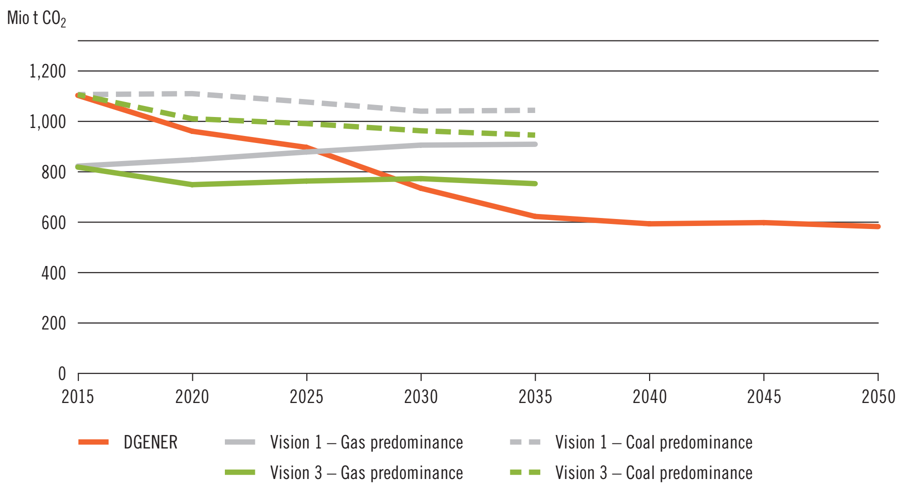


Figure 4.41: Estimated CO_2 emissions from the power generation sector

The following figure compares the cumulative CO_2 emissions curve for the lower cases (gas predominance) with the emissions under the baseline scenario from the DGENER report Energy trends to 2050. Under predominant use of gas over coal, total CO_2 emissions until 2035 are lower for both visions than those under the DGENER's trajectory. The green scenario would mean a 12 % reduction until 2035 of emissions for power generation compared to the DGENER scenario.

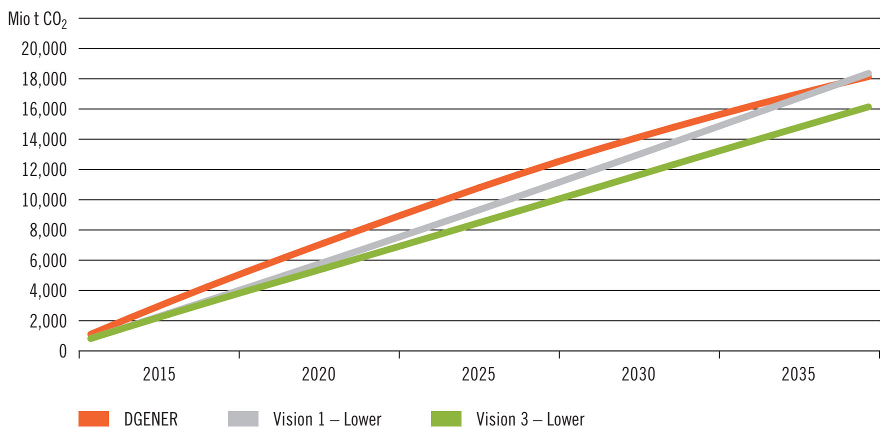


Figure 4.42: Estimated cumulated CO_2 emissions from the power generation sector in the lower case (gas predominance)

4.5 Comparison with other demand outlooks

ENTSOG has considered other demand scenarios to assess the supply/demand balance on an annual basis. Assumptions underlying these scenarios are given below:

IEA New Policies, Current Policies and 450 Scenario (IEA, 2013)

- **New policies (NPS):** national energy strategies following new and existing environmental measures and policies with the support of renewable energy, improvement of energy efficiency, development of alternative fuels and vehicles accompanied by an increase of the carbon price.
- **Current policies (CPS):** national energy strategies following already enacted policies and measures as of mid-2013 and do not implementing new environmental commitments or introducing new. Established trends in energy demand and supply continue. Carbon prices increase in time but remain on a lower level than in the new policies.
- **450 Scenario (450 S):** national energy strategies following a course compatible with a near 50 % change of limiting the long-term increase in the average global temperature to two degrees Celsius. This scenario represents a concentration level of greenhouse gas in the atmosphere which prevails in the middle of this century. Carbon prices assumed to increase 3-times respectively 4-times in comparison to the scenario of the current policies.

Eurogas Long Term Outlook for Gas to 2035: Base Case, Environmental Case and Slow Development Case

- **Base Case:** current national energy strategies and policies are prevailing with little or no future investments in the gas sector in most parts of Europe in the next five to ten years.
- **Environmental Case:** energy strategies focusing on a rebalancing in the energy mix and fostering more renewables and slightly less nuclear energy. Economic growth and a high innovation rate focusing on energy efficiency especially in home gas appliances and office heating characterize this scenario.
- **Slow Development Case:** gas is becoming less competitive as a result of global developments. Environmental policies remain hostile to gas, almost no innovation in energy efficiencies as well as weaker industrial performance in Europe.

DGENER Energy trends to 2050 (update Dec 2013) – Reference Case

This scenario is based on the assumption that the legally binding GHG and RES targets for 2020 will be achieved and that policies on energy efficiency, which were agreed at EU level in spring 2012, will be implemented in the member states. In comparison to the former 2009 update, a faster development in solar and photo voltaic (PV) technologies is expected. Slower developments for carbon capture and storage (CCS) and off-shore wind technologies are assumed. Nuclear power generation and its respective safety and security requirements are treated more tightly as international events such as the Fukushima accident have changed the perception of this technology. This scenario also includes the latest trends on population and economic developments in Europe.

The following figure shows the comparison between the range defined by ENTSOG's scenarios and the different scenarios described above. Most of the scenarios driven by environmental targets (DGENER Energy trends to 2050 and IEA 450 scenario) follow a trend which leads to lower levels than the long term ENTSOG scenario range. The IEA NPS is within the upper range of the ENTSOG's scenarios, whereas the IEA CPS reaches a higher level than the Green scenario post 2028.

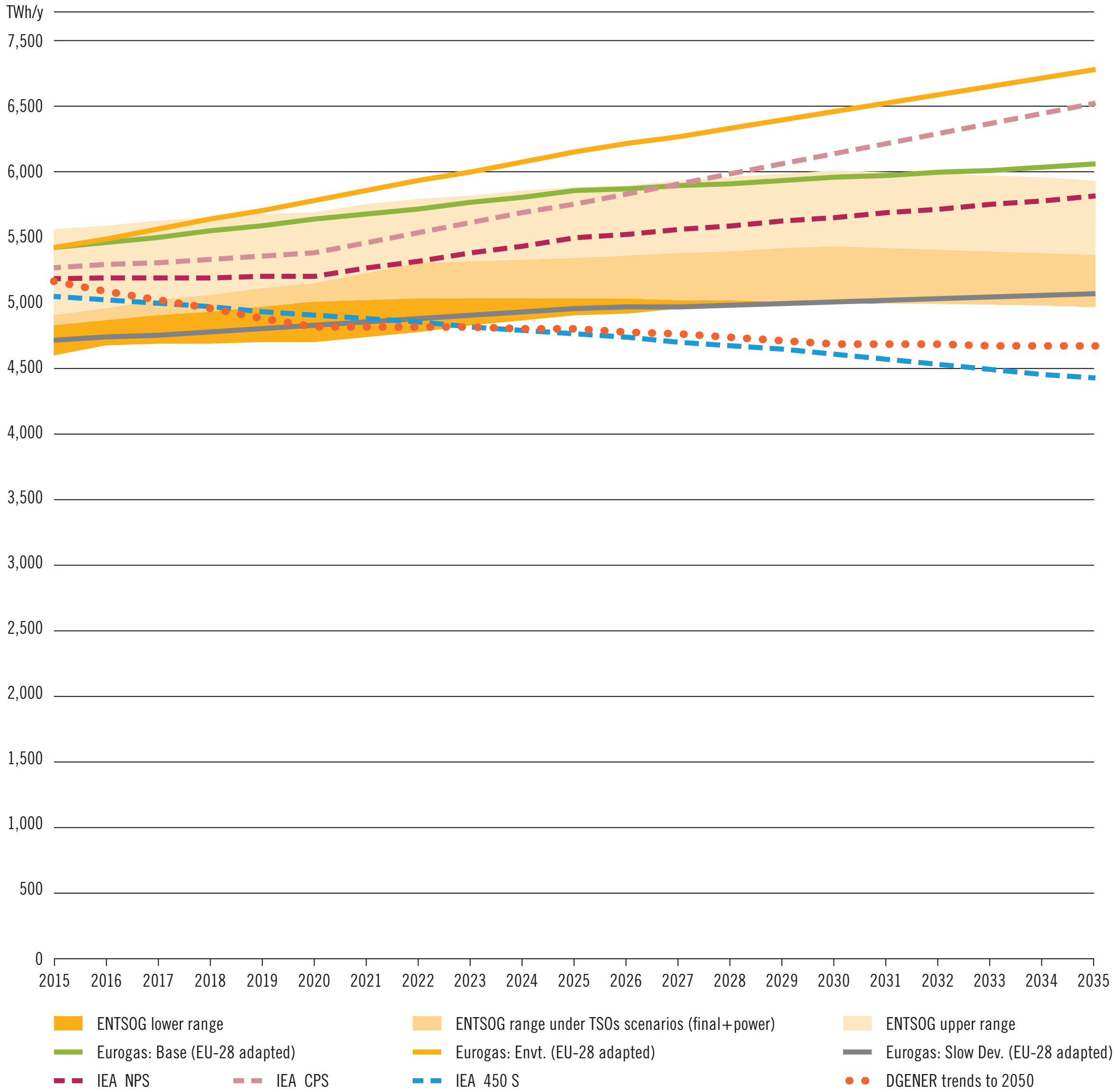


Figure 4.43: Comparison of ENTSOG's gas demand projections with other projections

The demand range (for final and power) in the TSOs' scenario is consistent with the range defined by Eurogas Base case and Slow Development scenarios. The upper range, corresponding to gas predominance in Vision 3 (Green scenario), reaches similar demand levels to the IEA NPS. Eurogas Environmental Case and IEA CPS are above the range defined by ENTSOG's scenarios, while the IEA 450 S and Commission's scenarios are below for the second half of the horizon.

Image courtesy of Fluxys Belgium

5 Supply

Image courtesy of FluxSwiss

5.1 Introduction

Forecasting gas supply exceeds the direct responsibility of most of the TSOs and will always depend on the information made available by other participants along the gas chain. Most of the supply data was collected from public information and as such ENTSOG cannot be held responsible for the accuracy of this data.

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 Algeria, Libya, Norway, Russia and the Caspian[1)] area, and LNG. Whenever a source exports gas through both pipe and LNG, the latter is always reported separately from the overall supply from this source and is gathered in the LNG supply scenario. As a reported supply source, LNG aggregates the potential production of over 20 producing countries including Algeria, Libya, Norway and Russia. With this approach ENTSOG does not disregard the potential diversification of LNG supplies, but recognizes the global nature of the LNG market. The assumption is that, under a perfectly-functioning LNG market, the same pricing mechanism would apply equally to all the LNG arriving to Europe, irrespective of the country of origin and destination.

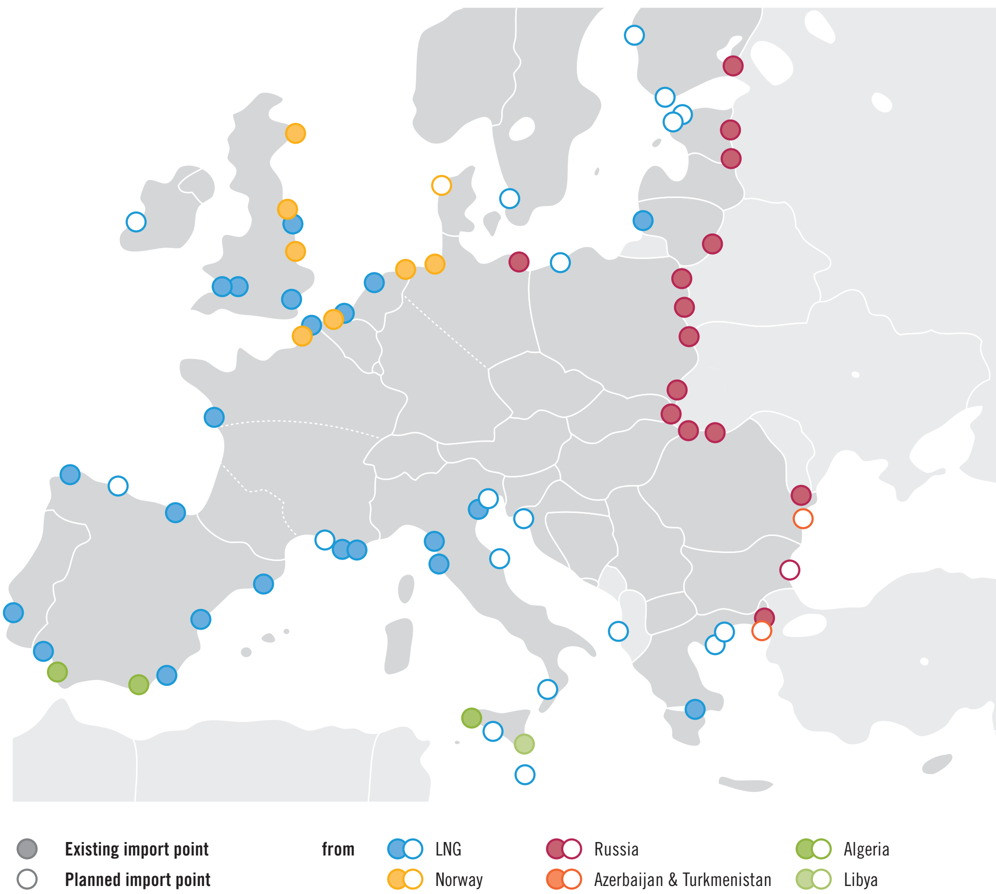


Figure 5.1: Existing and new import sources and routes[2)]

1) Due to the different status of the projects supplying gas from the Caspian area, a further differentiation between Azerbaijan and Turkmenistan sources has been applied.

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

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:

EXISTING IMPORT ROUTES OF GAS

Source	Route	Sub-route
LNG	United Kingdom	
	The Netherlands	
	Belgium	
	France	
	Spain	
	Portugal	
	Italy	
	Greece	
	Poland	
NORWAY	United Kingdom	
	Germany	
	The Netherlands	
	France	
	Belgium	

Source	Route	Sub-route
RUSSIA	Finland	
	Germany	
	Estonia	
	Latvia	
	Belarus	Lithuania
		Poland
	Ukraine	Poland
		Slovakia
		Hungary
		Romania
ALGERIA	Spain	
	Italy	
LIBYA	Italy	

Table 5.1: Existing import routes of gas[1]

1) Note that some of the projects will imply the definition of a new route


Image courtesy of Snam Rete Gas

5.2 Historic supply trend

5.2.1 EVOLUTION AT SOURCE LEVEL

The following tables illustrate the continuous decline of European indigenous production during the last ten years 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, mainly in the power generation sector.

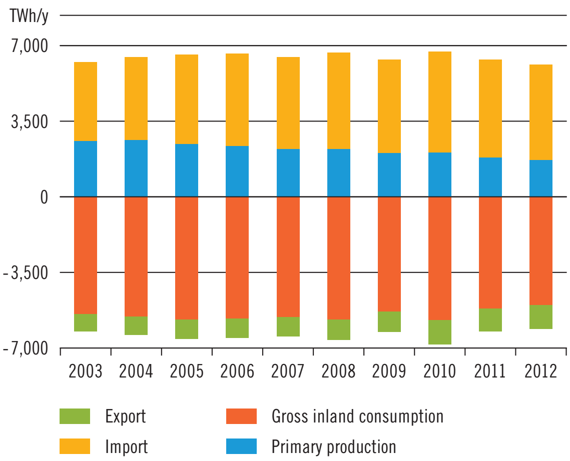


Figure 5.2: European gas balance: Entries vs Exits[1] 2003–2012 (Source Eurostat)

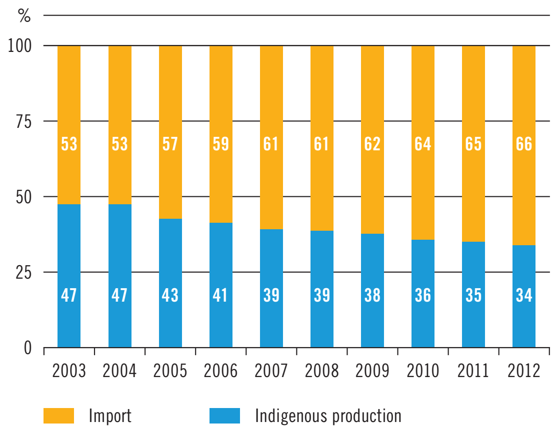


Figure 5.3: Evolution of indigenous production vs. import 2003–2012 (Source Eurostat)

Below figures show the evolution of the imports from the different sources during the last five 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 changes in the global LNG market.

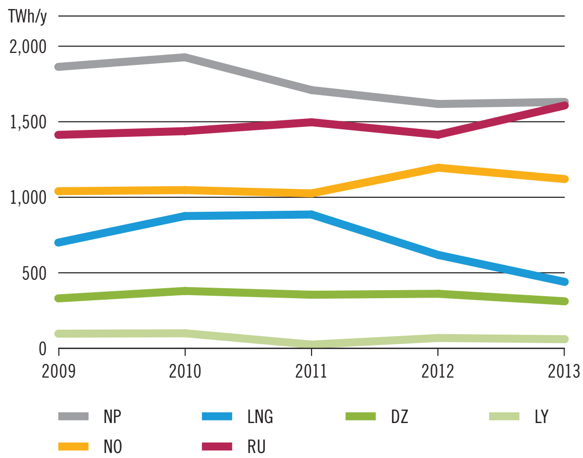


Figure 5.4: Evolution of imports 2009–2013

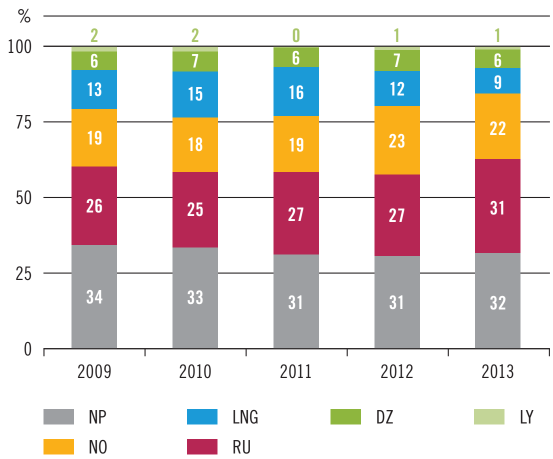


Figure 5.5: Evolution of supply shares 2009–2013

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

The following figures show 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.

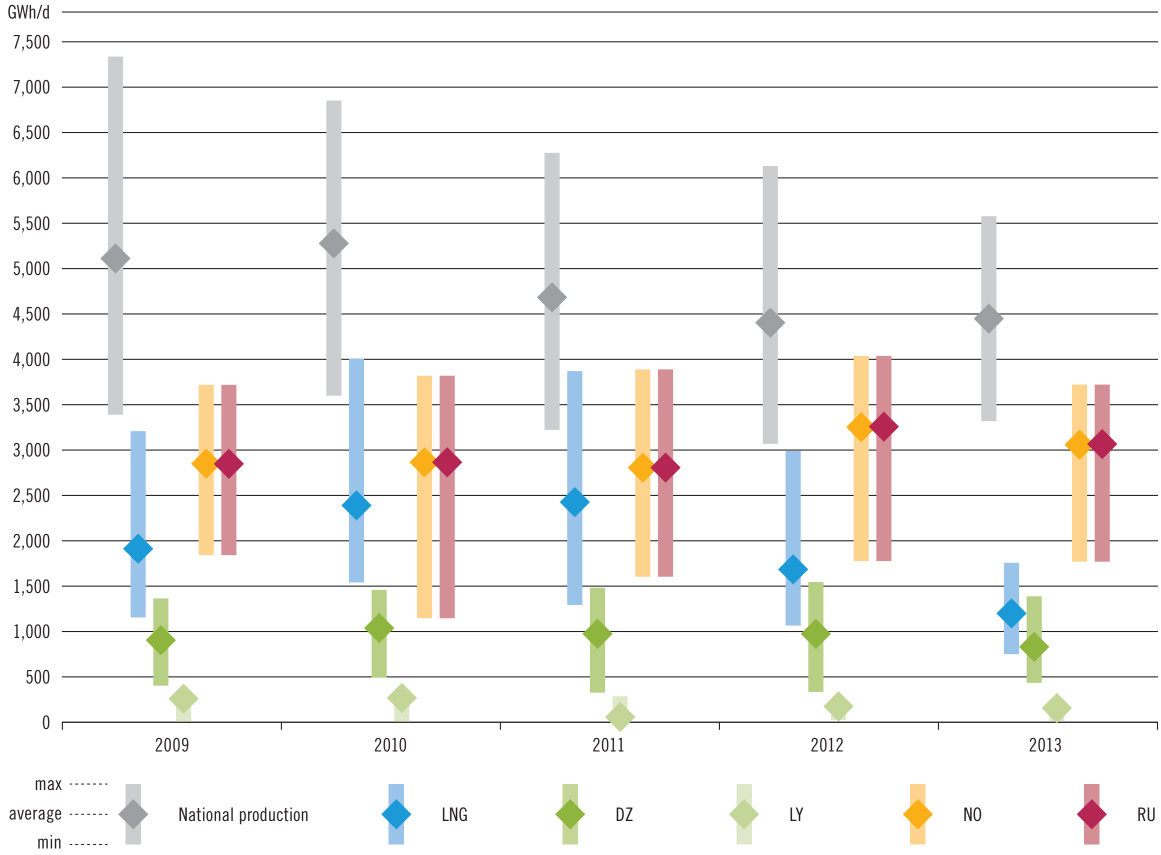


Figure 5.6: Daily flexibility (max, average, min)

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

5.2.2 EVOLUTION AT IMPORT ROUTE LEVEL

5.2.2.1 LNG import routes

The split of the supplies of each source 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 50 % in 2013 ranging from 39 % in Italy to 72 % in Belgium.

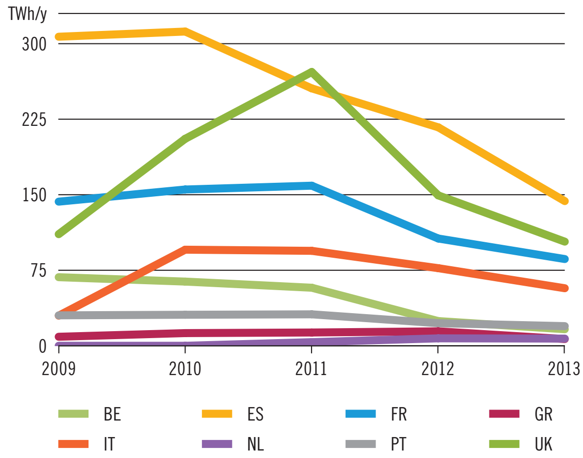


Figure 5.7: Split of the European LNG supply by route 2009–2013

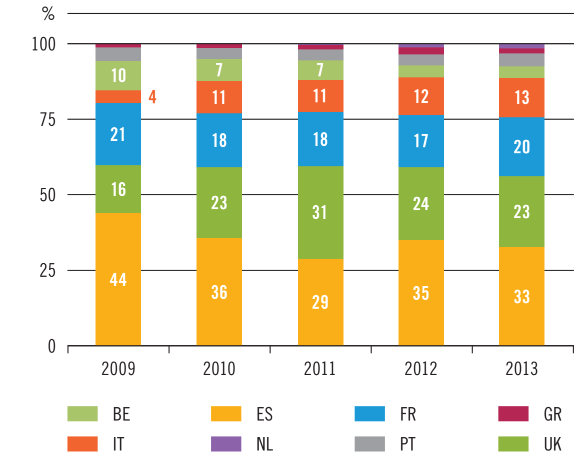


Figure 5.8: Shares of LNG import routes 2009–2013

The re-export of LNG cargoes significantly increased over the last three years in Europe. In 2012 Belgium re-exported around 39 %, Spain 9.5 % and Portugal 4 % of the LNG initially imported. In 2013, the figures increased up to 48 % for Belgium, 18 % for Spain and 15 % for Portugal[1]. This shows the functioning of the LNG market where high prices in Asia attract cargoes despite the existence of European destination clauses.

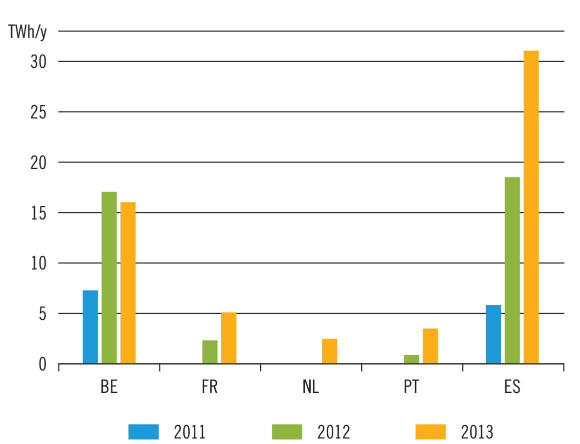


Figure 5.9: Split of European LNG re-exported in energy (Own depiction, based on data from GIIGNL)

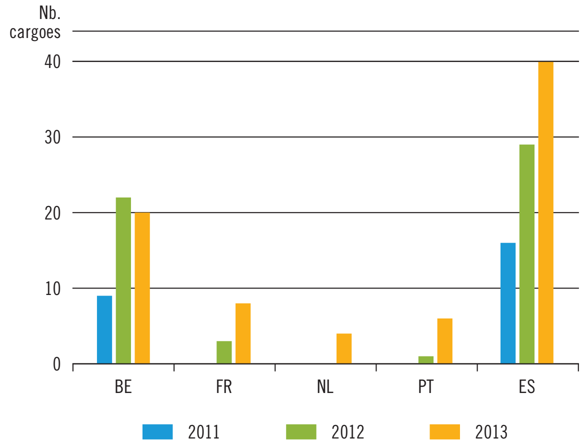


Figure 5.10: Split of European LNG re-exported cargoes (Own depiction, based on data from GIIGNL)

1) According to GIIGNL data

5.2.2.2 Algerian pipeline gas import routes

In 2013, the pipeline imports from Algeria were 18 % lower than the maximum registered in 2010. This decrease results from diverging evolution of exports to Italy (52 % decrease) and to Spain (77 % increase partly linked to the new MEDGAZ route). As a consequence the Italian route only represents 42 % of Algerian pipe imports compared to the 69 % back in 2009.

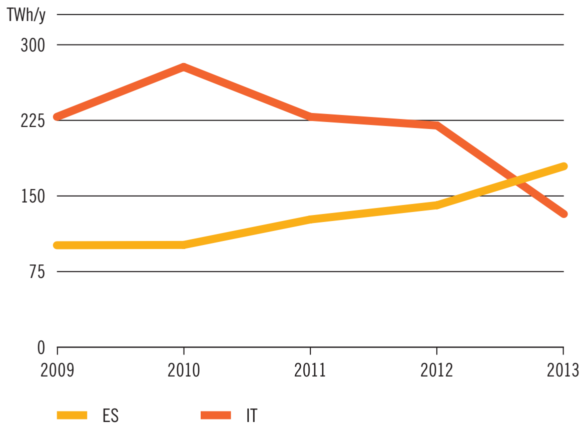


Figure 5.11: Split of the European Algerian supply by route 2009 – 2013

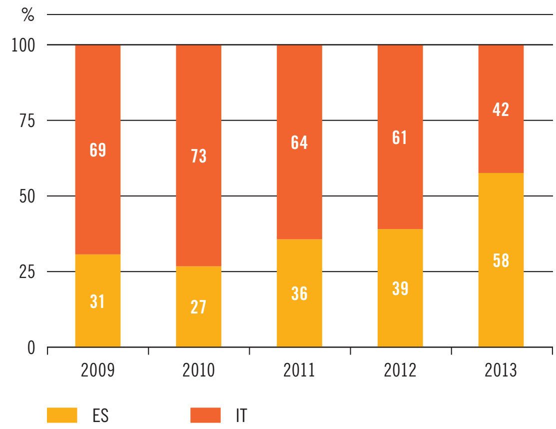


Figure 5.12: Shares of Algerian import routes 2009 – 2013

5.2.2.3 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. It derives from a combination of lower demand in the UK and increased LNG imports into the UK and Belgium.

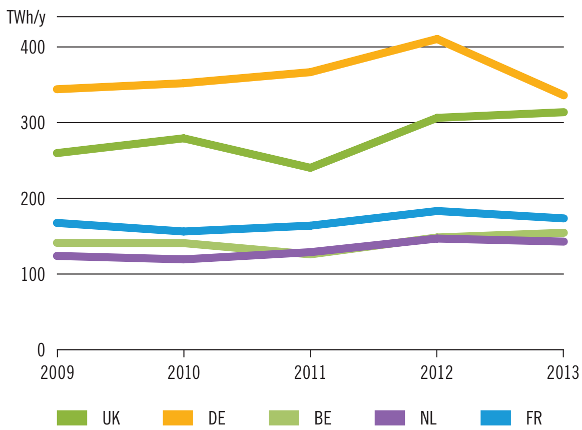


Figure 5.13: Split of the Norwegian supply by route 2009 – 2013

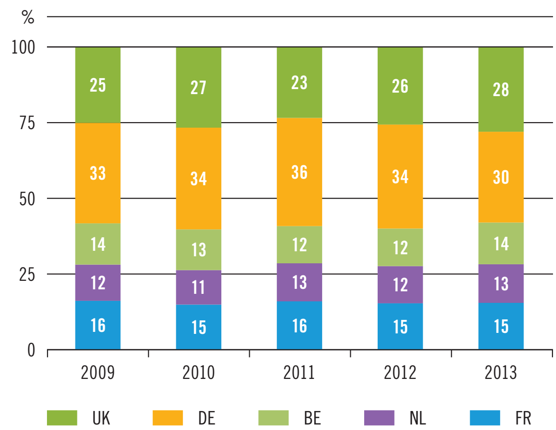


Figure 5.14: Shares of Norwegian import routes 2009 – 2013

5.2.2.4 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 transited 55 % of the total Russian imports in 2013.

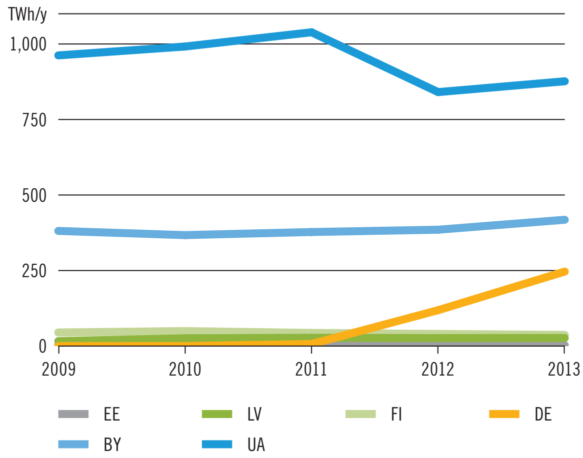


Figure 5.15: Split of the Russian supplies by route 2009 – 2013

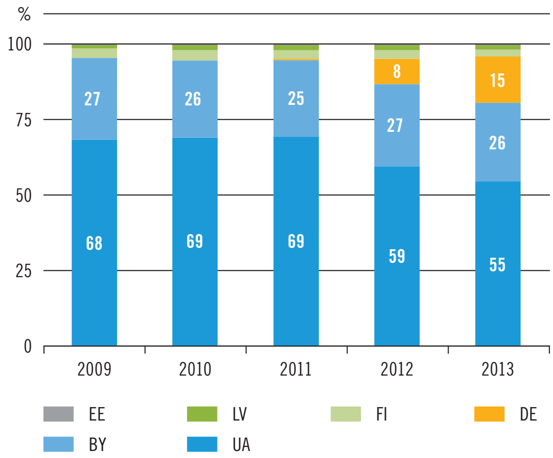


Figure 5.16: Shares of Russian import routes 2009 – 2013

5.3 Supply scenarios

For the purpose of this Report a supply scenario defines 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, intermediate and maximum scenarios have been defined for each source. The development of such scenarios is based on literature, reports, daily news and members' and stakeholders' feedback.

These scenarios cover both:

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

It is important to highlight that all potential gas supplies are regarded as pipeline bounded gas supplies except LNG. In each scenario 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 scenario is developed independently and no specific likelihood is defined.

5.3.1 INDIGENOUS PRODUCTION

This section covers the national production of gas from EU countries plus Bosnia, FYROM, Serbia and Switzerland. Such production covers conventional sources, shale gas and biomethane.

5.3.1.1 Conventional sources

Conventional gas production in Europe decreased by 17 % between 2010 and 2013. The evolution was not homogeneous. Production increased significantly in Bulgaria and slightly in the Czech Republic, Slovakia and Romania. The decrease of UK indigenous production by 39 % since 2009 accounted for almost all of the decline in the EU over the period.

Based on TSO information, it is expected that the EU indigenous production will decrease significantly over the next 20 years. This decrease could be slightly mitigated with the development of production fields in Cyprus[1] and in the Romanian sector of the Black Sea. Given the uncertainty of such developments, associated production is considered as Non-FID and is included only in the High Infrastructure Scenario (see Annex F).

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.

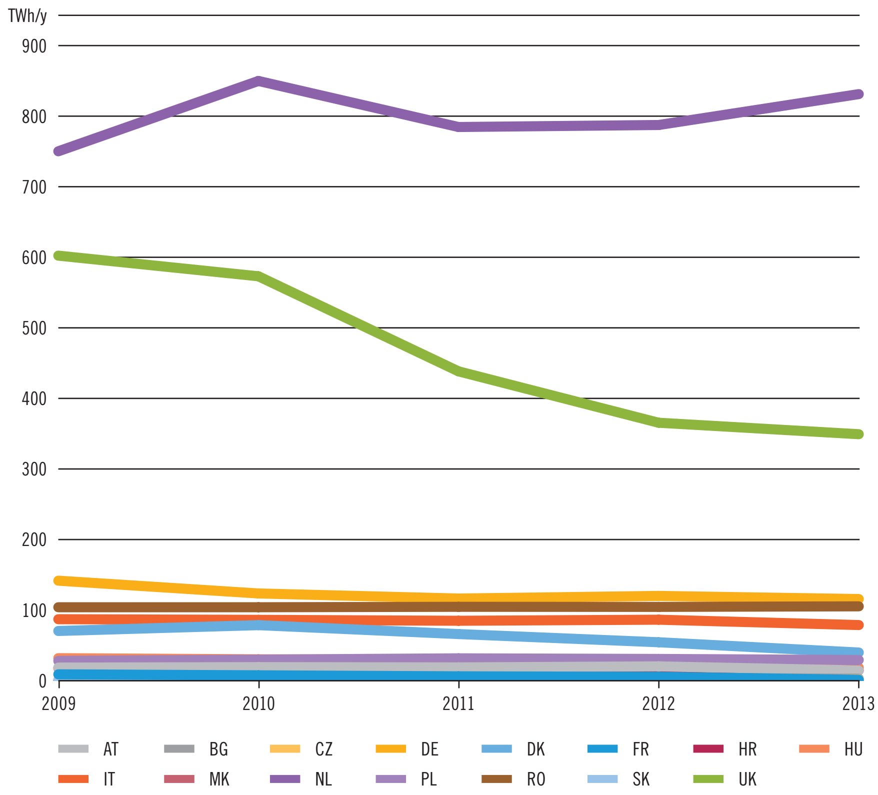


Figure 5.17: EU indigenous production 2009–2013. Country detail.

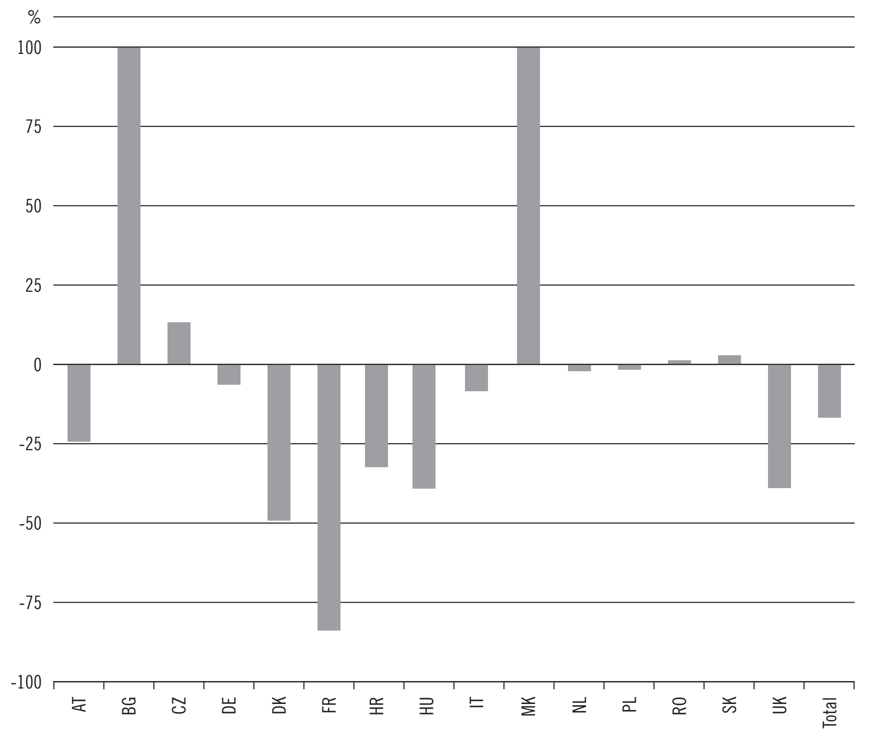


Figure 5.18: Evolution of EU indigenous production (%) between 2010 and 2013. Country detail.

Next figure shows that EU conventional production could decrease by 60 % by 2035 or even by 68 % if the Non-FID developments are not commissioned.

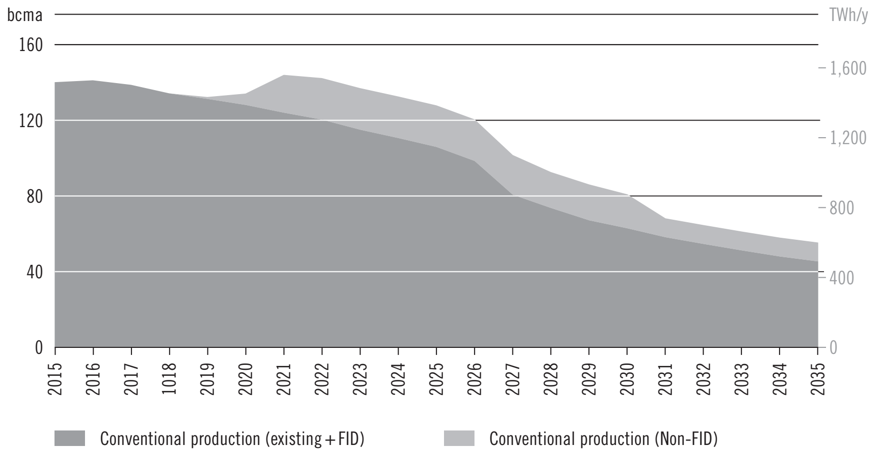


Figure 5.19: Potential of EU conventional production 2015 – 2035

Figures 5.20 to 5.23 show the potential evolution of conventional production by country. From 2030 the production in the Netherlands and the UK would decrease more significantly than in other countries in the absence of new discoveries.

The development of off-shore production would result in Romania significantly increasing its share of the EU conventional production from 2025. After 2030 Cyprus could become the third biggest EU producer after the Netherlands and the UK.

Conventional gas scenarios

As a difference with other supply sources being import or unconventional indigenous production, there is less uncertainty on the evolution of European conventional production. The main uncertainty is related to the development of the necessary infrastructures to connect these fields to the rest of the European gas system. For this reason there is one conventional gas scenario defined by Infrastructure Scenario:

- Low Infrastructure Scenario: TSOs' best estimates excluding Romanian Black Sea and Cyprus offshore production
- PCI Infrastructure Scenario: same as Low Infrastructure Scenario plus Cyprus offshore production
- High Infrastructure Scenario: same as PCI Infrastructure Scenario plus Romanian Black Sea production

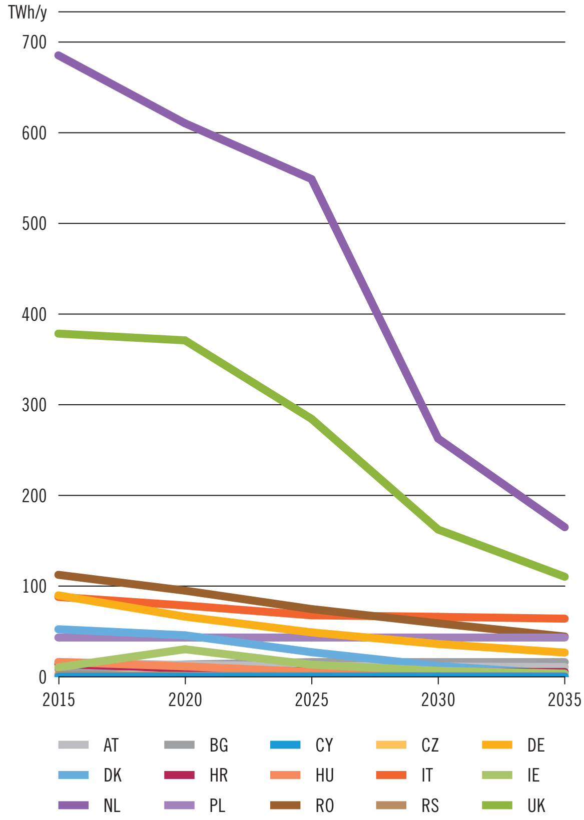


Figure 5.20: Potential of EU conventional production (excl. non-FID) 2015–2035

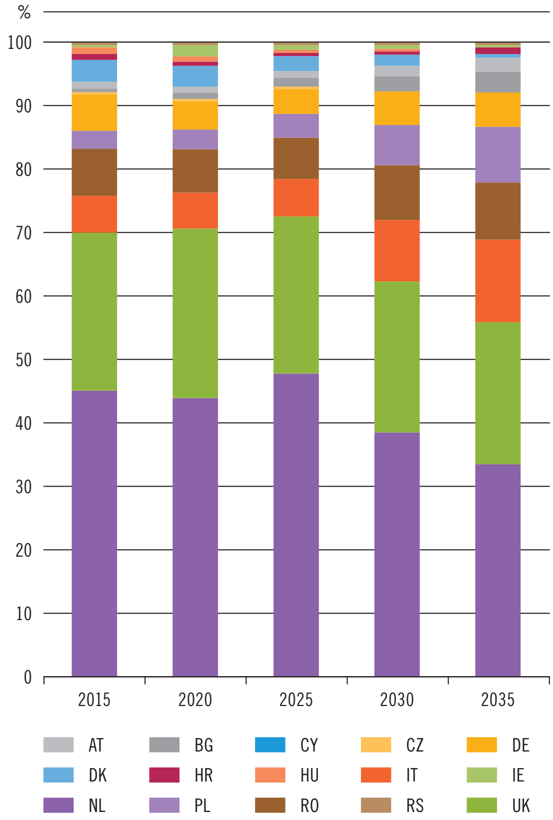


Figure 5.21: Shares of EU potential conventional production (excl. non-FID) 2015–2035

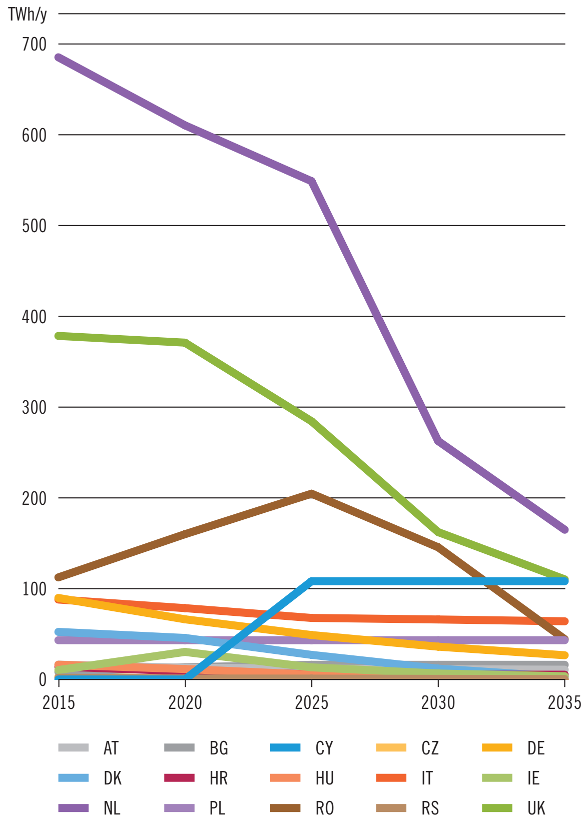


Figure 5.22: Potential of EU conventional production (incl. non-FID) 2015–2035

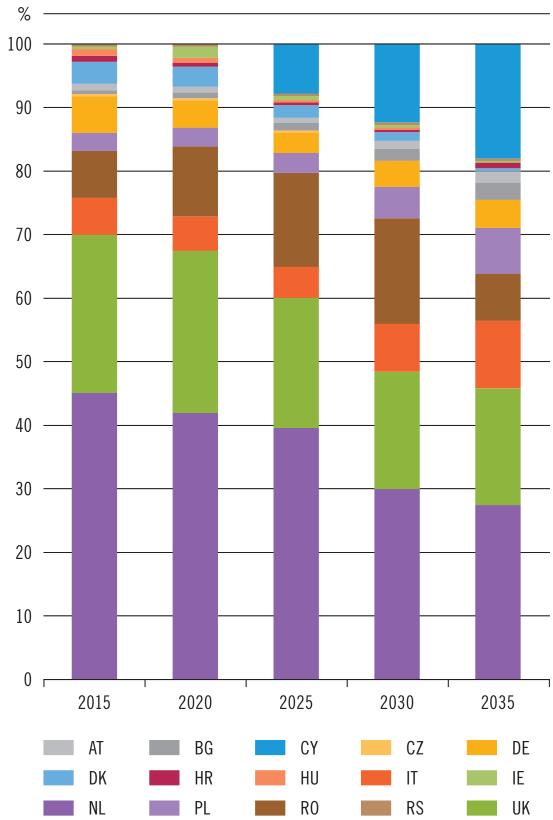


Figure 5.23: Shares of EU potential conventional production (incl. non-FID) 2015–2035

5.3.1.2 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 10,000 bcm (88,000 – 110,000 TWh) in their "Some Shale Gas" and "Boom Shale Gas" scenarios. These figures can be compared with the annual European gas demand (449 bcm / 4,939 TWh in 2013) and US recoverable resources (around 18,800 bcm[1]).

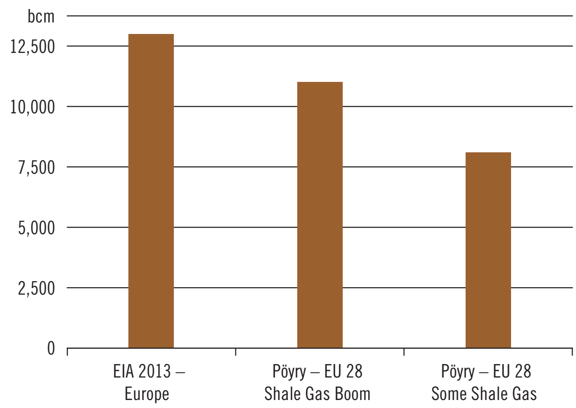


Figure 5.24: Technically recoverable shale gas resources in the EU (own depiction based on Pöyry 2013 "Macroeconomic Effects of European Shale Gas Production")

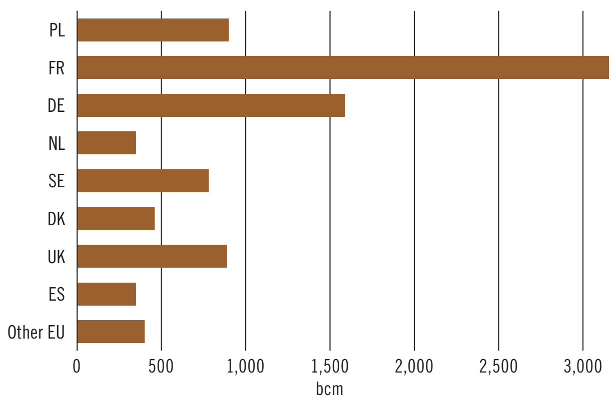


Figure 5.25: Technically recoverable shale gas in EU (source Pöyry "Some Shale Gas" scenario)

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. For example France and Bulgaria have taken measures preventing exploration and production whereas appraisal wells have already been drilled in Poland and the UK. In parallel some Member States are working on establishing a national consensus on a legislative framework covering fracking and the associated environmental impacts.

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

Shale gas supply scenarios

To determine potential shale gas production for its scenarios, 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, the below scenarios are only taken into account in the High Infrastructure Scenario.

Maximum shale gas scenario

Given the uncertainty surrounding EU shale gas production, this scenario 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.

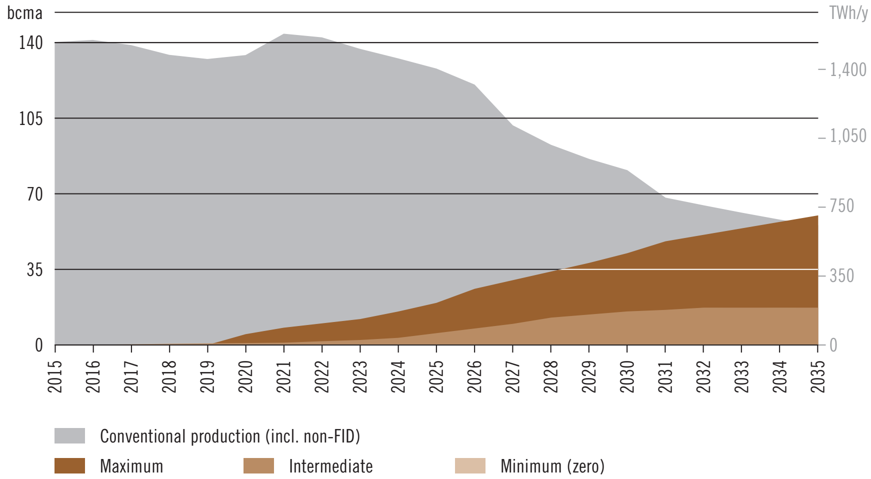
Intermediate shale gas scenario

This scenario is based on the data from TSOs estimates of shale gas production, collected by ENTSOG in July 2014. It should be noted that several TSOs have not been able to provide data on shale gas production in their countries. In such case no production has been included.

Minimum shale gas scenario

This scenario is based on no shale gas being developed in Europe in the upcoming years due to the high uncertainty. This implication is based on the current weak results of shale gas extraction in Europe, difficult geological formations, the lack of available trained staff and technologies in Europe, and also public and governmental opposition due to the risks associated to the extraction technics.


Image: iStockphoto.com



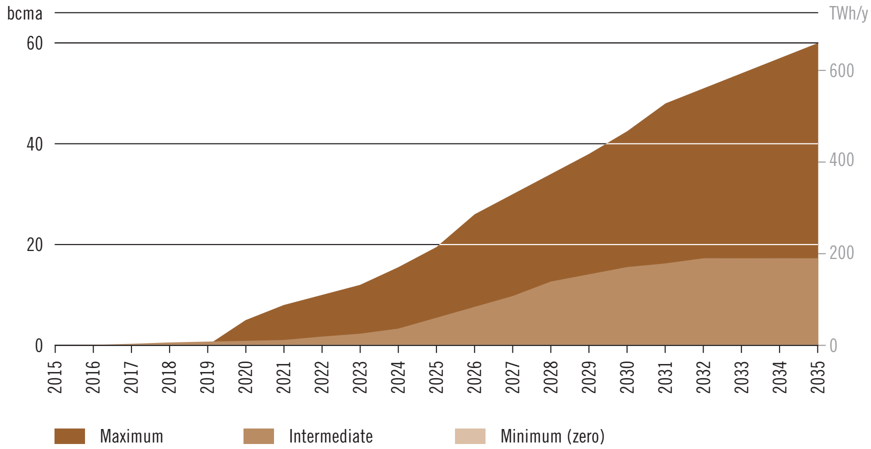


Figure 5.26: Potential scenarios for shale gas
(in comparison with/without conventional production)

POTENTIAL SCENARIOS FOR SHALE GAS					
GWh/d	**2015**	**2020**	**2025**	**2030**	**2035**
MAXIMUM	0	149	579	1,262	1,782
INTERMEDIATE	0	26	163	461	513
MINIMUM	0	0	0	0	0

Table 5.2: Potential scenarios for shale gas

4.3.1.3 Biomethane

Biomethane is biogas with natural gas quality after processing. 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 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.

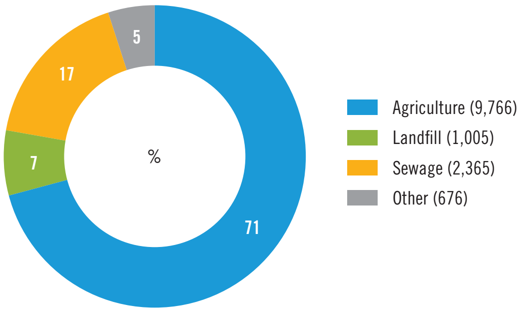


Figure 5.27: European biogas plants by source in January 2014 (Source European Biogas Association).

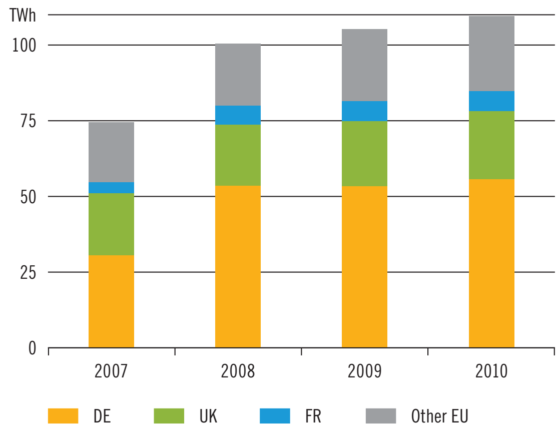


Figure 5.28: Evolution of biogas production in Europe (own depiction, source Eurobserv'ER, INSEE 2011)

In 2013 biomethane was produced from over 230 upgrading plants in 14 countries with injection into the transmission or distribution grids in 11 countries[1]. The current annual production of unblended biogas in Europe is approximately 14 bcm in natural gas equivalent (154 TWh) with expected production levels of 28 bcm (308 TWh) in 2020 according to the National Renewable Energy Actions Plans[2]. Currently Germany, Austria and Denmark produce most of their biogas from agricultural plants whereas the UK, Italy, France and Spain predominantly use landfill gas. According to the European Biogas Association, by 2030 40 % of the produced biogas is expected to be upgraded to biomethane. The specific nature of biogas means there is no concept of an existing reserve as volume will depend on future availability of raw materials.

Biomethane supply scenarios

These scenarios only cover the share of biogas upgraded to biomethane as only this proportion can be injected into the distribution or transmission grids. In creating the three following scenarios ENTSOG has used TSO estimates of July 2014 and the 2013 Green Gas Grids report from the European Biogas Association[3]. Due to the high uncertainty in the development of biogas and its injection into the networks ENTSOG has decided to define a wide range in its scenarios and to consider such potential only in the High Infrastructure Scenario.

1) AT, CH, DE, DK, FI, FR, LU, NL, NO, SE and UK

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

Maximum scenario

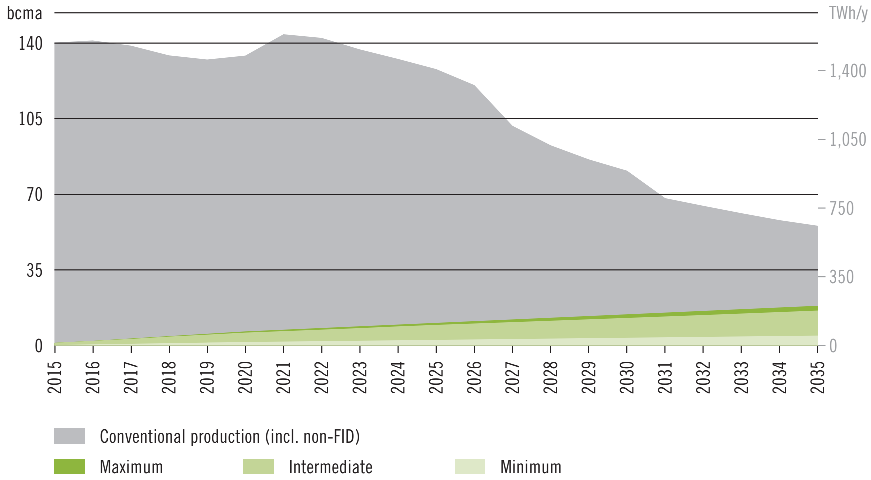
Following consultation with stakeholders, ENTSOG has applied a 80 % limiting factor to the 2013 Green Gas Grids projections.

Intermediate scenario

The intermediate scenario is based on TSO estimates of biomethane injection in gas grids. It should be noted that several TSOs have not been able to provide data on biogas production in their countries. In such case no production has been included.

Minimum scenario

Following consultation with stakeholders, ENTSOG has applied a 20 % limiting factor to the 2013 Green Gas Grids projections.



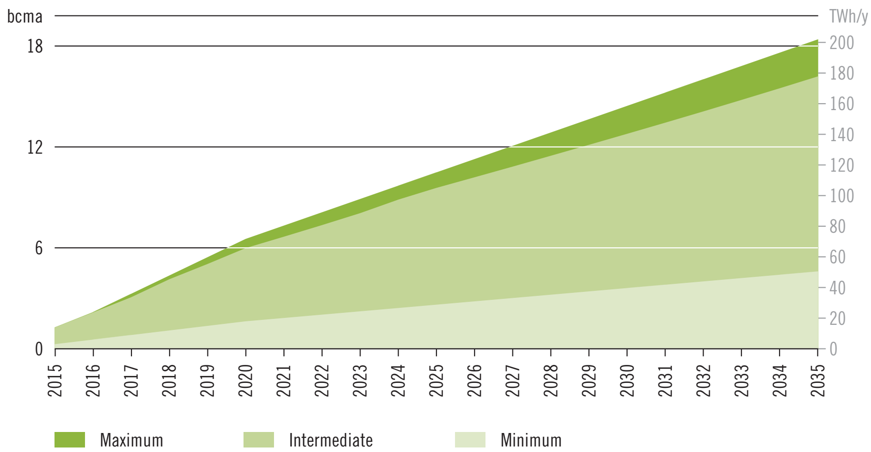


Figure 5.29: Potential scenarios for biomethane (in comparison with/without conventional production)

POTENTIAL SCENARIOS FOR BIOMETHANE

GWh/d	2015	2020	2025	2030	2035
MAXIMUM	32	194	311	429	547
INTERMEDIATE	32	178	284	380	481
MINIMUM	8	48	78	107	137

Table 5.3: Potential scenarios for biomethane

According to the TSO estimates, the largest share of biomethane injection will take place in France, reaching up to 60 % in 2035. This high share derives from a biomethane orientation in France which considers the possible development of a second (biomass gasification) and third (micro algae) generation processes of production. In 2035 France, United Kingdom, Germany, Denmark and the Netherlands would account for over 95 % of biogas supply.

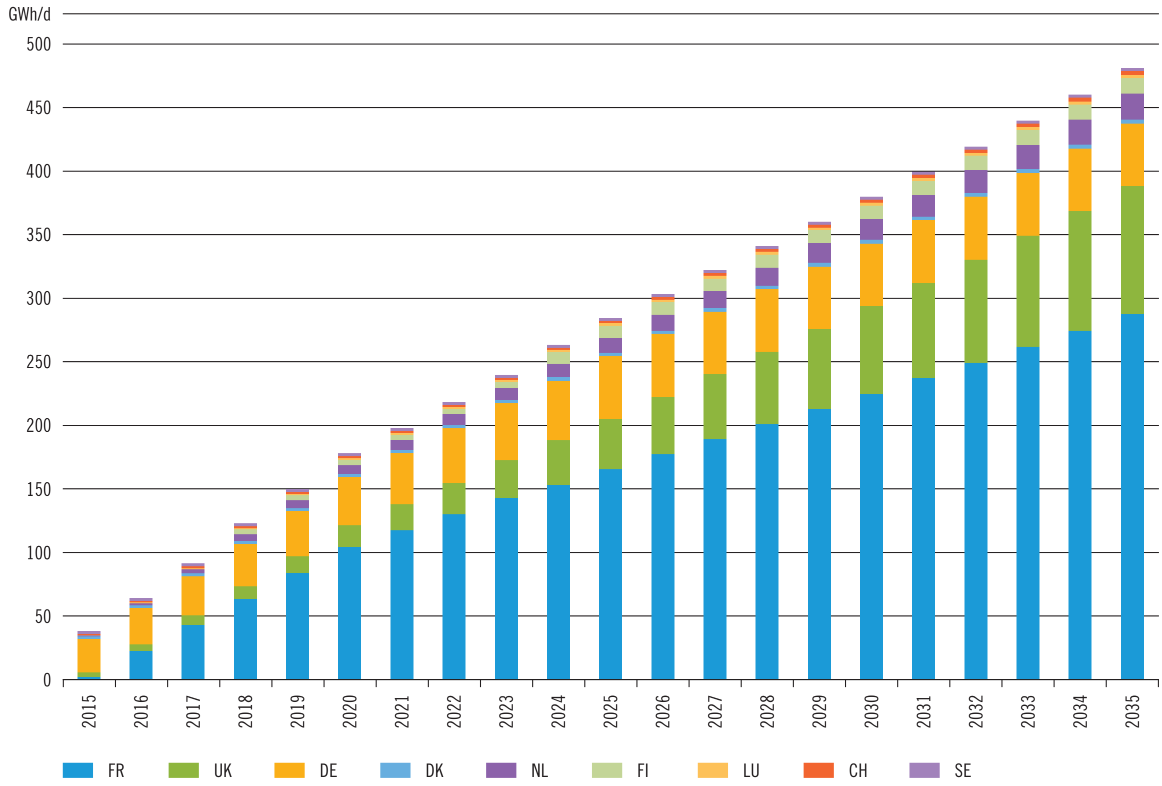


Figure 5.30: Biomethane intermediate potential scenario (split by country)

5.3.2 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. Upstream investments in these 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 materialize 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 through LNG. In addition a change in the share of sources or the introduction of new ones may require some adaptation of the European gas infrastructures.

5.3.2.1 Russia

Russia is currently the main gas supplier of the EU, providing an average daily delivery of 4,344 GWh/d representing 1,586 TWh (146 bcm) in 2013. It is expected to remain a major import source on the whole time horizon of this Report. Beyond the usual uncertainty related to production, European market could be on the medium term in competition with Russian demand and other export destinations such as China.

Reserves

Russia has the second largest proven gas reserves in the world behind Iran with 31,300 bcm at the end of 2013[1]. In the last decade the proved gas reserves of Russia slightly increased (+5 % between 2000 and 2013). Most of the reserves are located in Siberia with Urengoy, Yamburg and Medvezhye being the largest fields.

Production

In 2013, Russia was the second largest natural gas producer of the world behind the United States with 688 bcma. In the period 2003 – 2013 the natural gas production of Russia was around 600 bcma. The only exception was in 2009 with a decrease that could be linked to the economic down-turn and the Ukraine transit disruption.

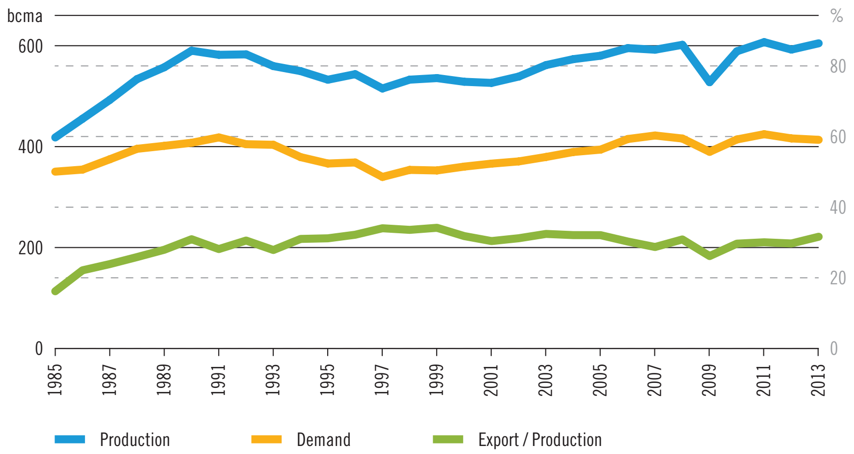


Figure 5.31: Natural gas production of Russia (source BP Statistical Review 2014)

As a difference with Norway, Russia has its own domestic demand that can influence its export potential. This internal demand of Russia remains stable around 400 bcma.

1) BP statistical review of world energy 2014.

Exports

Gas is exported to Europe through three main pipelines:

- **Nord Stream:** it is a 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[1].
- **Yamal-Europe I:** it 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[2].
- **Brotherhood (Urengoy-Uzhgorod pipeline):** it entered into operation in 1967 and it is the largest gas pipeline route from Russia to Europe. 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[3].

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

- **Blue Stream:** is 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 bcm.
- **North Caucasus:** it carries Russian gas to Georgia and Armenia and its annual capacity is around 10 bcm.
- **Gazi-Magomed-Mozdok:** it runs 640 km long between 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 bcm of gas per year from Azerbaijan to Russia.

In the last five years the largest recipients of Russian pipeline exports in the European Union were Germany and Italy. In 2013, these two countries amounted for 40 % of the 136 bcm of Russian gas imported into Europe. Outside the European Union the largest recipients were Turkey, Ukraine and Belarus.

Besides the pipeline exports, 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 2013 Russia exported around 14 bcm of liquefied natural gas. However, in comparison to the EU pipeline-bounded gas exports it is still a small amount (10.5 %). The Yamal and Shtokman LNG projects could increase the LNG export of Russia in the future but nowadays these projects are still uncertain.

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 through a 4,000 km long pipeline running from Eastern Siberia to Vladivostok. Even when this project is shared by the two stated owned companies Gazprom and CNPC, the investments are colossal[4] and first construction works have not yet started.

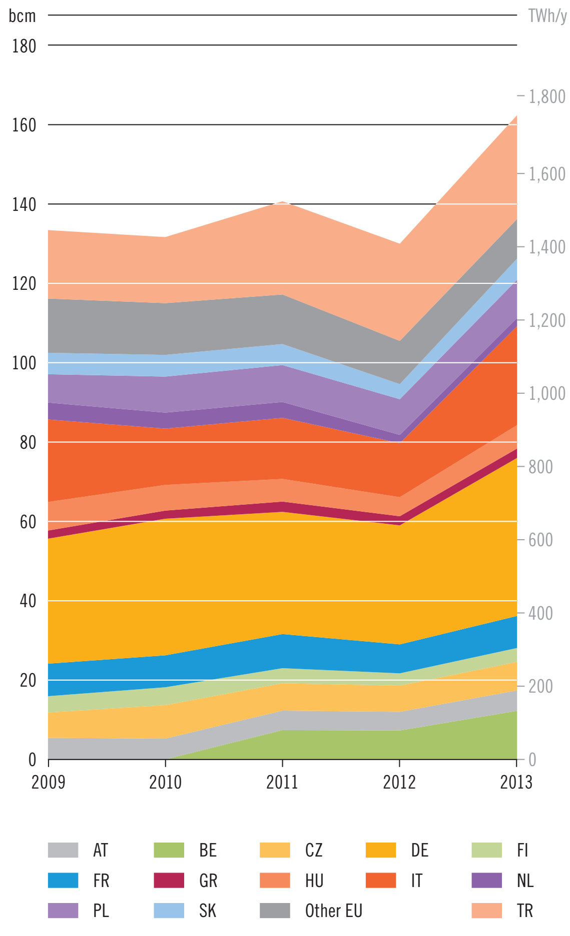


Figure 5.32: Russian natural gas trade movements by pipeline (source BP Statistical Review 2014)

1), 2), 3) According to Gazprom Export website.

4) According to official Russian and Chinese information overall cost could be around $ 75 billion with a $ 55 billion share for the Russia and a $ 20 billion share for China.

Supply scenarios

While the supply scenarios for Russia considered in TYDNP 2013 were based on the Russian Energy Strategy, the new scenarios are taken from different sources. The resulting figures are not so distant from the previous ones. A detailed comparison is shown in Annex C5.

Maximum Russian pipe gas scenario

This scenario 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 2035 are derived from the 2005–2030 trend.

Intermediate Russian pipe gas scenario

This scenario is the average of the maximum and minimum scenarios.

Minimum Russian pipe gas scenario

This scenario was taken from a presentation by the Russian Academy of Science[1)] which represents the contracted volumes of Russian gas by Europe. This source defines both the annual contracted quantities (ranging from 180 bcma in 2013 to near 120 bcma in 2030) and the minimum contracted quantities (around the 85 % of the annual contracted quantities). The latters were the ones used to define the minimum scenario.

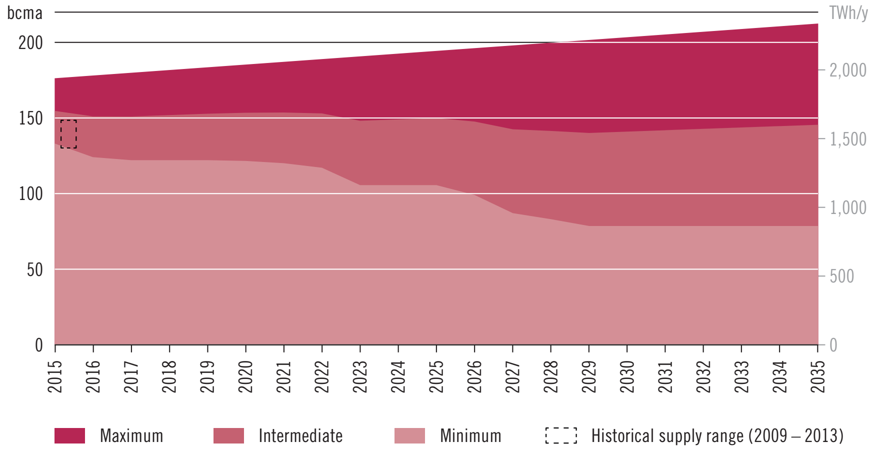


Figure 5.33: Potential pipeline gas scenarios from Russia

POTENTIAL PIPELINE GAS SCENARIOS FROM RUSSIA					
GWh/d	**2015**	**2020**	**2025**	**2030**	**2035**
MAXIMUM	5,177	5,499	5,768	6,036	6,304
INTERMEDIATE	4,549	4,554	4,450	4,184	4,318
MINIMUM	3,920	3,609	3,133	2,331	2,331

Table 5.4: Potential pipeline gas scenarios from Russia

1) Energy Research Institute of the Russian Academy of Science, Tatiana Mitrova, January 2014.

5.3.2.2 Norway

Norway is currently the second largest gas supplier of the EU, providing an average daily delivery of 3,000 GWh/d representing 1,100 TWh (100 bcm) in 2013. It is expected to remain a key import source well into the 2020s. Further out there is uncertainty over the level of Norwegian gas that can be still produced from declining existing fields. That means that new discoveries are required to replace these volumes.

Norwegian gas is exported via a well-developed offshore pipeline network connecting Germany, UK, France, the Netherlands and Belgium. In addition to these countries the gas is also exported through the European pipeline network into Spain, Italy, Czech Republic, and Austria amongst others.

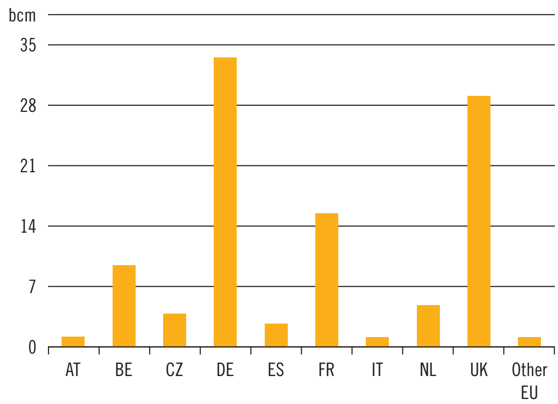


Figure 5.34: Norwegian pipeline exports by destination in 2013 (Source BP Statistical Review 2014)

EXPORT CAPACITY OF THE GASSCO OFFSHORE SYSTEM		
Pipeline	**Country**	**Capacity (million sm³/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 5.5: Export capacity of the Gassco offshore system (Source Gassco website)

Reserves

Norway has been supplying natural gas to Europe for over 40 years since production began in the early 1970s. Since then, the development of new fields has enabled the continuous increase of volume exported by Norway. However for the past decade the sold and delivered volumes have progressed faster than new discoveries (Reserves and contingent resources[1)]). Currently more than half of the reserves still remain but the overall production is expected to fall below current levels during the 21-year time horizon of this Report.

One of the main challenges for Norway is to decide about the most beneficial way to export the future Barents Sea production. An economical way would be to expend the offshore network to connect these new fields to the existing grid and export this production to Europe. For this solution to materialize, strong signals from European market are expected. Otherwise production is likely to be exported to the global market as LNG.

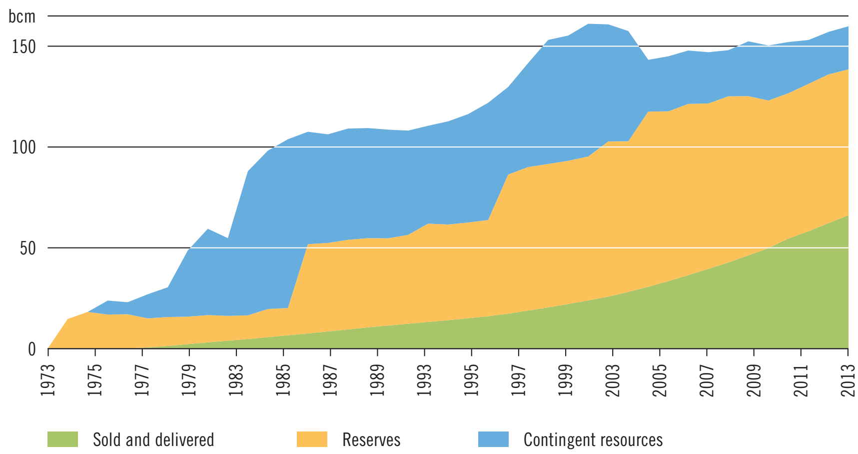


Figure 5.35: Evolution of Norwegian gas reserves 1973–2013 (Source Gassco website)

Supply Scenarios

The supply scenarios define a possible range of Norwegian gas exports to Europe by pipeline; exports via LNG are part of the LNG analysis later in this Report. The Norwegian supply scenarios 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 scenario represents the highest export case defined by the NPD/MPE and Gassco for the period until 2028 (undiscovered resources not included). To assess a plausible maximum for Norwegian supplies until 2035 ENTSOG has maintained volumes at the 2028 level.

Intermediate Norwegian pipeline gas scenario

This scenario is the average of the maximum and minimum scenarios.

Minimum Norwegian pipeline gas scenarios

This scenario represents the lowest export case defined by the NPD/MPE and Gassco for the period until 2028. To assess a plausible minimum for Norwegian supplies until 2035 ENTSOG has applied the forecasted decline rate between 2025 and 2028 to the rest of the period.

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

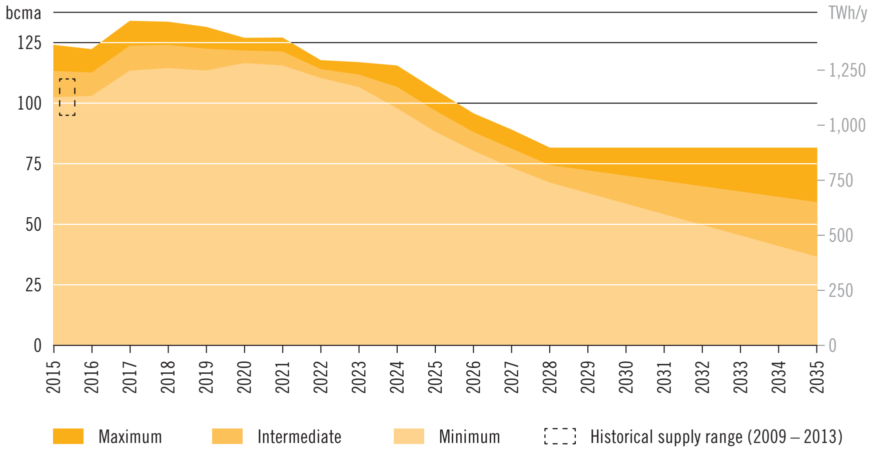


Figure 5.36: Potential pipeline gas scenarios from Norway

POTENTIAL PIPELINE GAS SCENARIOS FROM NORWAY					
GWh/d	**2015**	**2020**	**2025**	**2030**	**2035**
MAXIMUM	3,686	3,772	3,136	2,425	2,425
INTERMEDIATE	3,317	3,617	2,879	2,081	1,756
MINIMUM	2,952	3,462	2,621	1,737	1,087

Table 5.6: Potential pipeline gas scenarios from Norway

5.3.2.3 Algeria

Algeria is currently the third largest gas supplier of the EU and the fourth when considering LNG. It is providing an average daily delivery of 853 GWh/d representing 311 TWh (28 bcm) in 2013. It is expected to remain a key importer along the time horizon of this report. Beyond the usual uncertainty related to production, European market is competition with the Algerian internal and the global LNG markets.

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 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 within the historical Hassi R'Mel field. The rest comes from fields in the South and Southeast of the country. Besides that, Algeria holds vast untapped unconventional gas resources. According to official figures, these resources amount up to 19,800 bcm (218 TWh) of shale gas and additional 8,500 – 14,100 bcm (93,446 – 155,743 TWh) of tight gas[2]. Production start of unconventional reserves is expected for 2020.

Production and Consumption

Since 2005 some of the Algerian largest gas fields have begun to deplete and hence the production is slowly declining. Algeria aims to remedy at that situation bringing new gas fields on stream. Unfortunately many of these projects are behind schedule because of delayed governmental approval, difficulties in attracting investment partners and technical problems. Algeria state-owned company Sonatrach plans to invest 100 billion dollars by 2018 in the national oil and gas sector including 22 billion dollars for gas fields.

ALGERIA'S UPCOMING NATURAL GAS PROJECTS

Project name	Partners	Output (bcma)	Start year
Gassi Touli	Sonatrach	n.a.	2014 +
In Salah (expansion)	BP/Sonatrach	5.7	2015
Reggane Nord	Repsol/Sonatrach	2.9	2016
Timimoun	Total/Sonatrach	1.6	2016
Touat	GDF Suez/Sonatrach	4.5	2016
Ahnet	Total/Sonatrach	2.8 – 4.2	2016
Hassi Ba Hamou	BG Group/Sonatrach	2.0 – 2.8	2016 +
Isarene (Ain Tsila)	Petroceltic/Sonatrach	Tbd	2017 +

Table 5.7: Algeria's upcoming natural gas projects (Source EIA 2013, country report Algeria)

However, natural gas production is likely to continue to decline in the short-term but 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.

1) Country report Algeria, EIA, May 2013
2) Platts July 23, 2014, issue 141

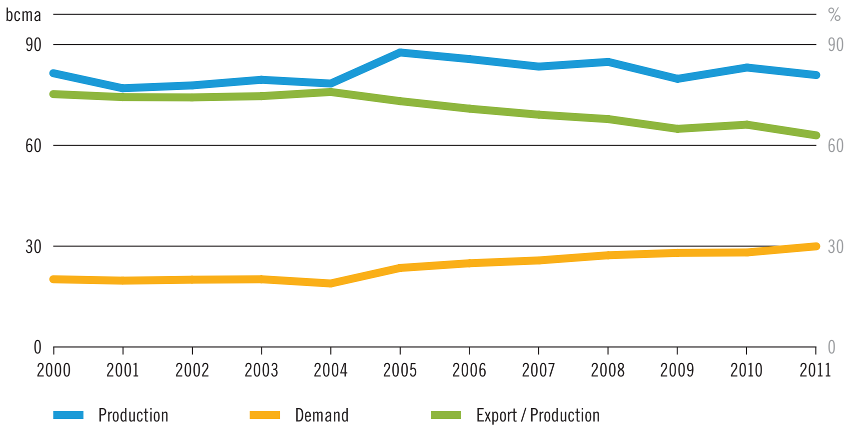


Figure 5.37: Algerian dry natural gas production and consumption (Source EIA 2013, country report Algeria)

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 12 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 8 bcma.

LNG plants

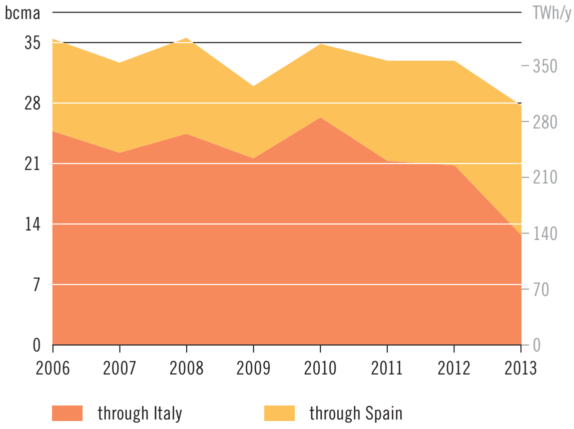
Currently, Algeria has three liquefaction plants, two in Arzew (after the closure of one unit in April 2010) in the West and one in Skikda in the East. Combined LNG production capacity of all four plants is 44 bcma of equivalent gas[1)] (484 TWh/y).

In 2013 Algeria exported 28 bcm (308 TWh) of natural gas via pipeline. 55 % of the pipe exports went through Spain (Portuguese and Spanish markets) while the remaining 45 % went through Italy (Italian and Slovenian markets). Algerian pipeline exports toward Spain were around 8–11 bcma (88–121 TWh/y) between 2006 and 2011. From 2012, with the setting up of the MEDGAZ pipeline, imports have increased up to around 15 bcma (165 TWh/y). In the meantime Algerian pipeline exports toward Italy were above 20 bcma (220 TWh/y) between 2006 and 2012. However, from 2013 a 40 % decline has been observed which could be linked to the renegotiation of long-term contracts between ENI and Sonatrach[2)].

Almost all of Algerian LNG exports went to Europe over the last years with France and Spain as the main destinations. In the period of 2007–2013 France counted for 41 % to 50 % of Algerian LNG exports when Spain amounted for 24 % to 35 % and smaller quantities were delivered to Greece. The main non-EU destination was Turkey and some small volumes also reached Asia (India and Japan received a combined 2 % of LNG exports in 2011).

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

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



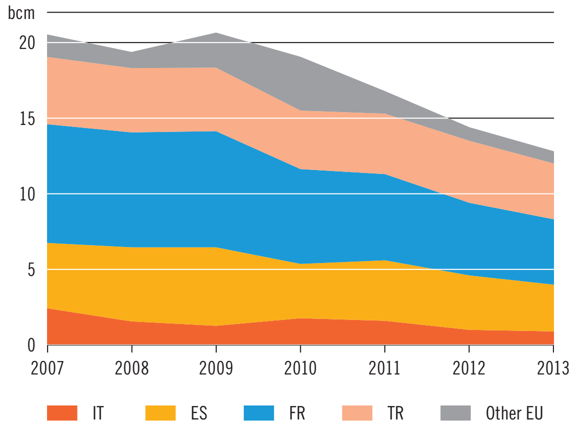
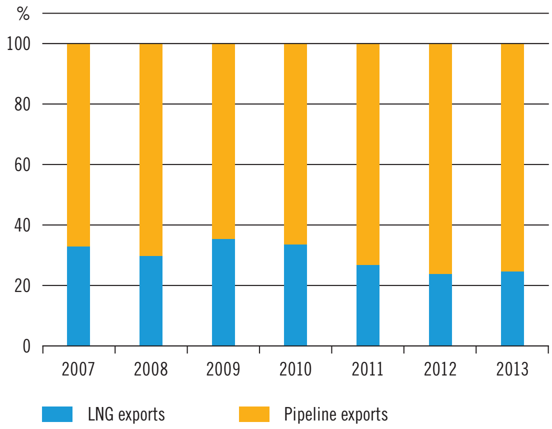


Figure 5.38: Algerian pipeline gas exports to Europe 2006 – 2013 (Source BP Statistical Review 2014)

Figure 5.39: Algerian LNG exports to EU and Turkey 2007 – 2013 (Source BP Statistical Review 2014)



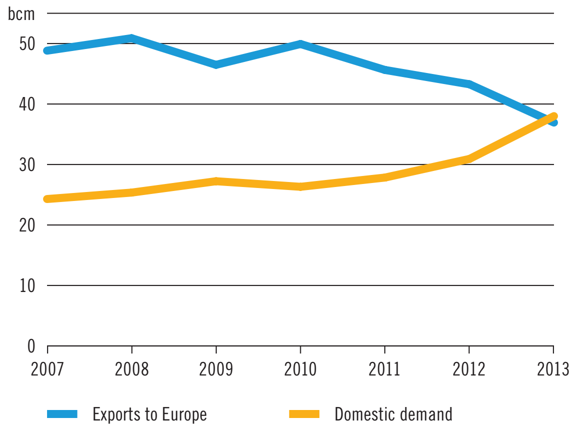


Figure 5.40: Breakdown of Algerian gas exports to Europe (Source BP Statistical Review 2014)

Figure 5.41: Breakdown of Algerian gas exports to Europe (Source BP Statistical Review 2014)

A further analysis shows a close correlation (above 90 %) between Algeria's national demand and exports to Europe. In the period 2007 – 2013, Algerian national gas demand has increased from 24 bcma to almost 40 bcma, representing an increase of 55 %. On the other hand Algerian gas exports to Europe have fallen from 50 bcma to less than 40 bcma representing a 25 % decrease. This illustrates the challenge of developing gas production facing both national demand and export expectations.

Supply scenarios

ENTSOG scenarios consider the interlink between production, national demand and exports. It also covers the possible split between LNG and pipe gas exports.

Maximum Algerian pipeline gas scenario

This scenario combines production projection from MEDPRO[1], demand forecast from the Algerian Ministry of Energy and the evolution of the breakdown between pipeline and LNG exports according to Sonatrach prevision. According to MEDPRO the Algerian production could evolve from 89 bcma in 2013 to twice this figure (160 bcma) by 2030. Production has been extrapolated up to 178 bcma in 2035. Demand evolution follows the intermediate scenario of the Algerian authorities which ranges from 36 bcm in 2013 to 64 bcm in 2030. These figures have been extrapolated by ENTSOG up to 75 bcm in 2035. The export potential is the difference between these production and demand figures. The share of LNG in the exports is set at 43 % in 2018 according to Sonatrach estimation. On the 2014–2018 period LNG share is interpolated starting from 2013 actual value (25 %) and targeting 43 %. Beyond 2018, the LNG share in Algerian exports is considered flat.

Intermediate Algerian pipeline gas scenario

Compared to the maximum scenario, this one only differs in term of production projection. MEDPRO figures have been replaced by the ones of the New Policies scenario coming from the World Energy Outlook 2013 of the IEA where the Algerian natural gas production would reach 132 bcm by 2034.

Minimum Algerian pipeline gas scenario

Compared to the intermediate scenario, this one only differs in term of respective share of LNG and pipeline exports. Here Algeria exports mostly target the global LNG market. This translates into a 90 % use of the liquefaction capacity estimated flat at 38 bcma.

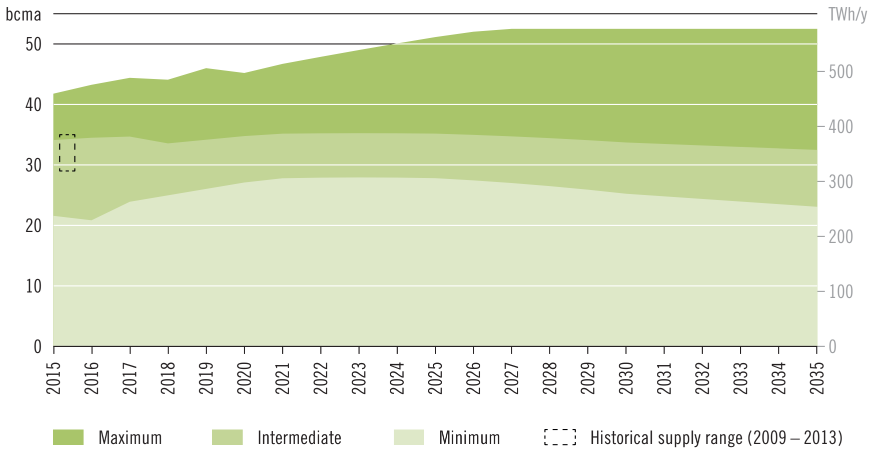


Figure 5.42: Potential pipeline gas scenarios from Algeria

POTENTIAL PIPELINE GAS SCENARIOS FROM ALGERIA

GWh/d	2015	2020	2025	2030	2035
MAXIMUM	1,241	1,342	1,519	1,559	1,559
INTERMEDIATE	996	1,033	1,045	1,001	965
MINIMUM	663	805	826	749	685

Table 5.8: Potential pipeline gas scenarios from Algeria

1) MEDPRO: Mediterranean Prospects, Outlook for Oil and Gas in Southern and Eastern Mediterranean Countries, October 2012, Manfred Hafner

5.3.2.4 Libya

Libya is currently the smallest pipeline gas supplier of the EU. It is providing an average daily delivery of 165 GWh/d representing 60 TWh (6 bcm) in 2013. It is expected to remain at this place 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.

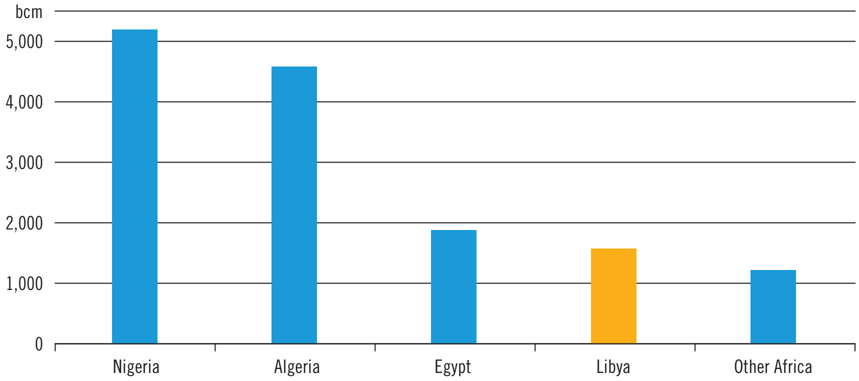


Figure 5.43: Natural gas proved reserves in Africa end 2013 (Source BP Statistical Review 2014)

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 bcm (59 TWh) in 2003 to nearly 17 bcm (187 TWh) in 2010. This is mainly pushed by exports and the goal to become an important gas supplier in the region. The still ongoing civil turmoil has deeply impacted both production and exports. Between 2010 and 2011 production dropped by more than 50 % down to around 8 bcm (88 TWh). According to BP Statistical Review 2013, natural gas production has since recovered to approximately 12 bcma (132 TWh/y). Nevertheless exports in 2012 were only around 7 bcm (72 TWh) representing 8 % of total exports from Africa.

Exports

Piped exports are transported through 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. More than 90 % of the overall exports are delivered by this pipeline the rest being exported as LNG.

After the United States and Algeria, Libya was the third country in the world which began exporting liquefied natural gas in 1971. Processed in Masra El-Brega LNG plant, LNG was mostly sent to Spain. The plant was damaged in 2011 and since that time Libya has not exported any LNG.

Figure 5.46 shows Libyan exports to Italy and their complete shutdown from March to mid-October 2011 due to the civil turmoil. Exports partially recovered in 2012 although still considerably lower than 2010 levels.

1) Country overview Libya, October 2013, EIA

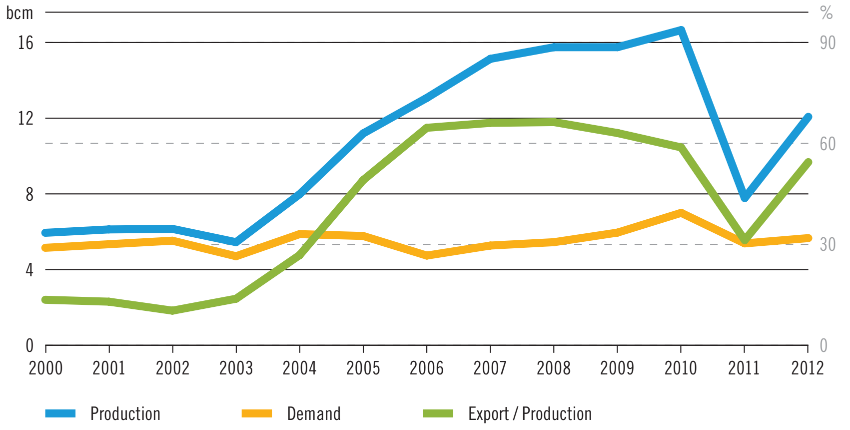


Figure 5.44: Libyan gas production, consumption and export ratio 2000 – 2012
(Sources BP statistical review and EIA)

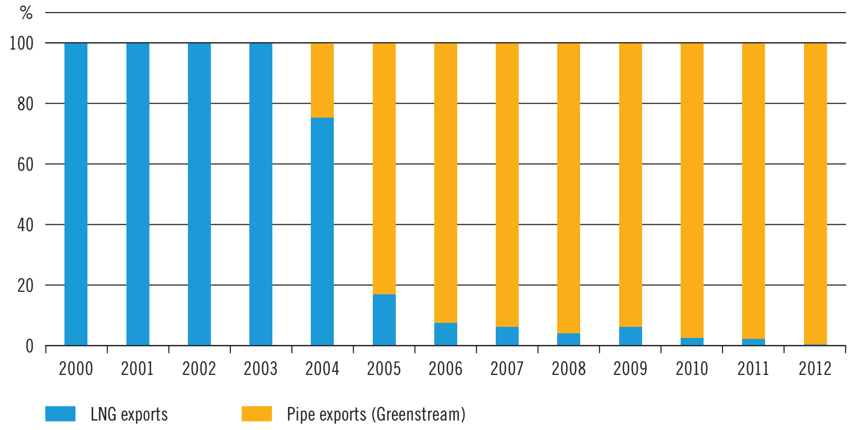


Figure 5.45: Libyan gas exports 2000 – 2012. Breakdown between pipeline and LNG exports
(Source Italian Energy Ministry, Snam Rete Gas and EIA)

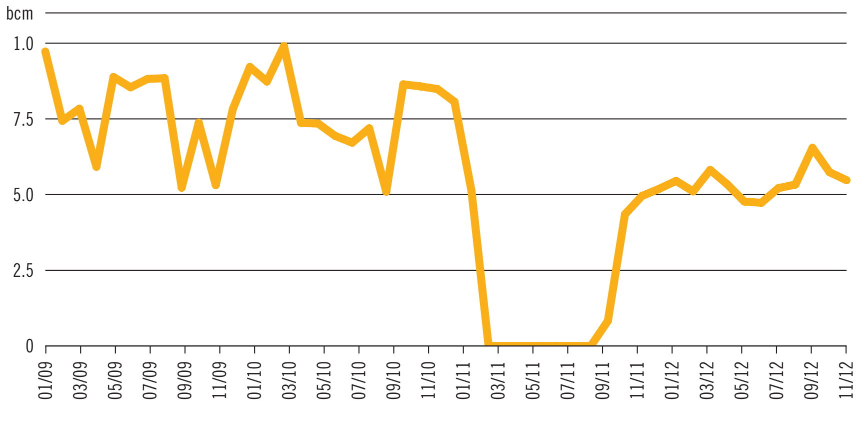


Figure 5.46: Libyan gas exports to Italy 2009 – 2012. Monthly detail
(Source Snam Rete Gas, public figures)

Supply Scenarios

ENTSOG scenarios consider the interlink between production, national demand and exports. It also covers the possible split between LNG and pipe gas exports. Remaining uncertainty around Libyan stability and its impact on gas exports were not considered.

Maximum Libyan pipeline gas scenario

This scenario has been calculated on the basis of the export capacity. The maximum scenario assumes a 95 % load factor of the Greenstream pipeline (354 GWh/d).

Intermediate Libyan pipeline gas scenario

This scenario is the average of the maximum and minimum scenarios.

Minimum Libyan pipeline gas scenario

This scenario is based on Mott MacDonald's report of 2010. According to its low case, the production potential ranges from 16 bcm (176 TWh) in 2015 to 20 bcm (220 TWh) in 2030. The figures have been extrapolated until 2035. Total exports have been derived from this production scenario applying the minimum export vs. production ratio of the last eight years (34 % according to the historical OPEC data). Then pipeline exports have been estimated at 97 % of overall Libyan gas exports (based on BP Statistical report 2012).

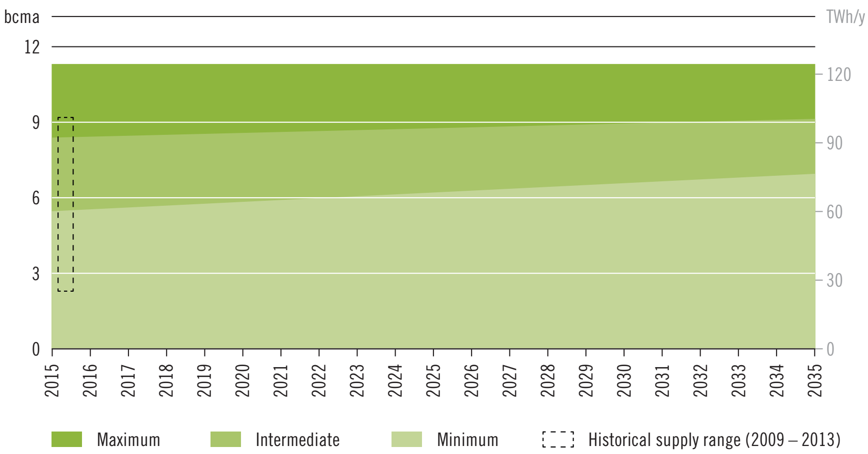


Figure 5.47: Potential pipeline gas scenarios from Libya

POTENTIAL PIPELINE GAS SCENARIOS FROM LIBYA					
GWh/d	2015	2020	2025	2030	2035
MAXIMUM	336	336	336	336	336
INTERMEDIATE	249	255	260	266	271
MINIMUM	162	173	184	195	206

Table 5.9: Libya pipeline gas potential scenarios

5.3.3 PIPELINE IMPORTS: CASPIAN GAS

Currently the EU is not importing Caspian gas. It is foreseen to become a new supply corridor at least at regional level. For the purpose of this Report it is considered to be the sum of the potential imports from Azerbaijan and Turkmenistan.

5.3.3.1 Azerbaijan

Reserves

Azerbaijan's proven reserves amount to roughly 900 to 1,400 bcm (9,900 to 15,400 TWh). The vast majority of these reserves comes 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. Within the last decade, domestic consumption has almost doubled. It will further increase as Azerbaijan continues to replace old oil-fired power plants with new combined cycle gas turbines. In 2011, around 70 % of the 18 bcm (197 TWh) produced gas is for domestic use.

A large part of Azeri gas is exported to Turkey. The South Caucasus Pipeline from Baku to Erzurum in Turkey is the main export line. Some volumes are also exported to Russia via the Gazi-Magomed-Mozdok Pipeline and to Iran via the Baku-Astara Pipeline.

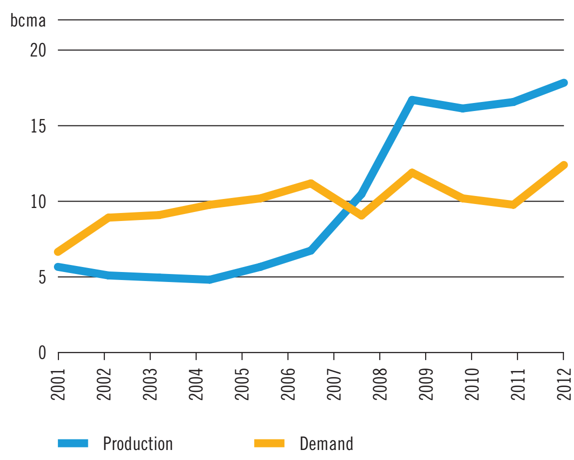


Figure 5.48: Azerbaijan's dry natural gas production and consumption 2001 – 2011 (Source EIA, country report from Azerbaijan, September 2013)

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 has increased since then. Gas is currently being produced under phase 1, which will see plateau production at around 9 bcma (100 TWh/y). Phase 2 will then add further 16 bcma (176 TWh/y) of gas production, with first deliveries in the beginning of 2019. Therefrom 6 bcma (66 TWh/y) are basically foreseen for Turkey and 10 bcma (110 TWh/y) are foreseen for EU. According to recent information from the Shah Deniz partners a possible phase 3 has been agreed. Reserves of this phase are estimated at 500 bcm (5,500 TWh), which would boost the fields total reserves to approximately 1,700 bcm[1)] (18,700 TWh). This phase would enable to maintain gas volumes at peak level of 25 bcma (275 TWh/y) for an extended period but there is still no final concept. As additional information is rare, ENTSOG's interpretation of phase 3 is that, this phase would enable the complete field of Shah Deniz to hold an overall production of 25 bcma. Phase 3 would then maintain the production level from previous phases.

In recent months the Trans Anatolian Pipeline (TANAP) and Trans Adriatic Pipeline (TAP) projects took their Final Investment Decision. In combination with the already decided extension of the South Caucasus Pipeline, it is most likely that the gas of Shah Deniz phase 2 will reach Southern Europe markets via Turkey.

1) Interfax: Natural Gas Daily, 14 March 2014

Supply Scenarios

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 scenario

As in TYNDP 2013, this scenario is based on the assumption of part of the 6 bcma (66 TWh/y) which were originally assigned to Turkey ending up in EU. Therefore, maximum potential of Azeri gas would be 16 bcma (176 TWh/y). Two ramp-up phases have been considered. A first one with the start of exports in 2019 and reaching the 10 bcma by 2022, and a second one, that starts by 2025 and would reach 16 bcma by 2028.

Intermediate Azeri pipeline gas scenario

This scenario considers the 10 bcma (110 TWh/y) for the EU market as it was done in TYNDP 2013. A ramp-up phase has been applied to gradually increase the gas imports from 2019 to 2022.

Minimum Azeri pipeline gas scenario

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

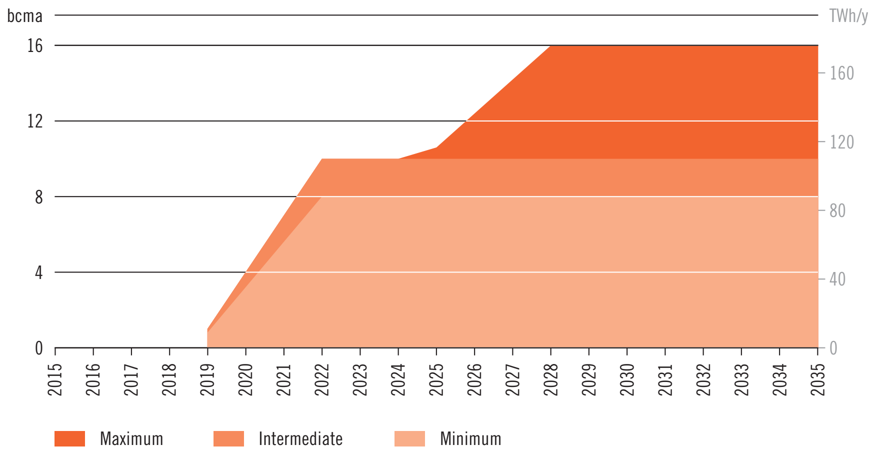


Figure 5.49: Potential pipeline gas scenarios from Azerbaijan

POTENTIAL PIPELINE GAS SCENARIOS FROM AZERBAIJAN					
GWh/d	**2015**	**2020**	**2025**	**2030**	**2035**
MAXIMUM	0	119	315	415	475
INTERMEDIATE	0	119	297	297	297
MINIMUM	0	95	238	238	238

Table 5.10: Potential pipeline gas scenarios from Azerbaijan

5.3.3.2 Turkmenistan

Reserves

With its 17,500 bcm (183,170 TWh) of proven natural gas reserves Turkmenistan ranks in the top four of countries with the largest gas reserves in the world. Natural gas plays a significant role in Turkmenistan energy mix with a 78 % share of the overall energy consumption and even 100 % in the power generation sector.

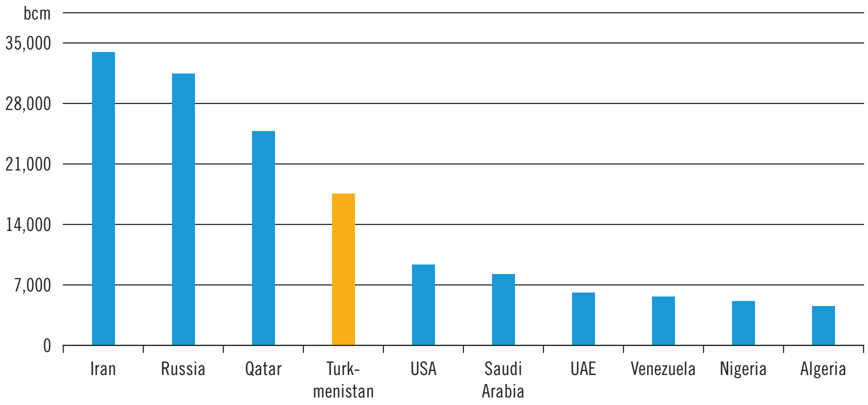


Figure 5.50: Proved natural gas reserves worldwide by country (Source own depiction based on data from BP Statistical Report 2014)

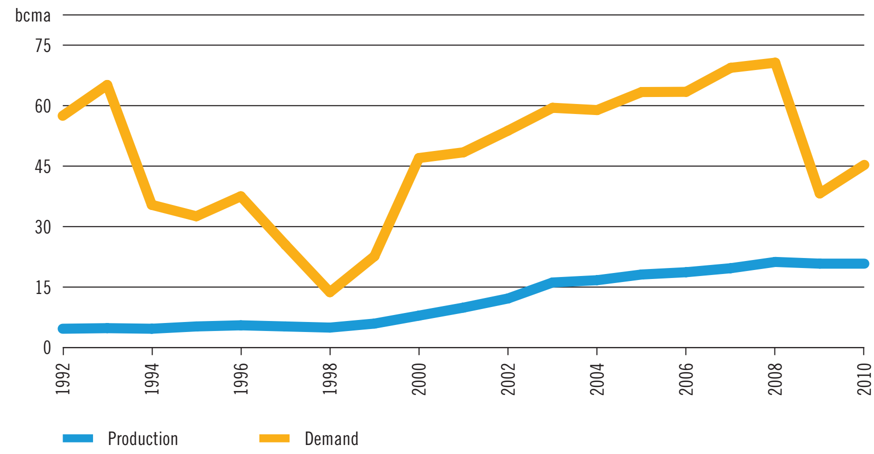


Figure 5.51: Turkmenistan's natural gas production and consumption 1992 – 2010 (Source EIA, Country Analysis Briefs, Turkmenistan, January 2012)

Exports

Since 1992, the key market of Turkmenistan gas is Russia but this has been changed abruptly in 2009. As a consequence of damages on the Central Asia-Center pipeline which brings gas to Russia, Turkmenistan exports suffered serious declines from a high of 71 bcm (781 GWh) in 2008 to 37 bcm (407 TWh) in 2009[1].

1) Country Analysis Briefs, Turkmenistan, EIA, January 2012

In recent years, Turkmenistan signed several agreements with international companies to support gas production. Through recently constructed pipelines to China and Iran, new export opportunities emerged. In July 2007, China signed a 30-year gas contract with Turkmenistan to off-take 31 bcma. In the years 2010 – 2012 Turkmenistan sent approximately 26 bcm of gas to Iran and almost 40 bcm of gas to China. In 2011 this country contracted additional volume which could bring total exports to 65 bcma in 2020[1] putting China on equal footing with Russia as destination market.

CURRENT PIPELINE INFRASTRUCTURE OF TURKMENISTAN			
Pipeline	**Destination**	**Capacity bcma**	**Operation**
Central Asia Center	Russia, Kazakhstan, Uzbekistan	99	Since 1969
Bukhara-Urals	Russia	20	Since 2001
Korpezhe-Kurt Kui	Iran	13	Since 1997
Dauletabad-Khangiran	Iran	12	Since 2010
Central Asia China	Line A, B	30	Since 2009, 2010
	Line C	25	In 2014/2015
	Line D	25	In 2020

Table 5.11: Current pipeline infrastructure of Turkmenistan
(Source EIA, Country Analysis Briefs, January 2012)

The idea of exporting gas from Turkmenistan through a Southern corridor to Europe is widely discussed but transport infrastructures are still missing. A possible opportunity is the Trans Caspian Pipeline (TCP) which would connect Turkmenistan with Azerbaijan across the Caspian Sea. The White Stream Pipeline project could then transport the gas through the Black Sea to the European border with landfall in Romania[2]. The alternative option would be to use the future Trans-Anatolian Pipeline (TANAP) but this will be dedicated to Azeri gas imports.

Supply Scenarios

Currently there is no facility to export gas from Turkmenistan to Europe and no Final Investment Decision has been taken yet in any foreseen project. To derive an EU gas supply potential, ENTSOG has considered information from IEA regarding past gas consumption, projection of gas production as well as own elaborations on exports to neighbouring countries. The following underlying figures have been used:

Two demand projections built on the basis of IEA[3] historical data: one on the basis of last 10-year records and another one on the basis of last 20-year records.

Future gas production derives from four IEA projections (WEO's between 2008 and 2010) with extrapolation after 2030[4]. Own elaboration of possible gas export of Turkmenistan to neighbouring countries[5]:

- **Russia:** Increasing exports from 10 bcm in 2012 to 15 bcm in 2025 remaining flat afterwards. The rationales behind would be the increase of Russian imports from Turkmenistan in order to hinder exports to the EU.
- **China:** Increasing exports from 21 bcm in 2012 to 35 bcm in 2030 considering a partial use of newly signed contracts. Then exports are considered flat afterwards.
- **Iran:** Increasing exports from 9 bcm in 2012 to 12 bcm in 2035.

1) Platts March 2014
2) It has to be noticed that the Caspian Sea has a special legal status requiring that such investment is agreed by all five adjacent countries (Russia, Kazakhstan, Turkmenistan, Iran, Azerbaijan)
3) http://valdaiclub.com/near_abroad/40360.html
4) Europe's energy Future: Natural Gas Supply between Geopolitics and the Markets, page 48
5) Base values of 2012 are from BP's Statistical Review

The resulting potential supply scenarios are the following:

Maximum Turkmenistan gas scenario

This scenario is based on the combination of the highest production projection and the lowest consumption projection (based on the last twenty years evolution). The exports to Europe are calculated by deducting the above explained export figures to neighbouring countries.

Intermediate Turkmenistan gas scenario

This scenario is based on the combination of the average of the four production projections and the average of the two demand projections. The same approach than in the maximum scenario has been used to derive exports to Europe.

Minimum Turkmenistan gas scenario

Given the uncertainty on any export infrastructure to Europe this scenario considers no Turkmenistan gas reaching the EU.

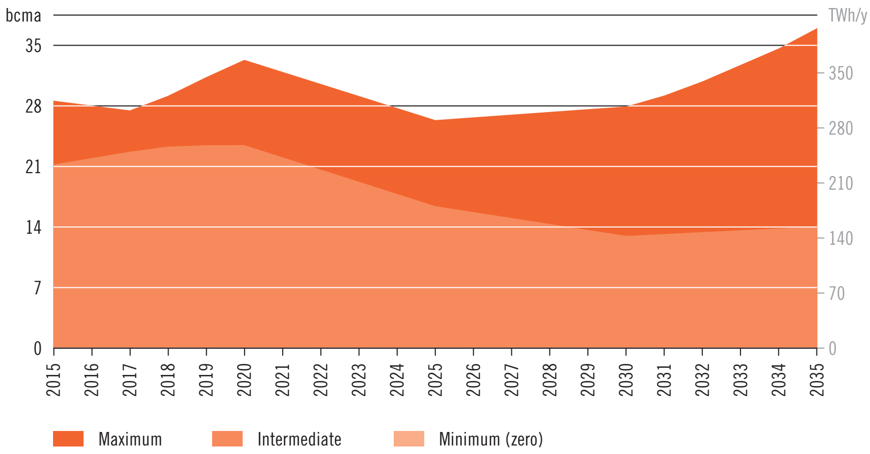


Figure 5.52: Potential pipeline gas scenarios from Turkmenistan

POTENTIAL PIPELINE GAS SCENARIOS FROM TURKMENISTAN					
GWh/d	**2015**	**2020**	**2025**	**2030**	**2035**
MAXIMUM	850	990	783	830	1,106
INTERMEDIATE	568	697	487	867	418
MINIMUM	0	0	0	0	0

Table 5.12: Potential pipeline gas scenarios from Turkmenistan

In the assessment chapter imports from Turkmenistan can only start when an infrastructure project is considered.

5.3.4 LNG

Until recently the share of LNG in the European gas supply mix had increased. It enables the connection of Europe to the global market and a large number of remote producing countries. The fast establishment of a global LNG market offers access to reliable and diversified source of supply. Therefore it offers shippers arbitrage opportunities at a global scale between different regional markets.

Image courtesy of Fluxys Belgium

5.3.4.1 LNG production

Production reached its historical maximum level of 329 bcm (3,619 TWh) in 2011 before a small 3 % decrease 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 Atlantic basin increased by almost a factor two while in the Pacific basin the growth was limited to 56 %. The different evolutions followed by the three basins have derived in a significant change in their shares. While in 2001 the Pacific basin represented over 52 % of the total LNG production, the Atlantic basin accounted for a 26 % and Middle East was 22 %. In 2012 the Middle East led the production with a 42 % share the while Pacific and Atlantic basins shares have been reduced to 36 % and 22 % respectively.

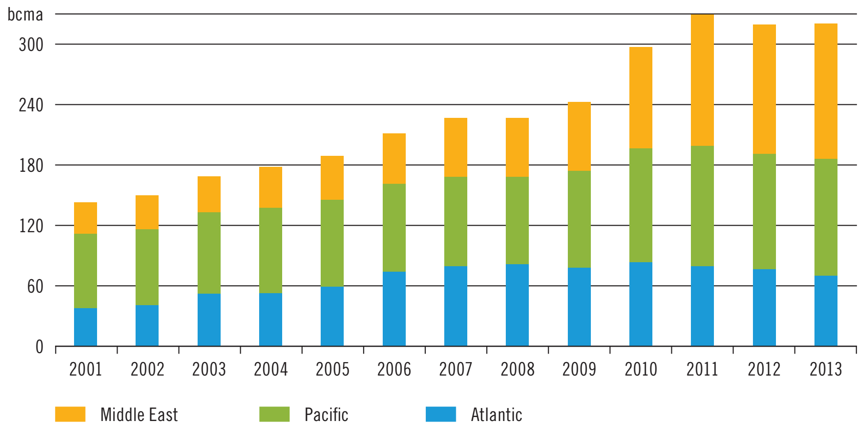


Figure 5.53: Evolution of LNG production by basin 2001 – 2013 (Source BP Statistical Review)

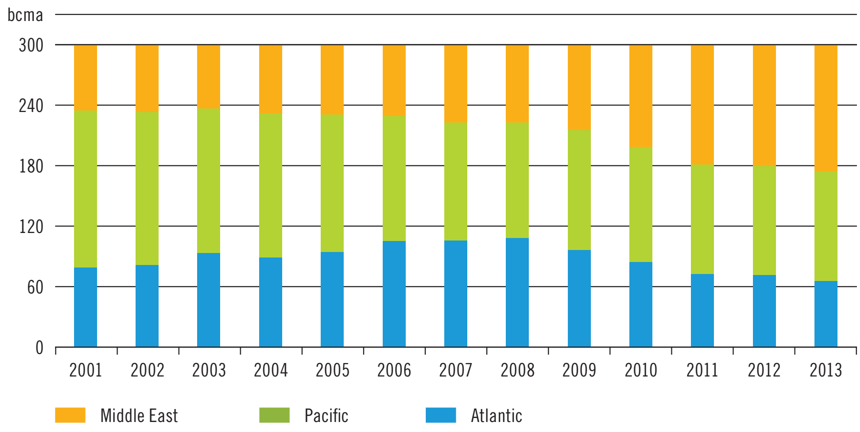


Figure 5.54: LNG Shares by basin 2001 – 2013 (Source BP Statistical Review)

Atlantic basin

The LNG production in the Atlantic basin (including Mediterranean Sea) reached its maximum in 2010 with 83.5 bcm (918 TWh). Since then it decreased by 16 % despite of the addition of Angola to the list of producing countries. This decrease is common to most of the countries of the region. Particularly significant were the decreases in Egypt (6 bcma), Algeria (4 bcma) and Nigeria (2 bcma).

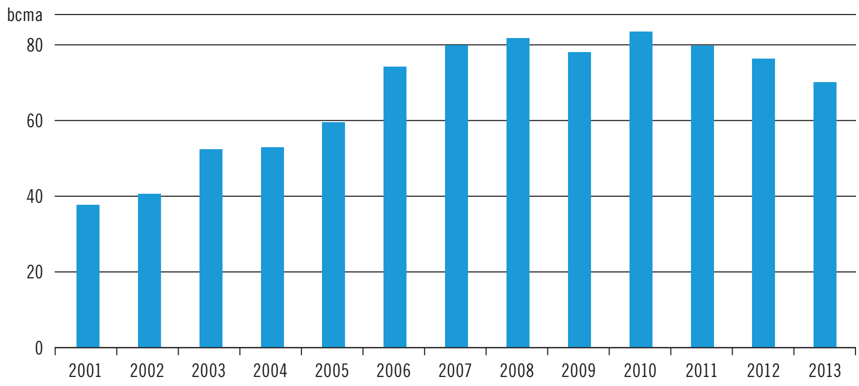


Figure 5.55: Evolution of LNG production in the Atlantic basin 2001 – 2013 (Source BP Statistical Review)

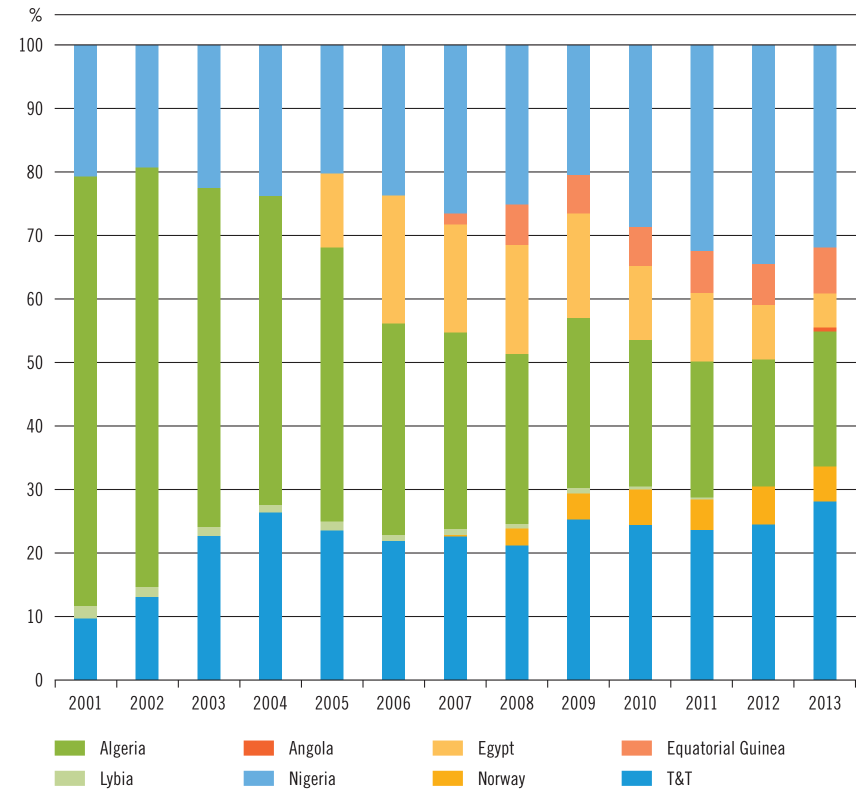


Figure 5.56: LNG Shares by producing country in the Atlantic basin 2001 – 2013 (Source BP Statistical Review)

In 2001, Algeria produced almost 70 % of the LNG in the Atlantic basin. During the 2001 – 2013 period new liquefaction plants were commissioned while Algerian LNG exports decreased. This has resulted in a diversification of LNG supply in the Atlantic basin. In 2013, the biggest Atlantic producer was Nigeria (with 32 % of the LNG produced in the basin), followed by Trinidad and Tobago (28 %) while Algeria falls to the third place with 21 %.

Middle East

The yearly LNG production in the Middle East steadily increased by 11 % on average until 2009. In 2010 the yearly increase reached a 47 % and in 2011 an additional 30 % thanks to the commissioning of new liquefaction trains in Qatar. This evolution has contributed to increase the share of Qatar up to 79 % of the Middle East production in 2013.

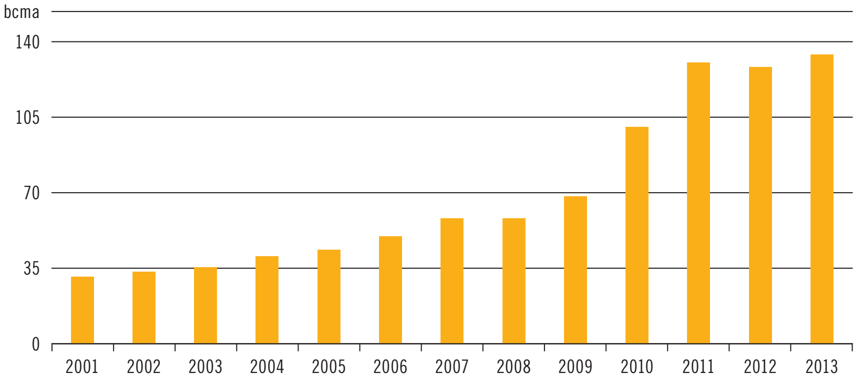


Figure 5.57: Evolution of LNG production in the Middle East 2001 – 2013 (Source BP Statistical Review)

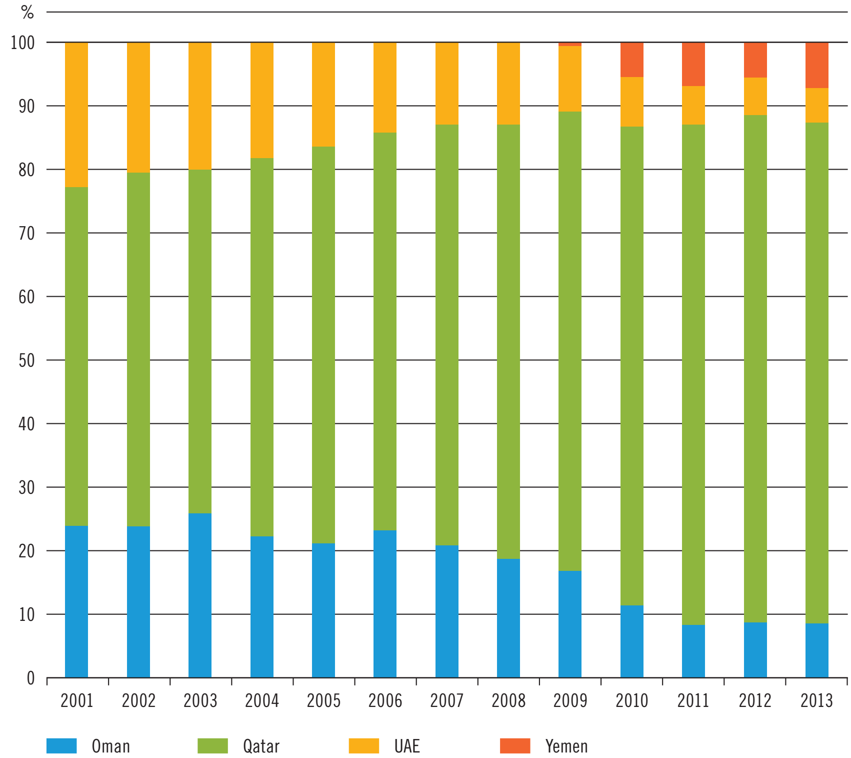


Figure 5.58: LNG Shares by producing country in the Middle East 2001 – 2013 (Source BP Statistical Review)

Pacific basin

The LNG production in the Pacific basin reached a maximum in 2011 with 119 bcm (1,309 TWh), and has remained stable close to this level since.

Figure 5.59: Evolution of LNG production in the Pacific basin 2001 – 2013 (Source BP Statistical Review)

Since 2001, there has been a 30 % decrease of Indonesian LNG exports. This reduction along with the increase in the Australian productions by a factor four and the arrival of Russia and Peru as Pacific exporting countries has significantly increased the diversification of LNG supply in this basin. In 2013 the main LNG producing country in the Pacific basin was Malaysia with a 29 % share of the exports.

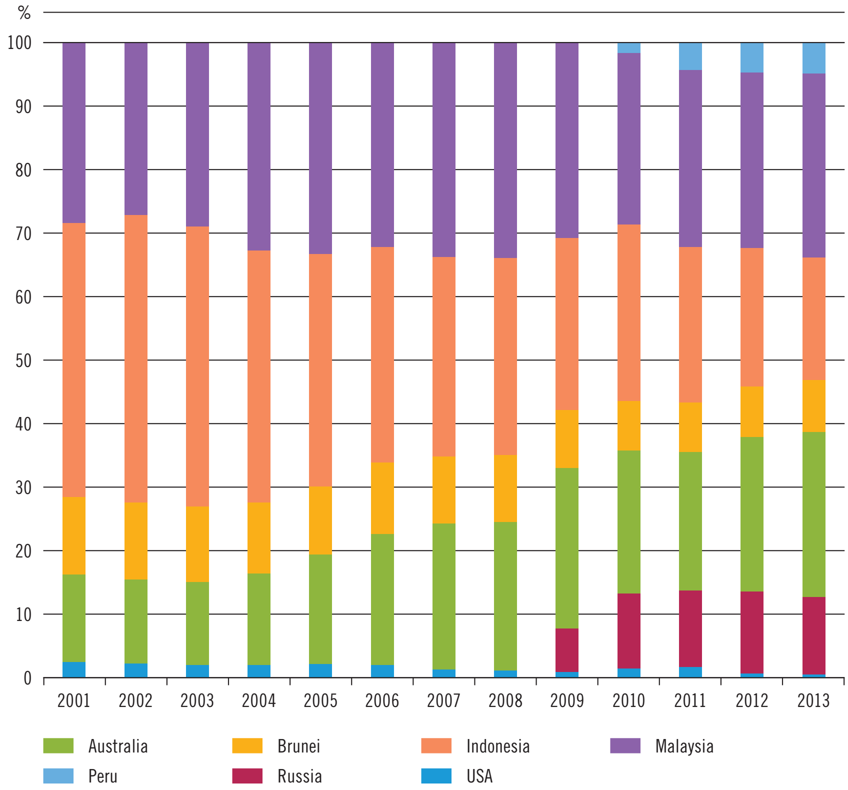


Figure 5.60: LNG Shares by producing country in the Pacific basin 2001 – 2013
(Source BP Statistical Review)

5.3.4.2 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 – 2013. 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 EU and Turkey. Their maximum shares of the global LNG imports were reached in 2009 with 29 % before dropping down to 16 % in 2013. Since 2009 the American markets have compensated each other with a simultaneous decrease of North American imports and an increase of South American imports.

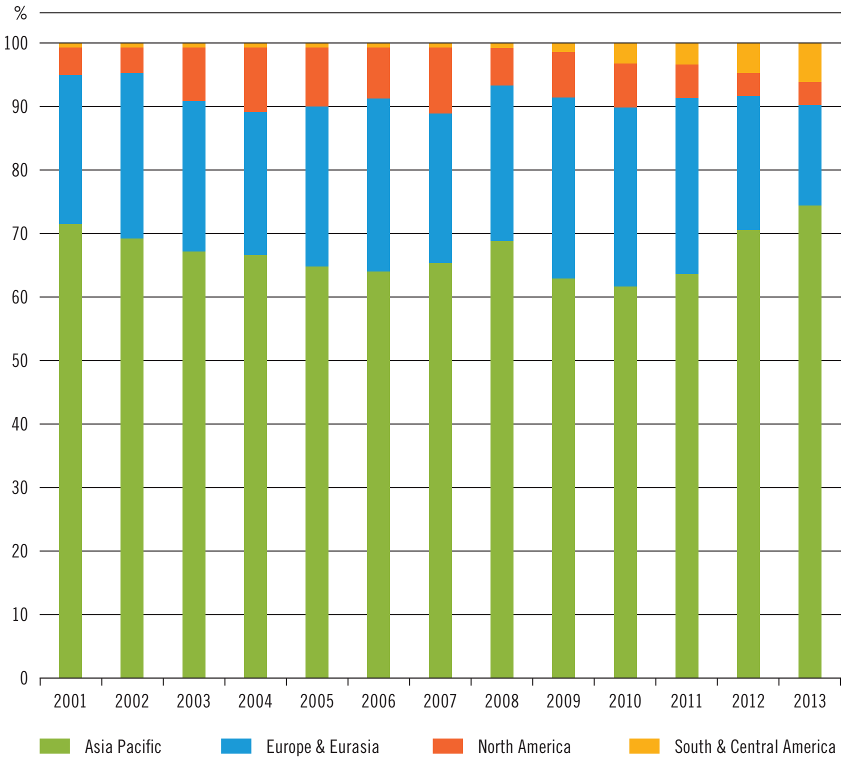


Figure 5.61: Evolution of LNG imports. Breakdown by geographical area 2001 – 2013 (Source BP Statistical Review)

Asia Pacific

The Asia Pacific gas market has been traditionally strongly dominated by Japan followed by South Korea, with minor consumptions in Taiwan. Despite the significant increase (14 % in 2011 and 11 % in 2012) in Japanese LNG imports following the nuclear accident in Fukushima, the weight of the country in the region was reduced down to 50 %. This was the result of the maturity of Japanese demand along with the sustained growth in the South Korean and Taiwanese consumption (8 % yearly growth on average) and the expansion of new markets particularly China and India.

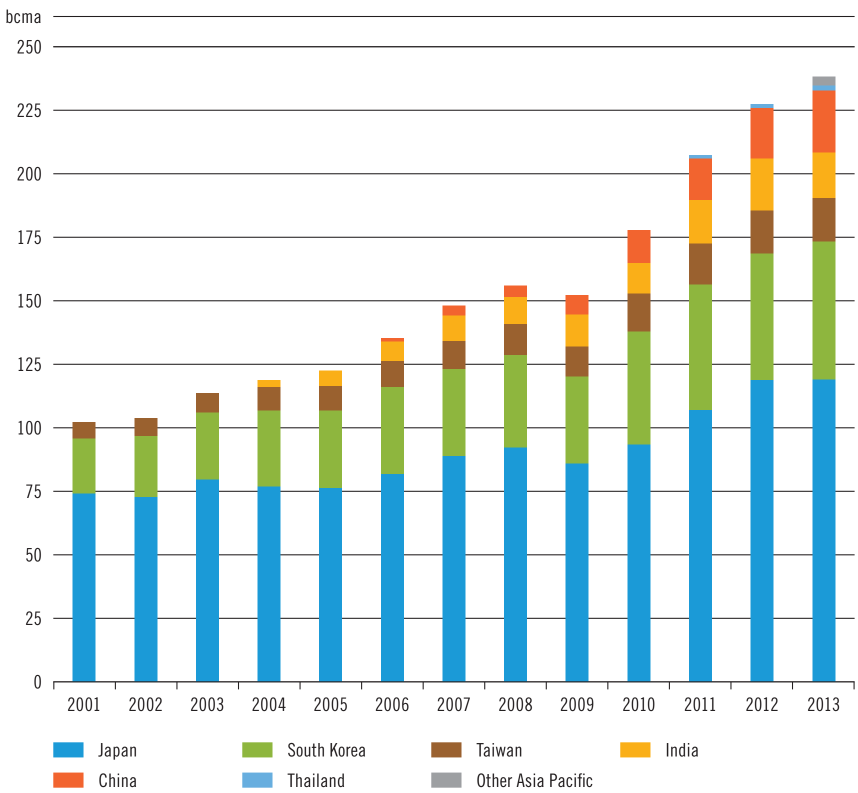


Figure 5.62: Evolution of LNG imports in Asia Pacific. Breakdown by geographical area 2001 – 2013 (Source BP Statistical Review)

EU and Turkey

This region experienced a strong growth of LNG imports between 2004 and 2011 (104 %). The sustained fall in 2012 and 2013 has driven LNG in 2013 to levels of before 2006. During this period EU share has stayed predominant with 90 % of regional imports.

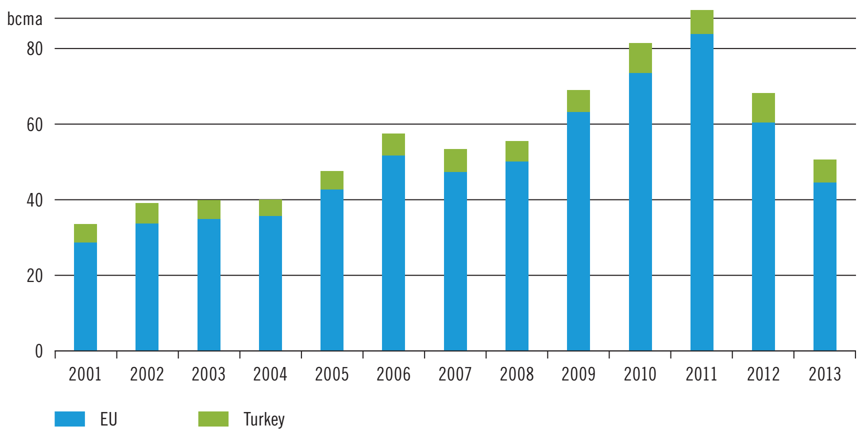


Figure 5.63: Evolution of LNG imports in Europe-Eurasia 2001 – 2013 (Source BP Statistical Review)

The reduction of the LNG imports since 2011 has negatively affected the utilization rate of LNG regasification terminals in Europe. These terminals have seen their load halved over the last two years.

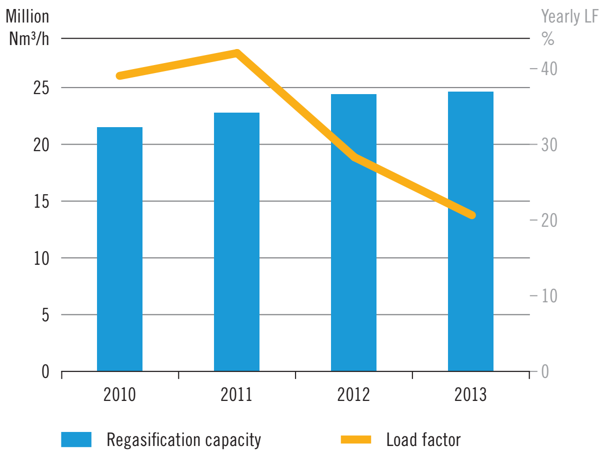


Figure 5.64: Evolution of the regasification capacity and yearly utilization of LNG terminals in Europe 2010 – 2013 (own elaboration from BP Statistical Review and GLE map)

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, the decrease of US LNG imports has been partially replaced by Mexico. Mexican LNG imports started in 2006 and accounted for 67 % (8 bcm) of the LNG in the area in 2013.

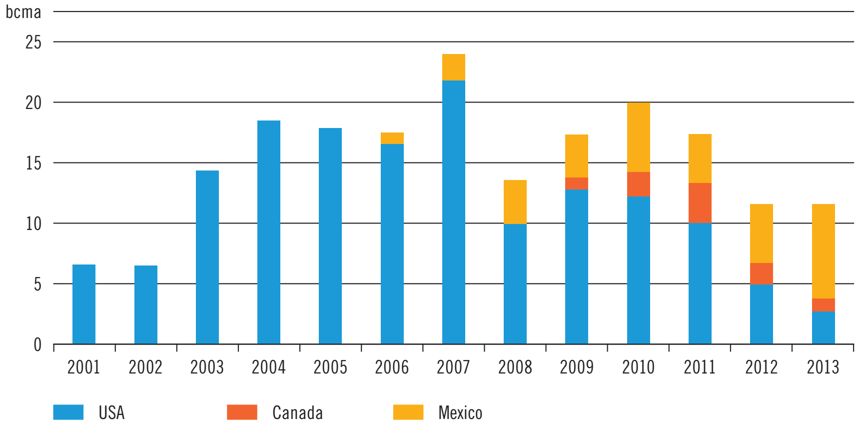


Figure 5.65: Evolution of LNG imports in North America 2001–2013 (Source BP Statistical Review)

South and Central America

The graph below shows the fast development of the LNG market in South and Central America. Until 2008 only small volumes were imported to Puerto Rico and Dominican Republic (labelled in the graph as Other South & Central America). Since 2008 Chile, Brazil and Argentina have become LNG importers. The average yearly growth in the South and Central America market has more than doubled since 2010.

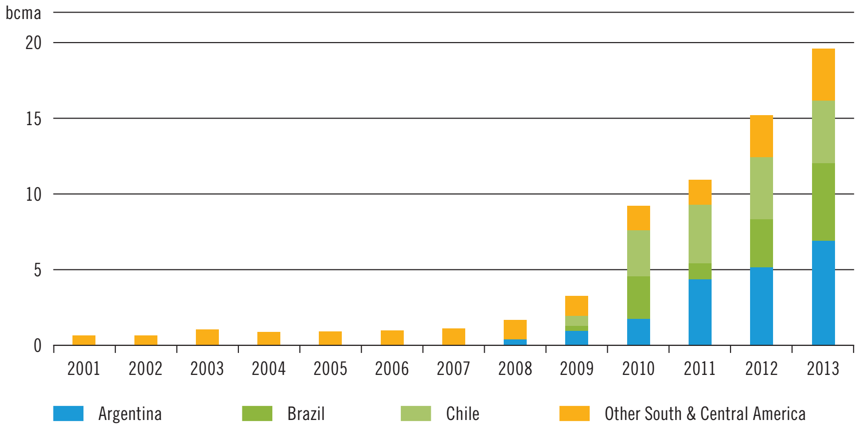


Figure 5.66: Evolution of LNG imports in South and Central America 2001–2013 (Source BP Statistical Review)

5.3.4.3 Liquefaction capacity[1)]

The existing balance between the liquefaction capacities in the different basins will come to an end with the commissioning of a very significant number of projects in the Pacific basin compared to the Atlantic basin. The liquefaction capacity in the Pacific basin will be increased by 58 % up to 166 MTPA (227 bcma), while in the Atlantic basin the increase will reach 22 % up to 123 MTPA (169 bcma). The Middle East will reduce its share in liquefaction capacity from current 33 % to 26 % due to the absence of new projects in the area.

When referring to other projects with commissioning dates planned before 2020, which are not under construction yet, the number of projects (and their associated capacity) would imply an additional increase in the total liquefaction capacity of some 80 % (from the existing projects plus those under construction. These less mature projects are split between the Pacific basin (50 % of the capacity), the Atlantic basin (38 %), and the Artic (12 %).

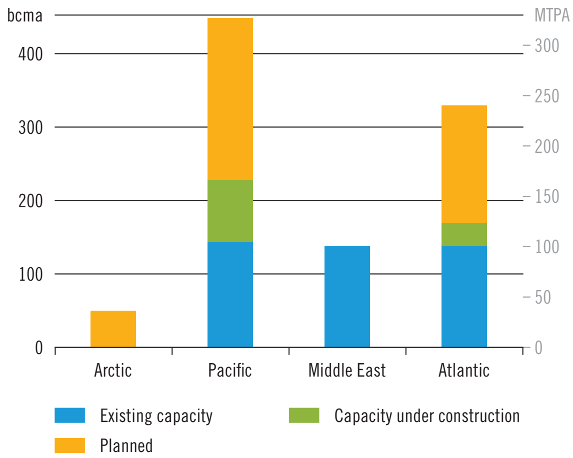


Figure 5.67: Evolution of liquefaction capacity by area. Existing, under construction and planned capacities (own elaboration based on GIIGNL and LNG journal)

1) liquefaction capacities are expressed in MTPA. The volume and energy content depend on the composition and the reference conditions of the LNG. For the understanding of these figures, the following approximation can be considered: 1 MTPA = 1.37 bcma (gas volume)

Atlantic basin

The expansion of liquefaction capacity under construction in the Atlantic basin is located in Algeria, with an increase of 5 MTPA (6 bcma) in Arzew- GL3Z (Gassi Touil)[1)] and in the United States, where the commissioning of the four trains of Sabine Pass with 5 MTPA each (6 bcma), will gradually come on stream between 2015 and 2017.

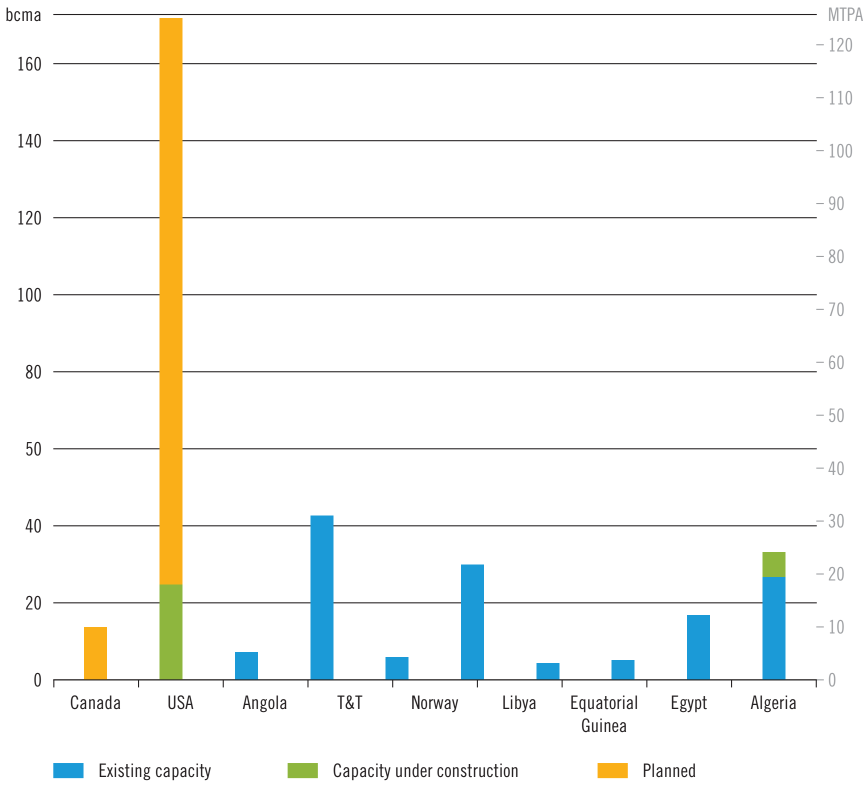


Figure 5.68: Potential evolution of the liquefaction capacity in the Atlantic basin. Breakdown by country (Source LNG journal)

The projects with planned commissioning dates before 2020, which are not under construction yet, are located in Canada (Goldboro LNG with 10 MTPA/14 bcma) and the United States (10 different projects with at total liquefaction capacity of 107 MTPA/147 bcma). The particular case of the LNG projects in the US is explained below.

In addition, there are three projects in Nigeria with a total increase of the liquefaction capacity of 38.4 MTPA (53 bcma) and one project in Canada which is still under study.

Pacific basin

In the Pacific basin, most of the liquefaction projects under construction are located in Australia, which is expected to triplicate its current liquefaction capacity up to 73 MTPA (100 bcma) by 2017. Other projects are under construction in Indonesia (3 MTPA/4 bcma), Malaysia (2 MTPA/3 bcma) and Colombia (1 MTPA/1.4 bcma).

1) That is expected to come into operation in autumn 2014 during the edition of this report.

In the Pacific basin there are a high number of projects that are not under construction yet but have a planned commissioning date before 2020. These projects would increase the liquefaction capacity in this area by 153 MTPA (210 bcma) in total. They are located in Canada (42 MTPA/58 bcma), Australia (35 MTPA/48 bcma), United States (28 MTPA/39 bcma), Mozambique (20 MTPA/28 bcma), Russia (10 MTPA/14 bcma), Papua New Guinea (8 MTPA/11 bcma), Malaysia (5 MTPA/7 bcma) and Indonesia (5 MTPA/6 bcma).

There are additional projects in Australia (Tassie Shoal with 3 MTPA/4 bcma) and in Russia (expansion of Sakhalin) with no agreed commissioning date.

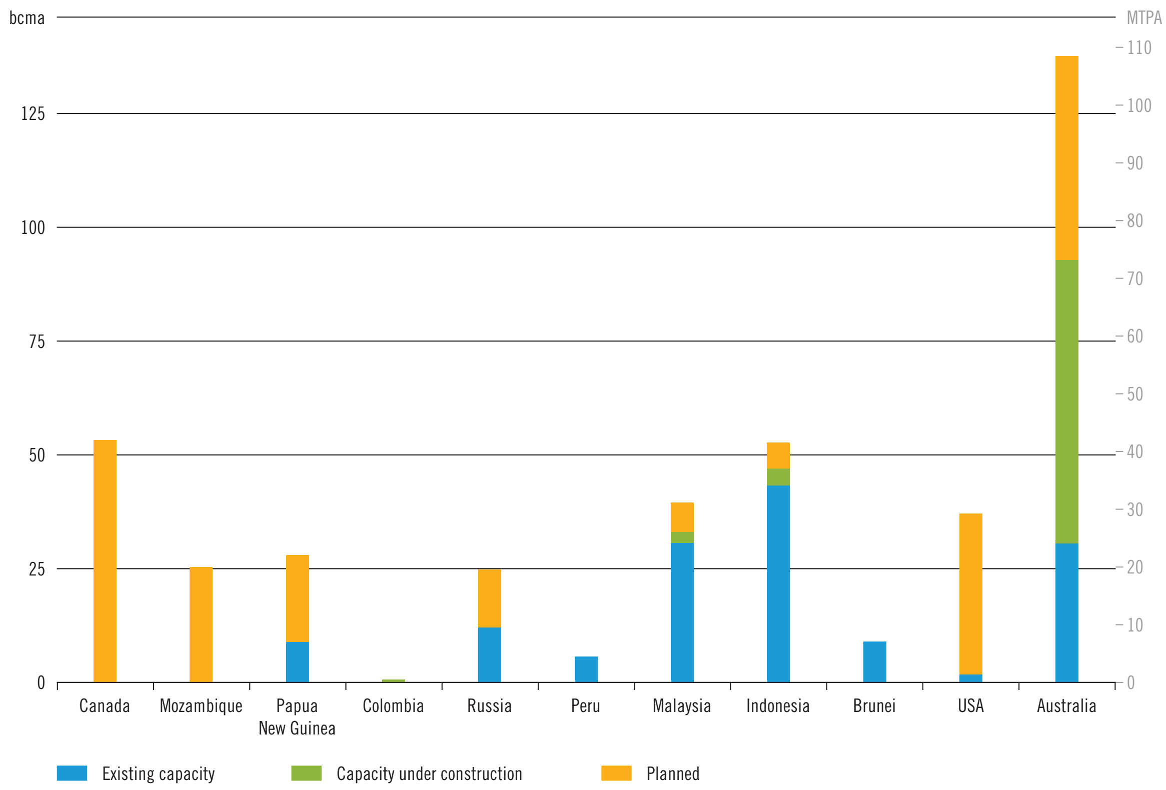


Figure 5.69: Potential evolution of the liquefaction capacity in the Pacific basin. Breakdown by country (Source LNG journal)

The Northern transit routes

A decrease of the ice in the Arctic area combined with the development of ice class LNG tanker fleets could allow the opening of new transportation routes between the Atlantic and the Pacific basins. This would allow exports of Artic gas sources in the form of LNG.

There are two Russian liquefaction projects targeting these sources: Yamal LNG, with 17 MTPA (23 bcma) to be commissioned by 2018 and Shtokman LNG with a planned capacity of 20 MTPA (27 bcma) and commissioning date in 2019. Neither of these two projects is currently under construction. In addition, LNG is one option for the development of the gas fields in the Barents Sea, but no concrete liquefaction projects have been defined for the time being.

US: the shale gas boom and the LNG exports[1)]

Until 2007 the USA was foreseen as one of the main future LNG importers. Nevertheless since the shale gas boom the gas production has followed a continuous increase, leading gas prices in the US to levels around 4 $/MMBTU, reaching minimums down to 2 $/MMBTU. The US recoverable shale gas resources are estimated to be 18,800 bcm (recoverable resources)[2)]. The current level of production is expected to be increased and maintained, allowing the US to become a net exporter by 2017. The low and stable gas price in the US compared to the Asian and European market prices, could create a strong business case for the export of LNG to these markets. The shale gas boom has encouraged the rapid emergence of liquefaction projects in the US, both on the western and eastern coasts. The enlargement of the Panama Canal will enable greater connection between the Atlantic and Pacific for LNG transportation.

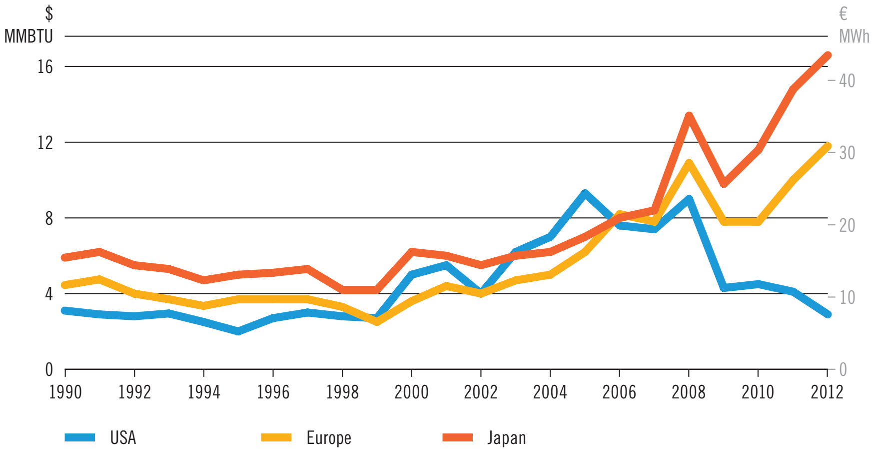


Figure 5.70: Evolution of gas prices in US, Europe and Japan (Source IEA WEO 2013)

Despite of the high potential for LNG exports, the American administration (DOE) has been cautious when considering approval for export projects to countries with no free trade agreement with the US. A significant increase in the exported volumes could result in a price increase for the American domestic consumers. As of September 2014, nine projects have received the approval for the Non-FTA application, with a total exporting capacity of around 105 bcma.

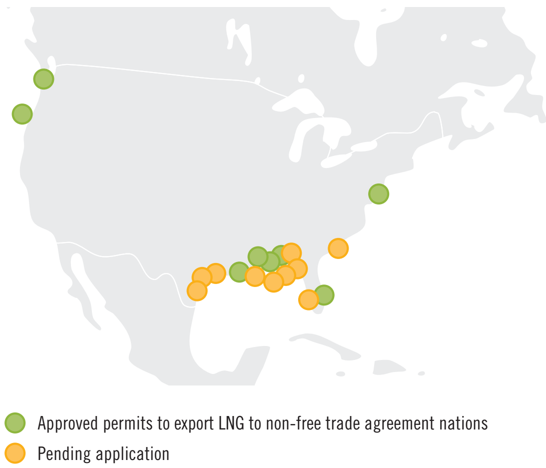


Figure 5.71: LNG exporting projects in the US (own depiction)

1) gas prices are expressed in $/MMBTU. The prices expressed in € will depend in the €/$ exchange rate. For the understanding of the figures below, the following approximation can be considered (corresponding to 1 € = 1.3 $): 1 $/MMBTU = 2,62 €/MWh)

2) EIA 2013

5.3.4.4 Liquefaction vs. regasification capacity

As shown in the next figure, in 2013 the regasification capacity was more than twice the liquefaction capacity. The difference between the LNG exporting and importing capacities is explained by:

- The flexibility of the LNG market leads to LNG becoming a fuel of choice and regasification capacity being built in order to take advantage of low LNG prices. LNG is expected to be replaced either by other sources of gas or by other fuels when the LNG price is not competitive.
- The use of LNG for managing demand variation by a combination of high regasification capacity and stock management. This is the case in the traditionally LNG dependent markets like Japan, South Korea or certain European countries like Portugal and Spain, where LNG constitutes a base-load fuel.

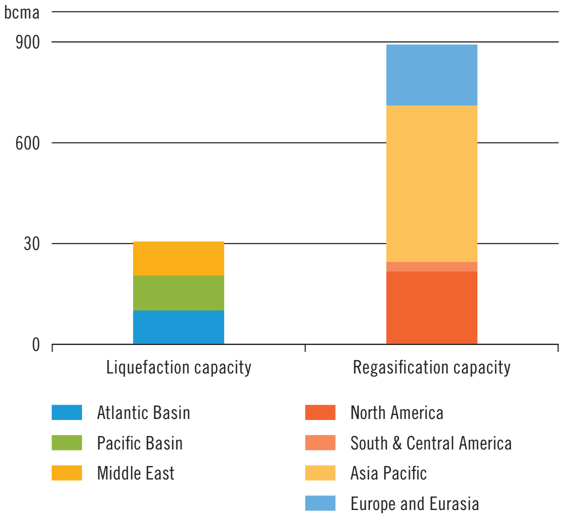


Figure 5.72: Liquefaction vs. Regasification capacity (Source GIIGNL 2013)

5.3.4.5 LNG as a market arbitration tool

The potential contractual right to change the destination of LNG cargos allows LNG to play an arbitration role between consumption areas. The price difference between markets can outweigh the extra costs of the maritime transport. The LNG market is a liquid market. According to the report of GIIGNL, 27 % of the total LNG volume was traded on spot or on short term basis in 2013[1], with the remaining 73 % traded on a medium or long term basis. Strict destination clauses may still apply; however, re-loading of LNG has increased its flexibility. The inherent flexibility of LNG leads to a high level of uncertainty when defining the potential LNG import scenarios to Europe. This will not only depend on the availability of LNG and liquefaction capacity, but also on the evolution of the energy demand, the price of alternative gas sources and the price of alternative fuels, in these competing markets.

1) GIIGNL report 2013: "The LNG Industry"

5.3.4.6 LNG supply scenarios

The range defined by the potential import scenarios for LNG reflects the particularly high uncertainty in the level of LNG supplies to Europe.

Maximum LNG scenario

The maximum supply scenario has been defined on the assumption of an increasing global LNG market, with Europe being a premium market. This means that European gas prices are comparatively higher than the price in competing markets and so they can attract LNG supplies.

The methodology used to define the maximum supply scenario applies the split between different current destination clauses (Europe / non-Europe / flexible) to the projected evolution of the LNG exports between 2014 and 2035. Europe is assumed to receive the LNG when the destination market is Europe as well as when the LNG is defined as flexible.

The projection of future world LNG supplies in 2035 (BP Energy Outlook 2030) is 830 bcma. The breakdown of this value per area is calculated by applying the following production share per area derived from the ExxonMobil Energy Outlook 2040 report: 30 % Atlantic basin, 20 % Middle East, 50 % Pacific basin. The table below contains the LNG production per area according to the existing contracts in 2014 (intermediate years have been interpolated).

EVOLUTION OF THE LNG EXPORTS PER AREA 2014 – 2035

bcma	2014	2015	2020	2025	2030	2035
ATLANTIC BASIN	113	119	152	184	217	249
MIDDLE EAST	155	156	158	161	163	166
PACIFIC BASIN	169	193	240	298	356	415

Table 5.13: Evolution of the LNG exports per area 2014 – 2035

The LNG production split in the following table is derived from the shares of the destination clauses of the existing contracts as in 2014.

SPLIT OF THE LNG EXPORTS DESTINATION BY AREA

%	to EU	to non-EU	Flexible
ATLANTIC BASIN	44	30	26
MIDDLE EAST	23	69	8
PACIFIC BASIN	0	96	4

Table 5.14: Split of the LNG exports destination by area

Applying these percentages to the LNG exports per area, and assuming that "Flexible" LNG is delivered to Europe, the maximum potential supply scenario for LNG is as follows:

SPLIT OF THE MAXIMUM SUPPLY SCENARIO PER PRODUCING AREA						
bcma	2014	2015	2020	2025	2030	2035
ATLANTIC BASIN	79	84	107	131	154	177
MIDDLE EAST	48	48	49	49	50	50
PACIFIC BASIN	7	8	10	12	14	17
TOTAL EU	134	140	166	192	218	244

Table 5.15: Split of the maximum supply scenario per producing area

Intermediate LNG scenario

The intermediate supply scenario for LNG is calculated as the average between the minimum and the maximum.

Minimum LNG scenario

The potential minimum LNG scenario has been defined on the assumption that current low levels of LNG imports cannot be sustained under a scenario of decreasing indigenous production and either increasing or sustained gas demand, and would not be consistent with increasing LNG regasification capacity. This scenario has been defined from the average LNG imports in 2011, 2012 and 2013, and is kept constant for the future.

POTENTIAL MINIMUM LNG SCENARIO		
Year	LNG imports (GWh/d)	Average 2011–2013
2011	2,427	1,744 GWh/d
2012	1,689	
2013	1,205	

Table 5.16: Potential minimum LNG scenario

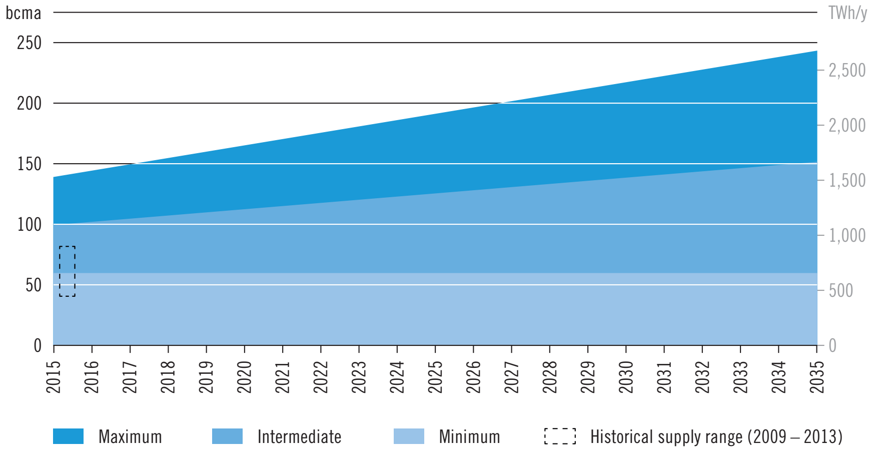


Figure 5.73: Potential LNG scenarios

POTENTIAL LNG SCENARIOS					
GWh/d	**2015**	**2020**	**2025**	**2030**	**2035**
MAXIMUM	4,129	4,904	5,679	6,454	7,229
INTERMEDIATE	2,951	3,339	3,726	4,114	4,501
MINIMUM	1,774	1,774	1,774	1,774	1,774

Table 5.17: Potential LNG scenarios

5.4 Aggregate potential supply to Europe

The potential supply to Europe is based on the aggregation of the scenarios defined above. As shown in the graph below, the three aggregate potential scenarios follow divergent trends. The maximum scenario represents a moderate increase (20%), while in contrast the intermediate scenario represents a moderate decrease (13%) and the minimum scenario represents a significant decrease (43%).

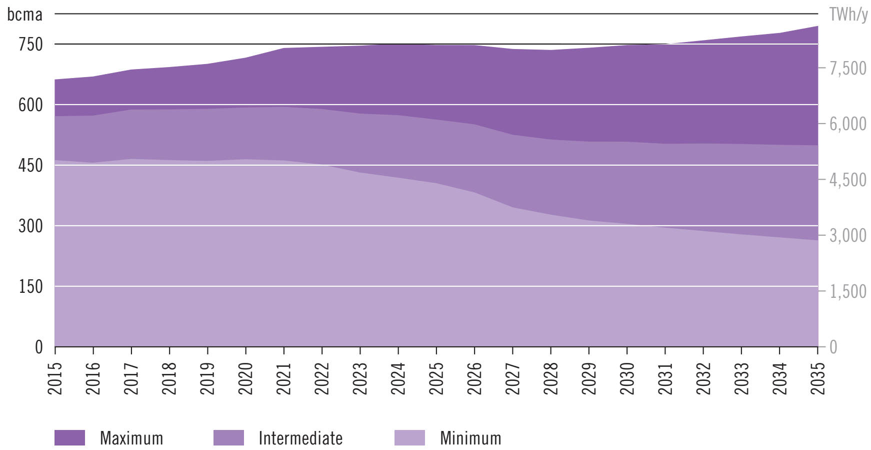


Figure 5.74: Aggregated supply potential to Europe

The following graphs show the evolution of the spread between the Minimum and Maximum potential supply scenarios. In absolute values, the maximum spread is found in LNG and Russian supply.

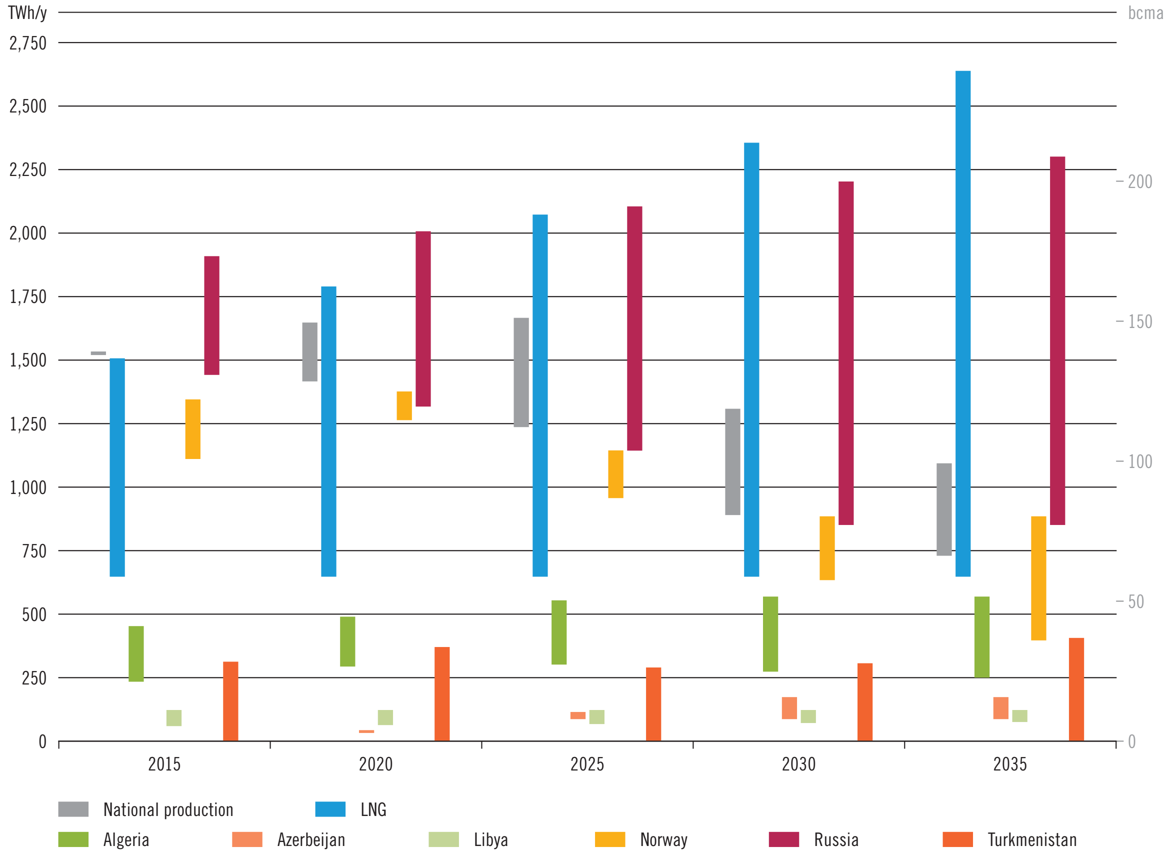


Figure 5.75: Evolution of supply ranges – Spread between potential maximum and minimum scenarios by source

EUROPE NEEDS TO ENLARGE ITS SUPPLY PORTFOLIO

When gas demand does not show a clear evolution, the requirements for gas imports are driven by the decreasing indigenous production. Under the current perspective the induced need for additional imports is likely to be met by Russian gas and LNG, especially under the Green scenario. In such a situation Europe would be in a challenging position resulting in a reduced market power.

Other sources are likely to stay at the current level (pipe gas from Algeria and Libya) or would only have a limited influence (Caspian gas) in absence of stronger market signals. Norway is a very particular case as there is a potential to deliver significant volumes from the Barents Sea gas fields from the mid 2020s. Nevertheless, the investments connecting this production to the existing European gas network is not yet decided and is in competition with potential LNG developments as a result of the lack of long term attractiveness of the continent. Other producers (e.g. North Africa and Middle-East) are facing the same challenges. Appropriate signals from Europe would enable the delivery of new supply to Europe improving both its energy security and its competitiveness while supporting high environmental standards.

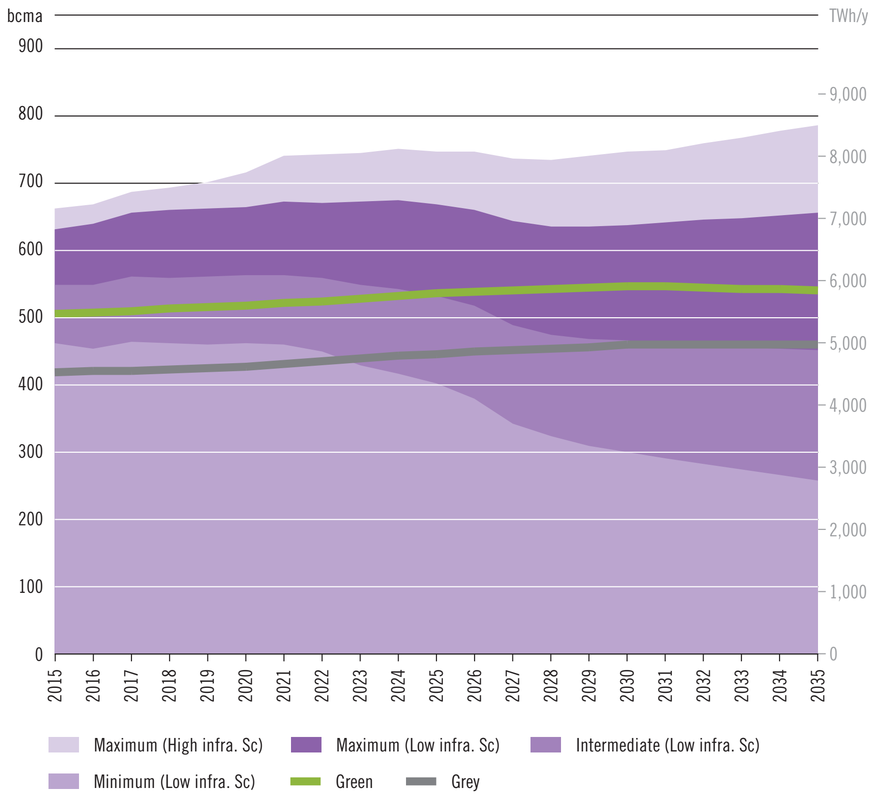


Figure 5: Comparison of gas demand and gas supply scenarios


Image courtesy of FluxSwiss

6 Assessment

Introduction | General trend
Infrastructure resilience
Influence of supply sources

Image courtesy of GRTgaz

6.1 Introduction

ENTSOG has carried out an extensive assessment of the European gas system in order to identify potential investment needs and solutions. This assessment represents the TYNDP-Step of the Energy System-Wide Cost-Benefit Analysis (ESW-CBA) and as such it focuses on different levels of infrastructure development rather than on single projects.

The analysis of project benefits will be carried out for each candidate Project of Common Interest submitted by promoters as part of the Project-Specific-Step of the ESW-CBA after the release of the Report. For this second PCI selection it is ENTSOG that will apply the methodology quantifying project benefits.

6.1.1 GENERAL CONSIDERATION ON ASSESSMENT RESULTS

In preparation to this individual assessment, the Report focuses on the Low and High Infrastructure scenarios. The assessment under the PCI one mostly served as a feedback loop to previous selection and results are very similar than under the High scenario.

As a comparison with TYNDP 2013, the assessment has been extended. First the considered period now covers a 21-year time horizon instead of a 10-year time horizon. This has increased the need to better capture future uncertainty through the selection of meaningful scenarios. Then the scope of the assessment is wider through the introduction of new indicators and financial analysis giving additional perspectives on the European gas system. New scenarios have been introduced for demand, infrastructure and gas prices.

The assessment also benefits from an enhanced modelling approach, which considers fuel prices, the dynamic simulation of gas demand for power generation and the seasonality of gas demand.

The following assessment results should not be understood as any form of forecast but rather as a robust approach identifying a potential future range of scenarios. This means that the evolution of indicator values over time and from one infrastructure scenario compared to another is more meaningful than the absolute values. In addition, there is no threshold defined for most indicators and this prevents the absolute definition of investment gaps. In the past, ENTSOG drew the attention of markets and institutions to this situation and the fact that defining a threshold level for triggering investment is beyond the remit TSOs and ENTSOG.

The results included in this chapter have been selected on the basis that they illustrate the main trends in the evolution of the European gas system. Detailed results are available in Annex E. The description of the modelling approach, indicators and financial analysis is available in Annex F.

6.1.2 INFRASTRUCTURE-RELATED MARKET INTEGRATION

ENTSOG has considered the full implementation of European regulations, which should result in gas flows reacting to price signals in every country. When considering the physical dependence on import sources, two approaches were analysed; one covered a focus on the national balance and one with a greater focus on cross-border flows.

Some limitations have been defined at supply source level in order to reflect possible contractual limitations such as contracted quantities and take-or-pay clauses.

The advantage of this assumption is to avoid the identification of erroneous investment gaps that might result from commercial arrangements. Such constraints should not be solved by infrastructure with long economic lifetime as this might create the risk of stranded assets.

The Report focuses on the infrastructure component of market integration. The modelling approach enables the assessment of the extent to which gas infrastructure (transmission, storage and LNG terminal) supports security of supply, competition and sustainability. In order to provide easily understandable results, ENTSOG has updated and developed its set of indicators together with the introduction of the financial analysis as a preliminary step of the project specific assessment. Indicators and financial analysis cover many different perspectives of the three pillars of the EU Energy Policy. It is often difficult to link a specific indicator to a single aspect of the EU Energy Policy; for example a project bringing a new source in one region will also improve source diversification and hence security of supply and competition.

6.2 General trend

The extension of the time horizon up to twenty-one years implies that the second part the Report covers a period likely to be very different from the current situation. In addition to the evolution of demand, the need for imports will depend on the availability of supply sources and the corresponding development of gas infrastructures. In order to identify the main drivers the analysis of such general trends is necessary.

6.2.1 EVOLUTION OF GAS DEMAND AND CO_2 EMISSIONS

The following graphs represent the average daily gas demand and CO_2 emissions resulting from the modelling of the Reference Case for the FID infrastructure scenario under the Green and Grey Global context. The results will be the same under the Non-FID scenario at the exception of Cyprus and Malta for which connecting projects are still not decided.

The fact that emissions marginally change between the two infrastructure scenarios illustrates that the impact of infrastructure projects on gas prices are not of the scale of the gas, coal and CO_2 price differential as defined by the Global Context.

This means that the analysis rather focuses on the adequacy of gas infrastructures and supplies to different Global Contexts which can only be influenced by global equilibrium and political actions (e.g. setting an appropriate ETS scheme).

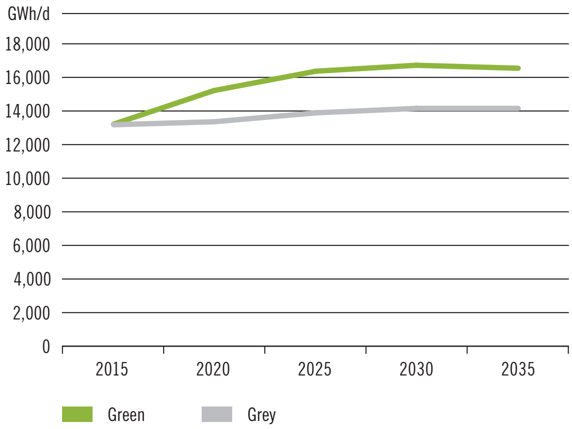


Figure 6.1: Evolution of total gas demand (Average day)

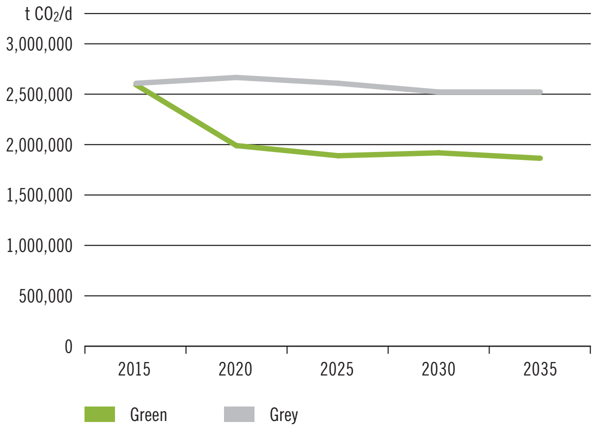


Figure 6.2: Evolution of the CO_2 emissions in the power generation sector (Average day)

The difference in the evolution of gas demand between the Green and Grey Global Contexts mostly arises from the power generation sector during the first five years of the time horizon; then after the difference remains basically stable. It derives from the fact that for 2015 gas, coal and CO_2 emission prices are set at the same level in both scenarios in order to reflect the current situation. Beyond 2020–2025, the Green scenario shows a gas demand level which is 16% higher than the Grey one but in terms of CO_2 emissions it is 25% lower than the Grey scenario. This opposite evolution of gas demand and CO_2 emissions illustrates the significant environmental advantage of using gas in the power generation sector.

6.2.2 EVOLUTION OF GAS SUPPLY

Over the TYNDP time horizon, Europe is likely to see major evolution in gas exports from surrounding regions. At the same time the LNG market is likely to change due to new available sources and hence this may lead to an evolution of its price in relation to pipeline bounded gas.

The following graphs represent the evolution of each source in the gas supply mix under:

- annual condition (Average day) with:
  - one pair of lines represents the minimum and maximum share of each source (respectively when the source is the most expensive then the cheapest) under the Low Infrastructure scenario
  - one pair of lines along the same approach under the High Infrastructure scenario
- peak condition (1-day Design Case) with one bar graph for the maximization of UGS (limited to a eighty percent deliverability) and another one for the minimization of UGS

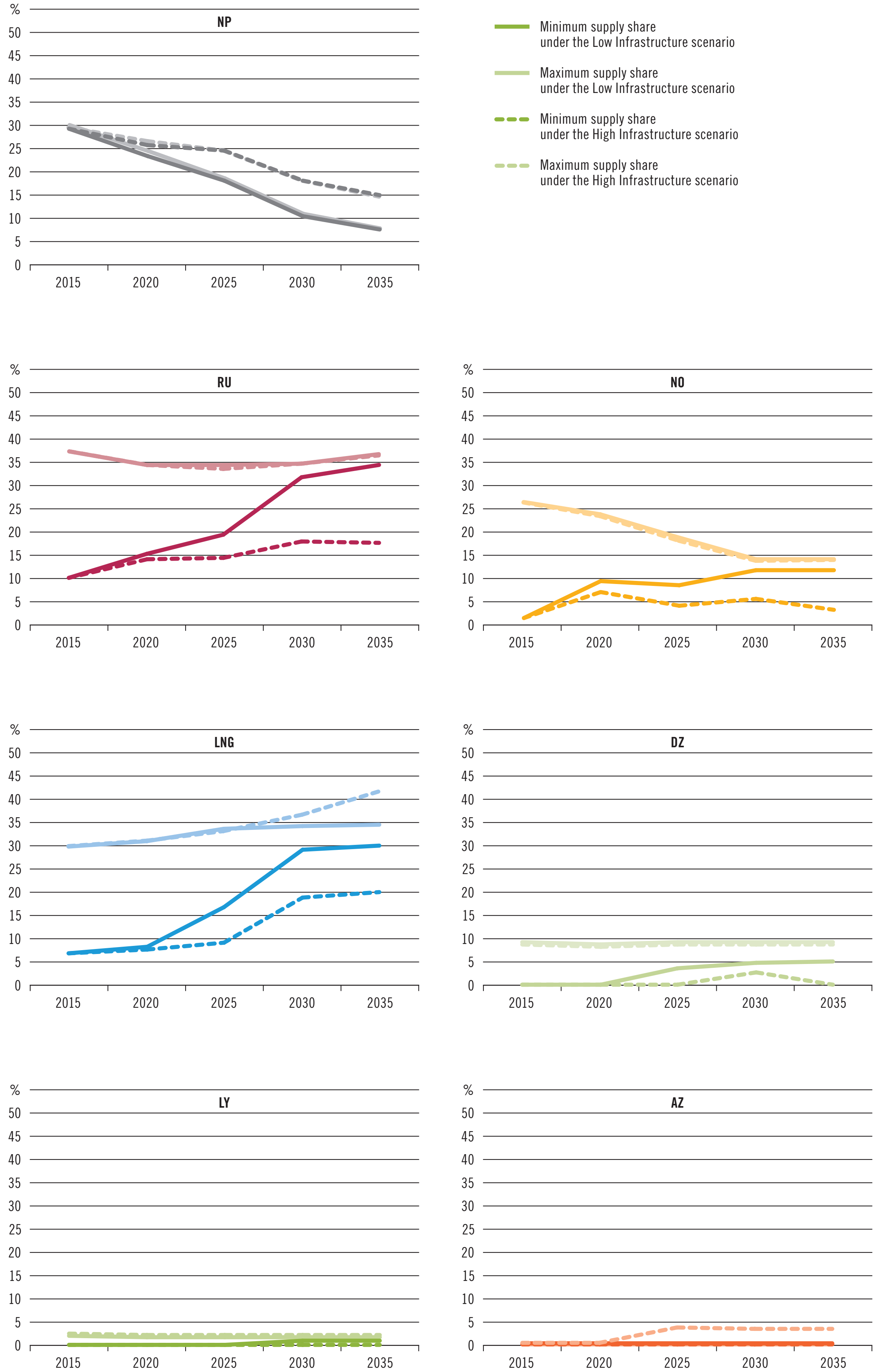


Figure 6.3: Minimum and Maximum supply share under Average day – Green scenario

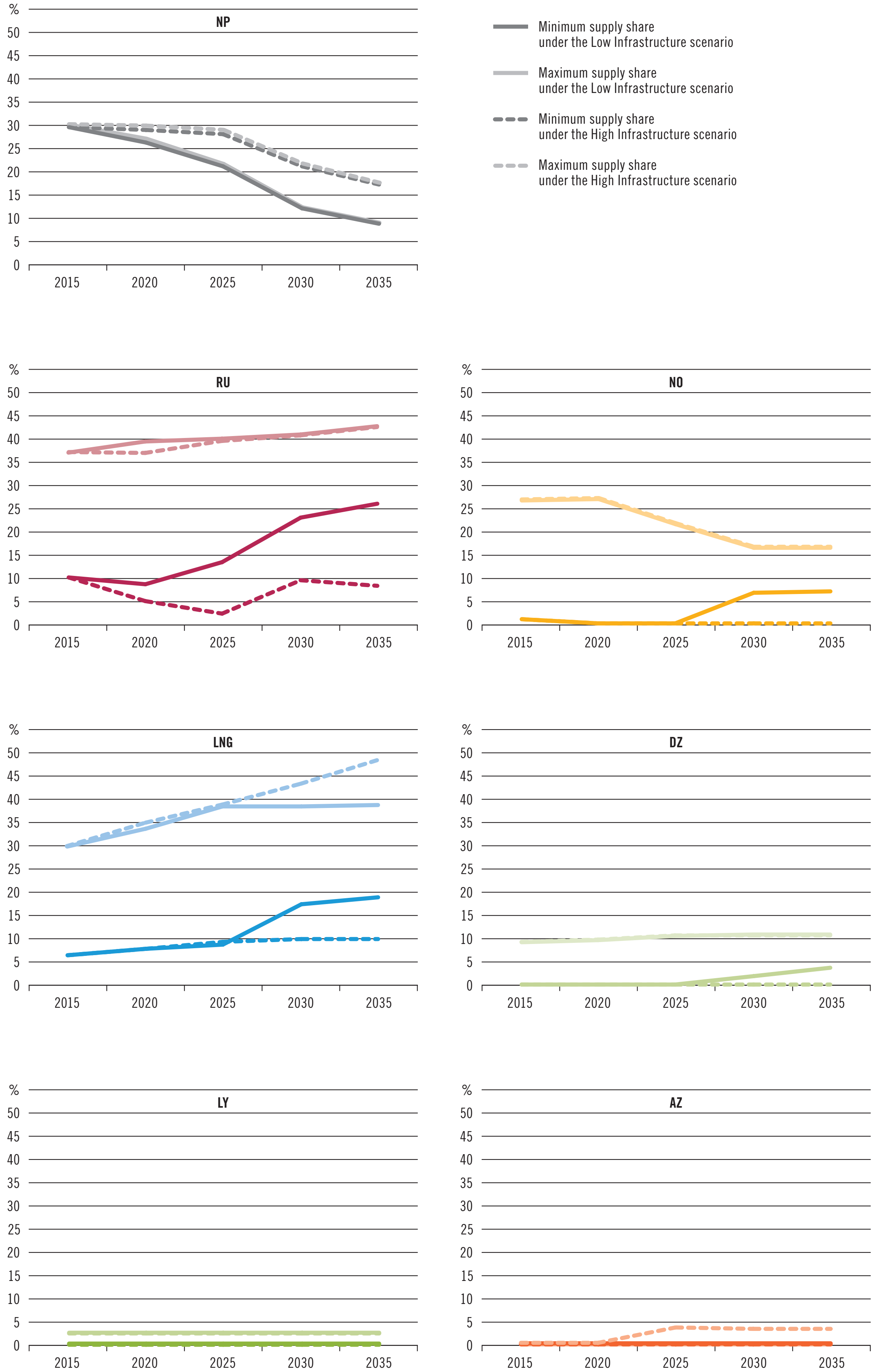


Figure 6.4: Minimum and Maximum supply share under Average day – Grey scenario

Figure 6.5: Supply shares under the 1-day Design Case – Green and Grey scenario

The graphs for Average day indicate the increasing predominance of Russian gas and LNG, even when more expensive than other sources, as they have to be used at a significant level. The additional supplies (Caspian gas, Romanian Black Sea, Cyprus national production, together with shale and biogas) under the High scenario can significantly mitigate the increasing dependence on Russian gas and LNG.

This confirms the findings of the supply chapter where the increasing need for imports can only be met by Russian gas and LNG, which have increasing availability over the time horizon, when Norwegian imports are decreasing and other import sources are too low.

This trend also appears on the graphs for the 1-day Design Case where it can also be noted the increasing minimum share in the coverage of peak demand along the time horizon. Under the High infrastructure scenarios additional supplies enable a lower minimum share of UGS in the coverage of the peak demand.

The next set of graphs illustrates the range of use of each import source compared to their minimum and maximum potential scenario under:

- annual condition (Average day):
  - the dots represent the deliverability of the sources as a percentage of their peak deliverability
  - the bars represent the range of use of the sources, the lower limits are set as the use of the sources under the expensive price configuration and the upper limits are set as the use of the sources under the cheap price configuration

- peak condition (1-day Design Case), the bars represent the range of use of the sources, the lower limits are set as the use of the sources under the expensive price configuration and UGS maximization and the upper limits are set as the use of the sources under the cheap price configuration and UGS minimization

This analysis of import sources shows that European gas system can take very high benefit from any source if its price decreases (the upper limit of the bar is very close from the dot). The only cases where the maximum potential scenario of a source is not reached are:

- For LNG in Design Case where the simultaneous delivery of all European terminals at maximum daily send-out capacity is slightly limited by gas infrastructure but Non-FID projects enable to reach a 95% load
- For LNG in 2035 for the Green scenario the offtake of LNG imports at the level of the maximum supply requires the commissioning of some Non-FID projects
- Under the Grey Scenario the lower demand level makes more difficult the reach of the maximum potential scenario especially:
  - Algerian gas in 2020 where this source are in competition with less elastic LNG in the two directly importing countries
  - In 2020 the additional indigenous production under the High infrastructure scenario (Romanian Black Sea, shale and biomethane) slightly hinders the maximization of the largest sources (LNG and Russian gas)

The width of the bars also illustrates the flexibility in the use of each supply source.

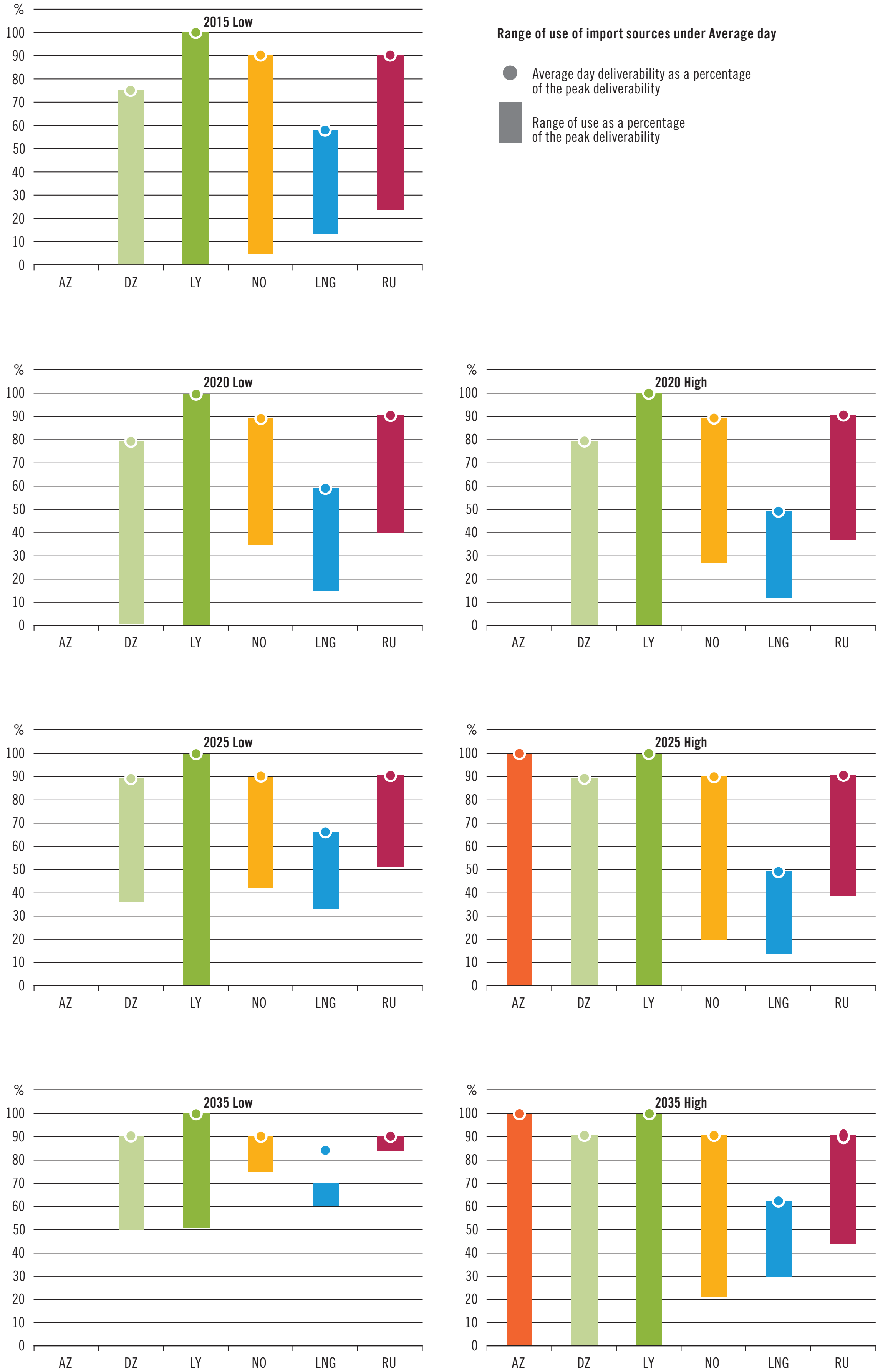


Figure 6.6: Range of use of each import source under Average Day – Green scenario

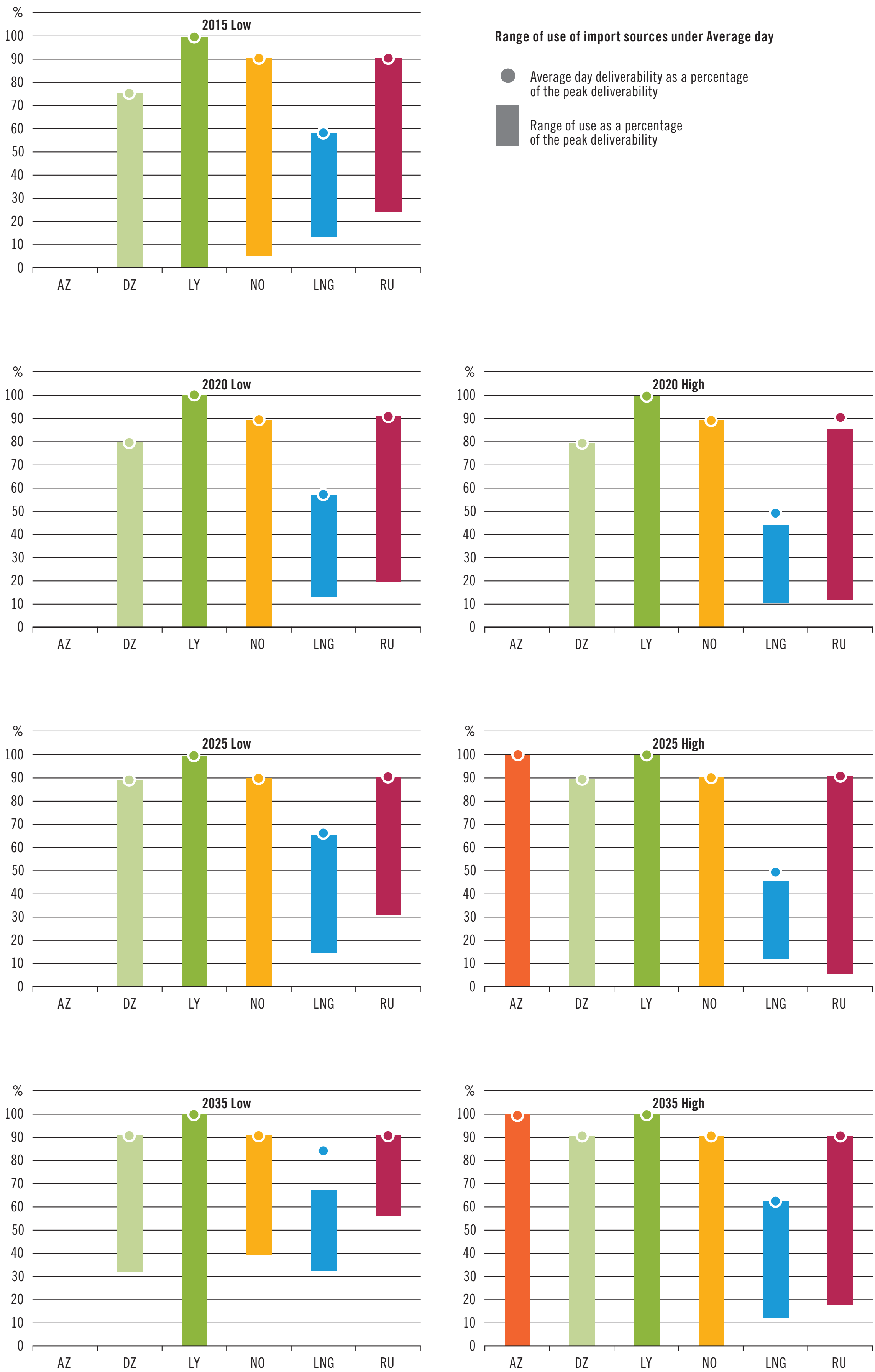


Figure 6.7: Range of use of each import source under Average Day – Grey scenario

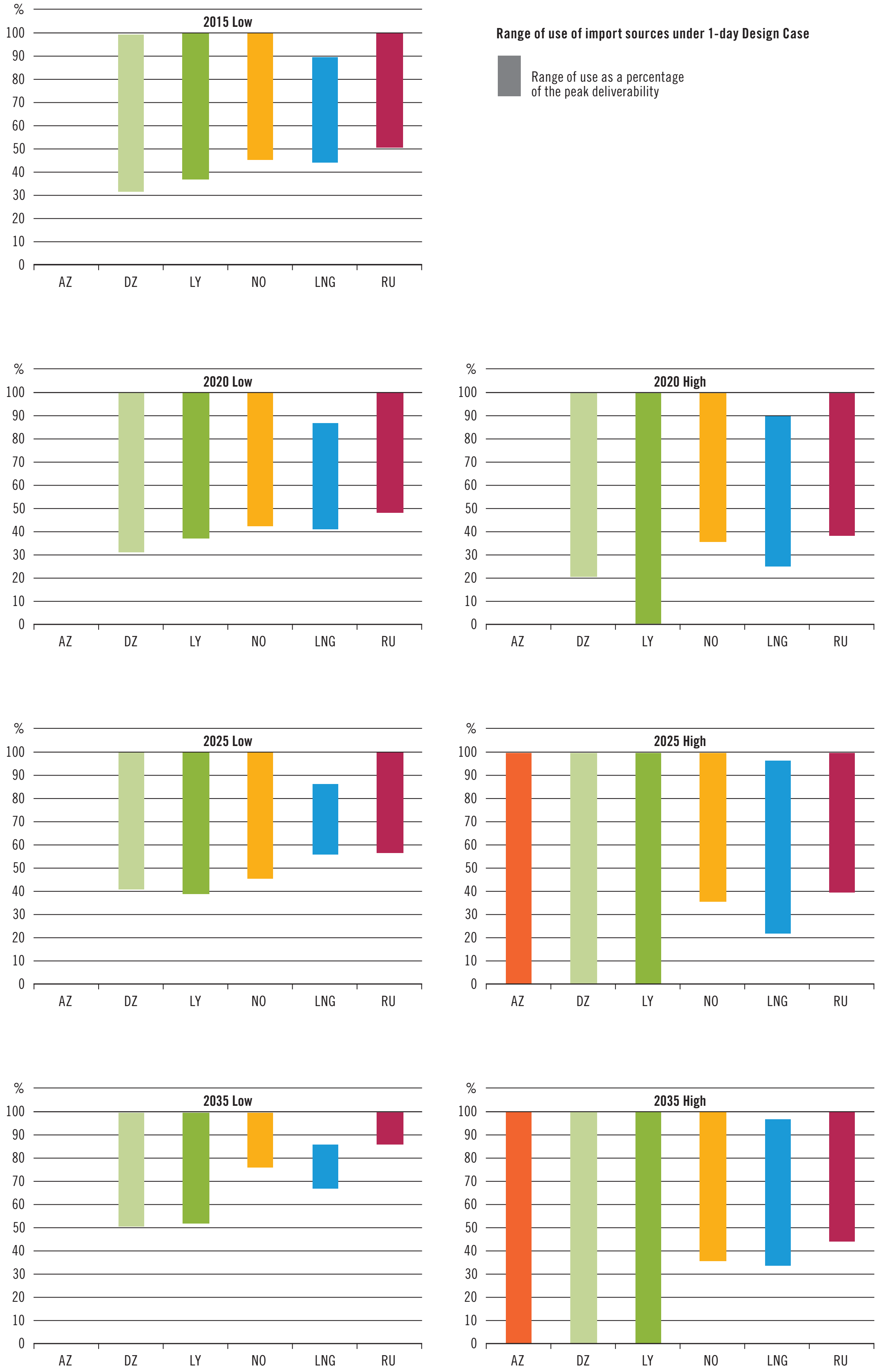


Figure 6.8: Range of use of each import source under 1-day Design Case – Green scenario

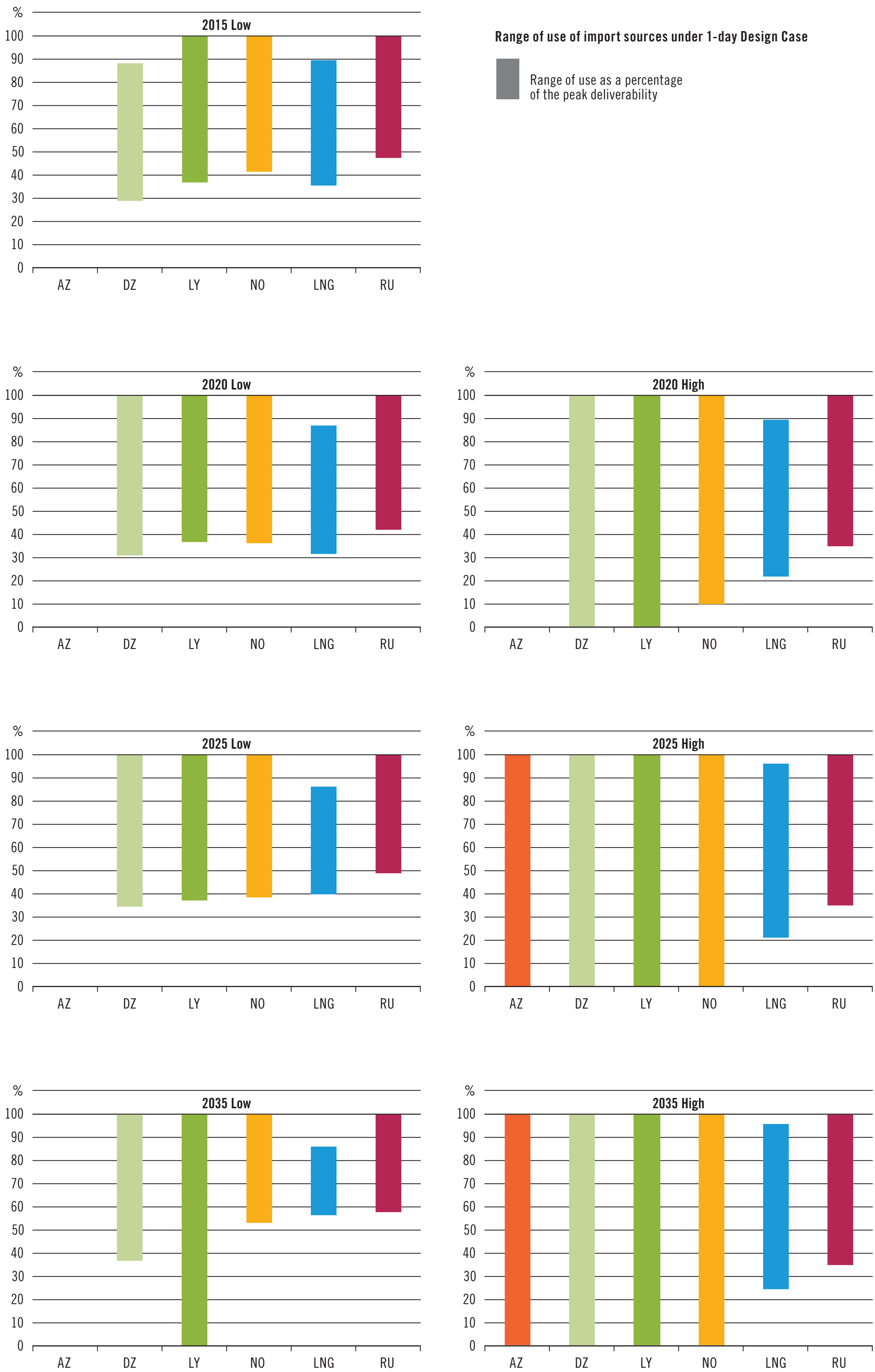


Figure 6.9: Range of use of each import source under 1-day Design Case – Grey scenario

This flexibility is very high in 2015 but goes reducing along the time horizon under the Green scenario. This indicates a tighter supply situation and less flexibility in the supply mix. This evolution starts later under the Grey scenario where lower demand requires less imports. The flexibility of large sources is also lower under the Design Case compared to the Average day despite the contribution of UGS.

Both for the Average day and the 1-day Design Case, the commissioning of Non-FID projects together with the connection of new sources help to maintain a high flexibility of the gas supply mix.

For the rest of the assessment chapter only the maximization of the UGS scenario was used. In respect of investment gap identification, this represents a conservative approach when considering the uncertainty around peak deliverability of import sources in the long term.

6.2.3 EVOLUTION OF USE OF UGS ON SEASONAL BASIS

Following graphs represent the share of the European aggregated UGS working gas volume (WGV) being injected and withdrawn during the year according to the simulations and driven by the seasonal swing of demand. Such volume should not be confused with the highest level reached by UGS over the year. As the model does not consider either the anticipation of a prolonged security of supply crisis or daily variability of power generation, the use of storage is only driven by cover of the seasonal swing and therefore only one annual cycle is considered. In addition sufficient gas should be present in the storages in order to ensure sufficient deliverability in case of peak demand or supply stress.

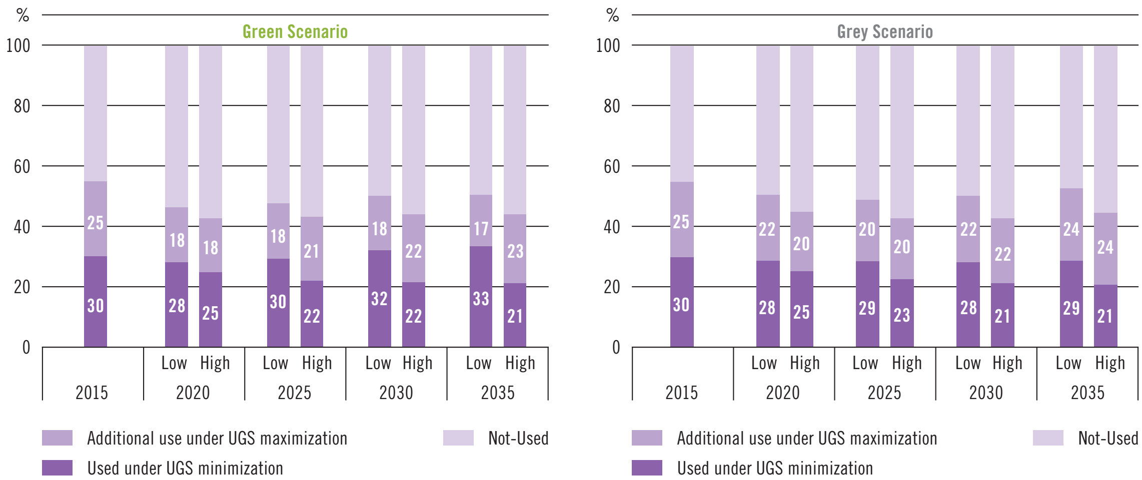


Figure 6.10: Seasonal variation of the WGV (% of capacity). Green scenario (left) and Grey scenario (right)

The graphs present the use of the WGV considering two UGS scenarios, where all seasonal swing is met by UGS (UGS maximization) and another where most of the swing is met by imports (UGS minimization).

The commissioning of UGS projects by 2020 could result in a decrease of the use of each individual UGS facility as the need for storage will be spread across more facilities. Beyond 2020 the use of storage would grow under the FID scenario as a result of the combined effect of no new UGS projects, decreasing indigenous production and no additional supplies such as Caspian gas. Small differences between the two Global Contexts are driven by higher relative seasonal swing in Grey and less competition for cheap supply due to overall lower demand in Grey, which could be stored in UGS.

6.3 Infrastructure resilience

This part of the assessment carried out by ENTSOG focuses on the ability of the European gas system to meet the supply demand balance under stressed situations. Such stress can result from climatic conditions (higher demand) or supply unavailability (source or infrastructure).

6.3.1 DISRUPTED DEMAND AND REMAINING FLEXIBILITY

Unlike previous TYNDPs, the Report does not identify which projects might directly mitigate the risks of demand disruption or low Remaining Flexibility. This change results from the new role of the TYNDP which is the basis for the selection of Project of Common Interest. The Report should not define the benefits of a project under a single criterion and the project specific assessment, defined by the TEN-E Regulation, will cover multiple criteria for assessing each candidate Project of Common Interest.

6.3.1.1 Evolution of demand disruption at aggregated European level

The following graphs show the disrupted demand under the two peak situations considered (1-day Design Case and 2-week Uniform Risk) at the aggregated European level for each Global Context. The level of disruption is directly influenced by the assumed eighty percent UGS deliverability under periods of high daily demand. Since 2007[1], storage has always had a sufficient volume in February to ensure a ninety percent deliverability rate with the exception of the February 2012 cold spell, when the withdrawal rate was limited to seventy percent.

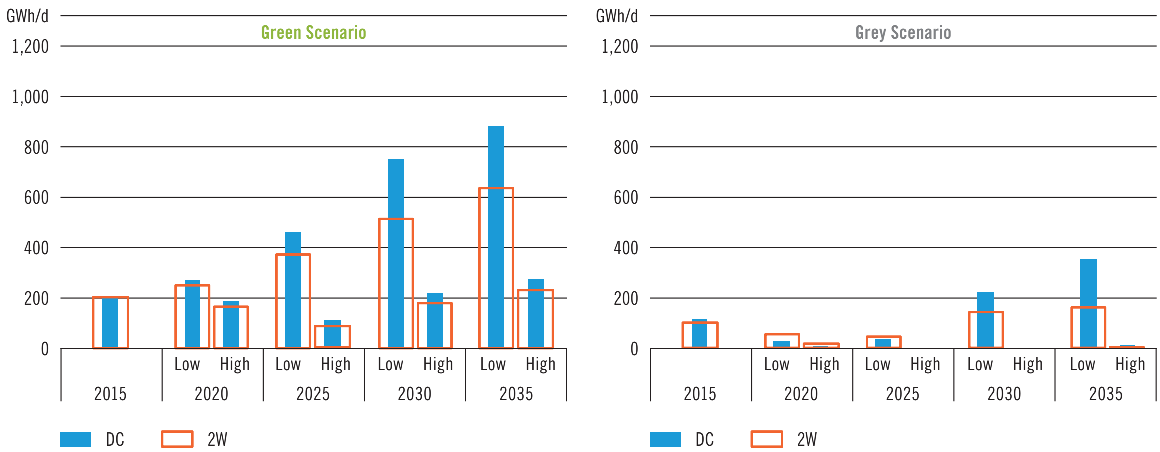


Figure 6.11: Disrupted demand (daily value) on the peak day and 2-week Uniform Risk average day. Green scenario (left) and Grey scenario (right)

1) This date refers to the start date of historical data on AGSI+ platform of GSE

In most of the cases, demand disruption is higher under the 1-day Design Case compared to the 2-week Uniform Risk due to the higher demand level. The only exceptions are in the Grey scenario for 2020 and 2025 when demand disruptions mostly occur in Greece where the peak balance relies on LNG tank storage. These facilities are usually not able to deliver at their maximum rate for a continuous fourteen day period assuming that there will be no additional cargo compared to an Average Winter day. This constraint is factored in the modelling approach.

The evolution of the European aggregated demand disruption under the Green and Grey scenarios is very similar the latter being lower due to overall lower gas demand. This shows that without new infrastructure projects demand disruption will increase in the most vulnerable areas as a result of higher demand and lower indigenous production. The commissioning of Non-FID projects enhancing market integration of the most affected areas and additional supply in the high scenario will strongly mitigate even if not completely under the Green scenario.

6.3.1.2 Geographical perspective of the Demand Disruption and Remaining Flexibility

The demand disruption analysis of the European gas system covers situations of high daily demand (1-day Design Case and 2-week Uniform Risk). The analysis is being carried out with and without import disruptions (being technical or transit ones).

The Remaining Flexibility indicator (RF) measures the resilience of a Zone. 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. This calculation is made independently for each Zone meaning that they do not cooperate when accessing the European supply flexibility. The higher the indicator value is, the better the resilience. In the case the RF is zero, the assessment provides the percentage of the Zone demand which is disrupted.

This new definition of the RF better measures possible supply or infrastructure limitations upstream from the considered country (see Annex F for the description of the indicator). As a consequence, identified RF levels are lower compared to those of TYNDP 2013. In addition, the new approach provides a better measure of the ability of the European gas system, from a supply perspective, to meet demand increases in small countries. Countries with large interconnection and relatively low demand will have a higher RF.

In cases where the RF reaches zero, this indicator is replaced by the Disrupted Demand rate (DD) of the Zone. The level of disruption derives either from a cooperative approach (under the disruption cases) or uncooperative approach (under normal situation) between European countries in order to mitigate its relative impact.

The following maps present results for the most extreme scenarios, which are the 1-Day Design Case of the Green Scenario both with and without disruption of Russian gas transit through Belarus or Ukraine. In case of disruption, the flow pattern resulting from modelling minimises the demand curtailment by spreading it between more countries. Comprehensive results for all cases can be found in Annex E with the other import disruptions which are not inducing additional demand curtailment.

6.3.1.3 Peak day under normal situation (without disruption)

The modelling approach does not provide flexibility between coal and gas in the power generation sector under the 1-day Design Case and 2-week Uniform Risk. This reduces the uncertainty on the peak gas demand and avoids to give an over optimistic perspective of RF that would result from a massive switch to coal under peak situation. This explains the demand disruption of Finland, FYROM and Greece even in 2015 at least for the Green Scenario. Part of demand curtailment in Greece derives from the very high share of gas-fired power generation estimated in line with the Vision 3 of ENTSO-E.

The higher aggregated demand in the Green Scenario results in a lower level of RF at the European level. The only exception is for the United-Kingdom in 2035 where demand is higher in the Grey scenario and the Remaining Flexibility lower.

The overall trend under the Low Scenario is a decrease of the RF and an increase of demand disruption in certain Baltic and South-Eastern Europe regions especially in the Green Scenario. This negative evolution is completely mitigated under the High Scenario for all countries with the exception of Bosnia-Herzegovina, Serbia and FYROM. This improvement results from the combined effect of new infrastructure projects enabling a better market integration and additional indigenous production (Black Sea, Cyprus, Shale gas and Biogas) as well as LNG terminals in areas where they grant the access to additional supply.

Romania's increasing demand can only be met through the decision to produce and connect Black Sea gas fields as assumed in the High Scenario. This has been taken into account only for the duration of current gas exploration licenses, which expire between 2030 and 2035.

In Sweden and Denmark there will be an increase in the RF with the extension of the interconnection with Germany at the end of 2015 (not considered in 2015 case). In the long run the situation will continue to improve as the result of demand decreasing in Denmark and Germany at a faster rate than indigenous production.

◢ **See figures 6.12 and 6.13 on pages 148–149**

6.3.1.4 Peak day under Ukrainian disruption

From a European perspective, the disruption of transit through Ukraine results in a lower availability of supply as Russian gas cannot be completely diverted through other routes. This is becoming more significant along the time horizon under the Green Scenario as the need for imports is growing. The impact of the disruption is gradually moving from a regional issue (South-Eastern Europe and slight impact on Poland) in 2015 to a European wide issue by 2035.

For South-Eastern Europe, the situation temporarily improves in 2025 with new supply and infrastructure projects in the High Scenario. In 2035, the increase in demand and the assumptions regarding Romanian Black Sea production (potential limited in time to the existing licenses) puts the region under pressure. An extension of the licenses and/or additional discoveries would mitigate this risk.

◢ **See figures 6.14 and 6.15 on pages 150–151**

6.3.1.5 Peak day under Belarus disruption

Under the Low Scenario, the impact of a transit disruption through Belarus would be limited to Baltic countries (from Finland to Poland) and there are enough Non FID projects to completely mitigate the impact by 2020.

Under the High Scenario, new infrastructure projects and additional supplies are mitigating the risk of disruption.

◢ **See figures 6.16 and 6.17 on pages 152–153**

6.3.1.3 Peak day under normal situation (without disruption)

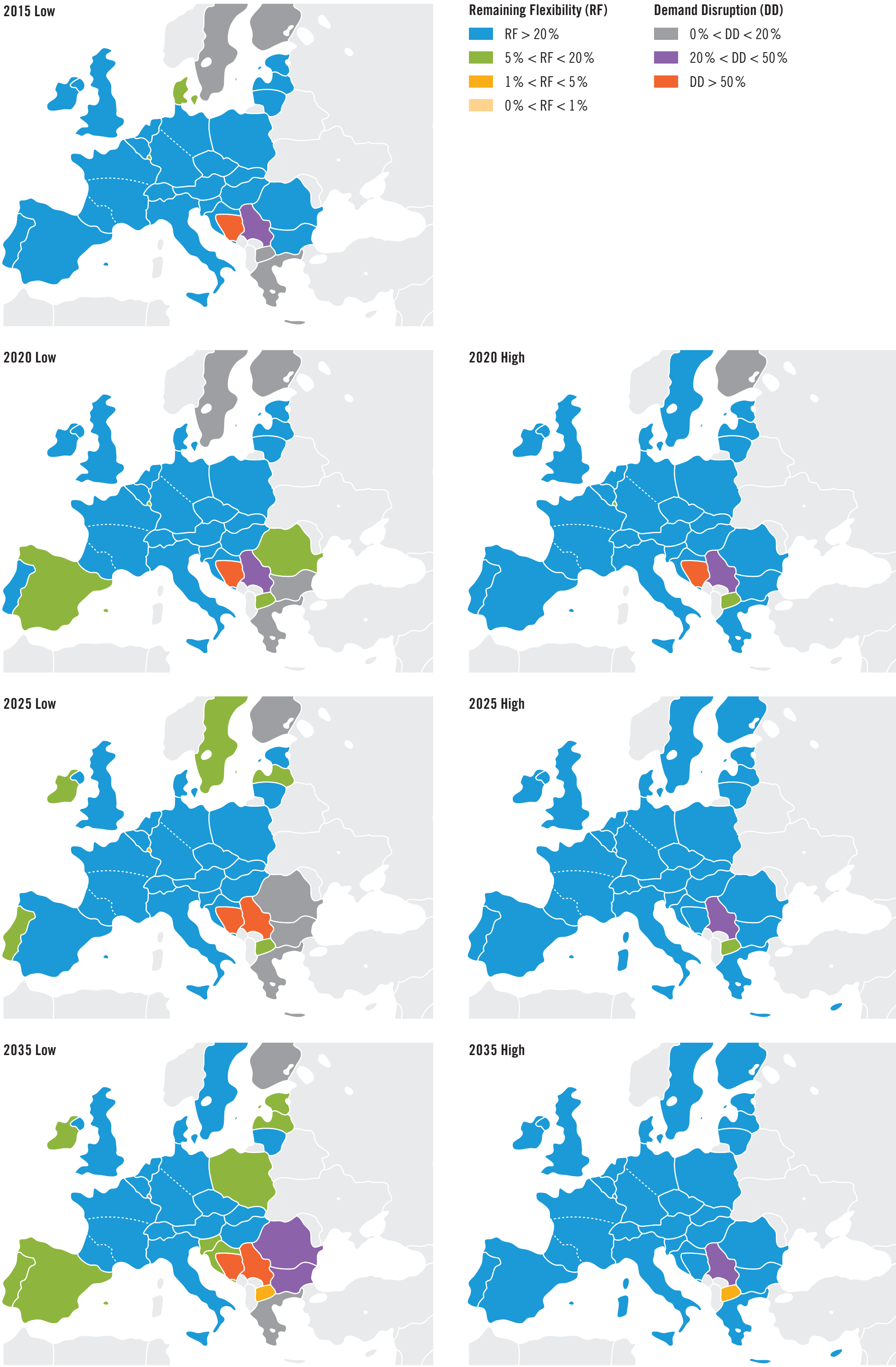


Figure 6.12: Evolution of Disrupted demand (DD) and Remaining Flexibility (RF). Normal conditions. Green scenario

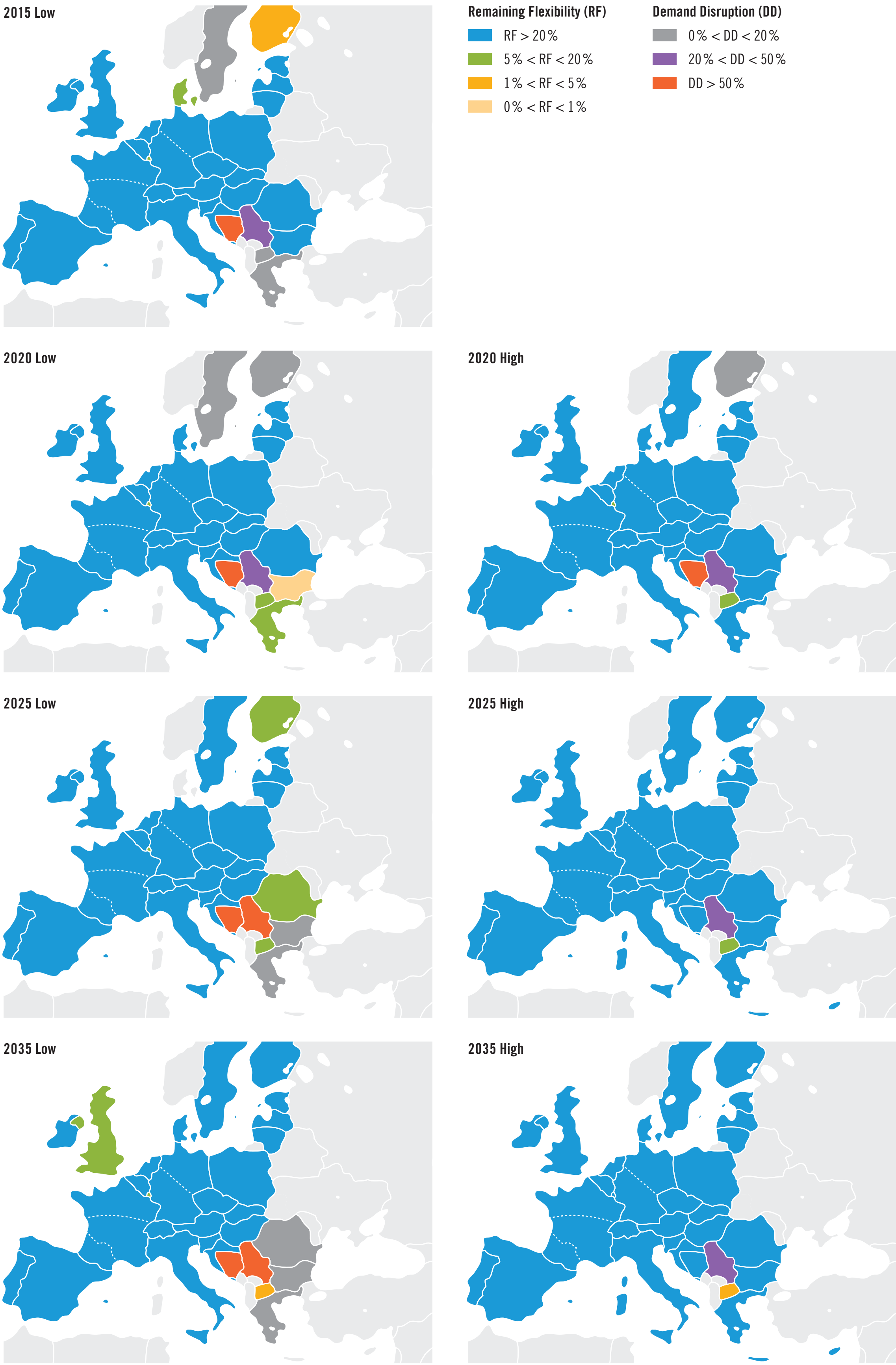


Figure 6.13: Evolution of Disrupted demand (DD) and Remaining Flexibility (RF). Normal conditions. Grey scenario

6.3.1.4 Peak day under Ukrainian disruption

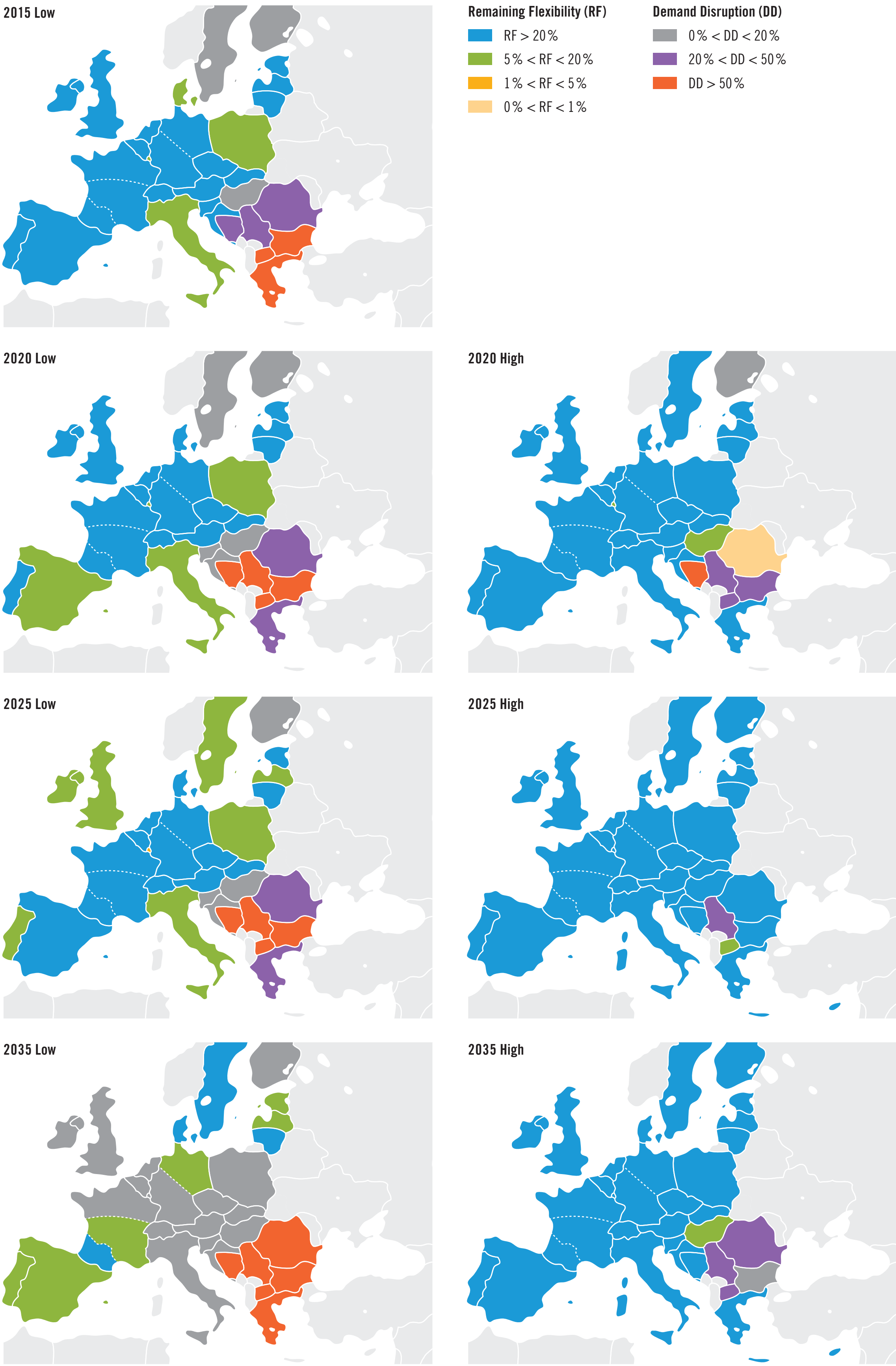


Figure 6.14: Evolution of Disrupted demand (DD) and Remaining Flexibility (RF). Ukrainian disruption. Green scenario

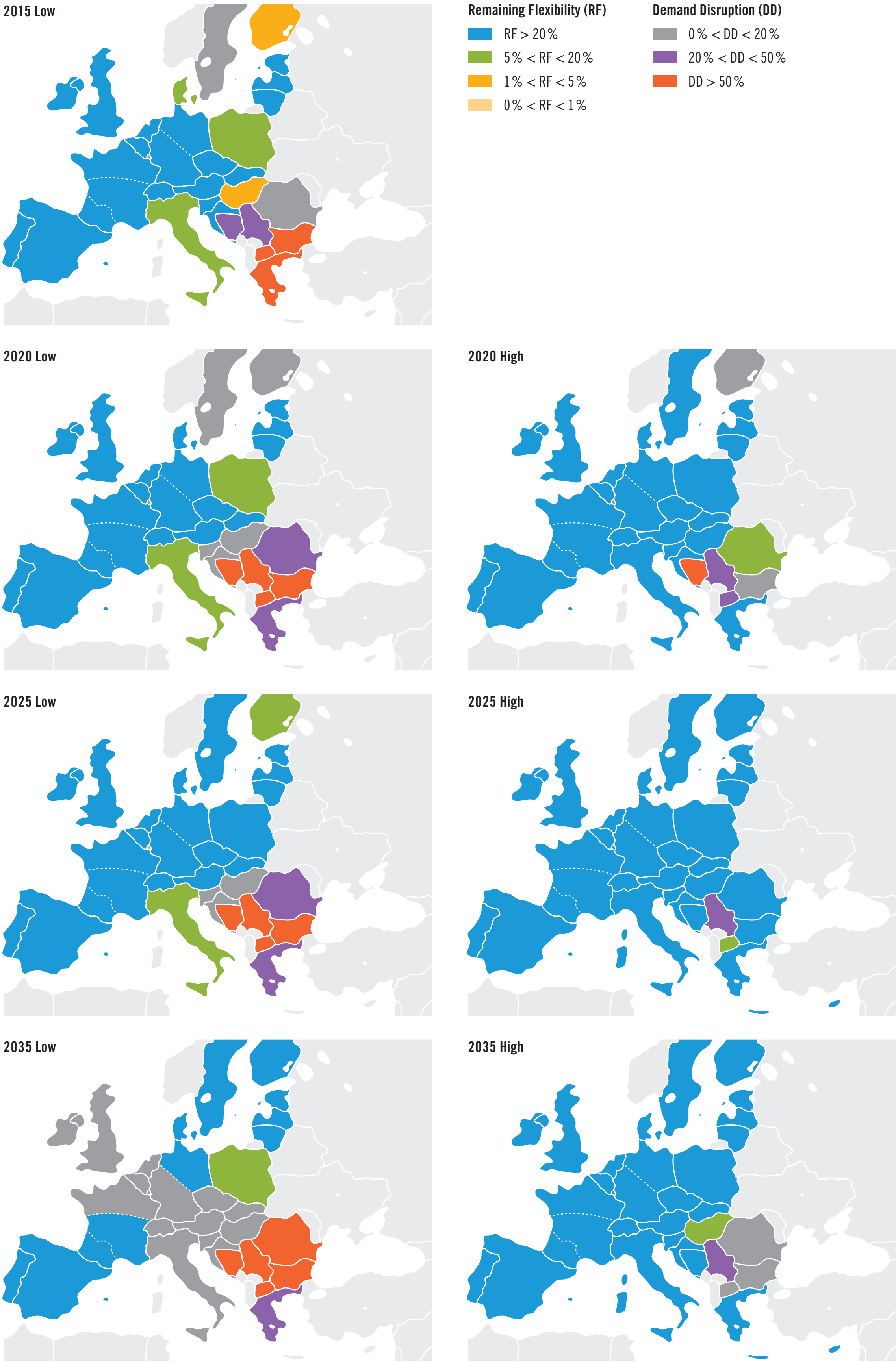


Figure 6.15: Evolution of Disrupted demand (DD) and Remaining Flexibility (RF). Ukrainian disruption. Grey scenario

6.3.1.5 Peak day under Belarus disruption

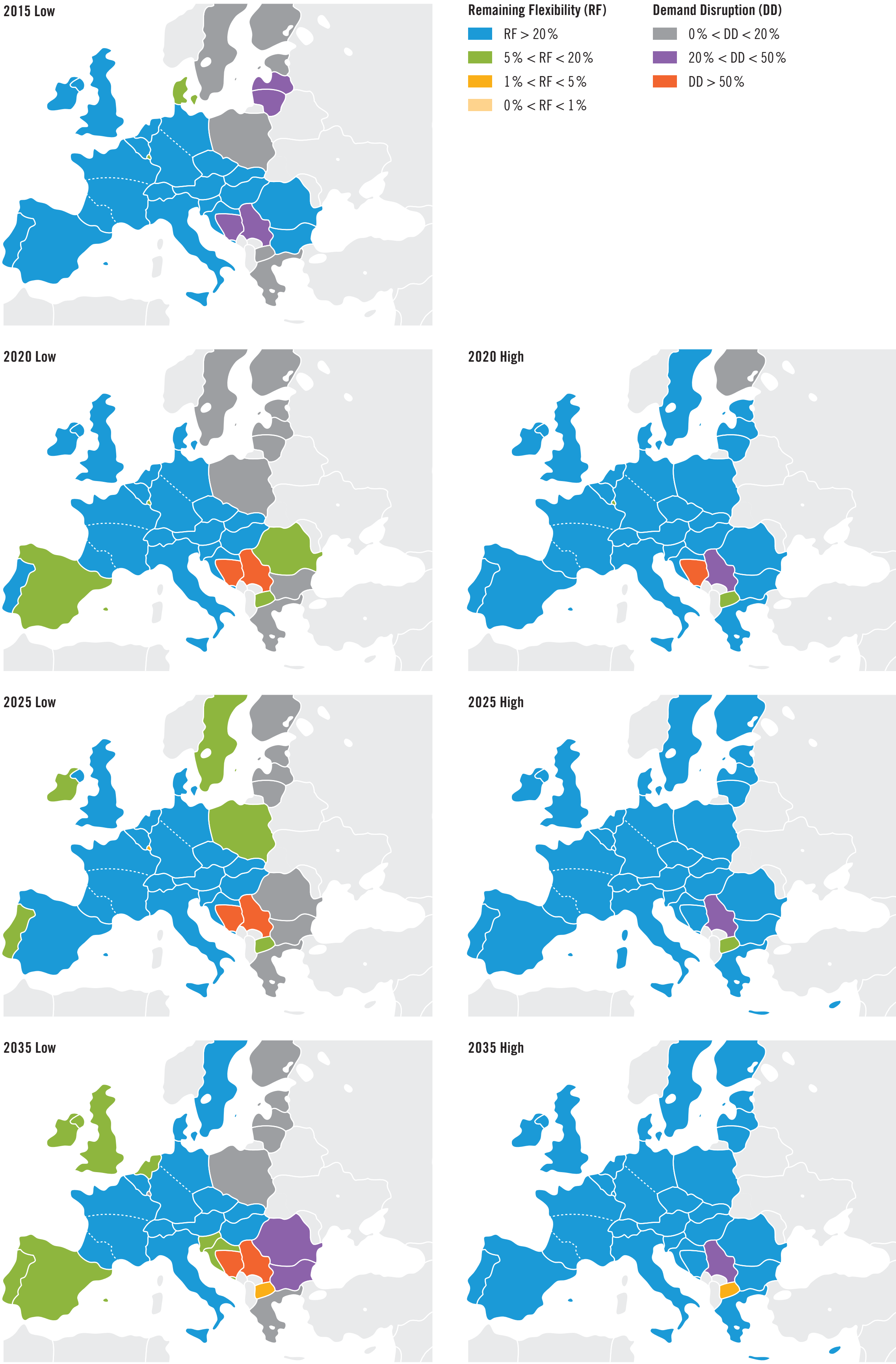


Figure 6.16: Evolution of Disrupted demand (DD) and Remaining Flexibility (RF). Belarus disruption. Green scenario

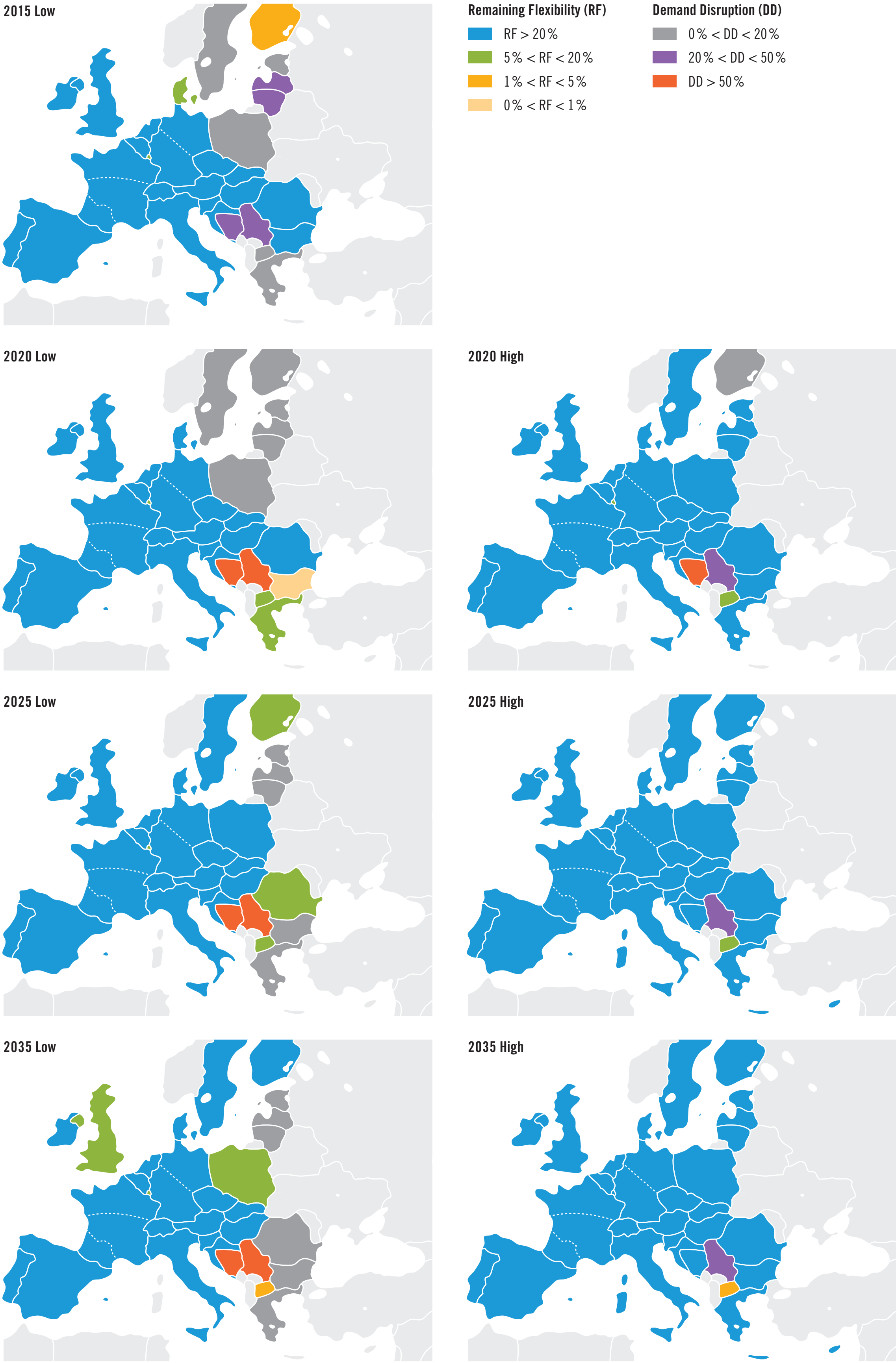


Figure 6.17: Evolution of Disrupted demand (DD) and Remaining Flexibility (RF). Belarus disruption. Grey scenario

6.3.2 CAPACITY-BASED INDICATORS

The capacity-based indicators focus exclusively on the infrastructure component of system resilience. These indicators consider the quantity and diversification of entry capacity and not the availability of supply.

6.3.2.1 Import Route Diversification (IRD)

The Import Route Diversification indicator focuses on how balanced the import capacity of a given Zone is. For example, a Zone is better diversified, from an import infrastructure perspective, if its entry capacity is equally split between four borders rather than being one predominant. The indicator formula is similar to the Herfindahl-Hirschman-Index (HHI) and hence, the lower the value, the better the diversification.

Figure 6.18 shows the evolution of the IRD indicator. There is no defined threshold for this indicator, hence three ranges have been defined from an equal distribution of the year 2015 i.e. one third of the Zones had an IRD below 3,585 (33-percentile), one third between 3,585 and 6,153 and one third above 6,153 (66 percentile).

The IRD indicator is only linked to infrastructure. The commissioning of FID projects is not sufficient to improve the situation of less diversified countries. The implementation of Non-FID projects would ensure that all countries, with the exception of Sweden, FYROM and Cyprus, at least reached the intermediate range.

See figure 6.18 on page 155

6.3.2.2 N-1 for ESW-CBA

The N-1 indicator is calculated for each country and derives from Regulation (EC) 994/2010 on Security of Supply. It focuses on the peak demand situation with the loss of the single largest infrastructure. It differs from the original indicator calculated by the Competent Authorities as it has to be:

- computed on a twenty-one year time horizon
- consistent with the capacity used in the Report (application of the lesser of rule to the capacity level on each side of a flange)

The higher the indicator value, the better the resilience.

Figures 6.19 and 6.20 show the evolution of the N-1 indicator for each country for both Green and Grey scenarios.

For both Green and Grey scenarios, the 2015–2020 evolution shows that FID-projects improve the situation in Scandinavia. At the same time, increasing demand in Poland reduces resilience. The implementation of Non-FID projects together with additional indigenous production will largely improve the situation across Europe and especially in South-Eastern Europe. Beyond 2020, the situation remains stable.

See figures 6.19 and 6.20 on pages 156–157

6.3.2.1 Import Route Diversification (IRD)

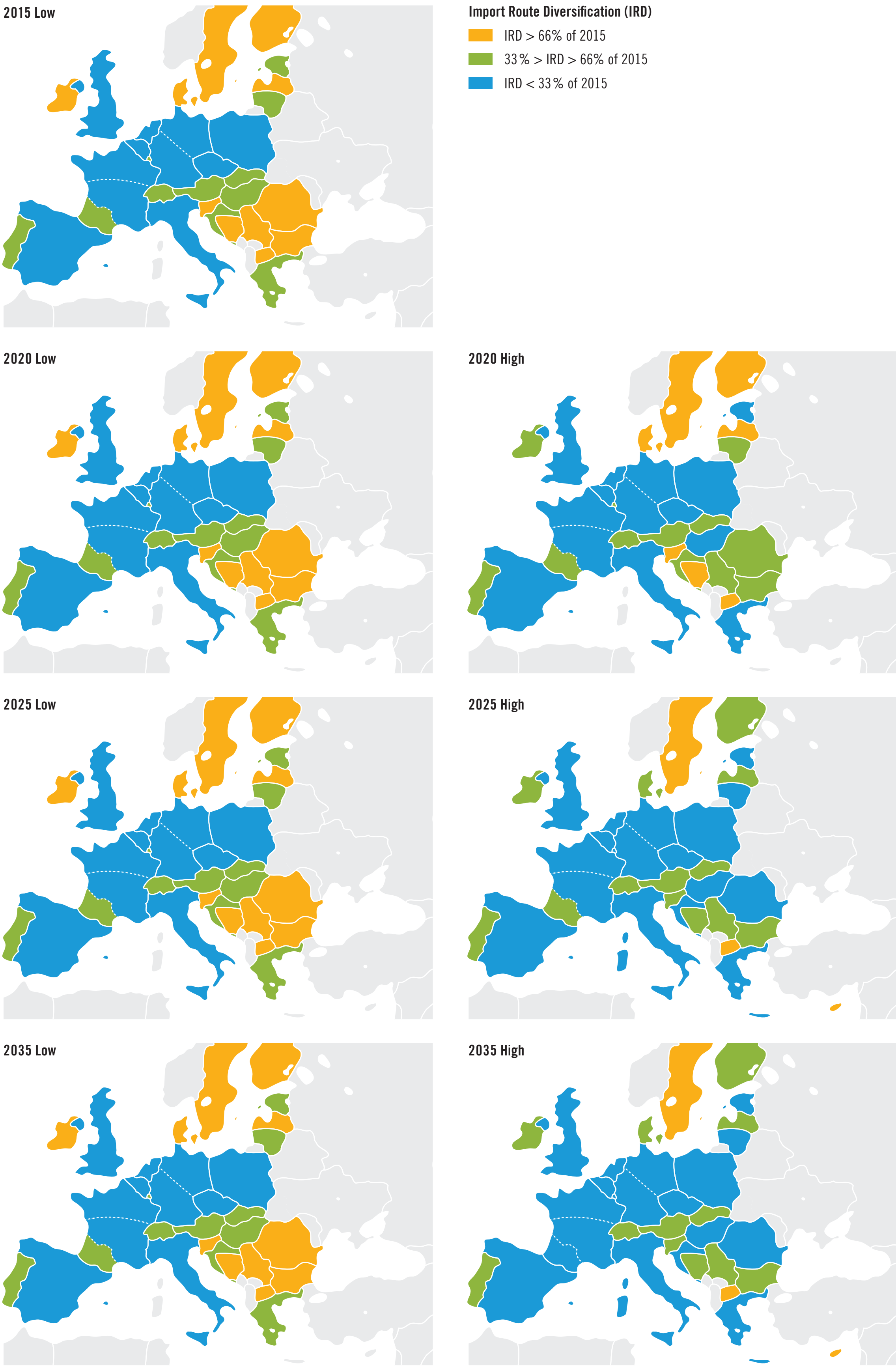


Figure 6.18: Evolution of IRD index

6.3.2.2 N-1 for ESW-CBA

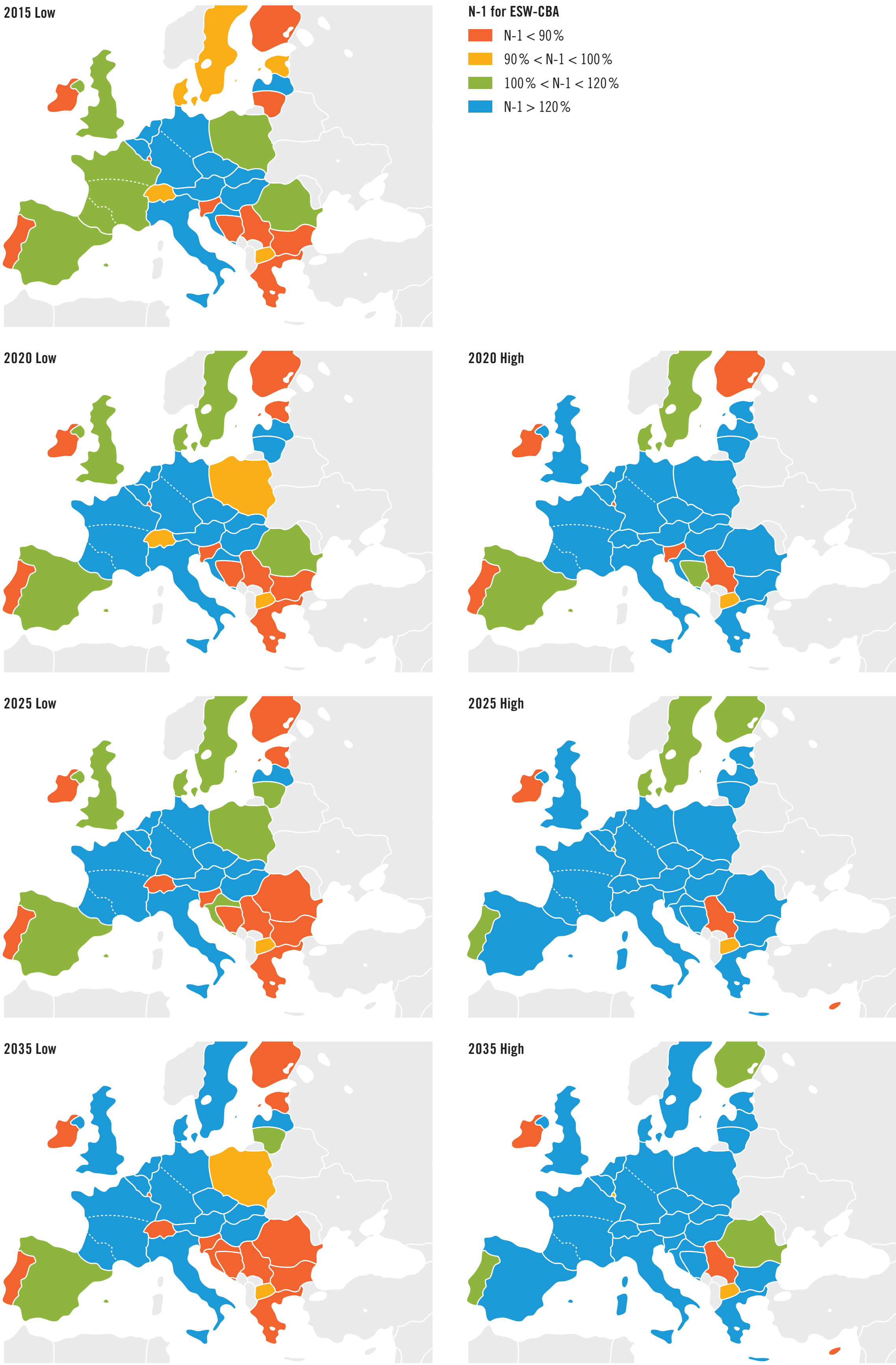


Figure 6.19: Evolution of N-1 index. Green scenario

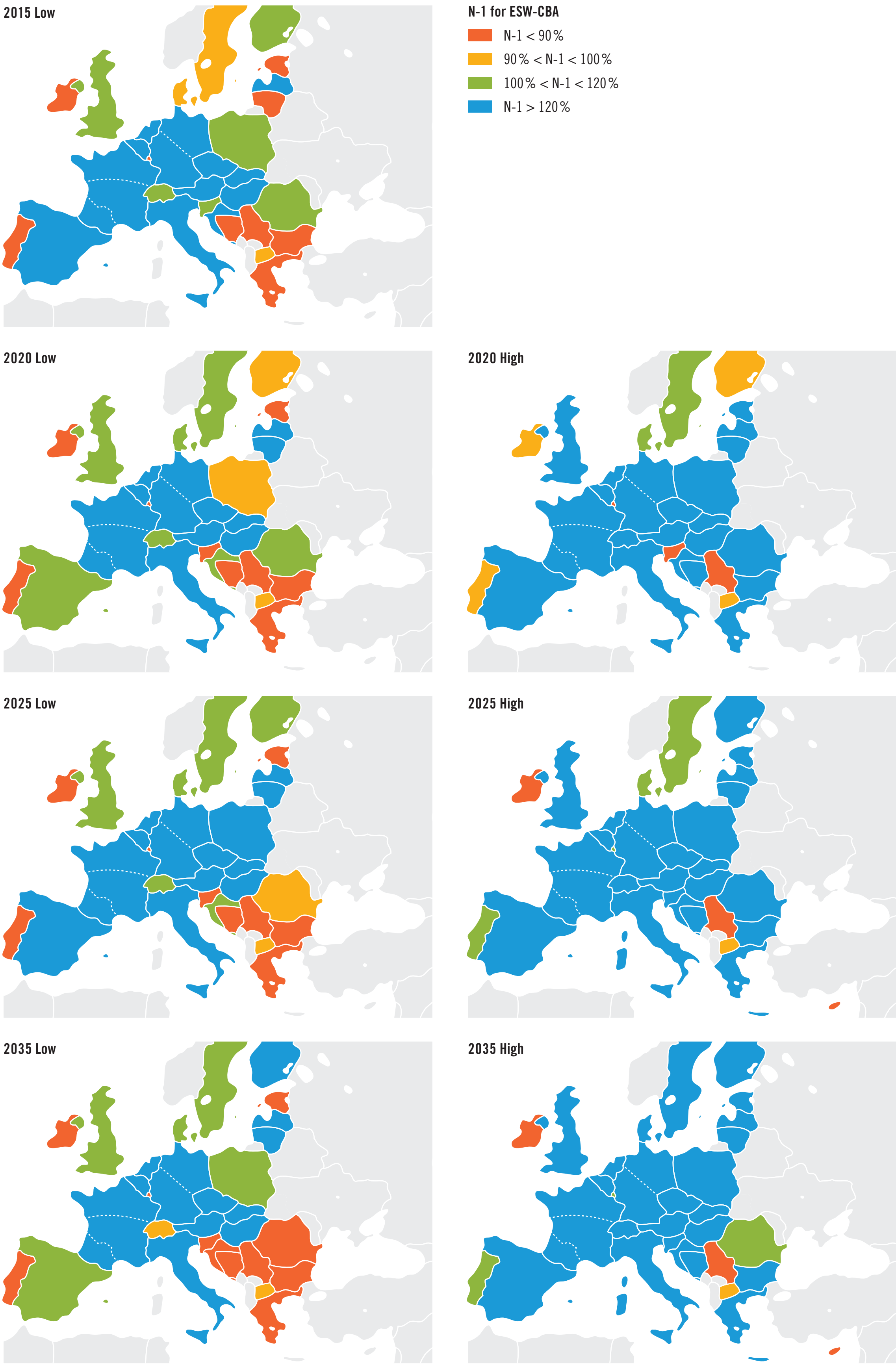


Figure 6.20: Evolution of N-1 index. Grey scenario

6.4 Influence of supply sources

This part of the assessment analyses the nature of the gas made available. It is carried out throughout the year including summer, winter and peak days.

The aim is to identify supply sources having a predominant role in the demand-supply balance for each country. This dependence is measured through the following indicators:

- From a physical perspective through the Cooperative and Uncooperative Supply Source Dependence
- From a price perspective through the Supply Source Price Dependence

This part of the assessment also measures the ability of each country to benefit from a reduction of the price of one or several import sources through the Supply Source Price Diversification indicator.

The existence of a global LNG market with one reference price leads to the consideration of LNG as a single source once it has entered the European gas system. From a security of supply perspective it is also important to acknowledge the embedded diversification of LNG supply. For this reason ENTSOG has not identified any LNG disruption event that could have a European impact. Therefore no LNG disruption was considered. In addition, the report identified in particular the ability of countries to benefit from further diversification through LNG due to its embedded diversification.

Image courtesy of OpenGrid Europe

6.4.1 PHYSICAL DEPENDENCE

This part of the analysis measures the extent to which an import source is physically necessary to ensure the balance of a given country. Considering the level of interconnection of the European gas system, many flow patterns are possible resulting in different views of the dependence.

Two extreme situations have been considered defined by the level of cooperation between market and institutional players of the different countries. Therefore for each combination of country and import source two indicators have been calculated:

- Uncooperative Supply Source Dependence (USSD): each country tries to minimize its own dependence on the considered source, so the countries closest to the source are likely to be more dependent
- Cooperative Supply Source Dependence (CSSD): all the countries together try to spread the dependency in order to avoid as far as possible countries with very high dependence

The lower the indicator is, the lower the dependence. When considering the dependence on a given source, a country having a USSD higher than its CSSD means that the country is supporting other countries in reducing their dependence.

An aggregated indicator per country has been defined on the basis of the combination of the Uncooperative Supply Source Dependence (USSD) and Cooperative Supply Source Dependence (CSSD) for each import source, assigning the same weight to each one of them, as follows:

$$USSD = (USSD_{RU})^2 + (USSD_{NO})^2 + (USSD_{LNG})^2 + (USSD_{DZ})^2 + (USSD_{LY})^2 + (USSD_{AZ})^2$$

$$CSSD = (CSSD_{RU})^2 + (CSSD_{NO})^2 + (CSSD_{LNG})^2 + (CSSD_{DZ})^2 + (CSSD_{LY})^2 + (CSSD_{AZ})^2$$

A country with a zero USSD means it can always use alternative sources to completely get rid of the minimized source. A country with a one hundred percent of USSD cannot use alternative sources unless some other countries support it.

The figures 6.21. and 6.22 on the following pages show the evolution of the aggregated USSD and CSSD for each country showing a significant dependence (USSD or CSSD higher than 20 %).

The increasing need of imports over the TYNDP period is illustrated by an increase in the supply dependence of many countries under the Low scenario. By 2035, most countries are dependent on at least one of the two predominant sources (LNG and Russian gas) as a result of decreasing Norwegian supplies and relatively low level of supplies from Algerian, Libyan and Azeri sources.

The analysis under the High scenario shows that new investment decisions and the development of new indigenous production can ensure a very low dependence for every European country. The only exceptions are in the Green scenario for Portugal and FYROM whose dependence mitigation depends on the cooperation of other countries.

The calculation of the indicators has identified significant physical dependence (USSD or CSSD above 20 %) on annual basis only to Russian and LNG supplies. Such dependence is illustrated by the Russian and LNG Cooperative Supply Source Dependence maps as this approach better shows the potential for infrastructure projects to reduce the dependence.

See figures 6.21 and 6.22 on pages 160 – 161

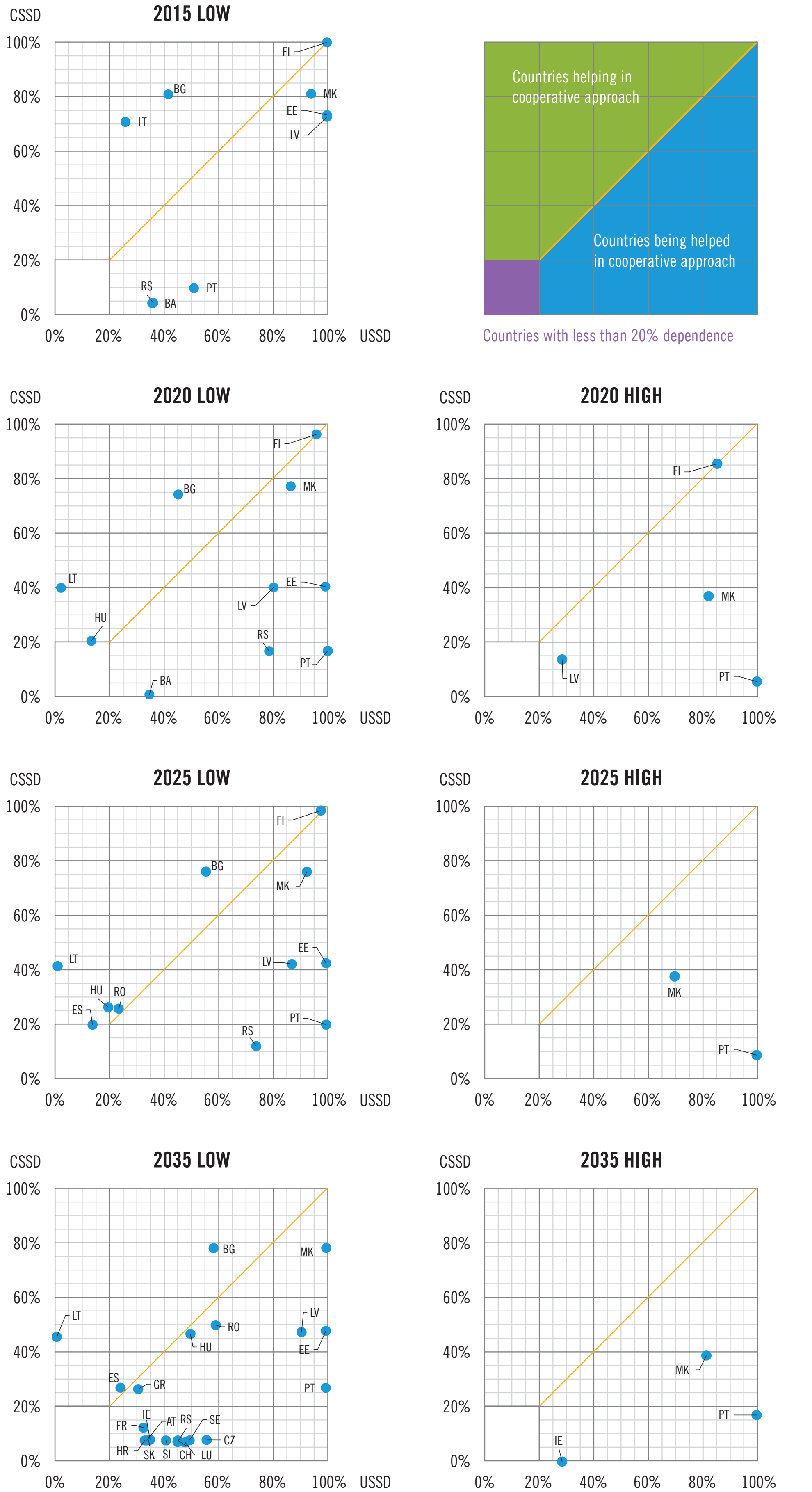


Figure 6.21: Evolution of CSSD and USSD combined indicators. Green scenario

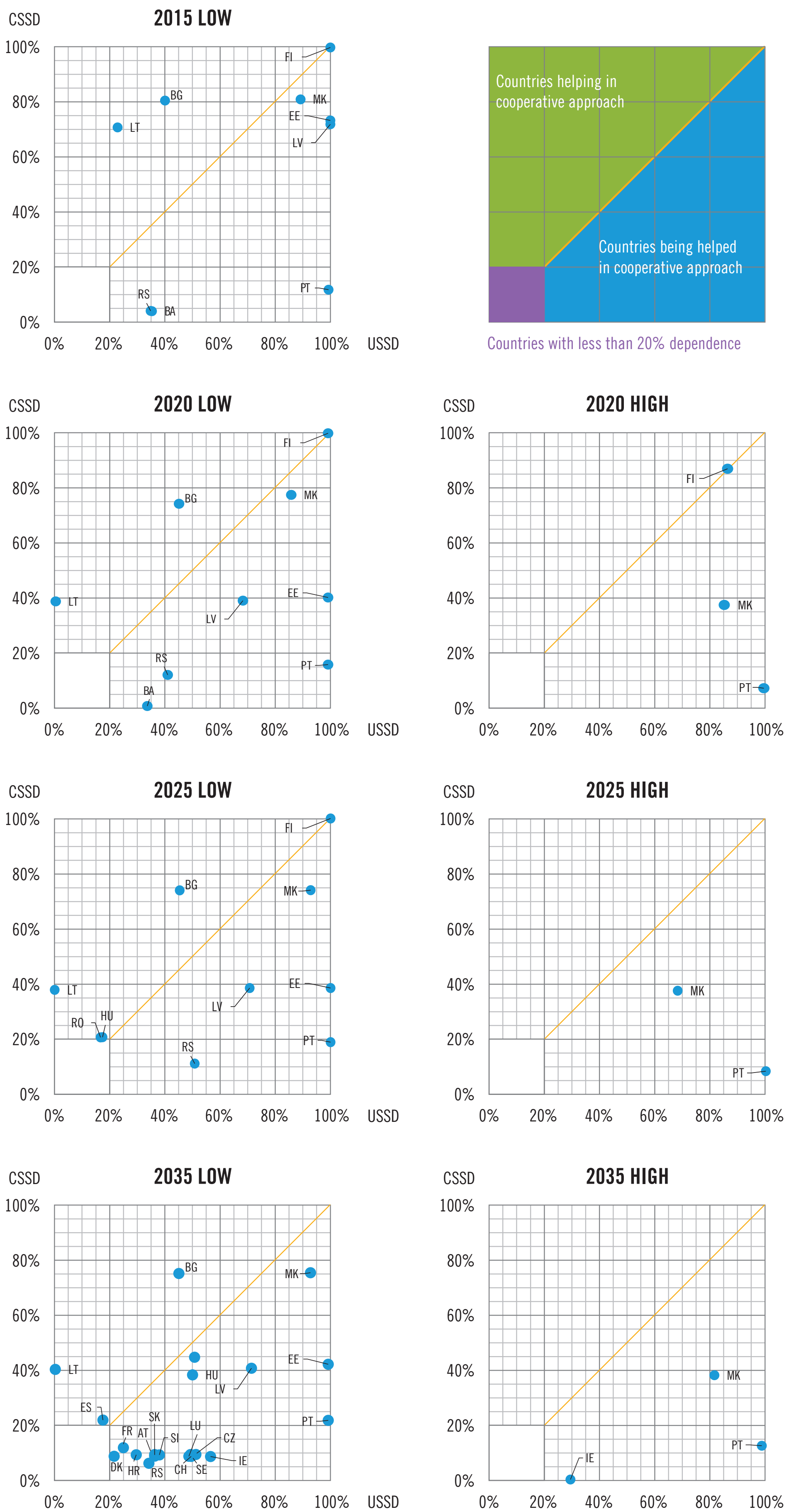


Figure 6.22: Evolution of CSSD and USSD combined indicators. Grey scenario

6.4.1.1 RU cooperative dependence – CSSD RU

The TYNDP 2015 version of the dependence indicator confirms the TYNDP 2013 results. Apart the improvement of the situation for Poland with FID project commissioned between 2015 and 2020, dependence on Russian gas will increase in the Baltic, Central-Eastern and South-Eastern Europe countries in the absence of new infrastructure projects. The extension of the TYNDP period shows that this growing regional dependence could spread to the whole of Europe under the Low scenario.

In 2035 only the Iberian Peninsula would have a Russian gas dependence below five percent due to the availability of Algerian gas and LNG combined with low interconnection to the rest of Europe. This dependence is primarily caused by a lack of available alternative volume and not only due to capacity congestion.

The High scenario illustrates the potential for new supplies (indigenous production, Azeri gas and new LNG terminals) and better market integration to maintain a low dependence on Russian gas across Europe. The end of the production license in the Romanian part of the Black Sea explains the surge in dependence on Russian gas by 2035 for the High scenario under the Green Global Context.

See figures 6.23 and 6.24 on pages 163 – 164


Image: iStockphoto.com

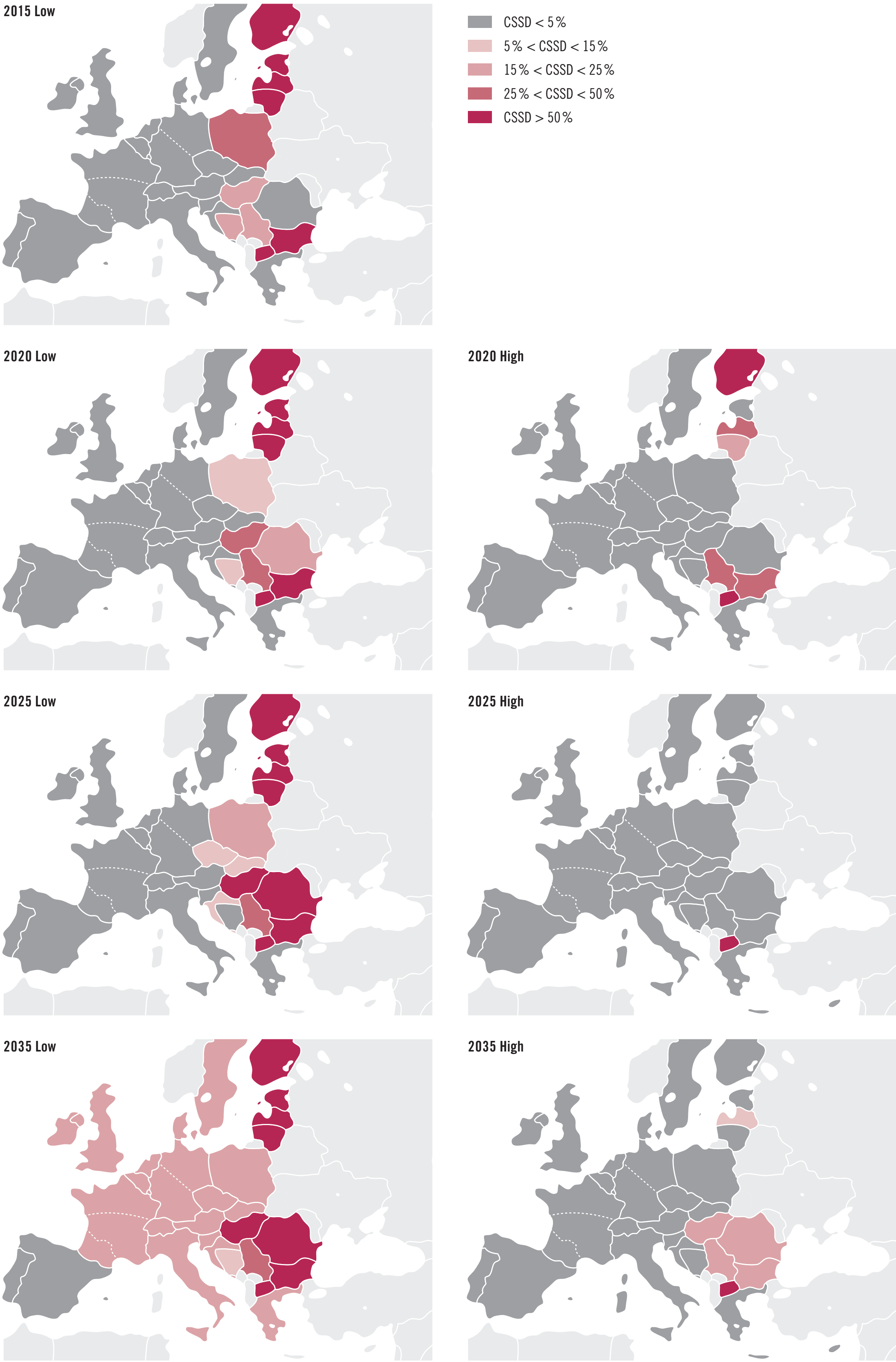


Figure 6.23: Evolution of CSSD-RU. Green scenario

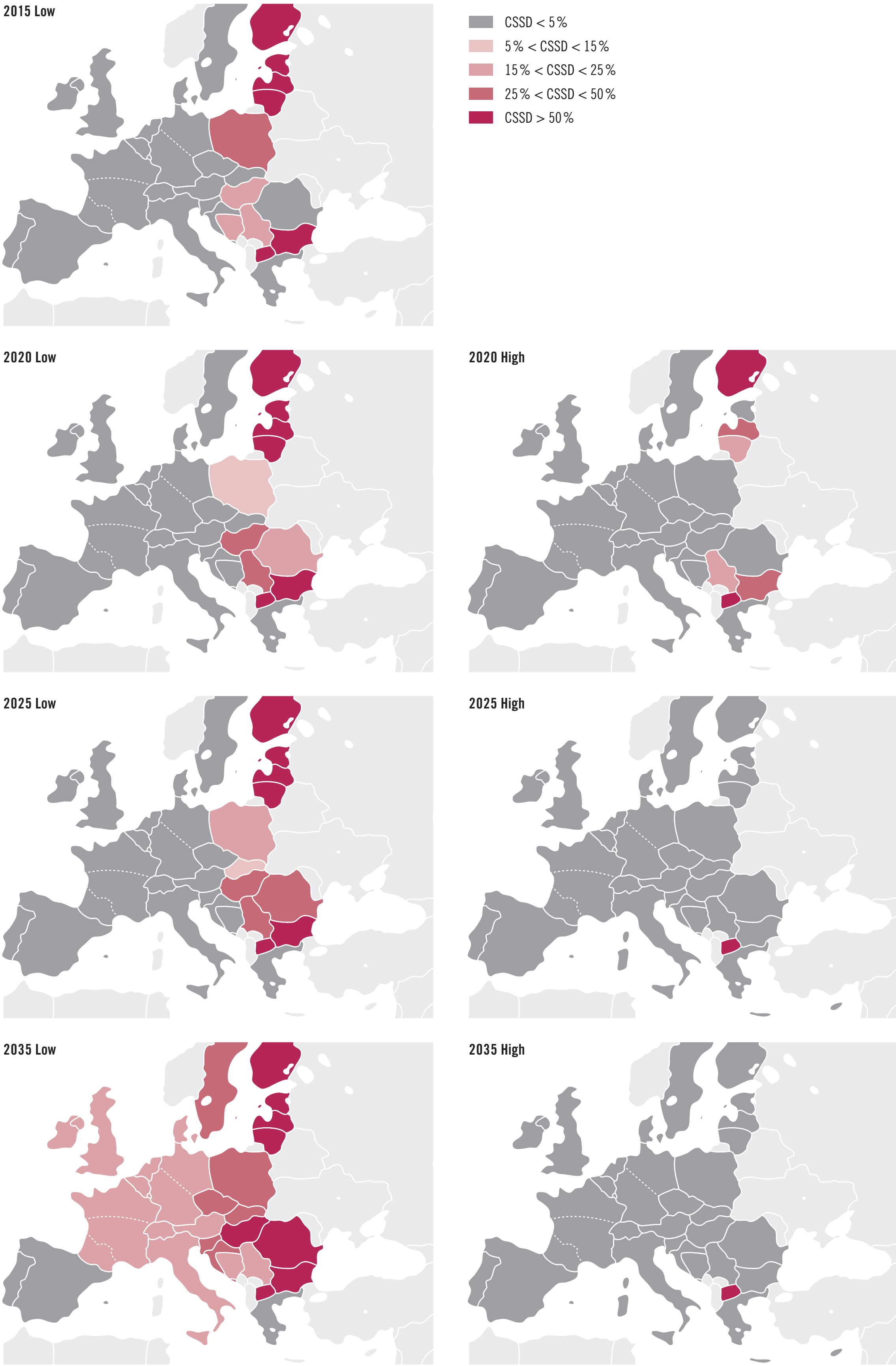


Figure 6.24: Evolution of CSSD-RU. Grey scenario

6.4.1.2 LNG cooperative dependence – CSSD LNG

Physical dependence to LNG shows mirror results compared to the Russian dependency and to the TYNDP 2013-2022. Under the Low scenario the dependence on LNG supply is limited to one region, the Iberian Peninsula and France before it extends to the whole Europe due to the decreasing share of all other supply sources except Russia. The commissioning of Non-FID projects and associated new supplies could reduce the dependency except for the Iberian Peninsula for which additional projects would be necessary to further reduce its physical dependency on LNG.

In 2035 under the Low scenario whole of Europe will become dependent on LNG even if in a lower extent than Iberian Peninsula and Greece. This dependence is primarily caused by a lack of available alternative volume and not only due to capacity congestion. For this same year under the Green Global context and High Infrastructure scenario, a small dependency to LNG appears for every EU Member State as there is not enough Russian gas available to compensate the minimization of LNG. This differs from the physical dependence on Russian gas. According to supply scenarios there is more LNG available than Russian gas at the end of the time horizon.

The commissioning of Non-FID projects and associated new supplies could reduce the dependency except for the Iberian Peninsula for which additional projects would be necessary to further reduce its physical dependency on LNG.

See figures 6.25 and 6.26 on pages 166–167

6.4.1.2 LNG cooperative dependence – CSSD LNG

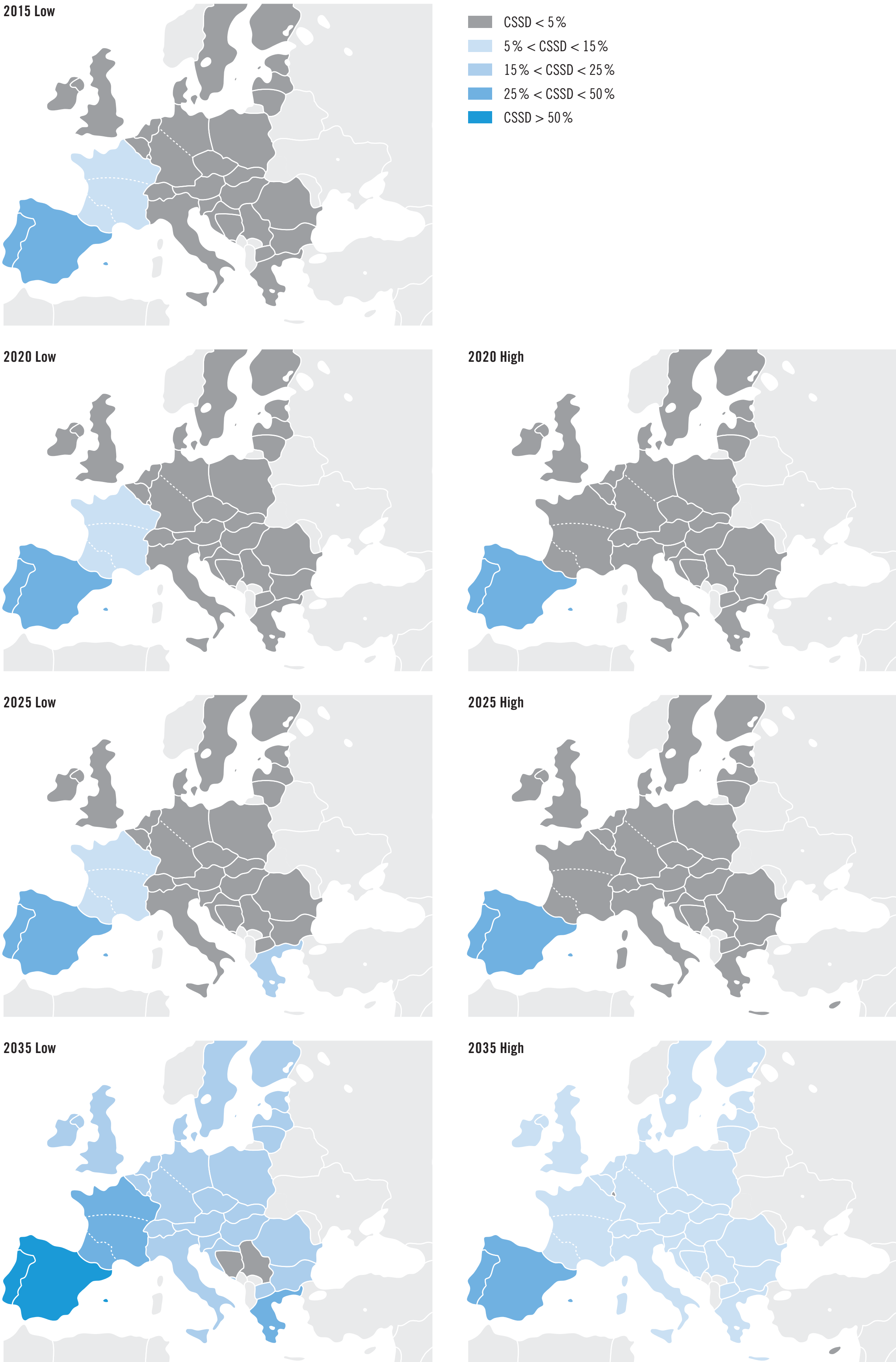


Figure 6.25: Evolution of CSSD-LNG. Green scenario

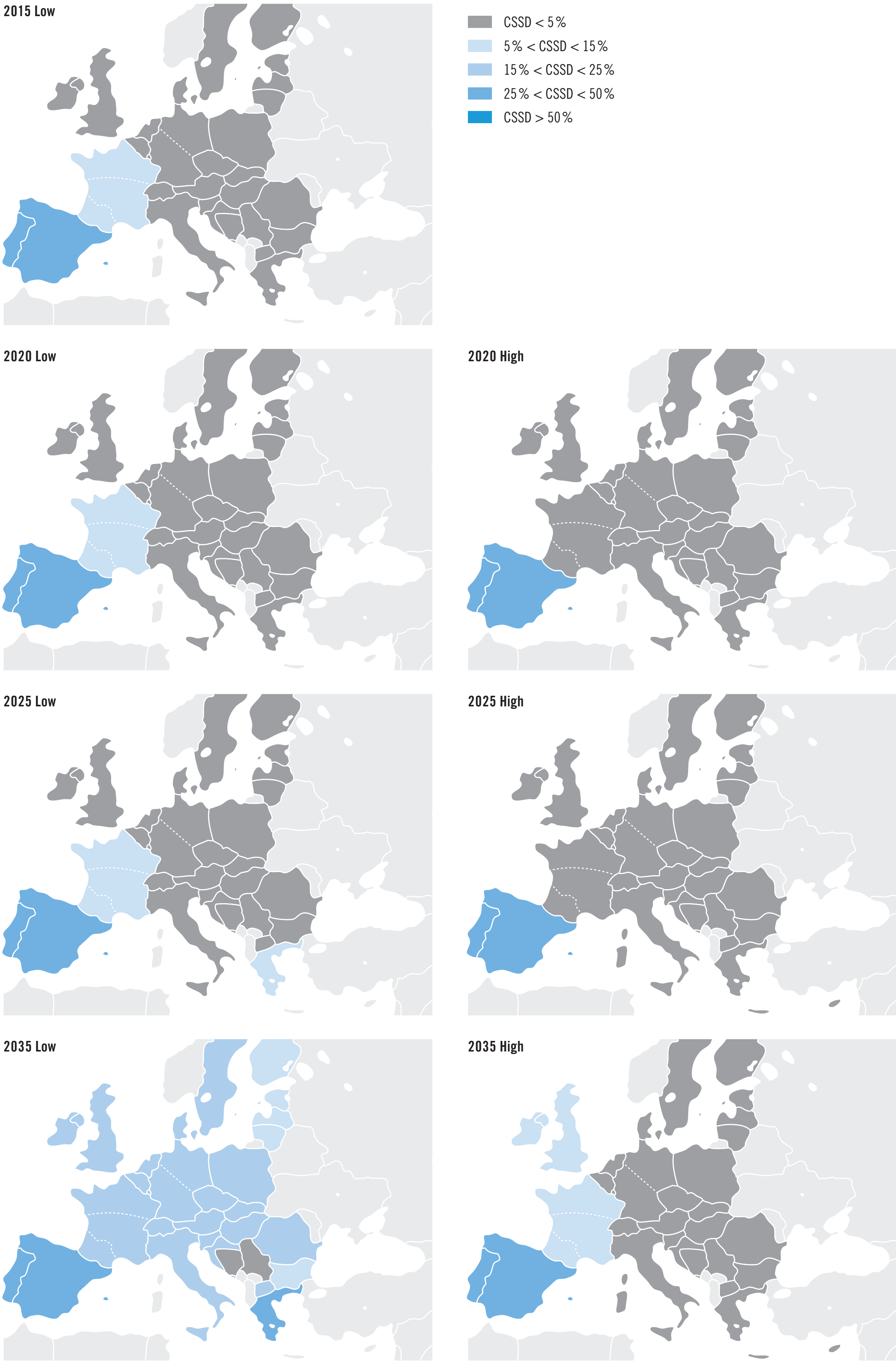


Figure 6.26: Evolution of CSSD-LNG. Grey scenario


Image courtesy of Latvijas Gāze

6.4.2 SUPPLY SOURCE PRICE DEPENDENCE (SSPDe)

The SSPDe indicator measures the exposure of each country, as the minimum impact on its gas bill, to the price increase of an import source. This approach is based on marginal gas prices and therefore a country can be dependent on a source, from a price perspective, which is not directly physically connected. This is due to the impact of those supply sources on interconnected markets. However, a well-integrated gas infrastructure is a pre-condition to mitigate the exposure to the increase of the price of one supply source.

The dependency of a country represents the extent to which it cannot avoid to mirror the price increase of any import source. Each supply source is tested one-by-one. The higher the indicator is, the higher the exposure to a price increase. A country having a SSPDe of forty percent towards Norwegian gas means that if Norwegian price increases by ten percent then the gas bill of that country would increase by four percent.

The following graphs show the magnitude of the price dependency of each country toward each source cumulated on the same stacked bar. A one hundred percent value indicates full exposure to the price increase of a source, therefore the stack graph can go beyond one hundred percent in case of a dependence toward several sources.

Results of the price dependence are very similar to those of the physical dependence. A small price dependence on Norwegian and Algerian gas appears in 2025 Green Low scenario due to the increasing import requirements.

Under the Low scenario, the price dependency increases across Europe over time as a result of increasing demand combined with decreasing indigenous production and Norwegian supply. Every EU Member States is becoming more dependent on Russian gas at the exception of Portugal, Spain and Greece who are increasingly dependent on LNG. Dependency on other sources increases when import requirements reach a very high level under the Green Scenario in 2025.

The commissioning of Non-FID projects will strongly mitigate the dependency of most of the countries. After 2025 the main mitigation effect results from the consideration of the new supply sources even if their positive impact recede in 2035 especially under the Green scenario.

See figures 6.27 and 6.28 on pages 170–173

6.4.2 SUPPLY SOURCE PRICE DEPENDENCE (SSPDe)

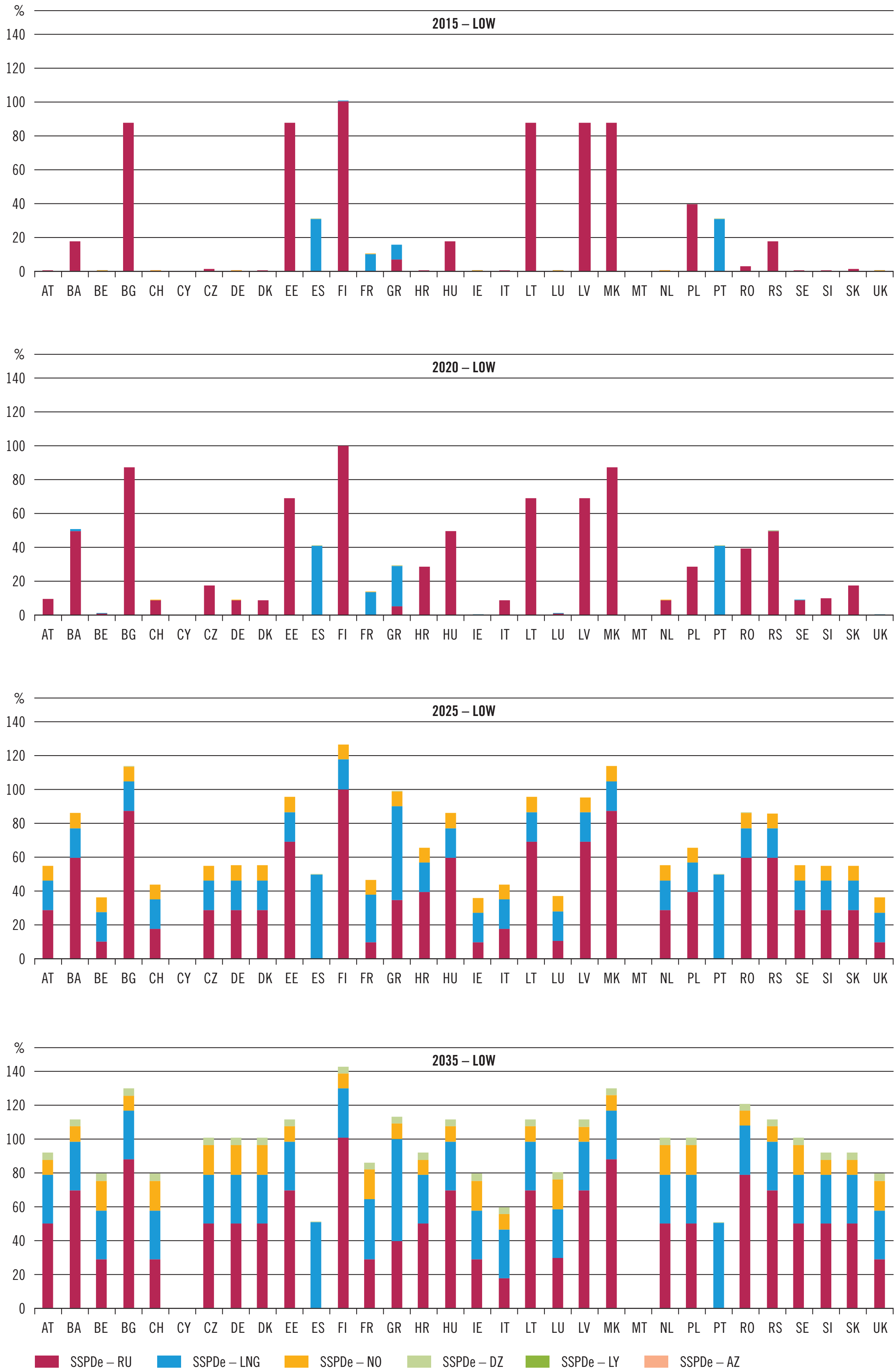
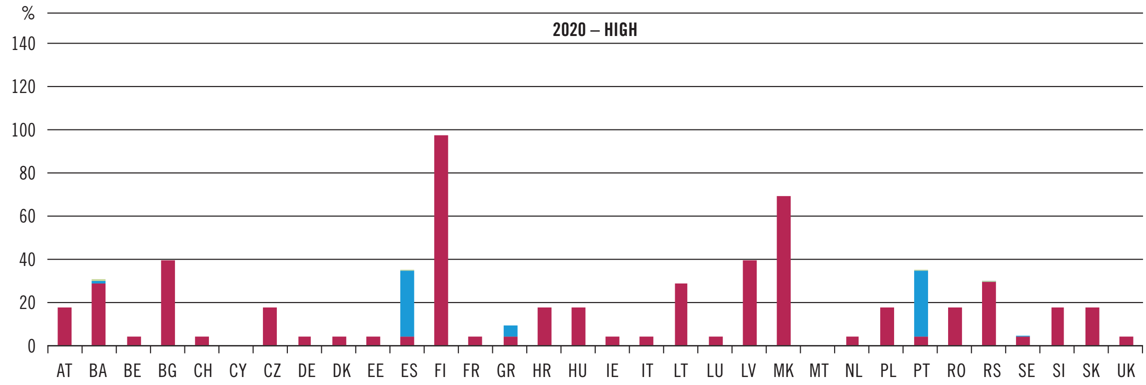
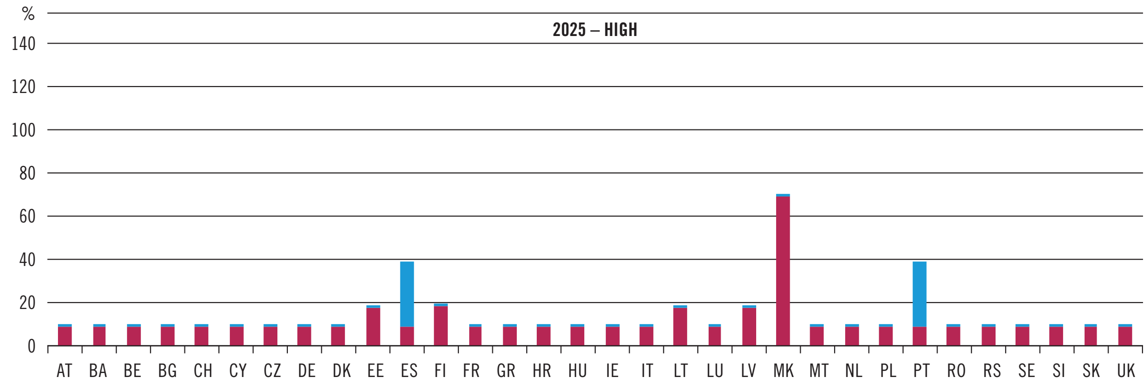


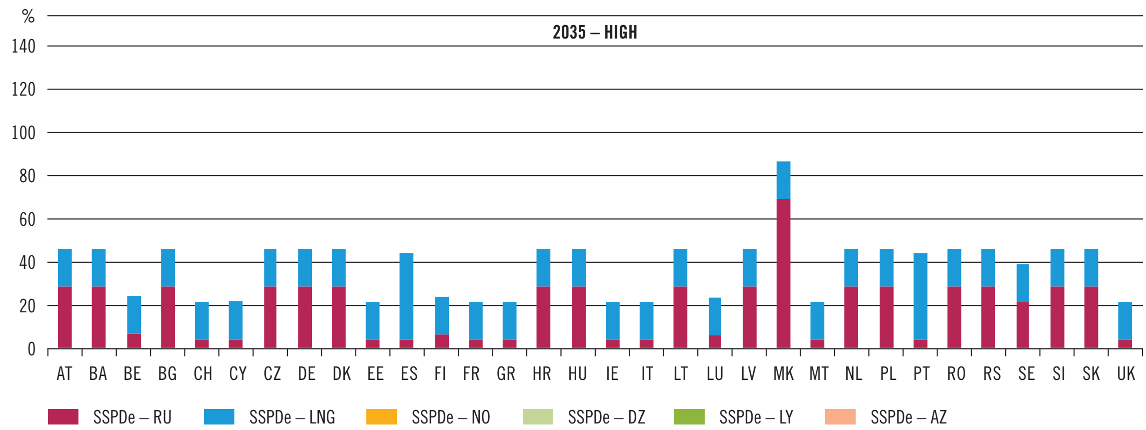
Figure 6.27: Evolution of SSPDe – all sources. Green scenario



%
2020 – HIGH
140
120
100
80
60
40
20
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK



%
2025 – HIGH
140
120
100
80
60
40
20
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK



%
2035 – HIGH
140
120
100
80
60
40
20
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK
SSPDe – RU
SSPDe – LNG
SSPDe – NO
SSPDe – DZ
SSPDe – LY
SSPDe – AZ

Figure 6.28: Evolution of SSPDe – all sources. Grey scenario

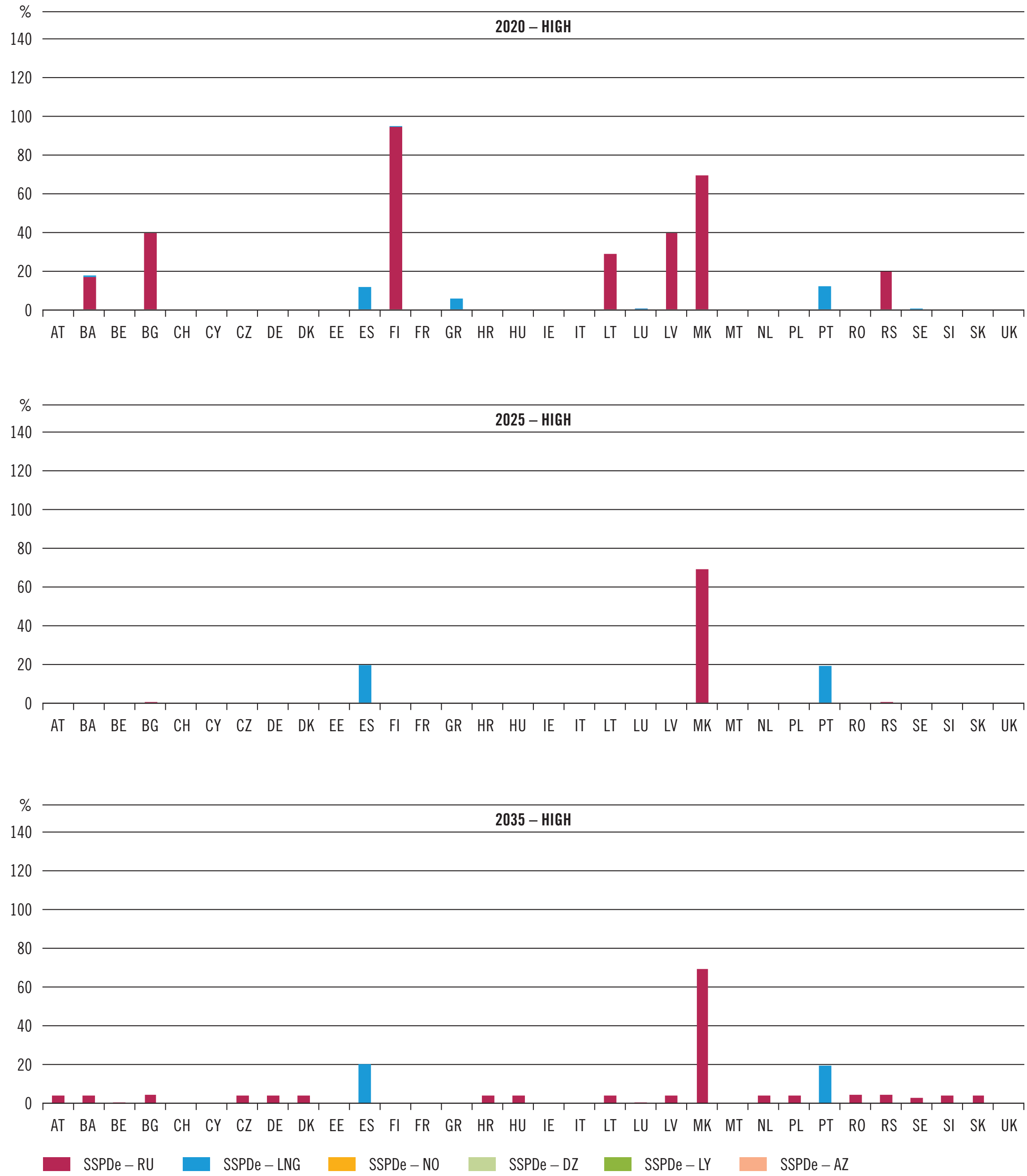

2020 – HIGH
2025 – HIGH
2035 – HIGH
%
140
120
100
80
60
40
20
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK
SSPDe – RU
SSPDe – LNG
SSPDe – NO
SSPDe – DZ
SSPDe – LY
SSPDe – AZ


Image courtesy of REN Gasodutos

6.4.3 SUPPLY SOURCE PRICE DIVERSIFICATION (SSPDi)

The Supply Source Price Diversification indicator measures the ability of each country to benefit from a decrease of the price of each import source. The approach is based on marginal gas prices and therefore a country can benefit from a source while not having physical access or being physically dependent on that source. However, a well-integrated gas infrastructure is a pre-condition to benefit from the decrease of the price of one supply source.

The diversification of a country represents its ability to mirror the price decrease of any import source. Each supply source is tested one-by-one without consideration of its maximum supply scenario meaning that the diversification is not simultaneous. The higher the indicator is, the higher the supply price diversification. A country having a SSPDi of thirty percent towards Russian gas means that if Russian price decreases by ten percent then the gas bill of that country would decrease by three percent.

The following graphs show the magnitude of the price diversification of each country toward each source by the addition of the SSPDi toward each supply source. A one hundred percent value indicates that a Zone can fully benefit from the price decrease of a source, therefore the stack graph can go beyond one hundred percent in case of diversification toward several sources.

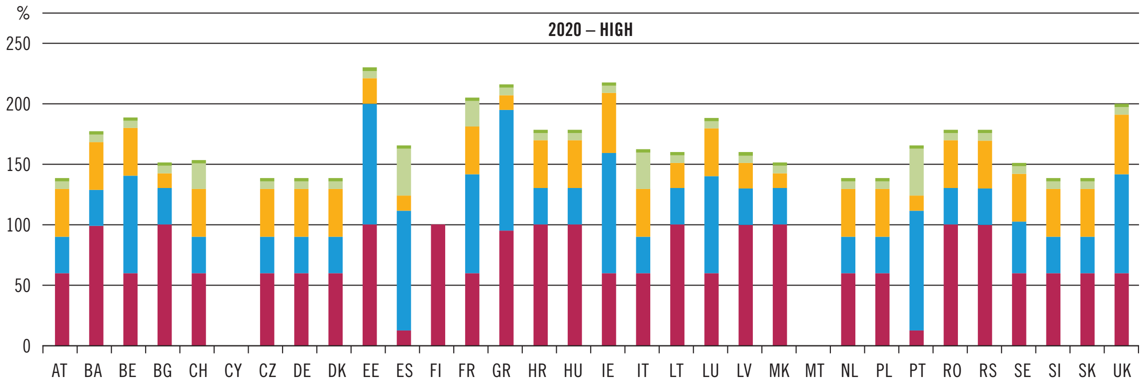
Under the Low scenario, the slow and overall reducing trend along the TYNDP time period illustrates the decreasing supply price diversification of Europe. This results from a combination of increasing demand and stable import capacities beyond 2020 under this infrastructure scenario.

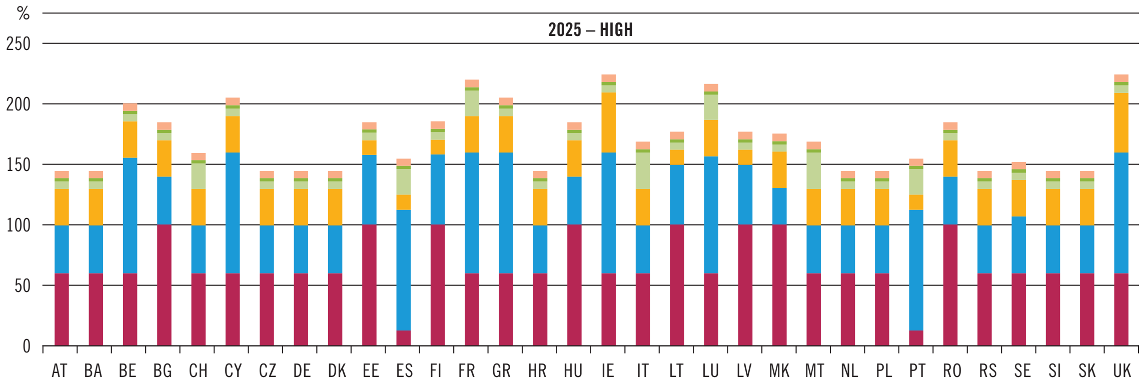
The commissioning of new import infrastructure up to 2025 improves the situation, compared to the Low scenario, as it enhances the import availability. With no additional import projects beyond 2025 the indicator decreases as a result of increasing demand. Details can be found in Annex E.

◢ **See figures 6.29 and 6.30 on pages 176–179**

6.4.3 SUPPLY SOURCE PRICE DIVERSIFICATION (SSPDi)

Figure 6.29: Evolution of SSPDi – all sources. Green scenario


%
2020 – HIGH
250
200
150
100
50
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK


%
2025 – HIGH
250
200
150
100
50
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK

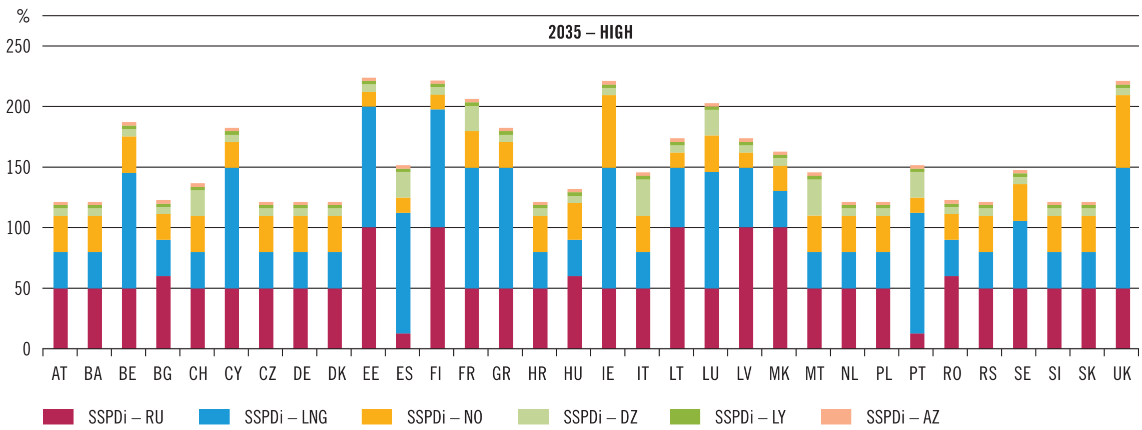
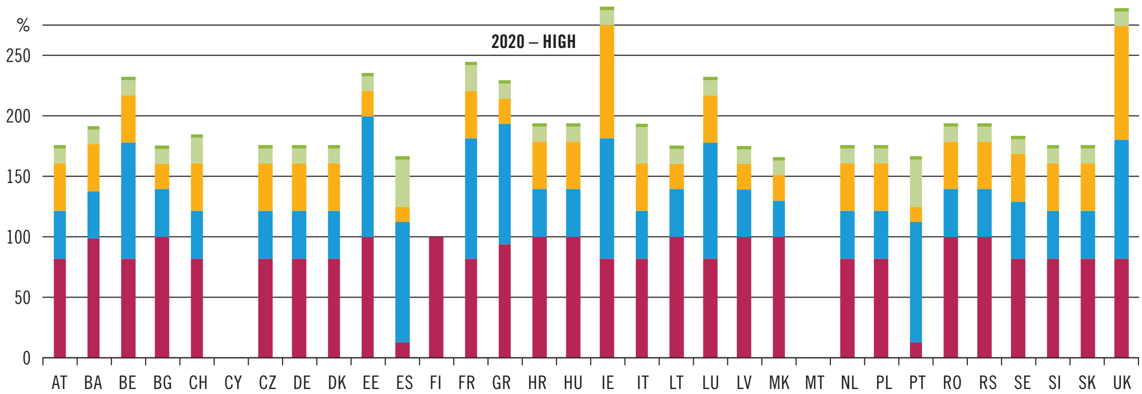
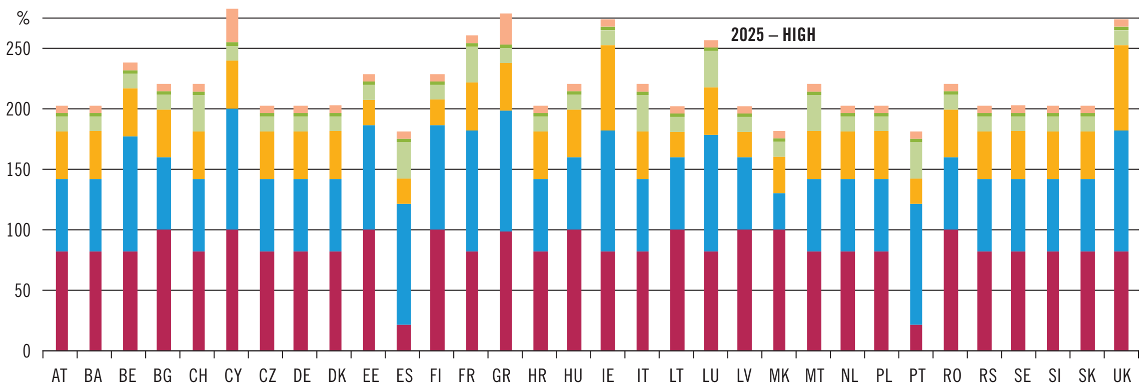

%
2035 – HIGH
250
200
150
100
50
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK
SSPDi – RU
SSPDi – LNG
SSPDi – NO
SSPDi – DZ
SSPDi – LY
SSPDi – AZ

Figure 6.30: Evolution of SSPDi – all sources. Grey scenario


2020 – HIGH
%
250
200
150
100
50
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK


2025 – HIGH
%
250
200
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100
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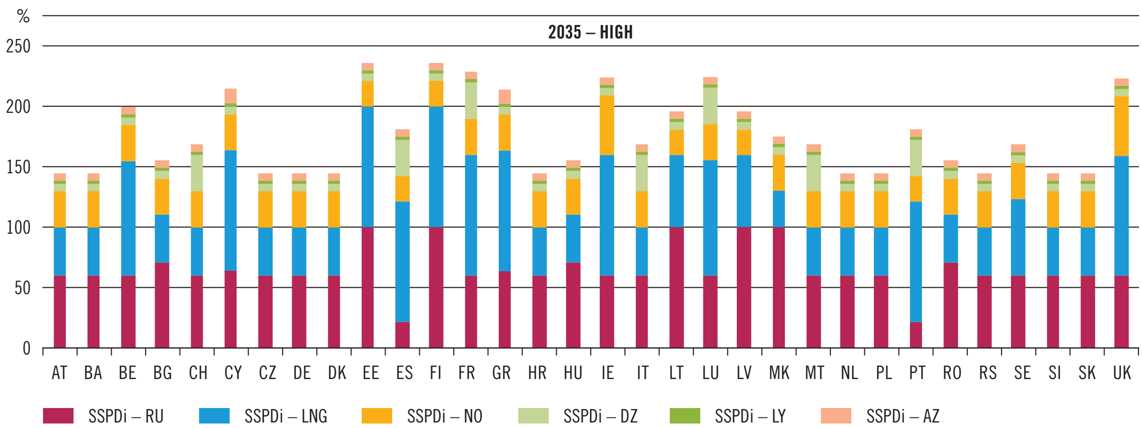
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK


2035 – HIGH
%
250
200
150
100
50
0
AT BA BE BG CH CY CZ DE DK EE ES FI FR GR HR HU IE IT LT LU LV MK MT NL PL PT RO RS SE SI SK UK
SSPDi – RU
SSPDi – LNG
SSPDi – NO
SSPDi – DZ
SSPDi – LY
SSPDi – AZ

6.4.4 GEOGRAPHICAL PERSPECTIVE OF THE SUPPLY SOURCE PRICE DIVERSIFICATION

In order to give a geographical view of the supply source price diversification for each country, an aggregated index was defined as the number of import sources influencing the gas bill of each country. Influence of the indigenous production is not considered here. This diversification should not be interpreted as a physical access to the sources.
For most of the countries the supply price diversification remains stable across the time horizon with a significant reaction (SSPDi above twenty percent) to three sources notwithstanding the embedded diversification of LNG. These homogenous results are influenced by the assumption of perfect market conditions and non-simultaneity of the diversification. The countries being influenced by less than three sources are:

- Portugal and Spain with a significant reaction to LNG and Algerian gas
- Greece with a significant reaction to LNG and Russian gas
- Baltic countries, Bulgaria and FYROM with a significant reaction to Russian gas

Only Italy, Slovenia and Croatia are significantly influenced by four sources. The considered import capacity from Libyan and Caspian sources is not sufficient to reach the twenty percent threshold.

Under the High scenario, the commissioning of LNG projects in the Baltic region and South-Eastern Europe improves the situation with a better reaction to LNG prices. The conjunction of new interconnection projects and lower European demand in the Grey scenario will further improve the diversification of the less interconnected regions such as the Baltic, South-Eastern Europe and Iberian Peninsula.

The commissioning of Non-FID projects enables the further spread of Algerian gas influence to Switzerland and France as well as Caspian gas influence in South-Eastern Europe. Under the Grey scenario the combined effects of a lower gas demand level and a better interconnection enables the influence of Russian and Norwegian gas to spread as far as the Iberian Peninsula.

Cyprus shows the same supply price diversification as Greece as the marginal price of its production is set by this downstream market.

The results of this diversification assessment differ from the analysis of supply diversification in TYNDP 2013 because they are now based on a price approach with a 20 % reaction threshold which is not equivalent to a 20 % physical supply share of the source.

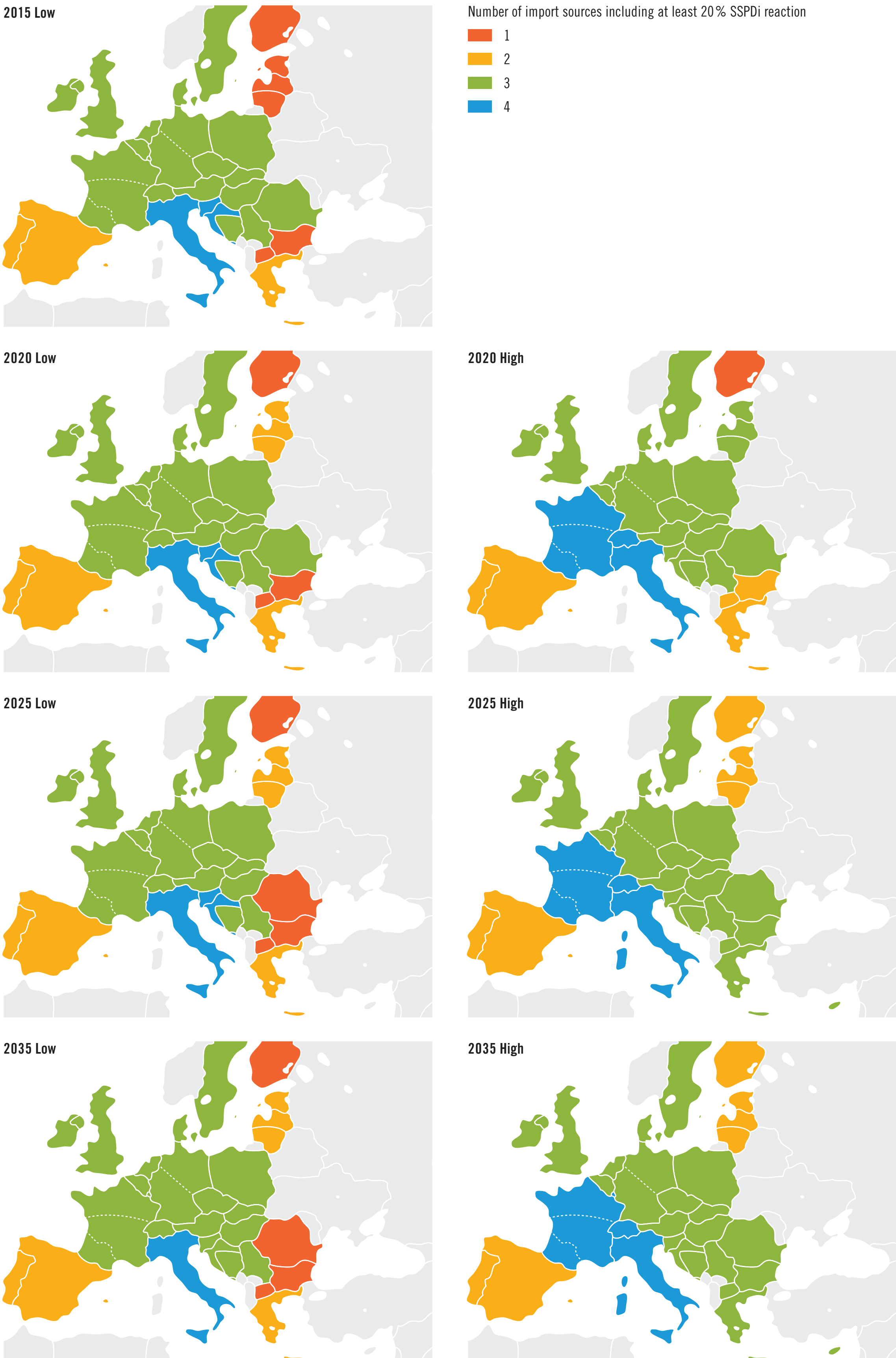


Figure 6.31: Number of sources with SSPDi > 20 %. Green Scenario

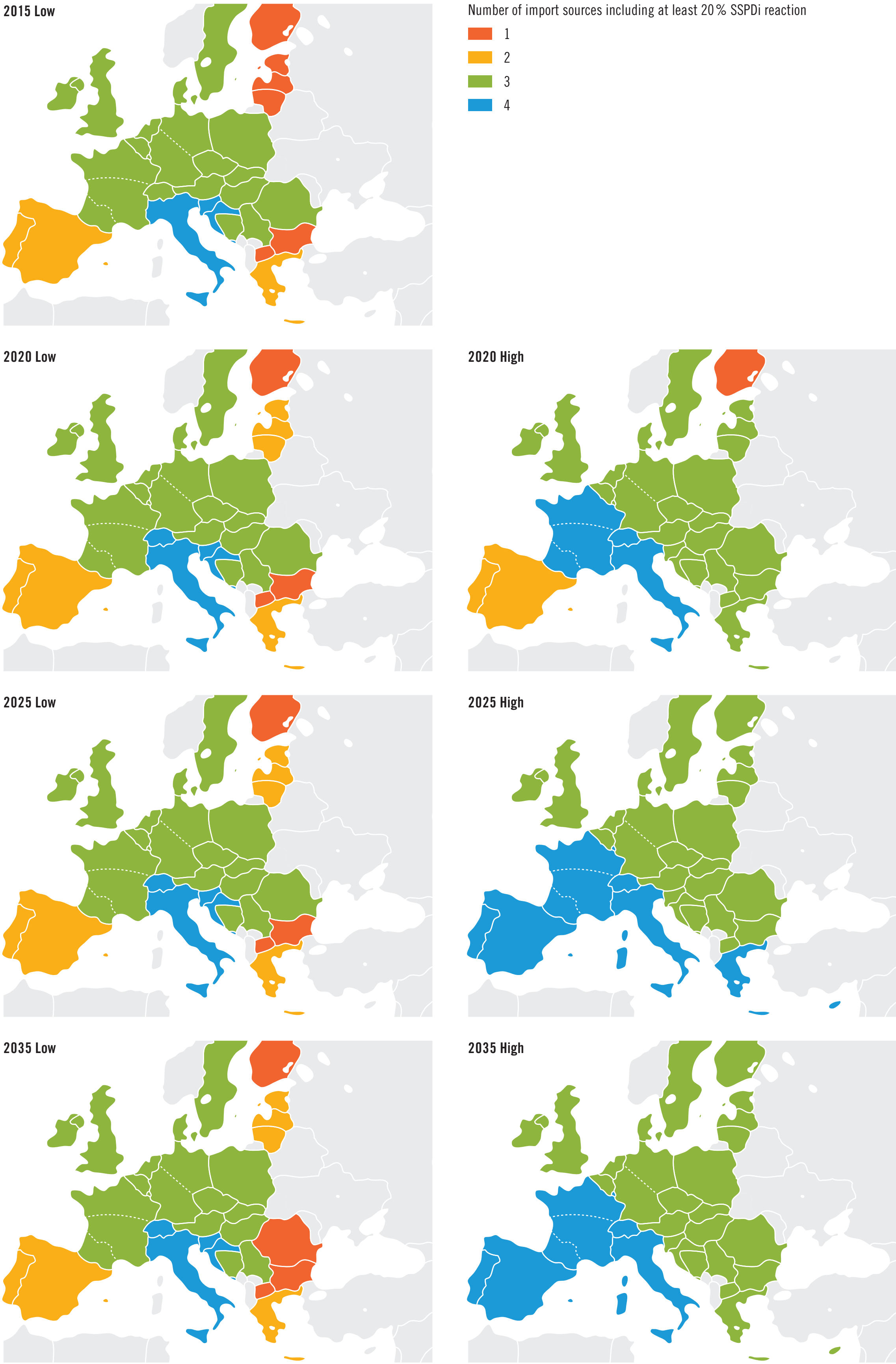


Figure 6.32: Number of sources with SSPDi > 20 %. Grey scenario

6.4.4.1 Focus on Supply Source Price Diversification for LNG

The Supply Source Price Diversification (SSPDi) considers LNG as a single source due to the existence of a global LNG market, therefore more detail has been provided for this source.

The comparison of the Low and High infrastructure scenarios illustrates in which extent Europe could better benefit from a potential decrease of LNG price through the commissioning of Non-FID projects.

See figures 6.33 and 6.34 on pages 184 – 185

6.4.4.1 Focus on Supply Source Price Diversification for LNG

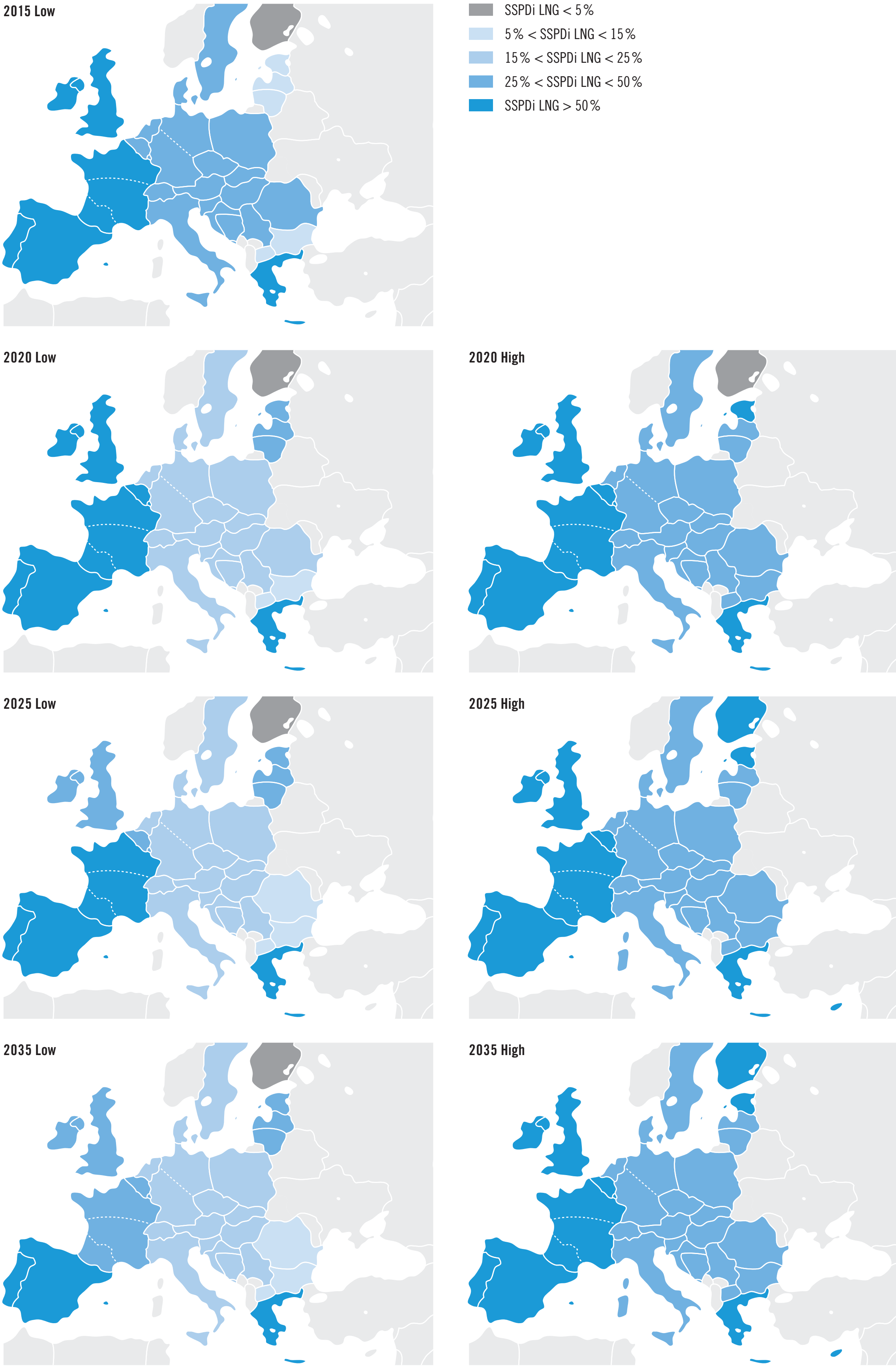


Figure 6.33: Evolution of SSPDi-LNG. Green scenario

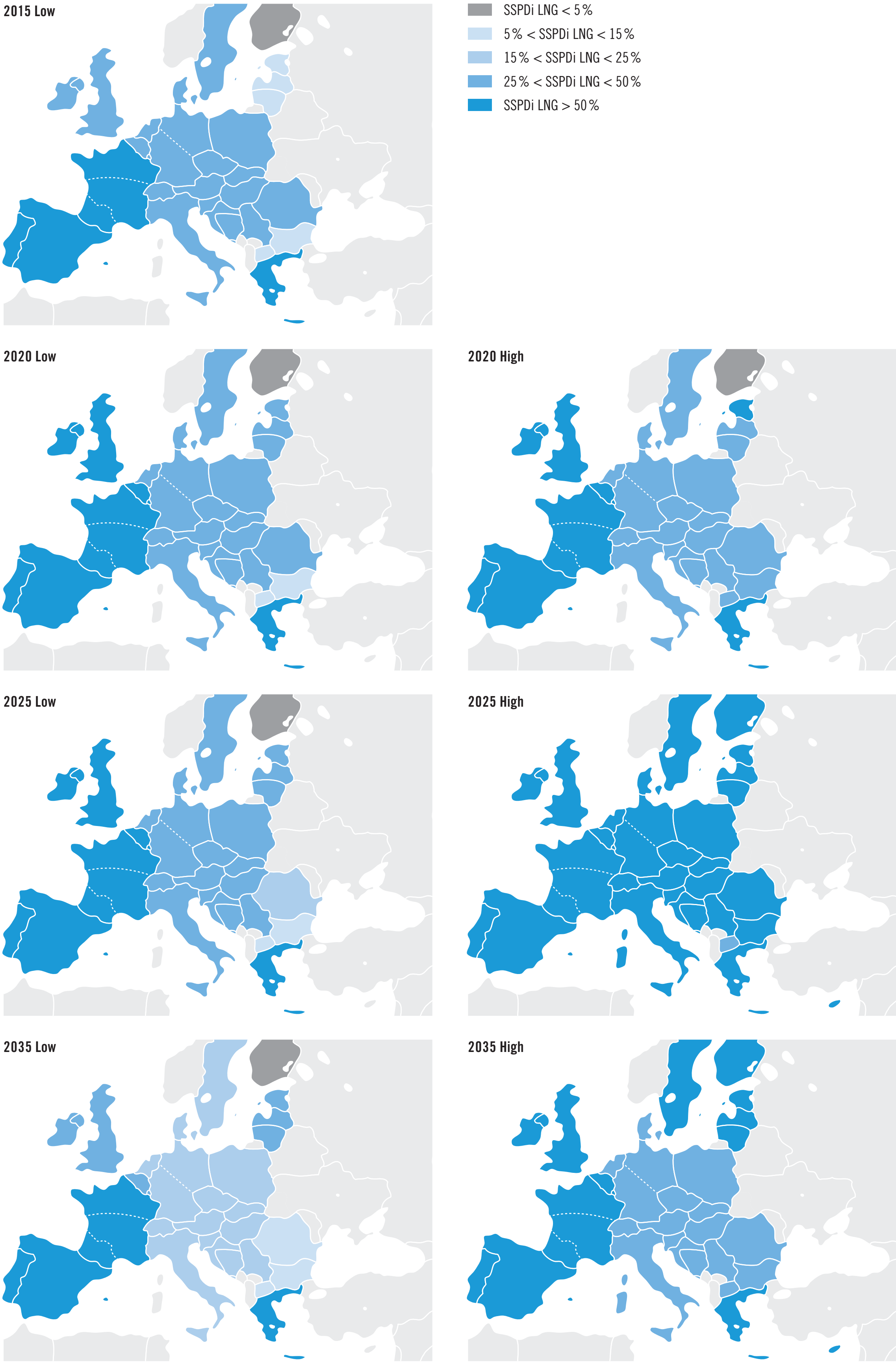


Figure 6.34: Evolution of SSPDi-LNG. Grey scenario

6.5 Monetization

6.5.1 EU TOTAL BILL

The following graphs show the monetization of the commodity components of the European bill (as defined in Annex F) along the time horizon:

- All gas flows entering Europe (imports and indigenous production)
- The coal quantity which contributes to filling the power generation thermal gap
- The CO_2 emissions from the power generation sector

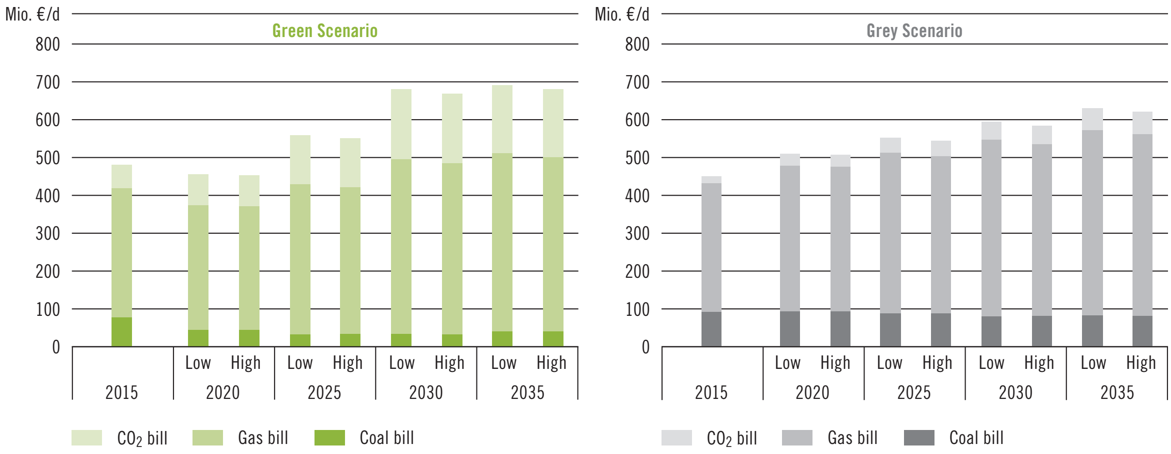


Figure 6.35: EU bill. Breakdown between gas, coal and CO_2. Reference gas price. Green (left) and Grey (right) scenarios

The higher level of the total bill under the Green scenario results from a much higher CO_2 emission price and a bigger gas demand. In the Green scenario high CO_2 prices foster the use of gas at the expense of more carbon intensive fuels. The figure "Evolution of the CO_2 emissions in the power generation sector (daily average)" (page 3) at the beginning of the Assessment chapter illustrates the resulting decreasing CO_2 emission under the Green scenario compared to the Grey one.

The graphs show that in both the Green and Grey scenarios the new infrastructure and supply projects associated with the High scenario result in a small decrease of the gas bill compared to the Low scenario; however, the new infrastructure is not able to change the gas versus coal balance with unchanged emissions and coal consumption.

Price configurations are not inducing a significant change in the coal and CO_2 components of the European bill and therefore these two components are not considered in the rest of the analysis. The following graphs illustrate the change in the European gas bill under the different price configurations according to the following ratio:

$$\frac{\text{EUgas bill}_{\text{price configuration}} - \text{EUgas bill}_{\text{Reference}}}{\text{EUgas bill}_{\text{price configuration}}}$$

The graphs are asymmetric because every country tries to reduce its exposure to a price increase (positive part) while maximising the benefit of a price decrease (negative part).

In line with the rest of TYNDP assessment, the European gas bill is most sensitive to LNG and Russian supplies. Norway's influence is rapidly limited by its decreasing export potential. Non-FID projects, taken into account in the High scenario, have the potential to limit the gas bill increase by giving access to the cheapest sources.

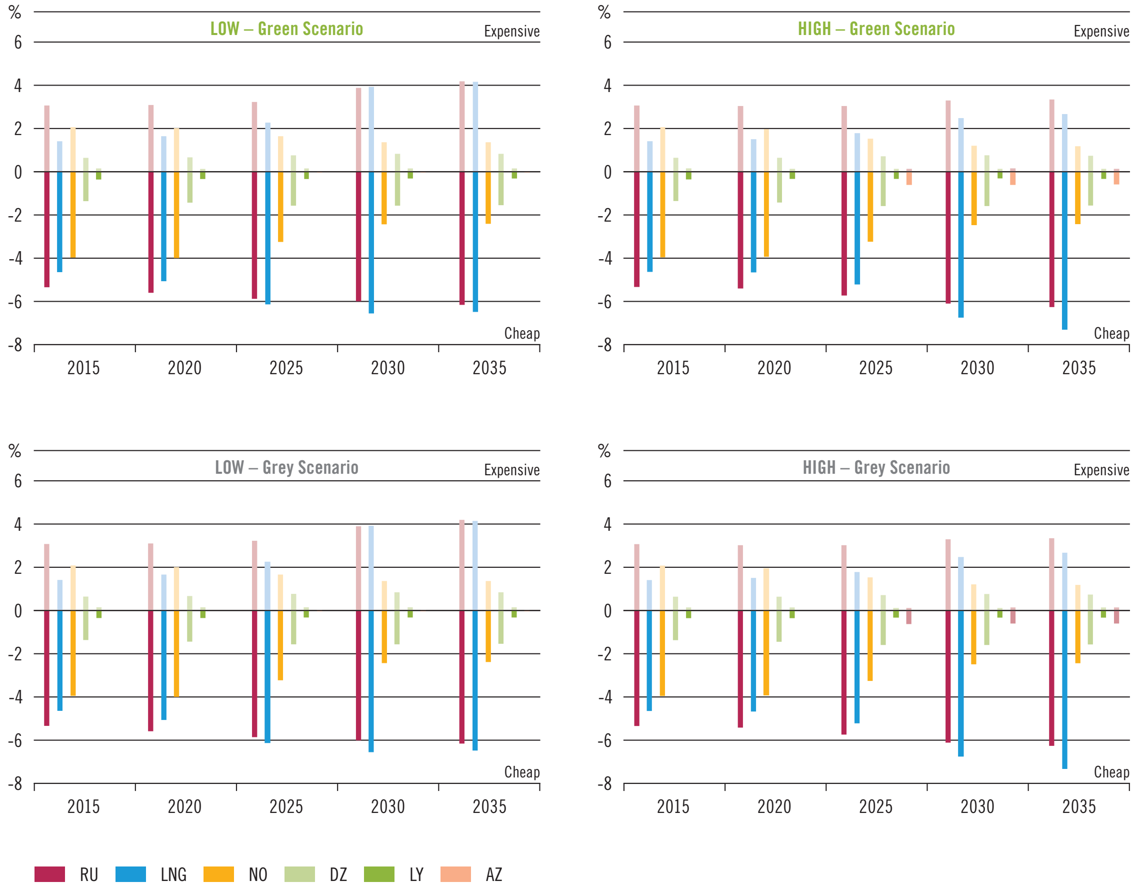


Figure 6.36: Influence of the gas price scenario in the European gas bill (towards the reference gas price). Green and Grey scenarios

6.5.2 GAS PRICE INDEX

The Gas Price Index (GPI) is calculated as a proxy for the gas bill per unit of gas demand and hence allows Zones to be compared which have different market sizes. At TYNDP level, the analysis of the index provides a common background to the monetization measure within the Project Specific-Step of the CBA. It is not the central indicator of this report as most of the information provided is illustrated by other indicators.

The main drivers for the evolution of this index at Zone level are:

- The overall impacts of new projects and associated supply decreasing the European gas bill
- The impact of projects enabling a wider spread of the price impact of the cheapest source
- The impact of projects mitigating the influence of the most expensive source

In addition when a source is considered as more expensive (higher price curve), countries are taking more of the alternative sources resulting in an increase of their price (see price curve profile in Annex F). This indirect effect of any price configuration participates to the impact on distant countries from the expensive source.

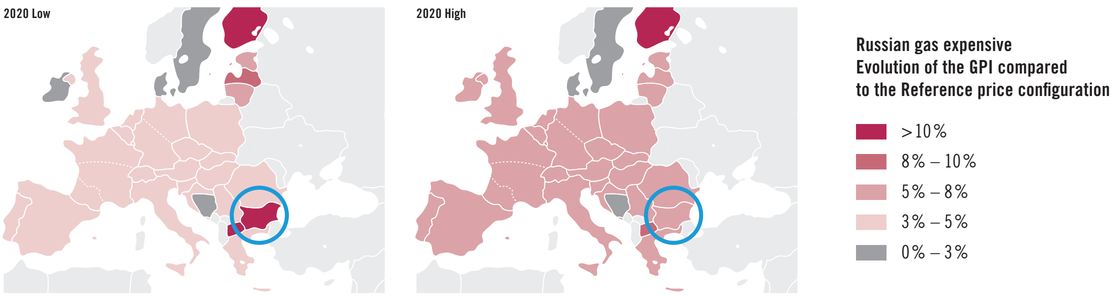
The results of this analysis should not be considered as an actual price forecast. In line with the rest of this Report results are influenced by the assumption of a perfect market functioning and a single import price curve per source.

The evolution of the Gas Price Index at Zone level has been analysed along the season (Average Summer day, Average Winter day, 1-day Design Case and 2-week Uniform Risk) for each of the thirteen price configurations for a given Green or Grey global scenario. Only the Russian, Norwegian and LNG expensive price configurations show significant results (the expensive source is 20 % higher than the other sources).

The following maps illustrate the evolution of the GPI of the Average Winter day under these three price configurations compared to the Reference Price configuration. The GPI under the Reference Price configuration is not the same for the Low and High Infrastructure scenarios nor between Green and Grey scenarios therefore the results should only be compared along the time dimension.

The GPI for countries where demand disruption has been identified is less impacted by the price configuration as a consequence of the curtailed demand (e. g. Bosnia-Herzegovina and Serbia).

Guidance for map interpretation:

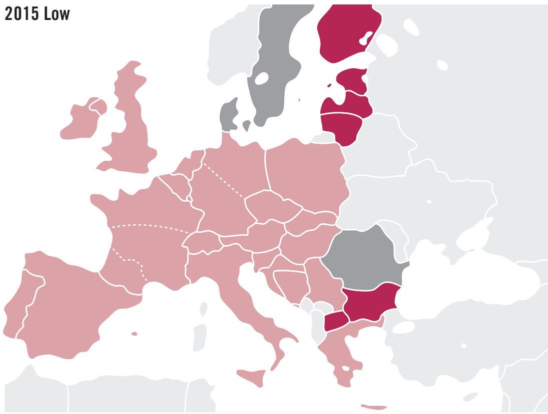


AVERAGE WINTER DAY GPI FOR BULGARIA AS FOUNDED FOR EVERY COUNTRY IN ANNEX F

EUR/GWh/d	Price configuration		GPI evolution
	Reference	RU expensive	
Low	20,284	23,410	(23,410 – 20,284) / 20,284 = 15 %
High	19,868	21,160	(21,160 – 19,868) / 19,868 = 7 %

This example also shows in which extent the different level of GPI between the Reference price configuration between Low and High Infrastructure scenarios prevents direct comparison of results.

2015 Low

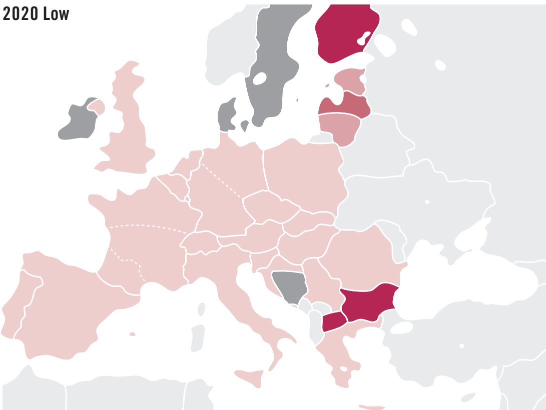


Russian gas expensive
Evolution of the GPI compared to the Reference price configuration

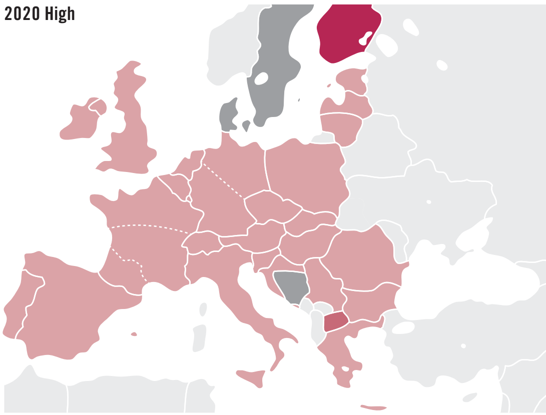
- > 10 %
- 8 % – 10 %
- 5 % – 8 %
- 3 % – 5 %
- 0 % – 3 %

Please take note that part of the benefits of Non-FID projects has already been considered in the decrease of the GPI of the Reference price configuration between Low and High scenarios. Therefore the level of the indicator for a given country should not be compared across the scenario but with the other countries for a given scenario.

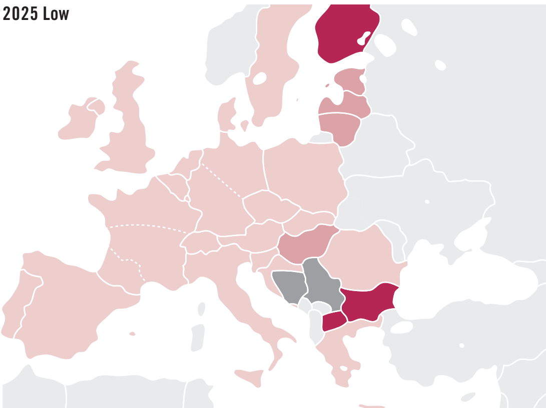
2020 Low



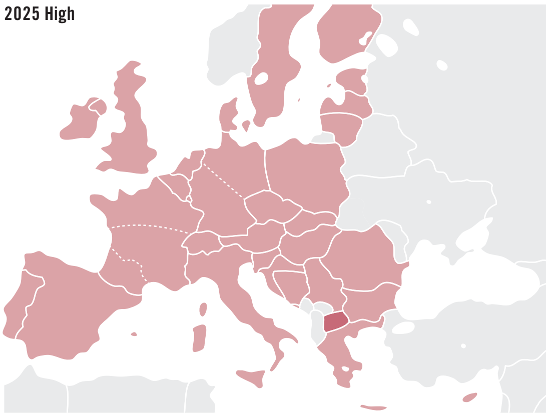
2020 High



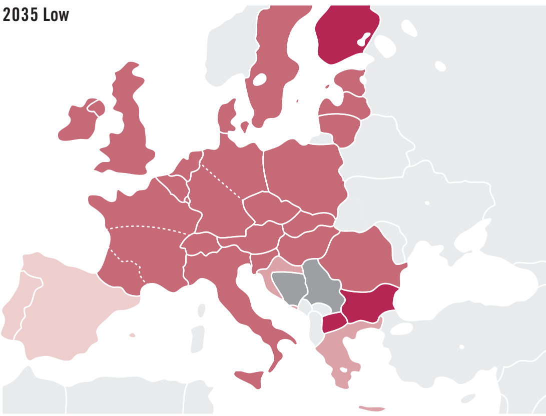
2025 Low



2025 High



2035 Low



2035 High

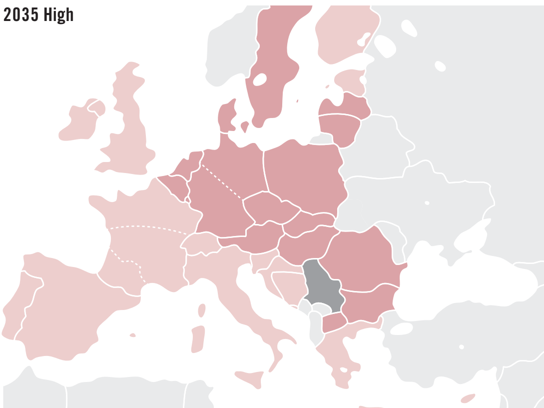
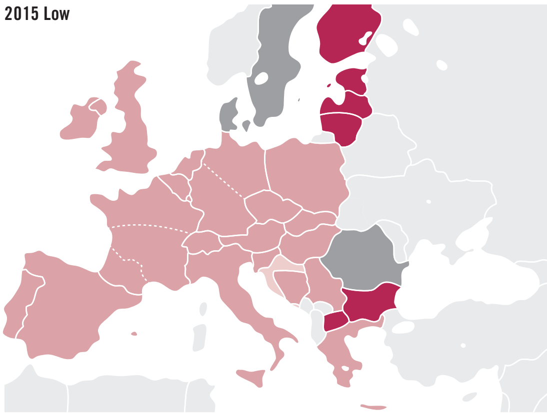


Figure 6.37: Evolution of the Gas Price Index comparison between Russian gas expensive and Reference price configurations Green scenario

2015 Low

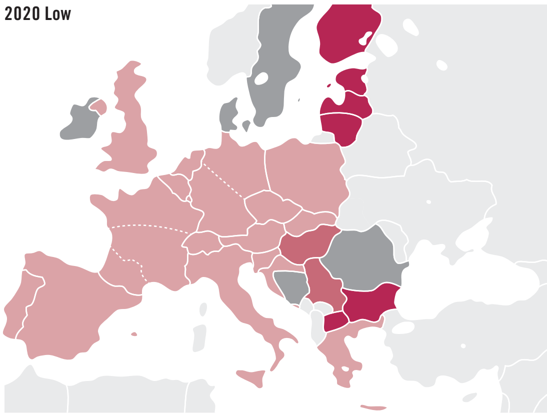


Russian gas expensive
Evolution of the GPI compared to the Reference price configuration

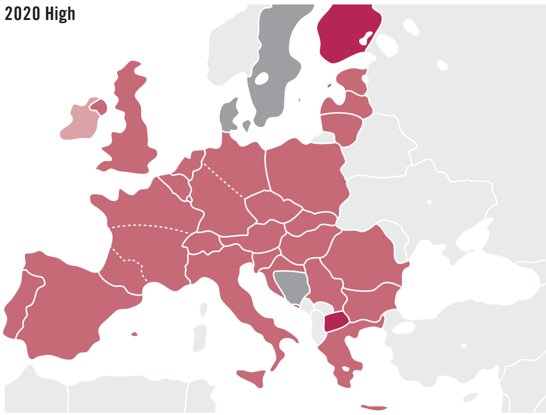
- > 10 %
- 8 % – 10 %
- 5 % – 8 %
- 3 % – 5 %
- 0 % – 3 %

Please take note that part of the benefits of Non-FID projects has already been considered in the decrease of the GPI of the Reference price configuration between Low and High scenarios. Therefore the level of the indicator for a given country should not be compared across the scenario but with the other countries for a given scenario.

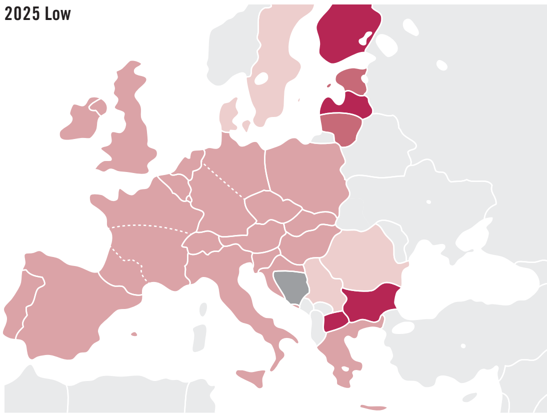
2020 Low



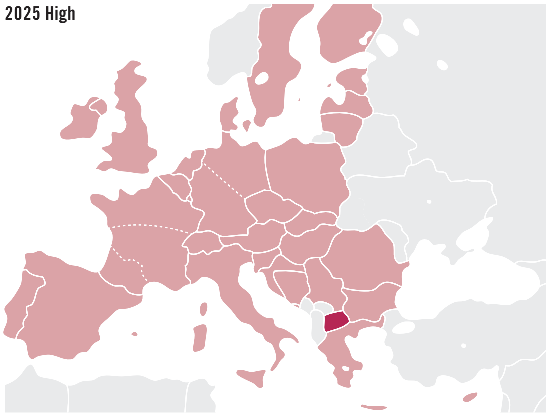
2020 High



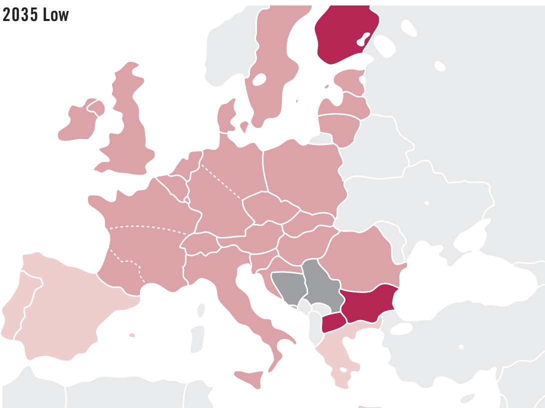
2025 Low



2025 High



2035 Low



2035 High

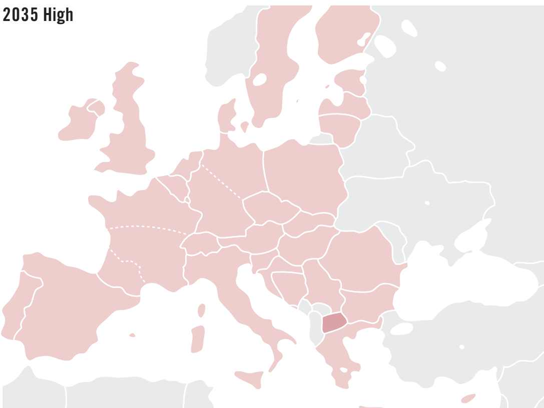


Figure 6.38: Evolution of the Gas Price Index comparison between Russian gas expensive and Reference price configurations Grey scenario

Green scenario

In 2015 Europe is uniformly impacted by an increase in the price of Russian gas imports. Difference with actual situation is explained by the assumptions of perfect market functioning and single price curve for Russian supply. However, the Baltic region, Bulgaria and FYROM are completely dependent on Russian gas and therefore showing the highest price exposure in comparison to the rest of Europe.

The high share of national production in Denmark, Sweden and Romania mitigates the influence of a Russian price increase. Situation differs for the Netherlands where a significant part of the national production is exported spreading its benefit while the country is importing non-EU gas.

Between 2020 and 2025 under the Low scenario, most of the countries are less impacted by the Russian price increase due to the improved availability of LNG. Most of the Baltic States are also able to benefit from this improvement due to the commissioning of LNG terminals. Ireland reduces its exposure due to an increase in national production.

Romania becomes as exposed as the other countries as it starts to need imports due to a decrease of national production. Hungarian exposure increases due to a higher gas demand.

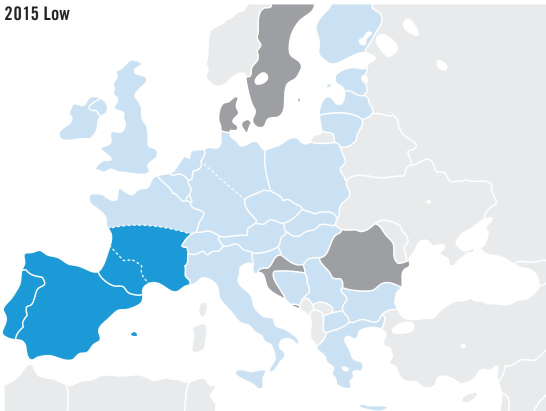
In 2035, the exposure of the whole of Europe increases under the effect of higher import needs and lower availability of alternative supplies with the exception of LNG. The limited interconnection capacity of the Iberian Peninsula with the rest of Europe maintains the predominance of LNG which limits the impact of the Russian price increase.

Under the High scenario, additional supplies and interconnection provide alternatives to Russian gas. As a result, the impact of a Russian gas price increase is uniformly spread across Europe. The Romanian Black Sea production benefits the whole region due to the associated interconnection projects. But it results at the same time in a price alignment of Romania with the other countries beyond 2020.

Grey scenario

In 2015, the situation is similar to the Green scenario. The lower level of demand in the Grey scenario results in a lower exposure of Romania lasting until 2025 in the Low infrastructure scenario. In 2035 compared to 2025 the lower demand reduces the impact of Russian gas price increases.

2015 Low

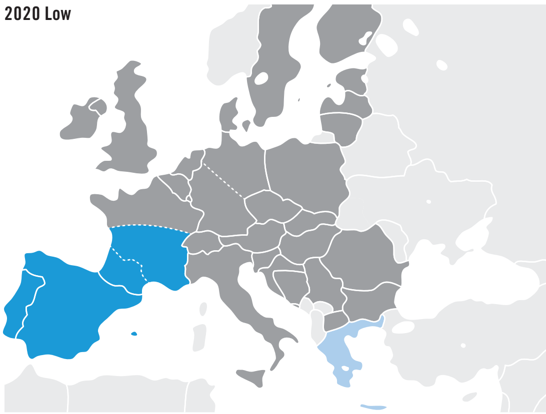


LNG expensive
Evolution of the GPI compared to the Reference price configuration

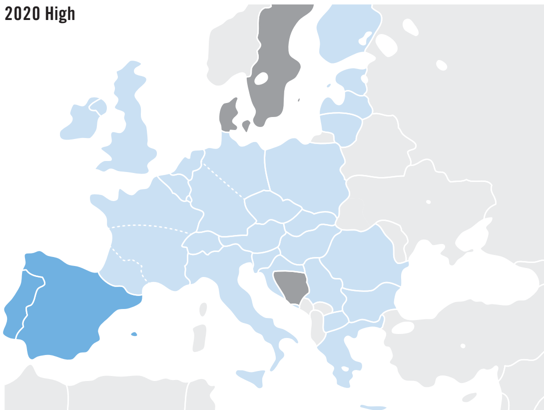
- > 10 %
- 8 % – 10 %
- 5 % – 8 %
- 3 % – 5 %
- 0 % – 3 %

Please take note that part of the benefits of Non-FID projects has already been considered in the decrease of the GPI of the Reference price configuration between Low and High scenarios. Therefore the level of the indicator for a given country should not be compared across the scenario but with the other countries for a given scenario.

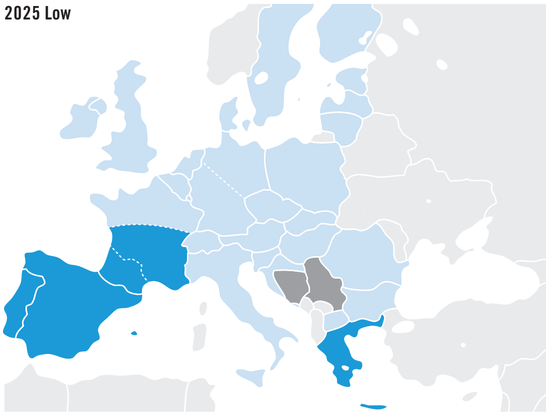
2020 Low



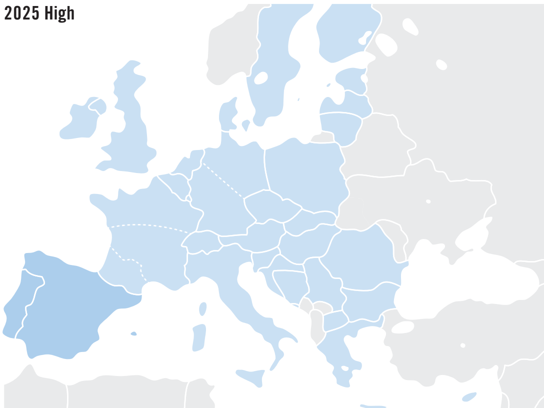
2020 High



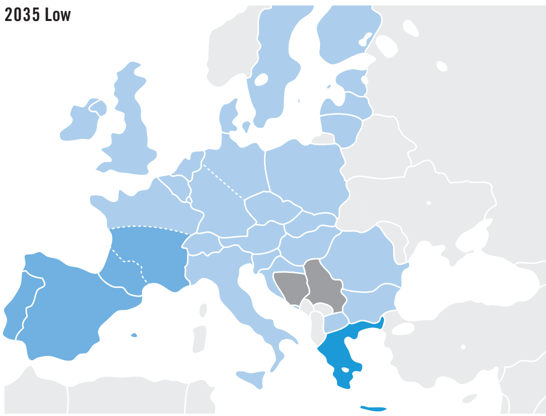
2025 Low



2025 High



2035 Low



2035 High

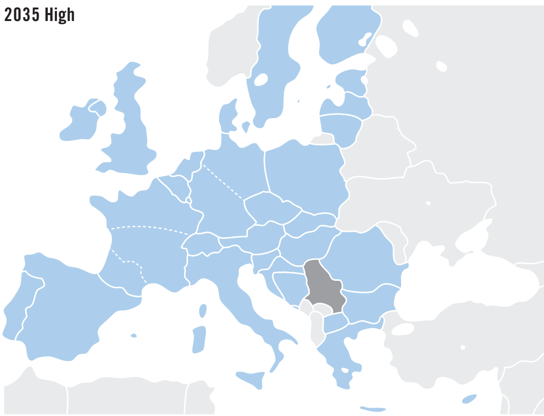
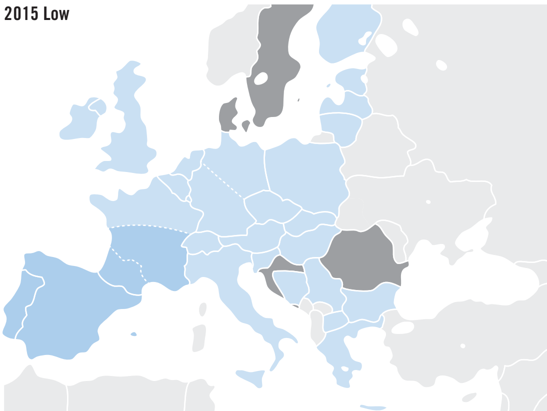


Figure 6.39: Evolution of the Gas Price Index comparison between LNG expensive and Reference price configurations
Green scenario

2015 Low

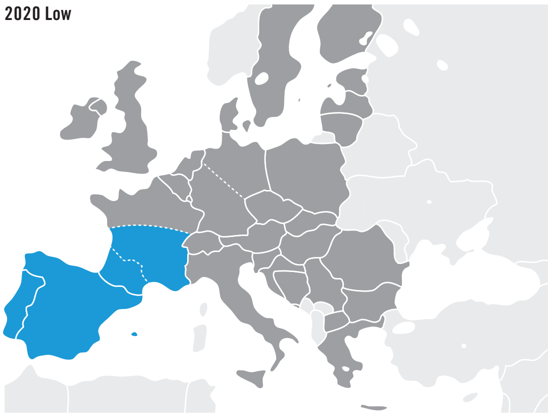


LNG expensive
Evolution of the GPI compared to the Reference price configuration

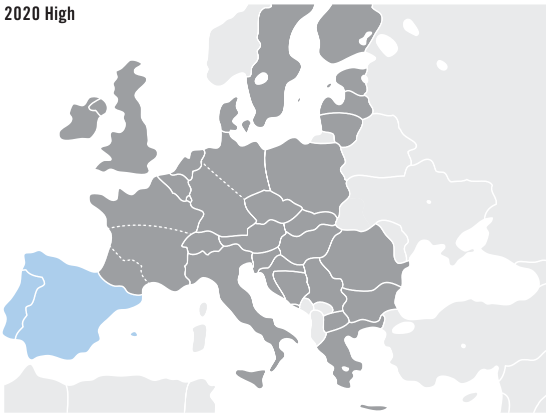
- > 10 %
- 8 % – 10 %
- 5 % – 8 %
- 3 % – 5 %
- 0 % – 3 %

Please take note that part of the benefits of Non-FID projects has already been considered in the decrease of the GPI of the Reference price configuration between Low and High scenarios. Therefore the level of the indicator for a given country should not be compared across the scenario but with the other countries for a given scenario.

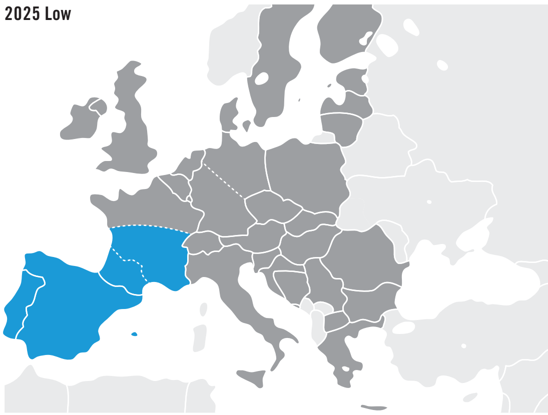
2020 Low



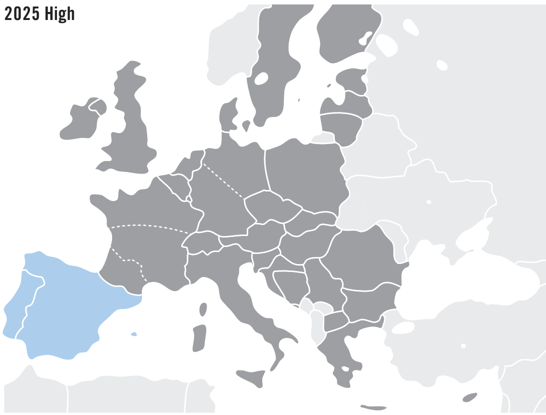
2020 High



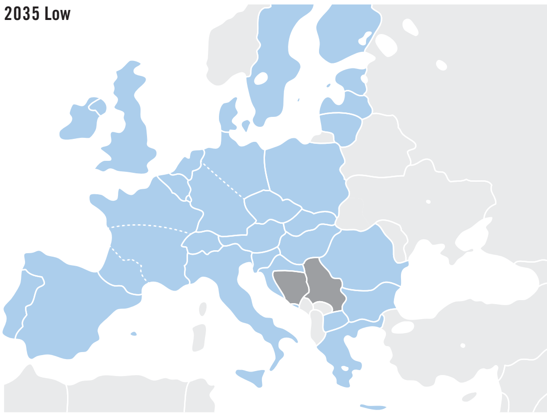
2025 Low



2025 High



2035 Low



2035 High

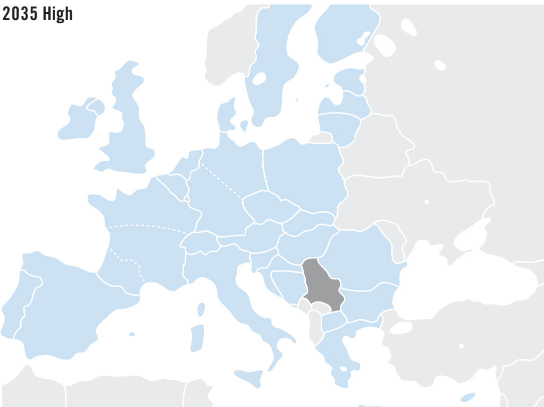


Figure 6.40: Evolution of the Gas Price Index comparison between LNG expensive and Reference price configurations
Grey scenario

Green scenario

For most of the EU countries, the impact of an increase of LNG price is very similar to the impact of an increase of Russian gas price. The exposure of countries not strongly dependent on LNG (see the Supply Source Price Dependence section) comes from both the minimum send-out associated with each LNG terminal and the price increase of alternative sources as their use increases.

In 2015, the whole Europe is slightly impacted by an increase in the price of LNG imports with the exception of the Iberian Peninsula and South of France where the price exposure is much higher. Due to their high national production and the limited export capability, Denmark, Sweden, Romania and Croatia are less impacted.

Between 2020 and 2025 under the Low scenario, most countries are less impacted by a LNG price increase due to the improved availability of Russian gas. The exceptions are Greece, because of a strong increase in demand, and for the Iberian Peninsula and South of France.

In 2035, the exposure of the whole of Europe increases under the effect of higher import needs and the lower availability of alternative supplies with the exception of Russian gas. It induces convergence with the South-Western Europe which was already strongly exposed to a rise in LNG price.

Under the High scenario, the additional supplies, delivered through the Southern Corridor (Cyprus and Romanian Black Sea production together with Azeri gas), help Greece to reduce its exposure to LNG price increase. The merger of French Zones and a better interconnection with the Iberian Peninsula reduce the strong dependence of this region on the LNG price. In 2035, the strong alignment of the whole Europe derives from the increasing exposure of all countries to LNG price.

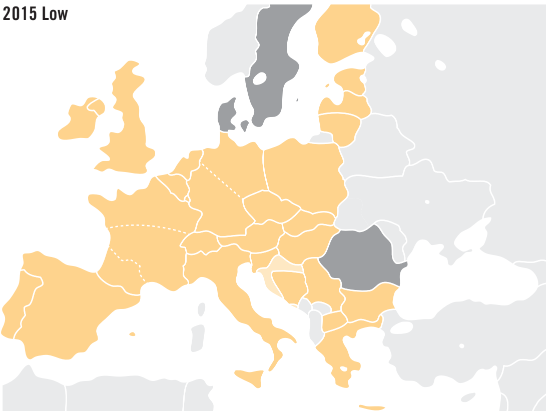
Grey scenario

The Situation is very similar to the Green scenario. The lower demand enables Europe, with the exception of the South-West region, to reduce its exposure to an increase in LNG price due to the availability of other supplies. This is highlighted for Greece, which has the same level of dependence as the rest of Europe.

The high level of market integration of countries receiving direct imports of Norwegian gas ensures their ability to mitigate the impact of a price increase of this source. As a result, the price reaction is uniformly spread across Europe even in case of no direct connection. This results from the increasing use of alternative sources. The only exceptions are countries with significant national production and low exports (Romania, Croatia, Denmark and Sweden as a side effect).

The impact of the Norwegian gas price is reducing over time due to its foreseen decreasing production levels.

2015 Low

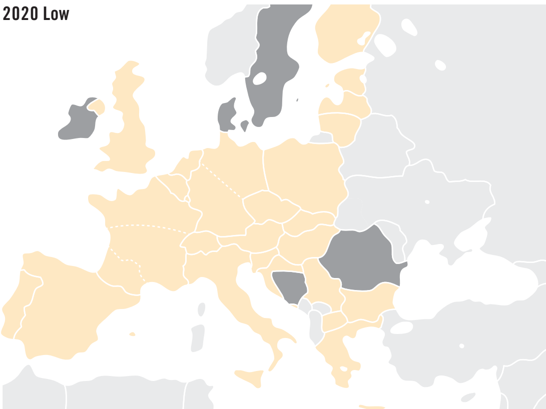


Norwegian gas expensive
Evolution of the GPI compared to the Reference price configuration

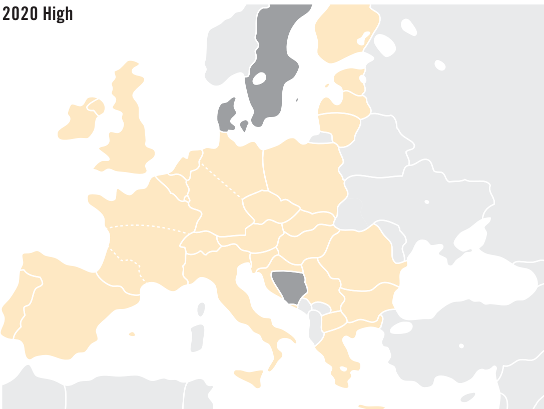
- > 10 %
- 8 % – 10 %
- 5 % – 8 %
- 3 % – 5 %
- 0 % – 3 %

Please take note that part of the benefits of Non-FID projects has already been considered in the decrease of the GPI of the Reference price configuration between Low and High scenarios. Therefore the level of the indicator for a given country should not be compared across the scenario but with the other countries for a given scenario.

2020 Low

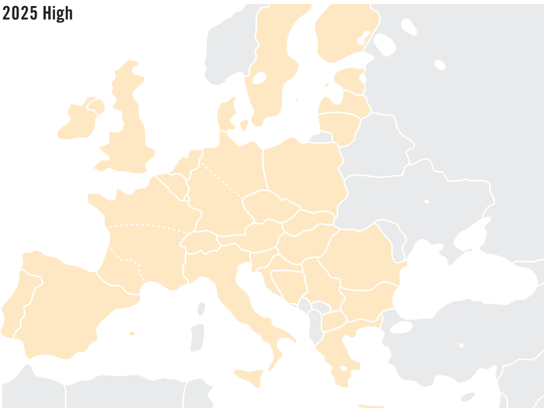


2020 High

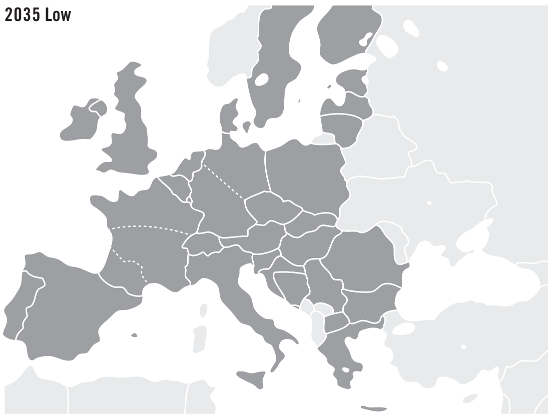


2025 Low

2025 High



2035 Low



2035 High

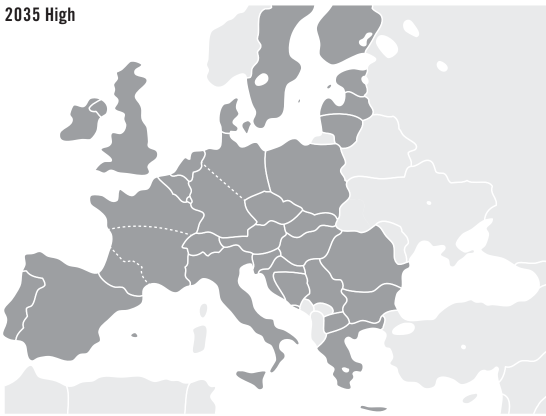


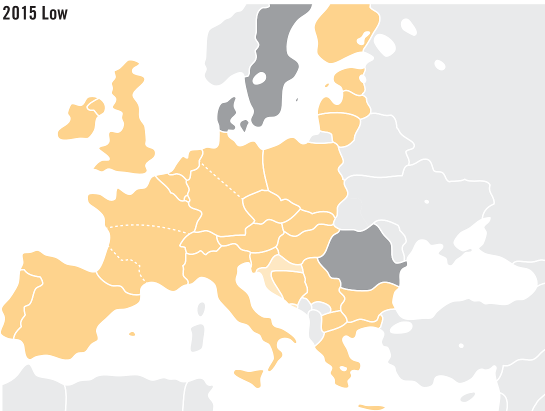
Figure 6.41: Evolution of the Gas Price Index comparison between Norwegian gas expensive and Reference price configurations Green scenario

Norwegian gas expensive
Evolution of the GPI compared to the Reference price configuration

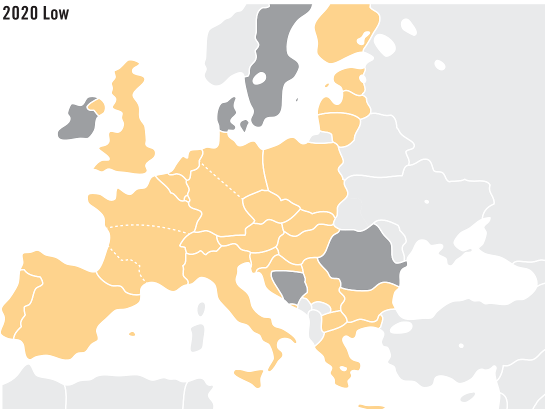
- > 10 %
- 8 % – 10 %
- 5 % – 8 %
- 3 % – 5 %
- 0 % – 3 %

Please take note that part of the benefits of Non-FID projects has already been considered in the decrease of the GPI of the Reference price configuration between Low and High scenarios. Therefore the level of the indicator for a given country should not be compared across the scenario but with the other countries for a given scenario.

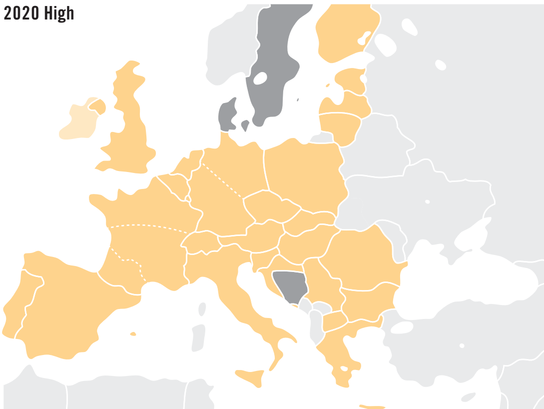
2015 Low



2020 Low

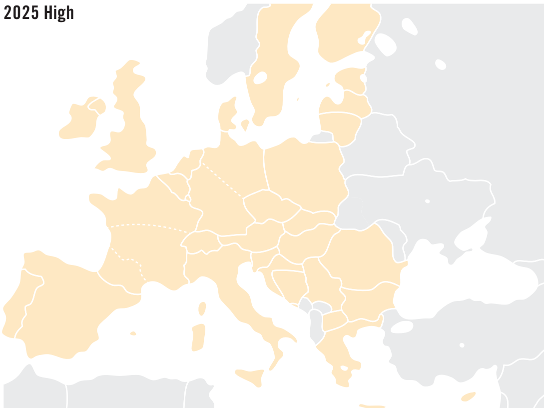


2020 High

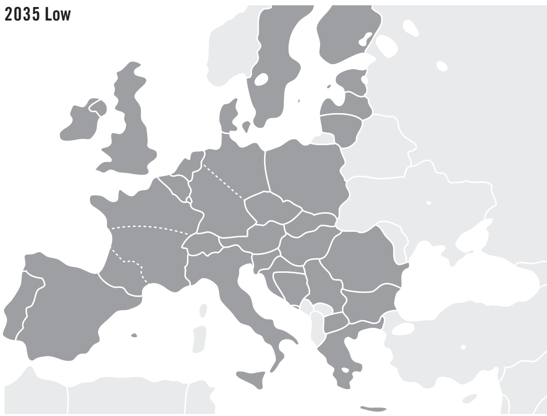


2025 Low

2025 High



2035 Low



2035 High

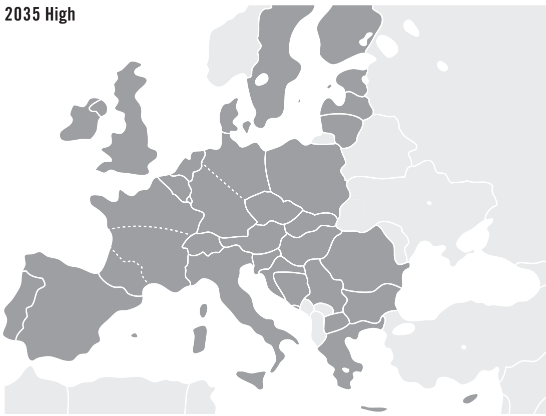


Figure 6.42: Evolution of the Gas Price Index comparison between Norwegian gas expensive and Reference price configurations Grey scenario

6.6 Price convergence

Price convergence measures the difference in marginal prices of gas for each of the Zones as resulting from the modelling of each price configuration, compared to the median of the marginal prices for all Zones. Results are presented for the Average Winter day, as this is when the highest price differentials are likely to occur. The marginal price for each Zone, climatic case and price configuration can be found in Annex E.

The only price divergences have been identified for the "LNG" and "Russian expensive" gas price configurations. The following maps show for each case the median marginal price and the deviation of each country to this value.

The high level of price convergence identified through the TYNDP modelling may appear inconsistent with experience of actual market prices. Nevertheless, price convergence is already observed along a diagonal from Ireland-UK to Italy-Austria.

Under the Russian expensive price configuration the strong price convergence across Europe derives from:

- The assumption of a full implementation of European regulation ensuring the move of gas along price signals (which is valid for every price configuration)
- The use of a single price for a given supply source independently of the import routes
- The fact that Russian gas sets the marginal supply for the whole Europe except for the Iberian Peninsula

In fact when a supplier is in a dominant position it is likely he will set a price higher than the average price. The supply dependence and diversification analysis helps to identify those markets where a supply source has a predominant role.

The extremely high premium appearing in Bosnia-Herzegovina, Serbia and Greece (only in 2035 Green and Low scenarios for the latter) results from their inability to meet demand. Part of demand curtailment in Greece derives from the very high share of gas-fired power generation estimated in line with the Vision 3 of ENTSO-E.

For the Green scenario starting in 2025, the implementation of Non-FID projects and additional supply sources enable Europe to strongly mitigate the increasing exposure to an increase of Russian gas price.

Under the LNG expensive price configuration the assessment replicates the observed premium between the North and South Zone in France. This situation derives from the strong role of LNG supply for the Iberian Peninsula and the South of France, as well as for Greece, and the lack of interconnection of these regions with the rest of Europe.

Under the Low scenario the European price convergence appearing in 2025 for the Green scenario results from the fact that LNG is setting the marginal price of every country as an effect of an increased need of imports. Such configuration only appears in 2035 for the Grey scenario.

Under the High Scenario, better interconnection and new supply enable most of Europe to temporary (2025 in Green scenario and 2025 to 2035 in Grey scenario) reduce LNG influence at the exception of Iberian Peninsula.

The strong discount observed in Romania in 2015 under the Grey Scenario is explained by the indigenous production which is sufficient to meet the winter average demand case.

Figure 6.43: Price convergence. Deviation from the median of the marginal prices for all Zones in the price scenario "Russia expensive". Green scenario

Figure 6.44: Price convergence. Deviation from the median of the marginal prices for all Zones in the price scenario "Russia expensive". Grey scenario

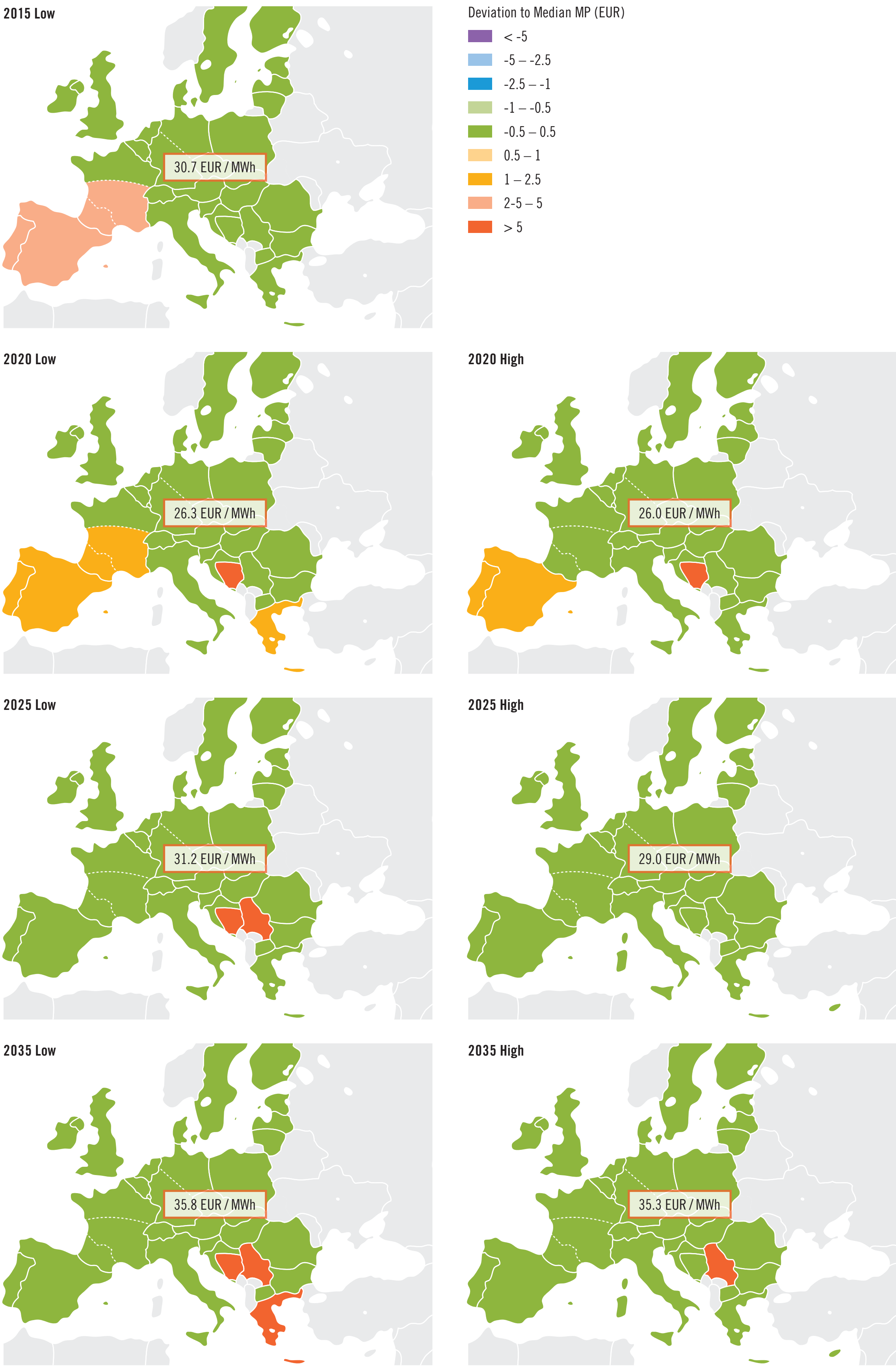


Figure 6.45: Price convergence. Deviation from the median of the marginal prices for all Zones in the price scenario "LNG expensive". Green scenario

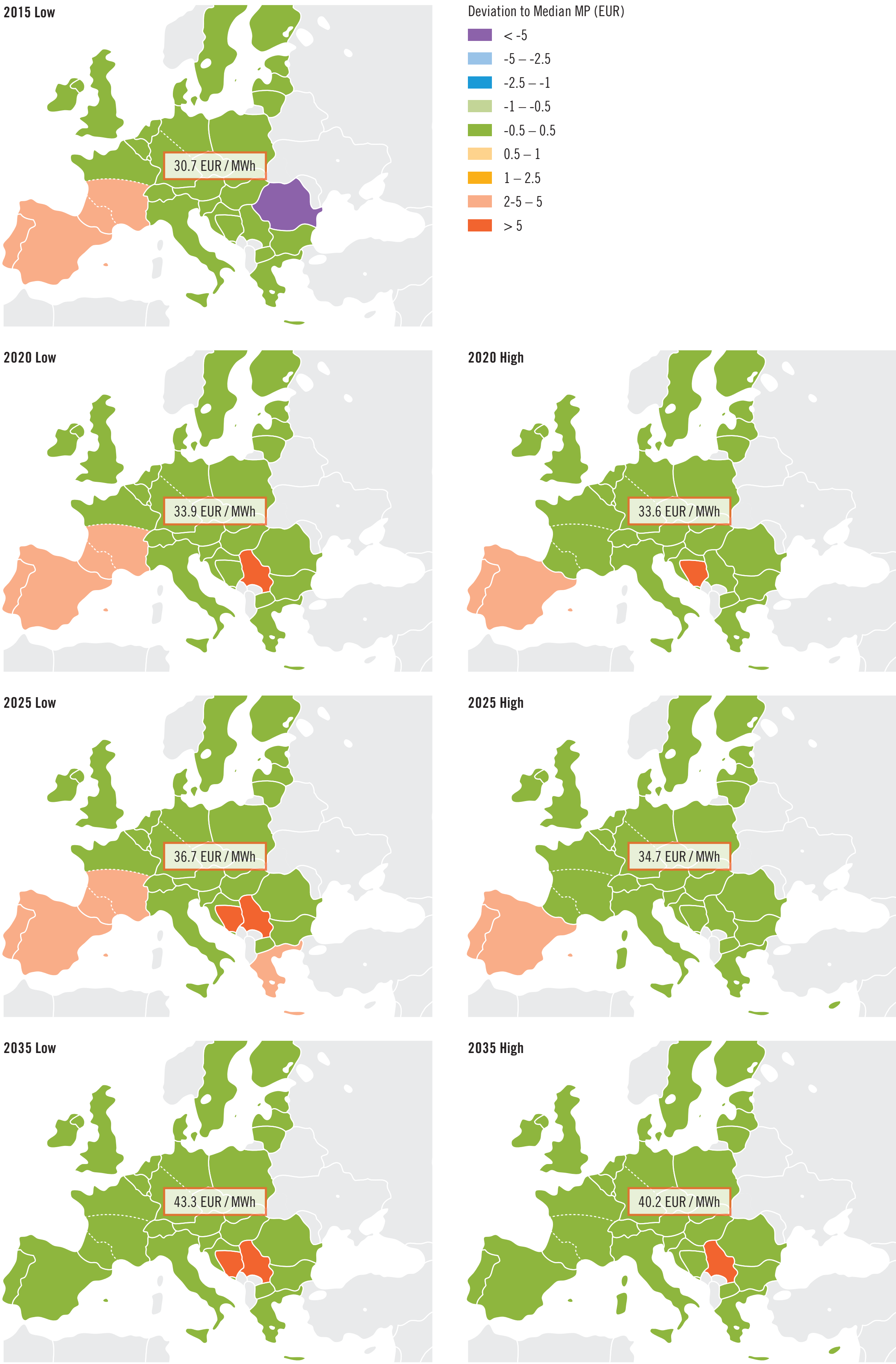


Figure 6.46: Price convergence. Deviation from the median of the marginal prices for all Zones in the price scenario "LNG expensive".Grey scenario

6.7 Analysis of the PCI Infrastructure scenario

The assessment carried out under the PCI infrastructure scenario intends to assess the overall impact of the potential commissioning of all PCIs resulting from the first selection round.

This scenario captures the cumulative impact of all existing PCI and their overall interaction whether positive (synergy) or negative (competition). The detailed results for each indicator can be found in the Annex E. The main differences with the High Infrastructure scenario are highlighted in this section.

6.7.1 GENERAL TREND IN SUPPLY

Considering that many of the Non-FID projects obtained the PCI label, the assessment results are similar to those of the High Infrastructure scenario. Nevertheless, a significant part of the additional indigenous production (shale gas, biogas and conventional production in Romanian Black Sea), which is included in the High Infrastructure scenario, is not considered in the PCI Infrastructure scenario. As a result the need for imports is around 30 % higher than in the High Infrastructure scenario.

6.7.2 INFRASTRUCTURE RESILIENCE

The implications of the demand disruption under the 1-day Design Case and 2-week Uniform Risk can be explained as follows:

- Sweden and Finland, whose demand evolution is expected to be supported by the development of biomethane, suffer from the same disruption compared to the Low Infrastructure scenario.
- In the case of an Ukraine disruption, there are no PCI sufficient to significantly mitigate the impact on South-East Europe other than Greece. Only the development of Romanian Black Sea supplies and their distribution in the region can have sufficient effect.
- PCIs resulting from the first selection round would have been able to completely mitigate the disruption of the transit of Russian gas through Belarus.

As the new Remaining Flexibility indicator considers the potential supply limitation, the main improvement at European level results from the additional supplies in the High Infrastructure scenario.

6.7.3 INFLUENCE OF THE SUPPLY SOURCES

The existing selection of PCIs would be able to significantly reduce the physical dependence of Baltic region, Central-Eastern and South-Eastern Europe on Russian gas and South-West Europe (Iberian Peninsula and South of France) on LNG. At the end of the TYNDP time horizon, the physical dependence of the whole of Europe can only be mitigated with the additional supplies considered in the High Infrastructure scenario.

Regarding the price dependence, there is no significant difference between the PCI and High Infrastructure scenarios. The only exception is the dependence on Russian gas under the Green scenario, where it is 10 % to 20 % higher than in the High Infrastructure scenario. This is due to the tighter supply situation combined with the higher gas demand under the Green scenario.

Regarding the price diversification, the additional indigenous production under the High Infrastructure scenario reduces the need for cross-border flows in a number of countries, therefore it is more meaningful to compare the PCI and Low infrastructure scenarios. In these two scenarios, the diversification towards Russian gas and especially LNG improves.

6.7.4 MONETIZATION

The CBA methodology applies a discount to the indigenous production price, in order to reflect the producers' benefit materialized within Europe, therefore the EU gas bill is significantly higher in the PCI Infrastructure scenario compared to the High Infrastructure scenario.

Image courtesy of Fluxys

6.8 Conclusion

Compared to previous TYNDP editions, ENTSOG has further developed its assessment methodology through the improvement of the modelling approach, the introduction of commodity prices, new scenarios and indicators. At the same time, comparability with previous reports (TYNDPs, Supply Outlooks and GRIPs) has been preserved. Results are consistent with previous TYNDP assessments for the first part of the considered period.

The results confirmed that most of Europe would benefit from a high level of infrastructure-related market integration and thus competitive position and secure supply, however, some areas are still isolated or not sufficiently interconnected. As a result, they suffer from both a lack of system resilience and diversification. This illustrates the link between security of supply and competition. For example, the Eastern part of Europe is still highly dependent on Russian supply from both physical and price perspectives. The same applies to South-Western Europe for LNG supplies. The Non-FID projects submitted by promoters have the potential to complete the market integration of Europe.

The situation changes beyond 2025 with a smaller gap between expected supply and demand especially under the Green scenario. The dependence on Russian gas, and to a lesser extent on LNG, is growing over the whole of Europe. This indicates that only new supplies would prevent Europe becoming more dependent on Russian gas and LNG. Otherwise Europe, as a price taker, will have limited power to influence gas prices.

Potential new sources of gas exist such as new conventional gas areas, shale gas and biomethane. Barents Sea production can also mitigate this increasing dependence if supplied to Europe through existing grid instead of being exported as LNG. Producers in North Africa, Middle-East and Caspian regions are in the same situation with significant upstream and exporting investments required before they can deliver additional volumes to Europe. All investments suffer from the current uncertainty on the role of gas in the EU energy mix. Natural gas has the potential to guarantee a well-supplied market and to be more than a bridging-fuel. The lack of recognition of such a potential hinders the triggering of new investment decisions in capital intensive long lifetime assets. Timely decisions are necessary to establish a fully developed internal gas market. Delayed investment decisions, given the lead time before project commissioning, would mean that the current situation will continue to deteriorate even with a stagnant gas demand.

Finally, gas power generation and the associated infrastructure have the potential to complement different levels of development and use of RES power generation, but new gas infrastructure will not significantly modify the competiveness of gas against coal without changes to energy policy. Only projects connecting new markets will induce the replacement of oil and LPG by gas in power generation. Only global market conditions and political action can enable Europe to take full benefit of gas as the best partner of RES.


Image courtesy of National Grid

7 Conclusions

- Introduction
- Stakeholder engagement process
- From projects to commissioned infrastructure
- A stable demand driven by global context
- Europe needs to enlarge its supply portfolio
- Market integration, a constant challenge
- Way forward

Image courtesy of Gasum

7.1 Introduction

This fourth edition of the Union-wide Ten-Year Network Development Plan demonstrates the experience gained by ENTSOG since its establishment back to 2009. The fundamental objectives stay the same, analysing the long term supply and demand adequacy and the consistent development of infrastructures, but the methodology has been strongly enhanced.

At the same time it confirms the benefit and challenges faced by European gas infrastructures in supporting the completion of the three pillars set by the EU Energy Policy (Security of supply, Competition and Sustainability).

The infrastructure-related market integration of the European gas system has been already achieved for consumers in many regions even if its benefits are sometimes not fully materialized due to a still ongoing and progressive implementation of market rules. Such achievements should not hide that some regions are still isolated or insufficiently interconnected with the European gas system.

7.2 Stakeholder engagement process

As for previous editions, this TYNDP is based on a consultation process with stakeholders and institutions as well as comments and the ACER opinion received on TYNDP 2013. In addition this TYNDP duly covers the CBA methodology as required by the TEN-E Regulation.

ENTSOG launched an integrated process (six Stakeholder Joint Working Sessions and two public workshops) to ensure a consistent development of the TYNDP and the CBA methodology. This process was based on three priorities:

- further consistency between the TYNDPs of ENTSOG and ENTSO-E
- consideration of prices in order to prepare the CBA methodology
- a better analysis of infrastructure project submission.

This process has supported the refinement of the TYNDP concept and has helped to build the required input dataset. The further improvement of the scenarios will be one of the main challenges of the next TYNDP edition.

7.3 From projects to commissioned infrastructure

The Infrastructure chapter shows that promoters strongly support infrastructure projects (transmission, UGS or LNG terminals). This is in line with EU energy policy which sets infrastructures as a main requirement for the completion of the Internal Energy Market.

As a result, projects from the Baltic region, Central-Eastern and South-Eastern Europe represent a significant share of all projects and this also reflects the share of investment needs in these countries. Nevertheless this political willingness, especially under uncertain conditions, is not sufficient to trigger the required investments.

The analysis of responses received from promoters related to investment barriers helps to better understand the current situation. The most recurrent answers refer to political and regulatory conditions. Gas infrastructure is a capital intensive investment which requires a long term visibility on transported volume to support final investment decision on the basis of project profitability. Unfortunately, the role of gas in the EU energy mix does not provide sufficient certainty to project promoters.

In addition, the current focus is rather on day-ahead market and excessive pressure on regulated tariff when at the same time the European regulatory framework is still not fully implemented. This undermines the economic benefits of market integration and does not provide appropriate incentives to trigger necessary projects for the future gas market. As a result there is an increasing trend to rely on political actions and co-financing to launch new investments. Unfortunately, this does not guarantee the long term attractiveness of the European market to producers.

The TEN-E Regulation could improve this situation and would be able to ensure the timely delivery of key infrastructures. ENTSOG is committed in this process with the development of the CBA methodology, its implementation and to give support to project promoters and Regional Groups. However, this bundle will have no effect when the environmental benefits of gas are not recognized and a sufficient share of gas in the European energy mix cannot be ensured.

7.4 A stable demand driven by global context

The evolution of gas demand is the main source of uncertainty for the gas industry. For this purpose ENTSOG has developed for the first time two demand scenarios reflecting different situations:

- a Green scenario reflecting positive economic situation, commodity prices favouring gas against coal and a strong development of RES power generation requiring the parallel development of flexible generation
- a Grey scenario reflecting an opposite situation

Considering that since 2010, European gas demand has continuously decreased mostly under the effect of a reduced share of gas for the power generation, particular attention was paid to the modelling of this sector. Therefore ENTSOG has developed an approach, based on ENTSO-E data, defining the share of gas for power generation on the basis of the electricity demand, generation mix and prices of gas, coal and CO_2. The Green scenario starts with a higher demand level. Then both scenarios show an average growth rate of about 0.4 % per year on the 21-year time horizon.

Image courtesy of Gasum

7.5 Europe needs to enlarge its supply portfolio

The Supply chapter investigates the possible evolution of indigenous production and import sources. The background of each source and the rationales of each scenario used in the assessment have been further developed with a special attention on LNG.

From an overall perspective the supply adequacy risks to become tighter along the time horizon and the Intermediate supply scenarios of the considered sources could no longer be sufficient to balance demand.

The main driver of such tight situation is the clear downward trend of indigenous production when compar ed to gas demand evolution. The large-scale development of new sources being conventional or shale gas together with biogas could strongly mitigate the decrease and thus limit the need of new imports.

Under current perspective the expected gas from North Africa, the Caspian region and potentially Middle-East will have mostly a regional influence and need stronger market and political signals to be of European relevance. At the same time Norwegian pipe gas export to Europe will certainly start to decline as early as 2025. Such decrease could be mitigated by the connections of Norwegian Barents Sea fields to the existing offshore network. However, this would also require strong signals from the European market.

In absence of such signals these producers might export gas to the global LNG market and will not support the diversification of the European gas supply. This would leave Europe mainly with Russian gas and LNG to compensate the strong decrease of European production. In such case Europe would be in the difficult situation of having limited control on the price of imported gas.

Such perspective should not be perceived as irreversible as sufficient gas reserves exist in European and surrounding regions to ensure a more diversified supply. Europe can benefit from those if it sends the appropriate message about the role of gas in the EU energy mix.

7.6 Market integration, a constant challenge

ENTSOG has implemented in this TYNDP the CBA methodology published in summer 2014 and approved by the European Commission in February 2015. It brings further the concept of infrastructure-related market integration capturing its benefits through a new series of indicators.

These indicators aim at signalling the availability and origin of supply and identify possible lack of infrastructures. As required by the TEN-E Regulation indicators now also cover the price dimension of gas, coal and CO_2 emissions.

For 2015, results confirm that market integration is a reality for a large part of Europe. This is confirmed by the actual price convergence in large part of Western Europe as well as the increasing price correlation across the continent. In fact the effect could be more visible if the European regulatory framework would be fully implemented. Nevertheless other regions suffer from a lack of sufficient integration or even from isolation. Such situation translates into high supply dependence on Russian gas in the Baltic region, Central-Eastern and South-Eastern Europe and to LNG in the Iberian Peninsula and South of France. The Baltic region and South-Eastern Europe are still vulnerable to a disruption of the transit of Russian gas through Belarus and/or Ukraine.

On the medium term the commissioning of already decided project will slightly improve the situation. But many more investment decisions are required to have an Integrated Energy Market covering all EU Member States.

After 2025 the situation changes, especially under the Green demand scenario, with a much tighter supply and demand balance. The whole Europe would then risk to become strongly dependent on both Russian gas and LNG. Given Europe situation of price-taker on the LNG market, it would put the continent under the influence of few external producers. This situation is consistent with the overall supply adequacy as analysed in the Supply chapter. Only access to new indigenous or pipe-bound sources will mitigate this dependence.

Image courtesy of FluxSwiss

7.7 Way forward

Since the first edition of the Union-Wide Ten Year Network Development Plan, ENTSOG is pursuing the same objective of assessing the long term adequacy of gas supply and demand and the consistent development of gas infrastructures.

The TYNDP is a living organism and each edition differs from the previous one. The same will happen with the next edition as it will look two further years ahead and will have to meet new expectations coming from an evolving market. Further influences are expected from the full implementation of the new network codes and new regulatory requirements.

From a regulatory perspective next TYNDP edition will have to cover the long term monitoring of gas quality as defined under the Network Code on Interoperability and Data Exchange. The feedback of the second selection of PCI, based on TYNDP, will certainly also provide ground for improvement of the methodology. Finally the ongoing discussion on the review of the Regulation on Security of Supply could impact the role of ENTSOG in the assessment of the European gas system.

The TEN-E Regulation has also set to ENTSOs the objective of defining a joint gas and electricity network and market model. Both associations have already accomplished a big step in that direction with the modelling in this TYNDP of the gas demand for power generation based on ENTSO-E and market data.

ENTSOG hopes that the public consultation on this Report will confirm it meets stakeholders and institutions key expectations. At the same time, it will give a view on the future challenges to be taken up by ENTSOG. The same will go with the ACER opinion on the report.

This constant evolution gives a predominant role to the consultation process which has multiple purposes, all of the same importance. First it ensures the adequacy of the TYNDP concept with stakeholder expectations and regulatory requirements which often requires the definition of a consensus among diverging views. Then it is supporting the elaboration of the methodology where the right balance should be defined between complexity and comprehensibility. Finally it should enable the sharing of information between market players and institutions in order to define the necessary data set which has a strong influence on the quality of the assessment.

Experience has proven that the last two objectives are difficult to achieve. Every stakeholder has his own expectations regarding the TYNDP, therefore compromise has to be reached on the scope of the report. Then the improvement of the methodology has required the use of data beyond TSO remit such as commodity prices or supply availability. On this point little feedback has been received from stakeholders on the ENTSOG default proposal even if the selection of scenarios has as much importance as the methodology itself.

Therefore every reader is invited to engage in discussions with ENTSOG on the way to improve the report and to prepare challenges ahead. ENTSOG will provide many opportunities to do so through public consultation, workshops and Stakeholder Joint Working Sessions. Specific proposals to improve the methodology and the dataset will be particularly appreciated.

Image courtesy of Enagás

Definitions

1-day Design Case (1-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.

14-day Uniform Risk (14-UR) 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.

Biomethane Biogas produced from biomass and waste which has been upgraded to natural gas quality for the purpose of grid injection.

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.

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.

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.

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.

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.

GHG Greenhouse gases.

Green Is a global context under which modelling takes place with the following assumption:
The price scenarios of gas, coal, oil and CO_2 correspond to the "Gone Green" projection in the UK Future Energy Scenarios 2014 from National Grid which is consistent with:

- a high price of CO_2 emissions due to the introduction of a carbon tax
- a continuous reduction in the oil-price linkage mitigating the increase of gas price

Grey Is a global context under which modelling takes place with the following assumption:
The price scenarios of gas, coal, oil and CO_2 correspond to the Current Polices Scenario from the IEA World Energy Outlook 2013 which is consistent with:

– lower price of CO_2 emissions as no new environmental political commitments are taken

– high energy prices following higher energy demand in absence of new efficiency policies but with prices still too low to trigger the development of renewables

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.

LDV Light Duty Vehicles.

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.

NERAP National Energy Renewable Action Plans.

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.

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 and gas supply, gas infrastructures, fuel prices and global context occur.

Shale gas	Natural gas that is trapped within shale formations. For modelling purposes it is only considered under the High Infrastructure Scenario.
Situation	Situation means a combination of conditions and circumstances relating to a particular occurrence of demand or supply, or both. Such conditions and circumstances may relate to e.g. time duration, climatic conditions, or infrastructure availability.
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 defined through three scenarios: Maximum, Intermediate and Minimum. Supply Potentials for a supply source have been developed independently with no assessment on the likelihood of their occurrence.
Supply Stress	Supply situation which is marked by an exceptional supply pattern due to a supply disruption. Specific Supply Stress situations have been defined in section 3.8. 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).
UGS	Underground Gas Storage.
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.
Zone	A balancing zone at which level the market shall balance gas demand and supply.

Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
bcm	Billion normal cubic meters (normal cubic meter (Nm^3) refers to m3 at 0°C and 1.01325 bar)
CIS	Commonwealth of Independent States
CS	Compressor Station
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.
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
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
GLE	Gas LNG Europe
GSE	Gas Storage Europe
GWh	Gigawatt hour
GWhe	Gigawatt hour electrical
IEA	International Energy Agency
IP	Interconnection Point
ktoe	A thousand tonnes of oil equivalents. 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
LNG	Liquefied Natural Gas
mcm	Million normal cubic meters (normal cubic meter (Nm^3) refers to m^3 at 0°C and 1.01325 bar)
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
NCV	Net Calorific Value
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
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
SoS	Security of Supply
Tcm	Terra cubic meter
TSO	Transmission System Operator
TWh	Terawatt hour
TYNDP	Ten-Year Network Development Plan
UGS	Underground Gas Storage (facility)

Country Codes (ISO)

AL	Albania
AT	Austria
AZ	Azerbaijan
BA	Bosnia 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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List of Annexes

All Annexes are available as PDF or Excel-file on the USB-card or on www.entsog.eu/publications/tyndp

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